ORIGINAL

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF	)	
BIG RIVERS ELECTRIC CORPORATION	)	Case No.
FOR ENFORCEMENT OF	)	2019-00269
RATE AND SERVICE STANDARDS	)	

Responses to Commission Staff's Initial Request for Information dated May 19, 2020

FILED: June 8, 2020

ORIGINAL

BIG RIVERS ELECTRIC CORPORATION

ELECTRONIC APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR ENFORCEMENT OF RATE AND SERVICE STANDARDS CASE NO. 2019-00269

VERIFICATION

I, Robert W. ("Bob") Berry, verify, state, and affirm that the data request responses filed with this verification for which I am listed as a witness are true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

Robert W Berry

Robert W. ("Bob") Berry

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by Robert W. ("Bob") Berry on this the 8th day of June, 2020.

Joy P. Parsley

Notary Public, Kentucky State at Large

My Commission Expires ______________

Notary Public, Kentucky State-At-Large
My Commission Expires: July 10, 2022
ID: 604480

BIG RIVERS ELECTRIC CORPORATION

ELECTRONIC APPLICATION OF
BIG RIVERS ELECTRIC CORPORATION
FOR ENFORCEMENT OF RATE AND SERVICE STANDARDS
CASE NO. 2019-00269

VERIFICATION

I, Michael W. ("Mike") Chambliss, verify, state, and affirm that the data request responses filed with this verification for which I am listed as a witness are true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

Michael W. Chambliss

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Michael W. ("Mike") Chambliss

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by Michael W. ("Mike") Chambliss on this the 8th day of June, 2020.

Joy P. Parsley

____
Notary Public, Kentucky State at Large

My Commission Expires ______________

Notary Public, Kentucky State-At-Large
My Commission Expires: July 10, 2022
ID: 604480

BIG RIVERS ELECTRIC CORPORATION

ELECTRONIC APPLICATION OF
BIG RIVERS ELECTRIC CORPORATION
FOR ENFORCEMENT OF RATE AND SERVICE STANDARDS
CASE NO. 2019-00269

VERIFICATION

I, Mark J. Eacret, verify, state, and affirm that the data request responses filed with this verification for which I am listed as a witness are true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

Mark J. Eacret

____
Mark J. Eacret

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by Mark J. Eacret on this the 8th day of June, 2020.

Joy P. Parsley

____
Notary Public, Kentucky State at Large

My Commission Expires ______________

Notary Public, Kentucky State-At-Large
My Commission Expires: July 10, 2022
ID: 604480

BIG RIVERS ELECTRIC CORPORATION

**ELECTRONIC APPLICATION OF
BIG RIVERS ELECTRIC CORPORATION
FOR ENFORCEMENT OF RATE AND SERVICE STANDARDS
CASE NO. 2019-00269**

VERIFICATION

I, Jeffrey T. ("Jeff") Kopp, verify, state, and affirm that the data request responses filed with this verification for which I am listed as a witness are true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

Jeffrey T Kopp

Jeffrey T. ("Jeff") Kopp

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by Jeffrey T. ("Jeff") Kopp on this the 8th day of June, 2020.

Joy P. Parsley

Notary Public, Kentucky State at Large

My Commission Expires ________

Notary Public, Kentucky State-At-Large
My Commission Expires: July 10, 2022
ID: 604480

BIG RIVERS ELECTRIC CORPORATION

ELECTRONIC APPLICATION OF
BIG RIVERS ELECTRIC CORPORATION
FOR ENFORCEMENT OF RATE AND SERVICE STANDARDS
CASE NO. 2019-00269

VERIFICATION

I, Michael T. ("Mike") Pullen, verify, state, and affirm that the data request responses filed with this verification for which I am listed as a witness are true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

Michael T. Pullen
____
Michael T. ("Mike") Pullen

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by Michael T. ("Mike") Pullen on this the 8th day of June, 2020.

Joy P. Parsley
____
Notary Public, Kentucky State at Large

My Commission Expires ______________

Notary Public, Kentucky State-At-Large
My Commission Expires: July 10, 2022
ID: 604480

BIG RIVERS ELECTRIC CORPORATION

ELECTRONIC APPLICATION OF
BIG RIVERS ELECTRIC CORPORATION
FOR ENFORCEMENT OF RATE AND SERVICE STANDARDS
CASE NO. 2019-00269

VERIFICATION

I, Paul G. Smith, verify, state, and affirm that the data request responses filed with this verification for which I am listed as a witness are true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry,

Paul Smith
____
Paul G. Smith

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by Paul G. Smith on this the 8th day of June, 2020.

Joy P. Parsley
____
Notary Public, Kentucky State at Large

My Commission Expires ______________

Notary Public, Kentucky State-At-Large
My Commission Expires: July 10, 2022
ID: 604480

**ELECTRONIC APPLICATION OF
BIG RIVERS ELECTRIC CORPORATION
FOR ENFORCEMENT OF RATE AND SERVICE STANDARDS
CASE NO. 2019-00269**

**Response to Commission Staff's
Initial Request for Information
dated May 19, 2020**

June 8, 2020

Item 1) ***Refer to the application, paragraph 14, and the informal conference memorandum filed into the record on March 9, 2020.***

a. Provide an update to the negotiations between the parties in this proceeding and identify the issues upon which the parties are in agreement and those which they are not in agreement with respect to BREC's application and the proposed Settlement Agreement, as of this date.

b. Identify and explain all decommissioning costs BREC is proposing to recover, the source of the proposed costs, and provide any studies, appraisals, etc., related thereto.

Response)

a. Henderson has been inconsistent on the extent to which it agrees or disagrees with Big Rivers' positions. For example, Henderson has stated:

> We do believe we are obligated for the long-term remediation of the ash pond, and that the costs should be allocated according to the capacity split (approximately 22/78 percent). We also believe that we are obligated on the asbestos remediation, again on the same split. I believe that these items should be addressed

separately from out agreement to close the plant early, and purchase bridge power.

See: Email from Chris Heimgartner to Bob Berry dated August 10, 2018, attached as Exhibit Pullen-3 to the Direct Testimony of Michael T. Pullen in this case. Henderson has since taken the position that it is not obligated on the asbestos remediation, that Big Rivers' calculation of the capacity split is incorrect, and that asbestos remediation should be addressed separately from other issues. And while Henderson continues to acknowledge it is responsible for a share of the ash pond costs, Henderson now claims that its share of those costs is 18.87%.

Henderson has stated that Henderson has no objection to Big Rivers' continued use of joint-use facilities in accordance with terms of the Station Two Contracts. The parties appear to disagree on all other issues set forth in Big Rivers' Application. Also, aside from discussions about who is responsible for closure of the ash pond, no negotiations are currently taking place between the parties.

b. Until such time that dismantling and final decommissioning occurs, Big Rivers seeks to recover the costs associated with maintaining Station Two in a safe condition.

The scope of the decommissioning includes asbestos removal; dismantling the boilers, steam turbine, precipitators, scrubbers, selective catalytic reactors, stacks, and transformers; on-site concrete crushing and disposal; debris removal; less salvage value for the scrap metal. The joint-use facilities listed on page 1 of 2 of Exhibit Pullen-13 to my Direct Testimony (with the exception of Item 15 – Station Two Ash Pond Dredgings in Green Station Sludge Disposal Landfill adjacent to Green River South of Green Station) also need to be decommissioned at this time. The scope also includes decommissioning of the cooling water intake, grounds, fuel oil storage, balance of plant buildings, coal handling facilities and coal yard, and final grading and seeding of the site. Based on the decommissioning study performed by Burns & McDonnell for the Coleman Station, Big Rivers anticipates the decommissioning costs for the preceding scope of work at Station Two to be in the range of [redacted] to [redacted]. A **CONFIDENTIAL** version of that decommissioning study is Attachment 1 to this response

Decommissioning of the Station Two ash pond which includes closure of the pond in accordance with the coal combustion residuals ("CCR") rule codified by the U.S. Environmental Protection Agency (EPA) at 40 CFR Part 257 (the "CCR Rule"). The estimated cost to decommission and close the Station Two ash pond is [redacted] based on the Burns & McDonnell Reid/HMP&L Station - CCR Pond Closure Evaluation, dated September 2019, Attachment 2 to this response. Portions of that document are **CONFIDENTIAL**.

The joint-use facilities listed in Exhibit Pullen-12 provided with my Direct Testimony are those joint-use facilities which Big Rivers continues to use in conjunction with the operation of its Green units. They will be decommissioned at a future date after the Green Station ceases to operate and is retired. Additionally, Item 15 – Station Two Ash Pond Dredgings in

Green Station Sludge Disposal Landfill adjacent to Green River South of Green Station, listed on page 1 of 2 of Exhibit Pullen-13 provided with my Direct Testimony, will also need to be decommissioned at a future date after the Green Station ceases to operate and is retired. Big Rivers does not have an estimated cost for this decommissioning work.

Finally, upon closure of the Station Two ash pond and Green landfill, there will continue be the requirement to perform annual groundwater monitoring in connection with the CCR regulations. Big Rivers currently estimates that this cost will be approximately [redacted].

Witnesses) Robert W. Berry (*a. only*) and
Michael T. Pullen (*b. only*)

Decommissioning Cost Estimate Study

Big Rivers Electric Corporation

Decommissioning Cost Estimate Study
Project No. 89539

3/3/2016

Decommissioning Cost Estimate Study

prepared for

Big Rivers Electric Corporation
Decommissioning Cost Estimate Study
Henderson, Kentucky

Project No. 89539

3/3/2016

prepared by

Burns & McDonnell Engineering Company, Inc.
Kansas City, Mo

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LIST OF ABBREVIATIONS

Abbreviation	Term/Phrase/Name
BMcD	Burns & McDonnell
BOP	Balance of plant facilities
BREC	Big Rivers Electric Corporation
C&D	Construction and demolition
GCL	Geosynthetic clay liner
Hz	Hertz
O&M	Operations and maintenance
PCB	Polychlorinated biphenyl
Plants	Power generation assets
STG	Steam turbine generator
Study	Decommissioning Cost Study

1.0 EXECUTIVE SUMMARY

1.1 Introduction

Burns & McDonnell ("BMcD") of Kansas City, Missouri, was retained by Big Rivers Electric Corporation ("BREC") to conduct a Decommissioning Cost Study ("Study") for power generation assets ("Plants") in Kentucky. The assets include two (2) coal-fired generating facilities. The purpose of the Study was to review the facilities and to make a recommendation to BREC regarding the total cost to decommission the facilities at the end of their useful lives. The decommissioning costs were developed by BMcD using information provided by BREC and in-house data available to BMcD.

This Study evaluated two (2) options for dismantling of the Kenneth C. Coleman Station including demolition to four (4) feet below grade and retiring the equipment in place. This Study also evaluated retirement in place for the Robert A. Reid Station.

1.2 Results

BMcD has prepared estimates in current dollars (2016$) for the decommissioning of the Plants. These costs are summarized in Table 1-1 and Table 1-2. For the below grade demolition, when BREC determines that the Plants should be retired, the above grade equipment and steel structures are assumed to have sufficient scrap value to a salvage contractor to offset a portion of the decommissioning costs. BREC will incur costs in the demolition and restoration of the sites less the salvage value of equipment and bulk steel.

Table 1-1: Four (4) Feet Below Grade Site Decommissioning Cost Estimate (2016$)

Plant	Decommissioning Costs	Credits	Net Project Cost
Kenneth C. Coleman Station	[redacted]		

Table 1-2: Retire in Place Site Decommissioning Cost Estimates (2016$)

Plant	Total Project Cost	Annual O&M Cost
Kenneth C. Coleman Station	[redacted]	
Robert A. Reid Station		

The total project cost in the below grade demolition includes the costs to return the site to an industrial condition suitable for reuse for development of an industrial facility. The retirement in place includes the cost for cleaning and securing the equipment in order to remove the Plant from service after its useful life.

The retirement in place also includes the maintenance of the facilities. A detailed breakdown of the decommissioning costs is shown in Appendix A.

1.3 Statement of Limitations

In preparation of this Study, BMcD has relied upon information provided by BREC. BMcD acknowledges that it has requested the information from BREC that it deemed necessary to complete this Study. While BMcD has no reason to believe that the information provided, and upon which BMcD has relied, is inaccurate or incomplete in any material respect, BMcD has not independently verified such information and cannot guarantee its accuracy or completeness.

Engineer's estimates and projections of decommissioning costs are based on Engineer's experience, qualifications and judgment. Since Engineer has no control over weather, cost and availability of labor, material and equipment, labor productivity, construction contractors' procedures and methods, and other factors, Engineer does not guarantee the accuracy of its estimates and projections.

Engineer's estimates do not include allowances for unforeseen environmental liabilities associated with unexpected environmental contamination due to events not considered part of normal operations, such as fuel tank ruptures, oil spills, etc. Estimates also do not include allowances for environmental remediation associated with changes in classification of hazardous materials.

2.0 INTRODUCTION

2.1 Background

Burns & McDonnell, ("BMcD") of Kansas City, Missouri, was retained by Big Rivers Electric Corporation ("BREC") to conduct a Decommissioning Cost Study ("Study") for power generation assets ("Plants") in Kentucky. The assets include two (2) coal-fired generating facilities. The purpose of the Study was to review the facilities and to make a recommendation to BREC regarding the total cost to decommission the facilities at the end of their useful lives.

BMcD has prepared decommissioning studies for over 100 facilities on various types of fossil fuel and renewable power plants using a proven approach to developing these estimates. These dismantlement studies and associated cost estimates were produced for various reasons, many of which have held up to strict scrutiny as part of a regulatory review process, which requires the results to be reasonable and defendable. BMcD has provided both written and verbal testimonies before public utility commissions, which have been well received and has confirmed the reasonableness of BMcD's estimate methodology. In addition to preparing demolition estimates, BMcD has supported demolition projects as the owner's engineer, to evaluate demolition bids and oversee demolition activities. This has provided BMcD with insight into the range of competitive demolition bids, which also assists in confirming the reasonableness of the decommissioning estimates developed by BMcD.

2.2 Study Methodology

The site decommissioning and retirement costs were developed using information provided by BREC and in-house data BMcD has collected from previous project experience. BMcD estimated quantities for equipment based on a visual inspection of the facilities, review of engineering drawings, BMcD's in house database of plant equipment quantities, along with BMcD's professional judgment. This resulted in an estimate of quantities for the tasks required to be performed for each decommissioning and retirement effort. Current market pricing for labor rates, equipment, and unit pricing were then developed for each task. The unit pricing was developed for each site based on the labor rates, equipment costs, and disposal costs specific to the general area in which the work is to be performed. These rates were applied to the quantities for the Plants to determine the total cost of decommissioning and retiring each site.

The decommissioning costs for the below grade included the cost to return the site to an industrial condition, suitable for reuse for development of an industrial facility, commonly referred to as a brownfield site. Included are the costs to decommission all of the assets owned by BREC at the site, including power generating equipment and BOP facilities. The decommissioning costs for the retirement in place include the costs of cleaning and securing the equipment in order to remove the Plant from service after its useful life. The retirement in place also includes the annual operation and maintenance costs of the Plants.

2.3 Site Visits

Representatives from BMcD visited each of the Plants covered by the Study in January of 2016. The site visits consisted of a tour of each facility with plant personnel to review the equipment installed at each site. Tours were conducted by plant personnel.

The following BMcD representatives comprised the site visit team:

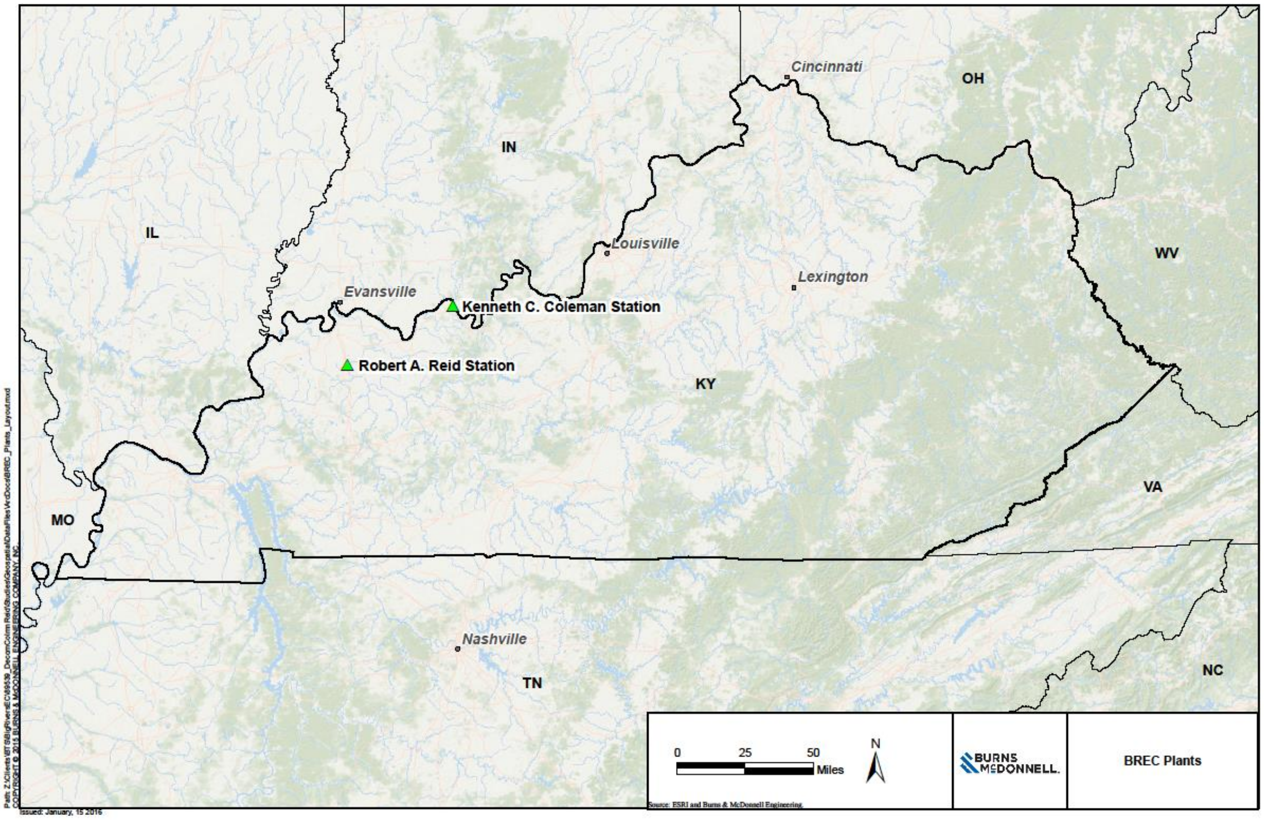
- Mr. Jeff Kopp, BMcD, Project Manager
- Mr. Thom Bristow, BMcD, Project Engineer

The site visits were performed on the following dates.

Table 2-1: Site Visit Dates

Plant	Site Visit Date
Kenneth C. Coleman Station	20-January-16
Robert A. Reid	20-January-16

Figure 1: BREC Facilities Visited



3.0 PLANT DESCRIPTIONS

The following sections provide site descriptions for each of the power plants included in this Study.

3.1 Kenneth C. Coleman Station

Kenneth C. Coleman Station consists of three (3) coal-fired boiler units located near Hawesville, Kentucky, approximately 60 miles east of Henderson, Kentucky. The Plant is located on the west bank of the Ohio River. The Plant has been idled since May 2014. Coleman 1 was commercialized in 1969 and is rated for 150 MW of net capacity. The unit is equipped with a Foster Wheeler boiler capable of producing 1,220,000 pounds per hour of steam, and a Westinghouse turbine-generator with nameplate capacity of 160 MW. Coleman 2 was commercialized in 1970 and is rated for 138 MW of net capacity. The unit is equipped with a Foster Wheeler boiler capable of producing 1,220,000 pounds per hour of steam, and a Westinghouse turbine-generator with nameplate capacity of 160 MW. Coleman 3 was commercialized in 1972 and is rated for 155 MW of net capacity. The unit is equipped with a Riley boiler capable of producing 1,160,000 pounds per hour of steam, and a General Electric turbine-generator with nameplate capacity of 165 MW. Low NO_x burners were installed to reduce NO_x levels for all three units. In 2004 all three boilers were retrofitted with over fire air combustion equipment to further reduce NO_X emissions. In 2006 the Plant was retrofitted with a limestone scrubber that combines all three (3) generation units into a single FGD to remove SO_2. The plant cooling water system is a direct, once-through cooling design supplied by the Ohio River. Each unit has a 350 foot stack that was bypassed at the time the FGD was installed. The FGD stack that is shared by all three (3) units stands 500 feet tall. There are a total of four (4) wells onsite that provide water to the plant.

3.2 Robert A. Reid Station

Robert A. Reid Station is part of Sebree Station which consists of two (2) other plants also owned and/or operated by BREC. Sebree Station is situated on the Green River approximately three (3) miles northwest of the town of Sebree. The Plant consists of one (1) coal-fired boiler unit. The Robert A. Reid Station steam turbine generating unit includes a Riley boiler with a steam flow capacity of 690,000 pounds per hour and a General Electric turbine-generator with nameplate capacities of 66 MW for the turbine and 96 MVA for the generator. The unit began commercial operation in 1966 and is currently rated at 65 MW. Precipitators are currently used for particulate emission removal. A Low NO_x burner and overfire air system is used to reduce NO_x levels. Circulating water for the unit comes directly from, and returns to, the Green River. Boiler exhaust is expelled through a 266 ft. chimney.

4.0 DECOMMISSIONING COSTS

The Study evaluated the decommissioning costs for Kenneth C. Coleman Station based on two (2) dismantlement options. The first option evaluates the cost for retiring the plant in place which includes performing tasks to reduce environmental and safety risks and securing the facility. The remaining option evaluates the demolition of the facility to a depth of four (4) feet below grade. For Robert A. Reid Station, the Study evaluated the decommissioning costs based solely on retiring the plant in place. More detailed breakdowns for each of the Plants are provided in Appendix A.

4.1 Demolition and Salvage Methodology

When BREC determines that Kenneth C. Coleman Station should be retired and below grade demolition is selected, the above grade equipment and steel structures are assumed to have sufficient scrap value to a salvage contractor to offset a portion of the site decommissioning costs. However, BREC will incur costs of decommissioning of the plant and restoration of the site to the extent that those costs exceed the salvage value of equipment and bulk steel.

The decommissioning costs include the cost to return the site to an industrial condition, suitable for reuse for development of an industrial facility. Included are the costs to dismantle all of the assets owned by BREC at the site, including power generating equipment and BOP facilities, as well as environmental site restoration activities.

For purposes of this Study, BMcD has assumed that the plant will be decommissioned as a single project, allowing the most cost effective demolition methods to be utilized. A summary of several of the means and methods that could be employed is summarized in the following paragraphs; however, means and methods will not be dictated to the contractor by BMcD. It will be the contractor’s responsibility to determine means and methods that result in safely decommissioning the plant at the lowest possible cost.

Asbestos remediation, as required, would take place prior to commencement of any other demolition activities. Abatement would need to be performed in compliance with all state and federal regulations, including, but not limited to requirements for sealing off work areas and maintaining negative pressure throughout the removal process. Final clearances and approvals would need to be achieved prior to performing further demolition activities.

High grade assets would then be removed from the site, to the extent possible. This would include items such as transformers, circuit breakers, electrical wire, condenser plates and tubes, and heater tubes to list a few. High grade material that would be removed from the site include precious alloys such as copper, aluminum-brass tubes, stainless steel tubes, and other high value metals utilized at plant. High grade asset removal would occur up-front in the schedule, to reduce the potential for vandalism, to increase cash flow, and for separation of recyclable materials, in order to increase scrap recovery. Methods of removal vary with the location and nature of the asset. Small transformers, small equipment, and wire would likely be removed and shipped as-is for processing at a scrap yard. Large transformers, steam turbine generators, and condensers would likely require some on-site disassembly prior to being shipped to a scrap yard.

Construction and Demolition ("C&D") waste includes items such as non-asbestos insulation, roofing, wood, drywall, plastics, and other non-metallic materials. C&D waste would typically be segregated from scrap and concrete to avoid cross-contaminating of waste streams or recycle streams. C&D demolition crews could remove these materials with equipment such as excavators equipped with material handling attachments, skid steers, etc. This material would be consolidated and loaded into bulk containers for disposal.

In general, boilers could be felled and cut into manageable sized pieces on the ground. First the structures around the boilers would need to be removed using excavators equipped with shears and grapples. Stairs, grating, elevators, and other high structures would be removed using an "ultra-high reach" excavator, equipped with shears. Following removal of these structures, the boilers would be felled, using explosive blasts. The boilers would then be dismantled using equipment such as excavators equipped with shears and grapples, and the scrap metal loaded onto trailers for recycling.

After the surrounding structures and ductwork have been removed, the stacks would be imploded, using controlled blasts. Following implosion the stack liners and concrete would be reduced in size to allow for handling and removal.

BOP structures and foundations would likely be demolished using excavators equipped with hydraulic shears, hydraulic grapples, and impact breakers, along with workers utilizing open flame cutting torches. Steel components would be separated, reduced in size, and loaded onto trailers for recycling. Concrete would be broken into manageable sized pieces and stockpiled for crushing on-site. Concrete pieces would ultimately be loaded in a hopper and fed through a crusher to be sized for on-site disposal.

The Plants contain significant amounts of scrap value that can be used to offset a portion of the costs incurred for each Plant. In BMcD's experience, the demolition cost typically exceeds the scrap value, resulting in a net cost, rather than a net benefit to the plant owner. In some cases, additional value can be realized if equipment can be salvaged for reuse rather than being simply scrapped. However, there are several significant challenges to salvaging the equipment for reuse, which tend to cancel out the additional value associated with salvaging the equipment. Generally, BMcD recommends that all equipment be valued as scrap for planning purposes, due to the speculative nature of salvage opportunities and prices.

Generally, BMcD's experience has been that equipment and structures are scrapped as part of a demolition project. In order to market the equipment as salvageable for reinstallation and reuse as operating equipment, these items would need to be carefully removed prior to demolition activities. This will increase the cost of removal of those specific items, and will therefore increase the overall demolition costs. The economics of removing select pieces of equipment become even less attractive when looking at extracting individual pieces of equipment, separate from a full demolition project, as the equipment brokers may remove the equipment under a separate contract prior to demolition.

There are several factors placing downward pressure on salvage values of used plant equipment, including the numerous plants slated for decommissioning that will cause a significant increase in supply of used equipment. Additionally, the opportunistic nature of the salvage market often creates challenges with matching the specific needs of the buyer to the equipment available from a particular seller of salvaged equipment. Essentially, the market for a piece of used equipment is limited to buyers whose equipment needs directly match the equipment for sale. Typically this is either a buyer who has experienced an equipment failure and would rather buy used equipment than wait for new equipment, or is a buyer in an overseas market. These factors greatly limit the number of potential buyers.

In BMcD's experience, the steam turbine generator set and generator step-up transformer have been the most likely pieces of equipment to be sold for salvage and reuse. Typical customers of this type of equipment are generally located overseas. Most of these markets have 50 hertz ("Hz") power systems, thus the turbine generator set would need to be retrofitted to convert from generating at 60 Hz to 50 Hz. Although the miscellaneous pumps and motors associated with these facilities can sometimes be sold for salvage, this is one of the more opportunistic markets where a specific buyer with a specifically matched need would have to be identified. These opportunities have been less likely to occur than these pieces of equipment being scrapped.

Through other recent projects, BMcD has been in discussion with equipment salvage brokers to gauge market interest for equipment associated with power plants. There was very little interest in the equipment on other projects with newer equipment and there would likely be no interest in the equipment at these Plants due to the vintage. Comments from the brokers on the other projects indicated that they expected any piece of equipment extracted separately from a full demolition project to be a net cost to the facility owner. Therefore, receiving scrap value for the equipment is likely the most economically attractive option.

4.2 Decommissioning Cost assumptions

Below is a list of general assumptions for all sites, as well as site specific assumptions applicable to each individual project.

4.2.1 General Cost Assumptions and Clarifications for All Sites

The following assumptions were made as the basis of all of the cost estimates.

1. All cost estimates are in current 2016 dollars.
2. All estimates are budgetary in nature and do not reflect guaranteed costs.
3. All work will take place in a safe and cost efficient method.
4. Labor costs are based on a regular 40 hour workweek without overtime.
5. Abatement of asbestos will precede any other work. After final air quality clearances have been reached, demolition can proceed.
6. All facilities will be decommissioned to zero generating output. Existing utilities will remain in place for use by the contractor for the duration of the decommissioning and demolition activities.
7. Soil testing and any other on-site testing has not been conducted for this study.
8. Transmission switchyards and substations within the boundaries of the plant are not part of the decommissioning scope. For purposes of this study, the division between generation assets and transmission assets is at the high side of the generator step-up transformers.
9. The costs for relocation of transmission lines, or other transmission assets, are specifically excluded from the decommissioning cost estimates.
10. All demolition and abatement activities, including removal of asbestos, will be done in accordance with any and all applicable Federal, State and Local laws, rules and regulations.
11. It is assumed that sufficient area to receive, assemble and temporarily store equipment and materials is available.
12. Any observable surface spills will be cleaned up.
13. All trash, debris, and miscellaneous waste will be removed and disposed of properly.
14. No environmental costs have been included to address cleanup of contaminated soils, hazardous materials, or other conditions present on-site having a negative environmental impact, other than those specifically listed in these assumptions. No allowances are included for unforeseen environmental remediation activities.
15. Handling and disposal of hazardous material will be performed in compliance with the approved methods of BREC’s Environmental Services Department.
16. Valuation and sale of land and all replacement generation costs are excluded from this scope.

17. Spare parts inventories were not provided to BMcD for review. BMcD assumes that to the extent possible spare parts will be sold prior to decommissioning and remaining spare parts will be scrapped by the demolition contractor.
18. Rolling stock, including dozers, plant vehicles, etc. is assumed to be removed by BREC prior to decommissioning.
19. A 20 percent contingency was included on the direct costs in the estimates prepared as part of this study to cover unknowns.
20. Indirect costs are included in the cost estimate to cover owner expenses such as management trailers, utilities, etc. which may impact the cost of decommissioning each site. An indirect cost of 5 percent was included in the estimates to cover such costs.
21. Market conditions may result in cost variations at the time of contract execution.

4.2.2 Demolition to Four (4) Feet Below Grade

This option considers the cost associated to demolishing Kenneth C. Coleman Station to four (4) feet below grade. The following section outlines the assumptions for decommissioning the plant to four (4) feet below grade.

1. All estimates are based on labor rates from RS means values for a demolition crew B-8 with adjusted rates based on the local site cost index for the Plants.
2. The estimates are inclusive of all costs necessary to properly dismantle and decommission the site to a marketable or usable condition. For purposes of this study and the included cost estimates, the site will be restored to a condition suitable for industrial use.
3. Demolition of the entire site and all associated units will occur in a single project.
4. After the barge unloading equipment and structure are removed, the mooring cells will also be removed. The area in front of the unloading facility will be filled with materials required to restore the original river bankline in accordance with the Corps of Engineers' requirements.
5. This cost estimate includes property tax liabilities that have been provided by BREC.
6. Concrete will be crushed on-site and buried in existing basements. Concrete in trenches and basements will be perforated to create drainage. Once the capacity of all existing basements has been exceeded, remaining concrete will be crushed and used as clean fill on-site. All other non-hazardous material with no salvage value will be disposed of off-site at the nearest landfill.
7. Step-up transformers and auxiliary transformers are included for demolition and scrap in all estimates.
8. Demolition will include the removal of all structures, equipment, tanks, conveyer systems, ancillary buildings, and any other associated equipment to four (4) feet below grade.
9. All above grade plant structures and materials such as fire walls, masonry, doors, windows, building finishes, plumbing, HVAC ductwork, lighting fixtures, cable trays, etc., will be demolished and disposed of off-site at the nearest landfill.
10. Foundations and ground floor slabs will be removed to four (4) feet below grade. The surface will be graded for drainage using onsite soil and seeded.

11. Except for the circulating water lines, underground piping will be abandoned in place. Concrete circulating water system pipes will be capped, have the tops broken out, and backfilled with on-site soil. Steel circulating water pipes will be removed and scrapped
12. All pipe supports, and pipe racks will be demolished and scrapped.
13. Hazardous material abatement is included as necessary, including asbestos, mercury, and polychlorinated biphenyls (“PCBs”). Lead paint coated materials will be handled by certified personnel compliant with OSHA Standards as necessary, but will not be removed prior to demolition. Scrap steel can be taken to scrap brokers with lead paint still intact, and will not impact the scrap value.
14. All portable tanks will be removed from the site and scrapped, including any propane tanks, oil storage tanks, and waste oil tanks.
15. Most, if not all, chemicals have been removed from the site, however, any remaining chemicals will be consumed or disposed of by the Plant prior to decommissioning, including process chemicals in equipment, stored chemicals, and laboratory chemicals.
16. No plant washdown is required since it was completed as part of placing the plant in long term layup.
17. All coal, ash, and other residue was cleaned and removed as part of the plant layup and not included in this cost estimate.
18. The substation equipment owned by the Plant including breakers, air break disconnect switch, busbars, grounding cable and transformers up to the interconnection point will be removed.
19. The coal pile area will be excavated to a depth of one (1) foot, graded, capped, and covered with imported topsoil.
20. Site areas will be graded to achieve suitable site drainage to natural drainage patterns, but grading will be minimized to the extent possible.
21. Major equipment, structural steel, generators, inlet filters, exhaust stacks, transformers, electrical equipment, cabling, wiring, pump skids, above ground piping, and equipment enclosures for the above equipment will be sold for scrap and removed from the Plant site by the demolition contractor. All other demolished materials are considered debris.
22. All production wells will be closed as per state regulations. Production wells will be filled with grout to approximately five feet below surface grade. The top five feet will be overdrilled and filled with soil backfill to grade on top of the grout. Monitoring wells will remain intact.
23. The scrap value of the equipment is based on the equipment being at the end of its useful life at the time of demolition; therefore, the equipment will not have a value on the grey market for reinstallation. Equipment will have value as scrap only at the time of site demolition.
24. [redacted]
25. [redacted]
26. The scope of the costs included in the Study is limited to the decommissioning activities that will occur at the end of useful life of the facilities. Additional on-going costs may be required, including, but not limited to groundwater monitoring associated with ash pond closure and/or other environmental monitoring activities. These costs are excluded from the cost estimates provided in this study.

4.2.3 Retirement in Place

This option considers the cost associated with retiring both Plants in place which includes tasks such as removing chemicals and other potential environmental hazards, and placing the equipment and Plants in a condition that reduces liabilities and risks, while minimizing retirement costs. The following section outlines the assumptions for retiring the Plants in place.

1. All units will be retired to zero generating output.
2. An asbestos inspection will be performed and any friable asbestos identified will be completely removed. It is assumed that a minimal amount of asbestos will require removal. This activity will precede any other work.
3. All access into the Plant, powerhouse, warehouses, and other plant structures will be secured.
4. No equipment or material will be removed for scrap sales.
5. Switchyard breakers will be opened. Switchyard disconnects will be opened and locked in the open position.
6. Oil-filled transformers will be drained and the oil disposed of properly.
7. Lubricating oil systems and hydraulic oil systems will be drained and the oil will be recycled or disposed of properly.
8. This cost estimate includes property taxes and insurance liabilities that have been provided by BREC.
9. No general and administrative fees were developed for this cost estimate but will need to be included in BREC's ongoing costs.
10. All water/steam spaces in the steam turbines, including the condenser, will be drained and opened.
11. Aircraft warning lights on the stacks will be maintained and remain operational.
12. All chimneys will be capped.
13. All batteries, including lead and nickel cadmium batteries will be removed and disposed of properly.
14. Mercury filled equipment and instruments, if applicable, will be removed and disposed of or recycled.
15. Freon will be removed and disposed of properly.
16. Annual operational and maintenance ("O&M") costs will apply for each year the Plant is in retired in place status.
17. Liability insurance costs are not included in BMcD's estimates of annual O&M costs; however, these costs should be considered by BREC as it is assumed that some level of liability insurance will still be required. Costs should be confirmed with BREC's insurance provider.

4.2.4 Site Specific Assumptions

The following assumptions were made specific to each plant cost estimate.

Kenneth C. Coleman Station

1. The Plant is currently in dry layup state with dehumidified air.

2. Asbestos has been abated around steam turbine generator ("STG") but remains around main steam lines.
   The condensers and circulating water lines have been drained.
3. The transformers still have oil but are PCB free.
4. Roughly 5000 gallons each of lube oil and seal oil remain on-site.
5. Sulfuric acid has been removed from the site.
6. All coal has previously been removed from site.
7. The condenser was retubed in the last five (5) years with admiralty brass.
8. The onsite section of rail is not part of this decommissioning estimate.
9. Mooring cells warning light system and cathodic protection system will remain active
10. Under either the demolition to four feet below grade or retirement in place scenario, the south pond will be capped with a combination of two (2) feet of clay and a geosynthetic clay liner ("GCL").
11. Under either the demolition to four feet below grade or retirement in place scenario, the contents of the east portion of sluice pond will be migrated to west portion of sluice pond. The west portion of sluice pond will be dewatered and an isolation berm will be built around it. It will be capped with a combination of two (2) feet of clay and a GCL. A groundwater monitoring system will be installed
12. Under either the demolition to four feet below grade or retirement in place scenario, the north pond will be dewatered and capped with a combination of two (2) feet of clay and a GCL.
13. Under the retirement in place scenario, all doors will be secured or welded shut and outstanding keys collected.
14. Under the retirement in place scenario, all windows up to twenty feet above grade will be boarded up.
15. Under the retirement in place scenario, branches into buildings from the fire mains in the yard will be valved off and fire risers in the building drained. Yard fire hydrants will be left in service.
16. Under the retirement in place scenario, access to duct bank manholes will be secured to prevent entry.
17. A new power supply for the firewater pump, barge clearance lights, FAA warning lights, and cathodic protection will be added by installing a new feed tied into the Kenergy line located adjacent to the plant.

Robert A. Reid Station

1. The 84-inch circulating water line and pump will be taken out of service and replaced with a smaller line and pump to serve HMP&L Station Two requiring HMP&L Station Two to be taken offline during this retrofit.
2. The Reid Station has a building heat system that will be maintained in service; therefore, no freeze protection modifications are required.
3. All chemicals still onsite at Reid can be transferred to some other plant owned by BREC at no net cost.
4. The Reid Station fire protection system will remain in service.
5. Sump pumps for all units are in the basement of Reid 1, which will need to be maintained.

6. The jockey pump that serves as a backup for the HMP&L fire protection system is fed by Reid's circulating water system. These jockey pumps will need to remain operational.
7. The Reid auxiliary transformers must remain operative to provide station power.
8. The compressed air system will remain in place and operational to allow for maintenance activities in the area of the Reid Station. The cooling water for the air compressors is fed from the Reid circulating water system, and will need to be modified.
9. Fly ash and bottom ash are currently routed to a common ash handling building with HMP&L and the over to the ponds. These lines from the Reid Station will need to be isolated from the remainder of the system.
10. The coal feed system must remain operative to serve HMP&L Station Two; however, the section of the coal feed system that serves the Reid Station needs to be blanked off to prevent coal from entering the Reid hopper.

4.3 Results

Table 4-1 presents a summary of the decommissioning cost for the Kenneth C. Coleman Station to four (4) feet below grade. This summary provides a breakout of the major decommissioning activities and the scrap value for the Plant.

Table 4-1: Four (4) Feet Below Grade Site Decommissioning Cost Estimate (2016$)

Plant	Decommissioning Costs	Credits	Net Project Cost
Kenneth C. Coleman Station	[redacted]		

Table 4-2 provides the total costs for retiring the Plants in place. The total project cost involves one-time costs regarding environmental and plant building items. The annual O&M costs include recurring costs involving the site security, environmental monitoring and administration.

Table 4-2: Retire in Place Site Decommissioning Cost Estimates (2016$)

Plant	Total Project Cost	Annual O&M Cost
Kenneth C. Coleman	[redacted]	
Robert A. Reid		

Table 4-2: 1

APPENDIX A - COST BREAKDOWNS

Table A-1
Kenneth C. Coleman Station
Decommissioning Cost Summary

	Labor	Material and Equipment	Disposal	Environmental	Total Cost	Scrap Value
Kenneth C. Coleman Station						
Unit 1	[redacted]					
Asbestos Removal						
Boiler						
Steam Turbine & Building						
Precipitator						
Stacks						
GSU & Foundation						
On-site Concrete Crushing & Disposal						
Debris						
Scrap						
Subtotal						
Unit 2						
Asbestos Removal						
Boiler						
Steam Turbine & Building						
Precipitator						
Stacks						
GSU & Foundation						
On-site Concrete Crushing & Disposal						
Debris						
Scrap						
Subtotal						
Unit 3						
Asbestos Removal						
Boiler						
Steam Turbine & Building						
Precipitator						
Stacks						
GSU & Foundation						
On-site Concrete Crushing & Disposal						
Debris						
Scrap						
Subtotal						
Handling						
Demolition						
Coal Storage Area Restoration						
Gypsum Stackout Area Restoration						
Limestone Handling Facilities						
Coal Unloading Structure						
On-site Concrete Crushing & Disposal						
Debris						
Scrap						
Subtotal						
Common Facilities						
Cooling Water Intakes and Circulating Water Pumps						
Roads						
All BOP Buildings						
Fuel Oil Storage Tanks						
All Other Tanks						
GSU & Foundation						
Closure of Deep Wells						
Closure of Metal Cleaning Pond						
Closure of Coal Runoff Pond						
Hazardous Waste Disposal						
On-site Concrete Crushing & Disposal						
Grading & Seeding						
Debris						
Scrap						
Subtotal						
Kenneth C. Coleman Station Subtotal						
TOTAL DECOM COST (CREDIT)					[redacted]	
TOTAL POND CLOSURE COST* (CREDIT)						
PROJECT INDIRECTS (5%)						
CONTINGENGY (20%)						
TAX LIABILITY						
TOTAL PROJECT COST (CREDIT)						
TOTAL NET PROJECT COST (CREDIT)						

*Pond closure costs were incorporated from Environmental Compliance Study, Project #83177, 5/1/2015.

Table A-2
Kenneth C. Coleman Station
Retire in Place Cost Summary

One Time Costs

Description	**Line Item Costs**
Asbestos Abatement	[redacted]
Shutdown Plant Equipment and Structures	
Coal Pile Remediation	
Ash Pond Remediation*	
Other Pond Remediation	
Unit Cleaup and Disposal	
Site Security	
Credits	
Retirement in Place Subtotal	
PROJECT INDIRECTS (5%)	
CONTINGENGY (20%)	
TOTAL PROJECT COST (CREDIT)	

Ongoing Costs

Description	**Line Item Costs**
Asbestos Inspection	[redacted]
Common Site Maintenance	
Chimney Inspection	
Site Security	
Environmental Monitoring	
Retirement in Place O&M Subtotal	
PROJECT INDIRECTS (5%)	
CONTINGENGY (20%)	
TAX LIABILITY	
INSURANCE PREMIUMS	
ANNUAL O&M COST	

*Pond closure costs were incorporated from Environmental Compliance Study, Project #83177, 5/1/2015.

Table A-3
Robert A. Reid Station
Retire in Place Cost Summary

One Time Costs

Description	**Line Item Costs**
Asbestos Abatement	[redacted]
Shutdown Plant Equipment and Structures	
Unit Cleaup and Disposal	
Retirement in Place Subtotal	
PROJECT INDIRECTS (5%)	
CONTINGENGY (20%)	
TOTAL PROJECT COST (CREDIT)	

Ongoing Costs

Description	**Line Item Costs**
Asbestos Inspection	[redacted]
Common Site Maintenance	
Chimney Inspection	
Site Security	
Retirement in Place O&M Subtotal	
PROJECT INDIRECTS (5%)	
CONTINGENGY (20%)	
TAX LIABILITY	
INSURANCE PREMIUMS	
ANNUAL O&M COST	

APPENDIX B - PLANT AERIALS

Figure 2: Kenneth C. Coleman Station

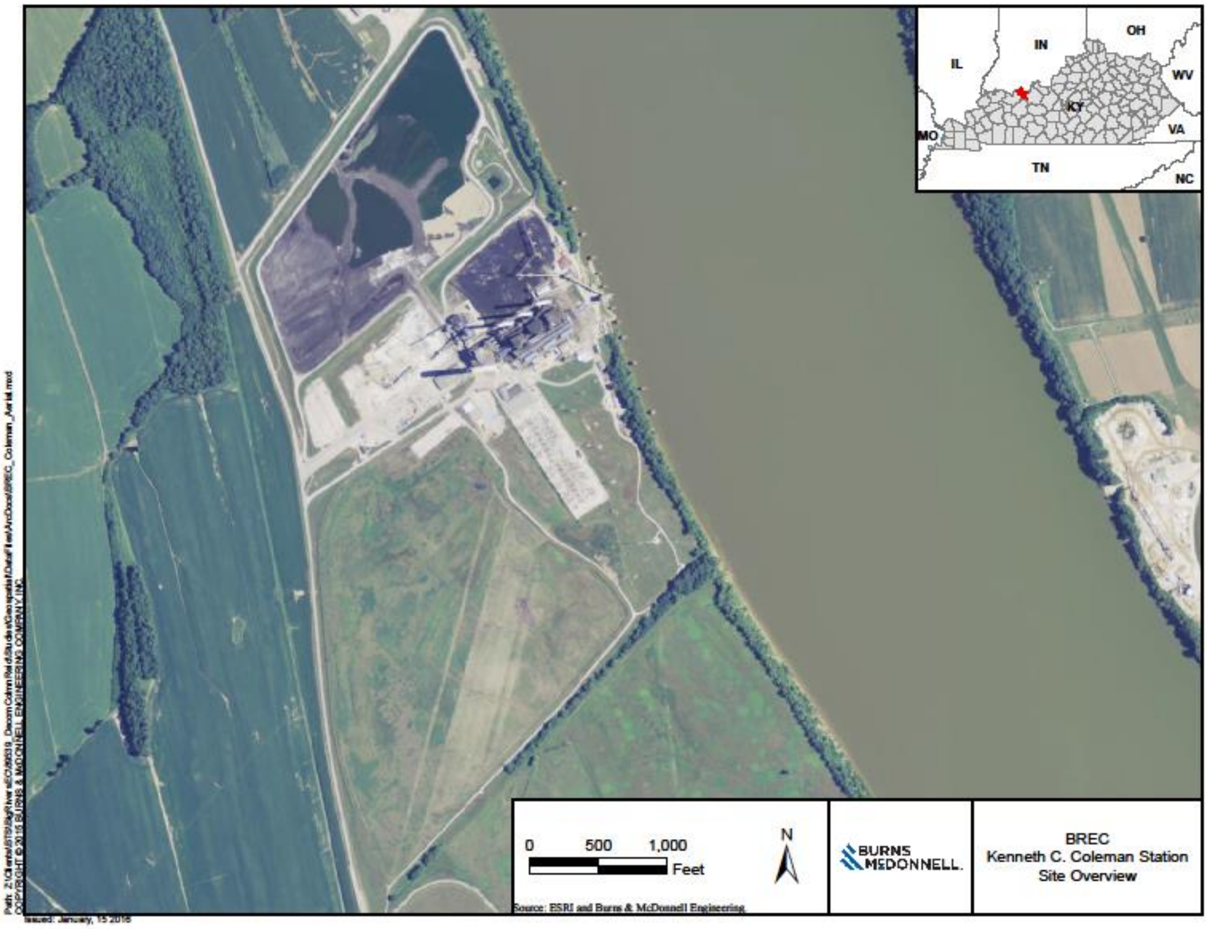
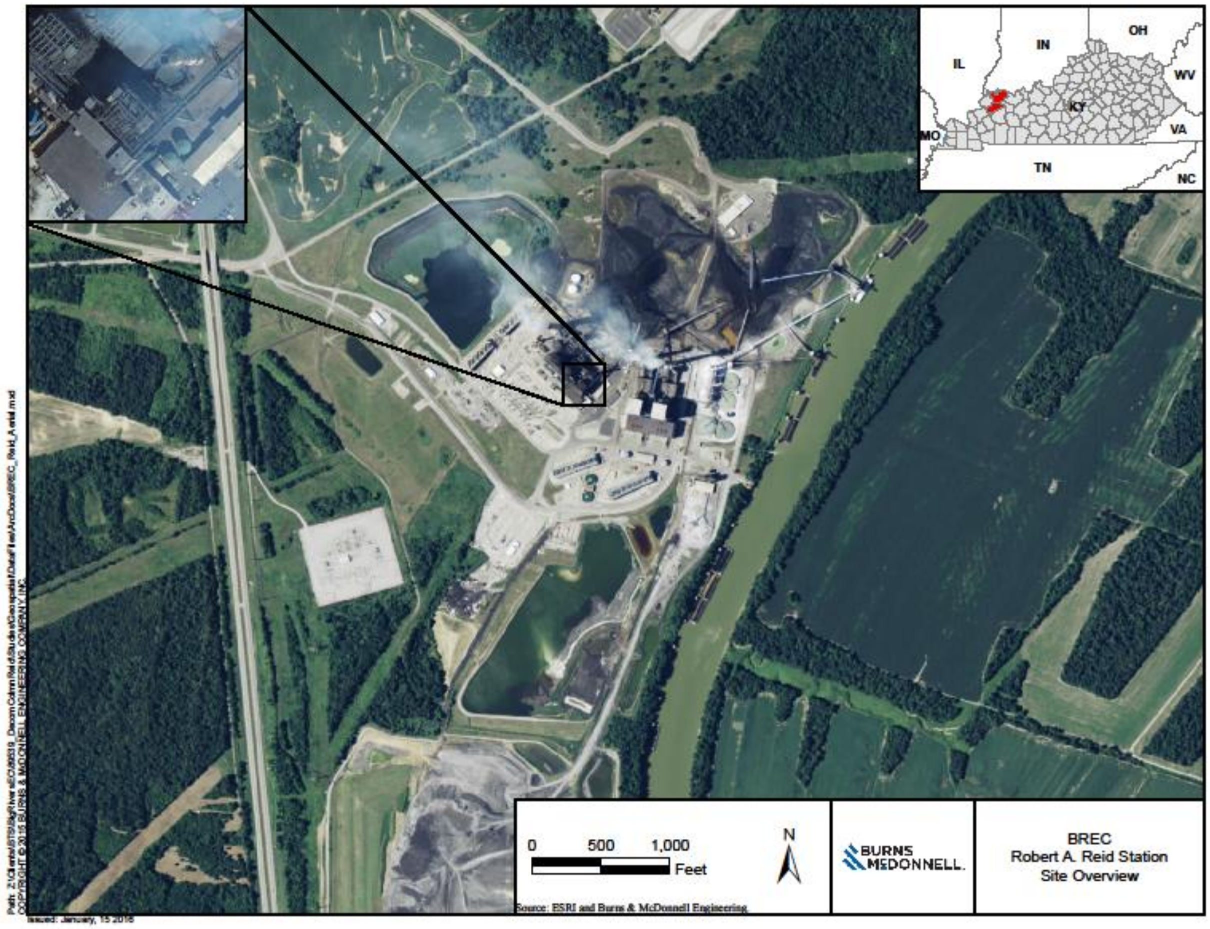


Figure 3: Robert A. Reid Station



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Reid/HMP&L Station - CCR Pond Closure Evaluation

Big Rivers Electric Corporation

Project No. 114088

Rev. B
September 2019

Reid/HMP&L Station - CCR Pond Closure Evaluation

Prepared for

Big Rivers Electric Corporation

Robards, Kentucky

Rev. B
September 2019

Prepared by

Burns & McDonnell Engineering Company, Inc.
Kansas City, Missouri

INDEX AND CERTIFICATION

Big Rivers Electric Corporation
Reid/HMP&L Station - CCR Pond Closure Evaluation

Report Index

Certification

I hereby certify, as a Professional Engineer in the Commonwealth of Kentucky, the information in this document was assembled under my direct supervisory control. This report is not intended or represented to be suitable for reuse by the Big Rivers Electric Corporation or others without specific verification or adaptation by the Engineer.

____
Kira E. Wylam, P.E. (License No. 30195)

Date: ______________________________

INDEX AND CERTIFICATION

Big Rivers Electric Corporation
Reid/HMP&L Station - CCR Pond Closure Evaluation

Report Index

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____
Nathan Textor (Kentucky License No. 29730)

Date: ______________________________

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LIST OF ABBREVIATIONS

Abbreviation	Term/Phrase/Name
BREC	Big Rivers Electric Corporation
CCR	Coal Combustion Residual
CCR Rule	Coal Combustion Residual Rule
cm/sec	centimeters per second
CPT	Cone Penetrometer Test
CRR	Cyclic Resistance Ratio
CSR	Cyclic Stress Ratio
CQA	Construction Quality Assurance
EPA	Environmental Protection Agency
KAR	Kentucky Administrative Regulations
KDOW	Kentucky Division of Water
KEEC	Kentucky Energy and Environment Cabinet
KPDES	Kentucky Pollutant Discharge Elimination System
OTD	One-Time Discharge
RCRA	Resource Conservation and Recovery Act
TSS	Total Suspended Solids
U.S.C.	United States Code

1.0 INTRODUCTION

Burns & McDonnell was retained by Big Rivers Electric Corporation (BREC) to perform an evaluation of the closure of the combustion residual (CCR) pond for the Reid/HMP&L unit at Sebree Station. The Reid/HMP&L units have not produced electricity since February 1, 2019; therefore, in accordance with the federal CCR Rule, BREC is required to close the Reid/HMP&L CCR pond, which will be referred to herein as “Ash Pond”. According to the federal CCR Rule, the Ash Pond will need to be closed within five years of initiating closure, or by April 17, 2024. This study seeks to develop scope and cost estimate for the closure of the existing Ash Pond at Sebree Station.

Burns & McDonnell investigated a closure-in-place option for the Ash Pond. The investigation consists of a summary of the closure in-place method, as well as a construction phasing plan, contracting plan, cost estimate, and project schedule. Throughout detailed design, unforeseen circumstances may require some of the details from the plan presented herein to change; however, this report provides definition for the overall project scope.

2.0 POND CLOSURE PLAN

2.1 Pond Description

The Ash Pond was in operation for approximately 40 years, during which it received predominantly sluiced bottom ash that was generated from the Reid/HMP&L units at Sebree Station. The Ash Pond is approximately 24 acres in surface area and is partially incised with a berm above grade on the south, east and west sides. The Ash Pond does not have a constructed pond liner and water is currently impounded in a portion of the pond approximately eight acres in size.

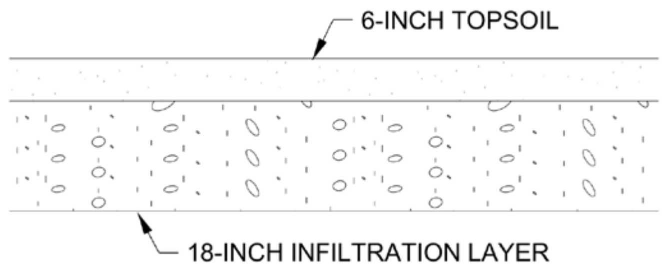
The closed pond surface will be sloped to the southwest to a ditch that will be drained via a culvert or an opening in the existing berm. Post-closure, existing Kentucky Pollutant Discharge Elimination System (KPDES) Outfall #004 will be closed, and the runoff will be conveyed to a newly constructed ditch that will eventually drain to existing Outfall #001.

2.2 Closure Cover System

On April 17, 2015, the Environmental Protection Agency (EPA) issued the final version of the federal CCR Rule to regulate the disposal of CCR materials generated at coal-fired units. The rule is administered as part of the Resource Conservation and Recovery Act (RCRA, 42 United States Code [U.S.C.] §6901 et seq.), using the Subtitle D approach.

The Reid/HMP&L Ash Pond is subject to the CCR Rule as well as the Kentucky Administrative Regulations (KAR). At the time this report was written, the Kentucky Energy and Environment Cabinet (KEEC) indicated "…Kentucky regulations designate coal ash ponds as permits-by-rule as long as they are in compliance with a KPDES permit from the Division of Water". For purposes of this report, Burns & McDonnell has assumed the Ash Pond will be capped in place with a cover system as outlined in the CCR Rule. The prescribed cover system for unlined impoundments consists of 18 inches of clay infiltration layer and 6 inches of topsoil that is capable of sustaining vegetation. A typical section of this proposed cover system is shown in Figure 2-1.

Figure 2-1: Typical Cover System



The permeability of the infiltration layer is to be less than or equal to the permeability of any bottom liner system or natural subsoils present per the CCR Rule, or no greater than $1x10^{-5}$ centimeters per second (cm/sec), whichever is less. The existing subgrade materials at the Reid/HMP&L Ash Pond have permeabilities higher than $1x10^{-5}$ cm/sec, so the 18-inch infiltration layer permeabilities as defined in the construction documents will need to match these values. This will be determined and verified when a borrow source is selected for the infiltration layer. For purposes of cost estimating in this report, the infiltration layer was assumed to have a permeability of approximately $1x10^{-5}$ cm/sec.

3.0 DESIGN CONSIDERATIONS

3.1 Geotechnical Seismic and Stability Evaluations

Based on the closure-in-place closure method to be utilized, the Ash Pond will be subjected to long-term conditions including seismic events. Additionally, since the CCR is impounded by built-up soil embankments, slope stability of these embankments is also a concern. The seismic hazards and conditions were evaluated as part of this closure evaluation. These evaluations included dynamic soil response analyses, liquefaction evaluations and slope stability calculations. Based on these evaluations, the Ash Pond is considered stable for long-term conditions. This section includes a general overview of the evaluations that were completed.

3.1.1 Geotechnical Investigation

To perform the required geotechnical evaluations, geotechnical data was required. An investigation was conducted that included drilling borings, pushing cone penetrometer test (CPT) soundings, and measuring soil shear wave velocities using the downhole method. This investigation was performed by S&ME, Inc. in the summer of 2019.

Borings were performed along the embankment crest and toe to provide information on subsurface materials and obtain samples for laboratory testing. Laboratory testing included Atterberg limits, grain size determinations and consolidated undrained with pore pressure measurements triaxial tests. This information was mainly used for slope stability evaluations.

CPT soundings were performed along the embankment toe to provide information on subsurface materials. CPT soundings were used mainly for the liquefaction evaluations as they are the most informative investigative technique for this evaluation. They were also considered in the slope stability evaluations.

Shear wave velocity measurements were made using the downhole method. The downhole method involves imparting a shear wave to the soil at the ground surface and measuring the time it takes to reach a CPT instrument capable of detecting shear waves. This is performed to multiple depths to compile a shear wave profile. Shear wave velocities were used for the dynamic soil response analysis.

One important consideration for a closure-in-place method is the permeability of the underlying materials, either liner or natural subgrade soils. As noted, there is no liner so only the natural subgrade soils need to be considered. Results of the investigation indicated the pond appears to be underlain by clay. Laboratory testing of the natural subgrade soils was performed as part of previous investigations provided by BREC.

Hydraulic conductivity was also correlated from CPT sounding data. Laboratory testing of natural subgrade soils indicated hydraulic conductivities between 4.4×10^{-8} and 1.0×10^{-9} cm/sec. CPT sounding correlated permeability values varied between approximately 3.0×10^{-5} and 3.0×10^{-7} cm/sec. These permeability values should be considered when determining cover system requirements during final design.

3.1.2 Dynamic Soil Response

The Reid/HMP&L site is in close proximity to both the New Madrid and Wabash faults. These faults are both capable of high magnitude earthquakes that can cause significant ground accelerations at the Ash Pond during a design seismic event. To understand the response of the soils underlying the Ash Pond during a design seismic event, a dynamic soil response analysis was performed.

The first step of the soil sample analysis is to determine the rock acceleration at the Reid/HMP&L site using a probabilistic hazard analysis. To do this, the computer program EZ-FRISK was utilized. EZ-FRISK incorporates seismic sources, their characteristics (probability of occurrence, magnitude, fault type, depth) and the distance to the site to determine a rock acceleration at the site based on a specified risk level. The risk level is generally defined by a probability of occurrence. For long-term structures such as landfills, a probability of occurrence of two percent (%) in 50 years is generally used. This probability of occurrence was utilized for this analysis.

EZ-FRISK used known seismic source data, seismic source characteristics and attenuation relationships for the Central United States to determine the rock acceleration at the Reid/HMP&L site. This acceleration is defined by what is termed a response spectrum. The response spectrum shows the distribution of accelerations to seismic wave periods and can be used to define the seismic load of a seismic event. This response spectrum is termed the target response spectrum for this analysis.

While the target response spectrum defines the seismic load at the site, it cannot be used as direct input into a dynamic soil response analysis. Instead, time history records are needed. These include characteristics such as acceleration, velocity and displacement versus time. For this analysis, actual time history records measured in the Central and Eastern United States were considered. However, based on the relatively small number of actual time history records, specifically with large magnitude seismic events, synthetic time histories were also considered. Each time history record considered has its own response spectrum. Since the time history records need to match the target response spectrum at the site, the time history records had to be spectrally matched using the computer program EZ-FRISK.

Spectral matching involves matching the time history record response spectrum to the target response spectrum in the frequency domain. This allows a high-quality match between the final time history record response spectrum and the target response spectrum. After EZ-FRISK matches the time history record response spectrum, the time history record including acceleration, velocity and displacement with time is then transformed using a Fourier Transform. The final time history record was then reviewed to confirm the appropriateness. Ten time history records were matched and used for the dynamic soil response.

The response of soil to seismic shaking is controlled by soil type, shear strength and shear wave velocity. A review of the information from borings, CPT soundings and downhole shear wave measurements was done for the Ash Pond. Based on this review, multiple soil design profiles were determined.

The computer program Deepsoil v7 was utilized to perform the dynamic soil response analysis. Using the spectrally matched time history records, the responses of the soil columns were calculated. The final dynamic soil response for the Ash Pond was based on the design profile that provided the highest accelerations for the average of the ten time history records used for the modeling. Calculations were performed using a nonlinear approach which best models the response of soil during a seismic event.

The most pertinent information to the overall evaluation obtained from the dynamic soil response analysis is the peak ground acceleration and the maximum stress ratio profile. Peak ground acceleration is utilized for modeling the stability of the embankment during a design seismic event. The maximum stress ratio profile is directly related to the liquefaction evaluation of the site. These pieces of information were incorporated into subsequent analysis.

3.1.3 Liquefaction

Liquefaction is the phenomenon where seismic shaking leads to an increase in pore pressures of a soil, decreasing the effective stress and subsequently decreasing shear strength. For significant seismic shaking, a near total loss of effective stress and shear strength occurs. Saturated sands are the most susceptible material to liquefaction. Effects of liquefaction include vertical settlement, horizontal spreading and slope failure caused by strength loss.

To evaluate liquefaction an understanding of the seismic load and resistance of the soils at a site is needed. The seismic load is defined by the cyclic stress ratio (CSR) and the resistance is defined by the cyclic resistance ratio (CRR). CSR was determined based on the maximum stress ratio profile calculated during the dynamic soil response analysis. CRR was determined based on the Robertson (2009) semi-empirical method using CPT sounding data.

Liquefaction calculations were performed using the computer program CLiq. Calculations were performed for each CPT sounding. Only minor layers of liquefaction are estimated to occur during a design seismic event at the Ash Pond. The effects of liquefaction include vertical settlement/horizontal spreading and loss of strength leading to slope failure. For vertical settlement/horizontal spreading, all layers estimated to liquefy, including relatively thin layers, were considered. No significant layers (minimum thickness of three feet) are estimated so no liquefiable layers were considered in the slope stability evaluations.

Vertical settlement is estimated to vary between 0 and 1 inch with an average of 0.5 inch. Horizontal spreading is estimated to vary between 0.5 and 20 inches with an average of nine inches. Based on these estimated values, release of CCR because of settlement or spreading is not expected during a design seismic event though some repair of the embankment and cover system will likely be required after a design seismic event.

3.1.4 Slope Stability

Since CCR will be impounded by built-up embankments, slope stability needs to be evaluated for conditions that will be encountered over a long period of time. These conditions include long-term steady state and seismic.

Long-term steady state conditions correspond to the current conditions of the embankment. All soils are modeled with drained, effective stress shear strength parameters and groundwater is modeled using average conditions. It should be noted based on the age of the embankments no excess pore pressures related to construction loading are present. Therefore, no end of construction condition is to be evaluated.

Seismic conditions correspond to the embankment during a design seismic event. There are two main ways to evaluate seismic stability. The first is to simply apply a horizontal load associated with an acceleration, such as the peak ground acceleration, to the entire embankment. An earthquake has a distribution of accelerations with magnitudes and directions that vary with time. A large majority of the accelerations experienced at the ground surface are either smaller than the peak ground acceleration or directed towards the embankment, away from the direction of slope failure. Thus assuming the peak ground acceleration as a constant load in a direction away from the embankment is a conservative approach.

There is also an approach by Makdisi and Seed which more accurately models the acceleration within the embankment and uses methods to estimate movement, if any, of the embankment during a seismic event. This type of analysis is known as a decoupled permanent-displacement analysis. Instead of providing a factor of safety as is generally done for slope stability evaluations, this method calculates a range of displacements that are estimated to occur during a design seismic event.

For this evaluation, the first approach was initially used as it is more conservative. This indicated a factor of safety below 1.0. Therefore, calculations using the Makdisi and Seed approach were made. Based on the relatively quick loading, total stress shear strengths are used for this analysis.

Minimum factors of safety vary for each condition analyzed. A review of recommended values included in the CCR Rule and United States Army Corps of Engineers' documentation were made. Based on this review, the minimum factors of safety for each condition are as listed below:

- Long-term steady state: 1.8.

As noted, for seismic stability, a range of displacements were calculated instead of a stability factor of safety.

Slope stability calculations were performed using the computer program UTexas 4. Calculations were performed on a critical section for the Ash Pond. This section was chosen based on embankment characteristics and subsurface materials. Based on these calculations, the embankment meets the minimum required slope stability factors of safety for long-term steady state and rapid drawdown conditions. For seismic conditions estimated displacements vary between 4 and 14 inches during a design seismic event. These displacements are considered acceptable and the embankment is considered stable.

Based on the closure-in-place closure method to be utilized, the Ash Pond will be subjected to long-term conditions including seismic events. Additionally, since the CCR is impounded by built-up soil embankments, slope stability of these embankments was evaluated. Based on the evaluations presented above, the Ash Pond is considered stable for long-term conditions.

3.2 Permitting

Burns & McDonnell anticipates permitting will play a role in the closure of the Reid/HMP&L Ash Pond. Appendix C contains a permitting matrix that provides an overview of the potential permitting requirements. Below is a more detailed discussion on the permitting requirements pertaining to the act of closing the Ash Pond.

3.3 Dewatering

At the start of closure construction, the Contractor shall begin lowering the water elevation in the Ash Pond. This may be done by discharging continuously out the existing Outfall 004, which ultimately drains into Outfall 001, per the site's Kentucky Pollutant Discharge Elimination System (KPDES) permit. The latest KPDES permit for the station was issued on June 15, 2018, and has requirements for Acute Whole Effluent Toxicity when discharging due to dewatering purposes. The KPDES permit constituent limits for Outfall 001 are shown in Table 3-1.

Table 3-1: Sebree Station KPDES Permit Summary

Outfall ID	Description	Reported Flow (MGD) Monthly Avg	Reported Flow (MGD) Daily Max	Treatment	Permit Discharge Limits Characteristic	Monthly Avg	Daily Max
001	Reid Ash Pond Discharge	Report	Report	Sedimentation and Neutralization	Total Suspended Solids	30.0 mg/l	99.7 mg/l
					Oil & Grease	15.0 mg/l	20.0 mg/l
					pH	6.0 (min)	9.0 (max)
					Chronic Whole Effluent Toxicity (WET)	N/A	2.35
					Acute WET (When Dewatering Only) *	N/A	1.00
					Total Recoverable Antimony	0.562	Report
					Total Recoverable Arsenic	0.135	0.306
					Total Recoverable Beryllium	0.401	Report
					Total Recoverable Cadmium	Report	0.005
					Total Recoverable Chromium	10.033	Report
					Total Recoverable Copper	0.017	0.028
					Total Recoverable Lead	0.008	0.028
					Total Recoverable Mercury	0.000046	0.0013
					Total Recoverable Nickel	0.096	0.867
					Total Recoverable Selenium	0.0045	Report
					Total Recoverable Silver	Report	0.015
					Total Recoverable Thallium	0.00042	Report
					Total Recoverable Zinc	0.222	0.222

* Two (2) discrete grab samples shall be collected 12 hours apart. The facility is not required to perform an Acute WET test is a Chronic WET was performed during that month. NODI Code 9 "Conditional Monitoring-Not Required This Period" can be used on the DMR for Acute WET during those months.

While it is anticipated the existing pond water quality would meet the KPDES permit discharge limitations, construction activities will disrupt the Total Suspended Solids (TSS) levels, shifting the discharges out of compliance. It is unlikely the water will be adequately be treated during construction through only temporary detention in the existing ponds.

If the pollutant concentrations in the Ash Pond water exceed the discharge limitations of the KPDES permit, the pond water will need to be treated for those specific pollutants whose concentrations exceed the water quality limits and then discharge the treated water through the permitted outfalls, or the untreated water may be pumped to a holding tank for off-site disposal at a treatment facility.

Another option the KDOW allows for is the authorized discharge of polluted waters through their One-Time Discharge (OTD) program. This program does not require a KDPES permit revision. Examples of potential OTDs as indicated by the KDOW include maintenance or repair of systems, hydrostatic tests of pipelines or of field-built, above-ground tanks, farm pond drainage, construction excavation de-watering, oil and gas pit close out, and fire system testing. An OTD request authorization may be obtained by BREC prior to the release of water out an existing outfall. Restrictions, limitations and requirements of the OTD permit are site specific, but in general, the discharge must meet the requirements set forth in 401 KAR 10:031 (Surface Water Standards) and should have no adverse effect on the environment. If needed, it is expected BREC would be able to receive OTD during dewatering of the Ash Pond as it has been allowed on similar pond closures elsewhere in Kentucky.

Once dewatering of the free water is completed, the dewatering of the CCR material may take place using a long-reach backhoe to create alternating piles the length of the pond, with channels in-between to accumulate the water draining from the CCR. A pump will likely be needed to remove surface water that cannot be removed with the in-place discharge system. Burns & McDonnell has assumed a temporary water treatment system will be rented for a total of four months during the closure of the Ash Pond, for a cost of approximately $4 million.

4.0 CONSTRUCTION CONSIDERATIONS

4.1 Construction Sequencing

For purposes of this study it is recommended that the Ash Pond closure project takes place in the following sequence:

- Dewatering of free water in the Ash Pond
- Dewatering of ash material in the Ash Pond
- Grading of CCR material in the Ash Pond
- Installation of cover system over prepared ash subgrade in the Ash Pond

CCR grading quantities were developed using topographical and bathymetric survey data completed by Associated Engineering in March 2019. A proposed, final site grading plan showing the final post-closure surface is included in Appendix A. It is assumed approximately 118,000 cubic yards of ash material will have to be relocated within the Ash Pond in order to obtain final grade elevations.

Water discharged during dewatering activities will need to meet the discharge limits of the current KPDES permit which is discussed in Section 3.2. Prior to and concurrent to dewatering, grading activities will begin. Such activities include excavating and moving CCR material from its current location for dewatering purposes and re-consolidation in the same or a different area. This leaves the finished CCR subgrade in a condition that should not pond, but instead drain stormwater off of its surface.

Once the CCR material is consolidated, a cover system, as described in Section 2.2 will be installed over the Ash Pond. For purposes of this report, the cross slope of the top of the final cover system has been assumed to be between 1.3 and 1.5 percent. The interior drainage channels have been assumed to have a slope of 1.1 percent.

4.2 Contracting Plan

The contracting plan developed for this project is for a single engineering contract to develop specifications, plans, Construction Quality Assurance (CQA) Plan and provide Contract Administration support and a single civil construction contract to execute the project based on the engineered plan drawings, specifications and CQA Plan. The civil contractor will execute the earthwork, ash material dewatering and treatment, ash consolidation, and capping system placement. The contractor may subcontract and coordinate specialty items of the work scope such as, but not limited to clearing and grubbing, dewatering and water treatment, and erosion control.

Burns & McDonnell recommends the civil contract be contracted as a lump sum agreement with adjustment unit pricing. The basis for payment would be per actual installed quantities as determined by in-place surveys. The contractor would perform work to the grades indicated and if more or less CCR material is present than expected, the contract price would be adjusted using the established contract unit prices.

5.0 PRELIMINARY PROJECT SCHEDULE

5.1 General

Under the CCR Rule, the closure of the Ash Pond at the Reid/HMP&L Station is required to be completed in five years. As indicated in the Notification of Intent to Close the Reid/HMP&L Station II Surface Impoundment document which was posted on BREC's public CCR website on May 17, 2019, the Ash Pond closure must be completed by April 17, 2024. The anticipated closure timeline, including permitting and engineering, is estimated to be completed in a little over two years. For purposes of this study, the start date of the final permitting and engineering activities was assumed to be September 2019.

The schedule includes approximately five months for detailed engineering design and a little over three months for the bid process. Once the final engineering design has been completed and submitted to the Kentucky Division of Waste Management, the division has 180 days to review the pre-permit application documentation. The permit review process should not exceed 365 days. A Level 1 schedule is included in Appendix B, which includes activities from engineering design to project completion.

Key construction activity dates depicted in the schedule are for a single construction crew, working 10-hour workdays for five days a week. The work could be completed on a shorter construction schedule if the contractor uses more than one crew or longer hours and 6 working days a week. The schedule does not include activities such as jurisdictional water delineations, endangered species studies, or other permitting which may be required and could increase the permitting and design support phase of the project.

The overall construction schedule reflects the volume of CCR material being graded and consolidated on-site. The estimated daily grading production rate of moving wet CCR material around within the pond is 3,500 cubic yards, assuming the use of two excavators and eight haul trucks. This estimate is based on other CCR unit closure projects Burns & McDonnell has been involved in.

6.0 COST ESTIMATE

The estimated cost for the closure of the Reid/HMP&L Ash Pond is summarized in Appendix D. The following outlines the basis for this cost estimate.

6.1 Cost Estimate Basis

The following methodology was used in the development of the project cost estimate.

- Estimate is based on the scope assumptions described in this report. Estimate quantities were developed based on the scope and issued to potential bidders for budgetary pricing.
- Construction costs were estimated from 2019 budgetary bids that were provided by local civil contractors. The bidders' unit pricing was averaged to determine a total project price.
- Project indirects were estimated based on Burns & McDonnell's experience. Percent allocations for indirects are as follows:
    - Construction Management – 5%
    - Engineering – 5%
    - Escalation – 3%
    - Owner's Costs – 5%
    - Project Definition and Estimate Contingency – 15%
- Cost estimate is based on 2019 dollars but escalated 3% per year for 2 years to estimate costs during construction.
- This estimate assumes that suitable volumes of topsoil and fill material will be available within five miles of Sebree Station for use at the Reid/HMP&L Ash Pond closure.
- The following major scope items are excluded from the estimated cost:
    - Costs for environmental studies and remediation.

6.2 Cash Flow

A preliminary cash flow has been prepared as in presentenced in Appendix D. The cash flow is based on the cost estimate in Appendix D and the schedule in Appendix B. The bid items presented in the cost estimate have been distributed as follows in the cash flow.

Table 6-1: Cash Flow Basis

Construction Activities	Start	End
Mobilization/Demobilization	3/31/2021	3/12/2021
Dewatering and Water Treatment	3/22/2021	7/9/2021
Clearing and Grubbing Existing Vegetation and Trees	3/15/2021	3/19/2021
Pond Solids Cut to Fill	3/22/2021	6/11/2021
Demolition 27" Steel Pipe	3/15/2021	3/19/2021
Demolition Floating Baffle Curtain	3/15/2021	3/19/2021
Erosion Control Installation and Maintenance	3/31/2021	11/12/2021
Misc (Borrow Area, Survey, etc)	3/3/2021	11/12/2021
Subgrade Finish Grading and Preparation	6/14/2021	7/9/2021
18" Protective Cover (Haul from Offsite Borrow Site)	7/12/2021	9/10/2021
Topsoil - 6" Depth from Offsite	9/13/2021	10/8/2021
Seeding	10/11/2021	10/29/2021
Quality Assurance/Quality Control	3/22/2021	10/8/2021
Construction Management (5%)	3/3/2021	11/12/2021
Engineering (5%)	9/27/2019	2/28/2020
Escalation (3% for 2 years)	3/3/2021	11/12/2021
Project estimate and scope contigency (15%)	3/3/2021	11/12/2021
Owner cost (10%)	9/7/2019	11/12/2021

All costs are distributed evenly between the dates above except for engineering which is distributed to start slowly and be heaviest during the middle of the timeline.

6.3 Limitations and Qualifications

Estimates and projections prepared by Burns & McDonnell relating to schedule, performance, and construction costs are based on our experience, qualifications and judgment as a professional consultant in the coal-fired power plant industry. Since Burns & McDonnell has no control over weather, cost and availability of labor, material and equipment, labor productivity, construction contractor's procedures and methods, unavoidable delays, construction contractor's method of determining prices, economic conditions, government regulations and laws (including interpretation thereof), competitive bidding and market conditions or other factors affecting such estimates or projections, Burns & McDonnell does not guarantee that actual rates, costs, performance, schedules, etc., will not vary from the estimates and projections prepared by Burns & McDonnell.

APPENDIX A – SITE PLAN

NORTH

0 100' 200'
SCALE IN FEET

PRELIMINARY - NOT FOR CONSTRUCTION

no.	date	by	ckd	description
2	08/09/19	KEW	MDB	ISSUED FOR REPORT
1	05/17/19	KEW	MDB	ISSUED FOR REV 1
0	04/30/19	KEW	MDB	INITIAL ISSUE

BURNS & McDONNELL
9400 WARD PARKWAY
KANSAS CITY, MO 64114
816-333-9400

designed: K. WYLAM
detailed: S. NICHOLS

Big Rivers ELECTRIC CORPORATION
Your Touchstone Energy® Cooperative
REID/HMP&L STATION
HENDERSON COUNTY, KENTUCKY

ASH POND
project: 114088
contract:
drawing: SKC005
rev.: 2
sheet — of — sheets
file 114088SKC005.DGN

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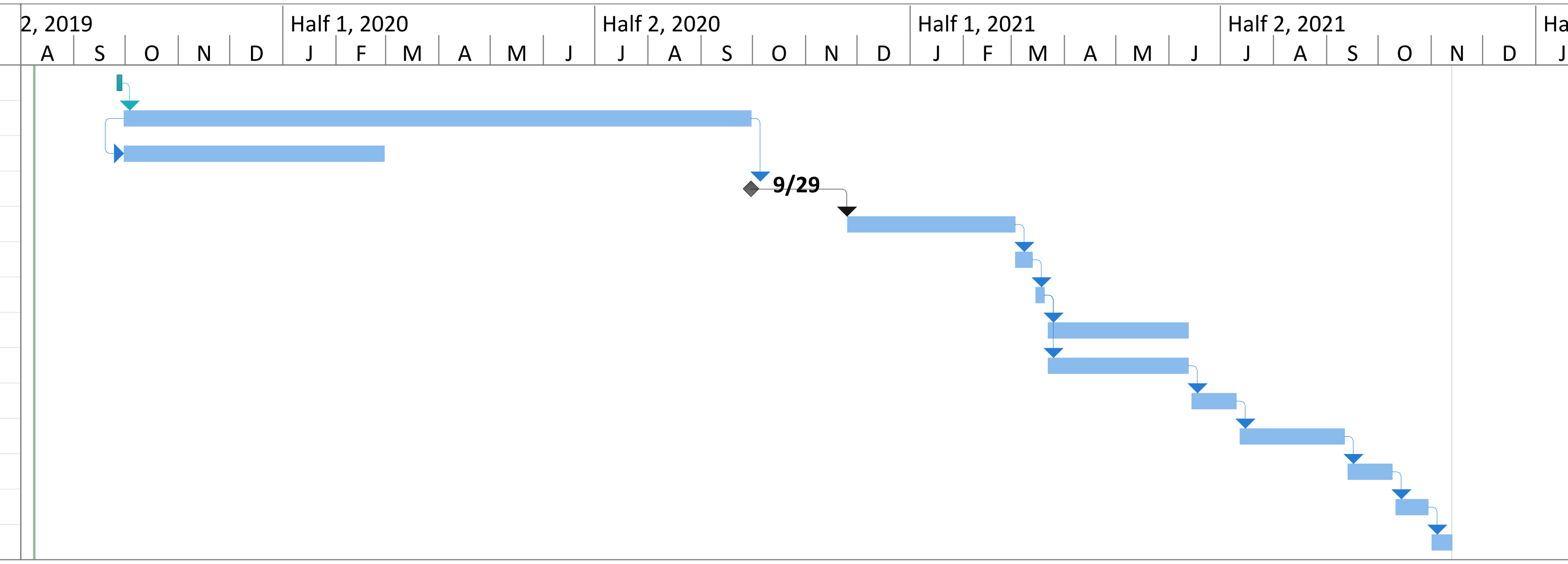
8/9/2019 sknichols 2:01:36 PM

APPENDIX B – CLOSURE SCHEDULE

ID	Task Mode	Task Name	Start	Finish	Duration	Predecessors
1		Engineering Notice to Proceed	Fri 9/27/19	Fri 9/27/19	1 day	
2		Permitting & Design Support	Mon 9/30/19	Tue 9/29/20	262 days	1
3		Engineering Design	Mon 9/30/19	Fri 2/28/20	110 days	2SS
4		BREC Receives Permits	Tue 9/29/20	Tue 9/29/20	0 days	2
5		Bid and Award Phase	Wed 11/25/20	Tue 3/2/21	70 days	4FS+40 days
6		Contractor Mobilization	Wed 3/3/21	Fri 3/12/21	8 days	5
7		Clearing, Grubbing & Misc. Demo	Mon 3/15/21	Fri 3/19/21	5 days	6
8		Dewater Ash	Mon 3/22/21	Fri 6/11/21	60 days	7
9		Grade CCR Material in Ash Pond	Mon 3/22/21	Fri 6/11/21	60 days	7
10		Prepare Ash Subgrade	Mon 6/14/21	Fri 7/9/21	20 days	9
11		Install 18" Infiltration Layer in Ash Pond	Mon 7/12/21	Fri 9/10/21	45 days	10
12		Install 6" Topsoil Layer in Ash Pond	Mon 9/13/21	Fri 10/8/21	20 days	11
13		Seeding of Ash Pond	Mon 10/11/21	Fri 10/29/21	15 days	12
14		Site Cleanup and Demobilization	Mon 11/1/21	Fri 11/12/21	10 days	13



Project: Reid/HMP&L Ash Pond Cl
Date: Fri 8/9/19

Task	Project Summary	Inactive Milestone	Manual Summary Rollup	Deadline
Split	External Tasks	Inactive Summary	Manual Summary	Progress
Milestone	External Milestone	Manual Task	Start-only	Manual Progress
Summary	Inactive Task	Duration-only	Finish-only	

APPENDIX C – PERMITTING MATRIX

Item No.	Permit/Clearance	Regulatory Agency	Details	When Required	Anticipated Agency Review Time	Associated Fees	Comments
Federal							
1	Clean Water Act - Section 404 Permit	U.S. Army Corps of Engineers, Louisville District	Required to dredge or place fill in a jurisdictional water, including wetlands Nationwide Permit: Less than or equal to 0.5 acre of wetland or stream impacts Individual Permit: Greater than 0.5 acre of wetland or stream impacts	Prior to construction	45 to 60 days for a Nationwide Permit 6 to 12 months for an Individual Permit	No application or mitigation fees	A wetland delineation will be required to determine the extent of wetland and stream impacts associated with site construction. If the project qualifies for a Nationwide Permit 39 (Commercial and Institutional Developments), a pre-construction notification would be required.
2	Section 7 Threatened and Endangered Species Consultation and Clearance	U.S. Fish & Wildlife Service (FWS), Ecological Services	If the project will potentially impact protected species or their respective habitat, or if a Section 404 and/or NPDES permit is required, then the FWS must be contacted. The FWS will determine the level of effort needed for the project to proceed (e.g., habitat assessment, species surveys, avian impact studies, etc.).	Prior to construction	30 days for initial response, additional 30 days for determination of field survey results (if required)	No fees	**Formal consultation likely not required if construction will take place in an already developed area and no Section 404 Permit is required.**
3	Migratory Bird Treaty Act / Bald and Golden Eagle Protection Act Compliance	U.S. Fish & Wildlife Service (FWS), Ecological Services	Required when construction or operation of a proposed facility could impact migratory birds, their nests, and especially threatened or endangered species	Prior to construction	30 days for data request, 30 days for report review	No fees	**Formal consultation likely not required if construction will take place in an already developed area and no Section 404 Permit is required.**
4	Notice of Proposed Construction	Federal Aviation Administration (FAA)	Required for the construction of structures 200 feet tall or within the distance to height ratio from the nearest point of a FAA airport runway. Notifying the FAA includes completing Form 7460-1 for all required structures and providing a site layout map depicting structure locations. Also required for construction equipment reaching heights over 200 feet.	Prior to construction	45+ days	No fees	**Likely not required unless construction equipment will reach heights over 200 feet.**
5	Spill Prevention, Control, and Countermeasure Plan Amendment	U.S. Environmental Protection Agency (EPA)	An amendment to the facility's SPCC Plan will be required to address changes to operation or site layout/drainage.	Prior to operation	Not required to submit the SPCC Plan to the EPA for review, unless requested.	No fees	
State - Kentucky							
6	Certificate of Public Convenience and Necessity (CPCN)	Kentucky Public Service Commission	Required for the construction of electric generating facilities	Prior to construction	120 days after the submission of a complete application	Project specific	**A CPCN is not likely required for the pond closures unless the Public Service Commission has a project cost or rate recovery threshold.**
7	Environmental Assessment (EA) or Environmental Impact Statement (EIS)	Kentucky Public Service Commission	Facility modifications to meet CCR requirements may trigger an EA or EIS if the project will request financing from the USDA Rural Utilities Service (RUS).	Prior to construction	6 to 9 months	No filing fees	**Because this project is environmentally beneficial and will reduce future risks to water quality, it is unlikely that the RUS would require an EIS.**
8	Groundwater Protection Plan	Kentucky Department of Environmental Protection Division of Water	If the facility has a Groundwater Protection Plan (GPP), as required by 401 KAR 5.037, it should be updated based on site changes and prior to the installation of groundwater monitoring wells. If the facility currently does not have a GPP, one may be required prior to groundwater monitoring well installation.	Prior to construction	Agency review of the GPP is optional unless required by a KYDEP inspector or the GPP Program. Must retain onsite records.	No fees.	**The project site is not located in a Wellhead Protection Area.**

Item No.	Permit/Clearance	Regulatory Agency	Details	When Required	Anticipated Agency Review Time	Associated Fees	Comments
9	Permit to Construct Across or Along a Stream and/or Section 401 Water Quality Certification (WQC)	Kentucky Department of Environmental Protection Division of Water	In addition to authorizing stream crossings, this permit also provides Section 401 WQC and floodplain construction approval. The purpose of the WQC is to confirm that the discharge of fill materials (Section 404 Permit) will be in compliance with the State's applicable water quality standards.	Prior to construction	20 business days	No fees	Assumes automatic Water Quality Certification authorization through the Corps' Nationwide Program. The permit application must be reviewed and signed by the local county floodplain coordinator(s) prior to submitting the application to the State. **The project site is located in the Ohio River floodplain.**
10	One-Time/Temporary Discharge Request for Off-Permit Authorization	Kentucky Department of Environmental Protection Division of Water	Required for temporary discharges of wastewater outside of permitted discharges. May be used for pond dewatering.	Prior to testing	30 days	No fees	
11	General Permit for Stormwater Discharges Associated with Construction Activities	Kentucky Department of Environmental Protection Division of Water	Required for all stormwater discharges from construction activities which will disturb 1 or more total acres of land. The General Permit requires the development of a Stormwater Pollution Prevention Plan (SWPPP) prior to submitting a Notice of Intent for permit coverage.	Prior to construction	7 days	No fees	The permit also authorizes the discharge of construction dewatering waters if managed through the use of appropriate best management practices.
12	KPDES Operational Discharge Permit Modification	Kentucky Department of Environmental Protection Division of Water	The facility will be required to modify its existing KPDES Operational Discharge Permit (KY0001937) to address operational and water quality changes related to the discharge of wastewaters.	Prior to operation	180 days prior to operational changes	$7,000	If the existing permit requires an operational Stormwater Pollution Prevention Plan (SWPPP), this plan must be updated to address operational changes/modified stormwater flows.
13	National Historic Preservation Act – Section 106 Clearance	Kentucky Heritage Council - State Historic Preservation Office (SHPO)	Under Section 106 of the National Historic Preservation Act, Federal agencies must work with the State Historic Preservation Office to address historic preservation issues when planning projects or issuing funds or permits that may affect historic properties and archaeological resources listed in or determined eligible for the National Register of Historic Places.	Prior to construction	45 Days	$40 for Preliminary Site Check through SHPO database	**Formal consultation likely not required if construction will take place in an already developed area and no Section 404 Permit is required.**
14	Threatened & Endangered Species Clearance (State)	Kentucky Department of Fish and Wildlife Resources, Kentucky State Nature Preserves Commission, and Kentucky Division of Forestry	Required when a proposed project may impact State-listed species or when a project lies within an area of known occurrence of listed species or the habitat of a listed species	Prior to construction	30 days for initial response, additional 30 days for determination of field survey results (if required)	No fees	**Formal consultation likely not required if construction will take place in an already developed area and no Section 404 Permit is required.**

APPENDIX D – COST ESTIMATE

Construction Activities	Qty	Unit	2019 Cost
Cap in Place - Ash Pond			
Mobilization/Demobilization	[redacted]	[redacted]	[redacted]
Dewatering and Water Treatment	[redacted]	[redacted]	[redacted]
Clearing and Grubbing Existing Vegetation and Trees	[redacted]	[redacted]	[redacted]
Pond Solids Cut to Fill	[redacted]	[redacted]	[redacted]
Demolition 27" Steel Pipe	[redacted]	[redacted]	[redacted]
Demolition Floating Baffle Curtain	[redacted]	[redacted]	[redacted]
Erosion Control Installation and Maintenance	[redacted]	[redacted]	[redacted]
Misc (Borrow Area, Survey, etc)	[redacted]	[redacted]	[redacted]
Subgrade Finish Grading and Preparation	[redacted]	[redacted]	[redacted]
18" Protective Cover (Haul from Offsite Borrow Site)	[redacted]	[redacted]	[redacted]
Topsoil - 6" Depth from Offsite	[redacted]	[redacted]	[redacted]
Seeding	[redacted]	[redacted]	[redacted]
Quality Assurance/Quality Control	[redacted]	[redacted]	[redacted]
Tariff 232	[redacted]	[redacted]	[redacted]
Direct Cost Subtotal			[redacted]
Survey			[redacted]
Geotechnical Investigation			[redacted]
Construction Management (5%)			[redacted]
Engineering (5%)			[redacted]
Escalation (3% for 2 years)			[redacted]
Total Direct and Indirect Cost			[redacted]
Project estimate and scope contigency (15%)			[redacted]
Total Project Cost			[redacted]
Owner cost (5%)			[redacted]
Total Project Cost Incl. Owner Cost			[redacted]

BREC Reid/HMPL Station, Closure In-Place

Project Cash Flow

Date	Incremental	Cumulative	Incremental %	Cumulative %	Millions
Aug-19	[redacted]				
Sep-19					
Oct-19					
Nov-19					
Dec-19					
Jan-20					
Feb-20					
Mar-20					
Apr-20					
May-20					
Jun-20					
Jul-20					
Aug-20					
Sep-20					
Oct-20					
Nov-20					
Dec-20					
Jan-21					
Feb-21					
Mar-21					
Apr-21					
May-21					
Jun-21					
Jul-21					
Aug-21					
Sep-21					
Oct-21					
Nov-21					

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BIG RIVERS ELECTRIC CORPORATION

**ELECTRONIC APPLICATION OF
BIG RIVERS ELECTRIC CORPORATION
FOR ENFORCEMENT OF RATE AND SERVICE STANDARDS
CASE NO. 2019-00269**

**Response to Commission Staff's
Initial Request for Information
dated May 19, 2020**

June 8, 2020

Item 2) ***Refer to the application, paragraph 17. Provide the status of the Station Two Bond issuance to extent of BREC's knowledge on this matter as of this date.***

Response) Prior to February, 1, 2019, Henderson verbally indicated that its bonds related to Station Two were still outstanding. Big Rivers is not aware of any change in the status of the bonds subsequent to the retirement of Station Two.

Witness) Paul G. Smith

BIG RIVERS ELECTRIC CORPORATION

ELECTRONIC APPLICATION OF
BIG RIVERS ELECTRIC CORPORATION
FOR ENFORCEMENT OF RATE AND SERVICE STANDARDS
CASE NO. 2019-00269

Response to Commission Staff's
Initial Request for Information
dated May 19, 2020

June 8, 2020

Item 3) ***Refer to the application, paragraph 37.***

a. ***State whether BREC will incur any costs related to the operation of the Green Station landfill once the Station Two ash pond coal ash residuals are decommissioned. If so, provide a schedule of such costs.***

b. ***Provide a schedule of all actual historical costs incurred and expected future costs BREC expects to incur and recover relative to the Henderson contracts in this proceeding, broken down by the operating facilities and joint facilities by account (number and name of account) by year.***

Response)

a. Yes. The provisions of the CCR Rule include a 30-year post closure care period which will require Big Rivers to maintain the integrity and effectiveness of the facility as well as conducting ongoing groundwater monitoring. The annual O&M costs are expected to be approximately $60,000 per year. It is always possible that either the federal or state regulatory authorities could implement new regulations, or change existing regulations, in such a way as to create additional costs relating to the maintenance of the landfill.

b. Please see attachment for a listing of joint facility maintenance costs, by account, for calendar year 2018.

Witness) Michael T. Pullen (*a. only*) and
Paul G. Smith (*b. only*)

Big Rivers Electric Corporation
Case No. 2019-00269

Joint Facility Maintenance Costs

Calendar Year 2018

Exhibit Document	Root Asset	Account	Loc	Station Two Costs
Totals				
Remain in Service	092017: R-00 #1 COAL CONVEYOR	51110000	1310	-
Remain in Service	092033: REID 00 NEW CRUSHER TO	51210000	1601	1,058
Remain in Service	091999: R-00 BARGE UNLOADER	51210000	1601	(491)
Remain in Service	091999: R-00 BARGE UNLOADER	51210000	1510	11,877
Remain in Service	092017: R-00 #1 COAL CONVEYOR	51210000	1510	7,058
Remain in Service	092033: REID 00 NEW CRUSHER TO	51210000	1510	9,065
Remain in Service	091999: R-00 BARGE UNLOADER	51210000	1510	103,859
Remain in Service	172534: MOORING CELLS	51210000	1510	29,504
To Be Decommissioned	093983: REID STA F.O.TK	51210000	1310	-
To Be Decommissioned	091989: CONVEYOR, 6A	51210000	1601	(463)
To Be Decommissioned	092096: GROUNDS	51110000	1601	1,525
To Be Decommissioned	091937: R-00 5B COAL CONVEYOR	51210000	1510	13,474
To Be Decommissioned	091942: R-00 4A COAL CONVEYOR	51210000	1510	23,589
To Be Decommissioned	091946: R-00 RECLAIM COAL YARD	51210000	1510	717
To Be Decommissioned	091949: R-00 RECLAIM COAL YARD	51210000	1510	985
To Be Decommissioned	091958: REID 00 2B COAL CONVEY	51210000	1510	18,450
To Be Decommissioned	091986: CONVEYOR, 6B	51210000	1510	1,850
To Be Decommissioned	091989: CONVEYOR, 6A	51210000	1510	6,154
To Be Decommissioned	092023: R-00 RECLAIM COAL YARD	51210000	1510	1,261
To Be Decommissioned	092024: R-00 4B COAL CONVEYOR	51210000	1510	15,747
To Be Decommissioned	092031: CONVEYOR, 5A	51210000	1510	20,769
To Be Decommissioned	099104: HMP&L ONE CIRCULATING	51310000	1510	751
To Be Decommissioned	099105: HMP&L TWO CIRCULATING	51310000	1510	1,546
To Be Decommissioned	097609: AUX.TRANSFORMER	51310000	1510	411
To Be Decommissioned	097619: AUX.TRANSFORMER	51310000	1510	411
To Be Decommissioned	188084: STEP-UP TRANSFORMER	51310000	1510	1,834
				270,943

ELECTRONIC APPLICATION OF
BIG RIVERS ELECTRIC CORPORATION
FOR ENFORCEMENT OF RATE AND SERVICE STANDARDS
CASE NO. 2019-00269

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dated May 19, 2020

June 8, 2020

Item 4) ***Refer to the application, paragraph 38. Identify and explain the parties' contractual obligations with respect to the Joint Facilities Agreement and provide a comparison of the financial impacts with respect to each party's position.***

Response) The contractual obligations of Big Rivers and Henderson with respect to the Joint Facilities Agreement ("JFA") have evolved over time as the JFA has been amended to accommodate the expansion of generation facilities and pollution control equipment at the Reid/Green/Station Two complex in Sebree, Kentucky. Because Big Rivers is uncertain regarding Henderson's position, Big Rivers cannot provide a comparison of the financial impacts with respect to each party's position.

The Reid plant was Big Rivers' first plant and was the first generator built at the Reid/Green/Station Two complex. Reid was a 65 MW coal-fired plant that went into service in 1966. It has not produced energy since 2015 and is planned for retirement in 2020. The original JFA, Power Sales Contract and Power Plant Construction and Operation Agreement were all entered into in 1970. Station Two was much too large to serve only the City load. As shown on Exhibit Pullen-1 to my

Direct Testimony, in 1973 Henderson reserved only 13 MW from Station Two. But the energy and capacity that the City did take was very economical due to economies of scale and the existing joint use facilities at Reid.

The contractual obligations of the parties in the original 1970 JFA were fairly straight-forward. Under Section 1.1, the City would construct Station Two so as to take advantage of Big Rivers' auxiliary facilities and operating personnel at Reid, with Big Rivers operating Station Two as an independent contractor. Under Section 1.5, as long as one party operates a power plant at the complex, then the joint use facilities must be provided by the other. Under Section 4.1, ownership title of the joint use facilities provided by the City remains with the City and the ownership title for joint use facilities provided by Big Rivers remains with Big Rivers. Under Section 5.1, the costs of operating, maintaining, repairing, renewing, replacing and adding to either parties' joint use facility are allocated to Station Two and Reid based upon their respective capacity (MW). Under Section 6.1, the parties are severally and jointly responsible for the continued operation, maintenance, repair, renewal and replacement of the joint use facilities. For example, as discussed on page 20 of my Direct Testimony, since February 1, 2019 (the retirement date of Station Two), Big

Rivers has paid 100% of the operations and maintenance costs attributable to our use of City-owned joint use facilities. Under Section 8.1, the JFA remains in force for as long as either party is using a joint use facility. Under section 9.1, the joint use facilities must be constructed, operated and maintained as required by any regulatory authority having jurisdiction thereof, *e.g.*, the Commission. Section 9.1 is particularly relevant to this case because this Section gives the Commission continuing jurisdiction over the Station Two ash pond (which is a joint use facility owned by the City) closure cost responsibilities under the CCR rule. In addition, even as to the Station Two Contracts that have expired, the Commission has continuing jurisdiction to enforce obligations arising out of the Contracts.

The first 231 MW unit at Big Rivers' Green station came on-line in 1979. The second 223 MW Green unit came on-line in 1981.

In 1993, the 1970 Power Sales Contract, 1970 Power Plant Construction and Operation Agreement and the 1970 Joint Facilities Agreement were all amended to allow for construction of a flue gas desulfurization ("FGD") system at Station Two to comply with the acid rain provisions of the Clean Air Act Amendments. The joint use of the existing Green FGD system greatly reduced the cost of the FGD system at Station Two.

- As stated in the 1993 Amendments:

  "WHEREAS, certain facilities now owned by Big Rivers subject to certain mortgage liens, and used in operating the FGD System of Big Rivers' Green generating Station, can be used jointly by the Green Station and Station two, thus greatly reducing the cost of the Station Two FDG System…"

The three page Exhibit 1 to the 1993 Amendment to the JFA provided significant additional detail as to what constitutes a joint use facility. In the 1993 Amendment, the definition of Station Two was clarified to include all existing facilities at the plant (two steam generators, two turbine generators, two electrostatic precipitators, two cooling towers, etc.) plus joint use facilities furnished and owned by the City. Exhibit 1, page 1 of 3, Part B lists all of the "Joint Use Facilities Provided By and Owned By the City But Located on Big Rivers' Property." Of particular relevance here are Items 13 (One Ash Pond and Effluent Lines) and Item 15 (Station Two Ash Pond Dredgings in Green Station Sludge Disposal Landfill adjacent to Green River south of Green Station). This means that the Station Two ash pond and all

Station Two ash pond dredgings stored in the Green landfill are part of the definition of Station Two.

Prior to the 1993 Amendments, Big Rivers had no responsibility for any decommissioning costs of Station Two or the City-owned joint use facilities. In the 1993 Amendments, the term of the Station Two Contracts (except the Joint Facilities Agreement) was extended to coincide with the economic life of the Station Two units, and Big Rivers agreed to share in Station Two decommissioning costs.

Station Two is solely owned by Henderson. Therefore, unless Station Two is decommissioned, Big Rivers has no cost responsibility for the retirement-in-place of Station Two, for Station Two ash pond closure costs under the CCR rule, or for the Station Two waste stored in the Green landfill. However, under Section 8 of the 1993 Amendments, if Station Two is decommissioned, then Big Rivers is responsible for 77.24% of all decommissioning costs.

The 1993 Amendments to the JFA also specified that the disposal, haulage, maintenance and other operating costs associated with Station Two waste stored in the Green landfill would be allocated among Green and Station Two based upon usage.

Finally, there were relatively minor changes to the JFA in the 1998 Amendments.

Witness) Michael T. Pullen

BIG RIVERS ELECTRIC CORPORATION

ELECTRONIC APPLICATION OF
BIG RIVERS ELECTRIC CORPORATION
FOR ENFORCEMENT OF RATE AND SERVICE STANDARDS
CASE NO. 2019-00269

Response to Commission Staff's
Initial Request for Information
dated May 19, 2020

June 8, 2020

Item 5) ***Refer to the application, Exhibit 1, and BREC's Motion to Amend Exhibits, filed on January 21, 2020. Provide an updated itemization of the costs and expenses shown on this exhibit along with the support or cost justification for each item.***

Response) Following is a summary of the total due from Henderson as originally filed, as subsequently amended, and the balance as of April 30, 2020:

Exhibit	Description	Originally Filed	Actual 12/31/19[1]	Actual 4/30/20
Smith-2	Excess Henderson Energy	($3,310,482)	($3,310,482)	($3,310,482)
Smith-3	Henderson Native Load	4,693,587	4,693,587	4,693,587
Smith-4	Other Operating Costs	(798,261)	(941,581)	(941,581)
Smith-5	Decommissioning Costs	134,098	716,458	909,629
	Total Due From/(To) HMPL	$ 718,942	$ 1,157,982	$ 1,351,153

[1] Amended exhibits filed January 21, 2020.

Exhibit Smith-4: Other Operating Costs, Fiscal Year 2018/2019 Settlement True-up reflects adjustment of severance costs from 2018 original estimate of $3,356,897 to 2019 actual costs incurred of $2,998,970, of which Henderson's share of the adjustment is $143,400. Other miscellaneous adjustments total $80.

BIG RIVERS ELECTRIC CORPORATION

ELECTRONIC APPLICATION OF
BIG RIVERS ELECTRIC CORPORATION
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CASE NO. 2019-00269

Response to Commission Staff's
Initial Request for Information
dated May 19, 2020

June 8, 2020

Exhibit Smith-5: Decommissioning costs. Please see Attachment 1 to this response for the itemized costs, by activity, by month, for the period January, 2019 through April, 2020.

The above response assumes the completion of full decommissioning of Station Two. As stated in the Application, and in the Direct Testimony of Mr. Berry (pages 45 & 46), if Henderson elects not to cooperate in fully decommissioning any portion of Station Two, any ongoing maintenance costs or other costs or liabilities, including but not limited to environmental remediation, are solely the responsibility of Henderson. In this case, the following table, along with Attachment 2, Exhibit Smith-1B, and Exhibit Smith-6 would apply.

Exhibit	Description	Actual 6/30/19	Actual 12/31/19[1]	Actual 4/30/20
Smith-2	Excess Henderson Energy	($3,310,482)	($3,310,482)	($3,310,482)
Smith-3	Henderson Native Load	4,693,587	4,693,587	4,693,587
Smith-4	Other Operating Costs	(798,261)	(941,581)	(941,581)
Smith-6	Ongoing Maintenance Costs	621,870	1,986,427	2,557,634
	Total Due From/(To) HMPL	$1,206,714	$ 2,427,951	$ 2,999,158

Witness) Paul G. Smith

Big Rivers Electric Corporation
A/R HMP - Decommissioning Costs
Case No. 2019-00269

	GROSS TOTAL	STATION TWO	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19
			STATION TWO					
RAMP DOWN								
SII Only	$ 1,630,497	$ 1,630,497	$ 33,249	$ 125,298	$ 99,117	$ 80,190	$ 34,628	$ 39,997
RD/SII	164,548	136,177	13,947	8,386	19,808	46,168	33,368	14,749
RD/GN/SII	260	97	-	63	34	-	-	-
	1,795,304	1,766,772	47,197	133,747	118,959	126,358	67,995	54,746
CCR Incremental Costs- SII Only	83,048	83,659	-	-	-	-	18,858	10,800
Ash Pond Closure (BP20G300E)	175,231	175,231	-	-	-	-	-	-
Auxiliary Power	107,956	107,956	-	20,524	13,730	8,771	5,265	4,649
Total Cost	$ 2,161,538	2,133,617	47,197	154,271	132,689	135,129	92,118	70,195
Henderson Allocation								
Percentage - Decommission		22.76%						
Amount		$ 485,611	$ 10,742	$ 35,112	$ 30,200	$ 30,755	$ 20,966	$ 15,976

Big Rivers Electric Corporation
A/R HMP - Decommissioning Costs
Case No. 2019-00269

	GROSS TOTAL	STATION TWO	STATION TWO Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19
RAMP DOWN								
SII Only	$ 1,630,497	$ 1,630,497	$ 21,308	$ 303,045	$ 96,560	$ 101,890	$ 104,642	$ 120,948
RD/SII	164,548	136,177	(248)	-	-	-	-	-
RD/GN/SII	260	97	-	-	-	-	-	-
	1,795,304	1,766,772	21,060	303,045	96,560	101,890	104,642	120,948
CCR Incremental Costs- SII Only	83,048	83,659	21,003	12,897	2,361	3,940	5,355	9,134
Ash Pond Closure (BP20G300E)	175,231	175,231	-	-	-	-	-	175,231
Auxiliary Power	107,956	107,956	5,471	4,767	5,022	5,525	7,559	6,176
Total Cost	$ 2,161,538	2,133,617	47,535	320,710	103,943	111,354	117,556	311,489
Henderson Allocation								
Percentage - Decommission		22.76%						
Amount		$ 485,611	$ 10,819	$ 72,994	$ 23,658	$ 25,344	$ 26,756	$ 70,895

Big Rivers Electric Corporation
A/R HMP - Decommissioning Costs
Case No. 2019-00269

	GROSS TOTAL	STATION TWO	STATION TWO Jan-20	Feb-20	Mar-20	Apr-20
RAMP DOWN						
SII Only	$ 1,630,497	$ 1,630,497	$ 137,619	$ 105,444	$ 79,121	$ 147,441
RD/SII	164,548	136,177	-	-	-	-
RD/GN/SII	260	97	-	-	-	-
	1,795,304	1,766,772	137,619	105,444	79,121	147,441
CCR Incremental Costs- SII Only	83,048	83,659	-	-	6,368	(7,057)
Ash Pond Closure (BP20G300E)	175,231	175,231	-	-	-	
Auxiliary Power	107,956	107,956	6,284	5,306	4,834	4,071
Total Cost	$ 2,161,538	2,133,617	143,904	110,750	90,323	144,455
Henderson Allocation						
Percentage - Decommission		22.76%				
Amount		$ 485,611	$ 32,752	$ 25,207	$ 20,558	$ 32,878

Big Rivers Electric Corporation
A/R HMP - Decommissioning Costs
Case No. 2019-00269

	GROSS TOTAL	STATION TWO	STATION TWO Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19
Landfill								
Slurry Wall (BP19G200E)	$ 2,204,264	$ 2,204,264	$ -	$ -	$ -	$ -	$ -	$ -
Leachate (BP19G201E)	1,409,260	1,409,260	-	-	-	-	-	-
	$ 3,613,525	3,613,525	-	-	-	-	-	-
Henderson Allocation								
Percentage - Landfill Decommission		12%						
Amount		$ 433,623	$ -	$ -	$ -	$ -	$ -	$ -
Transmission Assets (TMSTATIONS100)		122						
Amount Due From Henderson								
Total Allocated Decommissioning Costs		**$ 919,357**	**$ 10,742**	**$ 35,112**	**$ 30,200**	**$ 30,755**	**$ 20,966**	**$ 15,976**
Less: 2019 Payments (Aux Power Feb, Mar & Apr)		**9,728**	**-**	**4,640**	**3,104**	**1,983**	**-**	**-**
Balance Due		**$ 909,629**	**$ 10,742**	**$ 30,472**	**$ 27,096**	**$ 28,772**	**$ 20,966**	**$ 15,976**
Cumulative Amount Due								**$ 134,023.91**

Big Rivers Electric Corporation
A/R HMP - Decommissioning Costs
Case No. 2019-00269

	GROSS TOTAL	STATION TWO	STATION TWO Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19
Landfill								
Slurry Wall (BP19G200E)	$ 2,204,264	$ 2,204,264	$ -	$ -	$ -	$ -	$ -	$ 1,677,518
Leachate (BP19G201E)	1,409,260	1,409,260	-	-	-	-	-	1,255,561
	$ 3,613,525	3,613,525	-	-	-	-	-	2,933,079
Henderson Allocation								
Percentage - Landfill Decommission		12%						
Amount		$ 433,623	$ -	$ -	$ -	$ -	$ -	$ 351,969
Transmission Assets (TMSTATIONS100)		122						
Amount Due From Henderson								
Total Allocated Decommissioning Costs		**$ 919,357**	**$ 10,819**	**$ 72,994**	**$ 23,658**	**$ 25,344**	**$ 26,756**	**$ 422,864**
Less: 2019 Payments (Aux Power Feb, Mar & Apr)		**9,728**	**-**	**-**	**-**	**-**	**-**	**-**
Balance Due		**$ 909,629**	**$ 10,819**	**$ 72,994**	**$ 23,658**	**$ 25,344**	**$ 26,756**	**$ 422,864**
Cumulative Amount Due								**$ 716,458.25**

Big Rivers Electric Corporation
A/R HMP - Decommissioning Costs
Case No. 2019-00269

	GROSS TOTAL	STATION TWO	STATION TWO Jan-20	Feb-20	Mar-20	Apr-20
Landfill						
Slurry Wall (BP19G200E)	$ 2,204,264	$ 2,204,264	$ 65,936	$ 82,944	$ 134,150	$ 243,717
Leachate (BP19G201E)	1,409,260	1,409,260	146,359	(1,482)	1,158	7,664
	$ 3,613,525	3,613,525	212,295	81,462	135,308	251,381
Henderson Allocation						
Percentage - Landfill Decommission		12%				
Amount		$ 433,623	$ 25,475	$ 9,775	$ 16,237	$ 30,166
Transmission Assets (TMSTATIONS100)		122	122			
Amount Due From Henderson						
Total Allocated Decommissioning Costs		**$ 919,357**	**$ 58,350**	**$ 34,982**	**$ 36,795**	**$ 63,044**
Less: 2019 Payments (Aux Power Feb, Mar & Apr)		**9,728**	**-**	**-**	**-**	
Balance Due		**$ 909,629**	**$ 58,350**	**$ 34,982**	**$ 36,795**	**$ 63,044**
Cumulative Amount Due						**$ 909,628.67**

Big Rivers Electric Corporation
A/R HMP - Ongoing Maintenance, Environmental Remediation and Other Obligations of Henderson Arising Out of the Station Two Contracts
Case No. 2019-00269

	GROSS TOTAL	STATION TWO	STATION TWO Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19
RAMP DOWN								
SII Only	$ 1,630,497	$ 1,630,497	$ 33,249	$ 125,298	$ 99,117	$ 80,190	$ 34,628	$ 39,997
RD/SII	164,548	136,177	13,947	8,386	19,808	46,168	33,368	14,749
RD/GN/SII	260	97	-	63	34	-	-	-
	1,795,304	1,766,772	47,197	133,747	118,959	126,358	67,995	54,746
CCR Incremental Costs- SII Only	83,048	83,659	-	-	-	-	18,858	10,800
Ash Pond Closure (BP20G300E)	175,231	175,231	-	-	-	-	-	-
Auxiliary Power	107,956	107,956	-	20,524	13,730	8,771	5,265	4,649
Total Cost	$ 2,161,538	2,133,617	47,197	154,271	132,689	135,129	92,118	70,195
Henderson Allocation								
Percentage - Decommission		100.00%						
Amount		$ 2,133,617	$ 47,197	$ 154,271	$ 132,689	$ 135,129	$ 92,118	$ 70,195

Big Rivers Electric Corporation
A/R HMP - Ongoing Maintenance, Environmental Remediation and Other Obligations of Henderson Arising Out of the Station Two Contracts
Case No. 2019-00269

	GROSS TOTAL	STATION TWO	STATION TWO Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19
RAMP DOWN								
SII Only	$ 1,630,497	$ 1,630,497	$ 21,308	$ 303,045	$ 96,560	$ 101,890	$ 104,642	$ 120,948
RD/SII	164,548	136,177	(248)	-	-	-	-	-
RD/GN/SII	260	97	-	-	-	-	-	-
	1,795,304	1,766,772	21,060	303,045	96,560	101,890	104,642	120,948
CCR Incremental Costs- SII Only	83,048	83,659	21,003	12,897	2,361	3,940	5,355	9,134
Ash Pond Closure (BP20G300E)	175,231	175,231	-	-	-	-	-	175,231
Auxiliary Power	107,956	107,956	5,471	4,767	5,022	5,525	7,559	6,176
Total Cost	$ 2,161,538	2,133,617	47,535	320,710	103,943	111,354	117,556	311,489
Henderson Allocation								
Percentage - Decommission		100.00%						
Amount		$ 2,133,617	$ 47,535	$ 320,710	$ 103,943	$ 111,354	$ 117,556	$ 311,489

Big Rivers Electric Corporation
A/R HMP - Ongoing Maintenance, Environmental Remediation and Other Obligations of Henderson Arising Out of the Station Two Contracts
Case No. 2019-00269

	GROSS TOTAL	STATION TWO	STATION TWO Jan-20	Feb-20	Mar-20	Apr-20
RAMP DOWN						
SII Only	$ 1,630,497	$ 1,630,497	$ 137,619	$ 105,444	$ 79,121	$ 147,441
RD/SII	164,548	136,177	-	-	-	-
RD/GN/SII	260	97	-	-	-	-
	1,795,304	1,766,772	137,619	105,444	79,121	147,441
CCR Incremental Costs- SII Only	83,048	83,659	-	-	6,368	(7,057)
Ash Pond Closure (BP20G300E)	175,231	175,231	-	-	-	
Auxiliary Power	107,956	107,956	6,284	5,306	4,834	4,071
Total Cost	$ 2,161,538	2,133,617	143,904	110,750	90,323	144,455
Henderson Allocation						
Percentage - Decommission		100.00%				
Amount		$ 2,133,617	$ 143,904	$ 110,750	$ 90,323	$ 144,455

Big Rivers Electric Corporation
A/R HMP - Ongoing Maintenance, Environmental Remediation and Other Obligations of Henderson Arising Out of the Station Two Contracts
Case No. 2019-00269

	GROSS TOTAL	STATION TWO	STATION TWO Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19
Landfill								
Slurry Wall (BP19G200E)	$ 2,204,264	$ 2,204,264	$ -	$ -	$ -	$ -	$ -	$ -
Leachate (BP19G201E)	1,409,260	1,409,260	-	-	-	-	-	-
	$ 3,613,525	3,613,525	-	-	-	-	-	-
Henderson Allocation								
Percentage - Landfill Decommission		12.00%						
Amount		$ 433,623	$ -	$ -	$ -	$ -	$ -	$ -
Transmission Assets (TMSTATIONS100)		122						
Amount Due From Henderson								
Total Allocated Decommissioning Costs		**$ 2,567,362**	**$ 47,197**	**$ 154,271**	**$ 132,689**	**$ 135,129**	**$ 92,118**	**$ 70,195**
Less: 2019 Payments (Aux Power Feb, Mar & Apr)		**9,728**	**-**	**4,640**	**3,104**	**1,983**	**-**	**-**
Balance Due		**$ 2,557,634**	**$ 47,197**	**$ 149,630**	**$ 129,585**	**$ 133,146**	**$ 92,118**	**$ 70,195**
Cumulative Amount Due								**$ 621,870**

Big Rivers Electric Corporation
A/R HMP - Ongoing Maintenance, Environmental Remediation and Other Obligations of Henderson Arising Out of the Station Two Contracts
Case No. 2019-00269

	GROSS TOTAL	STATION TWO	STATION TWO Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19
Landfill								
Slurry Wall (BP19G200E)	$ 2,204,264	$ 2,204,264	$ -	$ -	$ -	$ -	$ -	$ 1,677,518
Leachate (BP19G201E)	1,409,260	1,409,260	-	-	-	-	-	1,255,561
	$ 3,613,525	3,613,525	-	-	-	-	-	2,933,079
Henderson Allocation								
Percentage - Landfill Decommission		12.00%						
Amount		$ 433,623	$ -	$ -	$ -	$ -	$ -	$ 351,969
Transmission Assets (TMSTATIONS100)		122						
Amount Due From Henderson								
Total Allocated Decommissioning Costs		**$ 2,567,362**	**$ 47,535**	**$ 320,710**	**$ 103,943**	**$ 111,354**	**$ 117,556**	**$ 663,459**
Less: 2019 Payments (Aux Power Feb, Mar & Apr)		**9,728**	**-**	**-**	**-**	**-**	**-**	**-**
Balance Due		**$ 2,557,634**	**$ 47,535**	**$ 320,710**	**$ 103,943**	**$ 111,354**	**$ 117,556**	**$ 663,459**
Cumulative Amount Due								**$ 1,986,427**

Case No. 2019-00269
Attachment 2 for Response to PSC 1-5
Witness: Paul G. Smith

Big Rivers Electric Corporation
A/R HMP - Ongoing Maintenance, Environmental Remediation and Other Obligations of Henderson Arising Out of the Station Two Contracts
Case No. 2019-00269

	GROSS TOTAL	STATION TWO	STATION TWO Jan-20	Feb-20	Mar-20	Apr-20
Landfill						
Slurry Wall (BP19G200E)	$ 2,204,264	$ 2,204,264	$ 65,936	$ 82,944	$ 134,150	$ 243,717
Leachate (BP19G201E)	1,409,260	1,409,260	146,359	(1,482)	1,158	7,664
	$ 3,613,525	3,613,525	212,295	81,462	135,308	251,381
Henderson Allocation						
Percentage - Landfill Decommission		12.00%				
Amount		$ 433,623	$ 25,475	$ 9,775	$ 16,237	$ 30,166
Transmission Assets (TMSTATIONS100)		122	122			
Amount Due From Henderson						
Total Allocated Decommissioning Costs		**$ 2,567,362**	**$ 169,501**	**$ 120,525**	**$ 106,560**	**$ 174,621**
Less: 2019 Payments (Aux Power Feb, Mar & Apr)		**9,728**	**-**	**-**	**-**	
Balance Due		**$ 2,557,634**	**$ 169,501**	**$ 120,525**	**$ 106,560**	**$ 174,621**
Cumulative Amount Due						**$ 2,557,634**

Big Rivers Electric Corporation
Interim Accounting Summary
Amounts Due (To) / From Henderson
Updated though **December 31, 2019**

Description	Reference	Amount ($) Due (To)/From
Excess Henderson Energy	Exhibit Smith-2	(3,310,482)
Henderson Native Load	Exhibit Smith-3	4,693,587
Other Operating Costs	Exhibit Smith-4	(941,581)
Ongoing Maintenance, Environmental Remediation and Other Obligations	Exhibit Smith-6	1,986,427
Total		2,427,951

Big Rivers Electric Corporation
Amounts Due (To) / From Henderson
Ongoing Maintenance, Environmental Remediation and Other Obligations
of Henderson Arising Out of the Station Two Contracts
Updated through **December 31, 2019**

Description	**Amount ($) Due (To)/From**
Ongoing Maintenance, Environmental Remediation and Other Obligatons	
January 2019 - December 2019	1,986,427
Total Ongoing Maintenance, Environmental Remediation and Other Obligations	1,986,427

BIG RIVERS ELECTRIC CORPORATION

ELECTRONIC APPLICATION OF
BIG RIVERS ELECTRIC CORPORATION
FOR ENFORCEMENT OF RATE AND SERVICE STANDARDS
CASE NO. 2019-00269

Response to Commission Staff's
Initial Request for Information
dated May 19, 2020

June 8, 2020

Item 6) ***Refer to the Direct Testimony of Robert W. Berry (Berry Testimony), page 18.***

a. Provide a complete list of all costs borne by BREC that Henderson was obligated, but refused, to pay, which BREC has passed through to its Member Cooperatives.

b. Provide the rate mechanism through which BREC passed these costs to its Member Cooperatives.

Response)

a. Big Rivers has ensured that all amounts for which Henderson is obligated, but refused, to pay are explicitly recorded as a receivable and are not passed through to Big Rivers' Member Cooperatives. However, such delay in payment results in additional financing costs to Big Rivers. If Big Rivers is required to permanently bear past and future costs that Henderson is obligated to pay, then Big Rivers earnings will be improperly reduced. This would result in lower MRSM TIER Credits and a lower equity ratio. A lower equity ratio will increase borrowing costs, provide less member equity to off-set regulatory assets and reduce the ability to rotate patronage capital.

b. Not applicable. Please see the response to sub-part a.

Witness) Robert W. Berry

**ELECTRONIC APPLICATION OF
BIG RIVERS ELECTRIC CORPORATION
FOR ENFORCEMENT OF RATE AND SERVICE STANDARDS
CASE NO. 2019-00269**

**Response to Commission Staff's
Initial Request for Information
dated May 19, 2020**

June 8, 2020

Item 7) *Refer to Berry Testimony, page 19 of 53, and Exhibit Berry-2.*

a. ***Explain the parties involved and the process by which Henderson determines its annual capacity reservation needs and whether there was a set schedule with an annual escalation of required capacity. Highlight the roles that MISO and BREC plays in this process, if any.***

b. ***Explain who determines and enforces the requirement that Henderson submit its capacity reservation.***

c. ***The Commission's January 5, 2018 Order in Case 2016-00278 defines Excess Henderson Energy (EHE) as "the difference between Henderson's reserved capacity under the Power Sales Contract, or 115 MW as of 2016, and the amount of capacity needed by Henderson to serve its native load and for sale by Henderson to third-parties." In that Order, the Commission found "that Big Rivers is not required to pay for any variable costs associated with Excess Henderson Energy that Big Rivers elects not to take." To the extent known, provide BREC's understanding of the basis for Henderson's claim***

that it does not have to accept ownership of the EHE. Explain whether the basis for Henderson's claim is that since it only reserved 115 MW of capacity, then in Henderson's view, the EHE does not exist because there is no difference between what it reserved and what was needed to serve native load.

d. For each year that Henderson submitted a capacity reservation less than its required reserve level, provide the amount of capacity that Henderson consumed relative to its capacity reservation and its required capacity reservation.

e. Identify and explain the contract that governs what happens in instances in which Henderson actually consumes more capacity than it reserved in a given period.

Response)

a. Per section 3.3 of the Power Sales Contract, in March of each year HMP&L provides to Big Rivers a capacity reservation letter for the following five years. HMP&L is required to reserve enough capacity to meet its annual peak demand plus reserves. Big Rivers does not know the process which Henderson used to calculate its capacity reservation, other than for the 2018 MISO Planning Year. The calculation that Henderson used for that year was provided in the Brad Bickett e-mail provided as Attachment 1 to Big Rivers' response to Item 24 of Commission Staff's Initial Request for Information. The Power Sales Contract allows HMP&L to increase or decrease its capacity reservation by a maximum of 5 MW each year. There was no known annual escalation and Big Rivers is unaware of any involvement by MISO.

b. Section 3.3 of the Power Sales Contract establishes the requirement for Henderson to provide its annual capacity reservation.

c. It is important to differentiate between the annual process by which Henderson establishes its capacity reservation and the hourly difference between that capacity reservation and actual Henderson load. The annual capacity reservation process is intended to ensure resource adequacy; that Henderson will have enough capacity to meet its annual peak load obligation plus reserves. Once that is established, the real-time difference between the capacity reservation and actual Henderson load becomes Exess Henderson Energy.

Big Rivers is not aware of any basis supporting Henderson's position that it does not own the Excess Henderson Energy that Big Rivers declined to take. Moreover, the Commission has already settled that issue.

d. Capacity is actually consumed prior to the start of the MISO planning year. Based upon the Henderson's projection of peak load and its SEPA allocation, the quantity of MISO Zonal Resource Credits (ZRCs) from Station Two required to meet Henderson's resource adequacy obligation for the planning year was established. That required capacity reservation quantity (measured in ZRCs) became unavailable for any other purpose.

e. None of the provisions of the Station Two Contracts authorize Henderson to consume more capacity than it was required to reserve. Because many costs under the Station Two Contracts were allocated between the parties based on Henderson's reservation, if Henderson were able to reserve less capacity than it required, it could have shifted Henderson's share of Station

Two Costs to Big Rivers. For that reason, the Station Two Contracts do not allow Henderson to reserve less capacity than required.

Witness) Mark J. Eacret

BIG RIVERS ELECTRIC CORPORATION

ELECTRONIC APPLICATION OF
BIG RIVERS ELECTRIC CORPORATION
FOR ENFORCEMENT OF RATE AND SERVICE STANDARDS
CASE NO. 2019-00269

Response to Commission Staff's
Initial Request for Information
dated May 19, 2020

June 8, 2020

Item 8) ***Refer to the Berry Testimony, page 28 of 53, and the Direct Testimony of Mark J. Eacret (Eacret Testimony), page 9 of 10. Explain why Henderson's post-termination decision to join MISO effects the allocation of MISO fees prior to the termination of the Station Two Contracts.***

Response) It does not. It illustrates, however, that while Henderson load has been part of MISO and incurring fees since December of 2010, Henderson's attitude towards paying those fees has been inconsistent. For the period from December 2010 through May of 2016, Henderson refused to pay its fees. For the period from June of 2016 through January of 2019, Henderson paid the fees subject to refund. For the period beginning February of 2019, Henderson has presumably been paying its fees.

When Henderson must pay MISO directly presumably it pays. When Henderson must reimburse Big Rivers for MISO fees incurred on its behalf, it refuses to pay or wants to make payment subject to refund. In both cases, Henderson enjoys the benefits of MISO membership.

Witness) Mark J. Eacret

ELECTRONIC APPLICATION OF
BIG RIVERS ELECTRIC CORPORATION
FOR ENFORCEMENT OF RATE AND SERVICE STANDARDS
CASE NO. 2019-00269

Response to Commission Staff's
Initial Request for Information
dated May 19, 2020

June 8, 2020

Item 9) ***Refer to the Berry Testimony, page 30 of 53.***

a. ***Provide any study or analysis that BREC preformed to determine that a severance package was the most reasonable alternative.***

b. ***Explain the process by which BREC's management approved the severance payments and provide any Board of Directors minutes that discuss the approval.***

c. ***State whether employees who received severance were required to waive any claims or rights in consideration for their receipt of the severance.***

d. ***Explain how the severance amounts were calculated.***

e. ***Explain whether the 11 involuntarily terminated employees were provided severance packages.***

Response)

a. Big Rivers reviewed employee age and tenure and determined that natural attrition was not a reasonable alternative to deal with the positions eliminated due to the closure of Station Two. Additionally, Big Rivers agreed to operate Station Two an additional 13 months for the sole benefit of Henderson. It was Big Rivers' belief that without a severance package it would not be able to operate and maintain Station Two for those additional 13 months.

b. Big Rivers instituted a Voluntary Work Force Reduction process within the targeted positions prior to any involuntary workforce reductions for both bargaining and salaried positions. Big Rivers evaluated the volunteers and awarded severance only to those employees whose positions were targeted for reduction. Big Rivers' Generation Bargaining Contract with IBEW 1701 provided the framework for the involuntary reduction in the bargaining work force, and Big Rivers chose the involuntary salaried employee reductions based on business needs. Please see the attached minutes from Big Rivers' Board of Directors meeting regarding severance.

c. A separation agreement was required to be signed by all severed employees. It waived, released, and discharged the company from any and all liability, claims, suits, *etc.*

d. All severed employees received six months base pay.

e. The eleven involuntarily severed employees received a severance of six months base pay.

Witness) Robert W. Berry

BIG RIVERS ELECTRIC CORPORATION
TELEPHONIC SPECIAL BOARD OF DIRECTORS MEETING
OCTOBER 31, 2018

A telephonic special meeting of the Board of Directors of Big Rivers Electric Corporation was held at 6 p.m., CDT, Wednesday, October 31, 2018.

Paul Edd Butler, Chair, presided and Bill Denton, Secretary-Treasurer, acted as Secretary of the meeting.

Upon calling the roll, the Secretary-Treasurer reported that the following directors participated in the call: Messrs. Butler, Elliott, Harris, Warren, Sills and Denton. Also participating in the call were Bob Berry, president/CEO; Lindsay Durbin, Mike Pullen, Paul Smith, and Mark Eacret, Big Rivers' management.

After an explanation by Bob Berry and upon management's recommendation, Director Denton moved that the following resolution be approved:

WHEREAS, on May 1, 2018, Big Rivers filed an application in Kentucky Public Service Commission Case No. 2018-00146, seeking, among other things, authority to establish a regulatory asset (the "Station Two Regulatory Asset") to defer the expenses Big Rivers incurs as a result of the termination of certain contracts pursuant to which Big Rivers operates and takes power from the Station Two generating station (the "Station Two Contracts"), which expenses include any severance expenses Big Rivers incurs as a result of the contract termination;

WHEREAS, on October 23, 2018, the Kentucky Public Service Commission issued an order approving a "Settlement Agreement, Stipulation, and Recommendation" among Big Rivers and the intervenors in Case No. 2018-00146, and granting Big Rivers' request to establish, for accounting purposes, the Station Two Regulatory Asset; and

WHEREAS, on October 29, 2018, the management of the Corporation completed successful negotiations with IBEW Local 1701 on a severance plan for bargaining employees, which plan management presented to the Board of Directors;

NOW THEREFORE BE IT RESOLVED, that the Board of Directors of the Corporation hereby approves the following severance benefits for both bargaining and non-bargaining employees whose employment is terminated as a result of the termination of the Station Two Contracts:

1. Eligible employees will receive a lump sum Severance Payout of six (6) months of base pay.
2. For eligible bargaining employees, the Corporation will reimburse 88% of the premium paid by an eligible employee for medical, dental, and/or vision coverage, for six (6) months following the employee's separation date. Additionally, if the employee has attained the age of 60 when the subsidy ends, then the employee will be eligible for the Retiree Medical Account.
3. For eligible non-bargaining employees, the Corporation will reimburse 90% of the premium paid by an eligible employee for medical, dental, and/or vision coverage, for six (6) months following the employee's separation date. Additionally, if the employee has attained the age of 60 when the subsidy ends, then the employee will be eligible for the Retiree Medical Plan on an 85 (Big Rivers' share) /15 (employee's share) co-share basis.
4. The Corporation will provide eligible employees Outplacement Services and access to the Employee Assistance Program for three (3) months following the separation date.

BE IT FURTHER RESOLVED, that the Board of Directors of the Corporation reserves the right to terminate these severance benefits at any time.

BE IT FURTHER RESOLVED, that the Board of Directors of the Corporation hereby authorizes its President and Chief Executive Officer, its Vice President Human Resources, and each of them, and any other employee of the Corporation authorized in writing by either of them (each, an "Authorized Representative"), to determine the eligibility of employees for the approved severance benefits, execute and attest on behalf of the Corporation all necessary instruments, papers, and documents, including any medical, dental, vision, or other plan amendments, make all such payments, and do all such other acts as in the opinion of the Authorized Representative may be necessary or appropriate in order to carry out the purposes and intent of the foregoing resolutions.

The motion was seconded and adopted by unanimous vote.

There being no further business to discuss, the meeting was adjourned by consensus.

____
Secretary-Treasurer

APPROVED:

____
Chair

**ELECTRONIC APPLICATION OF
BIG RIVERS ELECTRIC CORPORATION
FOR ENFORCEMENT OF RATE AND SERVICE STANDARDS
CASE NO. 2019-00269**

**Response to Commission Staff's
Initial Request for Information
dated May 19, 2020**

June 8, 2020

Item 10) ***Refer to the Berry Testimony, pages 36 and 37 of 53, and the Direct Testimony of Direct Testimony of Jeffrey T. Kopp in which they describe their understanding of the meaning of "decommissioning."***

a. Describe each basis for Mr. Berry's understanding of the meaning of the term "decommissioning" as he defined it in his testimony.

b. Describe each basis for Mr. Kopp's understanding of the meaning of the term "decommissioning" as he defined it in his testimony.

Response)

a. As stated on Page 36 of my Direct Testimony, I agree with Mr. Kopp that decommissioning is "the entire process associated with taking the plant out of service, demolishing the plant, and restoring the site to a state that is suitable for future industrial use. Decommissioning also includes all ongoing environmental monitoring and any environmental remediation that may be required in the future." This process includes all maintenance activities necessary to maintain the plant and the site in a safe, secure and legally compliant condition both before and after demolition.

I base my opinion on my more than 39 years of experience in the utility business in Kentucky. My understanding of the meaning of the term decommissioning is consistent with prudent utility practice, industry norms and Kentucky precedent.

In Case No. 2017-00179,[1] the Commission authorized Kentucky Power to decommission its 800 MW coal-fired Big Sandy plant and recover the costs through a Decommissioning Rider. Kentucky Power files annual decommissioning update reports in Case No. 2017-00179. Its August 15, 2019, report summarizes the cost of Big Sandy removal activity as: "Decommissioning of Big Sandy Coal—demolition of boiler and turbine infrastructure continued, with environmental remediation being performed" at a cost of $7,016,358.53. The same report summarizes the asset retirement obligation as: "fly ash pond closure" $21,129,372.83 and

[1] See: *In the Matter of: Electronic Application of Kentucky Power Company for (1) a General Adjustment of its Rates for Electric Service; (2) an Order Approving its 2017 Environmental Compliance Plan; (3) an Order Approving its Tariffs and Riders; (4) an Order Approving Accounting Practices to Establish Regulatory Assets and Liabilities; and (5) an Order Granting all Other Required Approvals and Relief* – Case No. 2017-00179 (Application filed June 28, 2017; Deficiencies cured with filing of July 12, 2017).

"removed asbestos" $3,413,327.76 with a total of $24,542,600.59. Finally, the report forecasts decommissioning costs for the upcoming year: "Plant Demolition/Removal of Equipment for Safety--$4.9 million;" "Continuation of the demolition of out buildings, turbine, and main boiler building;" "Removal of remaining coal related equipment;" "Big Sandy Fly Ash Reservoir Closure--$19.1 million (direct costs);" "Begin to excavate, haul, and place ash. Place borrow pit materials as subgrade fill. Installation of Geosynthetics;" "Maintain Safe Plant Environment as well as environmental compliance--$0.4 million." The quoted portions of this report are Attachment 1 to this response.

Louisville Gas and Electric has recently completed the decommissioning of its Paddy's Run and Cane Run coal-fired generating stations. Both coal-fired stations were dismantled, environmentally remediated then demolished. The Paddy's Run and Cane Run sites were both returned to green space.

According to the 2018 Annual Report of East Kentucky Power Cooperative ("EKPC"), the decommissioning process for EKPC's Dale

Station included demolition, removal of environmentally regulated materials such as asbestos, and conversion of the plant to a brownfield site. The excerpt therefrom is Attachment 2 to this response.

As noted by Mr. Kopp in his Response to Item 38 to Henderson's initial data requests, in Case No. 2017-00321[2] this Commission approved Duke Energy Kentucky's depreciation rates which included costs to decommission all of Duke's power plants by dismantling, demolishing and restoring the sites to a condition suitable for future industrial use.

My understanding of the meaning of the term decommissioning is also consistent with federal guidance. In a 2016 Report titled "Coal Plant Decommissioning," provided as Attachment 3 to this response, the United States Environmental Protection Agency noted:

> Decommissioning begins with an announcement that the plant is closing and ends when operations completely cease. Unlike nuclear plant decommissioning which the federal government strictly regulates, the process of decommissioning a coal-fired power plant is

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[2] See: *In the Matter of: Electronic Application of Duke Energy Kentucky, Inc. for: 1) an Adjustment of the Electric Rates; 2) Approval of an Environmental Compliance Plan and Surcharge Mechanism; 3) Approval of New Tariffs; 4) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 5) All other Required Approvals and Relief* – Case No. 2017-00321.

> not always clear and may overlap with remediation and redevelopment.
>
> Once the owner decides to close the plant, the owner should develop a strategy for managing the decommissioning process that serves his or her business needs. A wide range of management strategies may be considered, from the owner maintaining full control, to the selection of a third party to oversee the process. The owner also may sell the property to a developer or municipality early in the process.
>
> During decommissioning, the electrical generating units are shut down and all operating permits are terminated. Any unused coal and hazardous materials associated with both the generation process and the buildings/structures (e.g., process chemicals, asbestos in the building or in equipment, polychlorinated biphenyls [PCBs], lead) are removed. Electrical generating equipment is cleaned and may be removed for use at other locations or sold as scrap. Some demolition of buildings/structures may be performed to facilitate cleaning or equipment removal. Power plants with onsite coal ash ponds or solid waste landfills must follow the federal and state permit requirements for closure of these facilities.

Finally, my understanding of the meaning of decommissioning is consistent with the Electric Power Research Institute's use of the term in a 2010 Report, Attachment 4 to this response, titled "Decommissioning Process for Fossil-Fueled Power Plants":

> For purposes of this document, the term 'decommissioning' is intended to mean the process for removing from a plant site

> structures, infrastructures, impacts, and other encumbrances that may be present on a property. This includes environmental abatement and decontamination within super structures; demolition of structures, foundations, utilities, and other subsurface structures, remediation of impacts to the surface and subsurface, and reclamation of the property depending on the designated end use.

b. My understanding of the meaning of the term "decommissioning" is based on my experience preparing decommissioning cost studies for power generation facility owners, evaluating decommissioning options for power generation facility owners, testifying to decommissioning costs in rate case proceedings, discussions with demolition contractors and power generation facility owners, and my company's experience with serving as owner's engineer on decommissioning projects.

Witnesses) Robert W. Berry (*a. only*) and
Jeffrey T. Kopp (*b. only*)

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ELECTRONICALLY FILED

Gwen R. Pinson
Executive Director
Public Service Commission
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RE: **Case No. 2017-00179** (Post-Case Correspondence File)

Dear Ms. Pinson:

This letter constitutes the Read1st file required by 807 KAR 5:001, Section 8(5).

(a) General Description of the Filing – Kentucky Power Company is electronically filing today the following materials:

(i) The Read1st file required by 807 KAR 5:001, Section 8(5);

(ii) BSDR_2019_Annual_Update;

(iii) BSDR_2019_Support_1_Components;

(iv) BSDR_2019_Support_2_O_M_COR_ARO; and

(v) BSDR_2019_Support_3_Components_Rev.

(b) Materials Not Included In The Electronic Filing – Kentucky Power is filing in paper or CD format only:

(i) The paper medium copy of the electronic mail message required to be filed by 807 KAR 5:001, Section 8(5)(a).

(c) Attestation – The electronically-filed documents are a true representation of the original documents.

(d) Service – There are no parties to this proceeding who have been excused from electronic filing procedures [807 KAR 5:001, Section 8(7)(c)]. A copy of the materials identified in (a) above was filed using the Public Service Commission of Kentucky's electronic filing service, which will send an e-mail message to:

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(e) Other Matters – None.

Very truly yours,

Mark R. Overstreet

MRO

Kentucky Power Company
Decommissioning Rider
Summary of Cost of Removal Activity
July 2018 - June 2019

Description	Total
Decommissioning of Big Sandy Coal - demolition of boiler and turbine infrastructure continued, with environmental remediation being performed	7,016,358.53
Grand Total	**7,016,358.53**

Kentucky Power Company
Decommissioning Rider
Asset Retirement Obligation Spend Summary
Twelve Months Ended June 30, 2019

Work Performed	Amount
Fly Ash Pond Closure	21,129,372.83
Removed asbestos	3,413,227.76
	24,542,600.59

Kentucky Power currently estimates that it will incur the costs detailed below during the period July 2019 through June 2020. The Company's review and possible modification of these current plans is ongoing and actual costs may vary from the Company's current estimates as a result of changes in project schedules and scope.

Cost of Removal Activity

Plant Demolition/Removal of Equipment for Safety - $4.9 million

Anticipated removal activities include:
- Continuation of the demolition of out buildings, turbine, and main boiler building
- Removal of remaining coal related equipment

ARO Activity

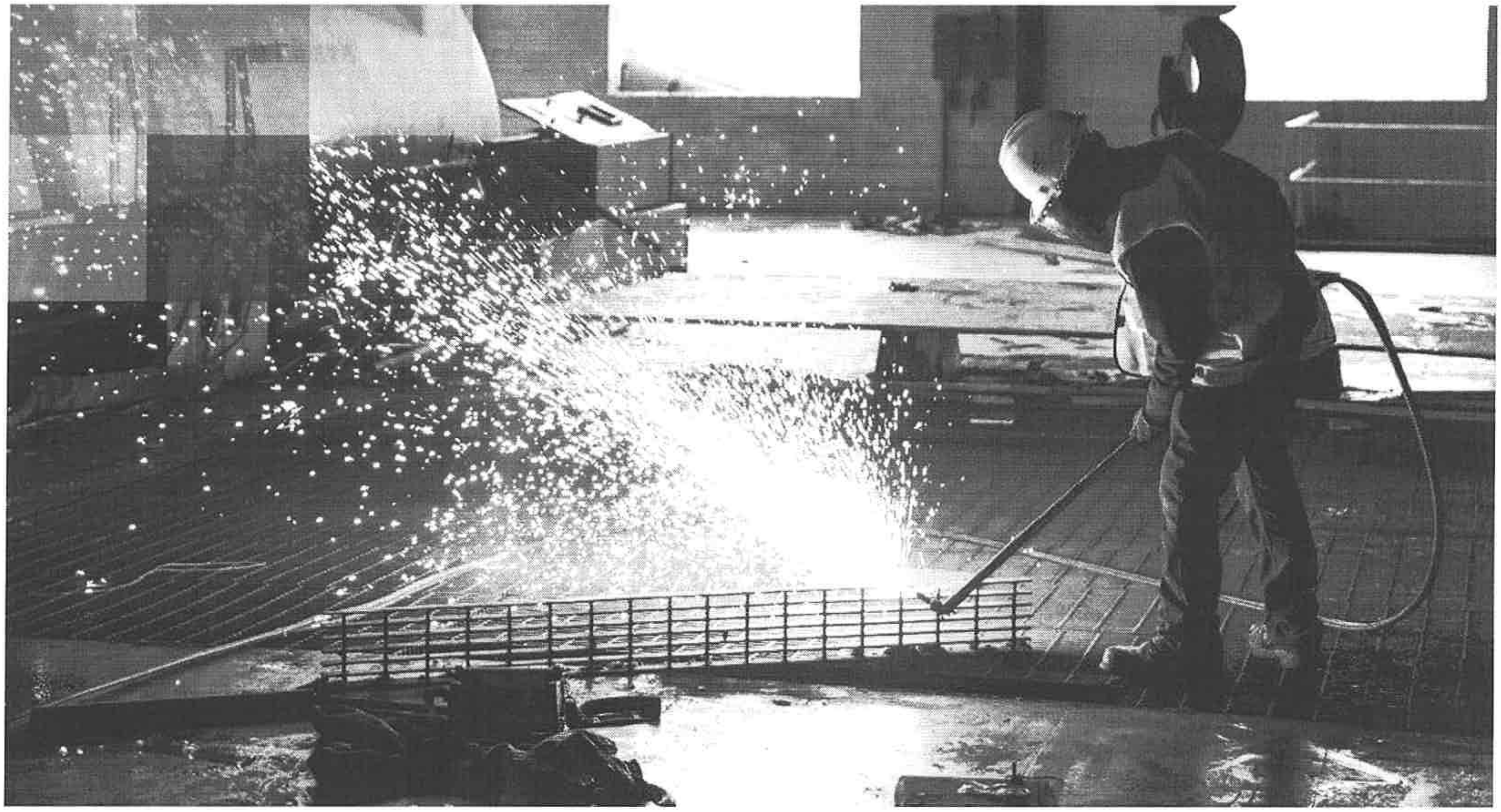
Big Sandy Fly Ash Reservoir Closure - $19.1 million (direct costs)

Start work on Phase 3
- Begin to excavate, haul, and place ash
- Place borrow pit materials as subgrade fill
- Installation of Geosynthetics

Big Sandy Unit 2 O&M Expense

Maintain Safe Plant Environment as well as environmental compliance - $0.4 million

Anticipate work includes sump pump repair expense, electricial breaker expense, and plant elevator maintenance.



A worker helps in the initial phase of a demolition project to remove the powerhouse and stacks at Dale Station, EKPC's first power plant.

Russell Marshall (left) and Cliff Harmon inspect equipment during the Dale Station demolition project.

Dale Station demolition

The Board approved the demolition of Dale Station at Ford on the Kentucky River. In preparation for the project, environmentally regulated materials such as asbestos were identified, removed and disposed of properly. Because the Dale switchyard and other transmission facilities are vital for maintaining the power delivery grid in the region, those facilities will continue to operate. The only structures to remain will be the office building and some outbuildings. Although Dale Station ceased to operate in 2016, the plant is being transformed into a valuable brownfield site.

COAL PLANT DECOMMISSIONING

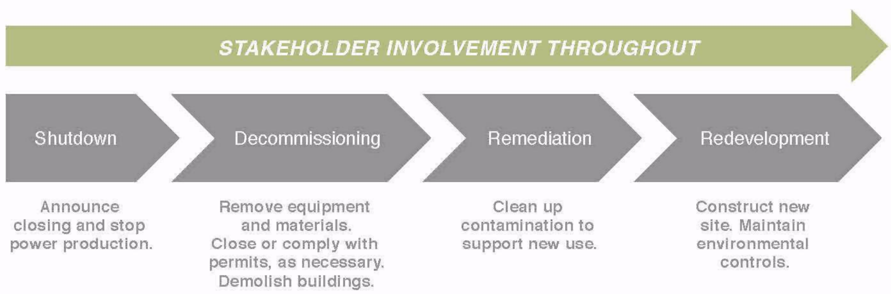
PLANT DECOMMISSIONING, REMEDIATION AND REDEVELOPMENT

Many coal-fired power plants are expected to close in coming years. Coal plant communities are faced with potentially long-term job and tax revenue loss, legacy environmental contamination and the need for new economic opportunities.

Site reuse options inform cleanup decisions and should be developed early in the process to determine the appropriate level of work needed for redevelopment. Understanding the range of reuse options will help in the development of realistic schedules and cost estimates.

Preparing a site for reuse often is a complex, multi-year process that includes decommissioning the existing power plant, cleaning up contamination (e.g., in materials, soil and ground water), and creating and implementing a redevelopment plan. Local leadership that is committed to public involvement and the establishment of a balanced and inclusive stakeholder group can guide the process by considering the many factors and unique conditions of a coal plant site, along with the community's redevelopment goals.

EPA prepared this fact sheet to help communities that may be affected by the closure of coal-fired power plants. Fact sheets covering stakeholder identification and facilitation, as well as financing options and incentives, are also available.



The Process

After a plant shuts down, the site will progress through decommissioning, remediation and redevelopment. Though it is not always possible, it helps to know site reuse options early in the process to inform cleanup decisions and determine the appropriate level of work needed in each stage of the assessment, cleanup and redevelopment process. Understanding the range of reuse options and needs associated with each will help in the development of realistic schedules and cost estimates. Time and costs associated with permits, approvals (of permits, plans, funding) and public involvement should be factored into redevelopment plans as well.

Environmental permits typically specify actions to take before, during and after closure. Plant owners must coordinate with public utility and environmental regulators to ensure compliance with permit requirements during the decommissioning, remediation and redevelopment process.

Typical Environmental Permits at Coal-Fired Power Plants

- Air pollution control
- Water withdrawal for cooling
- Water discharge
- Hazardous waste storage
- Fuel storage tanks
- Flue gas stack (Federal Aviation Administration)

Common Cleanup Methods at Coal-Fired Plants

Although the extent of the cleanup will depend on the final land use, many common methods are applied. For example:

- Asbestos, PCBs and other hazardous materials are removed from the buildings.
- Coal ash disposal areas are removed or capped with a protective cover of soil to ensure the waste is not accessible.
- Fuel tanks and any associated contaminated soil are removed.
- Concrete pads and soil around old transformers and hydraulic equipment are tested for PCBs and removed if necessary.
- Surface soil is tested for mercury and other airborne contaminants and removed if necessary.
- Soil around spills and leaks is tested and removed.
- Sites with old manufactured gas plants could contain coal tar and other hazardous materials, which require special methods for cleanup.

Decommissioning

Decommissioning begins with an announcement that the plant is closing and ends when operations completely cease. Unlike nuclear plant decommissioning, which the federal government strictly regulates, the process of decommissioning a coal-fired power plant is not always clear and may overlap with remediation and redevelopment.

Once the owner decides to close the plant, the owner should develop a strategy for managing the decommissioning process that serves his or her business needs. A wide range of management strategies may be considered, from the owner maintaining full control, to the selection of a third party to oversee the process. The owner also may sell the property to a developer or municipality early in the process.

During decommissioning, the electrical generating units are shut down and all operating permits are terminated. Any unused coal and hazardous materials associated with both the generation process and the buildings/structures (e.g., process chemicals, asbestos in the building or in equipment, polychlorinated biphenyls [PCBs], lead) are removed. Electrical generating equipment is cleaned and may be removed for use at other locations or sold as scrap. Some demolition of buildings/structures may be performed to facilitate cleaning or equipment removal. Power plants with onsite coal ash ponds or solid waste landfills must follow the federal and state permit requirements for closure of these facilities.

Remediation

Remediation involves the investigation and cleanup of hazardous materials to meet federal or state requirements. It also includes defining site-specific needs for redevelopment. The site owner is responsible for ensuring that the cleanup meets all regulatory requirements and works closely with stakeholders, environmental consultants and state environmental agencies to develop and execute the remediation plan.

The cost and extent of the cleanup will depend on the anticipated reuse of the site and the type and location of hazardous materials stored or disposed on the property. For example, if industrial use is planned, the cleanup requirements may be less stringent than what is required for residential use, because the likelihood of direct or prolong human exposure to contaminants will be lower. Many power plants are adjacent to bodies of water that may contain contaminants due to power plant operations, which must also be addressed as part of the cleanup. The cost of remediation can vary greatly—from hundreds of thousands of dollars to several million dollars or more.[1]

Remediation starts with collecting soil and ground water samples to investigate and document any contamination. Next, a plan for cleanup is developed and, once approved by state regulators, implemented.

[1]Relatively few published studies discuss the costs of remediation at coal-fired power plants.

At most sites, the public is invited to comment on the cleanup plan that is proposed by the state environmental agency, who is responsible for reviewing and approving the plan.

Occasionally, low levels of contamination may be left in places. In such cases, future site activities and uses may be restricted. Any restrictions on the future use of the property (due to contamination being left onsite) is documented in legal notices (e.g., land use restrictions and institutional controls that often are filed with or attached to property titles and deeds). These may include restrictions on drilling drinking-water wells or building residential dwellings. In addition, requirements to notify local authorities before digging or excavating in contaminated areas may be imposed.

Redevelopment

To evaluate different reuse options and facilitate a shared vision of the end result among stakeholders, redevelopment planning should start early in the process. A shared stakeholder vision helps avoid major changes to the plan later on, which could cause delays and waste valuable resources.

In addition to meeting stakeholder needs, reuse must conform to practical and legal conditions at the site. The following table describes some common considerations in planning a redevelopment project.

Things to Consider	Examples	Opportunities and Challenges
Who will control the site during redevelopment?	• Utility • Public agency • Private owner	• Utilities and private owners can control the reuse of the site within community regulations and to the extent that it is economically feasible. • Public agencies may have an opportunity to redevelop, using a combination of both public and private funds and partnerships.
What amenities are available at the site?	• Waterfront access and port facilities • Natural gas lines and electrical transmission stations • Technological infrastructure, including high-speed broadband access • Visual attractiveness, such as open fields, wooded areas, river and ocean views	• Waterfront access can open new opportunities for recreation, transportation and tourism. • Waterfronts also offer a base for offshore power generation and staging. • Reuse of waterfront properties may require climate resiliency planning to reduce the potential impacts of extreme weather events. • Existing infrastructure may attract the clean energy industry; the owners could restart electric generation with natural gas or biomass. • Including walking trails, parks and event venues, when possible, helps accommodate community needs for open spaces.

Things to Consider	Examples	Opportunities and Challenges
Are there opportunities for economic development?	• Employment opportunities • Tax revenue	• New commercial/industrial development can add direct and indirect jobs and can create tax revenues. • Commercial/industrial development can stimulate the expansion of nearby development projects.
Are there zoning issues?	• Local ordinances and overlay districts • Historic districts and historic building designations	• Redevelopment must comply with local zoning regulations, which can limit options unless the zoning changes. • Some cities apply additional zoning requirements that overlay the existing base zone. • Historic buildings can offer unique development opportunities but may limit options. • Historic buildings may invoke the need to comply with the Historic Preservation Act.
Are there land use restrictions?	• Environmental • State waters and ports • Utility easements	• Reuse options may be limited in areas with soil and ground water contamination. • Regulations may limit the redevelopment of land adjacent to water. • Utility companies may restrict access or use in areas with existing natural gas, electrical transmission and water utilities.
What's the property value?	• Cost of cleanup versus value of property after development • Market for redeveloped uses	• The value of the property after redevelopment must be balanced against the cost of decommissioning, remediation and redevelopment. • The proposed use of the site must be realistic and address community needs. Communities should consider performing a market analysis to identify viable options for redevelopment and to inform reuse decisions.
What about vehicular traffic and site access?	• Regional and local access to site • Traffic and population density patterns	• Industrial development will require transportation of raw materials and finished goods. Suitable roads, rail and ports must be available. • If reuse increases public access, adjacent neighborhoods must be able to accept increased traffic.

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EPA Publication #560-F-16-003

ELECTRIC POWER RESEARCH INSTITUTE

Decommissioning Process for Fossil-Fueled Power Plants

Cover photo by Chris White. Used by permission. Stack demolition, June 28, 2008. Xcel Energy High Bridge Power Plant

Decommissioning Process for Fossil-Fueled Power Plants

1020652

Final Report, January 2010

EPRI Project Manager
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This report describes research sponsored by the Electric Power Research Institute (EPRI).

The report is a corporate document that should be cited in the literature in the following manner:

Decommissioning Process for Fossil-Fueled Power Plants. EPRI, Palo Alto, CA: 2010. 1020652.

PRODUCT DESCRIPTION

This report describes a staged process for the decommissioning and possible demolition of fossil-fueled power generating facilities. Drawn from experience with power and major industrial facilities, the report provides the owner/operator of a plant that is approaching the end of its useful life with an overview of the key elements necessary to successfully implement decommissioning. The process is applicable to full decommissioning, demolition, and closure; to partial scenarios (that is, partial dismantling, remediation, and reclamation of the plant site); and to mothballing (that is, layup of a plant in operable condition).

Results and Findings

The decommissioning process is organized into five stages: project framing; site characterization; remediation and reclamation planning; implementation (the actual environmental abatement, demolition, and site remediation); and closure. In addition to steps within each stage, the role of the project team is described, addressing: project management, communication and consultation, and technical teams. Defining objectives for post-decommissioning land use early in the process has been found to be important to successful decommissioning. The report indicates how to manage bidding and contractual relationships and how to contain costs by managing contingencies through providing substantial data. The report includes charts and checklists that outline the stages, steps, and responsibilities.

Challenges and Objectives

The Electric Power Research Institute (EPRI) described case studies of decommissioning three power plants in a 2004 report (1011220). The current study, initiated for a firm involved in the closure of an urban power plant, organizes the many tasks and decisions involved in decommissioning a power plant into a step-wise, chronological framework delineating milestones, deliverables, and team roles. The process was introduced at EPRI's Plant Closure, Remediation, and Redevelopment Workshop held in November 2009.

The objective of this study is to describe a process for decommissioning fossil-fueled power plants that is adaptable to different sites and facilities with unique attributes, operating histories, and objectives. For this reason, the study is not an in-depth report on layup engineering options and the secondary market in plant equipment and components, for example, but rather a higher level review of decommissioning process management informed by lessons learned from similar undertakings. The process excludes fuel supply (such as mines at mine-mouth facilities), fuel transportation (for example, oil and gas pipelines), and electric transmission facilities (for example, high-tension power lines), which typically have their own operating approvals and separate processes.

Applications, Value, and Use

Companies embarking on decommissioning evaluations will be able to draw on this document for guidance in understanding and organizing stakeholder inputs and the flow and range of steps involved in plant decommissioning evaluations and implementation.

EPRI Perspective

The process described in this report serves as a guide and checklist for understanding the scope of efforts and involvement of multiple parties in full and partial decommissioning projects. Its strength is tapping broad experience in industrial facility decommissioning and land use decisions. With refinement and incorporation of site-specific information, the process defined here should assist companies in developing their own decommissioning procedures and mapping out the complexities, time, and costs that could be involved. Publication of this report coincides with EPRI's launching of the Power Plant Decommissioning Interest Group. This group taps into growing interest across the power industry in managing the retirement and replacement of older power plants as age, surging renewables generation in some areas, improved economics of gas-fired generation, and environmental pressures cause companies to restructure their generation portfolios.

Approach

Investigators convened a project team with broad experience in closures of large industrial facilities, environmental reviews, project management from permitting to construction, operation and decommissioning, and interaction with regulatory agencies. The document represents an assimilation and compilation of their experience.

Keywords

Decommissioning process
Fossil-fueled power plants
Plant closure
Power plant retirement
Site remediation and reclamation

ABSTRACT

This report structures the tasks and decisions involved in decommissioning a fossil-fueled power plant into a step-wise, chronological framework that delineates milestones, deliverables, and team roles. The decommissioning process is organized into five stages: project framing, site characterization, remediation and reclamation planning, implementation (the actual environmental abatement, demolition, and site remediation), and closure. In addition to steps within each stage, the role of the project team is described, addressing: project management, communication and consultation, and technical teams. Further, the report indicates how to manage bidding and contractual relationships and how to contain costs by managing contingencies through providing substantial data. The report includes charts and checklists that outline the stages, steps, and responsibilities.

ACKNOWLEDGMENTS

EPRI acknowledges the financial assistance of Exelon Power and the guidance of James M. Reilly, responsible for managing Exelon's decommissioning process. The motivation for this project is to bring a structure to fossil plant decommissioning that extends the insights gained in several case studies reported in a previous EPRI evaluation of decommissioning, or in the case of Exelon, to their considerable work on the scope and responsibilities of the team of individuals involved in gauging and implementing potential layup, dismantling, and decommissioning projects.

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1
OVERVIEW OF THE DECOMMISSIONING PROCESS

This document describes a staged process for decommissioning and demolition of fossil-fueled power generating facilities. **The intent of this document is to provide an owner or operator of a plant approaching the end of operational use with an overview of the key elements necessary to successfully implement the decommissioning project.** As such, this document does not include operation-level details concerning procedures, methods, or decisions. The document may also be useful for regulatory agencies and community stakeholders who have some level of involvement in a fossil-fueled power plant decommissioning project.

Important note: *For the purposes of this document, the term "decommissioning" is intended to mean the process for removing from a plant site structures, infrastructures, impacts, and other encumbrances that may be present on a property. This includes environmental abatement and decontamination within super structures; demolition of structures, foundations, utilities, and other subsurface structures, remediation of impacts to the surface and subsurface, and reclamation of the property depending on the designated end use. The term "remediation" in this document is a general term to mean environmental abatement and decontamination of an existing structure (prior to demolition) as well as the cleanup of impact to the environment.*

This staged process described herein begins after the decision to decommission a plant has been made, and ends with confirmation that the plant and corresponding property have been remediated and reclaimed in a manner that meets the post-decommissioning land use objectives for the site.

This document builds upon the descriptions of decommissioning tasks presented in previous power plant decommissioning guidance documents, such as EPRI's *Decommissioning Handbook for Coal-Fired Power Plants* (2004, 1011220) and the Environment Canada's *Environmental Codes of Practice for Steam Electric Power Generation – Decommissioning Phase* (1992). However, unlike these previous documents, the current document is more focused on organizing the many tasks involved in decommissioning a power plant into a step-wise framework that presents the tasks in chronological order. This document also places a major emphasis on describing milestones, deliverables and team roles along with the descriptions of various tasks involved in each step of the process.

It should be noted that this document does not specifically discuss project scenarios other than full decommissioning and demolition, such as partial decommissioning (i.e., partial dismantling, remediation and reclamation of only a portion of the plant or site) or "mothballing" (i.e., layup of the plant in operable condition so that it may be restarted at a future date) of the plant. However, most of the steps and concepts of this process would apply to any decommissioning scenario.

The process described in this document is intended to be applicable to any fossil-fueled power plant, including those fueled by coal, oil, natural gas, and petroleum coke ("petcoke"), and also is applicable to plants fueled by wood and waste products. It is the authors' experience that the environmental issues associated with specific power plants will vary with the types of fuel(s) used through the operational history of the plant; however, the process of decommissioning (as described in this document) is universally applicable, regardless of the fuel type.

In this document, the focus is on decommissioning the infrastructure that is directly involved in the generation of electric power, including main generating structures, support buildings, fuel and process chemical handling and storage facilities, power house and cooling structures (e.g., towers or ponds); and waste handling facilities that directly support the generation of power, including wastewater collection and treatment ponds and ash storage facilities. This document does not discuss the decommissioning of fuel supply (e.g., mines in "mine-mouth" facilities) or fuel transportation facilities (e.g., gas or oil pipelines), nor does it discuss decommissioning of electricity transmission facilities (e.g., high-tension power lines). These types of facilities typically have their own operating approvals, and therefore require a separate decommissioning process.

Overview of the Decommissioning Process

The process for decommissioning a fossil-fueled power generating plant is summarized on Figure 1-1.

> ***Quick Note:***
> *The processes described herein are included on the attached figures for quick reference. Please refer to these flow charts as you read!*

The reason for outlining a specific process is to guide the decommissioning through successive steps of evaluation and decision-making that will ultimately lead to a decommissioned site that (Environment Canada, 1992):

1. Minimizes risk to human health and safety;
2. Minimizes environmental impacts;
3. Complies with all applicable laws and regulations, that is, is consistent with all applicable codes, guidelines and recommended practices, and complies with federal, state and municipal land use requirements;
4. Is suitable for post-decommissioning land use objectives, whether this means unrestricted land use or a specific proposed land use;
5. Does not represent an unacceptable liability to present and future owners; and,
6. Is aesthetically acceptable.

Further, following a specific, proven process allows the owner / operator with the added benefits of:

- Cost containment due to a defined scope of work and elimination of variables;
- Management of liabilities related waste handling, as the process described herein places boundaries and requirements on how contractors can manage waste streams generated from the decommissioning process;

- Ability for the owner / operator to focus on other important issues not directly related to the decommissioning project, as this process allows other Team members to manage the day to day work elements.

The decommissioning process proceeds through five separate stages, each with specific tasks, team roles, deliverables and completion milestones. The stages are briefly introduced in this section of the document, and described in more detail beginning with Chapter 2.

Stages in the Decommissioning Process

- **Stage 1 - Project Framing.** This step is arguably the most important stage in the decommissioning process. It is in this stage that owner / operator, regulatory, and stakeholder expectations are first identified; project management, communication and consultation and technical teams are formed; a process for making site management decisions is developed; project management systems are developed and put in place; preliminary project schedule and funding arrangements are developed; and, preliminary post-decommissioning land use objectives are defined.

  It is the authors' experience that the more effort that is put into Stage 1 of the process, the more likely it is that the project will be completed successfully – that is, when the project is finished, the objectives defined during the project are met.

  > ***Quick Note:***
  > *One of the most critical elements to a successful decommissioning project is defining objectives for post-decommissioning land use early in the process.*

- **Stage 2 - Site Characterization**. This stage involves a series of focused site investigations, the findings for which provide an understanding of the potential subsurface environmental issues at the site, a description of hydrological and hydrogeological conditions on the property, an understanding of potential waste streams generated during the abatement and demolition work, and identification of constraints to meeting the preliminary post-decommissioning land use objectives for the site. Various agencies have developed guidance for tiered environmental site investigations; for the purposes of this document, we have elected to use the following nomenclature:
  - Phase I Environmental Site Assessment - a non-intrusive study of the historical uses of the property to identify potential environmental concerns.
  - Phase II Environmental Site Assessment - typically includes an intrusive sampling and analysis program designed to determine if residual impact is present in the surface or subsurface, and the corresponding magnitudes.
  - Phase III Environmental Site Assessment - involves additional sampling and analysis of subsurface media to further identify the magnitude and extent of impact so that strategies for future remedial action options can be developed.

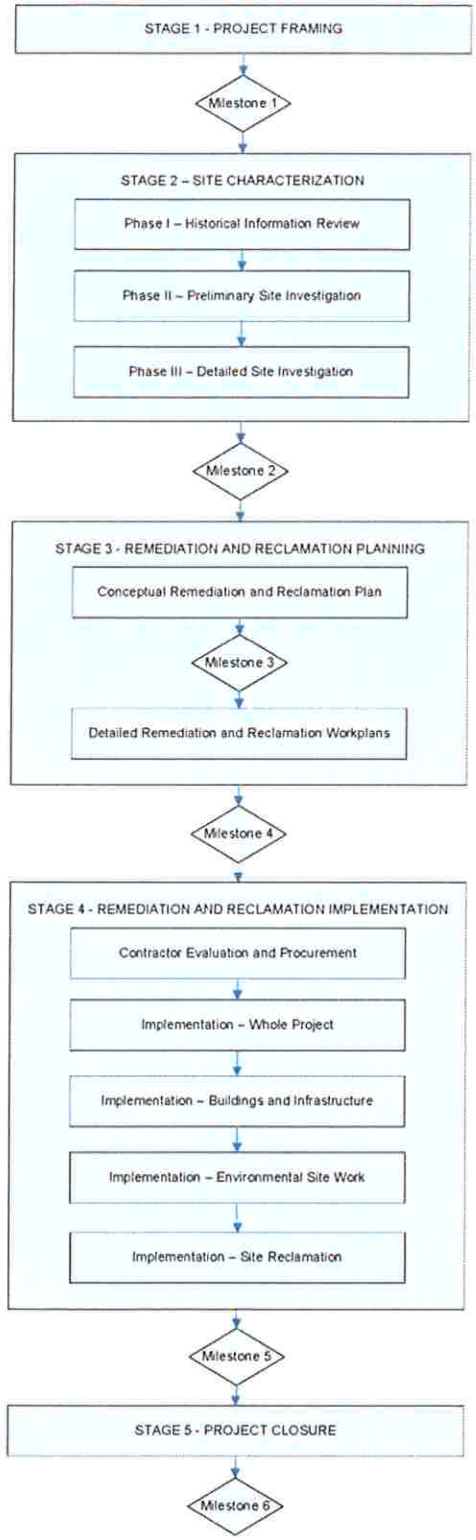


Figure 1-1
Staged Approach to Decommissioning Fossil-Fueled Power Generating Plants Stage

- **Stage 3 - Remediation and Reclamation Planning**. This stage includes the development of remediation and reclamation solutions that address the environmental issues, site conditions and constraints identified during Stage 2. These solutions must be developed in a manner that is consistent with the post-decommissioning land use objectives for the site. Stage 3 consists of two sub-stages:
    - the development of a Conceptual Remediation and Reclamation Plan;
    - the completion of a "pre-demolition" survey to identify environmentally-regulated materials and to confirm underground structures and utilities; and,
    - the development of Detailed Remediation and Reclamation Plans and Contract Documents.
- **Stage 4 - Implementation**. This stage includes the site workings according to plans developed in Stage 3. In this stage, environmental abatement, demolition, and site remediation occurs; the site is reclaimed according to the post-decommissioning land use objectives; and any long-term risk management measures are installed.
- **Stage 5 - Project Closure**. This stage includes those tasks necessary to confirm that the remediation and reclamation of the site has been successfully completed, the site meets the post-decommissioning land use objectives defined in earlier stages of the project, and that owner / operator, community stakeholders and regulatory review agencies have all confirmed their approvals for the project. Closure also prepares the site for ownership transfer, and/or redevelopment consistent with the post-decommissioning land use objectives. Long-term risk management controls (e.g., notification for deed to property, environmental monitoring programs and approvals, institutional access controls) are also put into place during this stage.

Project Teams

A successful decommissioning project requires the involvement of people with necessary interests and expertise. To accomplish the objectives of the decommissioning process, and to clarify roles and responsibilities, organization of project members into the following teams is suggested:

Project Management Team

The Project Management Team is responsible for managing the decommissioning process from start to finish, and ensuring that the objectives of the decommissioning process are met. The Project Management Team should include representation from, and perhaps lead by, the power plant operator. This is important because in most situations the operator also owns the site and has significant input into the decision as to what the post-decommissioning land use objectives are for the site. In other cases, the project management team may be led by a consultant hired by the plant operator.

The project management team leader should, ideally, have experience in the relevant facets of the decommissioning of large industrial sites – although not necessarily fossil-fueled power plants. It is the experience of the authors that the challenges of managing the entire process of decommissioning an industrial facility from start to finish are relatively similar regardless of the type of industrial process; and that these challenges are typically greater than the challenges of understanding the specifics of decommissioning a power plant. In other words, a project manager that has experience in decommissioning industrial facilities that were not exclusively power plants is more likely to be successful than a project manager who has extensive knowledge of power plant operations, but no decommissioning experience.

In addition to the team leader, the project management team should include (or at least have access to) personnel with the following expertise and roles:

- Senior management from the power plant operator, who understands and can represent the long-term corporate risk management policies and obligations (including financial, contractual and environmental risks) of the operator;
- Coordinators and/or communication facilitators, who can organize, chair and report on meetings held within the project team during planning and implementation;
- Public Relations specialists, who can be utilized for the communication of sensitive information to the public or media, if deemed necessary;
- Information management specialists, who will be responsible for managing the immense amount of data, figures, photos, reports and other information that will be used and/or generated by the project teams. These specialists may require expertise in databases, geographical information systems (GIS) or other systems necessitated by the project.
- Project management and coordination specialists, who will assist the project management team lead by coordinating the various project teams, and who will also track project deliverables, schedules and budgets.

In addition to the above-mentioned personnel, the project management team will include senior representatives of the communication and consultation team and the technical teams, which are described below.

Communication and Consultation Team

The communication and consultation team represents the interests of the operator, the applicable regulatory agencies (if applicable), and community stakeholders. Membership on this team includes representation from the power plant operator (which may include representatives of management and labor); but should also include representation from the regulatory agencies who will be reviewing the site decommissioning, and representation from affected community stakeholders who have a vested interest how the site is decommissioned and what land use(s) the site will be suitable for after the decommissioning is complete. The communication and consultation team provides operator, regulatory and community stakeholder input into the process of determining the post-decommissioning land use objectives for the site, and also provide input into decisions on how these objectives are to be met.

The specific membership of the team and amount of weight given to each member's input into decisions is best determined through a formal consensus-based decision structure. The overall objectives provide the context for this process, as described in the concluding comments on

"Making Site Management Decisions". If the site is located in a jurisdiction that has well-defined standards applicable to power plant decommissioning, and there are few or no affected community stakeholders with an interest in the site, then the need to have regulatory and community stakeholder input into the decommissioning process is lessened. However, if there is regulatory uncertainty (e.g., no jurisdictional standards for decommissioning, no precedents), or a high degree of community interest (e.g., the site is located in a developed area with many potentially competing desires for the site), then more emphasis must be put on the role of the communication and consultation team.

> ***Quick Note:***
> *The need to have more or less representation from the operator, regulatory agencies and community stakeholders is project-specific.*

Technical Teams

The decommissioning of a fossil-fueled power plant requires that the project team includes, or at least has access to, an experienced group of engineering, scientific and other support specialists. If a project is complex, these specialists can be organized into two sub-teams, "environmental" (responsible for environmental assessment, remediation and reclamation of the site) and "infrastructure" (responsible for dismantling the above and below ground infrastructure).

Membership on the environmental and infrastructure technical teams may include, as warranted by the project, experts in the following disciplines:

- Power plant operations
- Industrial facility decommissioning
- Asset valuation and reuse
- Contaminated site assessment
- Human health and ecological risk assessment
- Soil science and soil quality assessment
- Water quality assessment
- Reclamation
- Hydrology and surface water engineering
- Hydrogeology
- Geotechnical engineering
- Civil engineering
- Hazardous materials management
- Occupational Health & Safety
- Aquatic and, or, terrestrial ecology
- GIS, database and drafting; and
- Report production (administrative, editorial)

Tasks and Deliverables

Each stage in the decommissioning process includes specific tasks and sub-tasks to be administered in a chronological or, if appropriate, parallel manner. The project management, communication and consultation and technical teams have specific roles to play on each of the tasks, and in many cases there are specific deliverables that are produced at the completion of tasks. The tasks, team roles and deliverables associated with each stage of decommissioning are described in Chapter 2.

Decision Milestones

The staged decommissioning process requires that defined milestones be met at the end of each stage, before the next stage is started. The six decision milestones are shown in Figure 2, and introduced below. The specific tasks, deliverables and team roles that lead to each decision milestone are described in Chapter 2.

> ***Quick Note:***
> *The decision and progress milestones are shown on the attached flow charts at chronological positions. This helps to recognize the value of these important decision-making elements.*

- **Milestone 1** is reached at the end of Stage 1, Project Framing, and includes the acceptance by the project management and communication and consultation teams of the project decision support structure, project boundary description and initial description of post-decommissioning land use objectives. By accepting that this milestone has been reached, the project team also agrees to proceed with the next stage in the process, Site Characterization.

- **Milestone 2** is reached at the end of Stage 2, when the Site Characterization is complete and there is good understanding of environmental issues and constraints. At this milestone, the project management, communication and consultation, and technical teams compare the results of the Site Characterization with the post-decommissioning land use objectives developed in Stages 1 and 2, and determine whether or not there are incompatibilities. In other words, the question is asked: *"Do the results of the Site Characterization suggest that the site can be remediated and reclaimed in a way that meets the requirement of the intended post-decommissioning land use?"* If the answer is "no", then the project team must revise the post-decommissioning land use objectives. If the answer is "yes", then the process can advance to Stage 3, Remediation and Reclamation Planning.

- **Milestone 3** is reached at the completion of the Conceptual Remediation and Reclamation Plan for the site, in Stage 3 of the decommissioning process. The Conceptual Remediation and Reclamation Plan outlines remedial solutions for the site, given the results of the Site Characterization completed in Stage 2. At Milestone 3, the question is asked: *"Will the site remediation and reclamation as described in the Conceptual Plan meet the requirements of the post-decommissioning land use objectives?"* If the answer is "no", then the project team must revise the post-decommissioning land use objectives. If the answer is "yes", then the process can advance to the development of Detailed Remediation and Reclamation Workplans.

- **Milestone 4** is reached at the end of Stage 3, once the Conceptual Remediation and Reclamation Plan and the Detailed Remediation and Reclamation Workplans have been completed. The same question is asked as that in Milestone 3. If the answer is "yes", then the process can advance to Remediation and Reclamation Implementation, which is Stage 4 in the decommissioning process.

- **Milestone 5** is reached at the end of Stage 4, once the site has been remediated and reclaimed according to the Conceptual Plan and Detailed Workplans. At this milestone, the majority of the site works have been completed according to plan, with the exception of a few risk management tasks that occur in Stage 6. Milestone 5 includes acceptance by the project management, communication and consultation and technical teams that the remediation and reclamation of the site is complete, and the site will meet the post-decommissioning land use objectives defined and refined throughout the project.

- **Milestone 6** is reached when the decommissioning project reaches completion, and is one final check that the project management, communication and consultation and technical teams agree that the site decommissioning is complete, any required long-term risk management measures are in place and the site is suitable for the finalized post-decommissioning land use objectives. At completion of this milestone, the site may be redeveloped in a manner consistent with the post-decommissioning land use objectives, either by the power plant operator or another party.

Post-Decommissioning Land Use Objectives

One of the most critical elements to a successful decommissioning project is defining objectives for post-decommissioning land use early in the process. Post-reclamation land use objectives are the umbrella for all technical and contractual decisions made. These objectives drive the degree of site assessment, demolition, remediation, reclamation and long-term risk management required on the site.

The post-reclamation land use objectives are influenced by the short- and long-term risk management goals of the property owner. However, the definition of post-reclamation land use objectives should also include input gained from consultation with the appropriate regulatory agencies (if warranted) and community stakeholders. Involving regulatory agencies and community stakeholders in decisions about post-decommissioning land use objectives will greatly increase the probability that project acceptance will be achieved from the local community and the reviewing regulatory agencies.

Post-decommissioning land use objectives should take the form of a formal land use classification (e.g., "industrial", "commercial", "agricultural", "parkland", "residential") that is consistent with the land use designations used by regulatory agencies in the jurisdiction where the site is located. Typically, these land use classifications denote specific types of activities (human and ecological) that must be supported on the post-reclamation landscape, and are also reflective of the environmental receptors and exposure pathways that will be considered when assessing and making decisions regarding risk to people and ecological receptors on the site (see Chapter 3, Site Characterization for more details). Supported activities, exposure pathways and receptors that are incorporated into land use classifications vary to a great degree amongst different classifications and jurisdictions. Therefore, consultation with the applicable regulatory agencies regarding land use designations and supported land use practices is fundamentally important.

Preliminary post-decommissioning land use objectives are developed during Stage 1 of the decommissioning process through consultation amongst the appropriate Team members. As information becomes available (e.g., results of the Site Characterization), these preliminary land use objectives are re-examined for appropriateness and adjusted as necessary.

It is often the case that remediating the entire site to the highest environmental standard, which would allow unrestricted post-decommissioning land use, is not practically achievable. For example, it is possible that portions of the site may best be suited only for redevelopment as an industrial site. In these cases, which are more often the situation than not, future land use restrictions must be put in place (see the discussion on Closure, end of Chapter 2). Also, in any case where unrestricted land use is not possible, consultation with applicable regulatory agencies and community stakeholders throughout the decommissioning process becomes even more important.

Making Site Management Decisions

Ultimately, the closure/decommissioning process results in an altered land use configuration of the plant property; and potentially, the contiguous lands surrounding the property. Each plant site has the potential to bring new opportunities and challenges to the decision-making arena. Arriving at well-conceived, effective decisions is critical to the success of the project; this can be complicated because decisions are often made by committees evaluating and interpreting information without the context of the overall objectives or a focused plan. The figures in Appendix A provide a graphical representation for site management decision-making, including team responsibilities."

2
THE STAGED APPROACH TO DECOMMISSIONING

Stage 1 - Project Framing

Project Framing or Stage 1 of the decommissioning process is probably the most important stage in the decommissioning of a power plant (Figure 1-1 and Figures A-1 and A-2).[1] Stage 1 essentially sets the decommissioning project up for success or failure.

In Project Framing, the expectations of the site owner and operator, regulatory agencies and community stakeholders are first identified; project management, communication and consultation and technical teams are formed; a process for making site management decisions is developed and tried; project management systems are developed and put in place; preliminary project schedule and funding arrangements are developed; and, preliminary post-decommissioning land use objectives are defined.

> ***Quick Note:***
> *The reader can easily use this Chapter as a checklist; the idea is to provide items for readers to consider. How one names and designates responsibilities to the project committees should be project-specific. A condensed check-list is provided in Appendix B.*

Tasks

The tasks to be accomplished in Stage 1 – Project Framing, include (in chronological order of when tasks are first initiated):

1. The site owner and power plant operator establishes the Project Management (PM) Team, which will be responsible for implementing and managing the tasks required as part of Stage 1;
2. The PM Team develops a framework for the decision-making process for the project;
3. If necessary to refine funding requirements, the owner/operator engages the PM Team to obtain "directional" estimates for different end use scenarios - the directional estimates are intended as guidelines to facilitate end use decisions only.

[1] Appendix A provides charts delineating the tasks within each stage and the responsibilities of team members and other stakeholders. Appendix B offers a brief "checklist" of the major steps of the decommissioning process described in this chapter. Appendix C provides guidance on procedures for preliminary cost estimating.

4. The PM Team develops a preliminary description of the project boundaries, including obtaining information on the following, at a minimum:

   - relevant, applicable or affected stakeholders (which may include potential future property developers); the decision as to the breadth of stakeholders is made on a project-specific basis;
   - corporate policies, bylaws or environmental management systems (EMS) that may be applicable;
   - acknowledgement of relevant regulatory agencies (may include federal, state, municipal, tribal, international);
   - anticipated project timelines and schedules;
   - post-decommissioning land use objectives, taking into account long-term liability and indemnification goals as appropriate;
   - roles and responsibilities for other project team members;
   - labor considerations (union contract requirements if applicable, etc.).

> ***Quick Note - Estimating:***
> *Estimating is an important step; the reader should engage the assistance of an engineer or reputable contractor to help estimate for funding purposes. It is best to provide the estimator with a boundary of scope scenarios - it can be as easy as a one page list - to frame in a more accurate estimate. Hint: do not simply call a demolition contractor and receive a cost over the phone!*
> *Further comments in Appendix C.*

5. As part of the decision support structure, applicable operator and operator representatives, regulatory agencies and community stakeholders are identified and enlisted into the Consultation and Communication Team;
6. The PM and Consultation and Communication Teams meet to finalize the decision support structure for the project, and describe the roles, responsibilities and decision-making weightings for the each of the Consultation and Communication Team members;
7. The PM Team, working with the regulatory agency representatives (as necessary) on the Consultation and Communication Team, identify applicable requirements. Considerations related to current operating permits (i.e., the need to cancel, revise, maintain or replace) are also assessed at this time, and a preliminary plan is developed on how these impacts are best addressed.
8. The PM and Consultation and Communication Teams finalize the project boundary descriptions, taking into account the preliminary post-decommissioning land use objectives and decision-making elements;
9. The PM Team develops a project management system, which includes a document control system, data management system and data quality objectives, project health and safety considerations, contracting mechanisms, etc.

Deliverables

The deliverables from Stage 1 - Project Framing include:

- A list of the various project teams, team members, and roles and responsibilities;
- A project decision-making process, in flow chart or matrix form with supporting narrative;

- Project boundary description, including preliminary post-decommissioning land use objectives, and other components as described under Task 4 above;
- Directional estimates for different end use scenarios, if necessary; and,
- A project management system, including:
    - document control system,
    - data management system and data quality objectives, and
    - a project health and safety (H&S) plan.

Milestone 1

At the end of Stage 1, the PM and Communication and Consultation teams should agree on the project decision-making process, roles and responsibilities of key team members, project boundary description, post-decommissioning land use objectives, plant labor involvement (if applicable), and decommissioning scenarios. By agreeing on these project deliverables, Milestone 1 (Figure A-1) is reached, and the project can proceed to the next stage in the process, Site Characterization.

Stage 2 - Site Characterization

Site characterization is a critical step in the planning and implementation of the overall decommissioning process. The site characterization is a stepwise approach that provides the Owner / Operator an evaluation of environmental liabilities related to impacted surface and subsurface media. This information is used in end use determinations, funding, demolition planning, and long term management of properties.

The stepwise approach includes the following major phases:

- **Phase I Environmental Site Assessment** - A non-intrusive evaluation of potential areas of environmental concern.
- **Phase II Environmental Site Assessment** - Confirmation of presence or absence of impacted media related to findings of the Phase I ESA through physical sampling and analysis.
- **Phase III Environmental Site Assessment** - Further investigation of confirmed impacts designed to establish magnitude and extent of contaminants and to obtain data for remedial action planning.

A general description of the phased approach to site characterization is provided in this chapter.

Phase I Environmental Site Assessment

Objective

The purpose of the Phase I Environmental Site Assessment (ESA) is to evaluate the potential for impact to the environment as a result of past plant operations. For the purpose of this document "impact to the environment" relates to residual contaminants found in surface soil water, subsurface soil, sediments, and/or groundwater. The Phase I ESA is a non-intrusive study; no sampling or other physical characterizations are typically performed.

The *ASTM E1527 Standard Practice for Environmental Site Assessments: Phase I Environmental Site Assessment Process* details the process of undertaking a Phase I ESA. In the United States, this ASTM standard is used as the regulatory-accepted method throughout the country. For ease of reference, only the main elements of this process are described herein.

Tasks

There are four components to a Phase I ESA: Records Review, Interviews, Site Reconnaissance, and Reporting.

Task 1. Phase I ESA Data Gathering

- Records Review: Compilation of available records that describe the past and current occupants and activities of the plant property and, if available, surrounding properties. Records to review can be of several categories, including: Operational Records, Plant Infrastructure Drawings, Public Historical Documents; Environmental Documents.

- Interviews: Interviews with relevant site personnel, including past and present owners, operators and occupants; and local government officials (if warranted).

- Site Reconnaissance: Detailed site visit and walkover to document current conditions of the plant property and surrounding properties (if accessible), with a focus on areas of concern noted during the records review and interviews.

Task 2. Evaluation and Reporting

Upon completion of data gathering, the information obtained should be evaluated to gain an overview prior to, or in parallel with, the report preparation. This allows the Owner Team or PM Team to evaluate the completeness of the data and to consider the need for additional data gathering as part of the Phase I assessment.

One important aspect of the Phase I ESA process is to help identify areas of the site that have similar operational history, or similar issues of environmental concern (e.g. coal handling areas, ash disposal areas, lay down areas, transformer yards, etc.). When decommissioning large facilities, it is very helpful to segment the property into smaller, more manageable areas. It can also help in the management of data, and in reporting.

Deliverables

There are two deliverables related to the Phase I ESA:

1. A Phase I Environmental Site Assessment Report, documenting the site history, site conditions, site use, and issues of environmental concern (or "recognized environmental conditions" as referred to in the ASTM standard); and

2. If warranted, a site diagram showing logical subdivisions or areas of the plant property that have common environmental issues, and that can be managed through the decommissioning process in a similar fashion.

> ***Quick Note - Phase I ESA Report:***
> *The Phase I ESA Report can sometimes be written by environmental consultants in a manner that is speculative. Although professional opinions from the consultant are part of the ASTM requirements, the findings should be fact-based and without conjecture. Should the Phase I ESA become public record, phrases such as "likely contaminated" or "threat to the environment" may negatively affect public perceptions when the issues identified in the report have not yet been confirmed through intrusive sampling and analysis.*

Upon completion of the Phase I Environmental Site Assessment, the Owner Team will evaluate the potential environmental liabilities, and discuss these liabilities in the context of long term land use determinations, demolition planning, etc. In the event that the liabilities require confirmation through physical sampling and analysis of potentially affected media, a "Phase II ESA" would be performed as discussed in the next section.

Phase II Environmental Site Assessment

Objectives

The objective of the Phase II Environmental Site Assessment (ESA) is to further confirm the presence or absence of impact related to the environmental issues identified during the Phase I ESA. This is done through physical sampling and analysis and other mechanisms. Evaluation of the environmental issues is completed through a process of conceptual site model development and site investigation. Guidance on Phase II site assessments can be found in *ASTM E 1903-97, Standard Guide for Environmental Site Assessments: Phase II Environmental Site Assessment Process*. This standard process is summarized in the following tasks.

Tasks

Task 1. Development of Conceptual Site Models

> ***Quick Note - Smaller Projects:***
> *For smaller Phase II projects, Tasks 1 through 3 are easily done and not time consuming.*

The first task is to develop a conceptual understanding of the surface and subsurface environment related to issues of environmental concern (hereafter called Areas of Concern, or AOC) identified in the Phase I ESA, and for the plant property in general. The Conceptual Model describes the spatial relationships between contaminant and waste sources, surface and subsurface pathways (surface water bodies, soil and rock, groundwater flow), and potential receptors (surface water bodies, water supply wells, groundwater discharge areas).

Development of a Conceptual Model allows the investigator to qualitatively assess relationships between contaminant sources and pathways, and to identify areas of uncertainty that will require further investigation. The Conceptual Model also allows the investigator to plan the site investigation program in a methodical and defensible manner.

Detailed discussion of Conceptual Model development is found in *ASTM E1689-95(2003) Standard Guide for Developing Conceptual Site Models for Contaminated Sites*.

Task 2. Selection of Environmental Assessment Criteria

A list of chemicals of concern is typically established during the Phase I ESA program. Once the Conceptual Model(s) has been developed, and the qualitative relationships between sources, pathways and receptors are understood, decisions can be made on the applicable soil, surface water and groundwater quality criteria to be used for assessment of environmental quality data. Decisions on applicable criteria should be made in consultation with the local regulatory agencies, if warranted.

Task 3. Development of Data Quality Objectives

The Data Quality Objectives process is a seven-step process used to plan the collection of data of suitable type and quality to meets the needs of the study. The first five steps of the process are focused on determining the qualitative study needs, such as the nature of the problem to be investigated, the decisions to be made based on the data, the types of data needed, and a logical definition of how the data will be used to draw conclusions.

> ***Quick Note - Data Quality Objectives:*** *Establishing DQOs before implementing a sampling and analysis program helps to ensure a successful site investigation. By understanding the DQOs upfront, gratuitous sampling and analysis can be avoided; conversely, understanding DQOs also minimizes the potential for the analytical program to "miss" capturing the needed data, thereby avoiding additional mobilizations for incremental data collection.*

The sixth step involves definition of quantitative criteria on the quality and quantity of data to be collected. The seventh step is the design of the data collection program. The advantages of using the Data Quality Objectives process in study design include clear communication and documentation, defensible data collection, and logical decision structure.

Detailed guidance on application of the Data Quality Objectives Process is provided in *EPA/240/B-06/001 February 2006. Guidance on Systematic Planning using the Data Quality Objectives Process.*

Task 4. Design of Phase II Preliminary Site Investigations

Task 4 involves design of surface and subsurface site investigations based on the Areas of Concern identified during the Phase I ESA, and on the contaminant source and receptor relationships identified in the Conceptual Site Model(s). Objectives of the Phase II investigations can include:

- Identify the types of contaminants, the quantities, concentration ranges, and general locations;
- Identify potential off-site sources of contamination that may affect the project;
- Confirm soil, geological, hydrogeological and hydrological conditions of the Site and surrounding area;
- Provide the initial inputs to the identification of site remediation criteria.

The Phase II investigations may be specific to each AOC, but can also include data to support larger site-wide requirements. The deliverable from Task 4 is a Phase II Preliminary Site Investigation Work Plan that addresses each AOC or the entire site, if necessary.

Task 5. Development of Data Management System

An important aspect of the Phase II investigation process is to develop a system for managing all the chemical and physical data that will be gathered during the investigation phases. This can represent a significant amount of information, and should be handled and stored in an organized fashion to allow ongoing reference, and to provide quality and defensibility. Consideration should be given to developing and maintaining an electronic database for larger facility decommissioning programs.

Task 6. Development of Quality Assurance Project Plans

Task 6 involves the preparation of plans that summarizes the Data Quality Objectives for the Phase II investigations, and describes the quality assurance and quality control methods and measures to be implemented to meet the Data Quality Objectives. For smaller projects, this task may not be required as a stand-alone document but rather included in other planning documents.

Further discussion of Quality Assurance Project Plan format and content can be found in *EPA/240/R-02/009 Guidance for Quality Assurance Project Plans (G-5).*

Task 7. Development of Health and Safety Plans

Health and safety plans should be developed for the Phase II site investigation works, consistent with corporate, state and federal occupational health and safety requirements.

Task 8. Implementation of Phase II Preliminary Site Investigations

Upon completion of the planning tasks associated with Phase II ESA, the investigations can be implemented.

Task 9. Compilation of Data into the Data Management System

Data returned from the Phase II ESA should be checked and validated as described in the Quality Assurance Project Plan, and compiled into the project Data Management System for subsequent analysis and comparison.

Task 10. Revision of Conceptual Site Models

Upon completion of the Phase II investigations, the Conceptual Model should be reassessed. As data is reviewed and the Conceptual Site Model is revised, there may be opportunity to revise or adapt the Phase II investigations to consider changing uncertainties and priorities.

Task 11. Preparation of Phase II ESA Reports

The Phase II ESA report will detail the nature and probable extent of chemical impacts, will identify data gaps, and will provide recommendations for additional investigation or assessment.

Deliverables

Deliverables for the Phase II ESA process are noted in the Task descriptions above.

Upon completion of the Phase II ESA, an evaluation will be made to determine if contamination has been sufficiently characterized. If not, additional decisions will be made to proceed with Phase III Detailed Site Investigations on part or all of the Site.

Phase III Environmental Site Assessment

Objectives

The objectives of the Phase III ESA are to:

- delineate the extent of contamination
- further define the physical and chemical conditions of the site to assess contaminant movement along various pathways
- collect structural and soil data required to clean, demolish, stabilize and isolate structures and deposits;
- provide more detailed data to assess the validity of the remediation criteria; and
- provide information necessary to assess the feasibility of various remediation and reclamation options.

The Phase III ESA is typically focused on confirmed areas of known impact, and a larger number of samples are collected from fewer locations. This may also include more specific testing and analysis requirements to further refine the Conceptual Site Model. For example, pumping tests may be conducted to identify aquifer parameters to further define a groundwater pathway, or sorption coefficient tests may be performed to determine sorption properties of various chemicals of concern in soil.

Tasks

The Phase III ESA sequence is similar in nature to the Phase II ESA, specifically as it pertains to development of planning deliverables, such as health and safety plans, QAPP documents, Data Quality Objectives, etc. For ease of reference, duplicative tasks have not been included in this section.

Task 1. Selection of Remediation Criteria for Land Use Scenarios

Based on the potential end land use objectives, appropriate remediation criteria (or chemical endpoints) can be established for the remediation program. Remediation criteria involve simply reviewing applicable State or Federally promulgated cleanup requirements (where present). This is important as the initial task because it allows the Phase III ESA to be designed to collect data that supports the remediation criteria requirements.

Task 2. Determination of Requirements for Environmental Simulations and Risk Assessments

At this stage of the project, there may be requirements to conduct environmental simulations such as groundwater transport modeling to predict chemical concentrations at receptors. Further, there may be requirements to conduct ecological or human health risk assessments to assess possible risks to receptors from known or predicted chemical concentrations.

Data requirements for environmental simulations and risk assessments should be determined during this task, so that data collection can be included as part of the Phase III ESA.

This task is not always needed; the decision is based on the complexity of the site conditions and contaminants.

Task 3. Design of Phase III ESA

Upon completion of Tasks 1 and 2, the Phase III ESA can be scoped and planned accordingly.

Task 4. Implementation of Phase III ESA

Upon completion of the planning tasks associated with this phase, the investigations can be implemented.

Data returned from the Phase III ESA should be checked and validated as described in the Quality Assurance Project Plan, and compiled into the project Data Management System for subsequent analysis and comparison.

> ***Quick Note - Regulatory Agency Involvement:***
> *As part of the site characterization process, the Owner / Operator should consider engaging the appropriate regulating agency before or after the Phase III ESA. Depending on the nature of confirmed environmental impacts, there may be a requirement to notify the agency. Regardless, engaging the agency is often useful in that agency representatives can become integrated in the planning of future investigations or remedial actions, thus helping to expedite remedial action acceptance in the long term.*

Task 5. Revision of Conceptual Site Models

As with the Phase II ESA, the Conceptual Model should be reassessed upon completion of the Phase III ESA. Revision or adaptation of the Phase III ESA can be made during the investigation program in response to changing uncertainties and priorities.

Task 6. Preparation of Phase III ESA Reports

Task 6 involves preparation of the Phase III ESA reports that detail the extent and magnitude of contamination, a summary of environmental simulations, risk assessments, and remediation objectives, as well as identification of data needed to further develop remediation and reclamation options.

Deliverables

The deliverables associated with the Phase III Detailed Site Investigation include:

- The revised Conceptual Site Model
- The Data Quality Objectives for the Phase III investigations
- The Phase III ESA Work Plan
- The Phase III ESA Quality Assurance Project Plan
- A Data Management System updated with the Phase III data;
- Health and Safety Plans; and
- The Phase III ESA Reports.

Milestone 2

This Decision Milestone is reached upon completion of Stage 2 – Site Characterization. Site conditions should be sufficiently understood at this point to determine if the site can be remediated and reclaimed in a way that meets the requirements of the intended post-decommissioning land use. If the site cannot be remediated or reclaimed in this manner, then the project team must discuss the possibility of revising the post-decommissioning land use objectives. If the site can be remediated or reclaimed in a manner that meets the post-decommissioning land use objectives, then the overall decommissioning process can advance to Stage 3, Remediation and Reclamation Planning.

Stage 3 - Remediation and Reclamation Planning

Preparation of Conceptual Plans

Objectives

The objectives of the Conceptual Remediation and Reclamation Plan serve two distinct yet linked tasks: 1) remediation of surface and subsurface media, and 2) the physical abatement and demolition of the site structures.

- For Objective 1 above, the conceptual plan will identify potential subsurface remediation and reclamation options for the site, evaluate those options in terms of selection criteria such as engineering feasibility, stakeholder acceptance, schedule and cost, and select preferred remediation and reclamation options that will meet the requirements of post-decommissioning land use.
- For Objective 2 above, the conceptual plan will allow the Owner and PM to effectively scope the physical removal of the site structures in a manner that achieves Owner contracting and risk requirements, and the land use goals.

Preparation of Remediation and Reclamation Plans

Tasks to be undertaken in preparation of the Conceptual Remediation and Reclamation Plan include:

- Literature review of Remediation and Reclamation Options, and selection of options for further assessment;
- Design and implementation of bench-scale testing and computer simulations to support remediation and reclamation options feasibility assessment;
- Implementation of risk assessment and risk analysis to support remediation and reclamation options feasibility assessment (as necessary);
- Estimation of costs and schedules for Remediation and Reclamation Management Options;
- Selection of Preferred Remediation and Reclamation Management Options for each Area of Concern; and
- Preparation of a Conceptual Remediation and Reclamation Plan for review by the Owner and/or other teams.

The level of detail for the conceptual plans can be broad (matrix / graphic-based) or more detailed (including narrative descriptions and options summaries). The decision on the level of detail is a project-specific decision.

Preparation of Scope and Contract Documents - Abatement and Demolition

In this step of the decommissioning process, scope and contract documents are developed that will be used to guide the contractor bidding and work implementation. The documents are the next step in the progression of this process, created from the conceptual plans described above.

The major tasks to be completed include:

1. Deciding the best contracting mechanism for delivery of the project(s);
2. Planning for the control of environmental issues during the project
3. Planning for the control of health and safety issues during the project
4. Developing the detailed scope-of-work, project sequencing, and contract documents.

The main role-players in this step are the Owner's Project Management (PM) Team and the Technical Team comprised of both environmental and infrastructure consultants. The responsibility of the PM team is to:

- provide guidance to ensure that Owner requirements are met (e.g. financial, schedule, regulatory);
- provide guidance regarding site-specific operational, environmental or health and safety aspects that must be addressed during execution of the work; and,
- review and ensure that the contract documents reflect the Owner's overall objectives and requirements and minimize Owner risk for unnecessary cost overruns and other liabilities.

The responsibility of the Technical Team is to:

- provide technical expertise to the PM team during the planning phase of each task; and,
- produce high-quality documents that will facilitate completion of the project and meet the Owner's contracting and risk objectives.

The deliverable documents to be produced include:

- Environmental Control Plan (ECP)
- Health and Safety Plan (HASP)
- Overall Project Schedule
- Pre-Demolition Survey (regulated materials, infrastructures)
- Project Manual / Contract Documents

Task 1. Contracting

The Owner's PM team in conjunction with the Owner's purchasing department (if applicable) will decide on the preferred contracting mechanism for the project. There are several options available for administering the contracts, as presented below. Regardless of the contractual arrangement, the Owner should consider retaining an engineer and/or environmental consultant to act as the Owner's representative for reviewing and monitoring the work being conducted to ensure compliance with the contract requirements and applicable regulations.

Examples of Contract Administration Setup:

OWNER	OWNER	OWNER
↓	↓	↓
GENERAL CONTRACTOR	CONSTRUCTION MANAGER	MULTIPLE CONTRACTORS
↓	↓	
SUBCONTRACTORS	GENERAL CONTRACTOR	
	↓	
	SUBCONTRACTORS	

Typical pricing options include: stipulated fixed price, time-and-materials, Cost Plus with Fee, or a combination that might include unit-pricing for some aspects of the work. Use of the fixed price option places the risk for overruns on the Contractor. Use of the other options places the risk of overruns on the Owner.

The contract administration setup selected is dependent upon the experience, availability and ability of the Owner's staff to manage the project and the level of involvement in the day-to-day decisions that the Owner would like to have and also upon the Owner's tolerance or acceptance of variance in the ultimate cost of the project compared to projected costs at the onset of the project.

> ***Quick Note - Fixed Price Contracts:***
> *Experience shows that the best way to achieve cost containment on a building demolition project is to administer a fixed price contract. A good way to minimize contingencies a contractor builds into his/her costs is to be thorough in the pre-demolition phase: conduct a thorough hazards survey with quantities, provide plant structural and mechanical drawings for reference, provide old permits and reports; etc. The more information - and time - provided to a contractor during the bid process will result in a lower cost for a fixed price contract.*

Task 2. Control of Environmental Issues

The Owner's PM team in conjunction with the Technical team identifies the environmental aspects of the project, and collectively set forth responsibilities for addressing these issues. Environmental aspects of the project could include (but are not limited to): air emissions, storm water discharges/control, sanitary discharges, spills of regulated materials, solid waste control, and use and management of regulated materials. Use of the pre-decommissioning environmental survey (prepared in Stage 2) is a valuable tool for identifying environmental aspects.

The site work responsibility to address these aspects is generally assigned to the Contractors hired to execute the project; however, monitoring to ensure that the aspects are being addressed would be the responsibility of the PM team (such as the Environmental Consultant or Program Manager, as applicable).

A listing of the environmental aspects and parties responsible for addressing them is captured in the contract documents as a high-level Environmental Control Plan (ECP). A detailed ECP is a required submittal from the Contractor prior to the start of the project. This detailed ECP would be reviewed by the PM and Technical teams for consistency with the Owner's requirements contained in the high-level ECP.

Pre-Decommissioning Environmental Survey

A critical step in the planning and scoping of a successful abatement and demolition project is the pre-demolition environmental and infrastructure survey, or "Pre-Demolition Survey" for short. This survey provides a wealth of information that is later used during the bidding and implementation of the abatement and demolition project, such as

- An identification of building and process materials that require removal, handling, and special disposal as "regulated wastes" prior to, or during the demolition project. Without removing - or "abating" - these materials prior to demolition, the resultant demolition debris can become environmentally impacted, thereby rendering the debris as a contaminated waste stream and causing significant costs and undue cradle-to-grave liability (if applicable) to the Owner or other designated generator of the wastes.
- An identification of the infrastructures that serve the plant, including utilities, sub-slab pits and vaults, foundations of former structures, hidden slabs and abandoned piping, and other such items. It is very important to research and understand infrastructures, because any such items can delay a project considerably if not known or suspected up front.

> ***Quick Note - Pre-Decommissioning Infrastructure Surveys:***
> *A good mechanism for capturing the historical environmental and infrastructure information that is critical to an efficient demolition project is through a "Site Use History". The SUH process enables the Team member(s) to locate and evaluate current and historic information, such as previous reports, design and as-built drawings, permits, utility diagrams, past processes and operations, etc., and compile the salient information into one report for future reference by the Owner's Teams, contractors, and planners, as necessary.*

The Pre-Decommissioning Survey can be performed in parallel with the site characterization efforts, and should be completed prior to scoping the project to maximize the information used to develop the conceptual plans. An environmental consultant experienced with facility decommissioning projects should be retained.

Task 3. Health and Safety

The Owner's PM team in conjunction with the Technical Team identify the health and safety aspects of the project, and responsibility matrices for addressing those aspects. Health and safety aspects of the project could include (but are not limited to): site-specific health and safety procedures or Owner requirements, notifications to operational groups within the site that will remain active during the project, industrial hygiene type issues including use of personal protective equipment, disruption of utilities being used by active portions of the site, housekeeping at the project site, traffic, heavy equipment, excavations, confined spaces and burning and welding. The responsibility for addressing these aspects, as well as being in compliance with Federal, State, Provincial Occupational Health and Safety laws, is generally assigned to the Contractors hired to execute the project. However, monitoring to ensure that the aspects are being addressed would be the responsibility of the PM team (including the Environmental Consultant or Program Manager, as applicable).

The health and safety aspects identified by the PM and Technical team are captured in the Project Manual as a listing of the health and safety performance requirements that the Contractors will be required to follow. Detailed HASPs are a required submittal from the Contractor prior to start of the project. The submitted HASPs would be reviewed by the PM and Technical teams for consistency with the Owner's requirements.

Task 4. Scope of Work and Schedule

The Technical Team, with input from the PM team prepares a formal scoping document that will be used to describe the scope of the project, specify the Owner's requirements, and obtain firm pricing from potential Contractors (i.e. Bidders). This document essentially evolves into the "Project Manual", which can be defined as a merging of the reference, bid, and contract documents necessary to procure a contractor(s) and implement a project of this nature. The Project Manual should include the following elements:

- Pre-decommissioning survey reports (regulated materials survey, site use history)
- Contract drawings
- Site environmental investigation report
- The scope-of-work (SOW) for the project
- The project schedule milestones
- Specifications of how to execute the project
- Contract documents, general conditions, Owner requirements, and other reference materials.

Project Manual

The first three elements listed above are included to provide the bidding contractors with a detailed description of the current conditions of the site which they will use to complete their due diligence and prepare methods and costs. The pre-decommissioning survey reports are very important to identify the location, the nature and the quantity of regulated materials requiring disposal. Historical drawings (which are included as part of the site use history) are important because they will give the bidding contractors insight into:

- assessing how the site buildings were constructed and conversely how they may be demolished,
- estimating quantities of recyclable material,
- requesting additional analysis of samples of regulated materials during the bid cycle,
- locating underground utilities to be capped and abandoned, re-routed, or protected.

The site environmental investigation report would be provided to describe the nature and extent of impacted soil and/or groundwater and gives context to the remedial designs provided in the SOW section.

> ***Quick Note - Performance-Based Contract Documents:***
> *For most abatement and demolition projects, it is best to prepare a scope of work and technical specification document that is "performance based". This style of contract document provides the end requirements for the specific work tasks, with boundaries within which a contractor must work to ensure compliance with regulations and other stipulations of the contract. The actual means and methods are determined by the contractor and reviewed by the Owner team for compliance (see Stage 4 - Implementation). By not prescribing means and methods, the Owner minimizes its liability in the event that a contractor fails to perform the work in accordance with applicable regulations and safety requirements.*

The SOW provides a detailed list of tasks to be accomplished by the selected Contractor(s) in order to complete the entire abatement and demolition project. The SOW would include the design of the selected remedial option to be installed and any engineering designs for restoration of structures that may remain, and for abandonment or re-routing of utility infrastructures. The project schedule would show progress milestones that the Owner requires to be met and may show the general sequencing of the overall project should the Owner have logistical constraints that would govern sequencing of the work.

The specifications section provides a description of how the project should be executed. Ideally, the goal of the specification section is to be specific enough to set the boundaries of acceptable means and methods (e.g. prohibit the use of explosive techniques) but to be flexible enough to be able to best utilize the expertise of the selected Contractor to execute the project safely and in a cost-effective manner. The contract style of the specifications can vary from very prescriptive (i.e. describing means and methods) to very general (i.e. describing only the end result to be achieved) - see note on this page regarding "Performance-Based Contract Documents". It is recommended that a construction/demolition industry standardized format, such as Construction Specifications Institute (CSI), be used. The requirements of the environmental control plan and the health and safety plan requirements are presented in the specification section.

The list of individual specifications that are included in the project manual are unique to each project; however, the following general categories of specifications are common to all projects.

<u>General Conditions to complete the work</u>. Aspects in this category would include but are not limited to: site security, temporary utilities, traffic control, temporary office space, sanitation facilities for project personnel, and communications.

<u>Regulatory/Environmental Controls</u>. Aspects in this category would include, but are not limited to: the Owner's ECP (refer to Task 2), regulated material management, waste transport and disposal, recycling, permitting, storm water control, air emissions, sanitary discharges, noise control, and vibration control.

<u>Health and Safety Controls</u>. Aspects in this category would include, but are not limited to the Owner's health and safety requirements for working on the site (refer to Task 3), emergency procedures, and compliance with applicable regulations.

Technical / Performance Specifications. Aspects in this category would include, but are not limited to: descriptions of acceptable techniques to accomplish the SOW, prohibition of certain techniques, quality of materials used to construct new installations, performance requirements of installed systems, or building components or earthwork, and clean-up criteria or remediation goals.

Submittals / Communication / Planning. These sections describe the process by which the Owner and the Contractor communicate planning and execution issues. Aspects in this category would include, but are not limited to: permitting, method statements, designs, progress schedules, progress meetings, and Owner review and acceptance procedures. Typical planning-type submittals include, but are not limited to: Health and Safety Plan, Environmental Control Plan, Dust Control Plan, Noise and Vibration Control Plan, Construction Storm Water Control Plan, Emergency Response Plan, and Site Grading Plan. A good practice is to require submittal of detailed method statements covering activities that have critical safety or environmental aspects so the PM/Technical teams can assure the Owner that the appropriate level of pre-planning has occurred to minimize the potential for incidents.

Bidding Documents. The Bidding Documents are comprised of elements that address the commercial aspects of the project. These elements include, but are not limited to: terms and conditions, insurance requirements, bonding (if required), invoicing and payment terms, warranties, handling of revenue generated by scrap or other equipment and materials sold for re-use, and the bid form. The Contractor should also be required to provide: a general approach and description of the methodologies to be used, and a proposed schedule with milestones.

Bid Form. The objective of the bid form is not only to obtain pricing, but also to understand in a general sense how each bidding contractor intends to approach the project (in terms of level of effort) so that valid comparisons of the bids can be made. Preparation of the bid form may vary, depending on the Owner's needs and the type of contract (fixed price vs. time-and-materials), in terms of the level of detail of pricing requested from the bidding contractors. Having the bidders submit their proposed schedule with milestones is a useful tool for understanding how they will approach the project. Because the value of the revenue generated from scrap metal recycling is significant with respect to the value of the entire project, the methods for computing, accounting and receiving the value of the scrap metal should be clearly presented.

> ***Quick Note - Retain or Waive Recycle Rights?***
> *An Owner may retain or waive rights to recycle or sell assets from a structure. Assets include metallic scrap, equipment and furnishings, unused product, and aggregate (concrete, brick) generated during the project. Experience has shown that although it is contractually more efficient to waive rights to a contractor, it can be more lucrative for an Owner to retain rights to metallic steel and equipment and arrange a separate contract with a recycler or equipment divestment broker. Recycling or sale of aggregates (e.g., concrete crushed onsite) can be problematic with respect to the environmental condition of the material and long-term liability associated with its reuse in commerce. The Owner's team should evaluate this issue during the conceptual planning phase of the project.*

A good practice regardless of the type of contract is to ask for pricing detail for the major elements of work such as: utility infrastructure abandonment, environmental decommissioning, asbestos abatement, demolition, waste disposal, recycling revenue, site work for environmental remediation, and site restoration. Having this minimum level of pricing detail facilitates interrogation of the Bidders during the post-bid Contractor evaluation phase and a better comparison of the bids received. Additionally, the Bidders should be encouraged to propose "voluntary alternates" for elements of work where they believe that they can provide better value (e.g. time savings, cost savings, enhanced safety) to the Owner if alternate methods are used from those described in the specifications. In this manner, the Owner could benefit from unique expertise held by any one of the bidding firms.

Milestone 3

At the completion of the project manual and bidding documents, qualified firms must be selected and invited to bid on the project. The Owner's PM team, with consultation from the Purchasing Department and the Technical Team would select the firms qualified to bid on the project.

Stage 4 - Implementation

The objective of Stage 4 is to implement the solutions developed in Stage 3 (i.e., decommissioning, demolition, remediation, restoration) as the means to accomplish the project objectives (i.e. the envisioned end land use) developed in Stage 1. The main tasks to be accomplished are: environmental decommissioning of the site buildings, demolition of the site buildings, remediation of impacted soil and/or groundwater, closure of on-site waste management units, and site restoration. The major steps for each of these tasks will be further categorized as *whole project*, *buildings and infrastructure*, *environmental site work*, and *site restoration* and presented in time sequential order. However, to the extent that the *building and infrastructure* and *environmental site work* categories of activities do not occupy the same physical space on the property, they could be conducted as parallel activities.

The responsibility to implement the solutions is shared between the Owner's PM team and the Technical Team. The PM team's main role is high-level oversight of the project activities and progress and to act as the interface between Management and the Contractor when input is needed to solve technical or logistical issues. The Technical Team's main role is to help coordinate the Contractor's activities with those of the Owner, to provide detailed monitoring of the Contractor's activities to ensure compliance with the project manual and to ensure that the project activities are being conducted in accordance with all applicable Regulatory requirements.

Contractor Evaluation and Procurement

The Contractor evaluation and procurement process begins when the Project Manual/Bidding Documents are delivered to the qualified bidders. The following steps are critical to the success of this process.

<u>Pre-Bid Meeting</u>. The objective is to meet the bidders and to briefly explain, from the Owner's perspective, the scope of the project, the format of the bid form, commercial terms, and to outline the due diligence process. The participation of the PM and Technical Team in this meeting as well as a representative from the Purchasing Department, if applicable.

<u>Bid Cycle Due Diligence</u>. The objective of this step is for the bidder's to thoroughly familiarize themselves with the conditions and aspects of the project. Depending on the complexity of the

project, this step could take weeks or months. The bidders should be given access to inspect all facilities and they should be encouraged to request additional samples of potential waste streams so that they can accurately verify quantities of waste for pricing purposes. The objective from the Owner's standpoint is to have the bidders know enough about the site conditions and the scope-of-work that they can submit bids that are complete with minimal assumptions (or qualifications/caveats). The more qualifications/caveats that accompany a bid price, the more opportunity there is for the Contractor to submit change requests as the project progress, resulting in an escalation of cost.

The Technical team is primarily responsible for conducting the Bid Cycle activities which includes: escorting bidders during site inspections, collecting and analyzing all samples requested by the bidders, answering technical or commercial questions (with help from PM team), and providing all supplemental data and technical/commercial answers to all bidders in the form of addenda to the project manual.

Evaluation of Bids. The objective of this step is for the PM and Technical teams to analyze the pricing, schedule, qualifications/caveats, and the methods and schedule submittals contained within each bid in an effort to understand the approach and pricing provided by each bidder. In this manner the PM / Technical teams can compare the bids on an equivalent (i.e. "apples-to-apples") basis. An important element to this process is the post-bid interrogation. Each bidder is invited to discuss their approach and pricing assumptions and to answer other technical or commercial questions posed by the PM/Technical team. At the end of the evaluation process, the PM team recommends to the Purchasing Department the firm that presents the best opportunity for successful completion of the project.

Milestone 4

If the bid pricing is containable within the established project budget, then proceed to awarding the contract. If the pricing exceeds the established budget, then the PM and Technical teams should re-evaluate the scope-of work and the envisioned end land use and reconvene with the Management team to evaluate options for moving forward.

Contract Award and Finalization of Schedule. The Purchasing Department is responsible for notifying the successful bidder and awarding the contract. The schedule of activities should be finalized by the successful bidder, in conjunction with the PM and Technical teams, soon after award of the contract.

Implementation - Entire Project

This and the following sections describe major tasks that comprise the decommissioning process. The tasks are presented in sequential order. The duration of each task may vary on a case-by-case basis, but the typical sequencing is shown on the stage chart (Appendix A).

Quick Note - Finalizing Project Schedules:
Owner acceptance of the Contractor's project schedule immediately after project award is critical for protecting against schedule creep and subsequent claims for increased general conditions costs.

Permitting. Application for all applicable permits should be the first step in the process because the timing for receiving the permits may be variable depending on the governing agency (Federal, State, Provincial, Local). Much of the physical work (e.g. asbestos abatement, demolition) may not be allowed to proceed until the appropriate permits are issued depending on local regulations. The PM team and the Contractor would be responsible to prepare and submit permits.

Community / Regulatory Notifications. If additional notifications to regulatory agencies or the community-at-large are required, then this task should be accomplished early in the process. Depending on the sensitivity of the project or the interest taken by the community, there is the potential to spend several weeks of effort (or more) to accomplish this task.

Review and Acceptance of Submittals. Prior to the start of work, the Contractor should prepare and submit, for review and acceptance by the PM/Technical Team, all contractor submittals (work plans, safety plans, etc.) listed in the Project Manual. The purpose of this submittal and review process is to verify that the appropriate levels of pre-planning have been done to ensure that the project is executed without safety or environmental incidents occurring. This process also serves to notify the management structure of operationally active portions of the plant site (if any) of the types of activities that will be occurring. In this manner, coordination issues can be identified and resolved prior to the onset of decommissioning and demolition activities. Depending upon the ability of the Contractor to communicate effectively, the level of complexity of the project, and the workload of the PM team, this task could take several weeks.

> ***Quick Note - Contractor Submittals:***
> *This process can become tedious but perseverance by the PM/Tech teams in completing this process in a robust manner is critical for ensuring project safety and protecting against change order requests.*

Implementation - Buildings and Infrastructure

Disconnect plant from the distribution power grid. This work could be contracted to a specialty Contractor or included in the project manual with the general decommissioning and demolition work.

Remove surplus fuel. Surplus fuel should be removed and transported for: (a) re-use by the Owner elsewhere, (b) re-sale to third-parties, or (c) disposal.

Disposal of assets. If the Owner wants to recover monetary value from assets (furniture, non-process equipment, process equipment, or other material) and/or retire the asset from the book value of the property through re-deployment or sale for re-use, this activity is best done early in the decommissioning process because it could be a lengthy process. Assets to be re-deployed in another facility (operated by the same Owner) could either be removed by the Owner's forces or included in the Contractor's work scope. A third-party broker or liquidator could be used to dispose assets that are to be re-sold for reuse under a separate contract with the Owner. Alternatively, the contract for the decommissioning and demolition work could contain incentives for the Contractor to sell assets for re-use (including a revenue-sharing arrangement with the Owner). In any case, the asset may require some level of environmental decommissioning prior to shipment in accordance with governing Department of Transportation regulations.

> ***Quick Note - Asset Disposition:***
> *It is easy to pass the point of diminishing returns when disposing assets. In general, if the value to be received for the intact asset is less than the scrap value plus the cost to remove it and ship it, then re-deploying or selling the asset is not worth the effort.*

The time frame for undertaking the asset disposal process and the scope of the effort should be defined by the Owner in the project manual so that the decommissioning and demolition work doesn't get delayed by the asset disposal task.

<u>Environmental decommissioning and utility disconnection</u>. The regulated building materials should be removed from the plant buildings/structures to the extent required for demolition of the structures. Depending upon the work methods utilized and local regulations, not all regulated material needs to be completely removed prior to demolition. As an example, non-friable asbestos- containing roofing material may, in some cases, be left intact as the roof is demolished providing that adequate engineering controls are implemented to prevent release to the environment. Underground process piping should have residual material removed during this step and any floor penetrations covered to prevent demolition debris from collecting in the previously cleaned pipes.

It is recommended that sewer connections are plugged prior to commencement of the environmental decommissioning to eliminate the potential for discharges to the storm or sanitary systems. However, it would be beneficial if utilities such as electricity and potable water remain active as long as possible to facilitate the work inside the buildings and structures (for example asbestos abatement or residual chemical removal). At some point; however, the utilities need to be disconnected so that the building is isolated and completely de-energized. Following complete disconnection of the remaining utilities, regulated materials that are a part of the electrical systems (e.g. PCB-containing oil) and water distribution system would be removed.

At the completion of the environmental decommissioning activities, the Owner's environmental consultant would verify the level of cleanliness attained and that the building/structure has been adequately prepared for demolition.

<u>Protection of Existing Utility Infrastructure</u>. If there are utilities within the demolition zone that are active and need to remain so, they should be temporarily re-routed or protected prior to beginning demolition. Verification that the buildings/structures to be demolished are isolated and de-energized from utility feeds should be performed.

<u>Demolition</u>. Demolition of the above-ground buildings and structures can proceed after verification that all applicable permits have been received. The buildings/structures can then be demolished to grade level in whatever sequence is the most expedient as described in the Contractor's method statement submittal. The resulting debris would be disposed or recycled as appropriate.

<u>Removal of Slabs and Foundations</u>. Following removal of the building debris, removal of the floor slabs and foundations can commence. Typically, foundations are removed to a depth of 36-inches below the existing grade so that any remaining structures do not interfere with re-development activities. However, this depth can be modified depending on the re-development plans. The location and depth of the remaining foundations should be surveyed and tied into the vertical and horizontal control system and added to the post-demolition site conditions record drawing (a.k.a. "as-built" drawing).

Removal of Underground Process Piping or Abandoned Utility Lines. If underground process piping or abandoned utilities occur at a depth shallower than 36-inches below grade, they would typically be removed to prevent interference with re-development activities. If these infrastructures will remain because they occur at a depth that will not interfere with re-development, they can be abandoned in-place or filled with grout. Filling with grout is recommended for pipe diameters greater than 12-inches to minimize future settlement issues caused by pipe decay and collapse. Piping segments that remain in the ground and disconnection points from the utilities feeding the site should be surveyed and added to the post-demolition site conditions record drawing.

Implementation - Environmental Site Work

The following major tasks comprise the remediation and closure process and are presented in sequential order. The duration of each task may vary on a case-by-case basis; typical sequencing is shown on the stage chart (Appendix A). As previously stated, these activities could occur in parallel with the building decommissioning work as long as they are not located in the building demolition zone. If so, it is recommended that demolition occur prior to remediation so that any installed components of the remedial solution are not damaged.

Preparation of Area for Remedial Action. On-site waste management or disposal units and raw material storage areas may have surficial control features and structures associated with their operation. For example, ash lagoons or coal storage areas may have water discharge conduits/features that should be abandoned and plugged to prevent inappropriate discharges during remedial activities. New control features or systems should be installed to control, capture and discharge storm water that accumulates in the areas during remedial activities in accordance with applicable regulations.

Execution of Remedial Actions. Following site preparation and installation of the appropriate controls, remedial actions are undertaken in accordance with the designs and work plans included in the Project Manual. The range of remedial actions includes: gross material removal and disposal, in-situ treatment, isolation by capping, or some combination of all three.

Verification of Remediation or Verification of Performance. The effectiveness of the remedial actions to attain project goals is documented through various testing methods. Chemical laboratory analysis is used to document the attainment of soil and groundwater clean-up goals. Geotechnical testing or other physical testing procedures are used to document the attainment of performance goals for installed remedial solutions (e.g. caps, liners, extraction systems, barriers). Depending upon the ability to use field methods to verify attainment of remedial goals, the verification process may require several iterations of testing and further remedial action, so the duration of this task may require several weeks or months. In the case of in-situ remediation, attainment of remediation goals may require several years; however, the performance of the remediation system compared to the design specifications can be documented at the conclusion of installation.

Hand-Over Of Installed Remedial Systems to Owner. Once it has been verified that the performance of any installed remedial systems match the design criteria, the installation contractor "hands-over" responsibility for the system to the Owner. It is important for the Owner that the hand-over process be well documented and that, at a minimum, the following information be received from the Contractor: equipment operating manuals, warranties and/or service plans; and an operation and maintenance (O&M) plan. In addition, the Contractor could be requested to provide hands-on training sessions to the Owner's employees/subcontractors who will be responsible for operating and maintaining the system. At the conclusion of the hand-over process, the Owner may notify their insurance carrier of the presence and operating functions of the installed system.

Implementation - Site Restoration

Following completion of the slab and foundation removal, the piping and infrastructure removal, and the environmental site remediation, site restoration activities can begin in the disturbed portions of the site. Pits or deep depressions can be filled with inert, structurally stable fill material and compacted to meet the requirements of the re-development activities. Then the site is graded to the final contours shown on the site grading plan. If there will be a significant time-lag between completion of site decommissioning and site re-development activities, it is likely that the governing regulatory agency will require that disturbed portions of the site be stabilized by seeding for vegetative growth to prevent erosion. Contouring and grading of the site should take into account effective, non-erosive drainage of storm water across the site.

Milestone 5

Completion of the previously listed tasks constitutes completion of the Implementation stage and a transition into the Closure stage of the project.

Stage 5 - Closure

This stage of the decommissioning process includes those tasks that establish: (a) that the remediation and reclamation of the site has been successfully completed, (b) the site meets the post-decommissioning land use objectives established at the onset of the project, and (c) that the participating stakeholders agree that the completed project conforms to the pre-determined requirements. Closure also prepares the site for ownership transfer, and/or redevelopment consistent with the post-decommissioning land use objectives. Finally, long-term risk management controls (e.g. property deed restrictions, institutional access controls, environmental monitoring programs) are put into place during this stage of the process.

The responsibility to drive the closure process to conclusion is shared between the Owner's PM team and the Technical Team. The PM Team's main role is to prepare and file the legal documentation required to accomplish the post-decommissioning land use objective. The Technical Team's main role is to obtain or produce the "record" documentation needed by the Owner to manage their residual long-term environmental risk from having owned or operated the site.

Record of Site Conditions

Preparation of accurate records concerning the physical and environmental condition of the site at the conclusion of the decommissioning process is critical for managing long-term environmental risk and, or for successful redevelopment of the site.

Record drawings that document the remaining physical conditions of the site, often referred to as "As-built" drawings, provide information regarding:

- The location and elevation of cut and capped service utility feed lines,
- The location and elevation of infrastructure elements (e.g. decommissioned piping, foundations, etc) that were abandoned in-place,
- The location and elevation of installed remedial solutions (i.e. caps, liners, extraction system piping, groundwater wells, engineered barriers, etc), and
- The shape and elevation of the ground surface.

This type of information is especially useful to developers when planning for and re-developing the site.

Documents that record the environmental condition of the site, may be referred to as project completion reports or remedial action reports. These documents provide information regarding:

- Subsurface geological and hydrogeological conditions at the site,
- Attainment of cleanup criteria,
- Soil quality at the site and the lateral and vertical extent of remediated areas,
- Groundwater quality at the site,
- Installed remedial measures that mitigate future impact to the environment and exposure to human or other ecological receptors,
- Environmental monitoring program requirements,
- Institutional or engineering controls that form the basis for the closure and re-use strategy for the site.

The project completion report is typically the document upon which obtaining regulatory closure of the site is based. Upon review and acceptance of the project completion report, the regulating authority should issue to the Owner written confirmation that the closure of the site is accepted (e.g. No Further Action Letter, Covenant Not To Sue, etc.). Obtaining regulatory closure of environmental issues may not be necessary for property redevelopment by the existing Owner, but it is critical to moving forward with sale of the site.

Waste Management Records

Documentation that provides evidence of how decommissioning and demolition derived waste streams were disposed or recycled should be collected into a report and kept by the Owner to address potential future questions related to waste management issues. Documentation to be retained includes but it not limited to:

- Waste stream characterization data and waste profiling documents,
- Owner-generated shipping documents,
- Manifests (State, Federal, Provincial)
- Truck receipts from the accepting facility
- Certificates of destruction.

Depending upon the location of the project, there may be Local requirements to report waste disposal or recycling activities; therefore, organization of the waste management information into a clear, concise report facilitates ease of transmitting information to regulatory agencies.

Contract Closeout

Part of the overall closure process includes the closeout of all contracts related to the remediation, reclamation, abatement, and demolition work performed. This should be done in accordance with an Owner / Operator standard corporate contracting terms, and can be implemented by the PM Team. Elements to consider for ensuring contracts are closed out include:

- Receipt of waste management records as described above
- Final waivers of lien and invoices have been submitted by contractors
- Permits required for the site work have been closed out, if necessary
- Appropriate agency notifications of completion have been issued
- Final site inspections have been completed to the satisfaction of the PM Team
- Deed notices or other items related to the property have been filed, as necessary.

Deed Restrictions or Institutional Controls

Deed restrictions and institutional controls are land use control mechanisms that may be a part of the site closure strategy (e.g. areas requiring permanent, impervious cover, or digging prohibitions, etc). These mechanisms are typically in-place prior to obtaining final Regulatory closure and are described in the project completion report. Formal registration of land use controls / restrictions will ensure that future owners do not inadvertently cause damage to installed remedial measures or cause exposure to subsurface media that are inconsistent with the conditions under which Regulatory closure was obtained. Land use controls shall be registered on the property title in a manner that satisfies the requirements of Federal, State, Provincial, and Local governing authorities.

Establish Long-Term Monitoring Program (if required)

An environmental monitoring program may be an important part of the closure or re-development strategy for the site. If so, the Owner's PM Team should establish a plan for coordinating the monitoring program with the future activities planned for the site and then manage the process to ensure compliance with applicable environmental regulations. If ownership of the site will be transferred to a third party, the requirements for environmental monitoring should be clearly presented to the potential buyer and should be addressed in the property sale agreement.

Statement of Intent for Redevelopment

Should the Owner also be the party responsible for re-development at the site, Local governing authorities may require that a formal notification or statement of the Owner's intent to redevelop the site be filed in the public record. This statement would serve to transition the property from the decommissioning phase to the development phase. Again, depending upon the Local jurisdiction, a public comment period may be necessary prior to beginning re-development activities.

Ownership Transfer

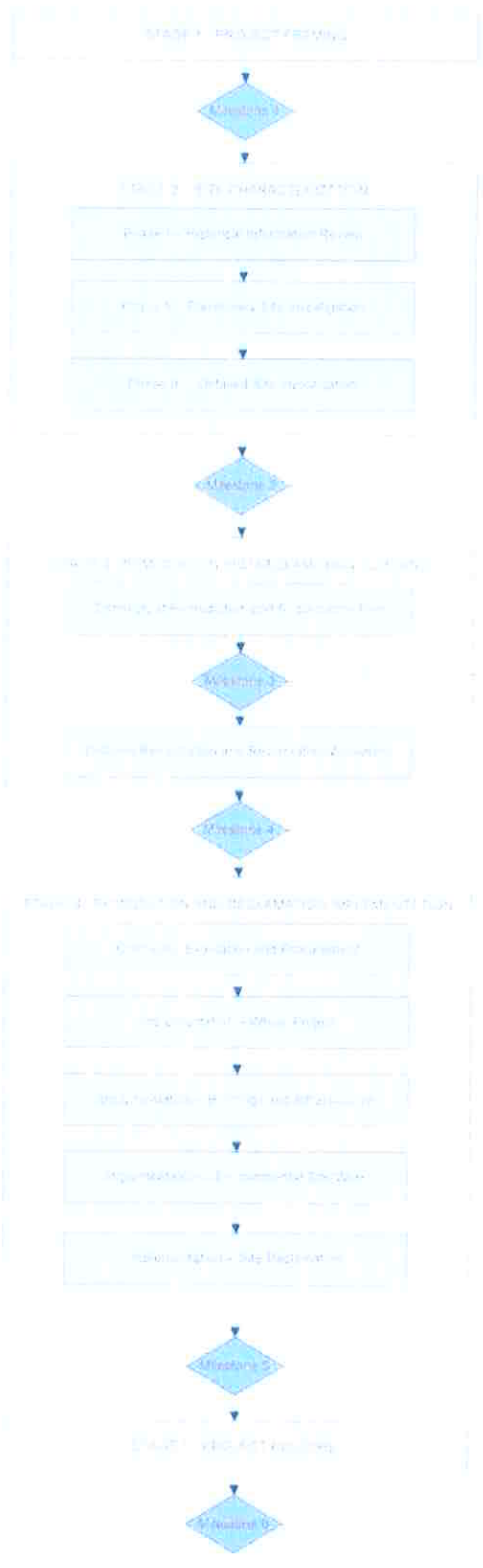
Transference of ownership is an important milestone in the history of a piece of industrial property and brings several future risk management issues, the importance of which cannot be over emphasized. The property sales agreement will likely address issues such as: future liability for past activities, indemnifications to cover previous or future activities, and restrictions on future land use. It is important that the closure phase of the decommissioning process be well documented so that future liability issues are addressed properly in the sales agreement documents. The Record of Site Conditions documents will be used to set a "baseline" condition at the time of ownership transfer and serves as a basis for identifying the responsibilities of the previous owner from those of the current owner for any environmental or property use issues that may arise in the future.

Milestone 6

The Closure stage is complete when all record documents have been received by the Owner, and closure of environmental issues is obtained from the governing Regulatory authority.

A
CHARTS: STAGES, TASKS AND RESPONSIBILITIES

The following charts provide an overview of all the stages (Figure A-1, emphasizing milestones) and the tasks and responsibilities within each stage (remaining figures).



Acceptance of decision support structure, project boundary description and initial description of post-decommissioning land use objectives; and agreement to proceed to Site Characterization

Comparison between post-decommissioning land use objectives and Site Characterization results – are there any incompatibilities?
- if yes, revisit post-decommissioning land use objectives
- if no, then agreement to proceed to Remediation and Reclamation Planning

Acceptance that the Conceptual Remediation and Reclamation Plan will meet the post-decommissioning land use objectives, given the information from Site Characterization
- if no, revisit post-decommissioning land use objectives
- if yes, then agreement to proceed to development of Detailed Remediation and Reclamation Workplans

Acceptance that the Conceptual Remediation and Reclamation Plan and the Detailed Remediation and Reclamation Workplans will meet the post-decommissioning land use objectives given the information from Site Characterization
- if no, revisit post-decommissioning land use objectives
- if yes, then agreement to proceed to Remediation and Reclamation Implementation

Acceptance that the remediation and reclamation of the site is complete, and the site will meet the post-decommissioning land use objectives defined and refined throughout the project

Project completion – agreement that site decommissioning is complete, and site meets finalized post-decommissioning land use objectives

Figure A-1
Milestones Associated with Each Stage in the Decommissioning of Fossil-Fueled Power Generating Plants

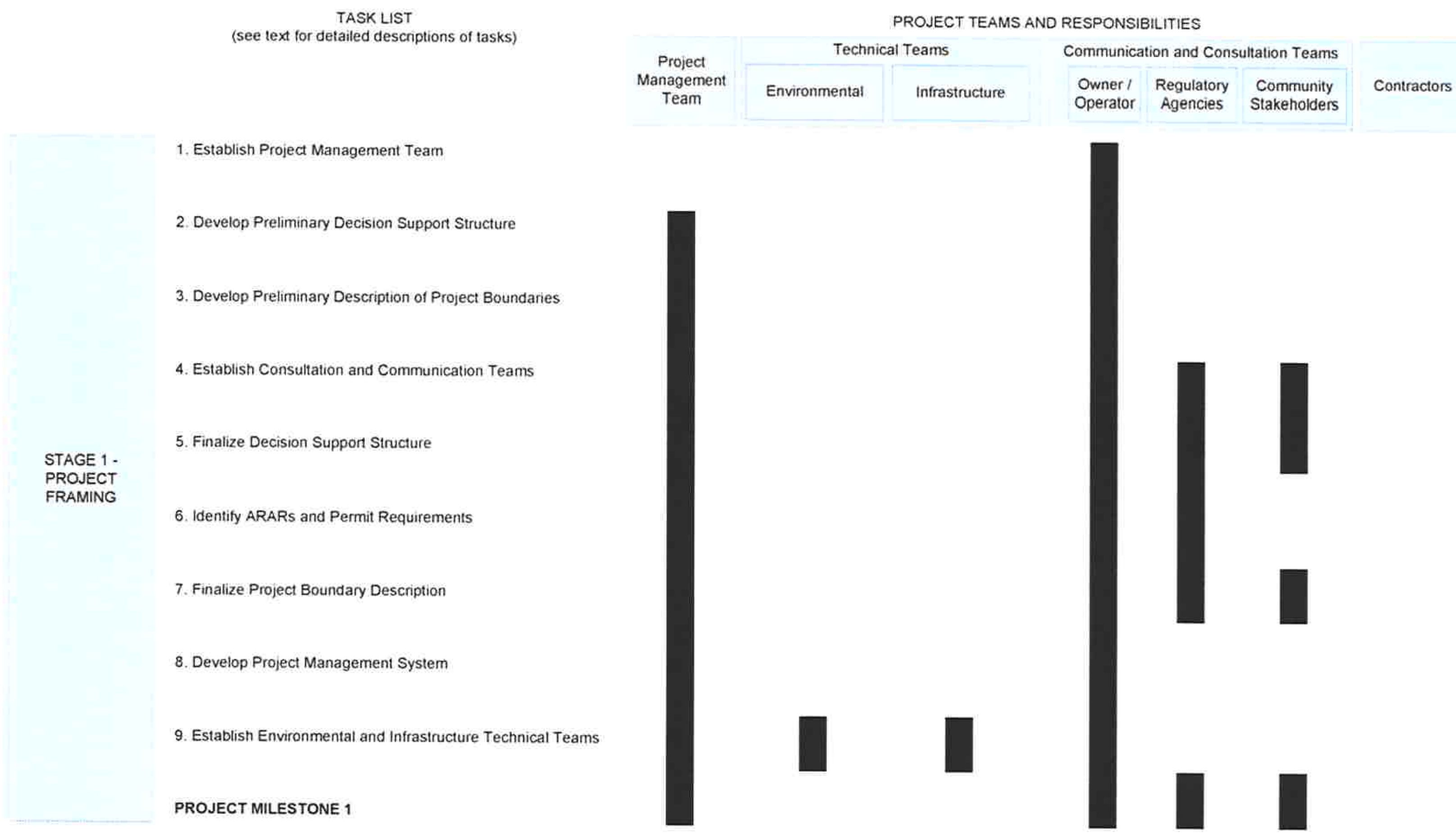


Figure A-2
Tasks and Team Responsibilities Associated with Stage 1 in the Decommissioning of Fossil Fueled Power Generating Plants

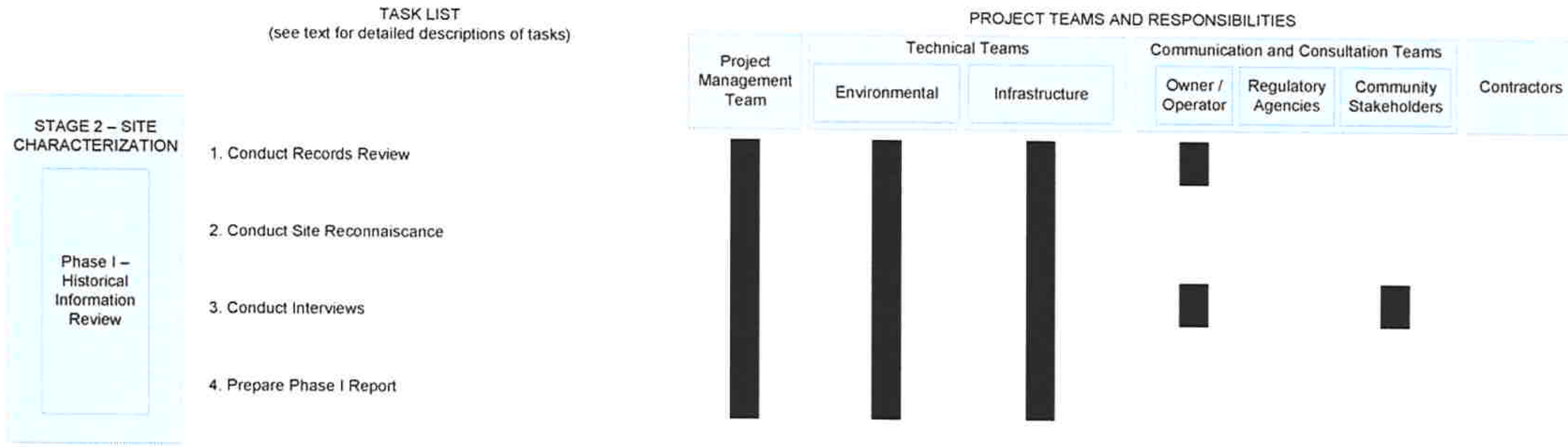


Figure A-3
Tasks and Team Responsibilities Associated with Stage 2, Phase I in the Decommissioning of Fossil-Fueled Power Generating Plants

Figure A-4
Tasks and Team Responsibilities Associated with Stage 2, Phase II in the Decommissioning of Fossil-Fueled Power Generating Plants

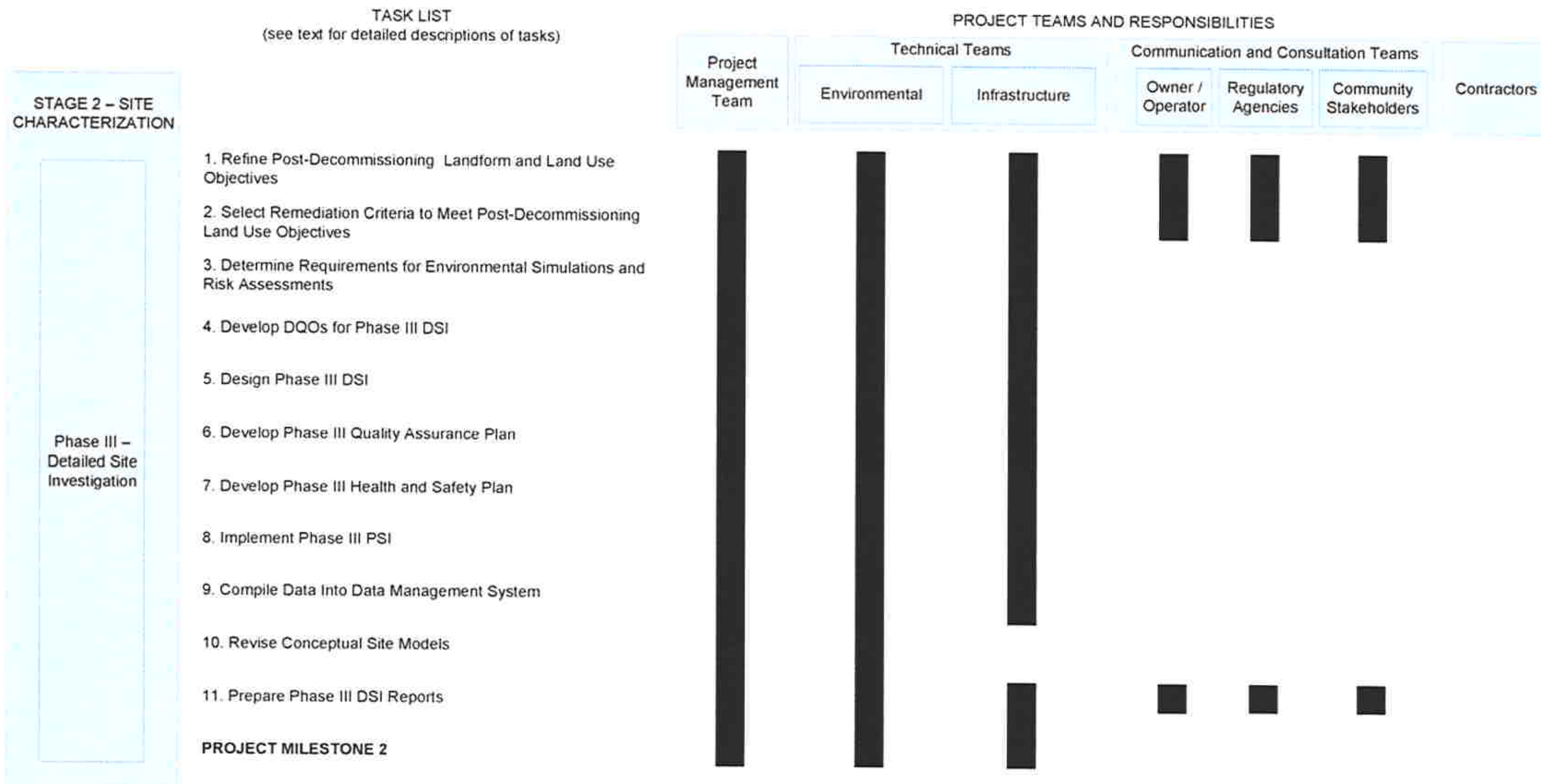


Figure A-5
Tasks and Team Responsibilities Associated with Stage 2, Phase III in the Decommissioning of Fossil-Fueled Power Generating Plants

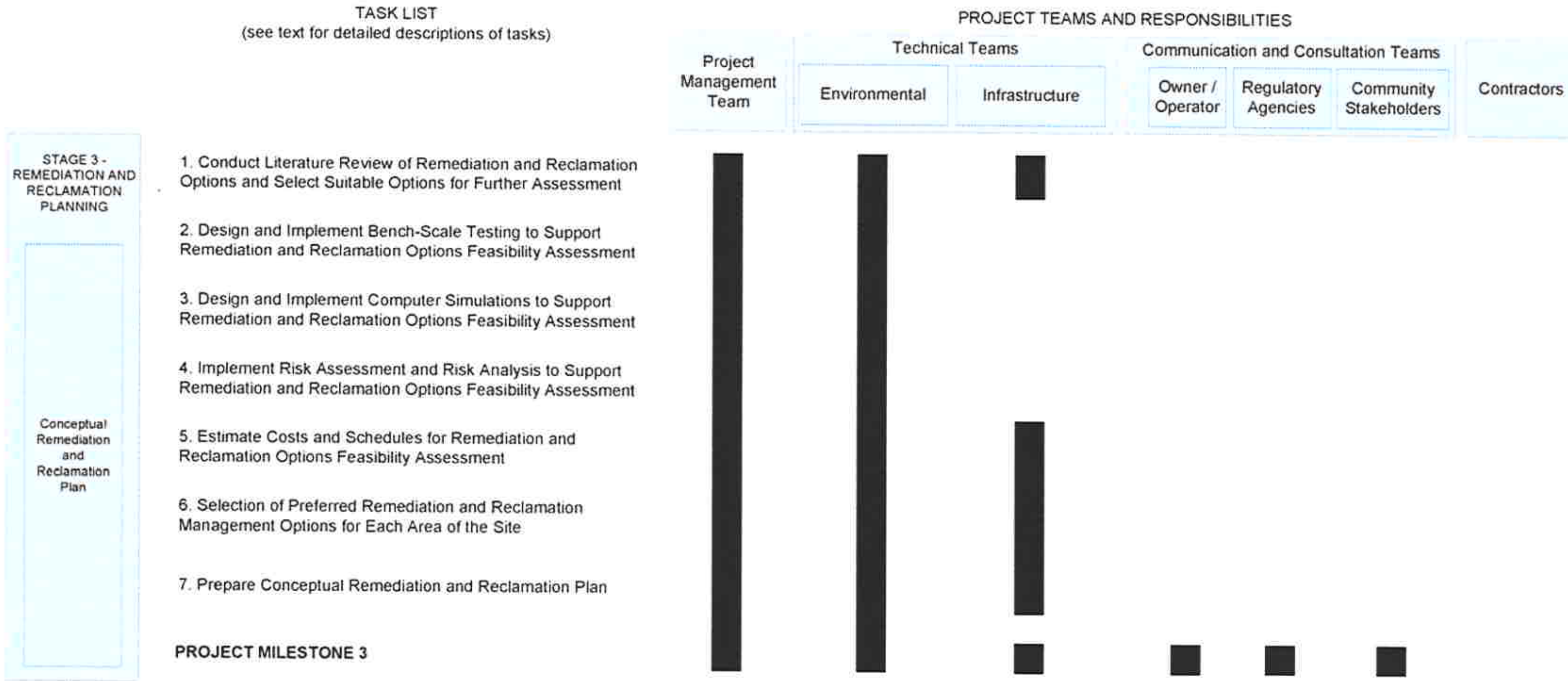


Figure A-6
Tasks and Team Responsibilities Associated with Stage 3 (Conceptual Remediation and Reclamation Plan) in the Decommissioning of Fossil-Fueled Power Generating Plants

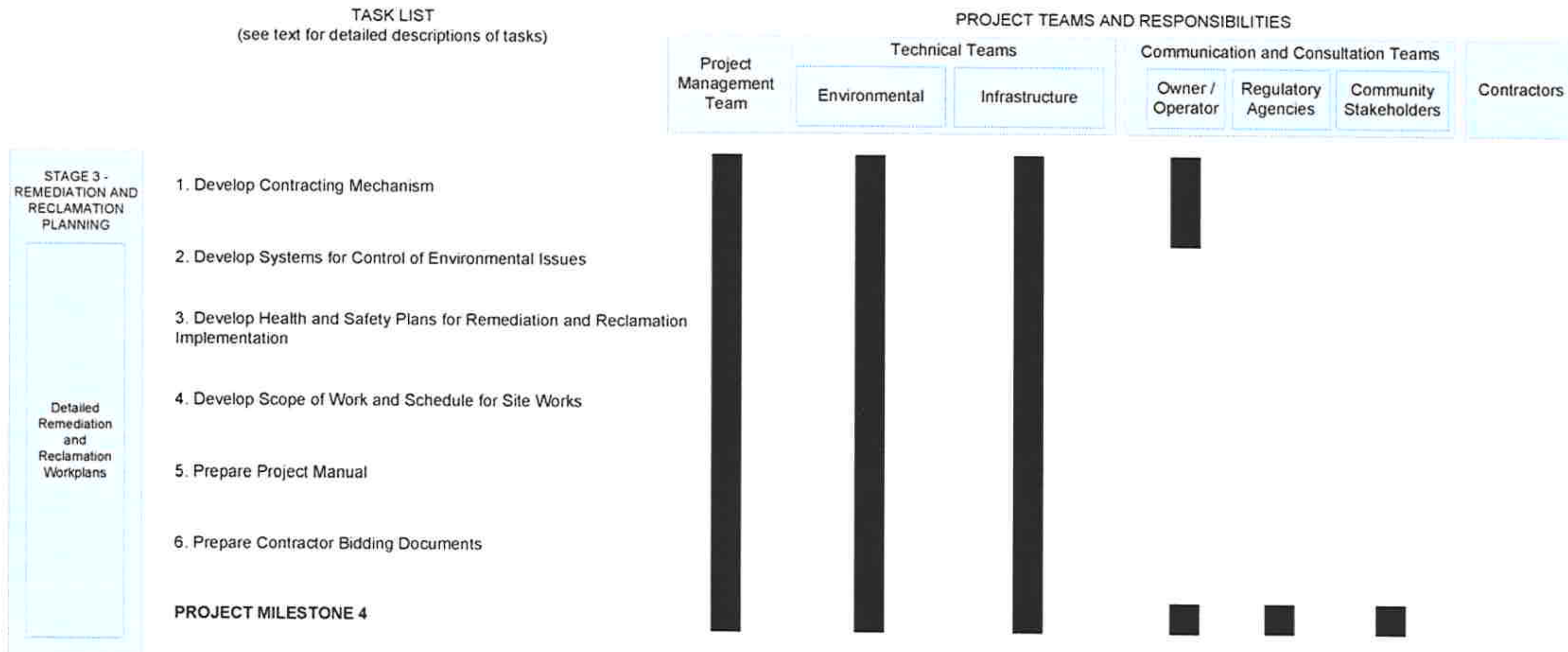


Figure A-7
Tasks and Team Responsibilities Associated with Stage 3 (Detailed Remediation and Reclamation Workplans) in the Decommissioning of Fossil-Fueled Power Generating Plants

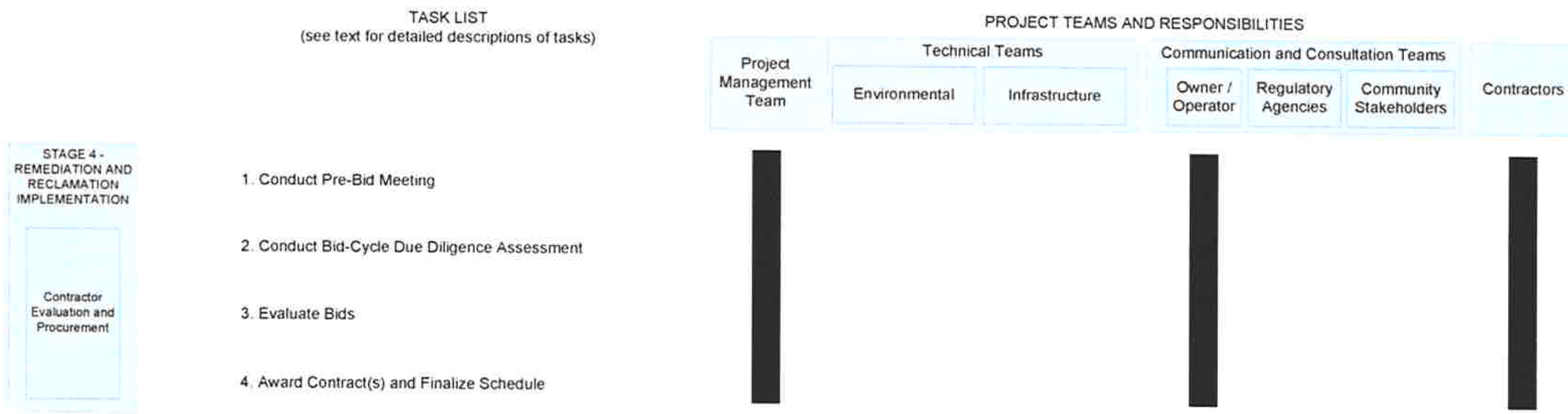


Figure A-8
Tasks and Team Responsibilities Associated with Stage 4 (Contractor Evaluation and Procurement) in the Decommissioning of Fossil-Fueled Power Generating Plants

	TASK LIST (see text for detailed descriptions of tasks)	PROJECT TEAMS AND RESPONSIBILITIES						
			Technical Teams		Communication and Consultation Teams			
		Project Management Team	Environmental	Infrastructure	Owner / Operator	Regulatory Agencies	Community Stakeholders	Contractors
STAGE 4 - REMEDIATION AND RECLAMATION IMPLEMENTATION Implementation – Whole Project	1. Prepare and Submit Permit Applications							
	2. Prepare and Submit Community and Regulatory Notification							
	3. Review and Accept Submittals According to Project Manual							

Figure A-9
Tasks and Team Responsibilities Associated with Stage 4 (Implementation – Whole Project) in the Decommissioning of Fossil-Fueled Power Generating Plants

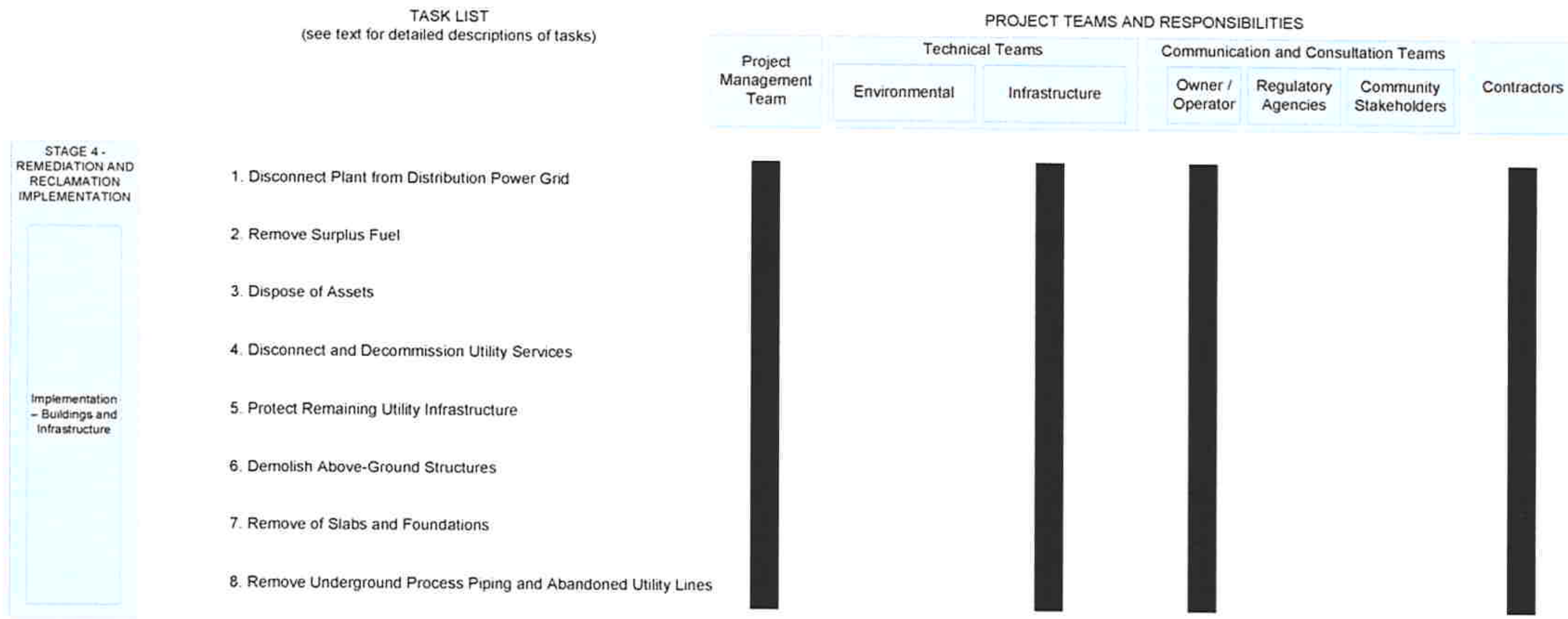


Figure A-10
Tasks and Team Responsibilities Associated with Stage 4 (Implementation – Buildings and Infrastructure) in the Decommissioning of Fossil-Fueled Power Generating Plants

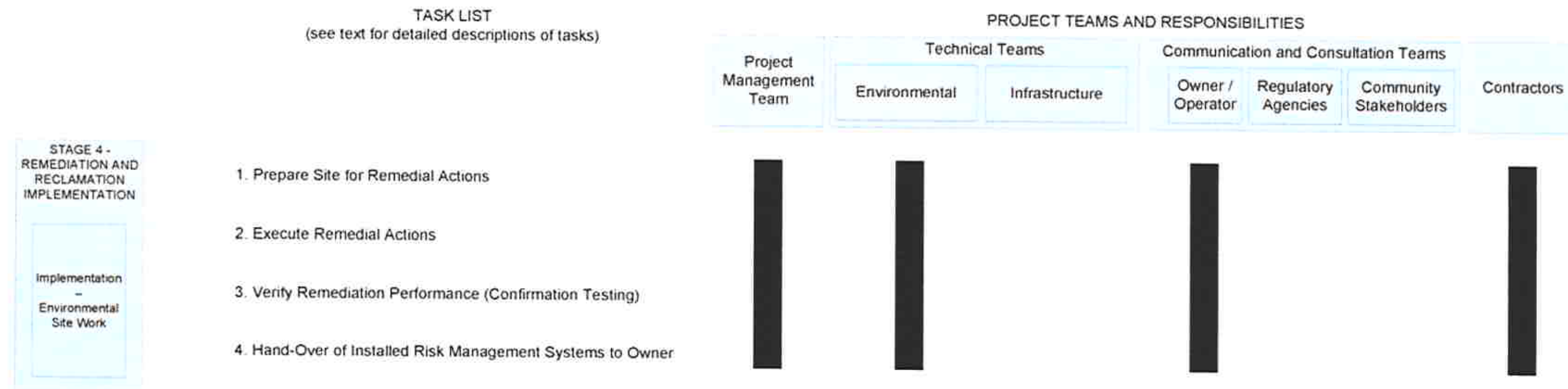


Figure A-11
Tasks and Team Responsibilities Associated with Stage 4 (Implementation – Environmental Site Work) in the Decommissioning of Fossil-Fueled Power Generating Plants

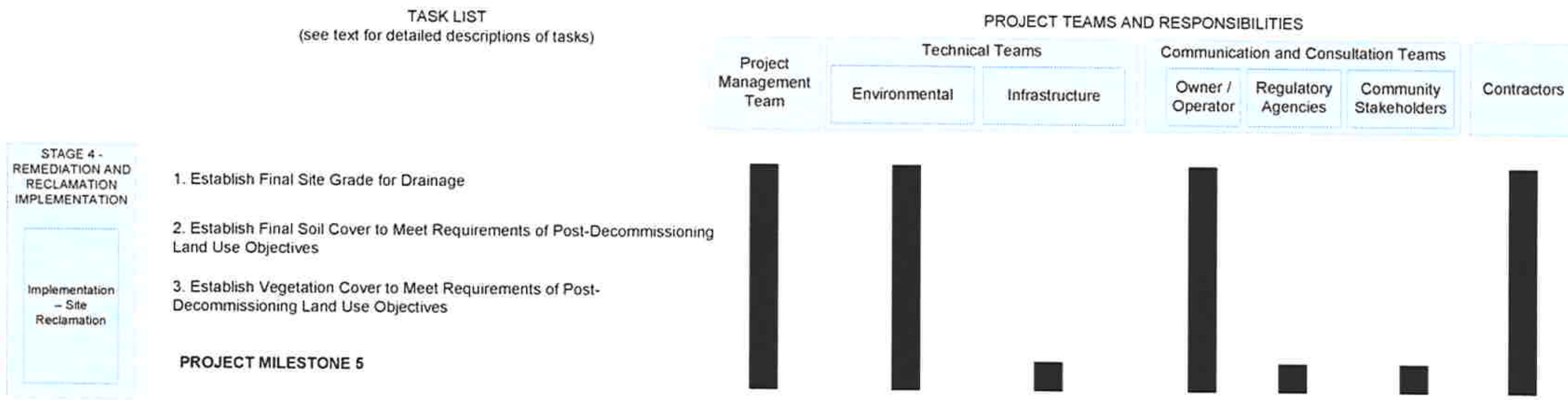


Figure A-12
Tasks and Team Responsibilities Associated with Stage 4 (Implementation – Site Reclamation) in the Decommissioning of Fossil-Fueled Power Generating Plants

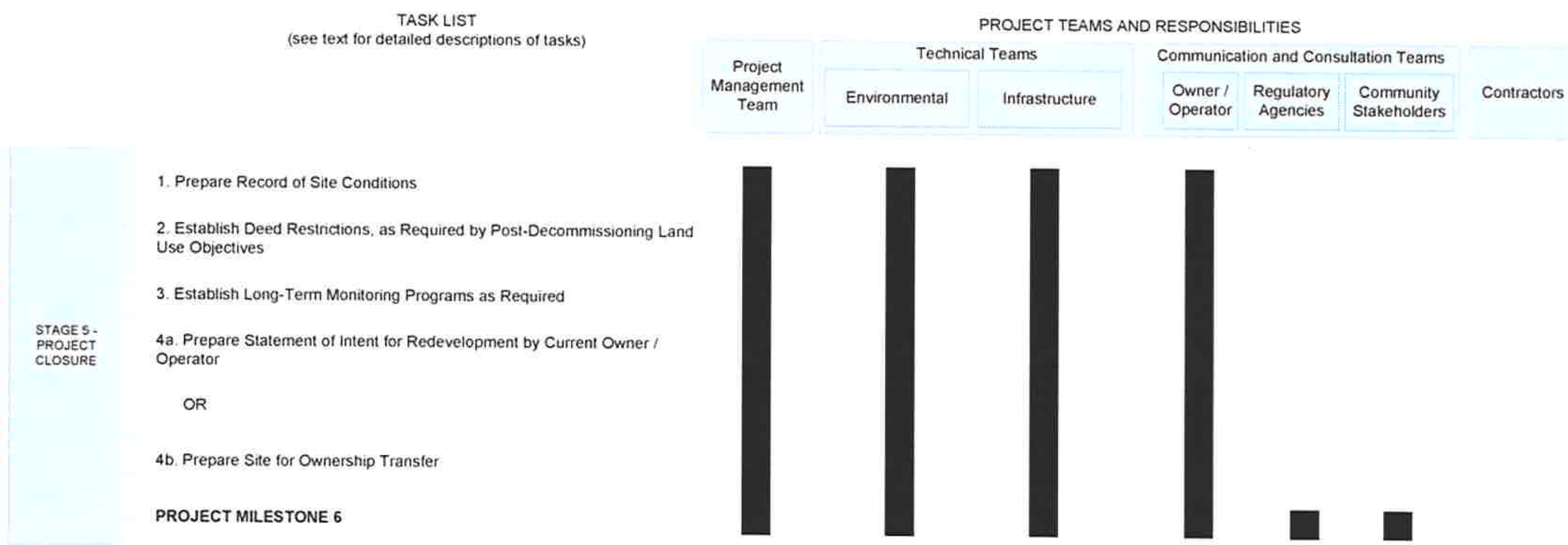


Figure A-13
Tasks and Team Responsibilities Associated with Stage 5 in the Decommissioning of Fossil-Fueled Power Generating Plants

B
DECOMMISSIONING PROJECT IMPLEMENTATION CHECKLIST

This document is intended to serve as a high-level roadmap to guide a project manager through the successful implementation of a decommissioning project. The items listed below assume that implementation of a decommissioning project has been approved.

Stage 1 – Project Framing

- ❑ **Establish the project team** and identify internal stakeholders that will have input into the final objectives and work scope for the project.
- ❑ **Develop end-use scenarios** for the subject property/facility with input from appropriate stakeholders.
- ❑ **Obtain directional, budgetary cost estimates** for each of the end-use scenarios.
- ❑ Review scenarios and cost estimates with decision-makers and **make final selection of the desired end use scenario** to be implemented. < Go – No Go decision >
- ❑ **Establish funding** for the decommissioning project.
- ❑ Establish project control structure by engaging Purchasing Department and other internal support functions as necessary (e.g. Legal, Engineering, Environmental Health & Safety, Real Estate, etc).

Stage 2 – Site Characterization

- ❑ Conduct a **Phase I environmental site assessment** and compile operational site use history information.
- ❑ Conduct a **Phase II environmental site assessment** (intrusive surface and subsurface sampling and analysis) if a real estate transaction or a significant change in land-use is being contemplated.
- ❑ Conduct a **Phase III environmental site assessment** if remediation of surface or subsurface materials is required to complete the real estate transaction or significant change in land-use being contemplated.
- ❑ Review the results of the environmental site assessment to **confirm that the planned end-use scenario is viable** from a technical and financial standpoint.

Stage 3 – Remediation and Reclamation Planning

- ❑ Conduct a regulated building materials survey (a.k.a. **pre-demolition survey**) and sampling program for the structures to be decommissioned/demolished.
- ❑ **Compile historic and current facility construction drawings** that are applicable to the buildings and infrastructures affected by the decommissioning project.
- ❑ Prepare **environmental remediation plan** and work scope for impacted surface and subsurface materials if required to complete the real estate transaction or significant change in land-use.

- ❑ Identify the **contract administration mechanism** and pricing option to be used (e.g. construction management involvement, fixed price vs. unit price, etc.) to deliver the completed project.
- ❑ Identify critical **health and safety and environmental** aspects of the project so that control mechanisms can be built into the project scope of work and technical specifications.
- ❑ Identify **critical sequencing and scheduling** aspects of the project so that important project milestones are included in the project scope of work requirements.
- ❑ Prepare the project scope of work, **technical specifications and contracting documents** (a.k.a. Project Manual or Tender Documents) which will be used to obtain bids and to administer the project during implementation.

Stage 4 – Implementation

- ❑ Identify, invite and **obtain price quotations** from qualified bidders for the work described in the Project Manual / Tender Documents.
- ❑ Evaluate the bids received to identify the contractor offering the highest value bid. **Award the project** and issue purchase orders and contracting documents to the winning contractor.
- ❑ Conduct the **pre-work submittal phase** of the project to ensure that applicable permits are obtained, that community and regulatory notices (if required) have been submitted, and that Contractor has sufficiently pre-planned the site work to address schedule, health and safety, and environmental aspects of the project.
- ❑ Establish mechanism for Owner's representative to **monitor on-site activities**; establish project control procedures; establish project communication plan.
- ❑ Contractor mobilization and **implementation of the physical site work** in accordance with the Project Manual.
- ❑ **Contractor de-mobilization** from the site and establishment of post-project security measures (if required).

Stage 5 – Closure

- ❑ Ensure that contractor has **closed-out all open permits** and made final regulatory notifications that are applicable to the project.
- ❑ Obtain **record of current site conditions** documentation from the contractor.
- ❑ Obtain all **waste management records** from the contractor and verify completeness.
- ❑ Obtain all commercial documents required by the contract; make final payment to the contractor and **close-out the contract.**
- ❑ **Complete internal requirements** regarding the change in operational status of the property/facility and engage appropriate internal functions (e.g. real estate, property accounting, tax, insurance, security, etc).

C
BEST PRACTICE – PRELIMINARY PROJECT ESTIMATING

Preliminary project estimating is a critical process for converting a "conceptual course of action" into a viable project that achieves the Owner's business objectives. The information obtained from the preliminary estimating process is used for:

- **strategic decision-making** including: property end-use decisions; strategies for maximizing asset value; and project Go – No Go decisions

- **establishing corporate funding** or reserves/provisions to cover execution of the project.

The goal for preliminary estimating is to obtain a realistically conservative estimate (within 20% or so) of the cost of a project to facilitate good decision making. The more information that is made available to those providing the estimate, the more realistic the estimate will be.

Steps – see next page

Steps

- **Identify viable end-use scenarios for the property.**

  Identifies range of end-uses that achieve corporate business objectives. Identify high value options; eliminate low value options.

- **Determine general scope-of-work action statements from owner to achieve each end-use scenario**

  Identifies work elements needed to achieve objectives. Facilitates cross-functional review and input by other corporate stakeholders. Minimizes surprises and scope changes later in project when they are more difficult to address.

- **Develop Owner timing requirements for each end use scenario.**

  Timing of project initiation affects holding cost. Schedule constraints impact project scenario cost estimates.

- **Visit property to inspect physical layout of facilities and property; obtain basic drawings and environmental data, if available.**

  Conduct site inspection and facility review to "sanity check" the conceptual end-use scenarios and work scopes. Identify discrepancies or site-specific features to address in final project planning.

- **Prepare written scope-of-work in outline form for each scenario (e.g., bullet list).**

  Provides a structured format for preliminary cost estimating that ensures all the work elements and implementation strategies of the entire project are included in the estimate.

- **Obtain preliminary cost estimate from internal or external sources for each scenario.**

  To attain the required accuracy in the cost estimate, the Owner's estimating department or a full service environmental / engineering consulting firm experienced in decommissioning / demolition projects reviews the work scope scenarios and provides cost estimates. Additional site visit may be required.

- **Provide output documents for use in further planning actions.**

  Prepare documents in a format easy to communicate to, and be understood by, the corporate decision-makers.

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BIG RIVERS ELECTRIC CORPORATION

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Response to Commission Staff's
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Item 11) ***Refer to the Berry Testimony, page 40 of 53. Provide the current status of the proceeding in the Webster County Circuit Court.***

Response) On December 5, 2018, Henderson filed a lawsuit against Big Rivers in Webster Circuit Court asking for a declaratory order that ownership of the Station Two site automatically reverted from Henderson to Big Rivers "upon the date the land ceased to be used for the operation and/or maintenance of the plant." *Webster Circuit Court Civil Action No. 18-CI-00200.* The parties have responded to each other's initial discovery requests, and both parties filed motions for summary judgment. Big Rivers asked the court to rule that the Station Two property does not automatically revert to Big Rivers, and Henderson asked the court to rule that it does. The court heard oral arguments on the motions on November 20, 2019, and the parties are awaiting a decision.

Witness) Robert W. Berry

Item 12) ***Refer to the Berry Testimony, page 47 of 53. Explain each basis for BREC's contention that Henderson continues to hold the title to waste placed in BREC's landfill.***

Response) The 1993 Amendments which authorized the construction of a scrubber on Henderson's Station Two plant (utilizing significant portions of Big Rivers' existing Green scrubber system) defined Station Two as its existing facilities (two steam generators, two turbine generators, two cooling towers, two electrostatic precipitators, etc.) plus joint use facilities "furnished and owned by City." Exhibit 1, page 1 of 3, Part B of the 1993 Amendments lists "Joint Use Facilities Provided By and Owned By the City But Located on Big Rivers' Property." Item 15 is "Station Two Ash Pond Dredgings in Green Station Sludge Disposal Landfill adjacent to Green River south of Green Station." Therefore, all of the Station Two waste in the Green landfill is defined to be part of the City's Station Two plant. This agreement was reached in 1993 to avoid the City having to build its own landfill, or contract out disposal to a third party. As stated on pages 48-49 of my Direct Testimony, Henderson saved over $3.1 million in 2015 alone by not having to store Station Two waste in a third party landfill. Pursuant to Section 4.1 of the Joint Facilities Agreement ("JFA"), title to any joint use facilities "provided by the City will remain in the City." (See also Section 13.1 of the Power Plant Construction and Operation Agreement, which states, "Except as otherwise provided herein, City shall have full ownership, management, operation and control of its Station Two" which includes, by definition, the City-owned joint use facilities. As stated in my Direct Testimony, if Station Two is decommissioned, then Big Rivers will be responsible for 77.24% of the Station Two waste when the Green landfill is itself decommissioned. However, if Station Two is not decommissioned, then Henderson will have full cost responsibility for Station Two, including all of the Station Two waste in the Green landfill.

Witness) Robert W. Berry

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Item 13) ***Refer to the Berry Testimony, page 48 of 53. Provide the contractual provision that allowed Henderson to place ash pond dredgings in the BREC landfill.***

Response) The Station Two Contracts provide that the Station Two ash pond dredgings would be placed in the Green landfill and would then be defined to be part of Station Two. This was addressed is Big Rivers' response to Item 12 of Commission Staff's Initial request for Information. As also addressed in Big Rivers' response to that Item 12, all Station Two waste in the Green landfill remains solely the property of the City. However, disposal, haulage, maintenance, and other operating costs associated with the dredgings would be split between the parties based upon usage.

With regard to the allocation of costs associated with the dredgings, please see the Joint Facilities Agreement, as amended. For example, the 1993 Amendments at pages 11-12, amending the Joint Facilities Agreement, provide:

> - 3.4 - The costs of operating and maintaining the FGD Joint Facilities described **in Exhibit 1, Page 3, Parts B and C hereto, and the cost of sludge stackout and disposal (including haulage and deposit in appropriate landfills) therefrom, shall be allocated to the Green Station and Station Two (except for the cost of coal and lime**

> **which shall be provided by each party for its own use) in the proportions** to which the stations put sulfur through the Green and Station Two FGD systems, based upon the tonnage of lime and coal and the sulfur and BTU content of the coal, and calculated as shown in the following example… (*emphasis added*).

The 1993 Amendments at page 13 under "Waste Treatment," state:

> **The "waste treatment" area power, maintenance and labor costs and the scrubber sludge disposal and storage costs would be split similarly**, except that Green and HMPL bleed flowmeters would be used to calculate TPY of waste to be treated and stored. The TPY of waste treated would be used in step (2) instead of TPY lime. (*emphasis added*).

Henderson's sharing in the disposal and haulage costs of the dredgings based upon usage did not relieve Henderson of ownership of all of the Station Two waste stored in the Green landfill, nor did it relieve Henderson of future costs associated with the dredgings.

Witness) Robert W. Berry

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Item 14) ***Refer to the Berry Testimony, page 49 of 53.***

a. Provide the calculation that produces 12 percent.

b. Confirm that Henderson's share of the landfill contents will reduce as other wastes are added.

c. Provide the estimated percentage of the landfill contents allocable to Henderson at the landfill's useful life.

Response)

a. The first step in the process is to determine the amount of material attributable to the City of Henderson that is stored in the Green Landfill. That is labelled "Henderson Waste in Green Landfill (tons)" in the formula below. The second step in the process is to determine the total amount of material that is stored in the Green Landfill. That is labelled "Total Waste in Green Landfill (tons)" in the formula on the next page.

$$\frac{\text{Henderson Waste in Green Landfill (tons)}}{\text{Total Waste in Green Landfill (tons)}} = \text{Percentage}$$

With Henderson Waste = 2,141,251 tons and Total Waste = 17,568,557 tons, the resulting calculation yields:

$$\frac{\text{2,141,251 tons}}{\text{17,568,557 tons}} = 12.19\%$$

Note: At the time Big Rivers' application was filed on July 31, 2019, the data range for the waste in the Green landfill was for the years 2001 through 2018.

b. Yes. For instance, as of December 31, 2019, the percentage of Henderson waste in the Green landfill is 11.25%. This is calculated as follows:

$$\frac{\text{2,618,667 tons}}{\text{23,274,384 tons}} = 11.25\%$$

Where Henderson Waste = 2,618,667 tons and Total Waste = 23,274,384 tons.

Note: As of June 8, 2020, the date of this response, the data range for the waste in the Green landfill is for the years 1995 through 2019.

c. Big Rivers does not have an estimated percentage of the landfill contents allocable to Henderson at the landfill's useful life. It is unknown at this time how much additional ash will be placed in the landfill prior to its closure. However, it is important to keep in mind that under the 1993 Amendments, all of the Station Two ash pond dredgings stored in the Green landfill are a joint use facility owned solely by Henderson. If Station Two is decommissioned, then Big Rivers would be responsible for 77.24% of those costs when the Green landfill is itself ultimately decommissioned. But if Station Two is not decommissioned, then Henderson will be responsible for 100% of the costs as the sole owner of Station Two, which includes joint use facilities.

Witness) Michael T. Pullen

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Item 15) ***Refer to the Berry Testimony, page 52 of 53, in which he states that BREC has already compensated Henderson for its continued use of joint-use facilities owned by Henderson by fulfilling its obligations under relevant contracts, including previously allowing Henderson to use joint-use facilities owned by BREC. Explain why BREC's previous and continued use of joint-use facilities owned by Henderson would not justify Henderson's continued use of BREC's landfill, as alleged by BREC, through the storage of waste from Station Two, without additional change.***

Response) The Green landfill is not a joint-use facility, even though all of the Station Two ash pond dredgings stored at the Green landfill are a joint use facility solely owned by Henderson. Under the Joint Facilities Agreement, as amended, Big Rivers is required to pay its share of the ongoing operation and maintenance costs for any City-owned joint use facility it continues to use. For example, as discussed on page 20 of my testimony, 100% of the operating and maintenance costs attributable to Big Rivers' on-going use of City-owned joint use facilities since February 1, 2019 have been allocated to Big Rivers. Similarly, Henderson is obligated to pay its share of the ongoing costs necessary to maintain the Station Two waste (ash pond dredgings) in the landfill, which waste is a joint use facility that will continue to be used by Henderson until the Green landfill is itself ultimately decommissioned.

Witness) Michael T. Pullen

Item 16) ***Refer to the Direct Testimony of Paul G. Smith (Smith Testimony), page 9 of 19. Even though separate inventories were maintained, explain whether Henderson was responsible for procuring and delivering its own share of the necessary coal and lime for Station Two or whether BREC or other entity performs those functions on its behalf.***

Response) Henderson was responsible for procuring and delivering its own share of the necessary coal and lime for Station Two.

Witness) Michael T. Pullen

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Item 17) ***Refer to the Smith Testimony, pages 18-19 of 19, and the Eacret Testimony, pages 9-10 of 10. Explain why BREC is not proposing to exercise its right to recover interest on past-due amounts owed by Henderson.***

Response) Big Rivers has not yet proposed to recover interest on the past-due amounts owed by Henderson. However, Big Rivers intends to exercise its right to quantify, and recover, interest per the Power Plan Construction and Operation Agreement, which will be collected for the benefit of Big Rivers' Members.

Witness) Paul G. Smith

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Item 18) ***Refer to Smith Testimony, Exhibit-Smith 3. Explain why BREC contends that any claim to the 2016 Coal Survey Adjustment costs shown on that exhibit were not release by the December 15, 2017 Settlement Agreement and Release.***

Response) Henderson's share of the 2016 Coal Survey Adjustment was separately assigned to its Excess Henderson Energy and Native Load based on consumption. The December 2017 Settlement Agreement and Release did not relate to Henderson's native load; therefore, the 2016 Coal Survey Adjustment related to Henderson's Native Load is still owed to Big Rivers, as reflected on Exhibit-Smith 3.

Witness) Paul G. Smith

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Item 19) ***Refer to the Direct Testimony of Michael T. Pullen (Pullen Testimony), page 16. Explain whether Station Two ash pond closure activities must follow municipal bidding and contracting requirements.***

Response) The City of Henderson is the sole owner and operator of the Station Two ash pond. As such, the Station Two ash pond decommissioning activities which include pond closure must follow municipal bidding and contracting requirements.

Witness) Michael T. Pullen

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Item 20) ***Refer to the Pullen Testimony, Exhibit Pullen-13. Explain whether any facility listed (excluding item 14) can be decommissioned without requiring municipal bidding and contracting.***

Response) The City of Henderson is the sole owner and operator of the joint-use facilities listed in Exhibit Pullen-13. As such, the decommissioning activities associated with each of the facilities listed must follow municipal bidding and contracting requirements.

Witness) Michael T. Pullen

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Item 21) ***Refer to the Eacret Testimony, Exhibit Eacret-2. Provide an explanation of the "ZRC" acronym used in this Exhibit.***

Response) ZRC stands for Zonal Resource Credit. ZRC is a MW unit of Planning Resource which has been converted from a MW of Unforced Capacity to a credit in MISO's Module E Capacity Tracking tool, and which is eligible to be offered by a Market Participant into the Planning Resource Auction, to be sold bilaterally, and/or to be submitted through a Fixed Resource Adequacy Plan.

It is essentially a MW of net capacity that has been adjusted for its historical performance.

Witness) Mark J. Eacret

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Item 22) ***Refer to Eacret Testimony, page 5 of 10. Explain whether MISO allows a member to reserve capacity outside of its load zone.***

Response) MISO does not prevent a member from reserving capacity outside of its load zone; however, price separation between Local Resource Zones occurs due to constraints binding in the Planning Resource Auction. Zonal Resource Credits (ZRC) receive the Auction Clearing Price based upon the Local Resource Zone where the Planning Resource underlying the ZRC is physically located. As the Market Participant responsible to MISO for settlement of charges related to Henderson, Big Rivers would have been subject to risk should price separation have occurred.

See MISO Business Practice Manual BPM 011-Resource Adequacy available at: https://www.misoenergy.org/legal/business-practice-manuals/.

Witness) Mark J. Eacret

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Item 23) ***Refer to Eacret Testimony, Exhibit Eacret-2. Explain whether the methodology used to calculate the resource adequacy requirement has changed for BREC and Henderson since Henderson joined MISO.***

Response) MISO's Planning Reserve Margin Requirement has remained the same: Coincident Peak Demand Forecast *times* (1 + Transmission Loss Percentage of the Local Balancing Authority) *times* (1 + Planning Reserve Margin in Unforced Capacity). The Coincident Peak Demand Forecast, Transmission Loss Percentage, and Planning Reserve Margin in Unforced Capacity are all subject to change annually.

Please see Section 3.1 Establishing Planning Reserve Margin Requirement Overview in MISO's Business Practice Manual BPM 011-Resource Adequacy available at: https://www.misoenergy.org/legal/business-practice-manuals/.

Witness) Mark J. Eacret

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Item 24) ***Refer to Eacret Testimony, page 5 of 10, and 1998 Amendments to the System Reserves Agreement Application, Exhibit 13, at 10 of 19. To the extent known, explain the reasoning for Henderson's rejection of BREC's capacity requirement calculation.***

Response) Exhibit Eacret-2 to my Direct Testimony presents the Big Rivers calculation of Henderson's capacity requirement for the 2018 Planning Year. Henderson rejected this calculation and presented an alternative calculation in an e-mail from Brad Bickett on May 16, 2018. That e-mail is Attachment 1 to this response.

A comparison of Big Rivers' calculation and Henderson's alternative calculation is presented in Attachment 2 to this response. The Henderson calculation took several liberties with the MISO approach as noted below.

1. Henderson reduced its "2018/2019" peak demand by 1 MW for "DSM/EE Activity". Henderson has no Demand-Side Management or Energy Efficiency programs of which Big Rivers is aware.

2. Instead of the 10.1% adder for Losses and Planning Reserves required by MISO, Henderson added a 15% "Reference Margin Level per NERC". Big Rivers does not know the source of that figure.
3. Henderson used 12 MW as its SEPA entitlement. Because of problems with some of the dams on the Cumberland River Hydro system, the ZRC credit of all SEPA customers in MISO had been reduced for several years. (The Big Rivers allocation had been reduced from 178 MW to 154 MW). The Henderson allocation had been reduced from 12 to 10 MW, yet Henderson gave themselves credit for 12 MW.
4. Based upon unit performance for the prior three years, the net capability of Henderson Unit 1 was reduced by 11% and the capability of Henderson Unit 2 was reduced by 21.2% for conversion into Zonal Resource Credits (ZRCs) in the Big Rivers calculation. Henderson used an "Industry average EFORd for comparable generators" of 6.85%. Big Rivers does not know the source of that figure.
5. Henderson then took the unrealistically low 6.85% EFORd and squared it before applying it to its capacity reservation. This is presumably because

Henderson had a "first call" on the generation from the plant. Essentially if both units were running, both Henderson and Big Rivers were taking energy, and one unit tripped, Henderson had a right to the output of the remaining unit up to its capacity reservation. However, by that time, frequently the market did not justify both units running, and Henderson had dropped the requirement that Big Rivers run the units even when uneconomic in order to benefit from the lower market prices. So even if MISO agreed with that approach to the calculation, there would be no guarantee that there would always be a second unit running. During the 2018 Planning Year (6/1/2017 to 5/31/2018) both units were running simultaneously during less than 20% of the hours.

By rejecting the MISO calculation used by Big Rivers and substituting its own calculation, Henderson was attempting to push more Station Two costs onto Big Rivers' Members.

Witness) Mark J. Eacret

Archived: Tuesday, June 02, 2020 6:25:19 PM
Subject: FW: HMP&L planning reserve information
Sensitivity: Normal

From: Brad Bickett [redacted]
Sent: Wednesday, May 16, 2018 3:25 PM
To: Eacret, Mark [redacted]
Subject: HMP&L planning reserve information

Mark,

See below the numbers that we talked about earlier:

HMP&L load requirement

• 18/19 peak demand	107.3MW
• DSM / EE activity	-1MW
• Total requirement with 15% reference margin level per NERC	122.2MW

HMP&L capacity

• SEPA firm peaking capacity	12MW
• Station Two reservation	115MW
• Industry average EFORd for comparable generators	6.85%
• ICAP*(1-(EFORd*EFORd))	114.5MW
• Total capacity for load with reserve	126.5MW

Let me know if you need anything else.

Brad

Big Rivers Electric Corporation
Case No. 2019-00269
Calculation of HMPL Resource Adequacy Requirement
2018/2019 Planning Year

		Big Rivers			**Henderson**
Projected HMPL NCP		107.3		Projected HMPL NCP	107.3
MISO Coincidence Factor		97%		DSM/EE Effect	(1.0)
Coincident Peak		104.0			
Losses	0.017	1.8			
Planning Reserves	0.084	8.7		15% Reference Margin Level per NERC	15.9
HMPL ZRC Requirement		114.5		HMPL ZRC Requirement	122.2
SEPA ZRC Allocation		(10.0)		SEPA Capacity	12.0
ZRC Balance Required		104.5		Station Two Reservation	115.0
ZRC/MW Capacity		0.838		Industry average EFORd for comparable generators	6.85%
2018/2019 Reservation Capacity Requirement		124.7		Station Two Reservation * (1-EFORd^2)	114.5

	Capacity	ZRC			
				Capacity Available	126.5
Unit 1	153.0	136.2	-11.0%		
Unit 2	157.6	124.2	-21.2%	Excess	4.2
	310.6	260.4			
		83.8%	One MW of Capacity equals .838 ZRC's.		

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Item 25) ***Refer to the direct testimony of Michael Chambliss, page 9 of 13, in which he states, "Station One has been retired and decommissioned, so Henderson's required standby capacity is equal to its reserved capacity from Station Two." State whether it is BREC's contention that Henderson was required to maintain standby capacity equal to its reserved capacity from Station Two through February 2019 or whether Mr. Chambliss is referring to some historical period to which that requirement applied, and explain each basis for the response.***

Response) Yes, it is Big Rivers' position that the System Reserves Agreement required Henderson to meet its own full contingency reserves requirement from the time Henderson's Station One was retired through February 2019.

Witness) Michael W. Chambliss