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Sep 23 2020

INFORMATION SHEET

PRESIDING: Chair Mitchell, Presiding; Commissioners Brown-Bland, Gray, Clodfelter, Duffley, Hughes, McKissick
PLACE: Held Via Videoconference
DATE: Tuesday, September 15, 2020
TIME: 9:00 a.m. – 12:28 p.m.
DOCKET NOS.: E-7, Sub 1214; E-7, Sub 1213; E-7, Sub 1187
COMPANY: Duke Energy Carolinas, LLC; Duke Energy Progress, LLC
DESCRIPTION: E-7, Sub 1213, In the Matter of Petition of Duke Energy Carolinas, LLC, for Approval of Prepaid Advantage Program; E-7, Sub 1214, In the Matter of Application of Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina; E-7, Sub 1187, In the Matter of Application of Duke Energy Carolinas, LLC, for an Accounting Order to Defer Incremental Storm Damage Expenses Incurred as a Result of Hurricane Florence and Michael and Winter Storm Diego

VOLUME NUMBER: 23

APPEARANCES
(See attached.)

WITNESSES
(See attached.)

EXHIBITS
(See attached.)

COPIES ORDERED: Downey, Culpepper, Holt, Cummings, Edmondson, Grantmyre, Dodge, Jost, Little, Luhr, Force, Townsend, Robinson, Kells, Mehta, Lee, Cress, Ross, Ledford, Smith, Schauer, Heslin, Su, Crystal and Beverly
CONFIDENTIAL TRANSCRIPTS and EXHIBITS ORDERED: Robinson, Heslin, Somers, Kells, Jagannathan, Mehta, Lee, Cress, Ross, Jenkins, Beverly, Ledford, Smith, Crystal, Su, Force, Townsend, Downey, Schauer, Culpepper, Cummings, Dodge, Edmondson, Grantmyre, Holt, Jost, Little, and Luhr

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DOCKET NO.: E-7, Sub 1214

E-7, Sub 1213

E-7, Sub 1187

BEFORE: Chair Charlotte A. Mitchell, Presiding

Commissioner ToNola D. Brown-Bland

Commissioner Lyons Gray

Commissioner Daniel G. Clodfelter

Commissioner Kimberly W. Duffley

Commissioner Jeffrey A. Hughes

Commissioner Floyd B. McKissick, Jr.

IN THE MATTER OF:

DOCKET NO. E-7, SUB 1214

Application of Duke Energy Carolinas, LLC,

for Adjustment of Rates and Charges Applicable to

Electric Utility Service in North Carolina

Noteworthy Reporting Services, LLC

DOCKET NO. E-7, SUB 1213

Petition of Duke Energy Carolinas, LLC,

for Approval of Prepaid Advantage Program

DOCKET NO. E-7, SUB 1187

Application of Duke Energy Carolinas, LLC,

for an Accounting Order to Defer Incremental Storm

Damage Expenses Incurred as a Result of Hurricanes

Florence and Michael and Winter Storm Diego

VOLUME 23

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E X H I B I T S

I/A

**THE STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS**

Before Commissioners: Susan K. Duffy, Chair
Shari Feist Albrecht
Dwight D. Keen

In the Matter of the Application of Atmos Energy Corporation for Adjustment of its Natural Gas Rates in the State of Kansas.	)))	Docket No. 19-ATMG-525-RTS

ORDER ON ATMOS ENERGY CORPORATION'S APPLICATION FOR A RATE INCREASE

This matter comes before the State Corporation Commission of the State of Kansas (Commission). Having reviewed the pleadings and record, the Commission makes the following findings:

1. On June 28, 2019, Atmos Energy Corporation (Atmos) filed an Application seeking an overall net revenue increase of $7.2 million, resulting from increasing base rates by $9.6 million, proposing a rate case expense surcharge of $817,882, rebasing amounts currently collected through the Gas System Reliability Surcharge Rider (GSRS) of $3.3 million; and adjusting $1.4 million of its Ad Valorem Tax Surcharge Rider (AVTS) into base rates.[1]

2. Atmos claims their current rates do not produce sufficient revenues to cover the costs to render reasonably sufficient and efficient service and, therefore, are not just and reasonable.[2] Without the proposed rate increase, Atmos contends it will be unable to acquire necessary capital at reasonable rates, carry out new construction, provide adequate gas supplies of gas and render the quality of service the public requires.[3] Atmos's Application is accompanied by supporting testimony from eight witnesses.[4]

[1] Application, June. 28, 2019, ¶ 4.
[2] *Id.*, ¶ 5.
[3] *Id.*
[4] *Id.*, ¶ 4.

3. The Commission has jurisdiction to supervise and control natural gas public utilities, as defined in K.S.A. 66-104, doing business in Kansas.[5] The Commission has the power to require all natural gas utilities governed by the Natural Gas Public Utilities Act to establish and maintain just and reasonable rates.[6]

4. Notice of the proposed rate increase, public hearing, and evidentiary hearing was provided by an insert with the monthly billing statement for each customer in Atmos's service territory as well as by publishing notice in the major newspapers in the region. The Commission received comments from the public at the September 17, 2019 public hearing in Overland Park, Kansas, where a record was made. The Commission also received 527 public comments through its Office of Public Affairs and Consumer Protection.[7] The Commission issues this Order with due consideration of those comments.

5. On July 25, 2019, the Citizens' Utility Ratepayer Board (CURB) was granted intervention.

6. On October 31, 2019, Commission Staff (Staff)[8] and CURB filed their direct testimony. In its direct testimony, Staff recommended a net revenue decrease of $593,764; CURB recommended a net revenue decrease of $3,157,324.[9]

7. On November 18, 2019, Atmos filed rebuttal testimony from eight witnesses. James F. Reda and John D. Quackenbush filed rebuttal testimony without having filed direct testimony. Reda's testimony focused on the reasonableness of total compensation levels for

[5] K.S.A. 66-1,201.
[6] K.S.A. 66-1.202.
[7] The public comments were entered into the record by the Prehearing Officer filing Notice of Filing of Public Comments on Dec. 18, 2019.
[8] Staff served the Direct Testimony of Justin T. Grady and Adam H. Gatewood on all parties via email on October 31, 2019. Due to a clerical error neither Grady's nor Gatewood's testimony was filed by 5:00 p.m. on October 31, 2019. On November 14, 2019, the Commission granted Staff's Motion for Leave to File Testimony Out of Time.
[9] Post-Hearing Brief of Commission Staff (Staff Brief), Jan. 16, 2020, ¶¶ 5, 6.

executives and the appropriateness of Atmos's annual and long-term incentive compensation programs.[10] Quackenbush's rebuttal testimony discussed the alternative regulatory mechanisms he approved for natural gas companies while he chaired the Michigan Public Service Commission,[11] and opined on the importance of Regulatory Research Associates' (RRA) assessments of state regulatory climates.[12]

8. The Parties were unable to reach a settlement, so the Commission held an evidentiary hearing, beginning December 10, 2019, and concluding December 12, 2019. Atmos, Staff, and CURB appeared by counsel and each party submitted prefiled testimony. The Commission heard live testimony from a total of 20 witnesses, including nine on behalf of Atmos, seven on behalf of Staff, and four on behalf of CURB. At the December 3, 2019 prehearing conference, the parties agreed to waive cross-examination of several witnesses. The parties had the opportunity to cross-examine the remaining witnesses at the evidentiary hearing as well as the opportunity to redirect their own witnesses. Following the evidentiary hearing, all of the parties submitted post-hearing briefs.

9. The major issues in dispute are:

- Return on Equity (ROE) / Capital Structure
- System Integrity Plan (SIP)
- Incentive Compensation
- Depreciation
- Rate case expense
- Other rate base and income statement adjustments

[10] Rebuttal Testimony of James F. Reda, Nov. 18, 2019, p. 3.
[11] Rebuttal Testimony of John D. Quackenbush, CFA (Quackenbush Rebuttal), Nov. 18, 2019, p. 12.
[12] *Id.*, pp. 14-15.

10. In determining rates, the Commission first establishes a revenue requirement and then designs a rate structure.[13] The revenue requirement includes rate base, operating expenses, and rate of return.[14] The rate of return is simply an opportunity to earn that rate, not a guarantee. Rate design includes allocating costs among and within the customer classes.

11. In setting rates, the Commission's goal is to balance the interests of all concerned parties and develop a rate within the "zone of reasonableness."[15] The parties whose interests must be considered and balanced include: (1) the utility's investors vs. the ratepayers; (2) present vs. future ratepayers; and (3) the public interest.[16]

12. In allocating the revenue requirement among the customer classes, the Commission follows cost causation principles,[17] so "that one class of consumers shall not be burdened with costs created by another class."[18]

A. RETURN ON EQUITY

13. Atmos initially proposed an ROE of 10.25%, with an overall rate of return of 7.98%.[19] Its witness, Dylan D'Ascendis, reached his ROE recommendation after applying several cost of common equity models, including the Discounted Cash Flow (DCF) model, the Risk Premium Model (RPM), and the Capital Asset Pricing Model (CAPM), to a proxy group of six natural gas distribution utilities and a separate proxy group of sixteen domestic, non-price regulated companies of comparable risk to the six natural gas companies.[20] D'Ascendis's models produced an ROE of 9.8% before he adjusted it upward by 0.40% for the small size of Atmos

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[13] *Kansas Gas & Elec. Co. v. Kansas Corp. Comm'n*, 239 Kan. 483, 500 (1986).
[14] *Id.* at pp. 500-01.
[15] *Id.* at pp. 488-89.
[16] *Id.* at pp. 488, 1070.
[17] *See* Order on Petitions for Reconsideration and Clarification, ¶¶ 14-15, Docket No. 05-WSEE-981-RTS (Feb. 13, 2006).
[18] *Jones v. Kansas Gas & Elec. Co.*, 222 Kan. 390, 401 (1977).
[19] Direct Testimony of Dylan W. D'Ascendis (D'Ascendis Direct), June 28, 2019, p. 2.
[20] *Id.*, p. 3.

Kansas's operations and another 0.04% for flotation costs to arrive at an ROE of 10.24%.[21] Inexplicably, D'Ascendis's rounded up to 10.25% to reach his initial recommendation.[22]

14. CURB's witness, Dr. J. Randall Woolridge, applied the DCF and CAPM to his own proxy group of gas distribution companies and concluded Atmos's ROE is in the range of 7.50% to 8.70%,[23] ultimately recommending an ROE of 8.7%.[24]

15. Staff recommends an ROE of 9.1%, with a range of 8.55% to 9.35%.[25] Staff witness Adam Gatewood's ROE of 9.1% results in an overall rate of return of 7.02%.[26] Gatewood performed DCF, Internal Rate of Return (IRR), and CAPM analyses using D'Ascendis's proxy group.[27] He relied on a DCF model using both short-term and long-term growth rate forecasts to arrive at a midpoint ROE of 8.15%.[28] Applying long-term growth rate forecasts to D'Ascendis's proxy group is one explanation for why Gatewood's recommended ROE is lower than D'Asendis's.

16. In his rebuttal testimony, D'Ascendis lowered his initial ROE recommendation from 10.25% to 9.9%,[29] based on an extraordinary decline in interest rates since he filed his direct testimony.[30] In his revised ROE recommendation, D'Ascendis starts with an ROE of 9.45% before applying a 0.40% upward size adjustment and a 0.03% flotation cost adjustment to arrive at his 9.9% ROE recommendation.[31]

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[21] *Id.*, p. 4.
[22] *Id.*
[23] Direct Testimony of J. Randall Woolridge, Ph.D. (Woolridge Direct), Oct. 31, 2019, p. 4.
[24] *Id.*, p. 58.
[25] Direct Testimony of Adam Gatewood (Gatewood Direct), Nov. 5, 2019, p. 2.
[26] *Id.*, p. 2. Gatewood's 7.02% overall rate of return is based on a 4.35% cost of debt. *See id.*, p. 3. Applying the 4.37% cost of debt the Commission adopts in paragraph 29 of this Order increases his overall rate of return to 7.03%.
[27] Staff Brief, ¶¶ 16-18.
[28] *Id.*, ¶ 17.
[29] Rebuttal Testimony of Dylan W. D'Ascendis (D'Ascendis Rebuttal), Nov. 18, 2019, p. 2.
[30] *Id.*, p. 5.
[31] *Id.*, p. 4.

17. In determining the appropriate ROE, the Commission is guided by *Federal Power Commission v. Hope Natural Gas Company*, 320 U.S. 591 (1944) and *Bluefield Waterworks & Improvement Company v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923) which find returns granted to regulated public utilities should be: (1) commensurate with returns on investment of similar risk; (2) sufficient to ensure the utility's financial integrity under proper management; and (3) adjusted to reflect changes in the money market and business conditions.[32] *Hope* and *Bluefield* have been adopted by the Kansas Supreme Court[33] and recognized by the Commission in Docket No. 10-KCPE-415-RTS (10-415 Docket).[34] While the Commission has substantial discretion in setting a fair rate of return, it must not be so unreasonably high or low as to be unlawful.[35]

18. Even after amending its proposed ROE in recognition of an extraordinary decline in interest rates, Atmos's proposed 9.9% ROE represents an increase of 80 basis points from its currently approved ROE of 9.1%.[36] Both Gatewood and Woolridge testified that there has been a clear downward trend in authorized ROEs for gas and electric utilities from 2000 to 2018.[37] Even Atmos acknowledges an overall downward trend in interest rates since 2008.[38] Atmos is the only party advocating an increase to its 9.1% ROE. Atmos's proposed ROE runs counter to the trends in Kansas and nationwide towards lower ROEs in recognition of historically low costs of capital.

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[32] *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 603, 64 S.Ct. 281, 288 (1944); *Bluefield Waterworks & Improvement Co. v. Public Service Comm'n of West Virginia*, 262 U.S. 679, 692-93, 43 S.Ct. 675, 679 (1923).
[33] *Kansas Gas*, 239 Kan. at pp. 489-90.
[34] Order: 1) Addressing Prudence; 2) Approving Application, In Part: and 3) Ruling on Pending Requests (10-415 Order), pp. 40-41, Docket No. 10-KCPE-415-RTS (Nov. 22, 2010).
[35] *Southwestern Bell Tel. Co. v. Kansas Corp. Comm'n*, 192 Kan. 39, 85-86 (1963).
[36] *See* Gatewood Direct, p. 30.
[37] Transcript of Evidentiary Hearing (Tr.), Dec. 10, 2019, Vol. 1, p. 48 (Woolridge); *id*, pp. 159-160 (Gatewood).
[38] D'Ascendis Rebuttal, pp. 5-6.

19. On cross-examination, D'Ascendis admits that the only model that produces a 9.9% ROE applies to companies that are not price/rate regulated with adjustments for company size and equity flotation.[39] Yet, D'Ascendis is unaware of any instance where the Commission has recognized a size adjustment in setting an ROE.[40] With an equity market capitalization of $11.4 billion, Atmos is hardly a small company.[41] Staff questioned the appropriateness for a size adjustment because an investor cannot purchase stock specific to Atmos's Kansas operations nor can anyone purchase debt specific to Atmos's Kansas operations.[42]

20. As Quackenbush testified, Atmos Kansas makes up only about 4% of Atmos's operations, so when investors contemplate investing in Atmos, they focus on states like Texas, Mississippi and Louisiana that make up the lion's share of Atmos's operations, and therefore, the regulatory risk that exists in those three states more significantly impacts Atmos's ability to attract capital.[43] Similarly, Quakenbush admits that Atmos is not currently experiencing any difficulty raising capital,[44] as evidenced by its ability to recently issue $800 million in 10-year and 30-years notes with a yield of 2.625 and 3.375 percent, respectively.[45] Based on these admissions, there is no justification for a size adjustment to ROE.

21. Atmos has not met its burden to demonstrate its existing 9.1% ROE is hindering its ability to raise capital, or insufficient to ensure the utility's financial integrity under proper management.

22. At the same time, CURB's recommended ROE range of 7.50% to 8.70% strikes the Commission as too low. Woolridge's recommended ROE is significantly below Atmos's current

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[39] Tr., Vol. 1, pp. 86-87.
[40] *Id.*, p. 93.
[41] Gatewood Direct, p. 24.
[42] *Id.*, p. 103.
[43] *Id.*, p. 217.
[44] *Id.*
[45] *Id.*, p. 218.

authorized ROE and is even further below the average rates of return being allowed to natural gas utilities. As D'Ascendis testified, since 2018, the average and median authorized ROEs for natural gas utilities are 9.63% and 9.7% respectively.[46]

23. An ROE of 9.1%, as recommended by Staff, is below that requested by Atmos, and above that recommended by CURB. The current Baa Corporate Bond yield of 4.5%[47] is actually lower than the 4.89% yield in place during the 14-ATMG-320-RTS Docket, (the last time the Commission set Atmos's ROE).[48] Since capital costs have declined since the Commission set the 9.1% ROE, the 80 basis points increase sought by Atmos is not justified. Having reviewed the evidence provided by D'Ascendis, Woolridge, and Gatewood, the Commission believes an ROE of 9.1% strikes the proper balance of allowing Atmos to access capital markets while acknowledging the economic impact of higher ROEs on ratepayers.

B. CAPITAL STRUCTURE

24. D'Ascendis recommends using Atmos's actual capital structure as of March 31, 2019 to develop the overall rate of return.[49] Therefore, he proposes a capital structure consisting of 39.88% long-term debt and 60.12% common equity.[50] D'Ascendis testified that since a 60.12% equity ratio is within the range of common equity ratios of other utility proxy group members, it would be inappropriate to substitute a hypothetical capital structure.[51]

25. Both Staff and CURB recommend a capital structure of 43.68% long-term debt and 56.32% common equity.[52] Woolridge testified that Atmos's proposed capital structure has more equity than the rest of the gas proxy members and should be adjusted to reflect the issuance of

[46] D'Ascendis Rebuttal, p. 47.
[47] Gatewood Direct, p. 32.
[48] *Id.*, p. 30.
[49] D'Ascendis Direct, p. 10.
[50] *Id.*
[51] *Id.*, p.21.
[52] Gatewood Direct, p. 17; Woolridge Direct, p. 24.

$800 million in senior notes on October 2, 2019.[53] Gatewood agrees that Atmos's proposed capital structure should be adjusted to reflect Atmos's issuance of $800 million in unsecured debt.[54] As Gatewood explained, the new debt issuance increases the balance of Atmos's long-term debt by 22% and since the debt bears a lower interest rate than the interest rate from the test-year, a lower rate of return is appropriate.[55] Gatewood testified that since Atmos has already issued the debt, adjusting its capital structure to reflect the debt is known and measurable and presents a better estimate of Atmos's actual costs going forward.[56]

26. On rebuttal, D'Ascendis argued that if the Commission elects to update the capital structure for post-test year events, it should also adjust the capital structure for all known and measurable post-test year events, including Atmos's two planned equity issuances in 2020, which would result in a capital structure of 58.22% common equity and 41.78% long-term debt.[57] Both Staff and CURB oppose including Atmos's planned 2020 equity issuances in the capital structure. CURB explains that those issuances were not raised in the evidentiary hearing and are not known and measurable.[58] Staff notes the adjustment related to the 2020 issuances is over a year removed from the test year and is not known and measurable.[59]

27. Atmos's concerns that factoring in the 2019 issuances, but not the planned 2020 offerings, would violate the principles of synchronization are not compelling. As Staff points out, all of the other adjustments, including those to plant in service and payroll, are not updated beyond September 30, 2019.[60] Staff argues the Commission should not adopt capital structure that was

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[53] *Id.*, p. 23.
[54] Gatewood Direct, p. 17.
[55] *Id.*
[56] *Id.*
[57] D'Ascendis Rebuttal, p. 14; Post Hearing Brief of Atmos Energy Corporation (Atmos Brief), Jan. 3, 2020, ¶ 23.
[58] Post-Hearing Brief of the Citizens' Utility Ratepayer Board (CURB Brief), Jan. 15, 2020, ¶ 26.
[59] Staff Brief, ¶ 40.
[60] *Id.*, ¶ 42.

updated during the hearing, including projected equity issuances that will not be finalized until 2020, and would not be synchronized with all of the other major elements of Staff's revenue requirement.[61] The Commission agrees.

28. Based on Gatewood's testimony that Atmos used the 2019 new debt to refinance existing short-term debt, rather than replacing long-term debt already accounted for in its long-term debt balances in the test year,[62] the Commission concludes the new debt is not be used to finance new plant and equipment outside of staff's update cutoff.

29. Including the new debt incurred in October 2019 has a significant effect on the Atmos's annual Gas Safety & Reliability Surcharge (GSRS) calculations, which are dependent on the rate of return set in this Docket.[63] Accordingly, failure to include the new debt from 2019 would result in customers paying higher GSRS charges based on an inflated rate of return.[64] This would result in shareholders, rather than customers receiving the benefit of cost savings from the new debt incurred in 2019.[65] Staff's recommended capital structure is within the 50% to 60% equity ratio range targeted by Atmos management.[66] Staff's proposed capital structure is within the range approved in Atmos's other divisions.[67] Therefore, the Commission approves the capital structure of 43.68% long-term debt and 56.32% common equity recommended by Staff and CURB. The parties agree that a 4.37% embedded debt cost is appropriate in this proceeding.[68] Accordingly, the Commission adopts a 4.37% debt cost in this proceeding.

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[61] *See id.*
[62] Gatewood Direct, p. 18.
[63] Staff Brief, ¶ 36.
[64] *Id.*
[65] *Id.*
[66] *Id.*, ¶ 37.
[67] *Id.*, ¶ 38.
[68] Atmos Brief, p. 12, n. 27.

C. SYSTEM INTEGRITY PLAN (SIP)

30. Atmos proposes a five-year pilot, SIP tariff to allow it to accelerate its replacement of obsolete materials in its Kansas underground pipes.[69] In its Post Hearing Brief, Atmos characterizes its proposed SIP as "essentially the same SIP mechanism agreed to by Atmos Energy, Staff, and CURB in Atmos Energy's last general rate case proceeding in the [16-ATMG-079-RTS] docket with one exception; the stipulated SIP in the 079 docket provided for a semi-annual rather than quarterly rate adjustments"[70] That characterization is misleading.

31. On cross-examination, Gary W. Gregory, Atmos's President of its Colorado and Kansas Division, admitted that the current SIP proposal does not include a $75 million cap over five years that was part of the SIP mechanism proposed in the 16-ATMG-079-RTS Docket (16-079 Docket).[71] Similarly, Gregory acknowledged the current SIP proposal does not include the three-year rate moratorium that was a condition of the SIP mechanism from the 16-079 Docket.[72]

32. In 2008, Kansas enacted a monthly Gas System Reliability Surcharge (GSRS) charge to allow natural gas utilities to invest in system integrity and to assist in complying with federal and state safety standards.[73] In 2018, the Kansas Legislature amended the Gas Safety and Reliability Policy Act, doubling the maximum monthly Gas System Reliability Surcharge (GSRS) charge on residential customers from $0.40 to $0.80.[74]

33. Atmos contends that the GSRS process produces an 11-month capital investment lag and does not cover the entire cost of investment for system integrity.[75] Therefore, Atmos believes a SIP mechanism is necessary. Both Staff and CURB oppose the proposed SIP. As Staff

[69] Application, ¶ 8.
[70] Atmos Brief, ¶ 31.
[71] Tr., Vol. 2, p. 257.
[72] *Id.*, p. 264.
[73] Direct Testimony of Gary L. Smith (Smith Direct), June 28, 2019, p. 9.
[74] K.S.A. 66-2204(e)(1); *See also* Smith Direct, p. 9.
[75] Smith Direct, p. 9.

witness Justin Grady testified, Atmos is fully recovering its investments in safety and reliability infrastructure today through the newly expanded GSRS.[76]

34. Staff recommends modifications to Atmos's proposed SIP: (1) capping the recovery of costs of incremental capital improvement at $50 million over five years; (2) beginning on January 1, 2021, and expiring on December 31, 2025; (3) requiring Atmos to file detailed annual SIP Plan Filings to be ruled on by the Commission each November 1; (4) requiring Atmos to make an annual surcharge filing by January 15, each year, with the first being due January 15, 2022; (5) providing only a return on and a return of capital expenditures above the $22 million per year in base safety, reliability, and GSRS-eligible capital expenditures; (6) requiring Atmos to file to renew, amend, or end the program by December 31, 2024; and (7) be accompanied by a three-year rate moratorium.[77]

35. Similarly, CURB explained it would be more amenable to the SIP if it would be: (1) used only after its GSRS is exhausted; (2) used only after taking advantage of depreciation; (3) limited to replacing cast iron or base steel pipeline; (4) updated annually; (5) limited to the monthly surcharge on residential customers to $0.40 per month; and (6) accompanied by a three-year rate moratorium.[78] The major difference between Staff's and CURB's proposed modifications is the size of cap.[79] Staff proposes a $50 million cap over the five-year pilot program, where CURB's proposal to limit the monthly surcharges equates to roughly a $35 million cap over the five-year period.[80]

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[76] Direct Testimony of Justin T. Grady, Nov. 4, 2019, p. 15.
[77] *Id.*, pp. 28-29.
[78] CURB Brief, ¶ 40.
[79] *Id.*, ¶ 41.
[80] *Id.*

36. In its Reply Brief, Atmos continues to misstate the character of its proposed SIP. Atmos makes the remarkable claim that, "[f]rom the Company's perspective, it proposed a SIP tariff that was virtually identical to the tariff agreed to between Atmos Energy, Staff, and CURB in the last Atmos Energy rate case and supported by the Staff and the Company in the 343 docket. The only difference is that Atmos Energy proposed a quarterly surcharge mechanism in this docket rather than a semi-annual surcharge mechanism."[81] Atmos then offers up a revised SIP that was not presented to the Commission until after the evidentiary hearing.

37. Under its revised SIP, Atmos proposes a semi-annual surcharge mechanism with a $35 million cap over five years.[82] Atmos's revised SIP appears to address the vast majority of both Staff's and CURB's concerns. The only matter remaining in dispute is the timing of the surcharge. By proposing a semi-annual mechanism, Atmos appears to abandon its initial request for a quarterly surcharge mechanism. At the very least Atmos's proposal proves it does not believe a quarterly surcharge is necessary. Atmos offers no evidence to support a semi-annual surcharge. Instead it simply states, "both Staff and Atmos Energy indicated they could live with a semi-annual surcharge mechanism which was the arrangement incorporated into the 079 settlement."[83] That statement does not provide sufficient justification for the Commission to adopt a semi-annual surcharge. Nor does it recognize the important elements of the 16-079 Docket settlement still missing from Atmos's proposal, notably a three year rate moratorium. Therefore, even though the 16-079 Docket settlement contained a semi-annual surcharge, that is not compelling evidence that a SIP should be collected on a semi-annual basis.

[81] Reply Brief of Atmos Energy Corporation (Atmos Reply Brief), Jan. 24, 2020, ¶ 19.
[82] *Id.*, Attachment A, p. 1.
[83] Atmos Reply Brief, p. 18.

38. Both Staff and CURB have supported an annual surcharge. Staff's and CURB's recommendations are supported by testimony from Justin Grady and Josh Frantz respectively. Furthermore, an annual surcharge is consistent with how the GSRS is collected. An annual surcharge is also less burdensome for the Commission and its Staff to administer. Since there is no evidence to support Atmos's revised semi-annual surcharge, and based on Atmos's acknowledgment that if the SIP mechanism was denied, it would continue to use the existing rate recovery options, such as the GSRS or rate cases, and more importantly, it would continue to spend and invest in its system and address safety issues without any pause, the Commission denies Atmos's proposed, modified SIP.

39. Both Staff and Atmos favor increasing the pace for replacing obsolete infrastructure.[84] The real dispute between the Staff and Atmos is the method of cost recovery.[85] The Commission is not opposed to a SIP in principle, just the SIP as originally proposed by Atmos. The Commission recognizes the urgent need to replace obsolete pipes, primarily bare steel and cast iron. Therefore, the Commission would approve the amended SIP proposed by Atmos in its Reply Brief, provided it includes: (1) an annual surcharge as suggested by CURB and Staff for replacing obsolete pipes, primarily bare steel and cast iron, and (2) is available only after its GSRS is exhausted; and (3) Atmos accepts a three-year rate moratorium. If after exhausting its GSRS, Atmos wishes to pursue a SIP including a $35 million cap over five years, with an annual surcharge, and a three-year rate moratorium, the Commission urges Atmos to collaborate with CURB and Staff to make a compliance filing, in accord with these conditions through a SIP tariff.

[84] *Id.*, p. 280.
[85] *Id.*, p. 281.

D. INCENTIVE COMPENSATION

40. Atmos claims its employee compensation plan supports and rewards high-performance by its employees, which benefits all stakeholders.[86] Staff recommends removing 100% of Atmos's short term Management Incentive Plan expenses, 50% of the time lapse portion of the Long Term Incentive Plan, and 100% of the expense associated with the Performance Based portion of the Long Term Incentive Plans allocated to Atmos's Kansas operations.[87] CURB recommends removing 100% of Atmos's compensation expenses beyond base salary.[88] Atmos contends that because its total compensation for employees (base pay plus incentive pay) is prudent and reasonable based upon those total salaries being below or at the total salaries paid in the market for similar positions, they should be recovered in rates.[89]

41. Atmos retained James F. Reda, who filed rebuttal testimony on the reasonableness of Atmos's total compensation levels, the competitiveness of Atmos's total compensation program, and the inclusion of incentive compensation in Atmos's cost of service.[90] In his prefiled rebuttal testimony, Reda states that Atmos's compensation levels compare favorably with the competitive market.[91] He reaches that conclusion because Atmos's compensation programs are at the 50th percentile of the marketplace and the incentive programs are tied to financial performance, which benefits all stakeholders.[92]

42. Despite Reda's concern that Atmos would not be able to retain qualified employees without its executive compensation program, on cross-examination, Reda admitted he did not conduct any studies on whether Atmos's ability to attract capital would be affected if the

[86] Atmos Post Hearing Brief, ¶ 51.
[87] Staff Brief, ¶ 86.
[88] CURB Brief, ¶ 75.
[89] Atmos Brief, ¶ 43(c).
[90] Rebuttal Testimony of James F. Reda, Nov. 18, 2019, p. 3.
[91] *Id.*, p. 8.
[92] *Id.*, p. 28.

Commission disallowed the incentive compensation programs in rates.[93] Similarly, he failed to conduct any surveys of Atmos executives to measure potential turnover if the Commission disallowed the incentive compensation programs in rates.[94]

43. Furthermore, even if the Commission excludes Atmos's compensation plans from rates, the evidence suggests Atmos's shareholders will gladly finance those programs. In his prefiled rebuttal testimony, Reda notes that in 2018, 94% of Atmos's shareholders approved the Company's compensation structure.[95] He argues the shareholder approval demonstrates the executive compensation structure adds value to shareholders and customers.[96] But when asked during cross-examination whether he believes the shareholders vote was influenced by whether they expect ratepayers to bear those costs, Reda answered no.[97] Likewise, when asked if he thought shareholders were concerned with who might be paying for these plans, he again answered no.[98] This is despite the evidence in the record that most of Atmos's jurisdictions disallow some portion of incentive compensation.[99] Therefore, Atmos's own expert implicitly acknowledges that its shareholders are willing to bear the cost of the incentive programs. Accordingly, there is no reason to burden ratepayers with costs, as shareholders have shown are perfectly willing to fund the incentive programs. If shareholders pay for the incentive programs, the incentive programs will continue to allow Atmos to recruit and retain valued employees.

44. Staff does not claim Atmos's compensation levels are unreasonable or imprudent; instead Staff believes Atmos's compensation metrics are too heavily weighted towards its financial

[93] Tr., Vol. 3, p. 549.
[94] *Id.*, p. 550.
[95] Reda Rebuttal, p. 4.
[96] *Id.*
[97] Tr. Vol. 3, p. 551.
[98] *Id.*, p. 552.
[99] Tr., Vol. 3, p. 556.

goals.[100] Staff relies on the Commission's Order in the 10-415 Docket, where the Commission announced its intent to exclude programs that focus on the financial aspect, rather than operational aspects of the business,[101] to argue Atmos's programs should be disallowed. According to Staff, since the 10-415 Docket was issued, the Commission has repeatedly affirmed its decision, notably in the 12-KCPE-764-RTS Docket (12-764 Docket).[102] Therefore, Staff believes the policy to disallow incentive programs that focus on the financial benefits to the utility is settled law.[103] Atmos disagrees.

45. CURB recommends disallowing all incentive compensation expenses over and above base pay, including the financial portion of incentive compensation expenses for non-management employees.[104] In both the 10-415 and 12-764 Dockets, the Commission explicitly rejected CURB's more aggressive incentive compensation argument.[105]

46. The Commission concludes there is no reason to revisit its prior decisions on incentive compensation. Likewise, the Commission concludes there is no reason to revisit its decision announced in the 10-415 Docket to disallow incentive programs that focus on the financial aspect, rather than operational aspects. Accordingly, the Commission reaffirms its intent to disallow the costs of management incentive programs that focus on financial criteria. The Commission adopts Staff's recommendation to remove 100% of Atmos's short term Management Incentive Plan expenses, 50% of the time lapse portion of the Long Term Incentive Plan, and 100% of the expense associated with the Performance Based portion of the Long Term Incentive Plans

[100] Tr. Vol. 3, p. 655.
[101] Direct Testimony of Kristina A. Luke-Fry, Oct. 31, 2019, p. 19.
[102] *Id.*
[103] Staff Brief, ¶ 90.
[104] CURB Brief, ¶ 75.
[105] *See* Order on KCP&L's Application for Rate Change, Docket No. 12-KCPE-764-RTS, Dec. 13, 2012, ¶ 47.

allocated to Atmos's Kansas operations. Pursuant to K.S.A. 77-415(b), the Commission designates this paragraph as precedential.

E. DEPRECIATION

47. There are three primary issues related to the testimonies of each party - net salvage, service lives and depreciation calculation procedure.[106] Ned Allis prepared a depreciation study for Atmos.[107] The study is based on the Equal Life Group (ELG) procedure, which differs from the Average Life Group (ALG) procedure, currently used to calculate depreciation rates for Atmos.[108] Staff witness Roxie McCullar believes the ALG procedure should continue to be used to calculate depreciation rates for Atmos.[109] Additionally, McCullar recommends adjustments to several of Atmos's proposed net salvage rates.[110] McCullar's adjustments would reduce Atmos's proposed Depreciation Rate and Expenses by $2,622,802.[111]

48. CURB's witness, James Garren, proposes lower depreciation rates than Allis due to adjustments to the average service lives used to calculate depreciation rates for seven distribution accounts; and a proposed alternative method of estimating future net salvage, based on the most recent five-year history of the Company's net salvage experience.[112] Garren expresses concerns with Allis's methodology: (1) it produces unrealistically high future net salvage ratios; and (2) second, because net salvage and retirements are not causally related or mathematically correlated in any way, relying on this ratio yields unreliable and unsound results.[113] Therefore, Garren proposes a methodology which utilizes the most recent five-year average of net salvage to

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[106] Rebuttal Testimony of Ned W. Allis (Allis Rebuttal), Nov. 18, 2019, p. 1.
[107] Direct Testimony of Ned W. Allis (Allis Direct), June 28, 2019, p. 1.
[108] *Id.*; Staff Brief, ¶ 106.
[109] Direct Testimony of Roxie McCullar (McCullar Direct), Oct. 31, 2019, p. 2.
[110] *Id.*, p. 11.
[111] *Id.*, p. 3.
[112] Direct Testimony of James S. Garren (Garren Direct), Oct. 31, 2019, p. 4.
[113] *Id.*

estimate future net salvage.[114] He estimates total future net salvage by multiplying the annual accrual requirement by the account remaining life.[115] Garren's adjustments would reduce Atmos's proposed Depreciation Rate and Expenses by $2,973,248.[116]

Net Salvage

49. Net salvage is gross salvage less cost of removal.[117] Net salvage is normally negative because cost of removal is typically greater than gross salvage for most accounts.[118] Depreciation rates are designed to recover future net salvage, not what has been recorded in the past.[119] Atmos, Staff, and CURB all propose different net salvage figures.

50. Allis proposes a methodology that calculates a ratio of annual net salvage over retirements, where he examines this ratio in five and ten year periods over the past fifteen years, and factors in the historical data, the age of the plant, managerial expectations, and the experience of other utilities in the industry, to arrive at a net salvage ratio for each account.[120]

51. On rebuttal, Allis claims Staff's and CURB's proposals rely almost entirely on historical data, compared to Atmos's forward looking proposals.[121] Allis accuses Staff and CURB of proposing alternatives that do not fully estimate future net salvage.[122] He argues that unlike Atmos, who has used the industry standard method of estimating future net salvage, Staff and CURB offer methodologies, which have no support from depreciation authorities and which at most have limited acceptance by regulatory commissions.[123] Allis contends that by failing to

[114] *Id.*, p. 34.
[115] *Id.*
[116] *Id.*, p. 36.
[117] Atmos Brief, ¶ 25.
[118] Allis Rebuttal, pp. 6-7, Garren Direct, p. 6.
[119] Allis Direct, pp. 13-14.
[120] Garren Direct, p. 27.
[121] Allis Rebuttal, pp. 1-2.
[122] *Id.*, p. 2.
[123] *Id.*

recover net salvage over the lives of the Company's assets, Staff's and CURB's proposals will produce intergenerational inequity, particularly as Atmos's accelerated pipe replacement program results in higher levels of net salvage.[124]

52. Atmos claims its uses the industry-standard method for analyzing net salvage is to express net salvage (and its components cost of removal and gross salvage) as a percentage or ratio of retirements,[125] whereas CURB's and Staff's methodologies consider the level of net salvage recorded in recent years, not as a percentage of retirements.[126]

53. As the Applicant, Atmos bears the burden of proof on all issues, including depreciation. The record contains several competing expert claims as to the correct methodology for determining the proper net salvage level, and Atmos is unable to prove that its methodology is the *only* methodology that will result in just and reasonable rates. While Atmos claims its methodology is superior to Staff's and CURB's, Atmos's net salvage estimates are not based purely on statistical analyses or historical net salvage amounts expressed as a percentage of retirements. As Allis states in his Direct Testimony, "the net salvage percentages in the Depreciation Study are based on a combination of statistical analyses and informed judgment."[127] Staff's depreciation witness McCullar testifies similarly, "[m]y proposed future net salvage accrual amounts are in current dollars that consider Atmos's historic practices, the impact of inflation, and builds a reserve for reasonable estimated future net removal costs associated with future retirements, based on the type of investments in the account, and my previous experience."[128]

[124] *Id.*
[125] Atmos Reply Brief, ¶ 28.
[126] *Id.*, ¶ 30.
[127] Allis Direct, p. 14.
[128] McCullar Direct, p. 12.

CURB's depreciation witness Garren, stands alone making a recommendation based strictly on the most recent five year average of net salvage.[129]

54. After examining the evidence on the issue of net salvage, the Commission is not convinced that it must adopt a particular methodology as the only "right" approach in this Docket. However, the Commission rejects CURB's methodology because it relies solely on recent historical net salvage experience. Although their methods of determining net salvage differ, Atmos, Staff, and CURB agree that the purpose of a net salvage analysis is to estimate the future level of net salvage that Atmos will incur as part of its depreciation expense. Both Staff and Atmos agree that a net salvage analysis should estimate appropriate levels of future net salvage, not solely rely strictly on historic expense levels. When deciding between Atmos and Staff's net salvage analyses, the Commission finds Staff's approach will best balance the interests of Atmos's current versus future ratepayers. Again, this finding is not based on adopting any particular methodology in this Docket, but that Staff's approach strikes the best balance between current and future ratepayers.

Service Lives

55. On the issue of the appropriate service life estimates for Atmos's assets, Staff and Atmos utilize the same service lives,[130] but CURB recommends longer service lives for seven accounts.[131] Allis claims CURB's proposals are not based on sound methodology and are not consistent with the recommendations of depreciation authorities.[132] Atmos also contends CURB's

[129] Garren Direct, p 34.
[130] *Id.*, pp. 2-3.
[131] *Id.*, p. 3.
[132] *Id.*

service life proposals do not account for accelerated modernization of infrastructure.[133] Finally, Atmos asserts CURB's approach conflicts with NARUC's guidance on the issue.[134]

56. The Commission agrees with Atmos that Atmos's service life proposals are consistent with both the need to accelerate the modernization of infrastructure, and with the recommendations of depreciation authorities such as NARUC. Therefore, the Commission accepts Atmos's proposed service lives as agreed to by Staff.

ELG versus ALG

57. On the question of whether to use the ELG or ALG procedure, Allis dismisses CURB's position as lacking any support, and Staff's arguments as not standing up to scrutiny.[135] While both ALG and ELG procedures are calculated to recover 100% of the original cost over the life of the plant, the ELG procedure should be adjusted annually and is front-loaded.[136]

58. Atmos acknowledges that adopting Staff's and CURB's recommendations to increase the lives of existing assets and decrease depreciation expense certainly achieves any short-term policy or goal of maintaining lower customer rates, as depreciation expense is the largest revenue requirement adjustment in this rate case.[137]

59. In its Reply Brief, Atmos argues that just because ELG produces higher depreciation rates does not mean that it is unjust and unreasonable and that ALG results in too low of depreciation rates in the early years of the life of property.[138] In doing so, Atmos has not demonstrated the Commission should change from its current process of applying the ALG

[133] Atmos Reply Brief, ¶ 42.
[134] *Id.*, 45.
[135] *Id.*
[136] McCullar Direct, p. 6.
[137] Atmos Brief, ¶ 42.
[138] Atmos Reply Brief, ¶ 52.

procedures to depreciation rates. Therefore, the Commission declines to deviate from the existing process. The Commission will apply ALG procedures to calculate Atmos's depreciation rates.

F. RATE CASE EXPENSE

60. The Parties agree that utilities are entitled to recover prudently incurred rate case expenses through rates.[139] Staff questions the costs associated with Reda's testimony regarding Atmos's incentive compensation plan and with Quackenbush's testimony regarding the proposed SIP.[140] CURB recommends allowing Atmos to collect its reasonable rate case expense through a three-year normalization.[141] CURB does not define what it considers reasonable rate case expense.

61. Atmos contends it would benefit the Commission to hear the perspective of someone from outside Atmos, who could provide a broader look at SIP-like mechanisms.[142] Therefore, Atmos believes the expenses of Quackenbush, a former regulator who had approved similar mechanisms, are justified for inclusion in rates.[143] The Commission disagrees.

62. As Quackenbush readily admits, he provides testimony on what other states have allowed for ROEs based on RRA reports.[144] He acknowledges that RRA's evaluation are from the perspective of investors.[145] Quackenbush's testimony is premised on his knowledge garnered as a former Michigan Commissioner. Expert testimony is proper if it will be of special help to the factfinder on technical subjects with which the factfinder is not familiar or if it would assist the factfinder in reaching a reasonable factual conclusion.[146] The Commission is capable of interpreting the RRA ratings without the aid of expert testimony. Furthermore, Quackenbush's

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[139] Rebuttal Testimony of Jennifer K. Story, Nov. 18, 2019, p. 28; Direct Testimony of Ian D. Campbell, Oct. 31, 2019, p. 6.
[140] Staff Brief, ¶ 163.
[141] CURB Brief, ¶ 101.
[142] Atmos Brief, ¶ 72.
[143] *Id.*
[144] Tr., Vol. 1, p. 210-211.
[145] Quackenbush Rebuttal, p. 15.
[146] *Sterba v. Jay*, 249 Kan. 270, 282 (1991).

testimony substantially overlaps with that of Gary L. Smith and Gary W. Gregory. Under these circumstances, Quackenbush's testimony has little probative value, therefore, the Commission disallows his expenses from rate case expense.

63. Atmos believes Reda's testimony is necessary to show the reasonableness of total compensation paid to Atmos's employees based upon what similar employees are paid in the market.[147] In addition, since Staff did not question the reasonableness of similar testimony in the recent Kansas Gas Service rate case, Atmos assumed Reda's costs were prudently incurred.[148] Staff counters by explaining that Reda's compensation is significantly higher than his counterpart in the Kansas Gas Service rate case.[149] As Justin Grady testified, Kansas Gas Service spent $42,590 on an external consultant for incentive compensation; whereas Atmos spent $79,000, nearly double the amount incurred by Kansas Gas Service.[150] Subsequently, on February 14, 2020, Atmos updated its estimated rate case expense, upping Reda's expenses to $91,368.[151] Reda's expenses are higher than either of the outside attorneys that tried this case and higher than its ROE witness. ROE is a much larger financial piece of Atmos's rate case than incentive compensation.

64. Grady also questions the need for Reda's testimony because he believes Atmos could have used internal employees as it did in its last rate case to testify on incentive compensation.[152] Since Staff's treatment of incentive compensation expense has been consistent since the 10-415 case, Grady sees no need for Atmos to incur the cost of an outside expert on incentive compensation.[153] Grady notes that Gary Gregory is already a witness in this matter and

[147] Atmos Brief, ¶ 71.
[148] *Id.*
[149] Staff Brief, ¶ 163.
[150] Tr., Vol. 2, p. 483.
[151] Estimated Rate Case Expense, Feb. 14, 2020, p. 1.
[152] Tr., Vol. 2, p. 482.
[153] *Id.*

that Barbara Myers, who is listed by Atmos on its rate case exhibit list as a manager of this filing, and has previously provided testimony on this topic, could have also testified in lieu of Reda.[154]

65. Reda did not prepare any studies for Atmos. Instead, he just reviewed two studies prepared by Pay Governance LLC for the Atmos Energy Board of Directors Human Resources Committee.[155] Both studies conclude that Atmos's total direct compensation levels were at or below the 50th percentile compared to its peer group and published survey data.[156] Since both studies were presented to Atmos back in October 2018,[157] the Commission questions the need to retain Reda to testify on these studies. Despite the Commission's concerns, since Atmos bears the burden of proof, it is entitled to pick a witness it believes will best present its case. Also, since the Commission did not disallow any rate case expense relating to incentive compensation in the recent Kansas Gas Service rate case,[158] it will not disallow all of Reda's expenses. While the Commission elects not to disallow all of Reda's expenses, it finds his expenses excessive and duplicative. Compared to the expenses incurred by Kansas Gas Service and also the expenses incurred by both Atmos's outside attorneys and Atmos's ROE witness, Reda's expenses are excessive. For these reasons, the Commission disallows half ($45,684) of Reda's expenses.

66. Atmos seeks to recover its rate case expense through a one-year surcharge on customer bills, but is willing to agree to a two-year recovery period.[159] CURB recommends allowing Atmos's rate case expenses to be recovered through a three-year normalization of those costs in base rates.[160] Staff opposes Atmos's proposed rate case expense surcharge because it

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[154] *Id.*
[155] Reda Rebuttal, p. 8.
[156] *Id.*, p. 9.
[157] *Id.*, p. 8
[158] *See* Tr., Vol. 2, p. 488.
[159] Atmos Brief, ¶ 73.
[160] CURB Brief, ¶ 101.

believes it will reduce Atmos's incentive to prudently manage its rate case expenses and because it would allow Atmos to recover its rate case expense too quickly.[161]

67. In Atmos's most recent rate case, the Commission ordered it to amortize its rate case expense over three years.[162] Atmos has not provided sufficient justification to change course. Therefore, the Commission finds Atmos should amortize its rate case expense over three years.

G. MONTHLY RESIDENTIAL CUSTOMER CHARGE

68. Currently, Atmos residential customers are charged a monthly fixed charge of $18.04 per month, in addition to paying for the volume of gas they use.[163] Atmos is seeking to increase the monthly fixed charge to $22.00.[164] Staff proposes a smaller increase to $18.89.[165] CURB recommends decreasing the monthly charge to $15.00.[166] CURB arrives at the $15.00 figure by performing a direct customer cost analysis,[167] which produces a residential direct customer cost in the range of roughly $9-$10.[168] Because the current fixed monthly charge is $18.04, CURB witness Watkins considers it excessive.[169] But Watkins stops short of recommending setting the fixed monthly charge at $10 because of gradualism and his assumption that the Commission will want to include some overhead expenses in the fixed charge.[170] Due to those two considerations, Watkins recommends a $15 customer charge.[171] On cross-examination,

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[161] Staff Brief, ¶ 159.
[162] *Id.*, ¶ 160.
[163] The Commission approved a residential fixed charge of $18.91 in Atmos's last rate case, Docket No. 16-ATMG-079-RTS. The $18.91 was reduced to $18.04 due to tax reform and further reduced to $17.72 for the period of April 2018-March 2019, due to the deferred revenue credit. Direct Testimony of Robert H. Glass, Ph.D. (Glass Direct), Oct. 31, 2019, p. 10, Table 4.
[164] Atmos Brief, ¶ 74.
[165] Staff Brief, ¶ 166.
[166] CURB Brief, ¶ 102.
[167] Tr. Vol. 3, p. 660.
[168] *Id.*, p. 661.
[169] *Id.*, p. 662.
[170] *Id.*
[171] *Id.*

Watkins acknowledges that shifting some costs from the fixed monthly charge to a volumetric charge could result in higher bills in cold weather.[172]

69. Atmos witness Paul H. Raab expresses his concern that Atmos faces a significant risk when it has to try to collect fixed costs through volumetric charges[173] because the costs remain fixed and Atmos may not collect enough revenues to meet its authorized rate of return.[174] Dr. Robert H. Glass, the Commission's Chief of Economics and Rates, testified that Atmos is best situated among gas utilities operating in Kansas because it is experiencing customer growth and has a weather normalization adjustment (WNA), which in addition to the weather normalization of the revenue requirement, protects Atmos from weather fluctuations,[175] and therefore, Atmos, should not require a higher customer charge.[176]

70. In Atmos's last rate case, Staff attempted to slow the trend of rising fixed monthly charges, where the fixed charges have increased at a greater rate than the commodity charge.[177] At the same time, Staff acknowledges that fixed costs should be recovered through fixed charges.[178] During the test year, 64% of the residential base rate revenue came from fixed charges.[179] CURB argues that by collecting roughly two-thirds of its residential base rate revenue through fixed charges, Atmos inhibits residential customer's ability to control their bills through conservation.[180]

71. The Commission concludes that an increase of the fixed monthly charge is not warranted based on Atmos's WNA and increasing customer base. At the same time, the

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172 *Id.*, p. 666.
173 *Id.*, p. 678.
174 *Id.*, p. 679.
175 *Id.*, p. 686.
176 *Id.*
177 Glass Direct, p. 21.
178 *Id.*
179 *Id.*, p. 22.
180 Direct Testimony of Glenn A. Watkins, Oct. 31, 2019, p. 27.

Commission is concerned that CURB's recommended $15.00 fixed monthly charge is not supported by competent evidence. The Commission finds that Staff's proposed $18.89 strikes the proper balance between allowing Atmos to collect its fixed costs and providing customers with some ability to manage their gas usage to lower their monthly bills. An $18.89 monthly charge is consistent with Kansas Gas Service's $18.70 and Black Hills Energy's $17.25.[181] Accordingly, the Commission adopts $18.89 as the monthly residential customer charge.

72. On the issue of weather normalization, Atmos agrees to accept Staff's WNA proposal. In doing so, Atmos expresses its desire to work with Staff to develop updated WNA tariffs and future WNA annual filings to incorporate the new classes and weather sensitivity factors.[182] Accordingly, the Commission directs the parties to jointly develop the updated WNA tariffs and future WNA annual filings to incorporate the new classes and weather sensitivity factors. The parties shall file a status update by June 1, 2020 outlining the proposed implementation process for Commission consideration.

H. OTHER RATE BASE AND INCOME STATEMENT ADJUSTMENTS

73. The Commission accepts the following uncontested accounting adjustments:

- Donation Expense (Staff IS-9) ($74,772)
- Other Postretirement Benefits (Staff IS-14) ($68,917)
- Interest on Customer Deposits (Staff IS-7) ($1,102)
- Advertising Expense (Staff IS-8) ($9,605)
- Pension Expense (Staff IS-13) ($65,132)
- Pension Tracker 1 and OPEB Tracker 1 (Staff IS-15) $98,094

[181] Tr. Vol. 3, p. 687.
[182] Rebuttal Testimony of Gary L. Smith, Nov. 18, 2019, p. 24.

- Leases (Staff IS-16) $76,517
- Weather Normalization (Staff IS-17) ($466,047)
- Customer Annualization (Staff IS-18) $119,039
- KCC Annual Assessment Expense (Staff IS-10) ($8,070)
- Customer Deposits (Staff RB-5) $40,502
- Prepayments (Staff RB-6) $62,178
- Storage Gas (Staff RB-7) $527,781

Construction Work in Progress (CWIP)

74. Atmos believes it should be allowed to include the CWIP balance of $1,620,606, in rate base because it has verified the listed projects will be completed and in service by no later than February 2020, within one year from the end of the test year.[183] CURB witness Andrea C. Crane does not believe most of the claimed CWIP were incurred before the end of the test year, and thus should be excluded from rate base.[184] CURB recommends including $1,307,897 of CWIP in rate base.[185] Staff recommends excluding all CWIP not closed to Plant in Service by August 31, 2019 from rate base.[186] Staff's adjustment would remove $11,110,143 from Atmos's rate base.[187]

75. Staff's review of Atmos's workpapers reveals Atmos missed the projected in-service date of approximately 55% of the projects it projected to be placed into service by September 30, 2019.[188] The only evidence that Atmos offers to suggest that projects were expected to be completed by February 2020 is hearsay testimony from Jennifer Story that Bart Armstrong

[183] Atmos Brief, ¶ 52.
[184] Direct Testimony of Andrea C. Crane (Crane Direct), Oct. 31, 2019, p. 11.
[185] *Id.*, p. 12.
[186] Staff Brief, ¶ 124.
[187] Direct Testimony of Brad Hutton, Oct. 31, 2019, p. 5.
[188] Staff Brief, ¶ 128.

verified that the projects listed on a worksheet would be completed by February.[189] Her testimony is not enough to demonstrate the listed projects will be in service by February 2020. Therefore, the Commission approves Staff's adjustment to remove $11,110,143 from Atmos's rate base.

Miscellaneous Expenses

76. Staff recommends disallowing $46,123 of miscellaneous expenses because those dues paid to professional organizations do not directly benefit ratepayers.[190] Atmos counters that only $29,047 should be disallowed because the cost of those licensing fees and membership dues are reasonable, Staff used an incorrect allocation factor, and Staff eliminated some legal expenses that Atmos did not include in its Application.[191] Staff claims to have corrected these errors in its final adjustments, which Atmos did not dispute.[192] Atmos did not present any evidence to rebut Staff's claim that the license fees and membership dues directly benefit ratepayers. Accordingly, the Commission adopts Staff's adjustment and disallows $46,123 of miscellaneous expenses because those dues paid to professional organizations do not directly benefit ratepayers.

Plant, Accumulated Depreciation, Accumulated Deferred Income Tax (ADIT), and Excess Deferred Income Tax (EDIT) Accounts

77. Atmos seeks to update Plant in Service to September 30, 2019, which would increase its rate base by $9,402,791.[193] Staff opposes updating Atmos's balances for Plant in Service beyond August 31, 2019, because nearly every other update to the test year is through August 30, 2019.[194] Staff's adjustment would increase Atmos's rate base by $7,840,069.[195] The

[189] Tr. Vol 2, p. 525.
[190] Staff Brief, ¶ 118.
[191] Atmos Brief, ¶ 64.
[192] Staff Brief, ¶ 119
[193] Atmos Brief, ¶ 55.
[194] Staff Brief, ¶ 131.
[195] *Id.*, ¶ 130.

Commission adopts Staff's adjustment as it more closely resembles Atmos's ongoing cost of doing business and is synchronized with the vast majority of other adjustments in this Docket.[196]

78. Staff advises that Plant in Service (and thus Depreciation Expense), ADIT, and Accumulated Depreciation need to be updated through the same date to avoid IRS Normalization Violations.[197] Therefore, the Commission finds that ADIT, Accumulated Depreciation, and Depreciation Expense should to be updated through August 31, 2019.

<u>**Accumulated Deferred Income Taxes (ADIT)**</u>

79. Staff proposed increasing ADIT by $1,081,792, which is an offset to Plant in Service, which decreases rate base.[198] Staff's adjustment is due to: (1) updating ADIT balances to update period of August 31, 2019; (2) remove ADIT associated with pension and FAS 106 costs; (3) remove ADIT associated with Regulatory Liability-Mid Tex; and (4) remove portions of ADIT corresponding to Staff's incentive compensation adjustment.[199] In acknowledging a difference in timing between the recovery of pension and post-retirement benefits in rates and the deduction for this amount on its tax return, Atmos claims that the timing difference is no different than any other timing difference for expense included in rates, and notes Staff has not made this adjustment in previous Atmos rate cases.[200] Atmos admits it mislabeled the Regulatory Liability-Mid Tex balance in its Application but argues that the balance should be included as an adjustment to rate base because it relates to pensions and post-retirement obligations.[201]

80. Staff claims its proposed adjustments to ADIT to remove the ADIT balances associated with pension expenses and FAS 106 costs are necessary to match up the removal of

[196] *See id.*, ¶ 132.
[197] Staff Brief, ¶ 141.
[198] *Id.*, ¶ 136.
[199] *Id.*
[200] Atmos Brief, ¶ 57.
[201] *Id.*, ¶ 58.

pension and FAS 106 costs from rate base.[202] Atmos has not effectively countered this rationale and Ms. Story admits that these balances are not in rate base.[203] Accordingly, the Commission accepts Staff's adjustments to ADIT for this issue. The remainder of Staff's adjustments to ADIT are consistent with its proposal to remove certain incentive compensation expenses from the revenue requirement.[204] Accordingly, since the Commission accepted Staff's proposal to remove certain incentive compensation expenses, it elects to adopt Staff's adjustments to ADIT.

Excess Deferred Income Tax (EDIT)

81. Staff recommends: (1) updating the level of EDIT amortization and Atmos's EDIT regulatory liability to reflect Atmos's most recent revisions to EDIT amounts; (2) removing portions of EDIT that correspond to equity compensation and incentive compensation amounts removed by Staff; and (3) amortizing the before-tax-gross-up EDIT balance to deferred tax expense, as in every single regulated utility rate case filed in Kansas since the implementation of the Tax Cuts and Jobs Act.[205] Staff recommends including $19,346,609 of EDIT regulatory liability and an EDIT amortization amount of ($711,062).[206] Atmos's only dispute with Staff's adjustment is its removal of certain EDIT amounts related to its incentive compensation adjustment. As the Commission has accepted Staff's incentive compensation adjustment, so too does it accept Staff's EDIT adjustment related to incentive compensation. Accordingly, the Commission adopts Staff's adjustments to EDIT.

[202] Staff Brief, ¶ 139.
[203] Tr. Vol 2, p. 526.
[204] Atmos Brief, ¶ 59.
[205] Staff Brief, ¶ 133.
[206] *Id.*, ¶ 134.

Accumulated Depreciation

82. Staff recommends decreasing Atmos's Rate Base by $2,161,428 to reflect the balance of Accumulated Depreciation through Staff's update period ending August 31, 2019. Staff's proposed adjustment would synchronize the balance of Plant In Service and its corresponding Accumulated Depreciation balances.[207] This adjustment to Accumulated Depreciation ensures ratepayers are given credit for the capital they have returned to Atmos, and therefore, no longer need to pay a return on.[208] Atmos's dispute with Staff appears to revolve around the timing to update the balance. The Commission adopts Staff's adjustment to synchronize Plant In Service and Accumulated Depreciation as of August 31, 2019.

Bad Debt Expense

83. Staff proposes to decrease operating expenses by $27,838 to account for bad debt expense. Staff used a three-year average net bad debt write-off percentage of 0.4004% through year-end August 31, 2019.[209] CURB favors a normalization adjustment that accounts for multiple years and would decrease operating expense by $46,869 to account for bad debt expense.[210] Atmos disputes CURB's and Staff's adjustments. Atmos argues CURB's adjustments are inconsistent with previous Atmos rate cases and will preclude the Company from recovering its actual costs.[211] Other than alleging Staff's methodology of using a three-year average is not consistent with past Commission practice in Atmos dockets, Atmos does not present a compelling reason to reject Staff's adjustment. Therefore, the Commission adopts Staff's adjustment to bad debt expense.

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[207] *Id.*, ¶ 135.
[208] *Id.*
[209] *Id.*, ¶ 146.
[210] CURB Brief, ¶ 93; Crane Direct, Schedule ACC-12.
[211] Atmos Brief, ¶ 63.

Depreciation Expense

84. Staff proposes decreasing annualized depreciation expense by $2,413,239, by increasing Atmos' pro-forma depreciation expense by $303,708 for updates to Atmos' Plant in Service and decreasing Atmos' depreciation expense by $2,716,947 to reflect Staff's recommended depreciation rates.[212] Any adjustment to depreciation expense needs to be synchronized with the updated Plant in Service date.[213] Having already adopted a Plant in Service date of August 31, 2019, the Commission adopts the same date for depreciation expense. Additionally, the Commission ruled above that Atmos' depreciation expense should be calculated using Staff's recommended depreciation rates. Accordingly, the Commission approves Staff's adjustment for depreciation expense.

Payroll Expense and Benefit Expenses

85. Atmos agrees with Staff's recommendation to update payroll and employee benefits expenses through August 31, 2019, but complains Staff's adjustment only included 11 months of the merit increases.[214] CURB recommends increasing payroll expense by $67,818.[215] Atmos also disagrees with CURB's payroll tax adjustment, claiming it mistakenly assumes that taxes are paid at the statutory rates.[216] Atmos seeks to add a 0.25% (one-twelfth of 3%) of the annualized merit increase to Staff's adjustment, which would increase payroll expense by $96,868 and increase employee benefit expense by $30,456.[217]

86. The Commission rejects Atmos' approach to calculating a full 12 months of merit increase because it multiplies the full year of payroll expense by 1.5%, when half of the months in

[212] Staff Brief, ¶ 150.
[213] *Id.*, ¶ 151.
[214] Atmos Brief, ¶ 60.
[215] CURB Brief, ¶ 92; Crane Direct, Schedule ACC-8.
[216] Atmos Brief, ¶ 60
[217] *Id.*

the test year already includes the potential 3.0% merit increase.[218] Additionally, Atmos's approach assumes that there are no hires, fires, or promotions since the test year. Staff's update, ending August 31, 2019, includes 12 months of actual known and measurable payroll expense that contains the changes to the test year payroll Atmos attempted to include in the cost of service. Accordingly, the Commission accepts Staff's adjustments.

87. Staff proposes decreasing operating expense by $202,065, by updating Atmos's benefits expense to account for actual expenses incurred by Atmos for the 12-months ending August 31, 2019.[219] CURB proposes a $26,847 increase in employee benefit expenses.[220] Atmos disputes CURB's adjustment to employee benefit expenses. The Commission rejects Atmos's adjustment because it is not based on actual known and measurable amounts, and is merely an estimate of how benefits expenses can change with changes to payroll expenses. Therefore, the Commission accepts Staff's adjustment which relies on known and measurable information, and more closely match Atmos's current cost of service.

Lobbying/Membership dues/Meals & Entertainment/SERP expenses

88. CURB asserts certain activities are not necessary for the provision of safe and adequate service and seeks to disallow up to 50% American Gas Association (AGA) dues expense not related to lobbying,[221] 50% of Atmos' request for meals and entertainment expenses not deducted from taxes,[222] and 100% of Atmos's supplemental executive retirement plan (SERP) expenses.[223] Staff does not contest Atmos's expenses in these areas. While K.S.A. 66-1,206(a) allows the Commission to disallow 50% of utility dues, donations and contributions to charitable,

[218] Staff Brief, ¶ 154.
[219] *Id.*, ¶ 157.
[220] Crane Direct, Schedule ACC-10.
[221] Atmos Brief, ¶ 65.
[222] CURB Brief, ¶ 100.
[223] Crane Direct, Schedule ACC-11.

civic and social organizations and entities, and not specific dues, donations and contributions which are found unreasonable or inappropriate, the Commission does not find that CURB has shown the challenged expenses are unreasonable or inappropriate. In addition, the Commission has already accepted Staff's adjustments to miscellaneous expenses, which removes various expenses that do not provide direct ratepayer benefits. Therefore, the Commission denies CURB's proposed adjustments for lobbying, membership dues, meals and entertainment, or SERP expenses.

Abbreviated Rate Case

89. Pursuant to K.A.R. 82-1-231(b)(3)(A), Atmos seeks to file an abbreviated rate case within 12 months of this Order.[224] The abbreviated rate case would be designed to update rates to reflect new non-growth revenue infrastructure investment that is not included in rates and is not eligible for recovery under Atmos's GSRS tariff or SIP tariff but will have been placed in service by the time the audit of the abbreviated filing is completed.[225] Staff argues because Atmos will fully recover its increase in safety, reliability, and GSRS-eligible Net Plant through the GSRS and SIP mechanism, an abbreviated rate case is unwarranted.[226] The Commission agrees. As discussed in paragraph 39, the Commission would approve a SIP with additional conditions, including a three-year rate moratorium. If Atmos elects to make a compliance filing with a SIP tariff, it will render its request for an abbreviated rate case moot. In the event that Atmos does not make a compliance filing, its request for an abbreviated rate case is denied.

90. Atmos requested a net revenue increase of $7,163,131. The Commission finds Atmos is entitled to a net revenue reduction of $223,953. Under Atmos's original request, the

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[224] Application, ¶ 9.
[225] *Id.*
[226] Staff Brief, ¶ 84.

average residential ratepayer's bill would have increased by $4.33 in winter months and $3.41 in summer months.[227] But under this Order, the average residential ratepayer's bill will only increase by $0.35 in winter months and $0.11 in summer months.[228] The slight increase in residential ratepayer's bills is designed to reduce the continued subsidization of the residential class, which represents about 72% of total base rate revenue collected,[229] by the commercial sales class, and bring the classes closer to parity.[230]

91. The Commission considered all of the evidence in the record and considered the positions and arguments of all the parties in making its findings and conclusions. The failure to specifically address a particular item, position, or argument offered into evidence does not indicate it was not considered by the Commission.

THEREFORE, THE COMMISSION ORDERS:

A. The Commission sets Atmos's overall revenue requirement based on an operating income of $14,780,974, a rate base of $242,313,526, a return on equity of 9.1%, and an overall rate of return of 7.03%. The Commission approves a base rate revenue requirement increase of $3,067,466. After accounting for the reduction of the GSRS charge by $3,291,419, the net impact on customers of this Order is a revenue requirement reduction of $223,953.[231]

B. Atmos's proposed SIP mechanism is rejected, but the Commission would approve a SIP tariff for a SIP with a $35 million cap over five years, and with an annual surcharge, three-year rate moratorium, and is available only after Atmos exhausts its GSRS, if sought by Atmos.

[227] *See* Direct Testimony of Paul H. Raab (Raab Direct), June 28, 2018, p. 24.
[228] *See* Glass Direct, p. 26, Table 11.
[229] *Id.*, p. 19.
[230] *See id.*, p. 20; Raab Direct, p. 26.
[231] *See* Attachment A to the Order for an overview calculation of the revenue requirement increase.

C. Pursuant to K.S.A. 77-415(b), paragraph 46 of this Order is designated precedential. Accordingly, this Order will be included in the Commission's index of precedential orders, published on the Commission's website.

D. The corresponding rate increases shall be set in accordance with the Commission's Final Revenue Requirement Calculation, attached as Attachment A. The Commission's Final Revenue Requirement Calculation is based on Staff's filed schedules and revised in accordance with the Commission's decisions on the contested issues.

E. Any party may file and serve a petition for reconsideration pursuant to the requirements and time limits established by K.S.A. 77-529(a)(1).[232]

F. The Commission retains jurisdiction over the subject matter and parties to enter further orders as it deems necessary.

BY THE COMMISSION IT IS SO ORDERED.

Duffy, Chair; Albrecht, Commissioner; Keen, Commissioner

Dated: 02/24/2020

Lynn M. Retz

Lynn M. Retz
Executive Director

BGF

[232] K.S.A. 66-118b; K.S.A. 77-503(c); K.S.A. 77-531(b).

ATMOS ENERGY
COMMISSION ORDER
SUMMARY OF ADJUSTMENTS TO RATE BASE
FOR THE TEST YEAR ENDED MARCH 31, 2019

	DESCRIPTION	AMOUNT
RATE BASE PER APPLICANT		248,709,964
	ADJUSTMENTS TO RATE BASE ACCEPTED BY THE COMMISSION	
STAFF-1	Removal of Construction Work in Progress	(11,110,143)
STAFF-2	Update of Plant to August 31, 2019	7,840,069
STAFF-3	Update of Accumulated Depreciation to August 31, 2019	(2,161,428)
STAFF-4	Update of Accumulated Deferred Income Tax to August 31, 2019	(1,081,792)
STAFF-5	Update Customer Deposits to August 31, 2019	40,502
STAFF-6	Update Prepayments to a 13 month average ending to August 31, 2019	62,178
STAFF-7	Update Storage Gas balances to August 31, 2019	527,781
STAFF-8	Update certain tax items from the Company's estimated to actuals	(513,605)
TOTAL ADJUSTMENTS TO RATE BASE		(6,396,438)
COMMISSION ADOPTED RATE BASE		242,313,526

ATMOS ENERGY
COMMISSION ORDER
SUMMARY OF ADJUSTMENTS TO OPERATING INCOME
FOR THE TEST YEAR ENDED MARCH 31, 2019

	DESCRIPTION	AMOUNT
OPERATING INCOME PER APPLICANT		12,798,524
ADJUSTMENTS TO OPERATING INCOME ACCEPTED BY THE COMMISSION		
STAFF-1	Payroll expense for 12 months ending August 31, 2019	(75,433)
STAFF-2	Payroll tax update (See Adj. No. 1)	49,345
STAFF-3	Benefit expense for 12 months ending August 31, 2019	202,065
STAFF-4	Equity Compensation Expense	559,029
STAFF-5	Depreciation Expense--Staff Depreciation Rates	2,413,239
STAFF-6	Bad Debt Expense	26,358
STAFF-7	Interest on Customer Deposits	1,102
STAFF-8	Advertising	9,605
STAFF-9	Donations	74,772
STAFF-10	Kansas Corporation Commission Assessment fees	8,070
STAFF-11	Miscellanous expenses	46,123
STAFF-12	Rate Case Expense	(323,667)
STAFF-13	Pension Expense Update through August 31, 2019	65,132
STAFF-14	OPEB Update through August 31, 2019	68,917
STAFF-15	Pension and Post Retirement tracker balances	(98,094)
STAFF-16	Lease Expense	(76,517)
STAFF-17	Weather Normalization	(466,047)
STAFF-18	Customer Annualization	119,039
STAFF-19	Income Tax Expense	(620,588)
TOTAL ADJUSTMENTS TO OPERATING INCOME		1,982,449
OPERATING INCOME ADOPTED BY THE COMMISSION		14,780,973

ATMOS ENERGY
COMMISSION ORDER
REVENUE REQUIREMENT CALCULATION
FOR THE TEST YEAR ENDED MARCH 31, 2019

LINE NO.	DESCRIPTION	AMOUNT
1	RATE BASE AS ADOPTED	242,313,526
2	RATE OF RETURN ON RATE BASE AS ADOPTED (1)	7.03%
3	NET OPERATING INCOME REQUIRED	17,034,641
4	PROFORMA OPERATING INCOME	14,780,973
5	DIFFERENCE	2,253,668
6	INCOME TAX FACTOR	0.734700
7	PROFORMA REVENUE INCREASE / (DECREASE)	3,067,466

(1) COMMISSION APPROVED CAPITAL STRUCTURE:

DESCRIPTION	CAPITALIZATION RATIO	COST OF CAPITAL	WEIGHTED COST OF CAPITAL
**********************	***********	******	*********
LONG TERM DEBT	43.68%	4.37%	1.91%
EQUITY	56.32%	9.10%	5.12%
TOTALS	100.00%		7.03%

CERTIFICATE OF SERVICE

19-ATMG-525-RTS

I, the undersigned, certify that a true copy of the attached Order has been served to the following by means of electronic service on 02/24/2020.

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CERTIFICATE OF SERVICE

19-ATMG-525-RTS

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/S/ DeeAnn Shupe
DeeAnn Shupe

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1142

In the Matter of:	)	
	)	**DIRECT TESTIMONY OF**
Application of Duke Energy Progress, LLC	)	**LAURA A. BATEMAN**
For Adjustment of Rates and Charges	)	**FOR DUKE ENERGY**
Applicable to Electric Service in North Carolina	)	**PROGRESS, LLC**

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND CURRENT POSITION.

A. My name is Laura A. Bateman and my business address is 411 Fayetteville Street, Raleigh, North Carolina. I am a Director of Rates & Regulatory Planning, employed by Duke Energy Carolinas, LLC, testifying on behalf of Duke Energy Progress, LLC ("DE Progress" or the "Company").

Q. WHAT ARE YOUR RESPONSIBILITIES IN THIS ROLE?

A. I have responsibility for the development of cost of service studies and quarterly financial reports for both DE Progress and Duke Energy Carolinas, LLC ("DE Carolinas").

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I obtained a Bachelor's degree from the University of Massachusetts at Amherst in 1994 and a Master of Business Administration degree from the University of North Carolina at Chapel Hill in 2003. Since 2003, I have worked for the Company in a variety of roles in Risk Management, Treasury, and Regulatory. I have been in the Rates & Regulatory Strategy group since 2007.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION IN CONNECTION WITH YOUR CURRENT RESPONSIBILITIES?

A. Yes. I have testified before this Commission in connection with Duke Energy Progress' general rate case proceeding in Docket No. E-2, Sub 1023. I have also testified before this Commission or submitted written testimony in *The*

Investigation of Proposed Net Metering Rule (Docket No. E-100, Sub 83), *Standards for Electric Utilities Relating to IRP, Rate Design Modifications to Promote Energy Efficiency Investments, Smart Grid Investments & Smart Grid Information Per Independence/Security Act 2007* (Docket No. E-100, Sub 123), and *Application for Approval of DSM and Energy Efficiency Cost Recovery Rider (*Docket No. E-2, Sub 931).

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to discuss the results of DE Progress' operations under present rates on the basis of an adjusted historical Test Period using the twelve month period ending December 31, 2016 (the "Test Period"). I discuss the additional revenue required as a result of the cost of service based on the pro forma costs in the test period. I discuss several pro forma adjustments to the Company's Test Period operating expenses and rate base. I explain the accounting requests the Company is making regarding deferral of costs for both certain purchased power expense and coal ash costs that are either over or under the levels set in this proceeding, and related to establishing regulatory assets for the unrecovered costs of the Asheville coal plant upon retirement and for meters retired as part of the Company's Advanced Metering Infrastructure ("AMI") deployment program. Finally, I discuss the prudency of the costs included in this request related to four solar generation facilities owned by DE Progress.

Q. DOES YOUR TESTIMONY INCLUDE ANY EXHIBITS?

A. Yes, I have included two exhibits. Bateman Exhibit 1 sets forth the operating results under current and proposed rates. Bateman Exhibit 2 summarizes the cost of service results and the proposed increases for the North Carolina retail jurisdiction by customer class.

Q. WERE THESE EXHIBITS PREPARED BY YOU OR UNDER YOUR DIRECTION AND SUPERVISION?

A. Bateman Exhibits 1 and 2 were prepared under my supervision.

Q. DID YOU PROVIDE ANY INFORMATION INCLUDED IN THE APPLICATION?

A. Yes, I provided the cost of service studies included in Item 45 of the Form E-1, and the pro forma adjustment work papers included in Item 10 of the Form E-1, filed with the Company's Application for Increase to Existing Rates and Charges (the "Application").

II. <u>DETERMINING THE REVENUE REQUIREMENT</u>

Q. WHAT IS THE REVENUE REQUIREMENT AND HOW DID DUKE ENERGY PROGRESS CALCULATE IT?

A. The revenue requirement represents the annual revenues necessary for the Company to recover its operating expenses (including depreciation and taxes) and provide its investors with a fair rate of return on the investment in rate base. DE Progress determined its operating costs by identifying depreciation and amortization expense, operations and maintenance expense ("O&M"), fuel expense, taxes, and other expenses charged to utility operations and recorded in its accounting records for the Test Period. The amount of rate base is determined by adding the year-end balances in the Company's accounting records of plant in service, accumulated depreciation, materials and supplies (including fuel inventory) and components of working capital less deferred taxes and operating reserves, including certain regulatory assets and liabilities. Next, a cost of service study is prepared that allocates and assigns these actual Company operating costs and rate base amounts to determine the per book cost for providing electric service to the Company's North Carolina retail operations. The cost of service studies, filed as Item 45 of DE Progress' Form E-1, were reviewed by Witness Hager and she describes the allocation process and methodologies used by the Company in this proceeding within her testimony.

Following the cost of service study, the actual Test Period expense and rate base levels, as allocated to the North Carolina retail operations, were adjusted for known and measurable changes, as described below and in the testimony of Witnesses Wheeler and McGee. DE Progress made certain accounting and pro forma adjustments to actual operating income and rate base for the Test Period to reflect known and measurable changes in order to (i) normalize for abnormal events; (ii) annualize part year recurring effects to a full year effect; and, (iii) show actual changes in costs, revenues or the cost of the Company's property used and useful, or to be used and useful within a reasonable time after the Test Period, in providing service.

After the determination of operating expenses and rate base for the Company's North Carolina retail operations, rate base is split between the

Company's debt investors and equity investors using the Company's proposed capital structure of 53 percent equity and 47 percent debt. Then, the annual cost of debt is calculated. The income available for the Company's equity investors is determined by subtracting the cost of debt from the operating income produced by the current revenues received from North Carolina retail customers less operating expenses. Finally, the required revenue increase necessary to produce the requested equity return on the amount of the equity invested in rate base is determined.

Bateman Exhibit 1 sets forth the rate base, operating revenues, operating expenses, and operating income the Company earned during the Test Period and the adjusted amounts the Company supports for use in calculating its proposed revenue requirement. In my Exhibit 1, I have indicated by asterisk the items the Company plans to update in this proceeding.

III. RESULTS OF OPERATIONS UNDER EXISTING AND PROPOSED RATES

Q. PLEASE DESCRIBE BATEMAN EXHIBIT 1 TO YOUR TESTIMONY.

A. Bateman Exhibit 1 sets forth the operating results and data required by Commission Rule R1-17(b) regarding operating income, calculation of additional revenue requirement, accounting adjustments, and rate base information. The operating results are based on the Test Period noted above, using the twelve months ending December 31, 2016, with appropriate adjustments. This information is also shown on Pages 1 through 4d of Exhibit C of the Company's Application.

Q. PLEASE EXPLAIN WHAT IS PRESENTED ON PAGE 1 OF BATEMAN EXHIBIT 1 ENTITLED "OPERATING INCOME FROM ELECTRIC OPERATIONS."

A. Page 1 summarizes the Company's operating income from electric operations for the Test Period both for total Company operations and North Carolina retail operations before the necessary accounting adjustments. It also shows the Company's operating income from electric operations for North Carolina retail operations after the necessary accounting adjustments and the rate of return on North Carolina retail rate base the Company would earn in the Test Period after reflecting those adjustments.

Column 1 and 2 set forth the actual operating revenues, expenses and rate base from the per book cost of service study (Form E-1, Item 45a) for the Company and for its North Carolina retail jurisdiction, respectively.

Column 3 summarizes the accounting adjustments allocated to North Carolina retail operations necessary to reflect a representative level of operating income and rate base based on known changes in costs. These adjustments are shown on Bateman Exhibit 1, page 3 and are explained later in my testimony.

Column 4 shows adjusted North Carolina retail operations.

Column 5, Line 1 shows the additional revenue requested in this proceeding of $477.5 million. This is the increase in revenues justified as necessary to cover the Company's cost of service, including a rate of return on members' equity of 10.75 percent as discussed in the testimony of Witness Hevert. Column 5 also shows the effect of the revenue increase on the

Commission regulatory fee, uncollectibles expense, income taxes, and cash working capital.

Column 6, Line 11 shows adjusted operating income after the proposed increase in revenues. Column 6, Line 12 shows the adjusted retail rate base. Dividing operating income by rate base produces the 7.66 percent overall rate of return that the Company is justifying in this case, as shown on Column 6, Line 13.

Q. PLEASE EXPLAIN WHAT IS PRESENTED ON PAGE 2 OF BATEMAN EXHIBIT 1 ENTITLED "CALCULATION OF ADDITIONAL REVENUE REQUIREMENT."

A. Page 2 sets forth the calculation of the additional revenue requirement necessary to produce a 10.75 percent rate of return on members' equity using the format required by Commission Rule R1-17(b)(9)e. To develop this figure, the North Carolina retail rate base was allocated to its capital source components of long-term debt and members' equity. This allocation was based on the capitalization ratios of 47 percent long-term debt and 53 percent members' equity which is the Company's targeted capital structure that this Commission found just and reasonable in its *Order Granting General Rate Increase*, issued in Docket No. E-2, Sub 1023 ("2013 Rate Case Order"), in the Company's last general rate case. Witness DeMay also comments in his testimony that the 53 percent equity ratio will help enable access to capital at reasonable rates.

The amount of operating income needed to cover interest applicable to North Carolina retail rate base was computed using the embedded cost of long-term debt rate. This amount is shown in Columns 4 and 7 on Line 1. Operating income needed to cover interest, shown in Columns 5 and 8 on Line 1, was deducted from total operating income shown in Column 5 on Line 3, to derive operating income remaining for members' equity at present rates as shown in Column 5 on Line 2.

Applying the 10.75 percent rate of return on members' equity to that portion of the North Carolina retail rate base financed by members' equity, shown in Column 6, Line 2 produces the operating income requirement for members' equity as shown in Column 8, Line 2.

The total operating income requirement shown in Column 8, Line 3 is the sum of the requirements for long-term debt and members' equity. Comparing the operating income requirement to the operating income before the proposed increase in Column 5, Line 3 results in the additional operating income requirement shown in Column 8, Line 4. To realize this additional operating income, the Company must also collect in revenues the increase the NCUC regulatory fee at a rate of 0.14 percent, uncollectible expense at a rate of 0.18 percent, state and federal income taxes at a composite rate of 37.06 percent, and the return on cash working capital requirements. The additional operating income requirement and the additional taxes and fees produces an additional revenue requirement of $477.5 million.

Q. HOW DO YOU PROPOSE TO ALLOCATE THIS ADDITIONAL REVENUE REQUIREMENT AMONG THE CLASSES?

A. Bateman Exhibit 2 shows how the additional revenue requirement is spread among the classes and how the target revenue requirements for rate design are established. The rate increase shown in the exhibit has been allocated to the rate classes on the basis of rate base, and then combined with an additional increase or decrease at the customer class level that results in a 25 percent reduction in each class's variance from the overall average rate of return. This additional increase or decrease at the customer class level nets to $0 for the North Carolina retail jurisdiction in total, but brings the customer classes closer to the average rate of return, and is an appropriate way to gradually bring rate classes closer to rate parity over time. This approach is consistent with the approaches in the last general rate proceedings for both DE Carolinas and DE Progress.

Q. PLEASE EXPLAIN THE ADJUSTMENTS THAT ARE NEEDED TO DEVELOP THE TARGET REVENUE INCREASES USED IN THE RATE DESIGN PROCESS?

A. The adjusted cost of service normalizes the test period revenue for weather impacts and customer growth as described in Section IV of my testimony. As a result, the Proposed Rate Increase shown in Bateman Exhibit 2, Column I, reflects normal weather and customer growth. However, in the rate design process, the revenue increase is spread over test period billing determinants (kWh, kW, etc.) to determine the rate increases. If the revenue increase is adjusted for weather and growth, but the billing determinants are not, in an extreme weather test period, the kWh would be abnormally high, resulting in a rate per kWh that is too low. Conversely, in a mild weather test period, the kWh would be abnormally low, resulting in a rate per kWh that is too high. For this particular Test Period, we also adjusted revenues for the impacts of Hurricane Matthew, as described in Section IV of my testimony. The billing determinents during the test period were unusually low due to power outages resulting from Hurricane Matthew. Absent an adjustment, dividing the target revenues by abnormally low billing determinents in the rate design process, would lead to rates per kWh that are too high. The adjustments made on Page 2, Columns N through Q, have an equivalent effect of adjusting the test period billing determinants for weather, customer growth, and the impacts of Hurricane Matthew, and therefore, are appropriate in developing the target revenues to be used in the rate design process. The proposed revenue increases by rate class on Bateman Exhibit 2, Page 2, Column S, were provided to Witness Wheeler and were used in the development of the rate design used in this case.

IV. ACCOUNTING AND PRO FORMA ADJUSTMENTS

Q. PLEASE EXPLAIN PAGE 3 OF BATEMAN EXHIBIT 1 CAPTIONED "DETAIL OF ACCOUNTING ADJUSTMENTS-NORTH CAROLINA RETAIL."

A. Page 3 sets forth the individual accounting and pro forma adjustments to operating revenues and expenses, including the income tax effects for North Carolina retail electric operations, that were shown in total on Page 1 of Bateman Exhibit 1 in Column 3. The totals of the columns shown on Line 36 of Page 3 are the amounts carried forward to Column 3 of Page 1 of Bateman Exhibit 1.

Q. PLEASE LIST THESE ACCOUNTING AND PRO FORMA ADJUSTMENTS.

A. The accounting and pro forma adjustments that were made by the Company are as follows (the chart below indicates which witness is sponsoring each adjustment):

ADJUSTMENTS TO OPERATING REVENUES AND EXPENSES (Page 3 of Bateman Exhibit 1)		
Line No.	**Adjustment Title**	**Witness**
1	Annualize retail revenues for current rates	Wheeler
2	Adjust other revenue	Wheeler
3	Normalize for weather	Bateman

ADJUSTMENTS TO OPERATING REVENUES AND EXPENSES		
(Page 3 of Bateman Exhibit 1)		
Line No.	**Adjustment Title**	**Witness**
4	Annualize revenues for customer growth	Bateman
5	Eliminate unbilled revenues	Bateman
6	Update fuel costs to approved rate	McGee
7	Eliminate costs recovered through non-fuel riders	Bateman
8	Annualize depreciation on year end plant balances	Bateman
9	Annualize property taxes on year end plant balances	Bateman
10	Adjust for new depreciation rates	Bateman
11	Adjust for post test year additions to plant in service	Bateman
12	Adjust for Asheville base load CWIP	Bateman
13	Adjust for transmission merger mitigation project	Bateman
14	Adjust nuclear decommissioning expense	Bateman
15	Adjust reserve for end of life nuclear costs	Bateman
16	Adjust coal inventory	Bateman
17	Adjust for Harris COLA	Bateman
18	Amortize deferred environmental costs	Bateman
19	Adjust for ongoing environmental costs	Bateman
20	Normalize for storm costs	Bateman
21	Annualize O&M non-labor expenses	Bateman
22	Normalize O&M labor expenses	Bateman

ADJUSTMENTS TO OPERATING REVENUES AND EXPENSES (Page 3 of Bateman Exhibit 1)		
Line No.	**Adjustment Title**	**Witness**
23	Update benefit costs	Bateman
24	Levelize nuclear refueling outage costs	Bateman
25	Amortize rate case costs	Bateman
26	Adjust aviation expenses	Bateman
27	Adjust for change in NCUC regulatory fee	Bateman
28	Adjust purchased power	Bateman
29	Adjust O&M for executive compensation	Bateman
30	Adjust for Customer Connect	Bateman
31	Adjust for Long Term Service Agreements	Bateman
32	Adjust for Deferred Tax Liability	Bateman
33	Adjust for North Carolina tax rate change	Bateman
34	Synchronize interest expense with end of period rate base	Bateman
35	Adjust cash working capital for present revenue annualized and proposed revenue	Bateman

Q. IN CALCULATING THE TOTAL REVENUE REQUIREMENT IN THIS PROCEEDING, DID YOU REVIEW EACH OF THE ACCOUNTING AND PRO FORMA ADJUSTMENTS?

A. Yes, I did.

Q. IN YOUR OPINION, DO THESE ACCOUNTING AND PRO FORMA ADJUSTMENTS REFLECT KNOWN AND MEASURABLE CHANGES TO THE COMPANY'S TEST PERIOD OPERATING EXPENSES, REVENUES, AND RATE BASE?

A. Yes. The adjustments set forth on page 3 of Bateman Exhibit 1, as more fully supported below and in the testimony of Witnesses McGee and Wheeler, reflect known and measurable changes to the Company's Test Period revenues, expenses, and rate base.

Q. PLEASE DESCRIBE THE PRO FORMA ADJUSTMENTS YOU ARE SUPPORTING.

A. The following are descriptions of the pro forma adjustments:

1. Annualize retail revenues for current rates

This adjustment annualizes revenue based on the rates in effect at the time of the application, excluding the Renewable Energy and Energy Efficiency Portfolio Standard ("REPS") rider, and removes revenues recovered through the Demand Side Management/Energy Efficiency ("DSM/EE") rider, the Joint Agency Acquisition Rider ("JAAR"), and the fuel Experience Modification Factor ("EMF") rates. This adjustment is discussed in more detail in the testimony of Witness Wheeler. The revenues recovered through the REPS rider are removed in Adjustment Line 7.

2. Adjust other revenue

This adjustment adjusts other revenue to reflect proposed changes to rates in the Company's Service Regulations and Rider MROP. The proposed changes are discussed further in Witness Wheeler's testimony.

3. Normalize for weather

This adjustment adjusts revenue to normalize for the impacts of weather. The kWh weather adjustment was developed based on a 30-year history of weather. This kWh adjustment was then multiplied by an average rate for each class to derive the adjustment to revenue. The average rate excludes the rates for the DSM/EE rider, REPS rider, JAAR and fuel EMF. However, since the rate includes the base fuel proposed in this case, an adjustment is also made to fuel expense to reflect the weather adjustment.

4. Customer Growth Adjustment

This adjustment annualizes revenue to reflect expected changes in the number of customers and usage per customer during the test period. This change in consumption was then multiplied by an average rate for each class to derive the adjustment to revenue. The average rate excludes the rates for the DSM/EE rider, REPS rider, JAAR and fuel EMF. However, since the rate includes the base fuel proposed in this case, an adjustment is also made to fuel expense to reflect the annualized change in kWh.

5. Eliminate unbilled revenues

This adjustment eliminates unbilled revenue and related taxes recorded by the Company in the test period.

6. Update fuel costs to approved rate and other fuel-related adjustments

This adjustment adjusts fuel clause expense during the test period to match the fuel clause revenues included in Adjustment Line 1. By matching the expenses to the revenue, the adjustment ensures that no increase is requested in this proceeding related to fuel and fuel-related expenses that are recoverable through the fuel clause. This adjustment is described in more detail in Witness McGee's testimony.

7. Eliminate costs recovered through non-fuel riders

This adjustment removes expense and rate base items recovered through the DSM/EE rider, the REPS rider and the JAAR. The revenues recovered through the REPS rider are also removed in this adjustment. The revenues recovered through the DSM/EE rider and the JAAR are excluded in Adjustment Line 1. The revenues, expenses and rate base items, if applicable, in each of these riders are reviewed each year in annual proceedings and should not impact the increase requested in this proceeding.

8. Annualize depreciation on year end plant balances

This adjustment reflects the annualization of depreciation expense using the current depreciation rates applied to the end of the Test Period level of plant in service. During the Test Period, the Company recorded depreciation for plant additions from the point in time when they went into service. This adjustment annualizes depreciation expenses to reflect a full year level of depreciation on plant in service as of the end of the Test Period using the depreciation rates that were in effect during the Test Period.

9. Annualize property taxes on year end plant balances

This adjustment annualizes Test Period property taxes on plant in service at December 31, 2016. Property taxes expensed in the calendar year 2016 were assessed based on property balances at the end of 2015. Likewise, property taxes expensed in the calendar year 2017 will be assessed based on property balances at the end of 2016. This adjustment increases property tax expense in the Test Period to reflect an annual level of expense for property taxes based on the end of the Test Period level of plant investment.

10. Adjust depreciation expense for new depreciation rates

This adjustment adjusts the annualized depreciation expense to reflect the new depreciation rates based on the updated depreciation study prepared by Gannett Fleming and discussed and supported by Witness Doss. Implementing the new depreciation rates will result in an increase to depreciation expense of approximately $132.1 million on a system basis, or $67.6 million on a North Carolina retail basis. The adjustment also increases depreciation reserves by one year's worth of the depreciation expense adjustment.

Originally, the depreciation consultant had proposed new depreciation rates that would fully depreciate the Asheville coal plant by its expected retirement date in 2020. In order, to mitigate the impact on customers in this case, DE Progress asked the consultant to adjust the rates to reflect a recovery of the remaining net book value of the Asheville coal plant over a ten-year period, similar to the treatment of other coal plants that were retired early in DE Progress' prior depreciation study. Since under this approach, the net book value of the plant will not be fully recovered at the time of retirement, the Company is requesting permission to establish a regulatory asset at the time of the plant's retirement for the remaining net book value and the ability to continue amortizing the costs over the remaining portion of the ten-year period at that time. We also request permission to defer to this regulatory asset any costs related to obsolete inventory, net of salvage, at the time of retirement.

The Company also requests permission to establish a regulatory asset for meters that will be replaced under the Company's Advanced Metering Infrastructure ("AMI") deployment program. The depreciation study recovers the remaining net book value of these assets over three years, which is the expected deployment period for the program. Therefore, we would expect the balance in the regulatory asset to be $0 at the end of this period. However, as the individual meters are replaced, the Company will need to move the retired meter balance out of Electric Plant in Service and Accumulated Provision for Depreciation of Electric Utility Plant (Accounts 101 and 108) and into the regulatory asset account, until the remaining balances are fully depreciated.

In addition to the other updates in the depreciation study, the costs associated with closing coal ash ponds have been removed from the depreciation rates. Currently, the Company is collecting costs associated with the closure of coal ash ponds in the cost of removal portion of its depreciation rates. These cost of removal rates were based on estimated closure costs included in the 2012 dismantlement studies prepared for the Company by Burns & McDonnell, a third party engineering firm. These cost estimates were prepared prior to the enactment of the North Carolina Coal Ash Management Act of 2014 ("CAMA") and the Environmental Protection Agency's Coal Combustion Residual ("CCR") Rule, and were based on the industry standards and best practices recommended by the engineering consultants at the time. Since that time, CAMA and the CCR rule have significantly increased the estimated closure costs for the Company's coal ash ponds, and changed the required accounting treatment, triggering asset retirement obligation accounting. For these reasons, the coal ash pond closure costs have been removed from the depreciation rates, and are instead being requested in Adjustments 18 and 19, described later in my testimony.

11. Adjust for post test year additions to plant in service

This adjustment increases operating expenses and rate base for significant production, transmission, distribution, general and intangible plant additions the Company has incurred and will incur from the end of the Test Period through August 2017. Witnesses Gillespie, Miller, and Simpson discuss these plant additions in their testimonies.

12. Adjust for Asheville base load Construction Work in Progress ("CWIP")

This adjustment increases rate base to include CWIP for its Asheville Combined Cycle project ("ACC Project"), in accordance with North Carolina General Statute 62-133(b)(1). The ACC Project consists of two highly efficient 280 MW combined cycle natural gas-fueled electric generating units with fuel backup and is scheduled to be completed and in service by December 2019.

The ACC Project was granted a certificate in Docket No. E-2, Sub 1089. The adjustment includes in rate base the projected CWIP balance for the ACC Project as of August 31, 2017, which is $192.8 million on a system basis, or $116.8 million on a North Carolina retail basis. This increase to rate base results in an increase to the annual revenue requirement of approximately $12.9 million.

13. Adjust for transmission merger mitigation project

This adjustment includes the costs related to the Greenville-Kinston Dupont 230 kV line. This transmission line was constructed and placed in service in 2014 in order to satisfy Federal Energy Regulatory Commission ("FERC") market mitigation requirements related to the Duke-Progress merger (Docket Nos. E-2, Sub 998 and E-7, Sub 986). However, the line was previously in the Company's 10-year site plan to be constructed and placed in service in June 2017. Ordering paragraph 10 of the Commission's June 29, 2012 order in the merger docket[1] states that the Company "shall not seek to recover from retail customers any costs associated with the Greenville-Kinston Dupont 230 kV line until the later of: (1) June 1, 2017, or (2) the actual in-service date of the line...." The line was placed in service in May 2014, and the new customer rates requested in this rate case will not go into effect until after June 1, 2017. Therefore, DE Progress is requesting to recover the costs associated with the Greenville-Kinston Dupont 230 kV line. The Company is not seeking to

[1] See the NCUC's June 29, 2012 "Order Approving Merger Subject to Regulatory Conditions and Code of Conduct" under NCUC Docket Nos. E-2, Sub 998 and E-7, Sub 986

recover costs associated with any of the other permanent transmission projects at this time.

14. Adjust nuclear decommissioning expense

This adjustment updates decommissioning expense to reflect several updates to model assumptions in the Company's 2014 decommissioning study. These updates are discussed by Witness Doss.

15. Adjust reserve for end of life nuclear costs

In its last general rate case, DE Progress established reserves for end-of-life costs associated with nuclear materials and supplies and with nuclear fuel. This adjustment adjusts the test period amortization expense to reflect updated estimates of the end-of-life costs.

16. Adjust coal inventory

This adjustment reduces the Company's actual coal inventory at the end of the Test Period to reflect a targeted 40-day full load burn for each of the coal generating plants. This change in coal inventory for the North Carolina retail jurisdiction is shown on Bateman Exhibit 1, Page 4c, Line 1, Column 3.

17. Adjust for Harris Combined Operating and Construction License Application ("COLA")

In Docket No. E-2 Sub 1035, the Company petitioned for approval to defer certain capital costs incurred for the development of Units 2 and 3 of the Harris Nuclear Station. The Commission approved the Company's petition on September 16, 2013. Witness Fallon discusses these costs in more detail. The total deferred costs are $45.3 million on a North Carolina retail basis ($70.3

million on a system basis.) This adjustment amortizes the deferred balance over a 5-year period, resulting in an annual revenue requirement of $9.1 million. Consistent with the Commission's order, the deferred balance is excluded from rate base and no return is included in this request.

18. Amortize deferred environmental costs

In Docket Nos. E-2, Sub 1103 and E-7, Sub 1110, the Company petitioned the Commission for authority to defer in a regulatory asset account certain costs incurred in connection with compliance with federal and state environmental requirements as it relates to Coal Combustion Residuals ("CCRs" or "coal ash"). The nature of these costs are described in more detail in Witness Kerin's testimony. No fines, penalties, or costs on which DE Progress has agreed to forego recovery are included in the deferral. This adjustment amortizes the deferred costs over a 5-year period. While the costs to comply with CAMA and the CCR Rule are largely duplicative, there are a small portion of the costs that the Company has determined are specific to CAMA, unique to North Carolina and appropriate for direct assignment to North Carolina, as discussed by Witness Kerin. In the deferral calculation, for the CAMA-specific costs, the adjustment first separates out the portion allocable to the wholesale jurisdiction and then direct assigns the retail portion to North Carolina retail. The deferral calculation also nets the total compliance costs allocated to North Carolina retail with the cost of removal that is being collected from customers in current rates for the active and retired coal ash ponds. Both the compliance costs and the cost of removal are based on actuals as of the end of the test period plus a projection through August 31, 2017. The total system spend on coal ash pond closure costs during this period for DE Progress is $482.7 million ($98.7 million in 2015, $212.7 million in 2016, and $171.3 million in the 2017 projected period). After applying allocations factors, netting with the cost of removal and incorporating the return on the deferred costs, the expected deferred balance as of August 31, 2017, on a North Carolina retail basis is $260.3 million. Over the 5-year amortization period, the annual amortization expense is $52.1 million. When added together with the net of tax return on the unamortized balance of $14.4 million, the total revenue requirement requested in this case for deferred coal ash pond closure costs is $66.5 million. Of the $260.3 million expected deferred balance, $15.1 million ($13.8 million of spend and $1.3 million of return) is related to 2017 beneficial reuse projected costs. While these amounts are included in this request, we believe these costs are more appropriately recovered through the annual fuel rider as discussed by Witness McGee. If the Commission approves the fuel rider treatment requested by Witness McGee, we would remove $15.1 million from the deferred balance in this adjustment.

19. Adjust for ongoing environmental costs

This adjustment increases O&M to reflect the expected ongoing annual level of expenses the Company will incur in connection with compliance with federal and state environmental requirements related to closing coal ash ponds. These costs are described in more detail in the Company's deferral request in Docket Nos. E-2, Sub 1103 and E-7, Sub 1110, and in the testimony of Witness Kerin. As with Adjustment 18, no fines, penalties, or costs on which DE Progress has agreed to forego recovery are included in this adjustment. The expected ongoing level of O&M is based on the Company's actual spend on coal ash during the test period, which was $212.7 million on a system basis, or $129.1 million on a North Carolina retail basis. Since the test period costs were deferred, the adjustment removes the deferral to reflect the ongoing expected level. The Company is also requesting permission to establish a regulatory asset/liability and defer to this account the North Carolina retail portion of annual costs over or under the amount established in this proceeding. This accounting mechanism will ensure that the Company only recover from customers its actual level of spending related to coal ash. In addition, since the amortization proposed in Adjustment 18 only includes deferred costs through August 31, 2017, the Company requests to defer to the regulatory asset the coal ash spend incurred after that date, but before new rates from this proceeding are effective.

20. Normalize for storm costs

This pro forma adjustment normalizes storm restoration costs to an average level of costs the Company has experienced over the last ten years. This pro forma also removes any storm costs from the 10-year average calculation that were included in the Company's 2016 deferral request, and instead includes an amortization of the deferred costs over a 3-year period. During the Test Period, the Company incurred $80 million of incremental operating expense and $49 million of capital on a North Carolina retail basis related to major storm restoration efforts. In Docket No. E-2, Sub 1131, the Company requested permission to defer these incremental costs, net of the $12.7 million that is currently in customer rates. The projected balance in the deferred account as of December 31, 2017, for the incremental operating expenses, depreciation and return on the capital, and return on the deferred costs, net of the amount in rates is $79.7 million. The 3-year amortization period results in an annual amortization expense of $26.6 million. When combined with the net of tax return on the deferred balance of approximately $3.6 million, the approximate revenue requirement requested in this case for the deferred 2016 storm costs is approximately $30.2 million. Finally, the adjustment removes the abnormal impacts to billed revenue that the Company experienced due to Hurricane Matthew. The high number of customer outages due to the storm caused billed revenue to be lower than normal during this period. To normalize this impact, the net lost revenues have been added back in this adjustment.

21. Annualize non-labor O&M expenses

This adjustment annualizes Test Period operating and maintenance expenses excluding fuel, purchased power, and labor costs to reflect the change in unit costs that occurred during this period.

22. Normalize O&M labor expenses

This adjustment adjusts the wages and salaries and related employee benefits costs to reflect annual levels of costs as of April 1, 2017. This adjustment also reflects changes in related payroll taxes.

23. Update benefits costs

This adjustment updates the test period cost of labor-related benefits to match the result of an updated study performed by the Company's consultants. This adjustment also removes benefits related amortizations that will expire in 2017.

24. Levelize nuclear refueling outage costs

In the Company's last general rate case, the Commission approved an accounting mechanism that levelized certain costs related to nuclear refueling outages. This adjustment annualizes the amortization expense related to this mechanism incurred during the test period to the level experienced at the end of the test period. This adjustment is consistent with the proposed treatment for future rate cases described in Levelization Attachment 2 of the Agreement and Stipulation of Settlement approved in the Company's last general rate case (Docket E-2, Sub 1023).

25. Amortize rate case costs

This adjustment amortizes the incremental rate case costs incurred for this docket over a 5-year period.

26. Adjust aviation expenses

This adjustment removes from expense certain corporate related aviation expenses incurred in the Test Period.

27. Adjust for change in North Carolina Utilities Commission ("NCUC") regulatory fee

This adjustment removes Test Period deferrals of and annualizes the North Carolina regulatory fee at the current rate of 0.14 percent. It also amortizes over a 3-year period the deferred incremental regulatory fees due to changes in the regulatory fee rate since the last rate case.

28. Adjust purchased power

This adjustment increases the Test Period purchased power expense to include avoided cost payments to solar qualifying facilities that are expected to start producing power after the end of the test period but before August 31, 2017. Under the Public Utility Regulatory Policy Act ("PURPA") requirements, DE Progress is required to purchase power from qualifying facilities ("QFs"). The purchased power costs can vary significantly from year to year, and only in certain circumstances are the costs recoverable through the annual fuel rider. In 2015, the Company's QF purchased power costs that were not recoverable through the fuel rider were $43.6 million on a system basis. In 2016, this expense was $52.0 million. This pro forma adjustment shows we expect to add an additional $14.9 million to the system annual expense just in the first eight months of 2017. Due to the volatility of these costs and the lack of the Company's ability to control the level of the costs, DE Progress is requesting permission to establish a regulatory asset/liability and to defer to this account the North Carolina retail portion of expense over or under the level established in this proceeding. This type of accounting mechanism would allow the Company a reasonable opportunity to recover its prudently incurred QF purchased power costs.

29. Adjust O&M for executive compensation

This adjustment removes 50 percent of the compensation of the four Duke Energy executives with the highest level of compensation allocated to DE Progress in the Test Period. While the Company believes these costs are reasonable, prudent and appropriate to recover from customers, we have-for purposes of this case-made an adjustment to this item.

30. Adjust for Customer Connect

This adjustment increases Test Period O&M related to the Company's Customer Connect project. The Customer Connect project will replace the Company's current billing system and is currently planned to be placed in service in 2021. The project is described in more detail in the testimony of Witness Hunsicker. Due to the nature of the project costs, a significant amount of the spending between now and the in-service date will be O&M. This adjustment increases test period O&M by $7.7 million (from $2.9 million to $10.6 million), which is the average incremental level on a North Carolina retail basis expected over the next three years. The Company is in the process of negotiating contracts for the primary software, systems integration and change management professional services, following an extensive request for proposal process conducted in

2016. The best and final offer that resulted from this process included an estimate of incremental Company labor needed to support the scope of the contracts, and so it was used as the basis for estimating the total project cost. While the contracts are not yet finalized, we expect them to be executed shortly, at which point the Company will be committed to the project and the costs can be confirmed as known and measurable.

31. Adjust for Long-Term Service Agreements ("LTSA")

This adjustment reduces the Test Period operating and maintenance expenses to reflect a normalized level of expenses the Company will incur under the LTSAs for its combined cycle units.

32. Adjust for deferred tax liability

In its May 13, 2014 order in Docket No. M-100, Sub 138, the Commission ordered, "That excess deferred income taxes for all utilities, as appropriate, including Piedmont, Aqua, and CWSNC, shall be held in a deferred tax regulatory liability account until they can be amortized as credits (i.e., reductions) to income tax expense for ratemaking purposes in each utility's next general rate case proceeding." This adjustment amortizes the excess deferred income taxes resulting from this order over a 5-year period.

33. Adjust for North Carolina tax rate change

This adjustment adjusts income tax expense to reflect the change in the North Carolina income tax rate from 4 percent to 3 percent that was effective January 1, 2017.

34. Synchronize interest expense with end of period rate base

This adjustment adjusts income taxes for the tax effect of the annualization of interest expense reflected in the pro forma cost of service.

35. Adjust cash working capital for present revenue annualized and proposed revenue

This adjustment adjusts cash working capital to incorporate the impact of the other pro forma adjustments. It also calculates the additional cash working capital required as a result of the proposed increase in rates. The adjustment is in accordance with the Commission's March 21, 2016 order in Docket No. M-100 Sub 137, and is shown on Line 2, Columns 3 and 5, of Bateman Exhibit 1, Page 4d.

Q. PLEASE EXPLAIN WHAT IS PRESENTED ON PAGES 4 THROUGH 4d OF BATEMAN EXHIBIT 1.

A. Page 4 shows total Company and North Carolina retail components of original cost rate base. The total Company amounts and North Carolina retail components were taken from the Company's Cost of Service Study as of December 31, 2016.

Pages 4a, 4b, 4c, and 4d are details of components making up original cost rate base as of December 31, 2016 adjusted for known and measurable changes. On each of these four pages, Column 1 shows the total Company per book amounts at December 31, 2016; Column 2 reflects the amount for North Carolina retail electric operations; Column 3 sets forth the accounting adjustments allocated to North Carolina retail operations; and Column 4 reflects the North Carolina retail amounts including adjustments.

Page 4a is a summary of the Company's investment in electric plant in service as of December 31, 2016 by functional classification. Page 4b details accumulated depreciation and amortization for each of the classes of electric plant in service. The depreciation rates for each class of property are shown at the bottom of the page on Lines 8 through 17. These depreciation rates are supported by Witness Doss. Page 4c is a summary of the Company's investment in materials and supplies as of December 31, 2016 included in rate base. Page 4d reflects the working capital investment included in rate base.

V. PRUDENCY OF UTILITY-OWNED SOLAR FACILITIES

Q. PLEASE DISCUSS THE PRUDENCY OF THE COMPANY'S NEW SOLAR FACILITIES?

A. Since its last general rate case, DE Progress has placed in service four utility scale solar facilities: Fayetteville Solar, Warsaw Solar, Elm City Solar, and Camp Lejeune Solar. Certificates for Public Convenience & Necessity ("CPCNs") were received for these facilities in Docket Nos. E-2, Sub 1054, E-2, Sub 1055, E-2, Sub 1056, and E-2, Sub 1063, respectively. The Commission's orders in these dockets included two conditions. The first condition is that in REPS rider and general rate case proceedings, the Company should fix the levelized avoided cost values for cost recovery purposes at the level used in the Company's analyses in the CPCN proceedings. These avoided cost levels were shown for each facility in Williams Exhibit 6 filed in the REPS rider proceeding (Docket No. E-2, Sub 1109) on June 30, 2016. The second condition required DE Progress, in REPS rider and general rate case proceedings, to itemize the actual monetization of certain tax benefits within its calculation of the levelized revenue requirement for each facility. The levelized revenue requirement shown for each facility on Williams Exhibit 6 filed in the REPS rider proceeding incorporates the actual monetization of certain tax benefits. While the realization of certain tax credits was delayed due to the extension of federal bonus depreciation, the levelized revenue requirements for all four facilities are both below the original estimates in the CPCN proceedings and below avoided cost. Therefore, these investments should be deemed reasonable and prudent. As these facilities were all placed in service before the end of the test period, their associated costs are included in the cost of service studies and revenue requirement in this proceeding.

VI. CONCLUSION

Q. IN YOUR VIEW, ARE OPERATING EXPENSES AND RATE BASE CALCULATED BY DUKE ENERGY PROGRESS IN THIS PROCEEDING IN ACCORDANCE WITH THE PROVISIONS OF N.C. GEN. STAT. § 62-133 AND NCUC RULE R1-17?

A. Yes, they are. The Company generally experienced a level of ordinary business expenses and rate base that was reasonable and necessary to provide safe and reliable electric service to its customers for the twelve month period ending December 31, 2016. In order to meet the requirements of N.C. Gen. Stat. § 62-133 and this Commission's Rule R1-17, the actual operating expenses and rate base levels for the Test Period were adjusted for known and measurable changes as described in Section IV of my testimony and in the testimonies of Witnesses McGee and Wheeler.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

PROGRESS ENERGY CAROLINAS, INC.
DOCKET NO. E-2, SUB 1023

TESTIMONY OF JAMES G. HOARD
ON BEHALF OF THE PUBLIC STAFF
NORTH CAROLINA UTILITIES COMMISSION

February 28, 2013

Q. PLEASE STATE FOR THE RECORD YOUR NAME, ADDRESS, AND PRESENT POSITION.

My name is James G. Hoard. My business address is 430 North Salisbury Street, Raleigh, North Carolina. I am the Director of the Public Staff – Accounting Division.

Q. WHAT ARE YOUR DUTIES?

A. I am responsible for the organization, planning, and performance of the work of the Public Staff Accounting Division, which includes, among other things, the following activities: (1) the examination and analysis of testimony, exhibits, books and records, and other data presented by utilities and other parties involved in Commission proceedings; and (2) the preparation and presentation to the Commission of testimony, exhibits, and other documents in those proceedings.

Q. PLEASE DISCUSS YOUR EDUCATION AND EXPERIENCE.

A. A summary of my education and experience is attached as Appendix A.

Q, WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to support the Agreement and Stipulation of Settlement (Stipulation) between Progress Energy Carolinas, Inc. (PEC or the Company), and the Public Staff regarding certain issues related to the Company's pending application for a general rate increase. Specifically, I discuss the accounting and ratemaking adjustments to which PEC and the Public Staff have agreed as set forth on page 1 of Settlement Exhibit 1 attached to the Stipulation, which is identical to Schedule 1 of Hoard Exhibit 1 attached to my testimony. In addition, I provide testimony on the Company's proposed levelization accounting for nuclear refueling outage costs.

Q. PLEASE DISCUSS THE COMPANY'S APPLICATION FOR A RATE INCREASE.

A. In its application filed on October 12, 2012, PEC requested $386,777,000 in additional North Carolina retail revenue. On January 18, 2013, PEC filed supplemental testimony and exhibits that presented additional adjustments to the Company's cost of service. These additional adjustments increase the Company's revenue requirement by $5,376,000.

Q. PLEASE DESCRIBE THE SCOPE OF THE PUBLIC STAFF'S INVESTIGATION INTO THE COMPANY'S FILING.

A. The Public Staff's investigation included a review of the application, testimony, exhibits, and other data filed by the Company, an examination of the books and records for the test year, and a review of the Company's accounting, end-of-period, other data, and after period adjustments to test year revenue, expenses, and rate base. It also included a review of the Company's responses to the Public Staff's data requests. At the conclusion of this investigation, PEC and the Public Staff entered into settlement negotiation and on February 25, 2013, filed a Notice of Settlement in Principle indicating that they had reached settlement of certain of the issues in this proceeding, including the revenue requirement. The Agreement and Stipulation of Settlement (Stipulation) between the Public Staff and PEC is being filed contemporaneously with my testimony.

Q. WHAT BENEFITS DOES THE STIPULATION PROVIDE FOR RATEPAYERS?

A. From the perspective of the Public Staff, among the most important benefits provided by the Stipulation are as follows:

(a) A significant reduction in the Company's proposed revenue increase in this proceeding.

(b) The effective phase-in of the revenue increase in two steps over a two-year period, accomplished through the use of various riders.

(c) The avoidance of protracted litigation by the Stipulating Parties before the Commission and possibly the appellate courts.

Based on these ratepayer benefits, as well as the other provisions of the Stipulation, the Public Staff believes the Stipulation is in the public interest and should be approved.

Q. ARE THERE ANY AREAS ABOUT WHICH THE PUBLIC STAFF AND PEC DID NOT REACH AGREEMENT?

A. Yes. The Public Staff and PEC did not reach agreement regarding the cost-of-service allocation methodology or the proposed Industrial Economic Rider. Public Staff witness McLawhorn presents the Public Staff's position on those issues. The Stipulating Parties also did not reach agreement on the Company's request for deferral costs associated with the new combined cycle (CC) plant in Richmond County, as filed in Docket No. E-2, Sub 1026 (Sub 1026). If the Commission approves the Company's deferral request, the stipulated revenue requirement would be adjusted pursuant to the Commission's Order in Sub 1026. The Company has indicated that while it does not necessarily agree with the Public Staff's characterization or explanation of the various adjustments, in the interest in compromise, it is not contesting the adjustments.

Q. WOULD YOU PLEASE BRIEFLY DESCRIBE THE STIPULATED REVENUE REQUIREMENT?

A. Yes. Schedule 1 of Hoard Exhibit 1 sets forth the rate base, net operating income, return, and revenue increase amounts agreed to by the Stipulating Parties.

Based on the level of rate base, revenue, and expenses annualized and normalized at December 31, 2012, the stipulated stepped-in increase in annual operating revenue is $151,354,000, effective June 1, 2013, followed by an additional increase of $31,403,000, effective June 1, 2014, for a total increase in rates of $182,757,000, effective June 1, 2014.

Q. PLEASE DESCRIBE THE ORGANIZATION OF YOUR EXHIBITS.

A. Schedule 1 of Hoard Exhibit 1 presents a reconciliation of the difference between the Company's revenue increase of $392,153,000, including the effect of supplemental adjustments, and the stipulated increase of $182,757,000, which is net of $28,308,000, related to the Company's DSM/EE Rider. Schedule 1-1 shows the calculation of the gross revenue effect factors, which are used to determine the amounts presented on Schedule 1.[1]

Schedule 2 presents the stipulated adjusted North Carolina retail original cost rate base. The adjustments to the proposed level of rate base are summarized on Schedule 2-1.

Schedule 3 presents a statement of net operating income (NOI) for return under present rates as adjusted. Schedule 3-1 summarizes the stipulated adjustments, which are detailed on backup schedules.

[1] Page 2 of Settlement Exhibit 1 is identical to Schedule 1-2 of Hoard Exhibit 1.

Schedule 4 presents the calculation of required NOI, based on the rate base and cost of capital as stipulated.

Schedule 5 presents the calculation of the increase in operating revenue necessary to achieve the required NOI.

Hoard Exhibit 2 provides computations of my adjustments to working capital and Hoard Exhibit 3 provides supporting computations for the Wayne CC deferral amount that is reflected on Hoard Exhibit 1, Schedule 3-1(k). Hoard Exhibit 4 describes the types of costs that will be included in the Company's proposed levelization of nuclear refueling outage costs.

Q. DOES SCHEDULE 1 OF HOARD EXHIBIT 1 REFLECT ADJUSTMENTS SUPPORTED BY OTHER PUBLIC STAFF WITNESSES?

A. Yes. These adjustments are as follows:

1) The stipulated capital structure, embedded cost of long-term debt, and return on common equity are supported by Public Staff witness Johnson;

2) The stipulated customer growth, weather normalization, and nuclear decommissioning funding adjustments are supported by Public Staff witness Hinton;

4) The stipulated level of coal inventory, nuclear outage expenses, end of life reserves for materials, supplies, and fuel at nuclear facilities;

base fuel factor; nuclear O&M - plant staffing, and nuclear plant maintenance backlog are supported by Public Staff witness Ellis;

5) The stipulated fuel revenues and expenses, general non-fuel variable operations and maintenance O&M expenses displaced by specific O&M adjustments associated with new generation facilities; inclusion of costs related to PEC's DSDR facilities in base rate cost of service; PEC's DSM/EE and Renewable Energy and Energy Efficiency Portfolio Standard (REPS) Riders; the North Carolina retail fuel line loss differential; and allocation of certain fuel-related costs in future fuel and fuel-related cost recovery proceedings are supported by Public Staff witness Maness.

Q. PLEASE DESCRIBE THE ADJUSTMENTS SHOWN ON SCHEDULE 1 OF HOARD EXHIBIT 1.

A. These adjustments are described below.

<u>UPDATED ACCUMULATED DEFERRED INCOME TAXES</u>

Q. PLEASE EXPLAIN THE ADJUSTMENT TO ACCUMULATED DEFERRED INCOME TAXES.

A. The test year utilized in this proceeding is the twelve months ended March 31, 2012; however, in its January 18, 2013, update, PEC has reflected actual plant additions through December 31, 2012, plus projected plant additions through January 31, 2013. PEC has proposed an adjustment that increases plant by $942.4 million, which includes $438.6 million for the

Wayne CC, plus over $500 million for other production, transmission, distribution, and general plant. Schedule 1 of Hoard Exhibit 1 includes an adjustment to reflect changes in the amount of accumulated deferred income taxes, as of January 31, 2013.

WAYNE CC DEFERRAL

Q. PLEASE EXPLAIN THE ADJUSTMENT TO THE WAYNE CC DEFERRAL.

A. The Company filed a request in Docket No. E-2, Sub 1026, seeking authorization from the Commission to defer as a regulatory asset the North Carolina retail allocable portion of the revenue requirement associated with its Richmond CC beginning July 1, 2012, and with its Wayne CC beginning upon its commercial operation on December 31, 2012. The Company requested the deferrals until its request for an increase in its base rates is granted in this case. In reply comments filed in that docket on December 20, 2012, the Company agreed that including a return on equity (ROE) of 10.5%, the same as that recently authorized for PEC's affiliate, Duke Energy Carolinas, LLC, is reasonable. The Company proposes to amortize the Wayne CC deferred costs over five years.

As stated in Comments and Reply Comments filed in Sub 1026, the Public Staff does not oppose approval of deferral accounting with respect to the Wayne CC using a ROE no greater than 10.5%. The Company used its proposed capital structure, debt cost rate, preferred stock cost rate, and the aforementioned 10.5% ROE, to produce an overall pre-tax rate of return

(ROR) of 11.63%. The Company then used its proposed pre-tax ROR of 12.31% for computing the levelized amortization expense.

The stipulated Wayne CC deferral amortization was computed in a manner consistent with the Commission's computation of similar amortizations in past cases. The stipulated amortization also reflects the following changes to the Company's computation to:

1. Adjust the computation of the rate of return deferral amount on production and transmission plant for December 2012 and January 2013;

2. Reflect the monthly rate of return percentages used in the computations of the deferral and levelized amortization amounts to produce the proper annual rate of return amount. The Company used the annual rate divided by 12 to determine the monthly rate of return percent and the amount of its deferred return. Using this method overstates the rate of return due to the effect of compounding. The computation of the deferral and amortization has therefore been adjusted so as to produce the target rate of return, on an annual basis;

3. Adjust the return on deferred costs to include a return on the deferred capital costs;

4. Adjust the monthly ROR used in the computation of the return on deferred costs to reflect the after-tax rate, instead of the pre-tax rate used by the Company. It is appropriate to use the after-tax rate so that all of the tax benefits related to the deferred costs are recognized in calculating the return;

5. Adjust the monthly rate of return percentage used in the computation of the levelized amortization amount to reflect the stipulated capital structure and cost rates in this case, compounded annually, based on mid-year cost recovery;

6. Adjust the Company's calculation of the deferral balance for the Wayne CC transmission plant by (1) removing ADIT that was included by the Company in error, (2) correcting the calculation of the depreciation reserve balance, (3) correcting the calculation of the beginning rate base balance for January 2013, and (4) correcting the calculation of the total costs for deferral to include the amounts for December 2012;

7. Remove property tax expense for December 2012, since the plant was placed in service on December 31, 2012;

8. Adjust the depreciation rate used to calculate the deferred depreciation expense for production plant to reflect the depreciation rate for the Wayne CC production plant calculated by the Company in its adjustment to include the Wayne CC plant in rate base; and

9. Adjust the amount of transmission plant placed in service in December 2012 to reflect the amount included in the Company's adjustment to include the Wayne CC plant in rate base.

RICHMOND CC DEFERRAL

Q. PLEASE EXPLAIN THE ADJUSTMENT TO THE RICHMOND CC DEFERRAL.

A. For the reasons set forth in the Public Staff's Comments and Reply Comments filed in Docket No. E-2, Sub 1026, the stipulated expenses have been adjusted to remove the amortization of the Richmond CC deferral. Should the Commission decide to permit deferral and recovery of costs related to the Richmond CC, I recommend that the Company's computation of the Richmond CC deferral amortization be adjusted in the manner that I have described above for the Wayne CC deferral.

LEVELIZED RECOVERY OF RETIRED PLANTS

Q. PLEASE EXPLAIN THE ADJUSTMENT TO REFLECT THE LEVELIZED RECOVERY OF RETIRED PLANTS.

A. The Company retired its Cape Fear, Lee, Robinson, Weatherspoon, and Morehead City plants earlier than anticipated in its last depreciation study. Due to the early retirements, the Company accelerated the depreciation of the remainder of these plants. In its new depreciation study filed in Docket No. E-2, Sub 1025, the Company has reflected an adjustment that removes from rate base the unrecovered balances of these plants, and adds a return to the amortization expense during the proposed amortization period. The Company used its proposed ROR in computing the levelized amount of retired plant for recovery.

Schedule 1 of Hoard Exhibit 1 includes an adjustment to the Company's annual amortization amount to reflect the stipulated ROR. Consistent with the Commission's treatment of DNCP's North Branch plant, proceeds received by the Company as the result of either the sale or salvage of the plant and land (net of tax), benefits received due to the write-off of the plant for tax purposes, and costs incurred in connection with dismantling the plant should be credited or charged to a regulatory asset as they occur.

NEW DEPRECIATION RATES

Q. PLEASE EXPLAIN THE ADJUSTMENT FOR NEW DEPRECIATION RATES.

A. The stipulated adjustment decreases NC retail depreciation expense by $4,853,000 related to its new depreciation rates. This adjustment reflects a reduction in the contingency factor used in estimating demolition costs from the 20% of estimated costs to 10% of estimated costs, and changes the index used to escalate the estimated demolition costs.

This adjustment also reflects use of an alternate escalation index, as discussed by Public Staff witness Hinton. PEC selected the Employment Cost Index – Total Private Compensation (ECI), prepared by the Bureau of Labor Statistics (BLS) of the United States Department of Labor, as the escalation index. This index measures changes in employment, but does not account for the cost of material and equipment needed, disposal of removed materials, and environmental restoration. The alternate index recommended by the Public Staff uses the ECI in combination with the Producer Price Index (PPI) for Intermediate Materials as a weighted index for estimating future demolition costs. The BLS develops the PPI by sampling the prices of many goods and services sold in the United States. The ECI has been applied to the labor costs in the decommissioning study, and the PPI has been applied to all other costs in the decommissioning study (material and equipment needed, disposal of removed materials, and environmental restoration) to develop a weighted index.

LABOR EXPENSES

Q. PLEASE EXPLAIN THE ADJUSTMENT TO LABOR EXPENSES.

A. The Company has reflected annualized labor expenses (payroll and related costs) as of March 31, 2012, plus labor expenses for 33 additional employees at its Wayne CC, an additional two months of labor expenses at its Richmond CC, 250 additional nuclear operations employees that it expects to add by March 31, 2013, less labor expenses for employees at its retired plants, and employees that it expects to retire under its Voluntary Separation Plan (VSP) by January 31, 2013.

The Company's labor expenses have been adjusted to reflect its annualized December 31, 2012, labor expenses, plus an estimate of the annual labor expenses related to its nuclear headcount initiative and VSP for the month of January 2013. As part of this adjustment, O&M expenses have been decreased to remove two months of Richmond CC labor expenses that were included twice by the Company, once in its Richmond CC O&M expense annualization adjustment and again in its labor expenses adjustment. The Company's December 31, 2012, labor expenses have been determined using the same methodology that the Company used to determine its March 31, 2012, annualized labor expenses. The December 31, 2012, amount incorporates the labor expense effects of the plant retirements, commercial operation of the Wayne CC and Richmond CC, nuclear headcount additions, and the VSP.

Q. WHY IS IT APPROPRIATE TO UPDATE THE LABOR EXPENSE?

A. The updated labor expenses reflect the Company's current actual labor expenses and match the treatment of other cost of service items that have also been updated. Subsequent to the end of the test year, PEC's parent corporation, Progress Energy, Inc., received approval to merge with Duke Energy Corporation in Docket Nos. E-2, Sub 998 and E-7, Sub 986. As a result, PEC has made a number of changes that directly affect its labor costs; including implementation of its VSP. In addition, PEC has closed several plants and increased the number of employees at its nuclear plants. Thus, a significant number of employees have retired, have been transferred, or have been hired since the merger was consummated on July 2, 2012. Updating labor expenses to reflect actual December 31, 2012, amounts, decreases the reliance on estimates, and is a more accurate representation of the level of employees to be used to calculate the appropriate amount of labor expense.

PROPERTY TAXES

Q. PLEASE EXPLAIN THE PROPERTY TAX EXPENSE ADJUSTMENT.

A. The Company has adjusted property tax expense based on plant in service and other taxable property balances as of the end of the March 31, 2012, test period, and has reflected property taxes related to the Wayne CC plant, as a component of that adjustment. The Company has also made adjustments for post-test year plant retirements and post-test year plant additions, but it did not remove the property taxes on the retired plants or include property taxes on the post-test year plant additions. Property tax expense has been adjusted to reflect the appropriate level of known and measurable ongoing expense.

DOE SETTLEMENT

Q. PLEASE EXPLAIN THE DOE SETTLEMENT ADJUSTMENT.

A. In 2011, the Company received $84.2 million from the DOE in settlement of a lawsuit related to funds paid by ratepayers for the handling of spent nuclear fuel. PEC credited a portion of the settlement to O&M and a portion to plant, thereby reducing rate base. In its cost of service, the Company adjusted O&M expenses to remove the $27.2 million credit (total system basis) recorded during the test period, but continues to reflect the reduction to rate base.

In its 2012 DNCP Order, the Commission determined that a similar DOE settlement received by DNCP should be flowed back to ratepayers by amortizing it over a seven-year period. Consistent with the treatment of DNCP's DOE settlement, the stipulated O&M expenses reflect an amortization of the DOE settlement credit over seven years beginning with PEC's receipt of the settlement, with a corresponding credit to rate base for the unamortized portion of the credit. The seven-year amortization period is consistent with the amortization period ordered by the Commission in the 2012 DNCP Order. The inclusion of the unamortized amount of the DOE settlement credit in rate base is consistent with the treatment of other unamortized debits and credits by the Company and the Public Staff.

LOBBYING EXPENSES

Q. PLEASE EXPLAIN THE LOBBYING EXPENSES ADJUSTMENT.

A. Stipulated O&M expenses have been adjusted to remove lobbying costs incurred by the Company during the test year. The costs to be removed were determined by applying the "but for" test for reporting lobbying costs as used in a Formal Advisory Opinion of the State Ethics Commission dated February 12, 2010, and approved by the Commission in its 2012 DNCP Order. The Commission recognized that lobbying included not only employees' direct contact with legislators, but also other activities preparing for or surrounding lobbying that would not have been conducted but for the lobbying itself. Applying this test resulted in the removal of a portion of the Corporate Public Affairs O&M expenses, PEC-External Relations, and Federal Affairs O&M.

ADVERTISING EXPENSES

Q. PLEASE SUMMARIZE THE ADJUSTMENT TO ADVERTISING EXPENSE.

A. The Company proposed to include $2,061,000 of advertising expense (including $11,000, reflected in EEI dues) in O&M expense in this proceeding. Based on Commission Rule R12-13 and prior orders, test year advertising expenses were reduced by $531,000 to exclude image, promotional, and competitive advertising, resulting in an adjustment to NC retail O&M expenses of $373,000. The purpose of the adjustment is to prevent ratepayers from being charged with expenses for advertising that does not enhance the utility's ability to provide efficient and reliable service or is not otherwise to the benefit of the using and consuming public.

AVIATION EXPENSES

Q. PLEASE EXPLAIN THE AVIATION EXPENSES ADJUSTMENT.

A. In her Supplemental Direct Testimony and Supplemental Exhibit, Company witness Bateman made an adjustment to reduce aviation expenses during the test period by 44% to remove a portion of expenses for flights not directly related to PEC customer benefits. Based on the Public Staff's further review of the Company's flight logs and the purposes listed for the flights, an additional 39% of expenses have been removed for flights deemed not directly related to PEC customer benefits, resulting in a stipulated expense that reflects an adjustment of $1,062,000 to the Company's proposed aviation expense.

VEGETATION MANAGEMENT

Q. PLEASE EXPLAIN THE ADJUSTMENT RELATED TO VEGETATION MANAGEMENT EXPENSES.

A. According to the application, PEC incurred total O&M expenses of $43,661,000 related to vegetation management (VM) during the test period - $32,749,000 for its distribution system and $10,912,000 for its transmission system. The Company proposed an adjustment to increase these expenses by $21,304,000 to $64,965,000, composed of $49,294,000 of distribution VM and $15,671,000 of transmission VM. During the test year, PEC changed from a reliability-based approach to a cyclical approach for distribution and transmission VM, which required a certain amount of short-term catch-up work to effectuate the transition. VM expenses have been adjusted to remove costs for VM work activities that are beyond ongoing cyclical VM work activities. This adjustment to distribution VM is calculated based on the ongoing level of annual target distribution VM miles and the test year VM actual cost per mile. The test year VM actual cost per mile of $4,563 provides a better measure of normal VM costs than the Company's calculation, because it excludes the costs of catch-up work.

This VM cost per mile is consistent with the amounts experienced by PEC in prior years. With regard to transmission VM, I have adjusted these costs to the highest level experienced by the Company during the 2007 – 2011 period, adjusted for the effects of inflation. The stipulated annual amount of VM costs, after adjustment, is $54,786,000, which is composed of $41,041,000 for distribution VM, and $13,745,000 for transmission VM. The level of VM costs remaining in O&M expenses after the stipulated adjustment, which exceeds actual test year expenses by $11,125,000, is adequate funding for maintaining a prudent VM program.

MERGER EFFECTS

Q. PLEASE EXPLAIN THE ADJUSTMENT TO REFLECT THE EFFECTS OF THE MERGER BETWEEN DUKE ENERGY CORPORATION AND PROGRESS ENERGY, INC.

A. O&M expenses were adjusted to remove costs that will either be reduced or no longer be incurred as the result of the merger. These cost reductions were offset by the amount of rent paid by PEC for two new office space leases, which do not expire until 2014 or later. The costs removed include the rent and various administrative fees incurred by the Company for Two Progress Plaza, industry association dues, stock listing fees, rating agency fees, and Directors and Officers liability insurance. Two Progress Plaza is the former headquarters building that PEC no longer occupies. The industry association dues, stock listing fees, and Directors and Officers liability insurance costs are items that were identified in documents provided in

Docket Nos. E-2, Sub 998 and E-7, Sub 986, as cost efficiencies resulting from the merger. These costs have been removed from the cost of service because they are not ongoing expenses.

NORMALIZATION OF NUCLEAR REFUELING OUTAGE COSTS

Q. PLEASE EXPLAIN THE ADJUSTMENT TO NORMALIZE NUCLEAR REFUELING OUTAGE COSTS.

A. The Company currently expenses nuclear refueling outage costs in the month that the costs are incurred. It proposes changing the method of accounting for these costs by accumulating the costs in a deferred account and then expensing them over the nuclear unit's refueling cycle. The Company has proposed an adjustment to reflect an annualized level of the expenses using its proposed accounting method.

I will address the Company's proposed change in accounting method later in my testimony, and focus my discussion here on the Company's proposed adjustment to O&M expenses for nuclear refueling outage costs. Because there is a separate adjustment that annualizes labor expenses as of December 31, 2012, base labor expenses have been removed from the computation of the nuclear refueling outage cost adjustment to avoid double-counting labor expenses. In the computation of the stipulated adjustment, labor expenses have been excluded from both the normalized level of nuclear refueling outage costs and the actual test year level of the costs.

EFFECT OF INFLATION ON NON-FUEL O&M EXPENSES

Q. PLEASE EXPLAIN THE ADJUSTMENT TO REFLECT THE EFFECT OF INFLATION ON NON-FUEL O&M EXPENSES.

A. In its adjustment to Annualize Non-Labor, Non-Fuel O&M Expense, the Company has adjusted O&M expenses, excluding fuel clause and labor costs, to reflect the rise in unit costs that occurred during the test period due to the effect of inflation. This adjustment has been modified to exclude other costs, such as aviation expenses, lobbying, and advertising expenses that have been specifically adjusted to annualized end-of-period levels, and thus require no additional adjustment for inflation. Because other cost of service items have been updated to January 31, 2013, the escalation in O&M expenses has been adjusted through that same point in time.

LEAD/LAG STUDY CASH WORKING CAPITAL

Q. PLEASE EXPLAIN THE LEAD/LAG STUDY CASH WORKING CAPITAL ADJUSTMENT.

A. The Company has proposed an adjustment that increases the amount of cash working capital (CWC) it may retain based on changes in its cost of service. The Company's proposed amount of CWC is based on the difference between its revenue and expense lags during its test year multiplied by its daily cost of service after the proposed rate increase. Because the proposed amount of CWC is dependent on the amount of the rate increase approved by the Commission, the Company has developed a formula that incorporates the approximate effect of the rate increase in its gross revenue requirements retention factor. The 0.23% CWC element of the retention factor is shown on Bateman Exhibit 2, page 1 of 2, line 22. The amount of CWC reflected by the Company is $141,394,000, which is composed of the $136,201,000 amount of Cash Requirements – Lead/Lag amount shown on Bateman Exhibit 1, page 2D of 4, column (5), less sales taxes CWC of $1,105,000, plus the $6,299,000 amount shown on Bateman Exhibit 1, page 1 of 4, column (g).

Consistent with the historical treatment of CWC in general rate cases before the Commission, and as discussed most recently in the 2012 DNCP Order, the Stipulation provides that CWC in this case be based on the Company's per books cost of service. The Commission concluded in its 2012 DNCP Order that while DNCP's position that CWC should be based on a pro forma cost of service had merit, changing the methodology for DNCP could affect the methodology used to compute CWC for other utilities and therefore found good cause to seek comments regarding this issue in a generic proceeding. Such a proceeding is now pending in Docket No. M-100, Sub 137.

MATERIALS AND SUPPLIES

Q. PLEASE EXPLAIN THE ADJUSTMENT TO MATERIALS AND SUPPLIES.

A. Based on the Public Staff's analysis and review, Materials and Supplies (M&S) have been adjusted to remove nuclear operations inventories that have been identified in a PEC internal audit report as excessive.

COAL INVENTORY

Q. PLEASE EXPLAIN THE ADJUSTMENT TO COAL INVENTORY.

A. As discussed by Public Staff witness Ellis, coal inventory has been reduced from the 50 day target that is used by the Company in its Application to a target of 40 days. The 40 day target agreed to in the Stipulation and the Company's methodology were used to calculate the amount of coal inventory.

END OF LIFE (EOL) RESERVE FOR NUCLEAR FUEL

Q. PLEASE EXPLAIN THE ADJUSTMENT TO THE EOL RESERVE FOR NUCLEAR FUEL.

A. The Company has increased test period expenses to add an annual accrual to accumulate a reserve for expenses related to the last core of nuclear fuel at the EOL of each nuclear unit. The cost of the last nuclear fuel core is not captured in the costs of decommissioning and is not expected to have any salvage value. PEC is proposing to create a reserve to start accruing for the expense related to a portion of the last core of nuclear fuel in the reactor at the EOL of its nuclear generating plants. As this last core of nuclear fuel would benefit the ratepayers served prior to the EOL of the nuclear plant, creating a reserve to accrue the expense would create a better matching of cost and benefit for ratemaking purposes. The annual accrual amount would be determined by dividing the projected remaining value of the last core of nuclear fuel at the EOL of each unit by the number of years remaining in the unit's life and summing this result for PEC's four nuclear units. The Company is requesting the approval of an annual accrual amount in this proceeding that would be reviewed and adjusted, if needed, in each future general rate case before the EOL of the plant. In her testimony, Company witness Bateman proposes that the reserve, once it is created, be an offset to rate base in the cost of service. It has been the longstanding practice of the Commission, when pro forma adjustments are made to expenses, that a matching adjustment should be made to rate base to reflect annualized levels of amortization of regulatory assets. Thus, an adjustment has been made to rate base in the current proceeding for one year's annual accrual.

EOL RESERVE FOR MATERIALS AND SUPPLIES

Q. PLEASE EXPLAIN THE ADJUSTMENTS RELATED TO THE EOL RESERVE FOR MATERIALS AND SUPPLIES.

A. As discussed above for the final nuclear core, the Company has proposed the establishment of a reserve with an annual accrual of $6.1 million, on a NC retail basis, for EOL nuclear M&S. According to Company witness

Bateman's testimony, the accrual amount was determined by dividing the projected inventory balance at the EOL of each unit by the number of years remaining in the unit's life. PEC assumed in its computations that the March 31, 2012, balance of nuclear M&S would be the projected inventory balance at the EOL of each unit and that the M&S inventory would have little or no salvage value at that time. Using these assumptions, the Company identified $141.2 million ($219.1 million x 64.454% NC retail allocation factor) of NC retail nuclear M&S inventory at its four nuclear plants. As discussed earlier, an adjustment was made to nuclear M&S for excessive M&S. The amount of nuclear M&S, after removal of the excessive nuclear M&S, on an NC retail basis, is $120.0 million.

Public Staff witness Ellis reviewed stock lists of the nuclear M&S items and determined that nuclear M&S, as of March 31, 2012, includes items that could be used at other nuclear plants or, in many instances, at the Company's fossil plants. Therefore, the nuclear M&S amount used as the base for computing the annual accrual amount has been reduced by 20% for items that may be used at other plants. The annual accrual was then determined by applying the same method as used by the Company. Finally, as done with respect to the EOL reserve for the nuclear fuel core, rate base has been adjusted for the amount of the first year's annual accrual.

DEFERRED GAINS

Q. PLEASE EXPLAIN THE ADJUSTMENT RELATED TO THE DEFERRED GAINS.

A. The Company has amortized its deferred gains related to the sale of emission allowances and portions of the Harris land over five years and reflected the full amount of these deferred gains as credits to rate base. Consistent with the treatment of the EOL reserves for nuclear fuel and nuclear M&S, and consistent with the longstanding practice of the Commission to make a matching adjustment to rate base when pro forma adjustments are made to expenses, the amount of these deferred gains reflected in rate base has been reduced by an annualized levels of the amortizations.

PREPAID DEFERRED DEBITS

Q. PLEASE EXPLAIN THE ADJUSTMENT RELATED TO PREPAID DEFERRED DEBITS.

A. Prepaid deferred debits are costs that are paid upfront and amortized to expenses over the period to which the expense relates. The prepaid deferred debits have been removed from rate base because the CWC associated with each of these items is already included in the lead-lag study. For instance, PEC added prepaid insurance to rate base but it also is included in the lead/lag study as an item that is paid in advance and is thus already added once to rate base.

INTEREST SYNCHRONIZATION CORRECTION

Q. PLEASE EXPLAIN THE INTEREST SYNCHRONIZATION CORRECTION ADJUSTMENT.

A. Interest synchronization synchronizes rate base and cost of capital with the tax calculation. This adjustment fully reflects the interest expense tax deduction effect of the Company's supplemental adjustments.

RETENTION AND GROSS-UP FACTORS

Q. PLEASE EXPLAIN THE RETENTION AND GROSS-UP FACTOR ADJUSTMENTS.

A. As described earlier, the Company included an element for CWC in its retention and gross-up factors. Because the Stipulation provides that the per books cost of service will be used for purposes of determining CWC, the CWC element has been removed from the retention and gross-up factors. The treatment of uncollectibles expense in the computation of the factors has also been corrected to reflect uncollectibles as a deduction for the regulatory fee and gross receipts taxes. The amounts for the regulatory fee and gross receipts taxes are determined based on revenues, net of uncollectibles.

POST TEST YEAR EXPENSES ADJUSTMENT

Q. PLEASE EXPLAIN THE POST TEST YEAR EXPENSES ADJUSTMENT.

A. This amount represents an allowance for changes in the cost of service not specifically addressed elsewhere. Because the Commission's decision regarding the cost-of-service allocation methodology may impact certain other adjustments, the amount of the post test year expenses adjustment is subject to change as necessary to maintain the revenue increase at the stipulated level.

LEVELIZATION ACCOUNTING FOR NUCLEAR REFUELING OUTAGE COSTS

Q. PLEASE EXPLAIN THE STIPULATION REGARDING THE COMPANY'S PROPOSED CHANGE IN ACCOUNTING FOR NUCLEAR REFUELING OUTAGE COSTS.

A. As stated earlier in my testimony, the Company currently expenses nuclear refueling outage costs in the month that the costs are incurred. These expenses can vary considerably depending on the number and length of refueling outages. PEC has proposed changing the method of accounting for those costs to levelize the costs, accumulate the costs for each nuclear unit in a deferred account, and then expense them over the unit's refueling cycle. In conjunction with this change in accounting, the Company has requested authorization from the Commission to establish a regulatory asset on its balance sheet. The nuclear refueling outage expenses at its nuclear units would be deferred in this account and thereafter amortized. Costs eligible for deferral include incremental costs incurred during the period beginning one month prior to the period for the scheduled outage and ending one month following conclusion of the scheduled outage. Specific details regarding the types of incremental costs eligible for deferral are provided in Hoard Exhibit 4. The deferred costs would be amortized to expenses over the number of months for the refueling cycle, 24 months for each of the Brunswick units, and 18 months for the Harris and Robinson units. In future rate proceedings, the test period amounts produced by this deferred accounting method, adjusted for costs deemed to be ineligible for deferral or disallowed on the basis of imprudence, would be used to determine recoverable nuclear refueling outage expenses.

Under the Company's proposed deferred accounting methodology, a different amortization period for nuclear refueling outage costs that were incurred prior to the end of a nuclear unit's operating life and have been deferred but not yet amortized to expenses could be approved by the Commission, as long as the Company is allowed to recover the costs. For example, if the Company deferred $10 million of outage costs one year before a nuclear unit's closing, and twelve months' amortization remained at the time the unit was retired, the Commission could order the Company either to expense the unamortized outage costs over some future period, such as three years, or to recover the unamortized outage costs in rates as an amortization expense based on the annualized recovery amount for that retired unit in a general rate case. Settlement Exhibit 2 sets forth the agreement between PEC and the Public Staff regarding the establishment of a regulatory asset on the Company's balance sheet to accumulate nuclear outage expenses in a deferred account, and then expense them over the nuclear unit's refueling cycle.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes, it does.

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DUKE ENERGY CAROLINAS

Docket No. E-7, Sub 1214
North Carolina Retail Operations
ARO-RELATED COAL ASH REVENUE REQUIREMENTS
COMPANY VS. PUBLIC STAFF

SUMMARY FOR DEC
INCLUDES DIFFERENCES DUE TO IMPRUDENCE DISALLOWANCES AND EQUITABLE SHARING

Estimated Balance at 7/31/2020 $ 261,242 (000s Omitted)

Year	Public Staff Recommended Revenue Requirement	Company Proposed Revenue Requirement (inc. Return on Rate Base)	Difference	Cumulative Difference
1	$ 9,712	$ 95,928	$ (86,215)	$ (86,215)
2	9,712	90,941	(81,229)	(167,444)
3	9,712	85,954	(76,242)	(243,686)
4	9,712	80,968	(71,255)	(314,941)
5	9,712	75,981	(66,269)	(381,210)
6	9,712	-	9,712	(371,497)
7	9,712	-	9,712	(361,785)
8	9,712	-	9,712	(352,072)
9	9,712	-	9,712	(342,360)
10	9,712	-	9,712	(332,647)
11	9,712	-	9,712	(322,935)
12	9,712	-	9,712	(313,222)
13	9,712	-	9,712	(303,510)
14	9,712	-	9,712	(293,797)
15	9,712	-	9,712	(284,085)
16	9,712	-	9,712	(274,372)
17	9,712	-	9,712	(264,660)
18	9,712	-	9,712	(254,947)
19	9,712	-	9,712	(245,235)
20	9,712	-	9,712	(235,522)
21	9,712	-	9,712	(225,810)
22	9,712	-	9,712	(216,097)
23	9,712	-	9,712	(206,385)
24	9,712	-	9,712	(196,672)
25	9,712	-	9,712	(186,960)
26	9,712	-	9,712	(177,247)
27	9,712	-	9,712	(167,535)
Total	$ 262,237	$ 429,772	$ (167,535)	

DUKE ENERGY CAROLINAS

Docket No. E-7, Sub 1214
North Carolina Retail Operations
ARO-RELATED COAL ASH REVENUE REQUIREMENTS
COMPANY VS. PUBLIC STAFF

DEC PROPOSED REVENUE REQUIREMENT

Estimated Balance at 7/31/2020 $ 378,464 (000s Omitted)
Beginning-of-Year Amortization Assumption

Year	Beginning Balance	Amortization	Amortization Grossed Up	Unamortized Balance	ADIT Balance	Balance for Return	Revenue Requirement Level Return	Total Revenue Requirement
1	$ 378,464	$ 75,693	75,981	$ 302,771	$ (70,698)	$ 232,073	$ 19,947	$ 95,928
2	302,771	75,693	75,981	227,078	$ (53,023)	174,055	14,960	90,941
3	227,078	75,693	75,981	151,386	$ (35,349)	116,037	9,973	85,954
4	151,386	75,693	75,981	75,693	$ (17,674)	58,018	4,987	80,968
5	75,693	75,693	75,981	-	$ -	-	-	75,981

SETTLED ROR (PRE_TAX)

	Cap	Cost Rates	Weighted ROR	Gross-Up	Pre-Tax ROR
Debt	0.4800000	0.0427000	0.0204960	0.9962055	0.0205741
Equity	0.5200000	0.09600000	0.0499200	0.7635890	0.0653755
Total	1.0000000		0.0704160		0.0859496

Duke Energy Carolina
Docket No. E-7, Sub 1214

North Carolina Retail Operations

ARO - RELATED COAL ASH REVENUE REQUIREMENTS DIFFERENCES
COMPARED TO INCREASED FINANCING COSTS

Year		(a) (Millions) Long Term Debt Issuances	(b) Basis Point Interest Rate Increase	(c) (Millions) Annual Interest Paid Increases
2020		Already Issued		
2021		$1,000 (1)	.05% (2)	$ .500 (3)
2022		409 (1)	.05% (2)	.205 (3)
2023		1,809 (1)	.05% (2)	.905 (3)
	Total	$3.218 Billion		$1.610

Year	(d) (Millions) Cumulative Interest Paid Increase	(e) (Millions) Public Staff Revenue Requirement Difference Annual	(f) (Millions) Cumulative Public Staff Revenue Requirement Difference
2021	$ .500	$86.215 (4)	$86.215
2022	$ .705	$81.229 (4)	167.444
2023	$1.610	$76.242 (4)	243.686

Reduction of Annual Revenue Requirement vs. Additional Interest

Year	(g) (Millions) Revenue Requirement Difference	(h) (Millions) Cumulative Interest Increase	(i) (Millions) Revenue Requirement Reduction
2021	$86.215	$ .500	$86.165 (5)
2022	81.229	.705	80.524 (5)
2023	76.242	1.610	74.632 (5)

Footnote

(1) DEC Corrected E-1 Item 38 Line 14 Long-Term Debt Issuances Filed February 14, 2020

(2) DEC Response to Public Staff Data Request 230, Item 6, five basis point financing increase if DEC downgraded First Mortgage Bond Moody's Credit Rating from Aa2 to Aa3.

(3) (a) times (b) equals (c)

(4) Public Staff Rebuttal Cross Examination Exhibit No. _____ titled ARO - RELATED COAL ASH REVENUE REQUIREMENTS COMPANY VS. PUBLIC STAFF

(5) (g) less (h) equals (i)

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Doss Rebuttal Exhibit 1

Accounting Standard Codification 410-20

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410-20-00 410 Asset Retirement and Environmental Obligations > 20 Asset Retirement Obligations > 00 Status

General

Subsection revised 01-Oct-2012

Combine Subsections

00-1 The following table identifies the changes made to this Subtopic.

Paragraph	Action	Accounting Standards Update	Date
Fair Value (3rd def.)	Added	Accounting Standards Update No. 2012-04	10/01/2012
410-20-55-27	Amended	Accounting Standards Update No. 2012-04	10/01/2012
410-20-55-66	Amended	Accounting Standards Update No. 2012-04	10/01/2012

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410-20-05 410 Asset Retirement and Environmental Obligations > 20 Asset Retirement Obligations > 05 Overview and Background

General

Subsection revised 01-Jul-2009

Combine Subsections

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05-1 This Subtopic establishes accounting standards for recognition and measurement of a liability for an asset retirement obligation and the associated asset retirement cost. This Subtopic also addresses the accounting for an environmental remediation liability that results from the normal operation of a long-lived asset.

05-2 Paragraph Not Used

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410-20-15 410 Asset Retirement and Environmental Obligations > 20 Asset Retirement Obligations > 15 Scope and Scope Exceptions

General

Subsection revised 01-Jul-2009

Combine Subsections

> Entities

15-1 The guidance in this Subtopic applies to all entities, including rate-regulated entities that meet the criteria for application of Subtopic 980-10, as provided in paragraph 980-10-15-2. Paragraphs 980-340-25-1 and 980-405-25-1 provide specific conditions that must be met to recognize a regulatory asset and a regulatory liability, respectively. (See paragraphs 410-20-55-1 through 55-12 and 410-20-55-21 through 55-22 for implementation guidance)

> Transactions

15-2 The guidance in this Subtopic applies to the following transactions and activities:

a. Legal obligations associated with the retirementof a tangible long-lived asset that result from the acquisition, construction, or development and (or) the normal operation of a long-lived asset, including any legal obligations that require disposal of a replaced part that is a component of a tangible long-lived asset.

b. An environmental remediation liability that results from the normal operation of a long-lived asset and that is associated with the retirement of that asset. The fact that partial settlement of an obligation is required or performed before full retirement of an asset does not remove that obligation from the scope of this Subtopic. If environmental contamination is incurred in the normal operation of a long-lived asset and is associated with the retirement of that asset, then this Subtopic will apply (and Subtopic 410-30 will not apply) if the entity is legally obligated to treat the contamination.

c. A conditional obligation to perform a retirement activity. Uncertainty about the timing of settlement of the asset retirement obligation does not remove that obligation from the scope of this Subtopic but will affect the measurement of a liability for that obligation (see paragraph 410-20-25-10).

d. Obligations of a lessor in connection with leased property that meet the provisions in (a). Paragraph 840-10-25-16 requires that lease classification tests performed in accordance with the requirements of Subtopic 840-10 incorporate the requirements of this Subtopic to the extent applicable.

e. The costs associated with the retirement of a specified asset that qualifies as historical waste equipment as defined by EU Directive 2002/96/EC. (See paragraphs 410-20-55-23 through 55-30 and Example 4 [paragraph 410-20-55-63] for illustration of this guidance.) Paragraph 410-20-55-24 explains how the Directive distinguishes between new and historical waste and provides related implementation guidance.

15-3 The guidance in this Subtopic does not apply to the following transactions and activities:

a. Obligations that arise solely from a plan to sell or otherwise dispose of a long-lived asset covered by Subtopic 360-10.

b. An environmental remediation liability that results from the improper operation of a long-lived asset (see Subtopic 410-30). Obligations resulting from improper operations do not represent costs that are an integral part of the tangible long-lived asset and therefore should not be accounted for as part of the cost basis of the asset. For example, a certain amount of spillage may be inherent in the normal operations of a fuel storage facility, but a

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catastrophic accident caused by noncompliance with an entity's safety procedures is not. The obligation to clean up the spillage resulting from the normal operation of the fuel storage facility is within the scope of this Subtopic. The obligation to clean up after the catastrophic accident results from the improper use of the facility and is not within the scope of this Subtopic.

c. Activities necessary to prepare an asset for an alternative use as they are not associated with the retirement of the asset.

d. Historical waste held by private households. (The guidance in this paragraph does not pertain to an asset retirement obligation in the scope of this Subtopic.) For guidance on accounting for historical electronic equipment waste held by private households for obligations associated with Directive 2002/96/EC on Waste Electrical and Electronic Equipment adopted by the European Union, see Subtopic 720-40.

e. Obligations of a lessee in connection with leased property, whether imposed by a lease agreement or by a party other than the lessor, that meet the definition of either minimum lease payments or contingent rentals in paragraphs 840-10-25-4 through 25-7. Those obligations shall be accounted for by the lessee in accordance with the requirements of Subtopic 840-10. However, if obligations of a lessee in connection with leased property, whether imposed by a lease agreement or by a party other than the lessor, meet the provisions in paragraph 410-20-15-2 but do not meet the definition of either minimum lease payments or contingent rentals in paragraphs 840-10-25-4 through 25-7, those obligations shall be accounted for by the lessee in accordance with the requirements of this Subtopic.

f. An obligation for asbestos removal that results from the other-than-normal operation of an asset. Such an obligation may be subject to the provisions of Subtopic 410-30.

g. Costs associated with complying with funding or assurance provisions. Paragraph 410-20-35-9 otherwise addresses the measurement effects of funding and assurance provisions.

h. Obligations associated with maintenance, rather than retirement, of a long-lived asset.

i. The cost of a replacement part that is a component of a long-lived asset.

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410-20-20 410 Asset Retirement and Environmental Obligations > 20 Asset Retirement Obligations > 20 Glossary

Accretion Expense

An amount recognized as an expense classified as an operating item in the statement of income resulting from the increase in the carrying amount of the liability associated with the asset retirement obligation.

Asset Retirement Cost

The amount capitalized that increases the carrying amount of the long-lived asset when a liability for an asset retirement obligation is recognized.

Asset Retirement Obligation

An obligation associated with the retirement of a tangible long-lived asset.

Conditional Asset Retirement Obligation

A legal obligation to perform an asset retirement activity in which the timing and (or) method of settlement are conditional on a future event that may or may not be within the control of the entity.

Legal Obligation

An obligation that a party is required to settle as a result of an existing or enacted law, statute, ordinance, or written or oral contract or by legal construction of a contract under the doctrine of promissory estoppel.

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Promissory Estoppel

"The principle that a promise made without consideration may nonetheless be enforced to prevent injustice if the promisor should have reasonably expected the promisee to rely on the promise and if the promisee did actually rely on the promise to his or her detriment." (See Black's Law Dictionary, seventh edition.)

Retirement

The other-than-temporary removal of a long-lived asset from service. That term encompasses sale, abandonment, recycling, or disposal in some other manner. However, it does not encompass the temporary idling of a long-lived asset. After an entity retires an asset, that asset is no longer under the control of that entity, no longer in existence, or no longer capable of being used in the manner for which the asset was originally acquired, constructed, or developed.

Closure

Related to the Resource Conservation and Recovery Act of 1976: the process in which the owner-operator of a hazardous waste management unit discontinues active operation of the unit by treating, removing from the site, or disposing of on site all hazardous wastes in accordance with an Environmental Protection Agency or state-approved plan. Included, for example, are the process of emptying, cleaning, and removing or filling underground storage tanks and the capping of a landfill. Closure entails specific financial guarantees and technical tasks that are included in a closure plan and must be implemented.

Disposal

Related to the Comprehensive Environmental Response, Compensation, and Liability Act of 1980 and the Resource Conservation and Recovery Act of 1976: under the Resource Conservation and Recovery Act of 1976, the discharge, deposit, injection, dumping, spilling, leaking, or placing of any solid waste or hazardous waste into or on any land or water so that such solid waste or hazardous waste or any constituent thereof may enter the environment or be emitted into the air or discharged into any waters, including groundwaters. Similarly under the Comprehensive Environmental Response, Compensation, and Liability Act of 1980 with regard to hazardous substances.

Hazardous Waste

Related to Resource Conservation and Recovery Act of 1976: a waste, or combination of wastes, that because of its quantity, concentration, toxicity, corrosiveness, mutagenicity or inflammability, or physical, chemical, or infectious characteristics may cause, or significantly contribute to, an increase in mortality or an increase in serious irreversible, or incapacitating reversible illness or pose a substantial present or potential hazard to human health or the environment when improperly treated, stored, transported, or disposed of, or otherwise managed. Technically, those wastes that are regulated under the Resource Conservation and Recovery Act of 1976 40 CFR Part 261 are considered to be hazardous wastes.

Natural Resources

Under the Comprehensive Environmental Response, Compensation, and Liability Act of 1980, natural resources are defined as land, fish, wildlife, biota, air, water, groundwater, drinking water supplies, and other such resources belonging to, managed or held in trust by, or otherwise controlled by the United States, state or local governments, foreign governments, or Indian tribes.

Discount Rate Adjustment Technique

A present value technique that uses a risk-adjusted discount rate and contractual, promised, or most likely cash flows.

Fair Value

The price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date.

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410-20-25 410 Asset Retirement and Environmental Obligations > 20 Asset Retirement Obligations > 25 Recognition

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General

Subsection revised 01-Jul-2009

Combine Subsections

> Background for Recognition

25-1 Paragraph 35 of FASB Concepts Statement No. 6, Elements of Financial Statements, defines a liability as follows {Note: The indented text below is reproduced from FASB Concepts Statement No. 6 and includes editorial changes for internal consistency within the Codification}.

> Liabilities are probable future sacrifices of economic benefits arising from present obligations of a particular entity to transfer assets or provide services to other entities in the future as a result of past transactions or events.

25-2 Probable is used with its usual general meaning, rather than in a specific accounting or technical sense (such as that in paragraph 450-20-25-1), and refers to that which can reasonably be expected or believed on the basis of available evidence or logic but is neither certain nor proved (Webster's New World Dictionary). Its inclusion in the definition is intended to acknowledge that business and other economic activities occur in an environment characterized by uncertainty in which few outcomes are certain (see paragraphs 44 through 48 of FASB Concepts Statement No. 6).

25-3 As stated in the preceding paragraph, the definition of a liability in Concepts Statement 6 uses the term *probable* in a different sense than it is used in paragraph 450-20-25-1. As used in Topic 450, probable requires a high degree of expectation. The term probable in the definition of a liability, however, is intended to acknowledge that business and other economic activities occur in an environment in which few outcomes are certain.

25-3A Paragraph 410-20-40-3 states that providing assurance that an entity will be able to satisfy its asset retirement obligation does not satisfy or extinguish the related liability.

> Fair Value Is Reasonably Estimated

25-4 An entity shall recognize the fair value of a liability for an asset retirement obligation in the period in which it is incurred if a reasonable estimate of fair value can be made. If a reasonable estimate of fair value cannot be made in the period the asset retirement obligation is incurred, the liability shall be recognized when a reasonable estimate of fair value can be made. If a tangible long-lived asset with an existing asset retirement obligation is acquired, a liability for that obligation shall be recognized at the asset's acquisition date as if that obligation were incurred on that date.

25-5 Upon initial recognition of a liability for an asset retirement obligation, an entity shall capitalize an asset retirement cost by increasing the carrying amount of the related long-lived asset by the same amount as the liability. Paragraph 835-20-30-5 explains that capitalized asset retirement costs do not qualify as expenditures for purposes of applying Subtopic 835-20.

25-6 An entity shall identify all its asset retirement obligations. An entity has sufficient information to reasonably estimate the fair value of an asset retirement obligation if any of the following conditions exist:

a. It is evident that the fair value of the obligation is embodied in the acquisition price of the asset.

b. An active market exists for the transfer of the obligation.

c. Sufficient information exists to apply an expected present value technique.

> Obligations with Uncertainty in Timing or Method of Settlement

25-7 The obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and (or) method of settlement. Thus, the timing and (or) method of settlement may be conditional on a future event. Accordingly, an entity shall recognize a liability for the fair value of a conditional asset retirement obligation if the fair value of the liability can be reasonably estimated. In some cases, sufficient information about the timing and (or) method of settlement may not be available to reasonably estimate fair value. An expected present value technique incorporates uncertainty about the timing and method of settlement into the fair value measurement. Uncertainty is factored into the measurement of the fair value of the liability through assignment of probabilities to cash flows.

25-8 An entity would have sufficient information to apply an expected present value technique and therefore an asset retirement obligation would be reasonably estimable if either of the following conditions exists:

a. The settlement date and method of settlement for the obligation have been specified by others. For example, the law, regulation, or contract that gives rise to the legal obligation specifies the settlement date and method of settlement. In this situation, the settlement date and method of settlement are known and therefore the only

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uncertainty is whether the obligation will be enforced (that is, whether performance will be required). In certain cases, determining the settlement date for the obligation that has been specified by others is a matter of judgment that depends on the relevant facts and circumstances. For example, a contract that provides the entity with an ability to extend its term through renewal should be evaluated to determine whether the settlement date should take into consideration renewal periods. Uncertainty about whether performance will be required does not defer the recognition of an asset retirement obligation because a legal obligation to stand ready to perform the retirement activities still exists, and it does not prevent the determination of a reasonable estimate of fair value because the only uncertainty is whether performance will be required.

b. The information is available to reasonably estimate all of the following:

1. The settlement date or the range of potential settlement dates

2. The method of settlement or potential methods of settlement (The term *potential methods of settlement* refers to methods of settling the obligation that are currently available to the entity. Therefore, uncertainty about future methods yet to be developed would not prevent the entity from estimating the fair value of the asset retirement obligation.)

3. The probabilities associated with the potential settlement dates and potential methods of settlement. (The entity should have a reasonable basis for assigning probabilities to the potential settlement dates and potential methods of settlement to reasonably estimate the fair value of the asset retirement obligation. If the entity does not have a reasonable basis of assigning probabilities, it is expected that the entity would still be able to reasonably estimate fair value when the range of time over which the entity may settle the obligation is so narrow and (or) the cash flows associated with each potential method of settlement are so similar that assigning probabilities without having a reasonable basis for doing so would not have a material impact on the fair value of the asset retirement obligation.)

25-9 In many cases, the determination as to whether the entity has the information to reasonably estimate the fair value of the asset retirement obligation is a matter of judgment that depends on the relevant facts and circumstances. It is expected that the narrower the range of time over which the entity may settle the obligation and the fewer potential methods of settlement the entity has available to it, the more likely it is that the entity will have the information to reasonably estimate the fair value of an asset retirement obligation. For an illustration of this guidance, see Example 3 (paragraph 410-20-55-47).

25-10 Instances may occur in which insufficient information to estimate the fair value of an asset retirement obligation is available. For example, if an asset has an indeterminate useful life, sufficient information to estimate a range of potential settlement dates for the obligation might not be available. In such cases, the liability would be initially recognized in the period in which sufficient information exists to estimate a range of potential settlement dates that is needed to employ a present value technique to estimate fair value.

25-11 Examples of information that is expected to provide a basis for estimating the potential settlement dates, potential methods of settlement, and the associated probabilities include, but are not limited to, information that is derived from the entity's past practice, industry practice, management's intent, or the asset's estimated economic life. The estimated economic life of the asset might indicate a potential settlement date for the asset retirement obligation. However, the original estimated economic life of the asset may not, in and of itself, establish that date because the entity may intend to make improvements to the asset that could extend the life of the asset or the entity could defer settlement of the obligation beyond the economic life of the asset. In those situations, the entity would look beyond the economic life of the asset in determining the settlement date or range of potential settlement dates to use when estimating the fair value of the asset retirement obligation.

25-12 An asset retirement obligation may result from the acquisition, construction, or development and (or) normal operation of a long-lived asset that has an indeterminate useful life and thereby an indeterminate settlement date for the asset retirement obligation.

25-13 If a current law, regulation, or contract requires an entity to perform an asset retirement activity when an asset is dismantled or demolished, there is an unambiguous requirement to perform the retirement activity even if that activity can be indefinitely deferred. At some time deferral will no longer be possible, because no tangible asset will last forever (except land). Therefore, the obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and (or) method of settlement.

> Uncertainty in Performance Obligations

25-14 This Subtopic requires recognition of a conditional asset retirement obligation before the event that either requires or waives performance occurs. Uncertainty surrounding conditional performance of the retirement obligation is factored into its measurement by assessing the likelihood that performance will be required. In situations in which the conditional aspect has only 2 outcomes and there is no information about which outcome is more probable, a 50 percent likelihood for each outcome shall be used until additional information is available.

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25-15 An unambiguous requirement that gives rise to an asset retirement obligation coupled with a low likelihood of required performance still requires recognition of a liability. Uncertainty about the conditional outcome of the obligation is incorporated into the measurement of the fair value of that liability, not the recognition decision. Uncertainty about performance of conditional obligations shall not prevent the determination of a reasonable estimate of fair value. A past history of nonenforcement of an unambiguous obligation does not defer recognition of a liability, but its measurement is affected by the uncertainty over the requirement to perform retirement activities.

> Acquired Asset Retirement Obligations

25-16 If a tangible long-lived asset with an existing asset retirement obligation is acquired, a liability for that obligation shall be recognized at the asset's acquisition date as if that obligation were incurred on that date.

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410-20-30 410 Asset Retirement and Environmental Obligations > 20 Asset Retirement Obligations > 30 Initial Measurement

General

Subsection revised 01-Jul-2009

Combine Subsections

> Determination of a Reasonable Estimate of Fair Value

30-1 An expected present value technique will usually be the only appropriate technique with which to estimate the fair value of a liability for an asset retirement obligation. An entity, when using that technique, shall discount the expected cash flows using a credit-adjusted risk-free rate. Thus, the effect of an entity's credit standing is reflected in the discount rate rather than in the expected cash flows. Proper application of a discount rate adjustment technique entails analysis of at least two liabilities—the liability that exists in the marketplace and has an observable interest rate and the liability being measured. The appropriate rate of interest for the cash flows being measured shall be inferred from the observable rate of interest of some other liability, and to draw that inference the characteristics of the cash flows shall be similar to those of the liability being measured. Rarely, if ever, would there be an observable rate of interest for a liability that has cash flows similar to an asset retirement obligation being measured. In addition, an asset retirement obligation usually will have uncertainties in both timing and amount. In that circumstance, employing a discount rate adjustment technique, where uncertainty is incorporated into the rate, will be difficult, if not impossible. See paragraphs 410-20-55-13 through 55-17 and Example 2 (paragraph 410-20-55-35). For further information on present value techniques, see the guidance beginning in paragraph 820-10-55-4.

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General

Subsection revised 01-Jul-2009

Combine Subsections

> Allocation of Asset Retirement Cost

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35-1 A liability for an asset retirement obligation may be incurred over more than one reporting period if the events that create the obligation occur over more than one reporting period. Any incremental liability incurred in a subsequent reporting period shall be considered to be an additional layer of the original liability. Each layer shall be initially measured at fair value. For example, the liability for decommissioning a nuclear power plant is incurred as contamination occurs. Each period, as contamination increases, a separate layer shall be measured and recognized. Paragraph 410-20-30-1 provides guidance on using that technique.

35-2 An entity shall subsequently allocate that asset retirement cost to expense using a systematic and rational method over its useful life. Application of a systematic and rational allocation method does not preclude an entity from capitalizing an amount of asset retirement cost and allocating an equal amount to expense in the same accounting period. For example, assume an entity acquires a long-lived asset with an estimated life of 10 years. As that asset is operated, the entity incurs one-tenth of the liability for an asset retirement obligation each year. Application of a systematic and rational allocation method would not preclude that entity from capitalizing and then expensing one-tenth of the asset retirement costs each year.

35-3 In periods subsequent to initial measurement, an entity shall recognize period-to-period changes in the liability for an asset retirement obligation resulting from the following:

a. The passage of time

b. Revisions to either the timing or the amount of the original estimate of undiscounted cash flows.

35-4 An entity shall measure and incorporate changes due to the passage of time into the carrying amount of the liability before measuring changes resulting from a revision to either the timing or the amount of estimated cash flows.

35-5 An entity shall measure changes in the liability for an asset retirement obligation due to passage of time by applying an interest method of allocation to the amount of the liability at the beginning of the period. The interest rate used to measure that change shall be the credit-adjusted risk-free rate that existed when the liability, or portion thereof, was initially measured. That amount shall be recognized as an increase in the carrying amount of the liability and as an expense classified as accretion expense. Paragraph 835-20-15-7 states that accretion expense related to exit costs and asset retirement obligations shall not be considered to be interest cost for purposes of applying Subtopic 835-20.

35-6 The subsequent measurement provisions require an entity to identify undiscounted estimated cash flows associated with the initial measurement of a liability. Therefore, an entity that obtains an initial measurement of fair value from a market price or from a technique other than an expected present value technique must determine the undiscounted cash flows and estimated timing of those cash flows that are embodied in that fair value amount for purposes of applying the subsequent measurement provisions. Example 1 (see paragraph 410-20-55-31) provides an illustration of the subsequent measurement of a liability that is initially obtained from a market price. (See paragraph 410-20-25-14 for a discussion on conditional outcomes.)

35-7 Paragraph 410-20-25-14 explains how uncertainty surrounding conditional performance of a retirement obligation is factored into its measurement by assessing the likelihood that performance will be required. As the time for notification approaches, more information and a better perspective about the ultimate outcome will likely be obtained. Consequently, reassessment of the timing, amount, and probabilities associated with the expected cash flows may change the amount of the liability recognized. See paragraphs 410-20-55-18 through 55-19.

> Change in Estimate

35-8 Changes resulting from revisions to the timing or the amount of the original estimate of undiscounted cash flows shall be recognized as an increase or a decrease in the carrying amount of the liability for an asset retirement obligation and the related asset retirement cost capitalized as part of the carrying amount of the related long-lived asset. Upward revisions in the amount of undiscounted estimated cash flows shall be discounted using the current credit-adjusted risk-free rate. Downward revisions in the amount of undiscounted estimated cash flows shall be discounted using the credit-adjusted risk-free rate that existed when the original liability was recognized. If an entity cannot identify the prior period to which the downward revision relates, it may use a weighted-average credit-adjusted risk-free rate to discount the downward revision to estimated future cash flows. When asset retirement costs change as a result of a revision to estimated cash flows, an entity shall adjust the amount of asset retirement cost allocated to expense in the period of change if the change affects that period only or in the period of change and future periods if the change affects more than one period as required by paragraphs 250-10-45-17 through 45-20 for a change in estimate.

> Effects of Funding and Assurance Provisions

35-9 Methods of providing assurance include surety bonds, insurance policies, letters of credit, guarantees by other entities, and establishment of trust funds or identification of other assets dedicated to satisfy the asset retirement obligation. The existence of funding and assurance provisions may affect the determination of the credit-adjusted risk-free rate. For a previously recognized asset retirement obligation, changes in funding and assurance provisions have no effect on the initial measurement or accretion of that liability, but may affect the credit-adjusted risk-free rate used to discount upward revisions in undiscounted cash flows for that obligation.

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General

Subsection revised 01-Jul-2009

Combine Subsections

> Settlement of an Asset Retirement Obligation

40-1 Typically, settlement of an asset retirement obligation is not required until the associated asset is retired. However, certain circumstances may exist in which partial settlement of an asset retirement obligation is required or performed before the asset is fully retired. The nature of asset retirement obligations in various industries is such that the obligations are not necessarily satisfied when the current operation or use of the asset ceases. These obligations can be settled during operation of the asset or after the operations cease. The timing of the ultimate settlement of a liability is unrelated to and should not affect its initial recognition in the financial statements provided the obligation is associated with the retirement of a tangible long-lived asset.

40-2 Paragraph 410-20-25-14 explains how uncertainty surrounding conditional performance of a retirement obligation is factored into its measurement by assessing the likelihood that performance will be required. If, as time progresses, it becomes apparent that retirement activities will not be required, the liability and the remaining unamortized asset retirement cost shall be reduced to zero.

40-3 Providing assurance that an entity will be able to satisfy its asset retirement obligation does not satisfy or extinguish the related liability. The effect of surety bonds, letters of credit, and guarantees is to provide assurance that third parties will provide amounts to satisfy the asset retirement obligations if the entity that has primary responsibility (the obligor) to do so cannot or does not fulfill its obligations. The possibility that a third party will satisfy the asset retirement obligations does not relieve the obligor from its primary responsibility for those obligations. If a third party is required to satisfy asset retirement obligations due to the failure or inability of the obligor to do so directly, the obligor would then have a liability to the third party.

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General

Subsection revised 01-Jul-2009

Combine Subsections

> Classification of Accretion Expense

45-1 Accretion expense shall be classified as an operating item in the statement of income. An entity may use any descriptor for accretion expense so long as it conveys the underlying nature of the expense.

45-2 See paragraph 230-10-45-17 for additional information about the classification of cash payments for asset retirement obligations as operating items on the statement of cash flows.

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> Statement of Cash Flows

45-3 Paragraph 230-10-45-17(e) states that a cash payment made to settle an asset retirement obligation is a cash outflow for operating activities.

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General

Subsection revised 01-Jul-2009

Combine Subsections

50-1 An entity shall disclose all of the following information about its asset retirement obligations:

a. A general description of the asset retirement obligations and the associated long-lived assets

b. The fair value of assets that are legally restricted for purposes of settling asset retirement obligations

c. A reconciliation of the beginning and ending aggregate carrying amount of asset retirement obligations showing separately the changes attributable to the following components, whenever there is a significant change in any of these components during the reporting period:

1. Liabilities incurred in the current period
2. Liabilities settled in the current period
3. Accretion expense
4. Revisions in estimated cash flows.

50-2 If the fair value of an asset retirement obligation cannot be reasonably estimated, that fact and the reasons therefor shall be disclosed.

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General

Subsection revised 01-Oct-2012

Combine Subsections

> Implementation Guidance

> > Determination of Whether a Legal Obligation Exists

55-1 This implementation guidance illustrates Section 410-20-15. In most cases involving an asset retirement obligation, the determination of whether a legal obligation exists should be unambiguous. However, in situations in which no law,

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statute, ordinance, or contract exists but an entity makes a promise to a third party (which may include the public at large) about its intention to perform retirement activities, facts and circumstances need to be considered carefully in determining whether that promise has imposed a legal obligation upon the promisor under the doctrine of promissory estoppel. A legal obligation may exist even though no party has taken any formal action. In assessing whether a legal obligation exists, an entity is not permitted to forecast changes in the law or changes in the interpretation of existing laws and regulations. Preparers and their legal advisors are required to evaluate current circumstances to determine whether a legal obligation exists.

55-2 For example, assume an entity operates a manufacturing facility and has plans to retire it within five years. Members of the local press have begun to publicize the fact that when the entity ceases operations at the plant, it plans to abandon the site without demolishing the building and restoring the underlying land. Due to the significant negative publicity and demands by the public that the entity commit to dismantling the plant upon retirement, the entity's chief executive officer holds a press conference at city hall to announce that the entity will demolish the building and restore the underlying land when the entity ceases operations at the plant. Although no law, statute, ordinance, or written contract exists requiring the entity to perform any demolition or restoration activities, the promise made by the entity's chief executive officer may have created a legal obligation under the doctrine of promissory estoppel. In that circumstance, the entity's management (and legal counsel, if necessary) would have to evaluate the particular facts and circumstances to determine whether a legal obligation exists.

55-3 Once an entity determines that a duty or responsibility exists, it will then need to assess whether an obligating event has occurred that leaves it little or no discretion to avoid the future transfer or use of assets. If such an obligating event has occurred, an asset retirement obligation meets the definition of a liability and qualifies for recognition in the financial statements. However, if an obligating event that leaves an entity little or no discretion to avoid the future transfer or use of assets has not occurred, an asset retirement obligation does not meet the definition of a liability and, therefore, should not be recognized in the financial statements.

55-4 Identifying the obligating event is often difficult, especially in situations that involve the occurrence of a series of transactions or other events or circumstances affecting the entity. For example, in the case of an asset retirement obligation, a law or an entity's promise may create a duty or responsibility, but that law or promise in and of itself may not be the obligating event that results in an entity's having little or no discretion to avoid a future transfer or use of assets. An entity must look to the nature of the duty or responsibility to assess whether the obligating event has occurred. For example, in the case of a nuclear power facility, an entity assumes responsibility for decontamination of that facility upon receipt of the license to operate it. However, no obligation to decontaminate exists until the facility is operated and contamination occurs. Therefore, the contamination, not the receipt of the license, constitutes the obligating event.

> > Expectation of Nonenforcement

55-5 This implementation guidance illustrates Section 410-20-15.Contracts between entities may contain an option or a provision that requires one party to the contract to perform retirement activities when an asset is retired. The other party may decide in the future not to exercise the option or to waive the provision to perform retirement activities, or that party may have a history of waiving similar provisions in other contracts. Even if there is an expectation of a waiver or nonenforcement, the contract still imposes a legal obligation. That obligation is included in the scope of this Subtopic. The likelihood of a waiver or nonenforcement will affect the measurement of the liability. For example, consider an entity that owns and operates a landfill. Regulations require that that entity perform capping, closure, and postclosure activities. Capping activities involve covering the land with topsoil and planting vegetation. Closure activities include drainage, engineering, and demolition and must be performed prior to commencing the postclosure activities. Postclosure activities, the final retirement activities, include maintaining the landfill once final certification of closure has been received and monitoring the ground and surface water, gas emissions, and air quality. Closure and postclosure activities are performed after the entire landfill ceases receiving waste (that is, after the landfill is retired). However, capping activities are performed as sections of the landfill become full and are effectively retired. The fact that some of the capping activities are performed while the landfill continues to accept waste does not remove the obligation to perform those intermediate capping activities from the scope of this Subtopic.

> > Acquisition, Construction, or Development of a Long-Lived Asset

55-6 This implementation guidance illustrates Section 410-20-15. Whether an obligation results from the acquisition, construction, or development of a long-lived asset should, in most circumstances, be clear. For example, if an entity acquires a landfill that is already in operation, an obligation to perform capping, closure, and postclosure activities results from the acquisition and assumption of obligations related to past normal operations of the landfill. Additional obligations will be incurred as a result of future operations of the landfill.

> > Normal Operations

55-7 This implementation guidance illustrates Section 410-20-15. Whether an obligation results from the normal operation of a long-lived asset may require judgment. Obligations that result from the normal operation of an asset should be predictable and likely of occurring. For example, consider an entity that owns and operates a nuclear power plant. That entity has a legal obligation to perform decontamination activities when the plant ceases operations. Contamination, which

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gives rise to the obligation, is predictable and likely of occurring and is unavoidable as a result of operating the plant. Therefore, the obligation to perform decontamination activities at that plant results from the normal operation of the plant.

55-8 For example, a certain amount of spillage may be inherent in the normal operations of a fuel storage facility, but a catastrophic accident caused by noncompliance with an entity's safety procedures is not. The obligation to clean up after the catastrophic accident does not result from the normal operation of the facility and is not within the scope of this Subtopic.

> > Components of a Larger System

55-9 An asset retirement obligation may exist for component parts of a larger system. In some circumstances, the retirement of the component parts may be required before the retirement of the larger system to which the component parts belong.

55-10 For example, consider an aluminum smelter that owns and operates several kilns lined with a special type of brick. The kilns have a long useful life, but the bricks wear out after approximately five years of use and are replaced on a periodic basis to maintain optimal efficiency of the kilns. Because the bricks become contaminated with hazardous chemicals while in the kiln, a state law requires that when the bricks are removed, they must be disposed of at a special hazardous waste site. The obligation to dispose of those bricks is within the scope of this Subtopic. The cost of the replacement bricks and their installation are not part of that obligation. This implementation guidance illustrates Section 410-20-15.

55-11 If assets with asset retirement obligations are components of a larger group of assets (for example, a number of oil wells that make up an entire oil field operation), aggregation techniques may be necessary to derive a collective asset retirement obligation. This Subtopic does not preclude the use of estimates and computational shortcuts that are consistent with the fair value measurement objective when computing an aggregate asset retirement obligation for assets that are components of a larger group of assets. This implementation guidance illustrates paragraph 410-20-30-1.

> > Obligations with Uncertainty About Government Enforcement

55-12 This implementation guidance illustrates Section 410-20-15. If, for example, a governmental unit retains the right (an option) to decide whether to require a retirement activity, there is some uncertainty about whether those retirement activities will be required or waived. Regardless of the uncertainty attributable to the option, a legal obligation to stand ready to perform retirement activities still exists, and the governmental unit might require them to be performed. Although the timing and method of settlement of the retirement obligation may depend on future events that may or may not be within the control of the entity, a legal obligation to stand ready to perform retirement activities still exists. The entity should consider the uncertainty about the timing and method of settlement in the measurement of the liability, consistent with a fair value measurement objective, regardless of whether the event that will trigger the settlement is partially or wholly under the control of the entity.

> > Expected Present Value Technique

55-13 This implementation guidance illustrates paragraph 410-20-30-1. In estimating the fair value of a liability for an asset retirement obligation using an expected present value technique, an entity shall begin by estimating the expected cash flows that reflect, to the extent possible, a marketplace assessment of the cost and timing of performing the required retirement activities. Considerations in estimating those expected cash flows include developing and incorporating explicit assumptions, to the extent possible, about all of the following:

a. The costs that a third party would incur in performing the tasks necessary to retire the asset

b. Other amounts that a third party would include in determining the price of the transfer, including, for example, inflation, overhead, equipment charges, profit margin, and advances in technology

c. The extent to which the amount of a third party's costs or the timing of its costs would vary under different future scenarios and the relative probabilities of those scenarios

d. The price that a third party would demand and could expect to receive for bearing the uncertainties and unforeseeable circumstances inherent in the obligation, sometimes referred to as a market-risk premium.

55-14 It is expected that uncertainties about the amount and timing of future cash flows can be accommodated by using the expected present value technique and therefore will not prevent the determination of a reasonable estimate of fair value.

> > Credit-Adjusted Risk-Free Rate

55-15 This implementation guidance illustrates paragraph 410-20-30-1. An entity shall discount expected cash flows using an interest rate that equates to a risk-free interest rate adjusted for the effect of its credit standing (a credit-adjusted risk-free rate). In determining the adjustment for the effect of its credit standing, an entity should consider the effects of all terms, collateral, and existing guarantees on the fair value of the liability.

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55-16 Adjustments for default risk can be reflected in either the discount rate or the expected cash flows. In most situations, an entity will know the adjustment required to the risk-free interest rate to reflect its credit standing. Consequently, it would be easier and less complex to reflect that adjustment in the discount rate.

55-17 In addition, because of the requirements in paragraph 410-20-35-8 relating to upward and downward adjustments in expected cash flows, it is essential to the operationality of this Subtopic that the credit standing of the entity be reflected in the discount rate. For those reasons, the risk-free rate shall be adjusted for the credit standing of the entity to determine the discount rate.

> > Calculation of Accretion Expense

55-18 This implementation guidance illustrates paragraphs 410-20-35-1 through 35-6. In periods subsequent to initial measurement, an entity recognizes the effect of the passage of time on the amount of a liability for an asset retirement obligation. A period-to-period increase in the carrying amount of the liability shall be recognized as an operating item (accretion expense) in the statement of income. An equivalent amount is added to the carrying amount of the liability. To calculate accretion expense, an entity shall multiply the beginning of the period liability balance by the credit-adjusted risk-free rate that existed when the liability was initially measured. The liability shall be adjusted for accretion prior to adjusting for revisions in estimated cash flows.

> > Changes in Assumptions and Legal Requirements

55-19 This implementation guidance illustrates paragraph 410-20-35-8. Revisions to a previously recorded asset retirement obligation will result from changes in the assumptions used to estimate the expected cash flows required to settle the asset retirement obligation, including changes in estimated probabilities, amounts, and timing of the settlement of the asset retirement obligation, as well as changes in the legal requirements of an obligation. Any changes that result in upward revisions to the expected cash flows shall be treated as a new liability and discounted at the current rate. Any downward revisions to the expected cash flows will result in a reduction of the asset retirement obligation. For downward revisions, the amount of the liability to be removed from the existing accrual shall be discounted at the credit-adjusted risk-free rate that was used at the time the obligation to which the downward revision relates was originally recorded (or the historical weighted-average rate if the year[s] to which the downward revision applies cannot be determined).

55-20 Revisions to the asset retirement obligation result in adjustments of capitalized asset retirement costs and will affect subsequent depreciation of the related asset. Such adjustments are depreciated on a prospective basis.

> > Interim Property Retirements

55-21 This implementation guidance illustrates Section 410-20-15. There is no conceptual difference between interim property retirements and replacements and those retirements that occur in circumstances in which the retired asset is not replaced. Therefore, any asset retirement obligation associated with the retirement of or the retirement and replacement of a component part of a larger system qualifies for recognition provided that the obligation meets the definition of a liability. The cost of replacement components is excluded.

55-22 Examples of interim property retirements and replacements for component parts of larger systems are components of transmission and distribution systems (utility poles), railroad ties, a single oil well that is part of a larger oil field, and aircraft engines. The assets in those examples may or may not have associated retirement obligations.

> > Historical Waste on Electrical and Electronic Equipment Associated with EU Directive 2002/96/EC

55-23 EU Directive 2002/96/EC was adopted on February 13, 2003, and directs EU-member countries to adopt legislation to regulate the collection, treatment, recovery, and environmentally sound disposal of electrical and electronic waste equipment. The actual legislation adopted by individual EU-member countries can have different requirements. An entity should apply the guidance herein, adjusted as needed for the specific requirements of the applicable EU-member country.

55-24 The Directive distinguishes between new and historical waste. All products put on the market on or before August 13, 2005, are deemed to be historical waste equipment for the purposes of the Directive. Example 4 (see paragraph 410-20-55-63) does not address the accounting for new waste because there should be little diversity in practice in the accounting for such waste. Costs relating to waste of new equipment are to be borne solely by the producers of the new equipment. This implementation guidance illustrates Section 410-20-15.

55-25 Under the Directive, the waste management obligation remains with the commercial user until the historical waste equipment is replaced, at which time the waste management obligation for that equipment may be transferred to the producer of the replacement equipment depending on the law adopted by the applicable EU-member country. If the commercial user does not replace the equipment, the obligation remains with that user until it disposes of the equipment. The Directive provides each EU-member country with the option to obligate commercial users to pay part or all of the costs associated with the historical waste even if the equipment is replaced. In this situation, the obligation would remain (partly or wholly) with the commercial user until the user disposes of the equipment.

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55-26 The accounting for the initial recognition and measurement of the liability and asset retirement cost should be consistent with paragraphs 410-20-25-1 through 25-4. The ability or intent of the commercial user to replace the asset and transfer the obligation does not relieve the user of its present duty or responsibility to settle the obligation. The replacement of the asset may, depending on EU-member country law, transfer the obligation to the replacement producer, and, if so, that transfer would affect the purchase price of the replacement asset. Upon initial recognition of a liability, an entity shall capitalize an asset retirement cost by increasing the carrying amount of the related asset by the same amount as the liability. The accounting subsequent to the initial recognition of the asset and liability should be consistent with the guidance in paragraphs 410-20-35-3 through 35-8.

55-27 If the asset is subsequently replaced, with the obligation being transferred to the producer of the replacement equipment, the commercial user should determine the portion of the total amount paid to the producer that relates to the replacement equipment (the new asset) and the portion that relates to the transfer of the asset retirement obligation. That determination should be based on the fair value of the asset retirement obligation, without the sale of the new asset. The price paid by the commercial user would not include any costs associated with the transfer of the obligation in situations in which the law in the EU-member country obligates commercial users to pay all of the costs associated with the historical waste even if the equipment is replaced. In those situations, the commercial user would not derecognize the liability from its balance sheet upon replacement, but rather when the obligation is ultimately settled.

55-28 The new asset should be measured as the residual amount (the excess of the price paid over the fair value of the asset retirement obligation transferred). That amount should be used in determining the new asset's cost basis. The commercial user should derecognize the liability from its balance sheet and recognize a gain or loss based on the difference between the carrying amount of the liability at the date of the sale and the portion of the sales price that relates to the obligation. The producer of the new asset should recognize revenue for the total amount received reduced by the fair value of the obligation upon the transfer of the obligation from the commercial user (that is, on a net basis). The requirements for the producer to measure the revenue from the sale of the new asset as the residual amount and recognize revenue only for the sale of the new asset are applicable for those producers for which the recycling of electronic waste equipment is not a revenue-generating business activity. In situations in which the recycling of equipment is a revenue-generating business activity for the producer, that producer should measure the revenue from the sale of the new asset and the assumption of the obligation in accordance with the provisions of Subtopic 605-25.

55-29 The producer of the new asset should derecognize that liability when the obligation is settled.

55-30 See Example 4 (paragraph 410-20-55-63), which describes accounting for obligations associated with Directive 2002/96/EC on Waste Electrical and Electronic Equipment adopted by the European Union. That Example refers to and paraphrases various provisions of the Directive. Nothing in that Example shall be considered a definitive interpretation of any provision of the Directive for any purpose.

> Illustrations

> > Example 1: Subsequent Measurement of a Liability Obtained from a Market Price

55-31 This Example illustrates the guidance in paragraphs 410-20-35-5 through 35-6. After initial measurement, an entity is required to recognize period-to-period changes in an asset retirement obligation liability resulting from the passage of time (accretion expense) and revisions in cash flow estimates. To apply the subsequent measurement provisions of this Subtopic, an entity must identify undiscounted cash flows related to an asset retirement obligation liability irrespective of how the liability was initially measured. Therefore, if an entity obtains the initial fair value from a market price, it must impute undiscounted cash flows from that price.

55-32 This Example illustrates the subsequent measurement of a liability in situations where the initial liability is based on a market price. Assume that the liability is initially recognized at the end of period 0 when the market price is $300,000 and the entity's credit-adjusted risk-free rate is 8 percent. As required by this Subtopic, revisions in the timing or the amount of estimated cash flows are assumed to occur at the end of the period after accretion on the beginning balance of the liability is calculated. At the end of each period, the following procedure is used to impute cash flows from the end-of-period market price, compute the change in that price attributable to revisions in estimated cash flows, and calculate accretion expense:

a. The market price and the credit-adjusted risk-free interest rate are used to impute the undiscounted cash flows embedded in the market price.

b. The undiscounted cash flows from (a) are discounted at the initial credit-adjusted risk-free rate of 8 percent to arrive at the ending balance of the asset retirement obligation liability per the provisions of this Subtopic.

c. The beginning balance of the asset retirement obligation liability is multiplied by the initial credit-adjusted risk-free rate of 8 percent to arrive at the amount of accretion expense per the provisions of this Subtopic.

d. The difference between the undiscounted cash flows at the beginning of the period and the undiscounted cash flows at the end of the period represents the revision in cash flow estimates that occurred during the period. If that change is an upward revision to the undiscounted estimated cash flows, it is discounted at the current credit-

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adjusted risk-free rate. If that change is a downward revision, it is discounted at the historical weighted-average rate because it is not practicable to separately identify the period to which the downward revision relates.

55-33 The following table illustrates the subsequent measurement of an asset retirement obligation liability obtained from a market price.

Subsequent Measurement of an Asset Retirement Obligation Liability Obtained from a Market Pric

	End of Period			
	0	1	2	
Market assumptions:				
Market price (includes market risk premium)	$ 300,000	$ 400,000	$ 350,000	$ 3
Current risk-free rate adjusted for entity's credit standing	8.00%	7.00%	7.50%	
Time period remaining	3	2	1	
Imputed undiscounted cash flows (market price discounted at market rate)	$ 377,914	$ 457,960	$ 376,250	$ 3
Change in undiscounted cash flows	377,914	80,046	(81,710)	
Discount rate:				
Current credit-adjusted risk-free rate (for upward revisions)	8.00%	7.00%		
Historical weighted-average credit-adjusted risk-free rate (for downward revisions)			7.83%	
Change in undiscounted cash flows discounted at credit-adjusted risk-free rate (current rate for upward revisions and historical rate for downward revisions)	$ 300,000	$ 69,916	$ (75,777)	$

55-34 The following table illustrates the measurement of liability under the provisions of the asset retirement obligation statement.

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Measurement of Liability under Provisions of Asset Retirement Obligation Statement

Period	Beginning Balance	Accretion (8.0%)	Change in Cash Flows	Ending Balance
0			$ 300,000	$300,000
1	$ 300,000	$ 24,000		324,000
2	324,000	25,920		349,920
3	349,920	27,994		377,914

Period	Beginning Balance	Accretion (7.0%)	Change in Cash flows	Ending Balance
0				
1			$ 69,916	$ 69,916
2	$ 69,916	$ 4,894		74,810
3	74,810	5,236		80,046

Period	Beginning Balance	Accretion (7.83%)	Change in Cash Flows	Ending Balance
0				
1				
2			$ (75,777)	$ (75,777)
3	$ (75,777)	$ (5,933)		(81,710)

Period	Beginning Balance	Accretion	Change in Cash Flows	Ending Balance
0				
1				
2				
3			$ 3,750	$ 3,750

	Total			
Period	Beginning Balance	Accretion Expense	Change in Cash Flows	Ending Balance
0			$ 300,000	$300,000
1	$ 300,000	$ 24,000	69,916	393,916
2	393,916	30,814	(75,777)	348,953
3	348,953	27,297	3,750	380,000

> > Example 2: Recognition and Measurement

55-35 The following Cases illustrate the recognition and measurement provisions of this Subtopic:

a. Initial measurement of a liability for an asset retirement obligation using an expected present value technique, subsequent measurement assuming that there are no changes in expected cash flows, and settlement of the asset retirement obligation liability at the end of its term (Case A)

b. Subsequent measurement of an asset retirement obligation liability after a change in expected cash flows (Case B)

c. Recognition and measurement of an asset retirement obligation liability that is incurred over more than one reporting period (Case C)

d. Accounting for asset retirement obligations that are conditional and that have a low likelihood of enforcement (Case D).

55-36 Cases A, B, C, and D incorporate simplified assumptions to provide guidance in implementing this Subtopic. For instance, Cases A and B relate to the asset retirement obligation associated with an offshore production platform that also

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would likely have individual wells and production facilities that would have separate asset retirement obligations. Those Cases also assume straight-line depreciation, even though, in practice, depreciation would likely be applied using a units-of -production method. Other simplifying assumptions are used throughout the Cases.

> > > Case A: Initial Measurement Using a Present Value Technique, Subsequent Measurement with No Change in Expected Cash Flows

55-37 This Case depicts an entity that completes construction of and places into service an offshore oil platform on January 1, 2003. The entity is legally required to dismantle and remove the platform at the end of its useful life, which is estimated to be 10 years. Based on the requirements of this Subtopic, on January 1, 2003, the entity recognizes a liability for an asset retirement obligation and capitalizes an amount for an asset retirement cost. The entity estimates the initial fair value of the liability using an expected present value technique. The significant assumptions used in that estimate of fair value are as follows:

a. Labor costs are based on current marketplace wages required to hire contractors to dismantle and remove offshore oil platforms. The entity assigns probability assessments to a range of cash flow estimates as follows.

Cash Flow Estimate	Probability Assessment	Expected Cash Flows
$ 100,000	25%	$ 25,000
125,000	50	62,500
175,000	25	43,750
		$ 131,250

b. The entity estimates allocated overhead and equipment charges using the rate it applies to labor costs for transfer pricing (80 percent). The entity has no reason to believe that its overhead rate differs from those used by contractors in the industry.

c. A contractor typically adds a markup on labor and allocated internal costs to provide a profit margin on the job. The rate used (20 percent) represents the entity's understanding of the profit that contractors in the industry generally earn to dismantle and remove offshore oil platforms.

d. A contractor would typically demand and receive a premium (market risk premium) for bearing the uncertainty and unforeseeable circumstances inherent in locking in today's price for a project that will not occur for 10 years. The entity estimates the amount of that premium to be 5 percent of the expected cash flows adjusted for inflation.

e. The risk-free rate of interest on January 1, 2003, is 5 percent. The entity adjusts that rate by 3.5 percent to reflect the effect of its credit standing. Therefore, the credit-adjusted risk-free rate used to compute expected present value is 8.5 percent.

f. The entity assumes a rate of inflation of 4 percent over the 10-year period.

55-38 On December 31, 2012, the entity settles its asset retirement obligation by using its internal workforce at a cost of $351,000. Assuming no changes during the 10-year period in the expected cash flows used to estimate the obligation, the entity would recognize a gain of $89,619 on settlement of the obligation. The entity would account for the asset retirement obligation as follows.

Labor	$ 195,000
Allocated overhead and equipment charges (80% of labor)	156,000
Total costs incurred	351,000
Asset retirement obligation liability	440,619
Gain on settlement of obligation	$ 89,619

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Initial Measurement of the Asset Retirement Obligation Liability at January 1, 2003

	Expected Cash Flows 1/1/03
Expected labor costs	$ 131,250
Allocated overhead and equipment charges (.80 × $131,250)	105,000
Contractor's markup [.20 × ($131,250 + $105,000)]	47,250
Expected cash flows before inflation adjustment	283,500
Inflation factor assuming 4 percent rate for 10 years	1.4802
Expected cash flows adjusted for inflation	419,637
Market-risk premium (.05 × $419,637)	20,982
Expected cash flows adjusted for market risk	$ 440,619
Expected present value using credit-adjusted risk-free rate of 8.5 percent for 10 years	$ 194,879

Interest Method of Allocation

Year	Liability Balance 1/1	Accretion	Liability Balance 12/31
2003	$ 194,879	$ 16,565	$ 211,444
2004	211,444	17,973	229,417
2005	229,417	19,500	248,917
2006	248,917	21,158	270,075
2007	270,075	22,956	293,031
2008	293,031	24,908	317,939
2009	317,939	27,025	344,964
2010	344,964	29,322	374,286
2011	374,286	31,814	406,100
2012	406,100	34,519	440,619

Schedule of Expenses

Year-End	Accretion Expense	Depreciation Expense	Total Expense
2003	$ 16,565	$ 19,488	$36,053
2004	17,973	19,488	37,461
2005	19,500	19,488	38,988
2006	21,158	19,488	40,646
2007	22,956	19,488	42,444
2008	24,908	19,488	44,396
2009	27,025	19,488	46,513
2010	29,322	19,488	48,810
2011	31,814	19,488	51,302
2012	34,519	19,488	54,007

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Journal Entries

January 1, 2003:		
Long-lived asset (asset retirement cost)	$ 194,879	
Asset retirement obligation liability		$ 194,879
To record the initial fair value of the asset retirement obligation liability		
December 31, 2003–2012:		
Depreciation expense (asset retirement cost)	19,488	
Accumulated depreciation		19,488
To record straight-line depreciation on the asset retirement cost		
Accretion expense	Per schedule	
Asset retirement obligation liability		Per schedule
To record accretion expense on the asset retirement obligation liability		
December 31, 2012:		
Asset retirement obligation liability	440,619	
Wages payable		195,000
Allocated overhead and equipment charges (.80 x $195,000)		156,000
Gain on settlement of asset retirement obligation liability		89,619
To record settlement of the asset retirement obligation liability		

> > > Case B: Initial Measurement Using a Present Value Technique, Subsequent Measurement with Changes in Expected Cash Flows

55-39 This Case is the same as Case A with respect to initial measurement of the asset retirement obligation liability. In this Case, the entity's credit standing improves over time, causing the credit-adjusted risk-free rate to decrease by 0.5 percent to 8 percent at December 31, 2004.

55-40 On December 31, 2004, the entity revises its estimate of labor costs to reflect an increase of 10 percent in the marketplace. In addition, it revises the probability assessments related to those labor costs. The change in labor costs results in an upward revision to the expected cash flows; consequently, the incremental expected cash flows are discounted at the current credit-adjusted risk-free rate of 8 percent. All other assumptions remain unchanged. The revised estimate of expected cash flows for labor costs is as follows.

Cash Flow Estimate	Probability Assessment	Expected Cash Flows
$ 110,000	30%	$ 33,000
137,500	45	61,875
192,500	25	48,125
		$ 143,000

55-41 On December 31, 2012, the entity settles its asset retirement obligation by using an outside contractor. It incurs costs of $463,000, resulting in the recognition of a $14,091 gain on settlement of the obligation. The entity would account for the asset retirement obligation as follows.

Asset retirement obligation liability	$477,091
Outside contractor	463,000
Gain on settlement of obligation	$ 14,091

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Initial Measurement of the Asset Retirement Obligation Liability at January 1, 2003

	Expected Cash Flows 1/1/03
Expected labor costs	$ 131,250
Allocated overhead and equipment charges (.80 × $131,250)	105,000
Contractor's markup [.20 × ($131,250 + $105,000)]	47,250
Expected cash flows before inflation adjustment	283,500
Inflation factor assuming 4 percent rate for 10 years	1.4802
Expected cash flows adjusted for inflation	419,637
Market-risk premium (.05 × $419,637)	20,982
Expected cash flows adjusted for market risk	$ 440,619
Present value using credit-adjusted risk-free rate of 8.5 percent for 10 years	$ 194,879

Subsequent Measurement of the Asset Retirement Obligation Liability Reflecting a Change in Labor Cost Estimate as of December 31, 2004

	Incremental Expected Cash Flows 12/31/04
Incremental expected labor costs ($143,000 – $131,250)	$ 11,750
Allocated overhead and equipment charges (.80 × $11,750)	9,400
Contractor's markup [.20 × ($11,750 + $9,400)]	4,230
Expected cash flows before inflation adjustment	25,380
Inflation factor assuming 4 percent rate for 8 years	1.3686
Expected cash flows adjusted for inflation	34,735
Market-risk premium (.05 × $34,735)	1,737
Expected cash flows adjusted for market risk	$ 36,472
Expected present value of incremental liability using credit-adjusted risk-free rate of 8 percent for 8 years	$ 19,704

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Interest Method of Allocation

Year	Liability Balance 1/1	Accretion	Change in Cash Flow Estimate	Liability Balance 12/31
2003	$ 194,879	$ 16,565		$ 211,444
2004	211,444	17,973	$ 19,704	249,121 [(a)]
2005	249,121	21,078		270,199
2006	270,199	22,862		293,061
2007	293,061	24,796		317,857
2008	317,857	26,894		344,751
2009	344,751	29,170		373,921
2010	373,921	31,638		405,559
2011	405,559	34,315		439,874
2012	439,874	37,217		477,091

Schedule of Expenses

Year-End	Accretion Expense	Depreciation Expense	Total Expense
2003	$ 16,565	$ 19,488	$ 36,053
2004	17,973	19,488	37,461
2005	21,078	21,951	43,029
2006	22,862	21,951	44,813
2007	24,796	21,951	46,747
2008	26,894	21,951	48,845
2009	29,170	21,951	51,121
2010	31,638	21,951	53,589
2011	34,315	21,951	56,266
2012	37,217	21,951	59,168

(a) The remainder of this table is an aggregation of two layers: the original liability, which is accreted at a rate of 8.5%, and the new incremental liability, which is accreted at a rate of 8.0%.

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Journal Entries

January 1, 2003:		
Long-lived asset (asset retirement cost)	$ 194,879	
Asset retirement obligation liability		$ 194,879
To record the initial fair value of the asset retirement obligation liability		
December 31, 2003:		
Depreciation expense (asset retirement cost)	19,488	
Accumulated depreciation		19,488
To record straight-line depreciation on the asset retirement cost		
Accretion expense	16,565	
Asset retirement obligation liability		16,565
To record accretion expense on the asset retirement obligation liability		
December 31, 2004:		
Depreciation expense (asset retirement cost)	19,488	
Accumulated depreciation		19,488
To record straight-line depreciation on the asset retirement cost		
Accretion expense	17,973	
Asset retirement obligation liability		17,973
To record accretion expense on the asset retirement obligation liability		
Long-lived asset (asset retirement cost)	19,704	
Asset retirement obligation liability		19,704
To record the change in estimated cash flows		
December 31, 2005–2012:		
Depreciation expense (asset retirement cost)	21,951	
Accumulated depreciation		21,951
To record straight-line depreciation on the asset retirement cost adjusted for the change in cash flow estimate		
Accretion expense	Per schedule	
Asset retirement obligation liability		Per schedule
To record accretion expense on the asset retirement obligation liability		
December 31, 2012:		
Asset retirement obligation liability	477,091	
Gain on settlement of asset retirement obligation liability		14,091
Accounts payable (outside contractor)		463,000
To record settlement of the asset retirement obligation liability		

> > > Case C: Recognition and Measurement Over More than One Reporting Period

55-42 This Case depicts an entity that places a nuclear utility plant into service on December 31, 2003. The entity is legally required to decommission the plant at the end of its useful life, which is estimated to be 20 years. Based on the requirements of this Subtopic, the entity recognizes a liability for an asset retirement obligation and capitalizes an amount for an asset retirement cost over the life of the plant as contamination occurs. The following schedule reflects the expected cash flows and respective credit-adjusted risk-free rates used to measure each portion of the liability through December 31, 2005, at which time the plant is 90 percent contaminated.

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Date	Expected Cash Flows	Credit-Adjusted Risk-Free Rate
12/31/03	$ 23,000	9.0%
12/31/04	1,150	8.5
12/31/05	1,900	9.2

55-43 On December 31, 2005, the entity increases by 10 percent its estimate of expected cash flows that were used to measure those portions of the liability recognized on December 31, 2003, and December 31, 2004, which results in an upward revision to the expected cash flows. Accordingly, the incremental expected cash flows of $2,415 [$2,300 (10 percent of $23,000) plus $115 (10 percent of $1,150)] are discounted at the then-current credit-adjusted risk-free rate of 9.2 percent and recorded as a liability on December 31, 2005. The entity would account for the asset retirement obligation as follows.

	Date Incurred		
	12/31/03	12/31/04	12/31/05
Initial measurement of the asset retirement obligation liability:			
Expected cash flows adjusted for market risk	$ 23,000	$ 1,150	$ 1,900
Credit-adjusted risk-free rate	9.00%	8.50%	9.20%
Discount period in years	20	19	18
Expected present value	$ 4,104	$ 244	$ 390
Measurement of incremental expected cash flows occurring on December 31, 2005:			
Incremental expected cash flows (increase of 10 percent)			$ 2,415
Credit-adjusted risk-free rate at December 31, 2005			9.20%
Discount period remaining in years			18
Expected present value			$ 495

Carrying Amount of Liability Incurred in 2003

Year	Liability Balance 1/1	Accretion (9.0%)	New Liability	Liability Balance 12/31
2003			$ 4,104	$ 4,104
2004	$ 4,104	$ 369		4,473
2005	4,473	403		4,876

Carrying Amount of Liability Incurred in 2004

Year	Liability Balance 1/1	Accretion (8.5%)	New Liability	Liability Balance 12/31
2004			$ 244	$ 244
2005	$ 244	$ 21		265

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**Carrying Amount of Liability Incurred in 2005
Plus Effect of Change in Expected Cash Flows**

Year	Liability Balance 1/1	Accretion (9.2%)	Change in Estimate	New Liability	Liability Balance 12/31
2005			$ 495	$ 390	$ 885

Carrying Amount of Total Liability

Year	Liability Balance 1/1	Accretion	Change in Estimate	New Liability	Total Carrying Amount 12/31
2003				$ 4,104	$ 4,104
2004	$ 4,104	$ 369		244	4,717
2005	4,717	424	$ 495	390	6,026

Journal Entries

December 31, 2003:		
Long-lived asset (asset retirement cost)	$4,104	
Asset retirement obligation liability		$4,104
To record the initial fair value of the asset retirement obligation liability incurred this period		
December 31, 2004:		
Depreciation expense ($4,104 ÷ 20)	205	
Accumulated depreciation		205
To record straight-line depreciation on the asset retirement cost		
Accretion expense	369	
Asset retirement obligation liability		369
To record accretion expense on the asset retirement obligation liability		
Long-lived asset (asset retirement cost)	244	
Asset retirement obligation liability		244
To record the initial fair value of the asset retirement obligation liability incurred this period		
December 31, 2005:		
Depreciation expense [($4,104 ÷ 20) + ($244 ÷ 19)]	218	
Accumulated depreciation		218
To record straight-line depreciation on the asset retirement cost		
Accretion expense	424	
Asset retirement obligation liability		424
To record accretion expense on the asset retirement obligation liability		
Long-lived asset (asset retirement cost)	495	
Asset retirement obligation liability		495
To record the change in liability resulting from a revision in expected cash flow		
Long-lived asset (asset retirement cost)	390	
Asset retirement obligation liability		390
To record the initial fair value of the asset retirement obligation liability incurred this period		

> > > Case D: Conditional with Low Likelihood of Enforcement

55-44 This Case illustrates a timber lease in which the lessor has an option to require the lessee to settle an asset retirement obligation. Assume an entity enters into a five-year lease agreement that grants it the right to harvest timber on a tract of land and that agreement grants the lessor an option to require that the lessee reforest the underlying land at the end

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of the lease term. Based on past history, the lessee believes that the likelihood that the lessor will exercise that option is low. Rather, at the end of the lease, the lessor will likely accept the land without requiring reforestation. The lessee estimates that there is only a 10 percent probability that the lessor will elect to enforce reforestation. Paragraph 840-10-15-15 explains that Topic 840 does not apply to lease agreements concerning the rights to explore for or to exploit natural resources such as timber.

55-45 At the end of the first year, 20 percent of the timber has been harvested. The lessee estimates that the possible cash flows associated with performing reforestation activities in 4 years for the portion of the land that has been harvested will be $300,000. When estimating the fair value of the asset retirement obligation liability to be recorded (using an expected present value technique), the lessee incorporates the probability that the restoration provisions will not be enforced.

Possible Cash Flows	Probability Assessment	Expected Cash Flows
$ 300,000	10%	$ 30,000
-	90	-
		$ 30,000
Expected present value using credit-adjusted risk-free rate of 8.5 percent for 4 years		$ 21,647

55-46 During the term of the lease, the lessee should reassess the likelihood that the lessor will require reforestation. For example, if the lessee subsequently determines that the likelihood of the lessor electing the reforestation option has increased, that change will result in a change in the expected cash flows and be accounted for as illustrated in Case B.

> > Example 3: Recognition of a Conditional Asset Retirement Obligation

55-47 This Example includes four Cases that illustrate when an entity would be required to recognize the fair value of an asset retirement obligation. The Cases do not provide specific guidance for determining when an entity has sufficient information to reasonably estimate the fair value of the asset retirement obligation. The determination as to when an entity has sufficient information to reasonably estimate the fair value of an asset retirement obligation should be based on the guidance in paragraphs 410-20-25-8 through 25-11. The Cases illustrate the initial recognition of a conditional asset retirement obligation based on the facts presented. Any differences in facts from those presented in the Cases may result in different conclusions.

55-48 The following Cases illustrate the guidance in paragraphs 410-20-25-7 through 25-11 and 410-20-30-1:

a. An entity has sufficient information to reasonably estimate the fair value of an asset retirement obligation at the time the obligation is incurred (Cases A and B).

b. An entity does not have sufficient information to reasonably estimate the fair value of an asset retirement obligation at the time the obligation is incurred (Case C).

c. An entity initially does not have sufficient information and later has sufficient information to reasonably estimate the fair value of an asset retirement obligation (Case D).

> > > Case A: Recognition when Fair Value Can Be Reasonably Estimated

55-49 Assume a telecommunications entity owns and operates a communication network that uses wood poles that are treated with certain chemicals. There is no legal requirement to remove the poles from the ground. However, the owner may replace the poles periodically for a number of operational reasons. Once the poles are removed from the ground, they may be disposed of, sold, or reused as part of other activities. There is existing legislation that requires special disposal procedures for the poles in the particular state in which the entity operates.

55-50 At the date of purchase of the treated poles, the entity has the information to estimate a range of potential settlement dates, the potential methods of settlement, and the probabilities associated with the potential settlement dates and methods based on established industry practice. Therefore, at the date of purchase, the entity is able to estimate the fair value of the liability for the required disposal procedures using an expected present value technique.

55-51 Although the timing of the performance of the asset retirement activity is conditional on removing the poles from the ground and disposing of them, existing legislation creates a duty or responsibility for the entity to dispose of the poles in accordance with special procedures, and the obligating event occurs when the entity purchases the treated poles. Although the entity may decide not to remove the poles from the ground or may decide to reuse the poles and thereby defer settlement of the obligation, the ability to defer settlement does not relieve the entity of the obligation. The poles will eventually need to be disposed of using special procedures, because the poles will not last forever. Additionally, the ability of the entity to sell the poles prior to disposal does not relieve the entity of its present duty or responsibility to settle the

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obligation. The sale of the poles transfers the obligation to another entity. The assumption of the obligation by the buyer affects the exchange price. The bargaining of the exchange price reflects the buyer's and seller's individual estimates of the timing and (or) amount of the cost to extinguish the obligation.

55-52 The asset retirement obligation should be recognized when the entity purchases the poles because the entity has sufficient information to estimate the fair value of the asset retirement obligation. Because the legal requirement relates only to the disposal of the treated poles, the cost to remove the poles is not included in the asset retirement obligation. However, if there was a legal requirement to remove the treated poles, the cost of removal would be included.

> > > Case B: Recognition when Fair Value Can Be Reasonably Estimated

55-53 Assume an entity recently purchased several kilns lined with a special type of brick. As of the date of purchase, the kilns had not yet been used in any smelting processes. The kilns have a long useful life, but the bricks are replaced periodically. Because the bricks become contaminated with hazardous chemicals while the kiln is operated, a state law requires that when the bricks are removed, they must be disposed of at a special hazardous waste site. The entity has the information to estimate a range of potential settlement dates, the method of settlement, and the probabilities associated with the potential settlement dates based on its past practice of replacing the bricks to maintain the efficient operation of the kiln.

55-54 Therefore, at the date the bricks become contaminated because of the operation of the kiln, the entity is able to estimate the fair value of the liability for the required disposal procedures using an expected present value technique.

55-55 Although performance of the asset retirement activity is conditional on removing the bricks from the kiln, existing legislation creates a duty or responsibility for the entity to dispose of the bricks at a special hazardous waste site, and the obligating event occurs when the entity contaminates the bricks. As of the purchase date, the kilns have not yet been used in any smelting processes, and the bricks have not yet been contaminated. Therefore, at the date of purchase, no obligation exists because the bricks have not been contaminated and could be disposed of without performing any special disposal activities.

55-56 The fair value of the asset retirement obligation should be recognized once the kilns have been placed into operation and the bricks are contaminated. Although the entity may decide not to remove the bricks from the kiln and thereby defer settlement of the obligation, the ability to defer settlement does not relieve the entity of the obligation. The contaminated bricks will eventually need to be removed and disposed of at a special hazardous waste site, because a kiln will not last forever. Therefore, the obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing of settlement. An asset retirement obligation should be recognized once the kilns have been placed into operation and the bricks are contaminated because the entity has sufficient information to estimate the fair value of the asset retirement obligation. The asset retirement obligation is the requirement to dispose of the contaminated bricks at a special hazardous waste site. The cost to remove the bricks is not part of the obligation and should be accounted for as a maintenance or replacement activity.

> > > Case C: Recognition when Entity Has Insufficient Information to Reasonably Estimate Present Value

55-57 Assume an entity acquires a factory that contains asbestos. After the acquisition date, regulations are put in place that require the entity to handle and dispose of this type of asbestos in a special manner if the factory undergoes major renovations or is demolished. Otherwise, the entity is not required to remove the asbestos from the factory. The entity has several options to retire the factory in the future including demolishing, selling, or abandoning it. The entity believes it does not have sufficient information to estimate the fair value of the asset retirement obligation because the settlement date or the range of potential settlement dates has not been specified by others and information is not available to apply an expected present value technique. For example, there are no plans or expectation of plans to undertake a major renovation that would require removal of the asbestos or demolition of the factory. The factory is expected to be maintained by repairs and maintenance activities that would not involve the removal of the asbestos. Also, the need for major renovations caused by technology changes, operational changes, or other factors has not been identified.

55-58 Although the timing of the performance of the asset retirement activity is conditional on the factory undergoing major renovations or being demolished, existing regulations create a duty or responsibility for the entity to remove and dispose of asbestos in a special manner, and the obligating event occurs when the regulations are put in place. Therefore, an asset retirement obligation should be recognized when regulations are put in place if the entity can reasonably estimate the fair value of the liability. In this Case, the entity believes that there is an indeterminate settlement date for the asset retirement obligation because the range of time over which the entity may settle the obligation is unknown or cannot be estimated. Therefore, the entity cannot reasonably estimate the fair value of the liability. Accordingly, the entity would not recognize a liability for the asset retirement obligation when regulations are put in place, but it should disclose a description of the obligation, the fact that a liability has not been recognized because the fair value cannot be reasonably estimated, and the reasons why fair value cannot be reasonably estimated. The entity would recognize a liability in the period in which sufficient information is available to reasonably estimate its fair value.

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> > > Case D: Recognition when Entity Initially Has Insufficient Information, but Later Has Sufficient Information to Reasonably Estimate Present Value

55-59 Assume an entity acquires a factory that contains asbestos. At the acquisition date, regulations are in place that require the entity to handle and dispose of this type of asbestos in a special manner if the factory undergoes major renovations or is demolished. Otherwise, the entity is not required to remove the asbestos from the factory. The entity has several options to retire the factory in the future including demolishing, selling, or abandoning it. At the acquisition date, it is not evident that the fair value of the obligation is embodied in the acquisition price of the factory because both the seller and the buyer of the factory believed the obligation had an indeterminate settlement date, an active market does not exist for the transfer of the obligation, and sufficient information does not exist to apply an expected present value technique. Ten years after the acquisition date, the entity obtains additional information based on changes in demand for the products manufactured at that factory. At that time, the entity has the information to estimate a range of potential settlement dates, the potential methods of settlement, and the probabilities associated with the potential settlement dates and potential methods of settlement. Therefore, at that time the entity is able to estimate the fair value of the liability for the special handling of the asbestos using an expected present value technique.

55-60 Although timing of the performance of the asset retirement activity is conditional on the factory undergoing major renovations or being demolished, existing regulations create a duty or responsibility for the entity to remove and dispose of asbestos in a special manner, and the obligating event occurs when the entity acquires the factory. In this Case, regulations are in place at the date of acquisition that require the entity to handle and dispose of the asbestos in a special manner. Therefore, the obligating event is the acquisition of the factory. If regulations were enacted after the date of acquisition, the obligating event would be the enactment of the regulations (see Case C).

55-61 Although the entity may decide to abandon the factory and thereby defer settlement of the obligation for the foreseeable future, the ability to defer settlement does not relieve the entity of the obligation. The asbestos will eventually need to be removed and disposed of in a special manner, because no building will last forever. Additionally, the ability of the entity to sell the factory does not relieve the entity of its present duty or responsibility to settle the obligation. The sale of the asset would transfer the obligation to another entity and that transfer would affect the selling price. Therefore, the obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and method of settlement.

55-62 In this Case, an asset retirement obligation is not recognized when the entity acquires the factory because the entity does not have sufficient information to estimate the fair value of the obligation. The entity would disclose a description of the obligation, the fact that a liability has not been recognized because the fair value cannot be reasonably estimated, and the reasons why fair value cannot be reasonably estimated. An asset retirement obligation would be recognized by this entity 10 years after the acquisition date because that is when the entity has sufficient information to estimate the fair value of the asset retirement obligation.

> > Example 4: Historical Waste on Electrical and Electronic Equipment Associated with EU Directive 2002/96/EC

55-63 This Example illustrates the guidance in paragraphs 410-20-55-23 through 55-29.

55-64 Assume an entity (a commercial user) is currently using electronic equipment that must be disposed of in accordance with the requirements of EU Directive 2002/96/EC. The EU-member country has not yet adopted the legislation. The entity has the ability either to replace the equipment or to dispose of the equipment without replacing it. In the EU-member country in which the entity operates, the producer of the replacement equipment will be wholly responsible for disposal costs if and when the equipment is replaced. The recycling of electronic waste equipment is not a revenue-generating business activity of the producer.

55-65 Upon the adoption of the legislation, the entity should recognize a liability for the fair value of the asset retirement obligation. Upon initial recognition of a liability, the entity should capitalize an asset retirement cost by increasing the carrying amount of the related asset by the same amount as the liability. The accounting subsequent to the initial recognition of the asset and liability should be consistent with the guidance in paragraphs 410-20-35-3 through 35-6.

55-66 The waste management obligation remains with the commercial user until the historical waste equipment is replaced or is disposed of by the commercial user itself. Assuming the equipment is replaced, the entity should determine the portion of the purchase price that relates to the cost of the replacement asset and the portion that relates to the assumption of the obligation by the producer. That determination should be based on the fair value of the obligation, without the sale of the new asset. The entity should recognize a gain or loss based on the difference between the carrying amount of the liability at the date of the sale and the portion of the sales price that relates to the obligation. The producer should recognize revenue for the total amount received, reduced by the fair value of the obligation, and recognize a liability for the fair value of the obligation upon transfer of the obligation from the commercial user. Assuming the equipment is disposed of by the entity rather than replaced, the entity should recognize a gain or loss based on the difference between the carrying amount of the liability at the date of the disposal and the actual cost of disposal. See paragraphs 820-10-55-77 through 55-81 for an illustration of an entity required to estimate the fair value of an asset retirement obligation.

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55-67 For the financing of historical waste, the Directive also distinguishes between historical waste from private households and historical waste from "users other than private households" (referred to as "commercial users").

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Combine Subsections

> Interest

60-1 For guidance related to capitalization of interest cost, see Subtopic 835-20.

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XBRL Links to Codification

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Doss DEC Supplemental Exhibit 1

I/A

Below is a listing of actvities considered for closure of Ash Basins

Ln#	Activity	Long Description	Charge Category	CAMA/CCR Rule reference (Note 1)	Comments
Basin Closure Planning Activities:					
1	Engineering Analysis	Preliminary Engineering analysis to develop high level basin closure plans; this includes documentation requested/required by DEQ	ARO	§ 130A-309.212.(a)	
2	Detailed engineering plans	Detailed engineering plans, drawings and estimates to develop the basin closure plan	ARO	§ 130A-309.212.(a)	
3	Groundwater wells to determine water flow	Installation of groundwater wells, to determine the direction of the flow of ground water, used in the development of closure plans	ARO	§ 130A-309.209, § 130A-309.212.(a)(3)b.	
4	Permitting activities	Costs to produce and submit documentation to obtain required permits	ARO	§ 130A-309.203.	
5	Closure plans	Labor to produce closure plans for submission to regulatory bodies	ARO	§ 130A-309.212.(a)	
6	Public meetings	Labor cost to plan/attend public meetings as required to obtain permits and closure plan approvals	ARO		
7	Corporate Communication	Community outreach and education/corporate communication	O&M	NA	*These costs are not required to comply with law*
8	Groundwater wells monitoring	Installation of groundwater wells, monitoring of results and 30 year maintenance	ARO	§ 130A-309.209, § 130A-309.212.(a)(3)b.	*Excludes secondary source wells and other wells that are not installed for the purposes of monitoring ash basins (such as wells drilled to monitor coal piles and gypsum stacker pads)*
9	Letter(s) of credit (3rd party) as needed		N/A	N/A	*Cannot be charged to ARO; rather would be considered for inclusion in determining the credit-adjusted risk-free rate used for discounting*
10	Engineering studies	Detailed engineering studies to support ARO/Regulatory estimates (internal or external)	ARO		
10-a	EPRI - Coal ash recycling technology and market study	Detailed coal ash recycling/beneficial reuse study required by CAMA	ARO		
11	Ash disposal/placement - "Tipping" fees at landfills	Costs to place materials at off-site or 3rd party owned landfills	ARO	§ 130A-309.212.(a)(1)a.&b.	
12	Charah Termination Fee	Fees to be paid to Charah in the event Duke does not meet the minimum ash storage tonnages, as identified in the contracts	ARO		*Note: CCP Organization would have to demonstrate these were prudently incurred*
13	Donations to counties or municipalities	Donations, charitable or otherwise in conjuction with ash contractual arrangements, not specified as an ash placement fee.	Other		*These costs shall be charged to 426.1 Donations expense*
14	ABSAT Team/Overhead (Hamrick)	Burdened labor allocated to ash basin closure (including expenses)	ARO	§ 130A-309.212.(a)	
15	General EH&S Activities	Compliance and research	ARO	§ 130A-309.212.(a)	
16	Program of record	Development of written program of record	ARO	§ 130A-309.212.(a)	
17	Finance support	Major Projects Finance	ARO	§ 130A-309.212.(a)	
18	Insurance Claim (Support)	Additional finance resources for pulling together coal ash-related insurance claims- time allocated for insurance claim support cannot be charged to ARO, and should be charged to Cap/O&M as appropriate. Insurance proceeds will be netted against Cap/ O&M accounts initially charged for claim support labor, and any insurance proceeds exceeding time charged to Cap/O&M accounts will be credited back to ARO Reg Asset, reducing customer receivable	CAP/ O&M		
19	Supply Chain support	Procurement, contract administration	ARO	§ 130A-309.212.(a)	
20	Project controls oversight	Monitor, control, report, and communicate status of Project scope, schedule, and cost. The PCS works with the PM to provide financial, schedule, and / or risk analyses throughout the lifecycle of the Project.	ARO	§ 130A-309.212.(a)	

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Ln#	Activity	Long Description	Charge Category	CAMA/CCR Rule reference (Note 1)	Comments
21	Contractor review of beneficial reuse	Contractor hired to review and make recommendation on the bid proposals we received on benefical reuse. CAMA required that Duke solicit bids to enhance our beneficial reuse of ash.	O&M		*This activity is similar to preliminary studies where we haven't yet selected the contract, but when the actual implementation of a contract for beneficial reuse is utilized for the removal of ash , then those costs can be recorded as an ARO.*
22	Landfill - Operating plant	Construction of landfill including permit, land acquisition, design - for disposal of production ash and future dry ash only	CAP	§ 130A-309.208.	*Please note - Subtitle D will have closure requirements of the landfill - once the landfill is constructed an ARO to close that landfill must be recorded.*
23	Landfill - Retired plant	Construction of landfill including permit, land acquisition, design - for disposal of existing ash	ARO	§ 130A-309.212.(a)(1)b.	
24	Landfill - Operating plant - combined use	Construction of landfill including permit, land acquisition, design - for disposal of existing wet and future dry ash combined	ARO	§ 130A-309.212.(a)(1)b.	*Includes Gallagher LF expansion engineering analysis/ infrastructure development*
25	Landfill cell closure	Applies to landfills that fall under CCR/ CAMA/ State-specific closure requirements	ARO	§ 130A-309.212.(a)(1)a.	
26	Movement of non-basin historical ash into landfill	Ash found on-site (non-production ash) and moved into on-site landfills, essentially used as fill material to close the landfill	ARO		
27	Post closure maintenance	Post closure maintenance of landfills as required by law	ARO	§ 130A-309.212.(a)(1)a.	Section 257.104(c) of CCR
28	Build Haul roads	Construction of haul roads to/from ash basin	ARO	§ 130A-309.212.(a)(1)a.&b.	
29	Duke labor costs	Duke labor, including burdens and expenses per Duke policy	ARO	§ 130A-309.212.(a)(1)a.&b.	
30	EPC Staff		ARO	§ 130A-309.212.(a)(1)a.&b.	
31	Engineering Procurement & Construction Management		ARO	§ 130A-309.212.(a)(1)a.&b.	
32	Safety Staff		ARO	§ 130A-309.212.(a)(1)a.&b.	
33	QA/QC Plan Development and Execution		ARO	§ 130A-309.212.(a)(1)a.&b.	
34	Field Construction staff		ARO	§ 130A-309.212.(a)(1)a.&b.	
35	Stabilization activities:	Dam stabilization to support timing/approach of basin closure (ex. Animal holes, large vegetation removal (e.g., trees))	ARO	§ 130A-309.212.(a)(4)	*Supports operation/stabilization of basin or dam until timing of closure.*
36	Dam breaching	Activities to prevent dam from breaching	ARO	§ 130A-309.212.(a)(4)	*Supports operation/stabilization of basin or dam until timing of closure.*
37	Dike butrous		ARO	§ 130A-309.212.(a)(4)	*Supports operation/stabilization of basin or dam until timing of closure.*
38	Erosion control	Ex. "rip rap" - which is a temporary structure that is removed after subsequent phases to stabilize and prevent erosion	ARO	§ 130A-309.212.(a)(4)	*Supports operation/stabilization of basin or dam until timing of closure.*
39	Material relocation/ grading		ARO	§ 130A-309.212.(a)(4)	*Supports operation/stabilization of basin or dam until timing of closure. This can be a dam stabilization activity and can also be associated with other CCP work.*
40	Seed/mulch area		ARO	§ 130A-309.212.(a)(4)	*Supports operation/stabilization of basin or dam until timing of closure. This can be a dam stabilization activity and can also be associated with other CCP work.*
41	Sheet Piling	Structural stabilization of dam walls	ARO	§ 130A-309.212.(a)(4)	*Supports operation/stabilization of basin or dam until timing of closure.*
42	Valves on settling ponds	These slide gate isolation valves provide the site with the ability to control flow into the weir boxes, which then discharges into the river or other body of water. During an emergency event, these slide gate isolation valves are used to stop the flow from the ash basin to the river, which helps to mitigate the risk of an unpermitted environmental discharge.	ARO	§ 130A-309.212.(a)(4)	*Supports operation/stabilization of basin or dam until timing of closure.*
43	Import fill/excavate fill or clay/dirt backfill		ARO	§ 130A-309.212.(a)(4)	*This can be a dam stabilization activity and can also be associated with other CCP work.*
44	Dewatering/Dewatering plan	Includes removal or grout of old stormwater pipes to the ash basin to stop water flow into basin	ARO	§ 130A-309.212.(a)(1)	*This includes the temporary System for ROB-121 which is a project to eliminate the discharge flow*
45	Dust Control		ARO	§ 130A-309.212.(a)	
46	Excavation of ash ponds/stacks/materials	*includes excavation on in scope ponds that are removed to build retention ponds*	ARO	§ 130A-309.212.(a)(1)b.	
47	Fill pond area and grade to drain		ARO	§ 130A-309.212.(a)(1)	
48	Grout fractured rock		ARO	§ 130A-309.212.(a)(4)	

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Ln#	Activity	Long Description	Charge Category	CAMA/CCR Rule reference (Note 1)	Comments
49	Loading and hauling of ash materials		ARO	§ 130A-309.212.(a)(1)a.&b.	
50	Mobilization/demobilization	Mobilization and demobilization of work crews and projects on site (includes on site trailers)	ARO	§ 130A-309.212.(a)(1)a.&b.	
51	Rail Loading and unloading		ARO	§ 130A-309.212.(a)(1)a.&b.	
52	Rail heads and spur construction	Includes renovation, rail transportation and/or rail leases	ARO	§ 130A-309.212.(a)(1)a.&b.	*ARO accounting is precedent over lease accounting*
53	Remove wetlands		ARO	§ 130A-309.212.(a)(1)a.&b.	
54	Restore ash stack area and cinder pit area		ARO		
55	Site stormwater controls	including redirection of storm and waste water **as required to close basin**	ARO	§ 130A-309.208.(c)& (d)	
56	Redirection of water from CC/CT sites	Redirection of water that is currently running into ash ponds that need to be dewatered. Includes new piping and avoids continuing to flow water into basin	ARO	§ 130A-309.208.(c)& (d)	
57	Synthetic capping	"cap in place"	ARO	§ 130A-309.212.(a)(1)a.	*More detail may be needed on technologies*
58	Truck wash/rail wash stations		ARO	§ 130A-309.212.(a)(1)a.&b.	
59	Truck/weigh scales	Scales used for weighing ash, including scales located on and off Duke property	ARO	§ 130A-309.212.(a)(1)a.&b.	
60	Vacuum wells		ARO	§ 130A-309.212.(a)(1)a.&b.	
61	Extraction wells and groundwater monitoring	Installation of extraction wells to pump the groundwater to arrest the off-site migration. Includes treatment of the pumped groundwater as needed to meet standards and returned either to the ash basin or the discharge canal. Maintain operation of wells until cleared by DEQ.	ARO		*Required by DEQ*
62	Coal Combustion Products Organization - Overhead allocated to ash basin closure:				
63	CCP Staff - burdened labor including expenses	Burdened labor allocated to ash basin closure (including expenses)	ARO		
64	General EH&S Activities		ARO		
65	Supply Chain function - procurement, contract admin		ARO		
66	Finance support, Major Projects Finance	Direct cost support including contract support, project support, budget support and financial support	ARO		
67	Project controls oversight	Direct project controls support including contract support, project support, budget support and financial support	ARO		
68	Governance & Ops Support (Kerin)	Burdened labor allocated to ash basin closure (including expenses)			
69	Quality Compliance and Oversight	This organization performs quality assurance and control activities to support the CCP & ABSAT organizations for ash basin closure. Responsible for field verification and report closeout. This team supports both ash basins and cooling ponds and activities can be easily segregated.	ARO		
70	Regulatory Affairs Filing and Support	This organization ensures that CCP/CAMA regulatory requirements are implemented, tracked and documented. They are tasked with maintaining the operational record by facility and submittal of documents to the regulator as required.	ARO		
71	Governance & Ops Support	This organization develops and documents the System Owner and business processes, including emergency preparedness and response.	O&M		*Corporate based support*
72	Organization Effectiveness	This organization is the internal controls for operations - responsible for human performance, Corrective Action Program (CAP or "root cause"), performance reporting and self-assessments.	O&M		*Corporate based support*
73	Emergency Preparation Plan Development	Development of Emergency Action Plans (EAPs) across CCP fleet for CCR units classified as high or significant hazard potential, in accordance with CCR Rule.	O&M		
74	Engineering (related to as basins/in scope impoundments) (Renner):				
75	CCR Related engineering – post April 17th	Burdened labor allocated to ash basin closure (including expenses)	ARO		
76	CCR Activities prior to April 17th, including engineering studies specific only to CCR		O&M		

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Ln#	Activity	Long Description	Charge Category	CAMA/CCR Rule reference (Note 1)	Comments
77	Project Engineering		ARO		
78	Outsourced engineering services		ARO		*Note: includes services of National Ash Management Advisory Board (NAMAB)*
79	Configuration Management		ARO		
80	Regional Engineering Services		ARO		
81	Geotechnical Engineering		ARO		
82	Project Management & Implementation (Emergent projects related to ash removal – Murray)				
83	Project initiation – Ash ponds and landfills		ARO		
84	Development of scope documents		ARO		
85	Project Controls	Scheduling and Estimating, Cost Management	ARO		
86	Project Managers, direct labor and expenses	Effective leadership and accountable for project outcomes	ARO		
87	Project Portfolio management		ARO		
88	Groundwater monitoring wells installation	- CAMA requirements	ARO	§ 130A-309.209, § 130A-309.212.(a)(3)b.	
89	Groundwater monitoring wells installation	- capturing results, analysis and required reporting – CAMA	ARO	§ 130A-309.209, § 130A-309.212.(a)(3)b.	
90	Groundwater wells	– 30 year post monitoring maintenance	ARO	§ 130A-309.209, § 130A-309.212.(a)(3)b.	
91	Groundwater Additional Source Wells (NC)	Wells to be drilled outside of basins (such as coal piles, gypsum storage areas and cooling ponds) in order to test for coal ash constituents. Data will be provided to NCDEQ in the Comprehensive Site Assessment.	ARO		*Wells are needed in order to provide sampling data to the NCDEQ- closure cannot be completed without these additional source wells*
92	Operations & Maintenance Activities (related to ash basins/in scope impoundments – Weisker):				
93	Plant demolition activities	Final dismantlement of generation plant	COR		
94	*By Products and Reagents Technical Support		ARO	§ 130A-309.212.(a)(3)b.	* *Need to quantify non-incremental and incremental portion.*
95	*Vegetation management on ash basins and landfills		ARO	§ 130A-309.212.(a)(3)b.	* *Need to quantify non-incremental and incremental portion.*
96	*QA field testing on CCR	This activity includes compaction of fill to meet standards	ARO	§ 130A-309.212.(a)(3)b.	* *Need to quantify non-incremental and incremental portion.*
97	Daily/Weekly/Monthly Inspections (vendor vs. "System Owners")		ARO	§ 130A-309.212.(a)(3)b.	* *Need to quantify non-incremental and incremental portion.*
98	Visual observations of leak detection system		ARO	§ 130A-309.212.(a)(3)b.	* *Need to quantify non-incremental and incremental portion.*
99	Camera inspection of leachate header and sumps		ARO	§ 130A-309.212.(a)(3)b.	* *Need to quantify non-incremental and incremental portion.*
100	Inspect landfill features: leachate, sumps, conveyance system, E&SC structures, dust control and storm water control		ARO	§ 130A-309.212.(a)(3)b.	* *Need to quantify non-incremental and incremental portion.* Please note that ARO cost treatment excludes GIB-156 project (leachate re-route that ties into plant FGD processes) in which installation should be charged as capital and maintenance of the system should be charged as O&M
101	Inspect for erosion, weeds, and other vegetation		ARO	§ 130A-309.212.(a)(3)b.	* *Need to quantify non-incremental and incremental portion.*
102	Removal of trees greater than 2 inches in diameter		ARO	§ 130A-309.212.(a)(3)b.	* *Need to quantify non-incremental and incremental portion.*
103	Mitigation of animal burrows	Basin stability for timing of closure	ARO	§ 130A-309.212.(a)(3)b.	* *Need to quantify non-incremental and incremental portion.*
104	Clean out of LCS Leachate header pipes and sumps		ARO	§ 130A-309.212.(a)(3)b.	* *Need to quantify non-incremental and incremental portion.*
105	Annual topographic survey and capacity analysis		ARO	§ 130A-309.212.(a)(3)b.	* *Need to quantify non-incremental and incremental portion.*
106	Annual Operational Report preparation and submittal		ARO	§ 130A-309.212.(a)(3)b.	* *Need to quantify non-incremental and incremental portion.*
107	Wet CCR Ash Basin Support	– daily logs, water levels discharge, water samples	O&M	NA	
108	Regulatory reqmnts and permit maint – solid waste		O&M	NA	
109	Purchase of mowers to comply with CAMA/CCR		ARO	§ 130A-309.212.(a)(3)b.	
110	Clarifying pond maintenance	This activity includes the annual maintenance, such as pond dredging, for ponds. These are not ash basin ponds	O&M	NA	
111	Operations and Maintenance Manuals (by station)	Detailed documentation of all of the Ash Basin facilities at each site of the inspection, operating and monitoring requirements	O&M	NA	
112	Repairs to landfill caps not subject or required by CCR	Repairs to existing assets, not intended for dam stabilization (ex. Pine Hall Road Landfill at Belews Creek)	O&M	NA	

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Ln#	Activity	Long Description	Charge Category	CAMA/CCR Rule reference (Note 1)	Comments
113	Dam breaching for purpose of new plant construction	Dam breaching/ ash excavation and compaction of soil to required 90% density= ARO; incremental compaction over 90% requirement= Capital	CAP/ARO		** Need to quantify non-incremental and incremental portion.*
114	Non-Ash Basin Management:				
115	Vegetation management for cooling ponds and other non-ash areas		O&M		
116	Gypsum Stacker Pad Construction		CAP		
117	Calibration of truck scales (for gypsum)		O&M		
118	Preparation and submittal of annual reports		O&M		
119	Fly ash silo unloading, equipment maintenance, inspection and calibration		O&M		
120	Haul road monitoring and maintenance	Maintenance/Repairs of haul roads- O&M. Activities such as paving may qualify for Capital treatment (capital project is subject to normal capitalization rules- see Company's Capitalization Policy).	CAP/ O&M		
121	Cooling Pond maintenance (Phase 4/5 - no ash in pond)		O&M		
122	Air quality projects – permits		O&M		
123					
124	**Operating Plant conversion requirements:**				
125	Dry Fly Ash or Bottom Ash Handling Conversion	– modifications to plant equipment	CAP	§ 130A-309.208.(e)	
126	Dry bottom ash handling	– wet rim ditch alternate solution	CAP	§ 130A-309.208.(f)	*Required for continued operation of plant - avoid if closing plant*
127	Dry bottom ash handling	– submerged flight conveyor system	CAP	§ 130A-309.208.(f)	
128	Retention pond and related new piping	Constructed in order to support the on-going operations of an operating plant to be used to accumulate storm water and waste water streams that would not have sufficient CCR material to be considered a location subject to the CCR retirement closure requirements. Includes projects for repurposing the basin into a retention pond where the work being performed does not relate to ash excavation or closing the basin (for example- installation and removal of a sheet pile wall where the wall is not needed for basin closure but rather to support the repurposing project).	CAP		*Required for on-going operations at the plant site for storm and wastewater streams.*
129	Ash Pond Level Instrumentation	Instruments to provide remote monitoring to detect surface water levels in the ponds, which will be communicated to a central server system for monitoring.	CAP/ ARO		*Active Plant- Capital; Retired Plant- ARO*
130	Transmission lines/towers located in ash basins	Costs to construct new relocated line/tower = capital; cost to remove tower in order to close basin = ARO	CAP/ARO		*Capital project is subject to normal capitalization rules.*
131	Transmission and Distribution Related Activities	Costs relating to the contruction of new assets to support on-going T&D activites- Capital. Costs to remove T&D assets to support basin closure- ARO.	CAP/ARO		*Capital project is subject to normal capitalization rules.*
132	Contact Water Management	Costs related to contact water management and/ or loss of containment events that are not part of the basin closure projects	O&M		

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Ln#	Activity	Long Description	Charge Category	CAMA/CCR Rule reference (Note 1)	Comments
	Other:				
133	Groundwater remediation	Environmental remediation activity	Environ Res		*Note: This would apply to plants without a closure obligation*
134	Bottled water to residents	Providing bottled water to residents	ARO		*Required by HB630- temporary supply until residents are permanently connected to a municipal water line*
135	Beneficial reuse (not Asheville)	Projects promoting public health and environmental protection, offering equivalent success relative to other alternatives, and preserving natural resources	ARO	§ 130A-309.212.(a)(1)b.	
136	Beneficiation Facilities	Includes Engineering Analysis and Construction	ARO		*Required per HB 630- supports closure timing and risk ranking*
137	NC CAMA - Regulatory fee	*"shall only be used to pay the expenses of the Coal Ash Management Commission and the DEQ in providing oversight of coal combustion residuals." (Fee = 0.03% of NC revenues for DEP/DEC)*	Other	§ 62-302.1.	*Prohibits the NCUC/SCPSC from allowing utilities to recover this fee*
138	Land purchases for groundwater remediation	Duke will purchase property adjoining our plants with contaminated groundwater to remediate groundwater	ARO		
139	Land purchases due to fugitive landfill dust	Duke will purchase property adjoining our plants due to fugitive dust coating neighboring properties from the construction of a landfill (Cliffside)	Other		*Note: Until the land is re-purposed and is used and useful for plant operations, this shall be charged to FERC account 121 (Nonutility property)*
140	Permanent Connections to (Municipal) Water Supply	Costs of providing permanent, alternative water supplies to neighbors **within a half mile of ash basin compliance boundaries** by Oct 2018. ARO activities include the following: Costs incurred to connect households to the water lines or to install whole house filtration systems, reimbursements to homeowners for installation of water filtration system or connection to municipal water system after receiving Do Not Drink letters (prior to passage of HB630), Payments to periodic maintenance on whole house filter systems, Water Testing for residents within a half mile of the basins in order to determine if the appropriate water filter is in place	ARO		*Required per HB 630- supports risk rankings and closure method Note: costs chargeable to ARO for all residents of the Misty Waters community in Belmont, NC*
141	Permanent Connections to (Municipal) Water Supply for residents across a body of water	**Groundwater testing for all residents across the body of water is chargeable as ARO.** If testing/data shows that groundwater is flowing underneath the river and contamination is present, permanent water source connections are chargeable to ARO. If no contamination is present, connections to permanent water supply should be charged as O&M.	ARO/ O&M		*Pertains to Asheville residents located across the French Broad river*
142	Compensation Packages to Homeowners within a half mile of ash basins	Goodwill payment (currently estimated to be $5,000 per household), stipend for 25 years of water bills, Property Value Protection Plan (PVPP) program costs through 10/2019	O&M		
143	Data gap wells	Groundwater monitoring wells which would support both ash basin closure and a secondary source monitoring (data gap wells). In order to be ARO, basis needs to be supported by comprehensive site assessment and corrective action plan. If this information is not present, should be treated as O&M or capital.	ARO / O&M / Capital		

Note 1: Please note, as of current, this is not an all-inclusive list

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Decommissioning Handbook for Coal-Fired Power Plants

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Technical Report

Decommissioning Handbook for Coal-Fired Power Plants

1011220

Final Report, November 2004

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REPORT SUMMARY

This handbook lays out the steps necessary to fully decommission a coal-fired power plant. The handbook includes ways to handle permitting, environmental cleanup, site dismantlement, site remediation, and discusses overall decommissioning costs. It is based on three actual case studies of coal plants recently decommissioned: the Arkwright coal-fired plant of Georgia Power, the Watts Bar coal-fired plant of TVA, and the Port Washington coal-fired plant of Wisconsin Electric Power.

Background

The average age of fossil generating plants in the United States now exceeds 30 years, and, increasingly, new more productive generating facilities will assume the role of producing energy. Choices exist though for the deployment of older fossil plants. They can be kept operating, if economically competitive, or can be laid up for months or years until market needs justify reactivation. Alternatively, they can be decommissioned, if warranted, and the site reused. A fundamental need for owners of coal-fired plants is to understand the most expedient and cost effective approach to returning the site to a "brownfield" condition.

Objectives

- To compile the latest technologies in a step-by-step approach to fully decommissioning a coal-fired power plant.
- To define cost-effective methods to rehabilitate the plant site and deal with all relevant environmental and regulatory issues.
- To describe how to handle air and water discharges, transformer oils, ash piles and ponds, asbestos disposal, and other site impacts.
- To review actual costs for decommissioning, based on past successfully decommissioned plants.

Approach

The project team selected three recently decommissioned coal-fired power plants that featured different outcomes for the sites. At Arkwright, the plant was removed completely and the site no longer used for generating electricity. At Watts Bar, where nuclear and hydro facilities also exist, the coal-fired plant was partially demolished and the site cleaned up. At Port Washington, the coal-fired plant was demolished and a combined-cycle gas-fired plant built on the same site. In face-to-face meetings, the team reviewed the decommissioning procedures followed by each of the three utilities and then developed the handbook based on a compilation of the practices applied. Each of the three case studies was also documented separately.

Results

It was clear to the team that the strategies employed for decommissioning depended on the future site use, inherent value of the property, and financing of the project. The team divided all plant decommissioning projects into four basic options:

- Maintain the site at present condition with minimal cleanup to meet environmental compliance and ensure safety
- Perform minimal dismantling and demolition while maintaining the site to meet environmental compliance requirements and ensure safety
- Dismantle to the degree required to meet specific needs of a planned reuse of the site
- Full decommissioning

Dealing with waste disposal locations at the site often required a major investment of time and money.

EPRI Perspective

As described in this handbook, fully decommissioning a fossil plant requires proven and cost-effective methods to rehabilitate the plant site so as to ensure environmental compliance for its future use.

What is remarkable is the sheer volume of older units that appear to be headed in the direction of decommissioning, as documented in EPRI's report 1004410 on the outlook for capacity retirements. Such older units may be used seasonally at times of greater demand, or even kept as peaking capacity for use only when electricity prices soar – rather like peaking combustion turbines are deployed. Alternatively, they may be laid up for a short time or indefinitely, in case the market situation changes in the future. However, layup is often a strategic prelude to full retirement since it involves less initial capital expenditure, and allows time to plan for ultimate redevelopment of the site.

What is made clear in EPRI's Decommissioning Handbook for Coal-Fired Power Plants is that there are serious issues in plant site decommissioning, most of them environmental. The disposal of many years of waste products – ash, water, oils, chemicals – and the removal of asbestos, PCBs, lead products, etc., requires both an understanding of the extent of the contamination as well as the best methods of removing and disposing of the substances.

Following decommissioning, site reuse can often result in significant added value for the company and for the local community. This report represents a significant industry advance by laying out the key issues in decommissioning a coal-fired plant.

Keywords

Plant Decommissioning
Coal-Fired Power Plants
Site Environmental Issues
Site Reuse

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GLOSSARY OF ACRONYMS

ACM	asbestos-containing material
ACOE	Army Corp of Engineers
ANSI	American National Standards Institute
ASTM	American Society for Testing and Materials
BTEX	benzene, toluene, ethyl benzene, and xylene
C/D	construction/demolition
CEM	Continuous Emissions Monitor
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act
CFC	Chlorofluorocarbon
CFR	Code of Federal Regulations
CT	combustion turbines
DSI	Dry Sorbent Injection
EPA	U.S. Environmental Protection Agency
EPRI	Electric Power Research Institute
ERT	Emergency Response Team
ESP	Electrostatic Precipitator
FAA	Federal Aviation Administration
HCFC	Hydrochlorofluorocarbon
HWSF	hazardous waste storage facility
IPP/IC	Integrated Pollution Prevention/Integrated Contingency
GPC	Georgia Power Company
GSU	generator step-up
kV	kilovolt
MW	megawatts
NEPA	National Environmental Policy Act
NFPA	National Fire Protection Agency
NIOSH	National Institute of Occupational Safety and Health

NPDES	National Pollutant Discharge Elimination System
O&M	operations and maintenance
OSHA	Occupational Safety and Health Administration
PCB	polychlorinated biphenyl
PEL	Permissible Exposure Limit
ppm	parts per million
RCRA	Resource Conservation and Recovery Act
RMPs	Risk Management Plans
SARA	Superfund Amendments and Reauthorization Act
SPCC	Spill Prevention, Control and Countermeasures
TCLP	toxicity characteristic leaching procedure
TDEC	Tennessee Department of Environment and Conservation
TSCA	Toxic Substances Control Act
TVA	Tennessee Valley Authority
USTs	underground storage tanks
WAC	Wisconsin Administrative Code
WBF	Watts Bar Fossil Plant
WDNR	Wisconsin Department of Natural Resources
We	Wisconsin Electric
WPDES	Waste Pollution Discharge Elimination System

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1 INTRODUCTION

The electric power industry projects that approximately 15,000 megawatts (MW) of coal-fired capacity will be retired from service during the period 2001 to 2010 with an additional 13,000 MW likely to be retired soon after 2010, amounting to a little under five percent of the total coal-fired generating capacity in the United States. The Electric Power Research Institute (EPRI) states in its publication, Outlook for Capacity Retirements Following U.S. Boom in New Supplies, that *"The principal reasons for the small amount of capacity currently facing retirement include lower cost of coal as a fuel source as compared to natural gas, lack of technology advancement in coal combustion, and the structure of the Clean Air Act, which did not impose as stringent requirements on existing coal-fired capacity as it did on new capacity"* ***(1)***.

Power plant retirement constitutes mothballing (or layup), as well as full decommissioning. In this publication, *retirement* will be used synonymously with full decommissioning. Retirement occurs when a plant is declared inoperable, meaning that it is either not economically or not technically feasible to restore the plant to operational status.

Most of the coal-fired power plants slated for retirement are older facilities with lower efficiency, higher emission rates, and lower capacity factors than their more modern counterparts. Retirement of these older plants would have a relatively small impact on the total U.S. coal-fired generation capacity, but conversely, their retirement would have a positive impact on emissions (**1**).

Drivers for plant retirements vary. Among the strongest of drivers are pollution prevention issues caused by current and projected environmental requirements recently announced. The retirement fate of many plants hinge on the future direction of environmental regulations and laws. Other drivers include: (1) overabundance of new capacity from other types of generation, especially the boom in gas-fired supplies; (2) replacement of older, less-efficient plants that have lower reliability and profitability; and (3) the unknowns associated with deregulation of the electric power industry.

Complete decommissioning requires that the plant site be cleaned or remediated to meet full environmental compliance to the extent that the site can be fully used in the future. Reuse of such sites can result in significant added value for the company and can be an asset for the local community as well. Some plant facilities are recognized by communities as being important landmarks. These communities may have a strong desire to preserve the physical facilities or parts of the facilities for posterity. The planned reuse of plant sites, following rehabilitation, can result in major advantages to the surrounding communities and lead to good collaborative efforts between the generating company, city councils, and other public agencies.

Early Examples of Decommissioning

In a white paper, EPRI briefly discussed the decommissioning and redevelopment of two utility sites that have become excellent landmark examples of site reuse: GPU Energy's Front Street Station and We Energies' Lakeside Station (**2**).

Figure 1-1
GPU donated the decommissioned station property to the Pennsylvania Historic and Museum Commission for the maritime museum and permanent berth of the U.S. Brig Niagara - an authentic replica of the U.S. flagship in the 1813 Battle of Lake Erie and Pennsylvania's official flagship.

GPU Energy's Front Street Station was a 118-MW coal-fired power plant located along Lake Erie on Presque Isle Bay. GPU Energy began planning the decommissioning of the plant in 1989. Because the plant was located in the Bayfront District, the city and county government, state agencies, business leaders, and the community became concerned about reuse of the plant site. GPU Energy and these entities coordinated the effort to dismantle and clean up the site so that buildings and infrastructure were preserved for future use. Decommissioning and redevelopment were completed in 1998. The Bayfront District is now a first-class tourist attraction and community cultural center complex that includes the Erie Maritime Museum, Erie County Public Library, and Liberty Park with walking and biking trails, playgrounds, and a dockside amphitheater.

We Energies' Lakeside Station on Lake Michigan, south of downtown Milwaukee, Wisconsin, in the village of St. Francis, was the world's first pulverized coal power plant. After We Energies decided to decommission the plant, Harnischfeger Industries, a major manufacturer of heavy machinery for the pulp/paper and mining industries, approached them with an interest in using the property for their corporate headquarters.

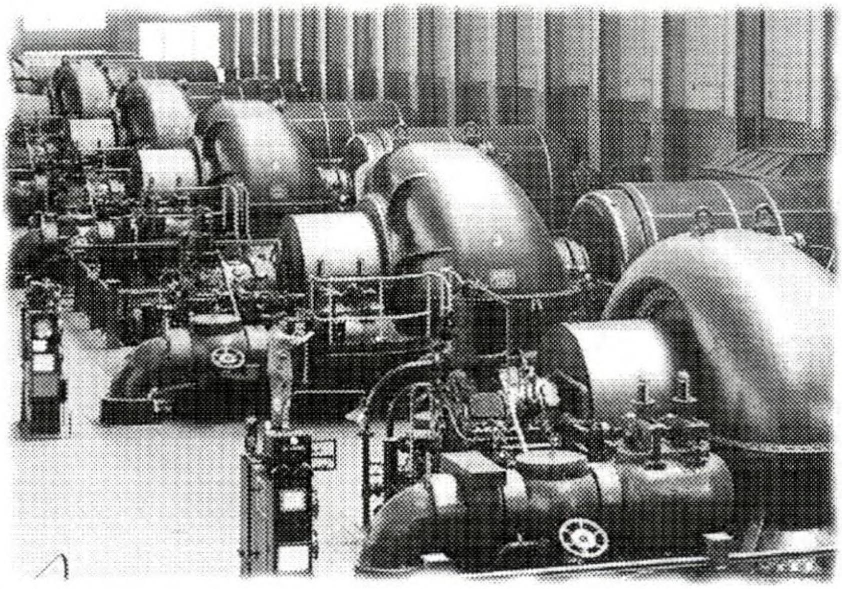


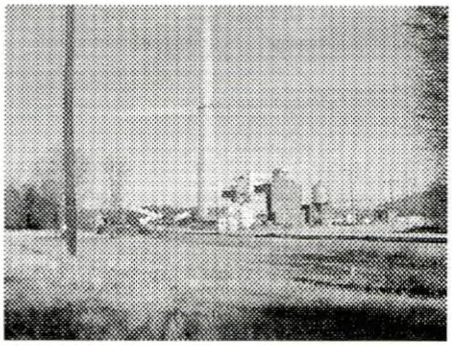
Figure 1-2
Lakeside Power Plant in Wisconsin, with an operating capacity of 40 MW became, in 1921, the world's first plant to burn pulverized coal exclusively.

This spurred interest in redevelopment of the site. We Energies and Harnischfeger Industries, working together, obtained approval from the state to develop the site, and the two entities shared the cost of the cleanup and stabilization of the property along the lake. Harnischfeger Industries then built its new corporate headquarters on the site and has remained there since 1996.

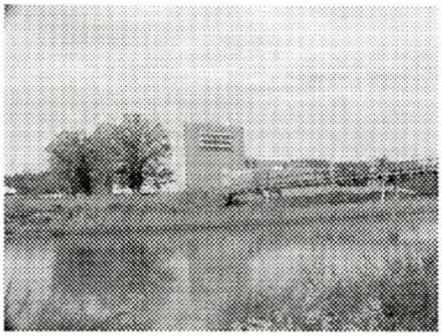
Examples of Decommissioning in this Handbook

The purpose of this report is to present the steps involved in the full decommissioning of older coal-fired power plants, including complete equipment removal and site cleanup.

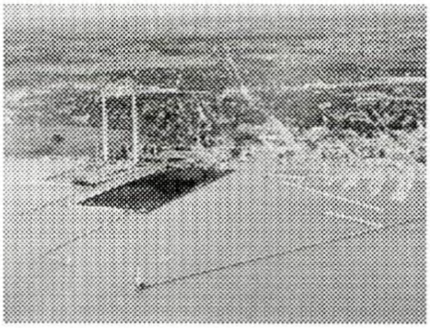
The report also includes the documented approaches taken to decommission three coal-fired power plants:



- Plant Arkwright in Macon, Georgia – Georgia Power Company (GPC). **See Appendix A.**



- Watts Bar Fossil Plant (WBF) in Rhea County, Tennessee – Tennessee Valley Authority (TVA). **See Appendix B.**



- Port Washington Power Plant in Port Washington, Wisconsin – Wisconsin Electric Power Company (We Energies). **See Appendix C.**

Figure 1-3
Plant Arkwright in Macon, Georgia (top); Watts Bar Fossil Plant (WBF) in Rhea County, Tennessee (middle); Port Washington Power Plant in Port Washington, Wisconsin (bottom)

Plant Arkwright is being fully decommissioned to a greenfield site but, as of mid-2004, no definite plans exist for site reuse. WBF decommissioning includes partial demolition and site cleanup, with TVA maintaining environmental compliance and safety at the plant site. Port Washington is in the process of contracting for full decommissioning; part of the site will be returned to the public for reuse, and part of the site will be converted by We Energies to a combined cycle power production facility that uses natural gas. The type of reuse by the public has not yet been defined.

2 OVERALL STRATEGY FOR DECOMMISSIONING A COAL-FIRED POWER PLANT

Preliminary Planning

Almost every utility is being faced with questions about what to do with older coal-fired power plants. Decisions must be made on whether to continue operations, to lay up to meet future demand, or to decommission. Decisions primarily are driven by plant operations and maintenance (O&M) costs, plant operability, cost/benefit analysis, projected environmental regulations, projected power demands, the utility's generation mix, public support, etc. As noted in the introduction of this publication, plant age and operability, along with environmental concerns and efficiencies, are resulting in more and more utilities choosing to decommission certain plants (**1**).

When a utility decides to decommission a plant, strategies for accomplishing this mission must be developed. No longer is it acceptable to lock the doors and walk away from an industrial facility. Laws, based on environmental and safety issues, as well as community concerns for appearance, make such action illegal. Facilities that are abandoned or not remediated properly can eventually become brownfield sites, with site remediation managed and regulated under the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) and, on a few occasions, the Resource Conservation and Recovery Act (RCRA). In today's marketplace, cost is always a major factor in determining the strategic process.

The extent of decommissioning and cleanup is also determined by the planned reuse of the plant site. The U.S. Environmental Protection Agency (EPA), state, and local remediation standards that must be met depend on whether the property reuse will be residential, commercial, or industrial. Predetermining the reuse of the site can reduce the costs of dismantling and cleanup when buildings and infrastructure are retained; environmental remediation methods can be chosen to meet specific needs; and cleanup standards to be attained may be less stringent (**3**).

The inherent value of property currently occupied by a utility is a significant factor in ultimate reuse opportunities. Lake front property in a metropolitan area will attract a lot of attention, whereas a former industrial site in a rural area may not have many parties interested in redevelopment. In some cases, the existing site has significant value to the utility because of security interests or because other suitable properties for re-powering are not available.

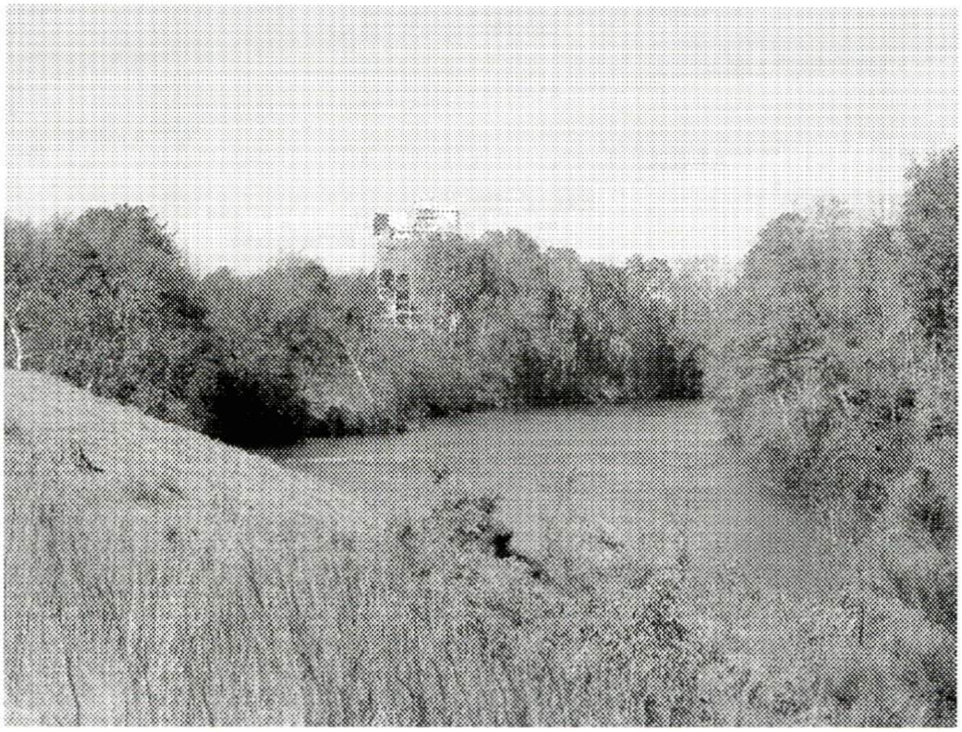


Figure 2-1
The Arkwright plant is on the Ocmulgee River, near Macon, GA, an area for potential re-development, or for open space and parkland.

Utilities usually approach decommissioning by adopting varying degrees of the following strategies:

- Maintain the site at present condition with minimal cleanup to meet environmental compliance and ensure safety (i.e., remove chemicals and oils, restrict access, etc.)
- Perform minimal dismantling and demolition in addition to maintaining the site to meet environmental compliance and ensure safety (i.e., remove salable and salvageable equipment, remove safety hazards, remove chemicals and oils, restrict access, etc.)
- Dismantle to the degree required to meet specific needs of a planned reuse of the site (i.e., remove internals of powerhouse or other buildings so that those structures can be remodeled inside and reused; remove some exterior structures or systems, such as coal handling systems; clean up coal yard; retain some foundations; meet residential, commercial, or industrial environmental standards regarding cleanups; etc.)
- Full decommissioning (i.e., dismantle all equipment; demolish all buildings and structures; clean up entire site, including wet and dry disposal areas, coal yards, etc., per required environmental standards.)

How to finance the decommissioning will strongly influence the strategy selected. If reuse of the site is planned, costs for the cleanup can be shared by the utility and the collaborating party. Sometimes, if reuse of the site will result in an economic advantage to the community, local and state governments may be willing to share in the costs through funding or tax incentives. Whatever strategy is chosen, close collaboration with affected local, state, and federal environmental agencies and public organizations must be pursued and maintained.

Once a decommissioning strategy is selected, the company must determine who will perform the decommissioning tasks. The following approaches may be taken:

- The utility manages the project and performs all dismantling, demolition, and clean-up tasks.
- The utility manages the project but contracts the decommissioning tasks to multiple contractors.
- The utility manages the project and contracts the decommissioning to a single contractor.
- The utility contracts for a turn-key operation.

General Environmental and Safety Regulatory Issues

Environmental regulations have had, and will continue to have, a profound influence on the design and operation of both new and existing power plants (**4**). Therefore, it is no surprise that one of the primary concerns in decommissioning a power plant is how to manage environmental issues. Existing permits must be modified, revised, or cancelled and/or new permits obtained.

Compliance with environmental statutes must be maintained throughout demolition and remediation. Compliance must also be maintained regarding any permits that have post-closure requirements, such as permits for coal ash ponds, hazardous waste storage or accumulation areas, or chemical cleaning ponds.

Planning should include an environmental assessment of the decommissioning process, with review of the draft plans by environmental leaders in the company. It is very important also to include state regulators (and, if applicable, EPA) early in the process, before actual decommissioning commences. Involving state and other regulatory officials should include a presentation of environmental plans. Different states will have different levels of authorization for permits in the various media (air, land, and water); therefore, plants may be regulated by both EPA and state environmental agencies, sometimes independently for the same environmental media.

Permitting

The types of permits applicable to a plant will depend on the various operations conducted, such as type of air emission controls, dry or wet disposal of ash, wastewater treatment, etc. Plants located in the middle of a coal field or in an urban setting may have additional environmental concerns that must be considered during decommissioning and that are not common to the general plant population. This permitting process may include canceling, revising, or maintaining old permits or applying for new permits.

Clean Air Act

Regulatory officials should be notified of the utility's intent to allow the plant air permit to expire. However, because decommissioning activities can result in visible emissions from demolition of buildings and disturbance of the soil, any changes due to expected increases/decreases in visible emissions should be communicated to regulators, and permit changes or new applications should be made. Risk Management Plans (RMPs) should be reviewed for required notifications when storage of onsite chemicals ceases. RMPs must be updated and resubmitted before changes are made at the site.

Figure 2-2
Cleanup of the coal yard (such as this one at Port Washington) will likely include an NPDES Stormwater Pollution Control Plan.

National Pollutant Discharge Elimination System (NPDES)

Shutdown of operations will result in the reduction or cessation of wastewater discharges to receiving waterbodies. However, stormwater discharges through NPDES points may continue during and/or after the demolition and remediation of the plant. Some of these discharges may even need to be re-routed. The NPDES permit must be revised to account for any changes in discharges of wastewater or stormwater. For remediation of the coal storage yard or other areas where greater than one acre is disturbed, a construction stormwater permit must be submitted to regulatory officials with a Stormwater Pollution Control plan and/or an Erosion Control plan. "Redwater" (low pH) conditions are not unusual in many of these settings where coal byproducts have been managed. Redwater conditions can lead to challenging treatment options.

Other permits that may require cancellation include water withdrawal permits for obtaining water from a river or permits maintained with the Coast Guard.

Waste Management

Coal-fired power plants typically maintain large volumes of various types of chemicals and materials essential to the operation of the plant. Fossil fuel power plants typically do not generate large quantities of hazardous wastes. In 1993, EPA determined that the large volume wastes, such as fly ash, boiler ash, boiler slag, and flue-gas emission control wastes, should not be regulated as Subtitle C wastes. These wastes were exempted from hazardous waste regulations and instead were addressed by Subtitle D of RCRA (for nonhazardous solid wastes). As a result, fossil fuel power generation waste management generally is addressed by state programs that vary considerably (**5**).

In addition to ash, slag, and flue-gas emission control wastes, typical wastes from coal-fired power plants are water treatment wastes, waste oils, oily refuse, wastewater treatment wastes, used SCR catalysts, degreasers, solvents, blowdown/metal-cleaning solutions, building sump wastes, and general refuse materials. Some of these are treated and disposed onsite in permitted facilities, and others are sent offsite for recycle/disposal. Well in advance of plant operations ceasing, plans should be made to stop orders and shipments of chemicals and other materials and to deplete onsite inventories, either through use or transfer to other facilities. Following shutdown, inventories of chemicals that cannot be recycled or reused, and thus have to be categorized as wastes, should be depleted in the manner already established for disposal during regular operation.

Solid Waste Landfills can be a Major Expense Item in Decommissioning

Some plants may have solid waste permits for dry stacking of fly ash, bottom ash, slag, and air pollution control residue. For other plants, the fly ash, bottom ash, slag, and air pollution control residue may be sent to surface impoundments that, in most states, do not need solid waste permits but must meet some solid waste regulatory design requirements. Also, plants may have surface impoundments for metal-cleaning wastes, boiler blowdown, or makeup water treatment sludge where the water overflow is recycled to the plant or discharged per the NPDES permit.

Closure of surface impoundments and landfills probably will be the most expensive tasks undertaken during a decommissioning process. In some states, surface impoundments may be included in the NPDES permit and not regulated under solid waste regulations until after operation of the impoundment has ceased for a specified number of days.

In a few cases, a plant may have an onsite RCRA hazardous waste storage facility (HWSF). If so, the HWSF must be closed per the post-closure plan included in the RCRA permit.

Permitted solid waste landfills or surface impoundments should be closed per the permit post-closure plans. Many permits and regulations require a prior notification of a set number of days before cessation of operation. Because many of the plants being decommissioned are very old, some of these permitted facilities may not be designed for proper containment per the latest regulations (i.e., clay or synthetic liners) and will require coordination with the regulatory officials to determine proper closure. Proper closure may require a dig and haul operation to transfer the waste to a new onsite permitted facility or to an offsite facility. Areas where the fly ash and bottom ash were temporarily stored before retrieval for beneficial reuse should be remediated per agreement with the regulatory officials. Surface impoundments permitted under NPDES may not have a specified post-closure plan on record with the pertinent regulatory office and may require negotiations for closure.

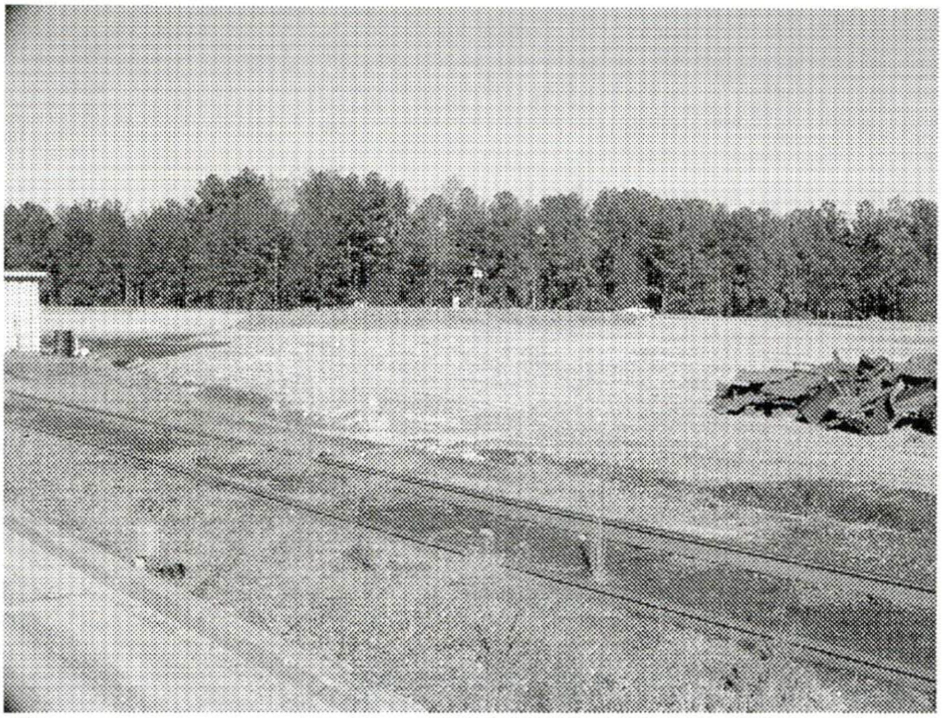


Figure 2-3
Storage of fly ash and other solids require closure according to the post-closure plans for the site. Where an impoundment is deployed, and if the site does not contain a liner, special arrangements may be needed with regulators before final closure can be effected.

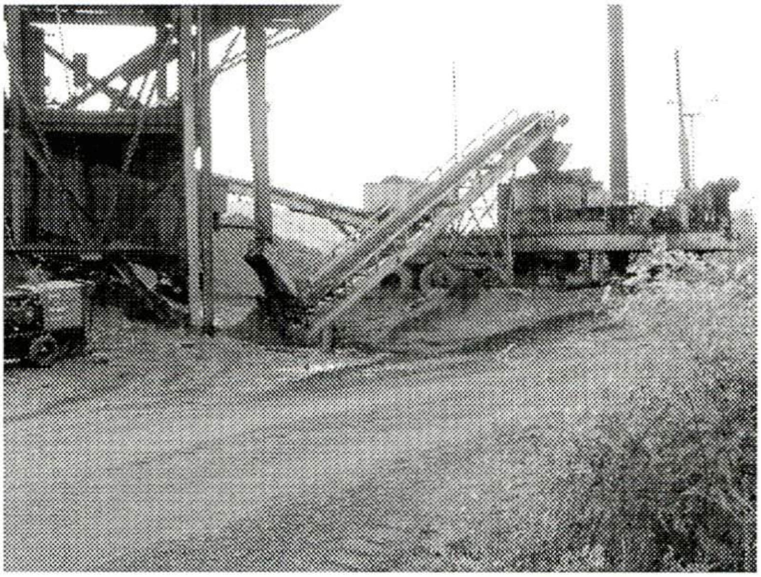


Figure 2-4
Slag and ash reclamation at Watts Bar. These actions may require removal of the materials to alternate facilities.

Capping Solid Waste Impoundments

Closure of most surface impoundments will require drainage, placement of an impermeable cap, and topping with soil and a vegetative cover. Proper placement of the cover and specified slopes will be required. Drainage should be consistent with the NPDES permit. The type and depth of cover required may vary based on the waste disposed in the impoundment. The caps for the impoundments will require continued maintenance to maintain the site contours, vegetative cover, and drainage. Some impoundments will require the installation and monitoring of groundwater wells. The waste in other surface impoundments may be excavated for disposal offsite, and the impoundment backfilled with clean material.

Some plants have permitted onsite construction/demolition (C/D), asbestos, or inert landfills. Because the volume of waste to be disposed may be drastically increased with a plant decommissioning, the permit should be reviewed for possible required notifications to regulatory officials regarding changes in amounts and types of wastes. Plants that do not have an existing C/D landfill must decide whether to seek a new onsite landfill permit or dispose of the C/D waste offsite. Much of the waste, such as brick and concrete, may be used as backfill in the basement of the power house or other recessed areas on the site. The C/D landfill will also require compliance with the permit's post-closure plan.

Asbestos

In older plants, the removal of asbestos-containing material (ACM) in some areas will be a major effort, involving significant expense and requiring completion before workers can safely begin equipment salvage and demolition activities. The ACM abatement effort should begin with a survey of ACM at the plant site to estimate the scope of the task. Asbestos regulations require proper notification before removal, good recordkeeping, and proper disposal techniques. ACM is one of the wastes that must be evaluated for onsite landfill or offsite disposal. ACM is difficult to identify in a survey, and some locations where ACM was used often are not discovered until the demolition process has begun. Therefore, contracts for second party ACM abatement should be carefully written and reviewed.

Chemicals and Materials Removal and Disposal

After stopping order and delivery of chemicals and other materials, disposal of wastes per normal operating procedures should be initiated. During dismantlement other chemicals and materials should be removed and periodically disposed or recycled. Any laboratory chemicals or inventories of metal-cleaning chemicals, which cannot be completely used before shutdown, should be sent for reuse at other company facilities, sold, or disposed properly. Freon, batteries, and residual oils (i.e., used lubricants, fuel, etc.) should be reused, recycled, or disposed of.

Mercury and PCBs

Older plants will have instrumentation and pressure-vapor lighting that contain mercury, or light ballasts and electrical equipment that contain polychlorinated biphenyls (PCBs) at regulated concentrations. The mercury and PCBs should be removed and disposed, or the equipment containing these compounds should be disposed properly. During dismantlement, light bulbs and florescent lighting should be removed and disposed per local and state regulatory requirements. The disposal procedures should be the same as those used during operation.

PCBs may also be present in electrical cables, wiring, fire retardant coatings, paint coatings, hydraulics, relays and controls inside the control room, lighting ballasts, and various items of switchyard equipment. All equipment or cables containing PCBs at concentrations greater that 50 parts per million (ppm) must be managed per regulations specified by the Toxic Substances Control Act (TSCA). Also, concentrations of PCBs between 2 to 49 ppm must be managed per the used oil regulation specified in 40 CFR 761.20 and 279.

Lead Paint

Lead paint is an issue for many older plants. Identification and removal of lead contamination may be required before workers can safely begin equipment salvage and demolition activities in some areas. Flakes of lead paint, which are produced during salvage and dismantlement, must be removed. Disposal or recycling facilities should be notified before shipping materials and equipment coated with lead paint.

If materials and chemicals are stored onsite in order to accumulate quantities for shipment, to await sampling results, or for some other reason, caution should be taken to maintain compliance with regulations for temporary storage of hazardous or special wastes. These requirements can include such things as time limits, container sizes, labeling/markings, inspections, or storage facility specifications.

Scrap Metal

Scrap metal that is being recycled is not subject to regulations under 40 CFR 262–266, 268, and 270, or to the notification requirements of RCRA. Hazardous materials contained in the piping and equipment being dismantled also may be exempted from RCRA. State regulations and the above federal regulations should be reviewed for application during decommissioning.

Coal Inventory

As much of the coal inventory as possible should be burned before plant operations are terminated. If this is not practical because operations cease as the result of equipment failure or a similar reason, the coal should be sent to another facility owned by the parent company or sold for reuse. Any coal residue that is mixed with the soil in the coal yard should be removed and disposed in the ash landfill or surface impoundment. Permission from regulatory officials may be required for this action, if it is not already covered by the solid waste and/or NPDES permits for the receiving facility. If excavation of the soil is required, the coal yard must be filled with clean material and contoured for stormwater runoff. Some regulators may require periodic sampling of monitoring wells.

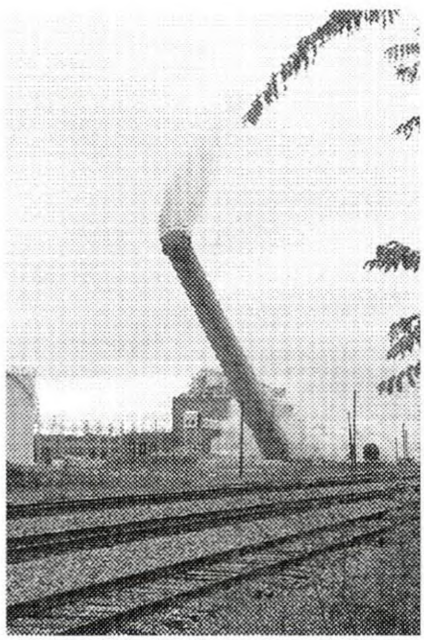


Figure 2-5
The stack is a landmark for airplanes, and for local citizens. Stack demolition is frequently a community event and observers should be kept at a safe distance. The dynamite charges must be placed so that the stack falls clear of any adjacent structures, as here at the Arkright plant.

Underground Storage Tanks (USTs)

If a plant still has USTs, the plant should already be registered with regulatory officials. Removal of the USTs should be performed in accordance with UST regulations. In some cases, monitoring wells may have to be installed, with periodic sampling required.

Federal Aviation Administration (FAA)

If a plant's flue-gas stack affects navigable airspace, the plant should already be registered with the FAA in order to meet obstruction lighting/marking requirements. Caution must be taken during decommissioning to ensure that the lighting for the stack is maintained until the stack is demolished. The FAA should be notified of the pending demolition, if not by requirement, then as a courtesy.

Superfund Amendments and Reauthorization Act (SARA)

Plants should keep a record of SARA-listed wastes, produced during demolition, for reporting on Form Rs. For example, the demolition actions of welding and cutting may cause the plant to exceed reporting limits of some compounds that did not previously require reporting. Local emergency management commissions also should be notified that chemicals will no longer be stored onsite.

National Environmental Policy Act (NEPA)

If the plant is a federally owned facility or if federal funds are being used for the decommissioning, the environmental impact of the planned action must be assessed before shutdown and dismantlement begin. Hopefully, this assessment need only be a supplement to NEPA evaluations performed for previous modifications to the plant.

National Historic Preservation Act

Before actual work on the decommissioning begins, important records and documents should be removed from the site. Because most of the plants to be decommissioned are older plants, care should be taken to evaluate whether any buildings, equipment, instruments, etc., should be preserved. Although many facilities may not be required to perform these evaluations by law, coordination with the state historic preservation officer is recommended to ensure a good neighbor policy.

Figure 2-6
Some buildings of historical value, such as this service/administrative center at Port Washington, may be preserved in the demolition.

Occupational Safety and Health Administration (OSHA)

OSHA regulates demolition in 29 CFR 1926, Subpart T. Also, company and general OSHA rules and regulations should be followed at all times for training, planning, personal protective equipment, markings, tools, electrical equipment, scaffolds, hoisting equipment, excavation, blasting, etc. In accordance with 29 CFR 1926.850 (a), prior to permitting employees to begin demolition operations, an engineering survey of the structure must be made by a competent person.

Proper blasting permits must be obtained before explosives are used during the demolition. Local and state construction permits or licenses may be required for other activities. A licensed and competent contractor who is familiar with these requirements is of utmost importance in these situations.

Notification for Deed to Property

When site remediation is completed, a notation on the deed should be made for any environmental remedial actions required by respective state laws.

Decommissioning Tasks

Utilities may decide on varying degrees of power plant decommissioning of a power plant (i.e., leaving some buildings, the switchyard, etc.) and different property reuses (i.e., residential, commercial, or industrial). The following process assumes the plant is still operating and that decommissioning will require complete dismantlement of buildings and removal of equipment with associated site cleanup to brownfield condition. After the overall strategy for the project is determined, decommissioning will normally consist of the following major tasks:

- Project planning
- Administrative actions
- Plant shutdown
- Site preparation for dismantlement
- Dismantlement of buildings and equipment
- Site remediation and restoration

Project Planning

Once the overall decommissioning strategy has been decided, more-detailed project planning should begin. The initial task will include information gathering essential to planning, such as site and building drawings, environmental assessment, safety engineering survey, and asset inventory. This information will be used to prepare preliminary scheduling and cost estimates.

The environmental assessment should include a review of existing permits, a projection of the need for permit revisions and for new permits, an inventory of chemicals, an ACM survey, and lead paint survey. If federal funds are received, the environmental assessment must include the appropriate NEPA documentation with proper approvals before work commences. The assessment should project environmental solutions and schedules for closure of RCRA sites and final site remediation. The safety engineering survey should identify potential situations that, during dismantlement, might require special preparations to prevent accidents. The survey also should identify any specialized training that might be required. The survey should be the basis of a site Health and Safety Plan. The asset inventory should include materials and equipment that can be salvaged for use at other parent company plants or sold for reuse or scrap. The inventory should include recommendations as to the condition of the materials or equipment to be reused, scrapped, or sold.

Based on these preliminary evaluations, decisions can be made as to the need for temporary storage of salvaged materials and equipment and whether temporary storage of hazardous materials will be required before shipment for offsite disposal.

The environmental assessment, safety engineering survey, and asset inventory should include sufficient detail to (1) prepare a preliminary project cost estimate that includes credit for salvage sales, (2) identify tasks in the preparation of bid proposals for work to be performed, and (3) prepare a preliminary project schedule.

Listing of Specific Tasks to be Accomplished

The end result of the project planning (i.e., cost estimate and schedule) should be a listing and order of tasks required to decommission the plant. Preliminary discussions with experienced demolition contractors would be helpful in determining the best order of events to follow for the dismantlement of equipment and buildings. Among the important decisions to ensure project progress and safety will be the determination of when and how to disconnect portions of the electrical and utility supplies. Although the decision to decommission the plant already will have been made, information from these preliminary evaluations should assist in making the decision as to when plant operations will cease.

During project planning, there might be a tendency to overlook or underestimate the long-term tasks that often occur toward the end of decommissioning. For example, the cleanup of the ash ponds can cost more than the sum of all the earlier tasks. The final tasks for turning property over to a local government or other new tenant may not be fully accounted for during project planning because the ultimate disposition of the property was not clear at that time.

The preliminary contracting strategy and list of tasks can be used to outline the type and number of contracts needed to accomplish decommissioning.

Administrative Actions

The major administrative task is the establishment of contracts for the actions to be taken in decommissioning. The types and number of contracts will be determined by the contracting strategy established by management and project planners.

Another administrative task is coordinating the cleanup of the plant offices, including the selection of existing plant records to be retained and their proper storage. Of particular importance is the retaining of environmental records for the regulated period of time. Some records also must be retained for historical significance.

A decision must be made as to where to establish the temporary offices required for overseeing the dismantlement of the plant and remediation of the site. The offices could be established in an existing building or in mobile offices. Site areas also should be set aside for establishment of temporary contractor offices and a materials and equipment laydown area. Setup would include coordinating installation of necessary utilities.

Plant Shutdown

The date for plant shutdown should be determined during the project planning phase. Electrical grid and economic factors will enter into this decision as well as decommission planning. A primary cost-savings concern for decommissioning is the depletion of fuels and chemicals used during operation. The more of these materials that are depleted, the less the expense incurred will be for transferring them to other plants for use or to other sites for sale or disposal. Routine orders of materials, chemicals, and office supplies should be stopped.

Environmental and other permits should be reviewed to determine their impact on the cessation of operations. For example, some permits specify that, if no activity occurs within a specified period of time, closure of the RCRA facility should begin.

Preparation for decommissioning also should include the flushing of all piping and appropriate equipment, especially chemical lines and the ash disposal lines. This is important for safety concerns during demolition and also to accommodate resale or recycling of the items.

Site Preparation for Dismantlement

Areas of concern in preparation for entering the buildings for dismantlement include:

- Safety training
- Utility supplies
- ACM abatement
- Lead abatement
- Materials and chemical removal

Based on the safety engineering survey and the tasks involved in the approach to be taken in dismantling the facilities (i.e., torching, blasting, entering confined space, rigging, etc.), training of all personnel on the site (utility and contractor) should be performed and documented. Also, appropriate personnel should be trained on applicable environmental permits and regulations.

One of the major safety and demolition concerns is the use of electricity. Major power sources must be deactivated for demolition, but at the same time, power may be needed in other areas of the site for activities. Also, the supplies of water and natural gas utilities must be scheduled and monitored. Because the plant emergency fire protection system will be disturbed during decommissioning, a temporary system should be established. This could be as simple as contracting with a local fire department for temporary support. Minimal auxiliary power may be required for area and building lighting, communications, stack lighting, etc.

Asbestos, Paint, and Chemicals Cautions

ACM should be removed based on the ACM survey. For worker safety and to comply with regulations, ACM must be removed from appropriate facilities and equipment prior to dismantlement activities that could break up, dislodge, or disturb the ACM. However, abatement performance can be scheduled ahead of separate site activities rather than completing abatement for the entire site before dismantlement begins. A majority of the ACM should be found on the equipment, ductwork, piping, and cable. Many plants will have ACM siding on older buildings, most commonly as transite. Plants that have undergone decommissioning report that new sources of ACM were found throughout the dismantlement, even though thorough surveys and prior abatement had been performed. It is beneficial to have a qualified asbestos inspector onsite throughout dismantling to make sure that asbestos-containing wastes are not introduced into the non-hazardous scrap pile.

For worker safety, any flakes of lead paint must be removed prior to worker activities, and the area should be monitored periodically for new accumulations during dismantlement. Lead paint removal also can be scheduled to occur prior to dismantling activities in affected areas rather than being completed at one time for the entire facility.

Before beginning dismantlement, materials and chemicals should be removed from the buildings and tanks. This would include fuel oils, metal-cleaning chemicals, laboratory chemicals, mercury, PCB-containing equipment, batteries, etc. Removal of lighting should be coordinated with the need for lighting for other activities within the buildings or areas.

Dismantlement of Buildings and Equipment

Dismantlement includes stripping all materials and equipment from the buildings and site and tearing down the buildings and separate support facilities.

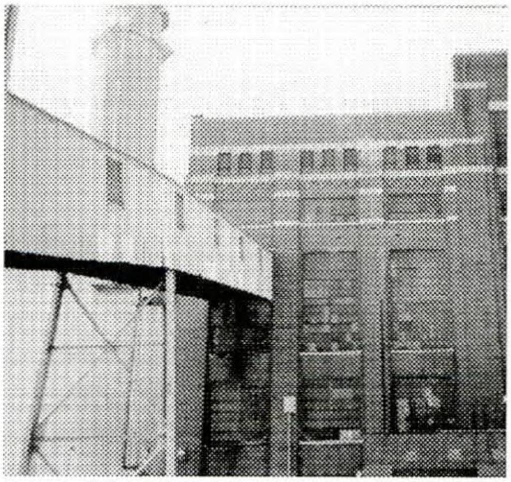


Figure 2-7
Demolition of the stack, coal conveyer, and powerhouse at Port Washington was done in conjunction with the construction of a new gas-fired unit on the same site.

Because there are various coal-fired power plant configurations, the types of equipment, buildings, and support structures will vary. Dismantlement typically will include the following:

- Salvage of materials and equipment
- Demolition of support buildings and structures
- Demolition of powerhouse
- Excavation of foundations and underground piping. Closure of surface impoundments and/or landfills
- Cleanup of coal storage yard.

Material and Equipment Salvage

Using the asset inventory, materials and equipment should be removed and offered to other internal utility sites for reuse, placed in the salvage sale for recycle or reuse, or disposed per regulations. The order of removal will be site dependant and scheduled by the demolition contractor. Removed items will be sorted in a laydown area by condition for reuse. Some items may contain ACM or PCBs, requiring disposal per regulations.

Typical salvageable items that could be reused include pumps, fans, compressors, tanks, electrical equipment, piping, and conveyor components. Because the plants usually are very old, precipitators, scrubbers, boiler components, tubes, economizers, reheaters, ductwork, etc., probably will be salvaged for scrap.

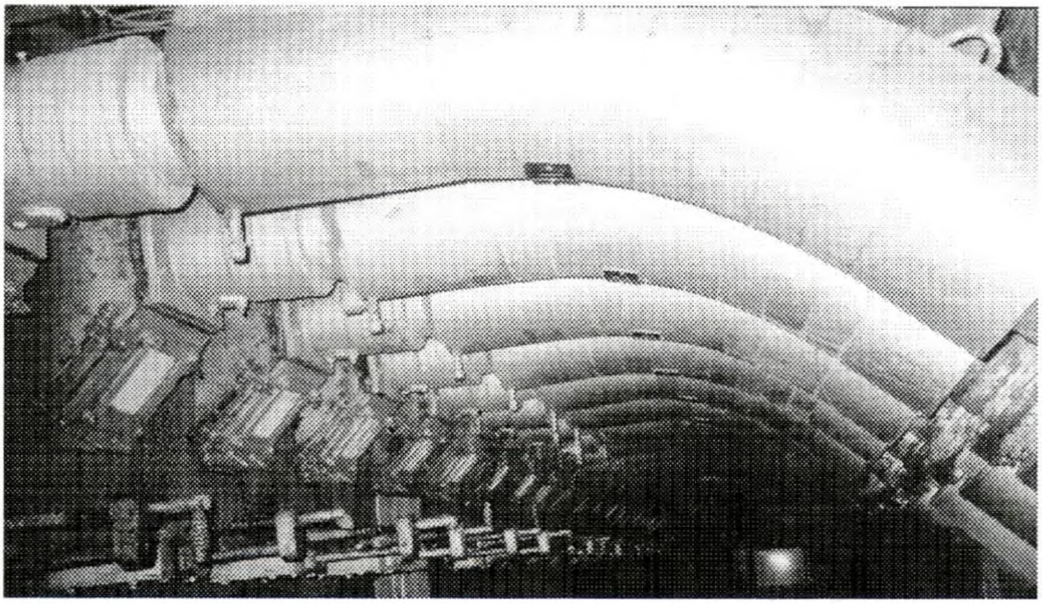


Figure 2-8
Burners, coal/air ducts, and other components from this 1930s vintage CE boiler at Port Washington will likely be sold for scrap. Any asbestos in the insulation must be carefully removed before full dismantling.

The reuse or scrapping of the turbines and generators will depend on the market at that time. Office furniture and electronic equipment should be returned to the leaser, offered to other internal utility sites, or salvaged for resale. Vehicles and heavy equipment used for site transportation and moving of materials and equipment, as needed for operations and coal handling, should be offered to other internal utility sites or for resale. Some of these can be used during decommissioning.

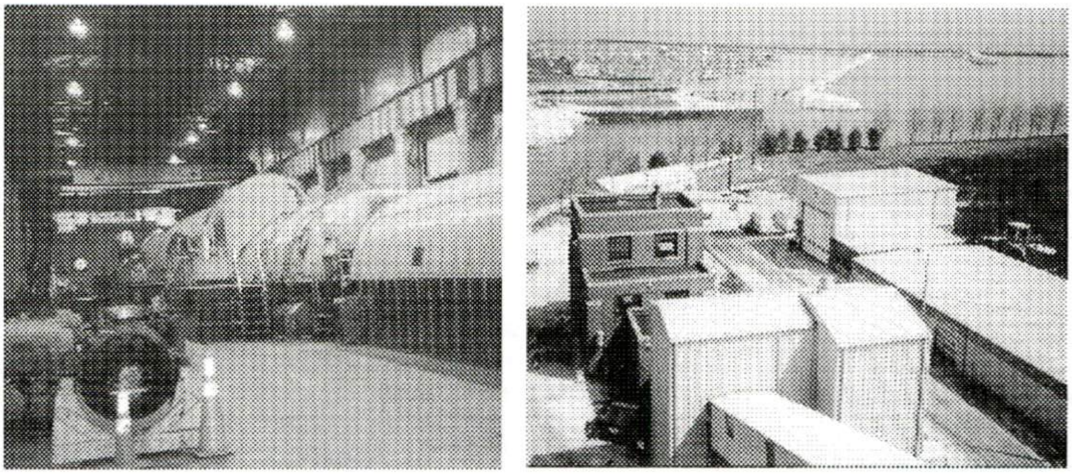


Figure 2-9
The turbine-generator building and the crushing house and conveyers at Port Washington will be removed once all salvageable material has been extracted.

Once the decision has been made as to the possible future use of support buildings, such as laboratories, offices, maintenance, etc., the remaining buildings should be demolished. After salvageable materials and equipment have been removed, support structures, such as pumping stations; coal preparation and handling facilities; rail, truck, or barge coal unloading facilities; railroad tracks; etc., should be demolished. Recyclable materials, such as metal beams, should be separated to be sold for scrap.

Use of Fill Debris

Demolition debris, such as brick and concrete, could be used for fill material for sumps or basements. Some plants will have metal flue-gas stacks on the powerhouse roofs, and others will have brick or concrete stacks on the ground. The demolition contractor will determine whether to let the roof stacks fall when the building structure is imploded and then remove them, or to remove them with a crane. The ground stacks probably will have to be felled with explosives. The deposition on the inside of the stacks should be analyzed for hazardous flue-gas components to determine what may be done with the stack materials. Hopefully, the metal stacks can be recycled and the brick and concrete debris used as backfill in the powerhouse basement or other depressions.

Figure 2-10
The turbine hall at Arkwright will use fill to bring the site up to grade level. A ramp was constructed at one end to permit dump trucks to enter the space.

Once the internal equipment and components are removed, demolition of the powerhouse should begin. Some of the internal items associated with the boiler floor structures may be too large or inaccessible to safely or economically remove before imploding the powerhouse. This also may be true of items located on the roofs of some plants, such as tanks, stacks, and fans. The demolition contractor must decide the best way to deal with the powerhouse basement. If the building is imploded before the basement is filled with inert material, it will be difficult to separate and remove recyclable and non-inert material from a deep basement. Also, it will be difficult to partially fill the basement before imploding the building structure. For many sites, obtaining clean, inert fill material is a problem. If the future use of the site or the future condition of the site is decided before decommissioning, some of the road bed material at the site may be used.

Most plants will have many concrete foundations and underground piping throughout the site. Although it depends on the future plans for the site, most of these should be removed. The rule-of-thumb used for most sites is to remove the foundations to two feet below future grade. Future contouring of the site must be considered in determining grade. Although the foundations will contain metal reinforcing, most regulatory agencies allow their use as backfill material. Some plants may be allowed to plug underground piping and leave it in place. Others may have to remove the underground piping for salvage or disposal.

Closing Surface Landfills

Figure 2-11
Ash ponds such as this one at Arkwright, often take a significant time for remediation. The extent of the clean up might depend on the future re-development plans.

Closure of the surface impoundments and/or landfills may begin any time after they are taken out of service. As stated earlier, closure must be in compliance with existing permits or regulations and coordinated with regulatory officials. These disposal areas include ash ponds, slag ponds, metal-cleaning ponds (chemical ponds), ash piles (used for accumulation before hauling for industrial use), C/D landfills, etc. Closure of these areas usually will take the longest remediation time and may be the most-expensive tasks associated with decommissioning.

After surplus coal is removed, any coal residue that is mixed with the soil in the coal yard should be removed and disposed in the onsite ash landfill or surface impoundment or hauled to an offsite permitted facility. Permission from regulatory officials will be required for this action unless it is already covered by the RCRA and/or NPDES permits for the receiving facility. After the coal and soil mixture is removed, the coal yard should be backfilled with clean material and contoured as needed for stormwater runoff.

Site Remediation and Restoration

To determine the extent of the site remediation and restoration needed, it is important to understand the redevelopment plans for a site. Knowledge of future plans for a site helps to identify existing structures that may be beneficial for reuse and what level of site investigation and clean-up standards will be required. Most sites can follow the EPA guidance and information presented for brownfield sites (**6**). EPA has defined brownfield sites as "abandoned, idled, or under-used industrial and commercial facilities where expansion or redevelopment is complicated by real or perceived environmental contamination." Power plant decommissioning sites can be classified as brownfields because they generally are under-used industrial facilities where redevelopment is complicated by real or perceived environmental contamination. Typically, coal-fired power plants have few hazardous waste sites; therefore, contamination would be mostly perceived. As noted in the environmental assessment section of this report, clean-up standards will depend on whether the anticipated redevelopment is residential, commercial, or industrial. Also, the applicable regulations, laws, and guidelines will vary from site to site and depend on the regulatory authority that oversees the site.

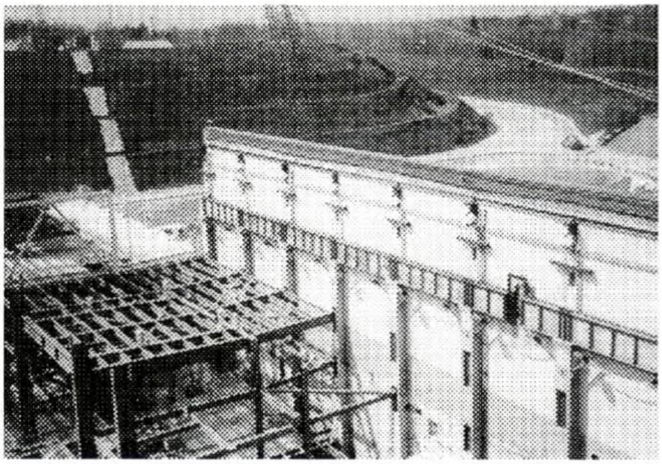


Figure 2-12
Part of the Port Washington site will be used for a new gas-fired combined cycle, shown under construction. The original wall will be retained.

Cleanup of Brownfield Sites

EPA provides information on cleanup of brownfield sites. This information may be accessed at the Web sites: http://www.epa.gov/ and http://www.clu-in.com/. EPA also has published a brownfields guide entitled "Road Map to Understanding Innovative Technology Options for Brownfields Investigation and Cleanup, Third Edition." The road map includes an outline of the steps involved in the cleanup of a site slated for redevelopment and a range of innovative technology options and resources available. The steps to be taken in a clean-up project include:

- Site assessment (American Society for Testing and Materials [ASTM] Phase I environmental site assessment)

- Site investigation (ASTM Phase II environmental site assessment)
- Clean-up options
- Clean-up design and implementation

The purpose of the site assessment is to evaluate the potential for contamination at a particular site. Any further environmental investigation and cleanup depends on whether potential environmental concerns are identified in the site assessment. The site assessment relies mostly on the collection and review of historical documents and on interviews about past and current uses and environmental conditions of the site. An important reference will be the spill history and records required by some environmental permits and documents. The environmental assessments performed in preparation for decommissioning should include this historical search and projection of contaminated sites.

Generating units generally are characterized as having several contamination problems that are relatively immobile but that often occupy large sites. When the contamination is relatively immobile, utilities commonly do not face groundwater remediation problems.

Figure 2-13
Removal of relatively immobile contamination might include fly ash and bottom ash piles, coal piles, rail facilities, substations, and transmission towers.

Such areas for coal-fired power plants might include the coal yard, electrical substations, chemical and metal-cleaning ponds, ash piles or ponds, tank areas, rail facilities, and petroleum-use equipment locations.

Site Investigations

The site investigation phase should focus on confirming whether or not contamination exists at a site, locating any existing contamination, and characterizing the nature and extent of that contamination. Based on the site assessment, sampling of potentially contaminated areas should be performed following established protocols. If predicted by the site assessment or by results from sampling during this phase, migration pathways of contaminants should be evaluated. Historically, contaminants of concern for coal-fired power plants include: (1) arsenic, cadmium, chromium, iron, lead, mercury, nickel, selenium, manganese, and zinc from the fly ash and coal pile areas; (2) polychlorinated biphenyls, polycyclic aromatic hydrocarbon, BTEX (benzene, toluene, ethyl benzene, xylene), and other petroleum hydrocarbons from oil storage and mechanical and electrical equipment; and (3) copper, iron, nickel, chromium, and zinc from metal cleaning and cooling tower blowdown wastewaters.

Special circumstances, such as historical spills, may require investigation for other contaminants. The results of the site investigation can be used to perform a baseline risk assessment to calculate risk to human health or the environment and the concentration levels of contaminants that will require cleanup. In some cases, regulatory action levels of contaminant concentration will be used to determine the appropriate and feasible levels of cleanup. Most entities support the use of risk-based clean-up standards that are specific to the end use of the property rather than "one number fits all" scenarios. Less stringent action levels may be negotiated with regulatory officials if the reuse of the property is known or if deed-record or restrictions are acceptable to redevelopment entities. Projection of the particular clean-up method to be used also can help in designing sampling and analytical plans.

Monitoring and Sampling

Relying on the data collected from the site assessment and investigation phases, clean-up alternatives are evaluated. The technologies should be evaluated for their capability to meet specific clean-up levels and redevelopment objectives, such as schedules, costs, and compatibility with the surrounding environment, area (urban, rural, etc.), and demographics. The need for future monitoring or controls also should be considered when evaluating the various technologies. For example, dig-and-haul with no future maintenance and monitoring may be preferred to a technology that requires the installation of monitoring wells because concentrations of contaminants remain after treatment.

After the areas of contamination are identified and the clean-up technologies are selected, the clean-up plan can be designed and implemented. Following cleanup of the site area, confirmatory sampling should be performed using specific sampling and analytical protocols. Successful confirmatory sampling results are a prerequisite for owners and/or regulatory officials who certify that the property is clean and can be accepted for transfer. It is important to realize that this clean-up phase can be performed concurrently with some of the demolition activities.

Costs for Decommissioning

The costs for decommissioning a power plant will vary considerably depending on the plant and on its location. **Cost information is provided for each of the three reference projects shown in Appendices A, B, and C**. Breakdown of costs as presented by the various utilities are shown in these Appendices.

- Plant Arkwright had four coal-fired units with a 160 MW capacity located outside of Macon, Georgia in a rural area. The units were built in the 1940's and the **estimated cost of decommissioning is $19M**. Plant operations ceased in September 2002 and demolition was completed in March 2004. Cleanup of the site and closure of the ash ponds is anticipated to be complete in 2006.
- Watts Bar Fossil Plant had four coal-fired units with a 240 MW capacity located in Rhea County, Tennessee in a rural area. It is collocated with Watts Bar Hydroelectric Plant and Watts Bar Nuclear Plant. The units were also built in the 1940's. **The estimated cost of decommissioning is $17M - $25M.** The facility was in and out of standby mode from 1983 to 2000 when the decision was made to retire the facility. Contracts for reclaim of boiler slag and ash from the ash ponds for commercial use as a low-duct blasting abrasive are in place through 2007. This plant is a state of partial demolition while maintaining environmental compliance and safe conditions.
- Port Washington Power Plant had six coal-fired units with a 341 MW capacity located in the City of Port Washington, Wisconsin in a scenic part of the city on the banks of Lake Michigan. The units were built in the 1930's and 1940's. **The decommissioning of Units 4-6 was completed in 2003 at a cost of approximately $12.4M. The decommissioning of Units 1-3 are scheduled to begin in November 2004 and be completed in December 2006 at a cost of $17M - $22M.** We Energies is replacing the coal-fired units with two natural gas-fired combined cycle units with a total capacity of 1000 MW. We Energies is providing the former coal dock and 45 acres of land for future development by the community.

3
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A DECOMMISSIONING PLANT ARKWRIGHT, MACON, GEORGIA, GEORGIA POWER COMPANY

Introduction

Georgia Power Company (GPC) retired Plant Arkwright in December 2002. Plant Arkwright was one of two power plants to be retired and dismantled by GPC. Decommissioning of the plant is anticipated to be completed in 2006.

Plant Description

The Arkwright Steam Plant was designed as a four-unit coal-fired electric generating plant located on the Ocmulgee River near Macon, Georgia (Figure A-1). The four coal units had nameplate ratings of 40 MW each. Unit 1 was completed in 1941, Unit 2 in 1942, Unit 3 in 1943, and Unit 4 in 1948. Units 1 and 2 had Westinghouse turbine generators with Combustion Engineering manufactured boilers. Units 3 and 4 had General Electric turbine generators coupled with Babcock and Wilcox boilers. The boilers for all four units were 800-psi and were rated at 400,000 pounds of steam per hour with 850-degree-Fahrenheit steam temperature.

All units were served by one 564-foot concrete stack with one brick liner. Air quality control was achieved using a cold-side precipitator on each unit. The once-through cooling system was served by intake and discharge structures. Fuel-handling facilities included a coal yard, unloading system, conveyors, a crusher house, and a transfer house. The ash system included a 4,000-linear-foot ash disposal pipe trench and two active ash ponds, Number 2 (6 acres) and Number 3 (20 acres). There was one retired ash pond on the site (11 acres). The plant has one 115-kV switchyard which served all generating units.

Other site structures included a water treatment building, warehouse, lighter oil storage facility, natural gas metering station, and retaining wall on the river. Also located on this site were two 15 MW combustion turbines (CT) that were installed in 1969.

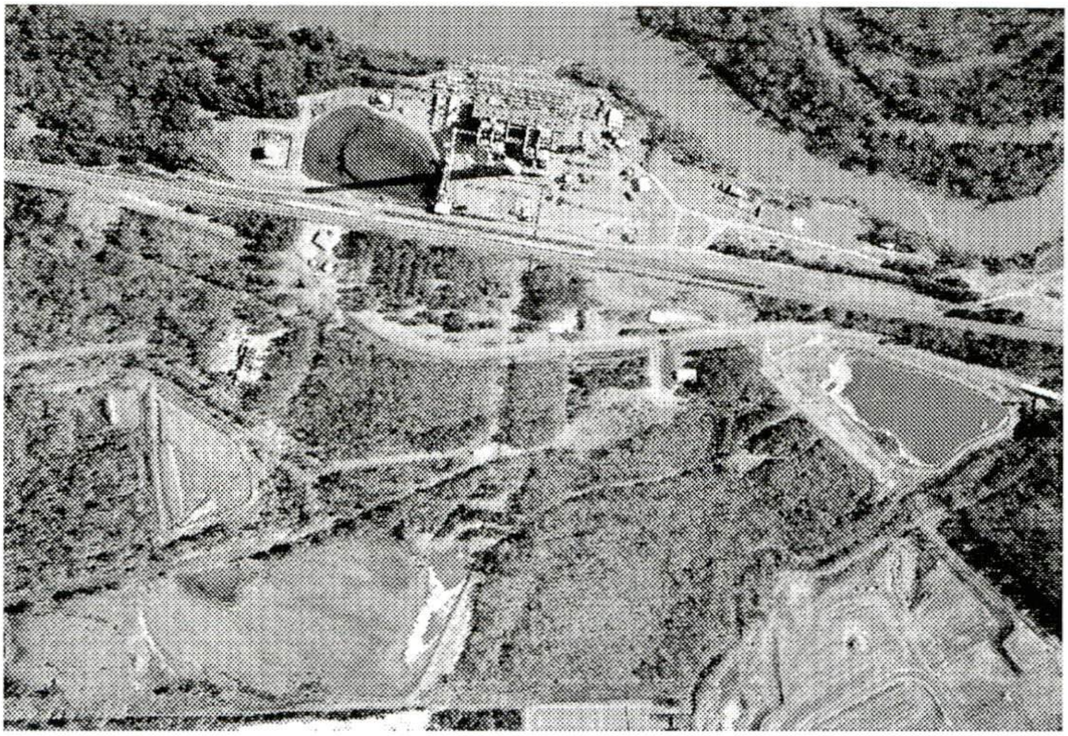

Figure A-1
Aerial View of Plant Arkwright Before Decommissioning. Located on the Ocmulgee River the site included three ash ponds. The switchyard seen behind the boilers was not decommissioned.

Decommissioning Strategy

When GPC made the decision to decommission the plant and restore the site to a condition suitable for future development, it planned to accomplish the decommissioning in two major phases. Phase I consisted of the dismantlement and demolition of the major plant equipment and structures (Figures A-2 thru A-4). Phase II consisted of the ash pond closures, environmental assessment, and any necessary clean-up of the plant site.

The first activity was to develop a dismantling plan. The strategy to achieve Phase I included: (1) evaluation of environmental and permit changes/requirements, (2) asset disposition involving the transfer of materials and equipment to other plants in the system and the salvage and resale of materials and equipment, and (3) dismantlement of the powerhouse and associated structures not slated to remain. The strategy for Phase II included the closing of the three ash ponds and an ash monofill, the preparation of the site for reuse by completing a comprehensive environmental assessment, remediating any environmentally impacted areas, and final site restoration consisting of filling and grading.

GPC personnel were responsible for the environmental evaluation, asset deposition, and closure of the ash ponds. Most of the dismantling work, including asbestos containing material (ACM) abatement and plant site preparation, was performed by a general contractor.

To obtain a general contractor, GPC started with a list of approximately 32 potential contractors. Through a questionnaire, the list was reduced to ten bidders. Bid packages were issued to these contractors for proposals and a pre-bid meeting was held. A sealed bid system with reverse auction on the actual scope of work was used. Bids were evaluated with consideration for exceptions given in determining pricing shown on the bid board. The final bid process included seven contractors. The contract was awarded based upon best value for GPC.

The decommissioning strategy included a plan to keep electrical power to the essential systems during dismantling while deactivating power to non-essential systems. The essential systems included plant lighting, turbine crane, switchyard station service, stack lighting, powerhouse elevators and batteries. Decommissioning also required prior planning for electrical disconnects to insure safety and power when needed. Essential plant records were stored for preservation before decommissioning commenced.

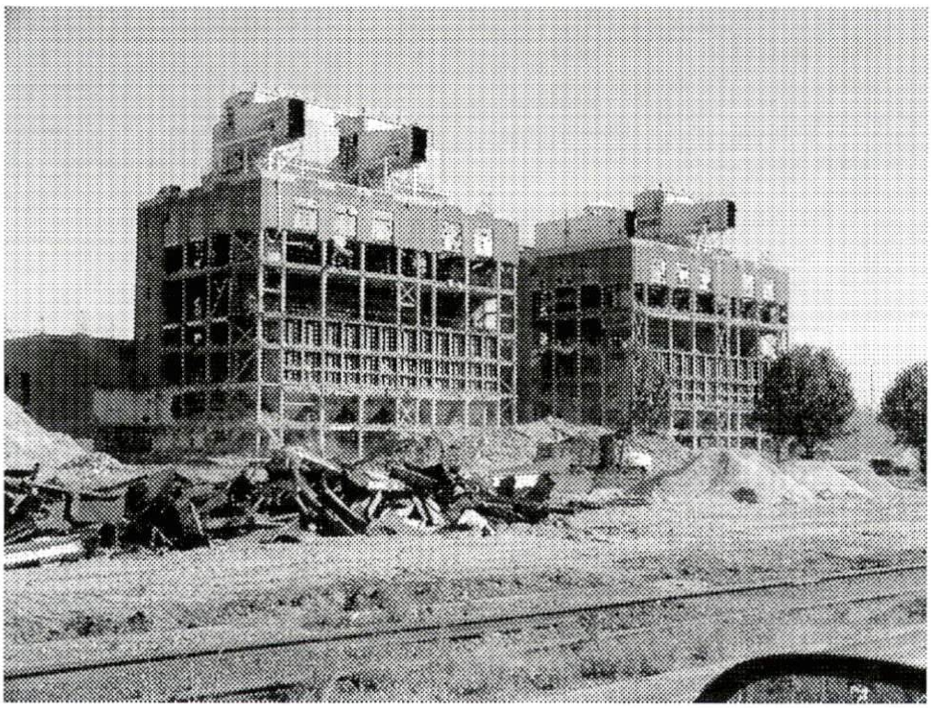

Figure A-2
Plant Arkwright During Dismantling of Powerhouses. The four 40 MW units date from 1941 to 1948. There was one stack.

Figure A-3
Plant Arkwright During Dismantling of Powerhouses. Handling asbestos prior to building demolition was a key activity.

Figure A-4
Plant Arkwright During Dismantling of Powerhouses. No land disturbances were conducted in a 25-foot stream buffer along the Ocmulgee River.

Environmental Evaluation

The planning process for Plant Arkwright included an environmental evaluation to determine the effects of decommissioning on the environment. The evaluation included decisions on handling remaining chemicals and materials, and the need for new permits or changes in existing permits to comply with regulations.

GPC included the state regulators at the beginning of the decommissioning process. Different environmental media experts in the company were assembled to discuss the environmental evaluation. In compliance with the Clean Air Act permit, GPC notified regulatory officials of the last day of generation and set the official permit closure date at December 31, 2002.

The surface water withdrawal permit was retained in the event new generation is constructed at the site. The National Pollutant Discharge Elimination System (NPDES) industrial wastewater permit comes up for renewal every five years. At the time of renewal, the NPDES industrial wastewater permit will be revised to delete all of the discharge points except the overflow stormwater discharged through ash pond number 2 to the creek.

Notifications for demolition were made including asbestos removal notification and blasting permits. Since stormwater discharges from the demolition area were determined to be via sheetflow to the Ocmulgee River, coverage of the demolition activities under the NPDES Construction Stormwater Discharge permit was not required. In addition, no land disturbing activities were conducted in the 25-foot stream buffer along the Ocmulgee River during the demolition activities.

For ash pond number 1, application for a Dredge and Fill Permit from the U.S. Army Corps of Engineers was made for work on the stream banks next to the river. Stream bank repairs on Ash Pond No. 1 were not required to be covered by the NPDES Construction Stormwater Discharge Permit (GAR 100001) since stormwater from this area enters the Ocmulgee River via sheetflow. However, construction activity on top of Ash Pond No. 1 and adjacent to the Norfolk-Southern railroad tracks was permitted under the NPDES Construction Stormwater Discharge permit since stormwater from these areas discharges to Beaver Dam Creek via a point source (dry drainage ditch). No stream buffer variances were required since no land disturbing activity was performed within the 25-foot buffer along Beaver Dam Creek.

The Federal Aviation Administration (FAA) required that lights on the stack be maintained until the stack came down and then written notification of the stack removal was required.

The biggest issues identified were the abatement of ACM throughout the plant site and the closures of the ash ponds which included the resulting effect on the NPDES industrial wastewater permit.

Closing Ash Ponds

A permit modification was sought for the ash monofill site. This modification was to allow construction, demolition, and asbestos wastes to be disposed in two separate trenches in the permitted ash monofill. Because most of the equipment/materials were reused and the debris (i.e., concrete, brick, etc.) was used as fill material onsite, very little solid waste was generated from the decommissioning of the plant.

There are three ash ponds located on the site. There is no chemical pond (which is often associated with coal-fired plants) at the site. Ash pond number 1 has not been used for several years. Ash ponds numbers 2 and 3 were active until Plant Arkwright was retired. Ash pond number 2 was used as a polishing pond and received discharges from the plant's basement sump. Water from pond number 3 overflowed to pond number 2 before being recycled to the plant for reuse. Pond number 2 will not be closed but will be the stormwater discharge point for the revised NPDES industrial wastewater permit. The NPDES industrial wastewater permit was revised because the water from the ash ponds was no longer recycled to the plant but was discharged to a creek. Ash from pond number 2 will be removed to pond number 3.

After the plant is retired and the ash ponds are no longer used for ash disposal, they are considered in Georgia to be essentially solid waste landfills which require permitting or closure. Permitting and planning is expected to take 1 to 2 years with actual closure expected to take 6 months to a year. In agreement with the state regulators, pond number 1 was closed with a cap under 1988 regulations which were in effect when the pond was retired. Pond number 3 will be closed under the new regulations after ash is brought from pond number 2. A soil and geotechnical evaluation will be performed and ash pond number 3 will be closed with a cap as a subtitle D facility with monitoring. Problems encountered included the fact that some ash was found outside the ash pond footprint and none of the ponds were lined when installed. The cost of closing the ash ponds is greater than the combined cost of the other decommissioning activities for the plant site.

Dealing with Asbestos and Other Wastes

An asbestos survey was performed in preparation for ACM abatement. ACM abatement was planned in stages with some areas requiring abatement before actual equipment/materials removal and demolition could begin. ACM not included in the initial survey was found throughout demolition. Proper notification to regulatory officials and proper recordkeeping was required and upheld during decommissioning.

GPC decided to burn the remaining coal supply before shutdown. GPC personnel removed lube oils from equipment and fuel oil from the tanks for reuse or disposal. Residual used oils were recycled during operations. The dismantlement contractor was responsible for the removal and disposal of Freon and batteries. The contractor was responsible for the removal and disposal of light bulbs, florescent lighting and high pressure mercury vapor lighting. GPC was responsible for the removal and disposal or recycle of mercury obtained from instrumentation. Even with these initial removals, chemicals, materials, and oils had to be removed and disposed or recycled periodically during dismantlement. GPC disposed of PCB containing materials and light ballasts as was done during operation.

Because Plant Arkwright was an older plant, lead paint was an issue. The biggest problem with lead paint is exposure to workers from flaking or cutting of painted materials. Disposal in a Subtitle D landfill is allowed in Georgia if the material passes the toxicity characteristic leaching procedure (TCLP) test. Most of the metal which was removed was sent to a smelter without removing the paint.

Site Cleanup Following Dismantlement

Assessment and remediation of the switchyard and other plant areas started as soon as dismantlement was completed. The environmental assessment and remediation are being performed under State Superfund requirements and the Hazardous Site Response Act. This includes an environmental assessment phase and a cleanup phase. The assessment includes testing of the soil and groundwater, evaluation, planning, and plan approval. The non-residential or industrial standards were used to develop the assessment and remediation plan. Cleanup and preparation of the site will be performed in accordance with the remediation plan. GPC will perform the environmental sampling, testing and reporting that will continue to be required for the site after Plant Arkwright is retired.

Asset disposition

Disposition of the current warehouse inventory valued at $2.2 million was accomplished in three ways: (1) usable parts were sent to other GPC plants upon request, (2) common materials were sent to a central company stores, and (3) the remaining parts and materials were sold or scrapped.

Automatic re-orders of parts and materials were stopped and service agreements terminated at the announcement of the plant's retirement. All leased office equipment was returned and remaining equipment sold or transferred to other plants. Plant Arkwright was responsible for the distribution or disposal of portable test equipment, tools, and other furnishing.

Major plant equipment was advertised for sale and buyers were sought for the steam turbines and other major plant equipment. Major equipment was sold as a whole rather than as parts. Plant equipment that had to be scrapped was disposed by the dismantlement contractor. The CTs and the steam units were removed from dispatch availability in 2002 after the peak season.

Dismantlement Tasks

Asbestos Abatement

Handling of ACM was performed according to applicable local, state, and federal regulations, as well as GPC Environmental, Health and Safety Control Documents and Asbestos Abatement Procedures. A qualified contractor was hired to conduct all asbestos removal from the site. Asbestos abatement activities were carried out in enclosed containments by trained personnel. All asbestos was thoroughly wetted, bagged, labeled and placed in dumpsters for disposal at a permitted solid waste landfill. Oversight of asbestos abatement compliance was the contractor's responsibilities. Area air monitoring was conducted by a third party. GPC periodically reviewed asbestos activities, records and qualifications, and conducted inspections of abatement activities.

Switchyard

The switchyard remained in-service during decommissioning and continues to operate as part of the GPC grid (Figure A-5). The demolition contractor did not perform any work in the switchyard. All switchyard work was handled by GPC. Dismantlement of the plant required that the switchyard controls be moved from the plant to a new building in the switchyard.

GPC removed all generator step-up (GSU) transformers, other transformers, breakers, and other generating equipment that was above ground between the high side of the GSU and the turbine building wall inside the switchyard. GPC also removed the structures and cabling associated with the generating equipment in this same area. The GSUs had to remain energized to provide a reliable source of power to the switchyard controls. Once the new switchyard control power source was installed the GSUs were de-energized and removed.

The demolition contractor was responsible for the disposal of the removed structural steel and cabling from the switchyard and removal of the foundations of the removed equipment.

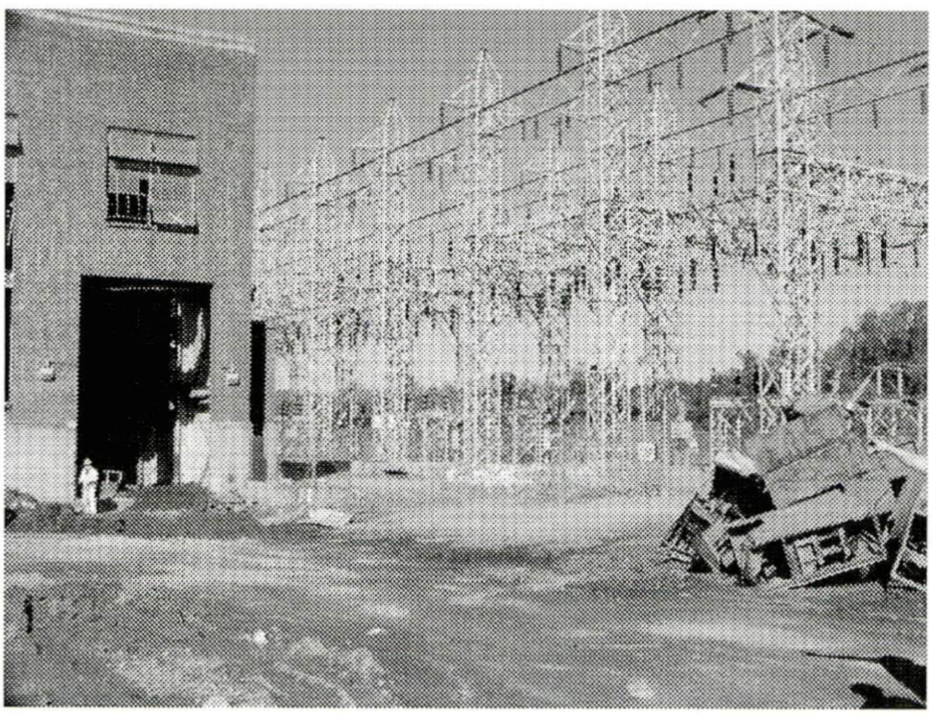

Figure A-5
Plant Arkwright Switchyard Which Remains In Service. Electrical power to essential systems (such as plant lighting, turbine crane, and power house elevators) was retained while power was deactivated to all non-essential systems.

Disposition of the Plant Structures

Structures which were demolished and all associated equipment dismantled included:

- Administration Building
- Potable Water System
- Project Services Shed
- Club House
- Ash Silo
- Water Treatment Building
- Old Maintenance Building
- Emergency Response Team (ERT) Building
- Turbine Building
- Both Boiler Houses
- Natural Gas House
- Used Oil Storage Building
- Shaker House
- Fossil Fuel Building
- Chlorinator Shed
- Compressed Gas Shed
- Air Compressor House
- Fire House
- Yard Lighting
- Fire Protection System
- Circulating Water Intake and Discharge
- Oil and Water Storage Tanks
- Stack
- Precipitators
- Hay Barn

Structures which remain include:

- Roadways, Curbs and Gutters
- Sidewalks

- Parking Lots
- Fences
- Railroad Track System
- Warehouse
- Training Building

Use of Fill below Grade Level

Buildings and structures other than the powerhouse were demolished to the concrete slab, or to grade, if not on a slab. After the interior equipment was removed, the powerhouse basement cavities were partially filled with uncontaminated brick and concrete debris and the powerhouse structure imploded (Figure A-6). In filling the cavities, larger pieces of material were placed at the bottom. As the compaction need increased toward the top, the size of the fill material decreased. The powerhouse was cleared to the base slab after demolition. All foundations were removed to one foot below grade. The area was filled to one foot from grade and covered with dirt up to grade.

Explosives were used to lay the chimney to the ground and the debris was used as fill material (Figures A-7 and A-8). The chimney foundation and other sub-surface foundations were either punctured to provide drainage as needed, or removed.

The intake and discharge bulkhead structures were left in place. All screens, pumps, hoists and other equipment were removed from the structures. The gates were put in place to limit access to the tunnels. The bulkhead structures (intake and discharge) were filled with rip-rap to a level above the tunnels to prevent access. All open drains, piping or other penetrations were plugged with concrete to prevent any fluid from entering or exiting the drains, piping or penetrations before covering.

All piping and pipe supports were removed and scrapped or properly disposed. All above ground tanks were cleaned and demolished to base slab. All slabs and containment structures were removed. The water tanks on top of the powerhouse remained until the powerhouse structure was imploded and then the tank debris was removed. The open hopper pit and all of the other open pits created by the demolition of buildings or structures were filled with uncontaminated brick and concrete debris up to one foot of grade level and covered with dirt up to grade.

The above ground portion of the plant natural gas system was removed and salvaged including the heaters, filters, pig launcher and pig receiver. The piping was removed to three feet below ground. All gas piping three feet or more below ground was purged with nitrogen and capped.

Figure A-6
Plant Arkwright During Filling of Powerhouse Basement Cavities. A ramp was contructed to fill the basement to grade level.

Figure A-7
Explosives Were Used to Lay the Plant Arkwright Chimney to the Ground (View 1). Clearly the direction of stack fall was critical.

Figure A-8
Explosives Were Used to Lay the Plant Arkwright Chimney to the Ground (View 2).

Schedule and Costs

Plant Arkwright ceased generation on September 15, 2002. Demolition of the plant structures was completed on March 24, 2004. The environmental assessment for remediation of the site will be completed by December 31, 2004. Cleanup of the site including closure of the ash pond numbers 1 and 3 and the onsite landfill will be completed in 2006.

The total cost incurred for the decommissioning of the Arkwright plant is estimated to be approximately $19,000,000. Estimated costs for separate tasks are as follows:

TASK	COST, $
Indirect Project Support	3,700,000
Dismantlement	2,000,000
Asbestos Removal & Other Environmental	3,300,000
Ash Pond Closures	10,700,000
Salvage	(700,000)
Total	19,000,000

B
DECOMMISSIONING WATTS BAR FOSSIL PLANT, RHEA COUNTY, TENNESSEE, TENNESSEE VALLEY AUTHORITY

Introduction

The Watts Bar Fossil Plant (WBF) was the first steam plant constructed by the Tennessee Valley Authority (TVA) to help meet the growing demand for electricity due, in great part, to World War II production efforts (Figures B-1 through B-3). Construction began on July 31, 1940. The first of four 60-MW units was placed in commercial operation on February 15, 1943, and the last unit on April 8, 1945. After 15 years of operation, the plant was placed in an extended shutdown mode in 1957. Because of rapid load growth, the plant was returned to service in 1970. But with WBF's relatively high cost of power production, the plant was again shut down and then placed in extended shutdown mode in 1983. Much of the plant equipment was laid up for potential future operation. In the ensuing years, several restart studies were performed. None indicated that returning WBF to service would economically benefit TVA. In 1997, as a cost saving measure, TVA terminated air permits for the plant. Until July 14, 2000, the turbines were turned on a weekly basis to prevent bowing of the turbine shaft. At that time, the turning operation was terminated. At present, WBF is in decommissioning status.

Figure B-1
Watts Bar Fossil Plant Powerhouse Entrance.This 240 MW, 4-unit coal fired plant was built from 1943-1945 in Rhea County, Tennessee.

Figure B-2
Watts Bar Fossil Plant Powerhouse. Coal conveyor with Transite Panels Removed is Shown on the Right. The coal-fired plant used 82 acres of the 1067 acre site. Also on the site are a nuclear and a hydro plant.

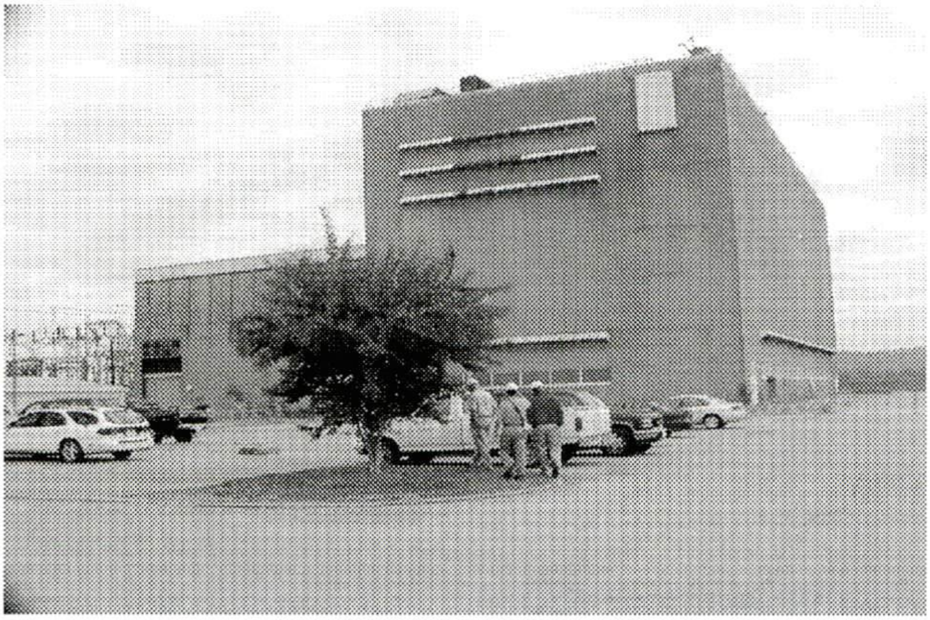

Figure B-3
Watts Bar Fossil Plant Powerhouse, Turbine Room, and Switchyard. The coal-fired plant was selected for partial decommission and for site cleanup, while retaining the need for environmental compliance and safety.

Plant Description

WBF is located in Rhea County, Tennessee, just downstream from the Watts Bar Dam on the western side of the Tennessee River. WBF uses 82 acres of the 1,067 acres of the Watts Bar Reservation. Also located on this reservation are the two-unit Watts Bar Nuclear Plant and the Watts Bar Hydroelectric Plant.

When constructed, the WBF units were considered to be on the leading edge of design. The turbines are horizontal-cylinder, single casing, impulse design, with 17 stages. The first stage is 2-row construction, and the remaining rows are single-row construction. The turbine is designed for steam conditions at 850 pounds per square inch, 900°F, and 2-inch mercury condenser backpressure. The direct-connected generator was 60,000-kilowatt rated capacity, air cooled, and turned at 1,800 revolutions per minute rated speed. The total nameplate capacity of the plant was 240 MW.

Decommissioning Strategy

After the plant was placed in extended shutdown mode in 1983, several investigations were conducted to study plant restart. The last two formal studies were performed in 1992 and 1994. The 1992 assessment was undertaken to determine the minimum restart requirements as part of a long-term plan for maintaining and upgrading the facility for extended operation. The assessment determined that no "fatal flaws" existed to prevent the plant from being restarted. However, this assessment did not include diagnostic or functional tests that would have taken about nine months and would cost approximately \$2 million. The study projected that the engineering and construction phases would require 35 months to complete and would cost \$74 million.

WBF was included as part of a multiphase repowering study conducted in 1994 that considered 10 repowering alternatives. The decision was to continue on course for WBF and not convert the plant to municipal waste and biomass, natural gas, or other alternatives. The various restart options considered in the 1994 study were again evaluated in 2000. Neither the 1992 nor 1994 studies were updated in light of the new source performance standards that would be applicable because the air permits had been terminated. Considering the rehabilitation expense and the termination of the air permits in 1997, TVA determined that operating the plant was no longer a viable option and the plant should be retired.

During the restart evaluation in 2000, TVA also considered three decommissioning options: (1) take no action and maintain the site in present condition, (2) partial demolition and site cleanup, and (3) total demolition and site closure. The final decision was to perform partial demolition and site cleanup and to maintain environmental compliance and safety at the site.

Environmental Evaluation

An Environmental Site Assessment was completed for WBF in August, 2000. The objective of the site assessment was to determine the plant's environmental status and to specify environmental compliance liabilities and issues. This report identified existing and potential environmental issues and prioritized those posing risks. Recommendations were made on how to remedy current and future liabilities that had been identified.

Potential environmental issues identified during inspection were:

- Asbestos
- Lead paint
- Mercury
- PCBs

Additional areas of concern included:

- Solid waste
- Switchyard remediation
- Chemicals of concern
- Safety

The identified environmental risks were considered to have the potential to be in violation of federal, state, or local environmental laws, regulations, or permits.

Asbestos

Numerous areas both inside and outside the powerhouse were identified where ACM had become dilapidated or water damaged and had fallen to the floor. Additional areas were noted where the intact ACM did not demonstrate cohesive characteristics, resulting in a high potential for additional releases with little or no disturbance. Transite panels (non-friable asbestos mixed with concrete) on the buildings and conveyer belt systems generally were in good condition. However, paint was peeling from the panels. Thus, it was determined that the panels were beginning to weather, causing some of the asbestos to become friable and increasing the risk of employee exposure as well as the inconvenience of having a reportable release of asbestos. No evidence inside the building of airborne friable asbestos being released to the outside environment existed. However, the building had to be sealed and closed to ensure that no future releases escape to the outside. Another consideration was to prevent asbestos from falling off equipment and contaminating water discharges from the powerhouse.

Lead Paint

Numerous areas, both inside and outside the powerhouse, were identified where lead paint had fallen to the floor, becoming a hazardous waste. Of greatest concern was the possibility that the lead paint could be swept up and disposed in a regular solid waste container, thus resulting in the illegal disposal of a hazardous waste. Also identified were areas where intact lead paint was peeling and where additional releases were a high probability. Examples of areas of concern were the deteriorating and flaking paint on the exteriors of the buildings and coal-handling structures.

Mercury

More than 330 items of mercury-filled equipment, including manometers, switches, thermometers, etc., were found in the powerhouse. Some of the pieces were not intact and had to be evaluated for mercury spills.

PCB

The assessment identified 14 PCB-contaminated transformers onsite that would require proper management and removal. A review of available records, from 1982 to the time of the assessment, revealed spills of PCB oil from transformers. These spills required further cleanup.

Solid/Hazardous Waste

Several ponds on the WBF reservation were observed during the site assessment, including the ash pond, chemical treatment pond, slag pond, settling pond, and coal-yard pond. Between the slag pond and the ash pond is the redwater ditch that is high in iron content. The ditch collects acidic runoff from the slag pile and dry storage area. The water in the ditch normally flows to an accumulation area, is pumped to the redwater pond, and then overflows to the ash pond. Potential for unintended bypass of the redwater ditch was of concern because of the ditch design. The coal yard no longer stores coal.

Through a competitive bidding process, TVA, in March 1996, awarded to Grangrit, Incorporated, and Stan-Blast Abrasive Company a contract for the removal of boiler slag and ash from the storage areas for use as low-dust blasting abrasives. Removal of the slag and ash is still in progress (Figure B-4 through B-6). WBF has a National Pollutant Discharge Elimination System (NPDES) permit that authorizes the discharge from the ash pond and the stormwater outfalls. The outfalls are monitored as required by the permit. Because of actions by Stan-Blast, control of pH in the ponds gets special attention. The state regulatory agencies were notified that an air permit was not required for the Stan-Blast operations.

Figure B-4
Watts Bar Fossil Plant Slag and Ash Reclamation (View 1). While the slag and ash is being removed, that will continue until 2007, the ponds will not be re-mediated. Then final clean-up requirements will be negotiated with the Tennessee Department of Environment and Conservation.

Figure B-5
Watts Bar Fossil Plant Slag and Ash Reclamation (View 2). Several ponds were studied in the environmental site assessment completed in August 2000, including ash pond, chemical treatment pond, slag pond, settling pond, and coal year pond. The Watts Bar National Pollutant Discharge Elimination System (NPDES) will be maintained and the outfalls monitored.

Figure B-6
Watts Bar Fossil Plant Slag and Ash Reclamation (View 3). The contract for this work, begun in 1996, continues through 2007.

Switchyard Remediation

The WBF switchyard provides power to the plant, utility building via the station service transformers, and the Watts Bar Nuclear Plant engineering office complex. Within the switchyard is a main transformer and a station service transformer for each of the four units. Banks A, B, and C are out-of-service. Only the main transformers in Bank D are in service. The transformers were tested and were found to contain less than 50 ppm PCB. During the site assessment, oil stains from spills were observed in the switchyard, requiring cleanup and monitoring.

Chemicals and Oils of Concern

Chemicals, used for plant operations, that required reuse or disposal as a waste were identified. Because the plant had not been operated for quite some time, many of the chemicals already had been sent to other sites for reuse. Approximately 200 gallons of hydrazine, stored in 55-gallon drums in the turbine bay, and other chemicals in the laboratories were identified. Several oil tanks in the powerhouse contained oil and were included in the Spill Prevention, Control and Countermeasures (SPCC) inspections. Although the oil in the tanks (i.e., turbine oil tank, dirty/clean oil tank, turbine lube oil tank) was not being used, the age of the tanks presented a liability of releasing oil to the environment.

Safety

In addition to environmental issues, the assessment identified the following safety concerns:

- Exterior transite asbestos paneling was coming off the hopper building.
- A side roof structure of the hopper building, which is covered with asphalt roll roofing, was deteriorating, thus resulting in decay of the wood supports. The roof is at ground level and posed a safety hazard of someone falling through the structure.
- The powerhouse roof precipitator steel frame was corroding because it was uncoated, and metal plate panels had the potential to fall off and cause damage to the roof or blow into the switchyard.
- The roofs of the office building and turbine room were leaking, resulting in interior damage.
- The exterior brick on the powerhouse had significant cracking. The brick on a parapet wall on the boiler roof showed signs of being pushed out.

Decommissioning Tasks

As stated earlier, TVA's decommissioning strategy was to perform partial demolition and site cleanup. A priority was to clean up and stabilize immediate environmental and safety hazards and provide sufficient O&M to maintain compliance. TVA now has restricted access to the powerhouse and other areas at WBF because of concerns with asbestos and lead paint exposure and injury from unstable equipment or structures. TVA continues to monitor the plant area for environmental and safety concerns and to meet regulatory control and reporting requirements. The environmental and safety clean-up and remediation tasks began immediately following the risk identification in the August 2000 Environmental Site Assessment.

WBF has an NPDES permit that authorizes the discharge from the ash pond and the stormwater outfalls. The permit requires routine monitoring of the outfalls and routine inspections in accordance with the Integrated Pollution Prevention/Integrated Contingency Plan (IPP/ICP).

The following three options to address mitigation were evaluated in the August 2000 Environmental Site Assessment for each of the environmental liabilities or risks identified:

1. Do not remediate or remove areas of environmental concern, but implement management procedures to clean up any future releases or spills on a periodic or as-needed basis (i.e., remove asbestos lying on the floor and lead-based paint from the floor area; clean up mercury, PCB oil, or other spills upon discovery; etc.).
2. Fully characterize, clean, and remove released hazards, and stabilize environmental liabilities (i.e., encapsulate friable asbestos, install oil water separator for switchyard, remove low-cost issues such as mercury-filled equipment, etc.).
3. Remove and abate all environmental issues in preparation for complete facility demolition.

The level of mitigation prescribed for each of the identified risks varied and was based on liability potential, regulations, assigned priority, and costs. A discussion of mitigations performed follows.

Asbestos

Approximately 420 cubic yards of ACM was removed and disposed in the Chestnut Ridge Landfill in Heiskell, Tennessee. This included asbestos-containing transite panels from portions of the coal conveyor system. An asbestos O&M plan was developed and implemented. Access to the asbestos areas is restricted and controlled. The powerhouse building was prepared to be airtight. The practice is to inspect for ACM periodically, block off areas where ACM has fallen, and clean up the fallen materials annually or more frequently, if volume dictates. Asbestos assessments are performed annually under contract.

Lead Paint

Lead-based paint flakes were collected and disposed as a hazardous waste. The blue transite panels were removed because, in addition to containing ACM, they had been painted with lead-based paint. The restricted and controlled access to the asbestos areas also serves to prevent access to the areas where lead-based paint is flaking and falling. Areas at the plant are monitored periodically, and flakes that accumulate on the floor are cleaned up, as needed.

Mercury

The more than 330 mercury-filled devices from within the powerhouse and car dumper building have been scheduled for removal and disposal.

PCB

Seven areas contaminated with PCBs were encapsulated, and 14 transformers were removed.

Solid/Hazardous Waste

TVA has decided not to remediate the coal yard at this time. TVA also has decided not to remediate the ponds while the recovery of slag and ash is continuing. Improvements were made to the redwater ditch and its equipment. The caustic drip system for controlling the pH to the ash pond continues to be managed and maintained.

The ash removal contract continues until 2007. TVA expects to continue ash removal until all the ash is recovered. TVA developed a sediment and erosion control plan for the bottom-ash washing and screening operation and for other ash removal activities, and ensures compliance with the plan. Once the ash is removed, or if the operation is discontinued, TVA will negotiate clean-up requirements with the Tennessee Department of Environment and Conservation (TDEC).

WBF recycled 1,011 tons of structural metal.

Switchyard Remediation

TVA removed some of the transformers and installed a secondary containment downstream from the switchyard. The risk of an oil spill was reduced by draining and recycling 21,050 gallons of oil from transformers located in the switchyard.

Chemicals and Oils of Concern

Six 55-gallon drums of hydrazine were transported to a recycling facility. A 28,000-gallon propane tank was sold through TVA's Investment Recovery group. Chemicals used for plant operations were transported to other TVA sites for reuse. Some remaining chemicals are being used as needed onsite (e.g., floor cleaners, "Current Issue" cleaner). Oil was drained from the powerhouse lube oil tanks and the drains blank flanged. Approximately 38,300 gallons of oil was recycled.

Safety

In addition to installing a security fence to restrict and control access to the WFB site, TVA provided additional lighting for critical areas of the powerhouse to ensure safety. TVA, in addition to taking 4 precipitators and 2 stacks from the powerhouse roof, removed 2 conveyor structures and a hopper building to improve safety. A new powerhouse roof was installed with new roof flashings and drains. The exterior parapet wall was repaired to ensure safety and to maintain building integrity by preventing internal damage and release of asbestos and lead-based paint.

TVA will continue to provide sufficient O&M funds to maintain regulatory environmental and safety compliance.

Costs

Preliminary TVA estimates project the cost of taking the WBF site to greenfield conditions to be $17 million to $25 million (values are in calendar year 2000 dollars). This includes minimal estimates of $4.5 million for lead and ACM removal, $0.5 million for switchyard removal (not including resulting improvements required for service to other areas), $2.8 million for dry solid waste area remediation, and $6.2 million for wet solid waste area remediation. Estimates for remediation of dry solid waste areas are based on approximately $80 per acre, and for remediation of wet solid waste areas, approximately $170 per acre.

TVA began the decommissioning tasks to reduce environmental and safety risk in fiscal year 2001. Since then, TVA has spent approximately $2.34 million. And, TVA is budgeting $200,000 per year for O&M costs to monitor and maintain compliance and safety at WBF.

C
DECOMMISSIONING PORT WASHINGTON POWER PLANT, PORT WASHINGTON, WISCONSIN, WISCONSIN ELECTRIC POWER COMPANY

Introduction

Wisconsin Electric Power Company, a Wisconsin corporation, doing business as We Energies, completed the demolition of coal-fired power Units 4, 5, and 6 and the south chimney in 2003. Decommissioning of Units 1, 2, and 3 and the north chimney will begin in October 2004 with completion anticipated by January 31, 2006 (Figure C-1). The coal-fueled units are being replaced by two 500-megawatts (1,000 megawatts total) natural gas units (Figure C-2).

This report describes the planned decommissioning of the remaining coal-fired Units 1-3 with associated support facilities and the north chimney. We Energies is coordinating the decommissioning of the coal-fired power plant and redevelopment of the 243-acre site with the City of Port Washington, the Wisconsin Public Service Commission, and other state agencies. Redevelopment of the site includes the installation of the natural gas power facility, preservation of historical aspects of the coal-fired power plant, and donation to the city of the 1,000-foot long coal dock and over 45 acres of land south of the plant for future development. The historical structures which will be preserved are shown in Figures C-3 through C-6.

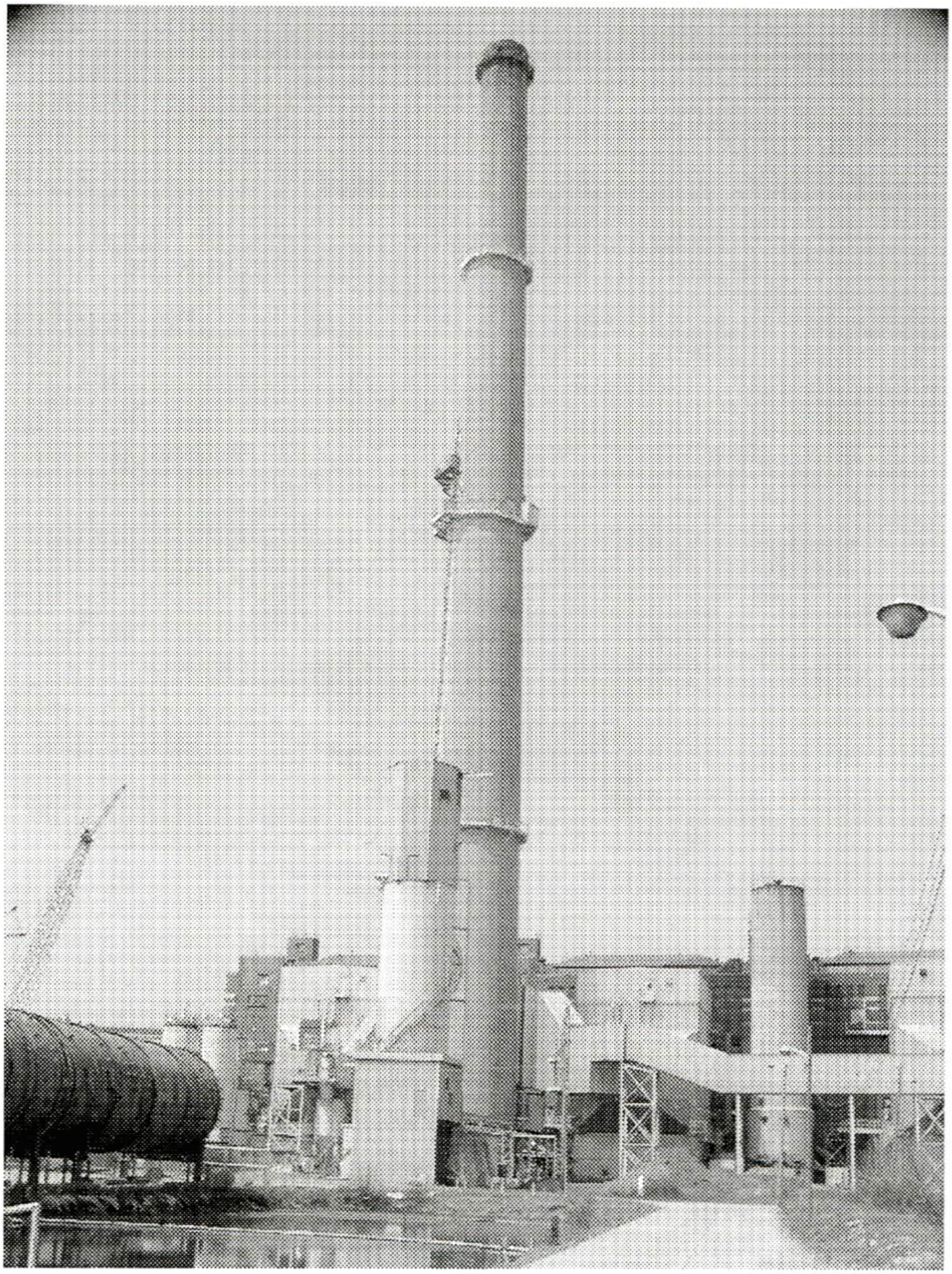

Figure C-1
Port Washington Power Plant with Stack. The coal-fired plant was a six-unit, 341 MW plant installed from 1935 to 1950. It is being replaced by a gas-fired combined cycle on the same site.

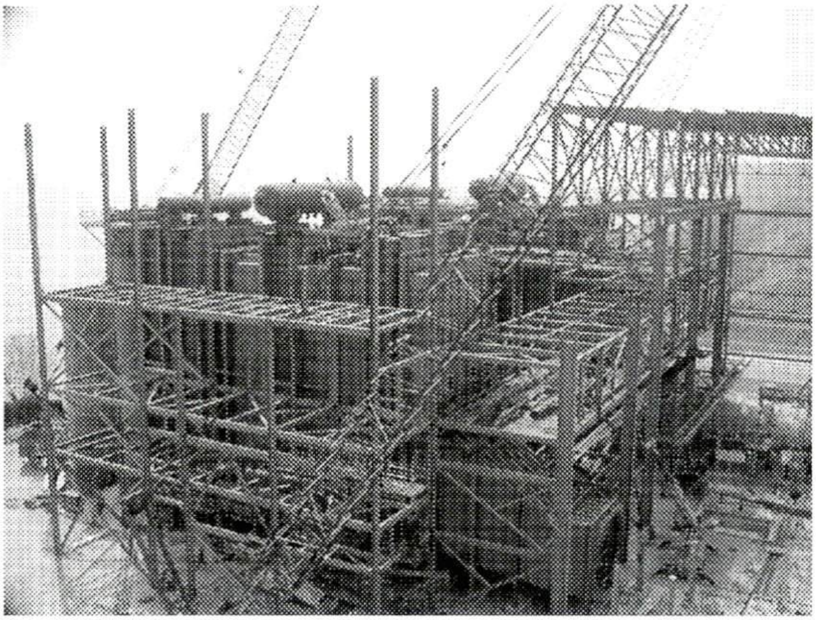

Figure C-2
Construction of Natural Gas Units Which are Replacing the Coal-Fired Units at the Port Washington Power Plant. Construction of the new plant proceeds at the same time as final coal plant demolition.

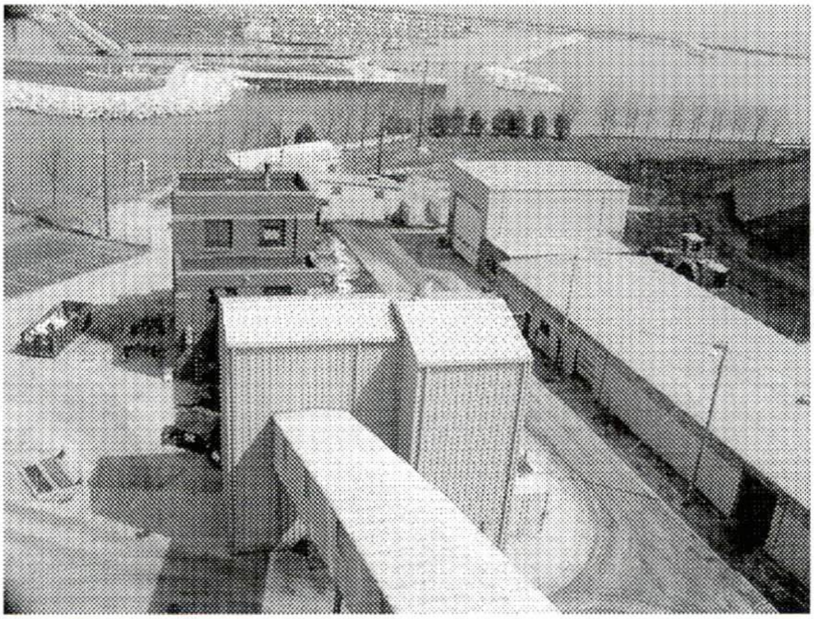

Figure C-3
Port Washington Power Plant Coal Crusher Building. The coal crusher building and coal conveyers will be removed, permitting a recreational path and public access to the beach south of the plan0074

Figure C-4
Port Washington Power Plant Historical Admin/Service Building. The building will be retained, along with the auxiliary boiler building and supporting equipment.

C

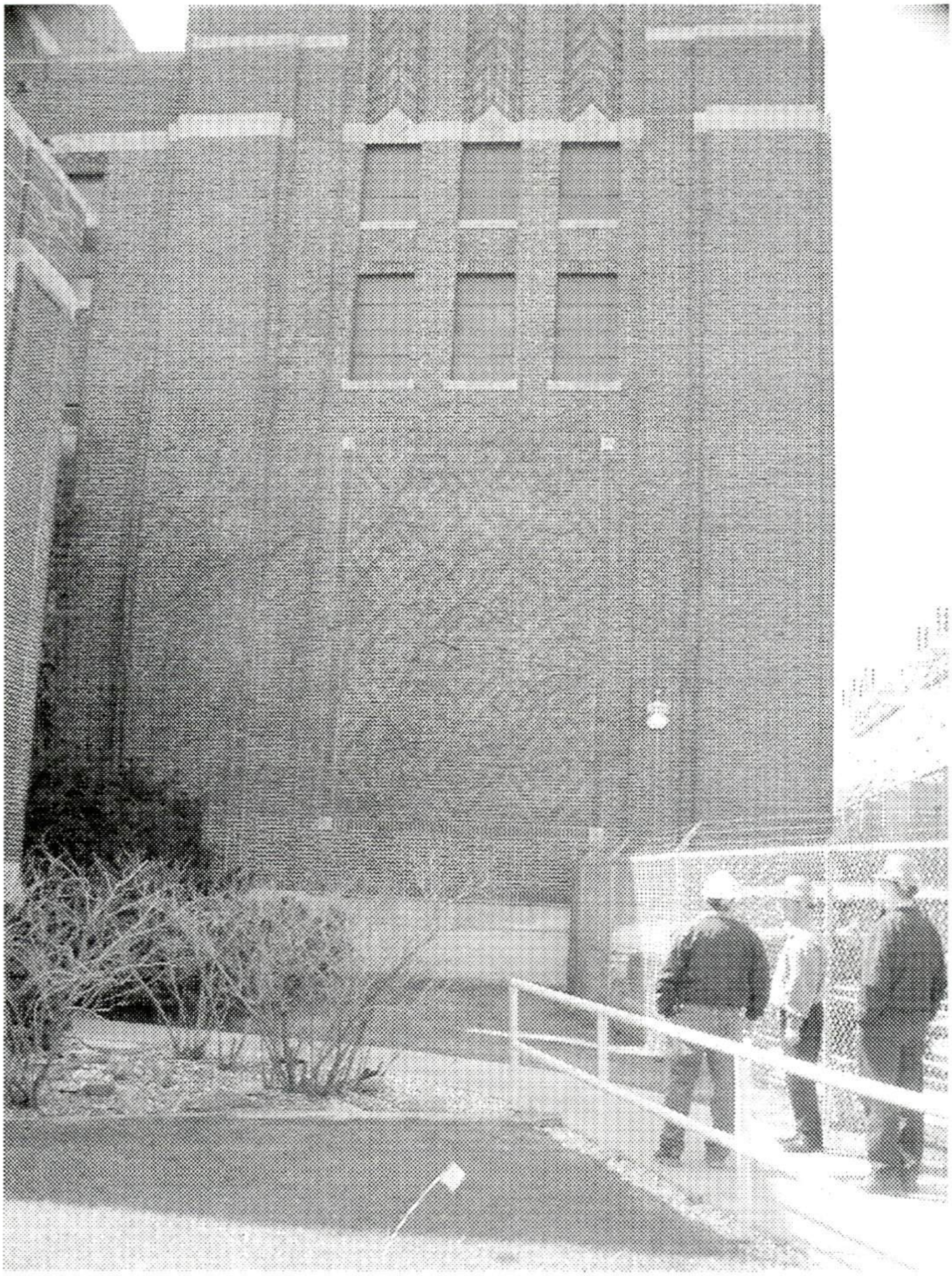

Figure C-5
Port Washington Power Plant Historical North Wall of Powerhouse. This wall will be retained alongside the new gas-fired power plant.

Figure C-6
Port Washington Power Plant Historical West Wall of Powerhouse. This wall is being preserved next to the new natural gas units. Also seen here is new land and roadway construction for access to the new gas-fired plant.

Plant Description

The Port Washington Power Plant is located in the City of Port Washington, Wisconsin on the shores of Lake Michigan. The Port Washington Power Plant was constructed during the height of the Depression in the early 1930s providing employment for hundreds of people at the plant site. It took more than five years and about $7.5 million to build Unit 1 of the Port Washington Power Plant. Earth-moving equipment scooped 275,000 cubic yards of dirt out of a bluff on the Lake Michigan shoreline to make room for the plant. The dirt was used to form the fill for the plant's 1,000-foot-long coal dock (Figure C-7). The first generating unit was placed in service on September 1, 1935, the 100th anniversary of the founding of the City of Port Washington. An old photograph of the Port Washington Power Plant prior to demolition of any of the units is shown in Figure C-8.

The performance of the plant's Allis-Chalmer's 80,000-kilowatt turbine-generators and Combustion Engineering's boilers was a major part of the reason Port Washington was the world's most-efficient power plant for its first 13 years of operation. After the initial generating unit was placed in service in 1935, new generating units were added in 1943, 1948, 1949, and 1950 for a total of 341-megawatts of power. Each unit required its own chimney. In the mid 1960s, two 500-foot stacks replaced the shorter ones.

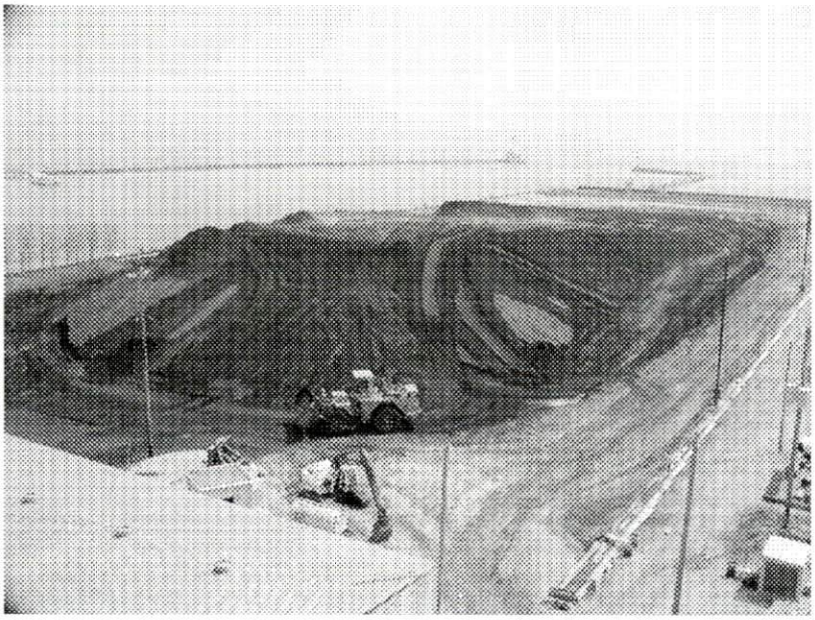

Figure C-7
Port Washington Power Plant Coal Dock. The 1000 ft long coal dock was originally constructed in 1935 from 275,000 cubic yards of dirt from a bluff on the Lake Michigan shoreline that made room for the plant.

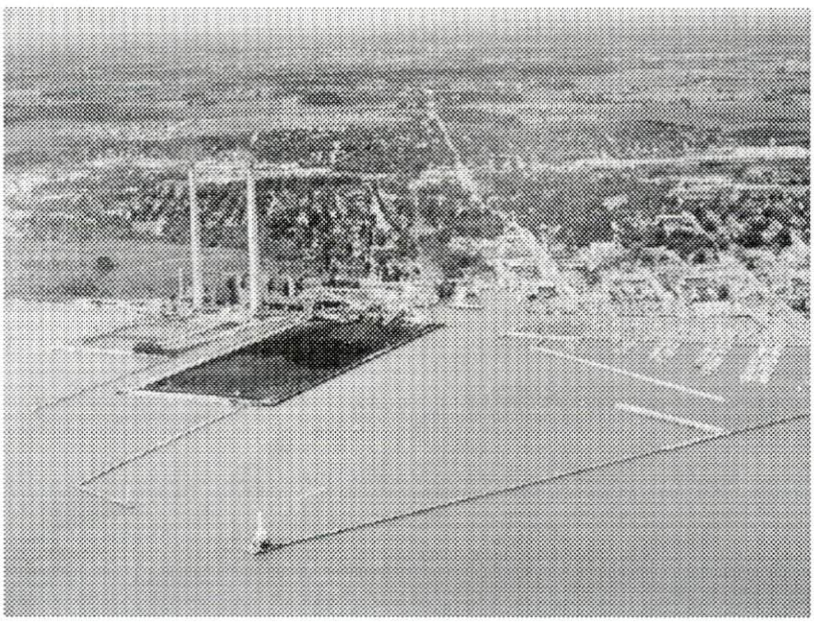

Figure C-8
Port Washington Power Plant on Lake Michigan in Wisconsin Prior to Demolition of Any Coal-Fired Units. The 1000 ft coal dock and 45 acres of land south of the plant will be made available for future development.

Decommissioning Strategy

Once We Energies made the decision to complete the decommissioning of the Port Washington coal-fired power plant and replace it with a natural gas power generation plant, they began developing a strategy to accomplish the tasks. The initial task was to include the City of Port Washington and the state of Wisconsin in the decision process. Based on negotiations with the city and state, We Energies decided to preserve the architectural integrity of the existing buildings with historical significance while improving the overall look of the plant site with the installation of the new natural gas power plant. The conversion frees up land for public use, including a recreational path and public access to the beach south of the plant. The 1,000-foot long coal dock and over 45 acres of land south of the plant are being made available for future development.

To complete the dismantlement of the selected coal-fired facilities, We Energies decided to contract for a turn key operation with a few exceptions. We Energies began soliciting bid proposals in February 2004. The Contractor's base bid proposals were to be on a firm, lump sum basis. Contractors were also encouraged to offer other arrangements; i.e., fixed fee, shared cost savings, cost reduction incentives, etc., if the alternative pricing would be advantageous to We Energies.

The Contractor will be responsible for complete demolition of the Port Washington Power Plant Unit 1, 2, and 3 facilities as defined in the specification and drawings provided by We Energies. The work will include the abatement, removal, and disposal of all asbestos containing and hazardous materials on the project site. The Contractor will demolish and remove from site all power plant equipment, electrical gear, controls, piping, and all structural steel and concrete pedestals from Unit 1, Unit 2, and Unit 3 at the Port Washington Power Plant. Removal and demolition also includes the east yard buildings (including equipment, foundations, and basins), #7 stack, and north coal handling area buildings, foundations, and equipment. The work will include the supply of all necessary labor, materials, equipment, storage facilities, permits and fees, and temporary facilities as required for completion of the work.

We Energies or others by contract will perform additional tasks such as the following:

- Isolation of all systems and equipment for removal purposes.
- Draining and disposal of lubricants within equipment lubrication sumps and reservoirs.
- Relocation of spare parts and salvaged equipment from the work site not included in the work scope.
- Removal of the liquid propane storage tanks currently located on the north side of the facility.
- Removal of CO_2 from the Unit 2 and Unit 3 generator purge systems, the Unit 1 auxiliary and spare transformers, and the Unit 3 auxiliary transformer.
- Removal of bulk hydrogen from the Unit 2 and Unit 3 turbine-generators.
- Removal of Halon from the fire suppression system in the Unit 2 Satellite room and Unit 3 Terminal Room.

- Removal of Dry Sorbent Injection (DSI -sodium bicarbonate) material from the storage tanks.
- Removal of any fuel oil from within the underground fuel oil storage tanks.
- Isolation of the main transformers from the switchyard bus system.
- Draining and disposal of the main and auxiliary transformers coolant.
- The development of abandonment plans for concrete settling basins, east coal pile runoff pond, and tertiary settling pond.
- The design and installation of a temporary storm water treatment system for the coal dock and north yard areas during the demolition of the existing facility.
- Asbestos abatement of the concrete stack (with the exception of residual asbestos under fasteners and attachments such as platform supports, conduits, elevator rails, and enclosure abutments).

Environmental Evaluation

We Energies will require the Contractor to comply with the requirements of applicable laws and regulations, the noncompliance with which would materially and adversely affect We Energies' business or it financial condition. As a minimum, applicable codes and regulations included:

- Wisconsin Administrative Code (WAC).
- Occupational Safety and Health Administration (OSHA).
- Environmental Protection Agency (EPA).
- Wisconsin Department of Natural Resources (WDNR).
- National Fire Protection Agency (NFPA).
- American National Standards Institute (ANSI).
- National Institute of Occupational Safety and Health (NIOSH).
- Wisconsin Department of Health and Family Services for Asbestos and Lead Paint Certifications.

The Demolition Contractor will be required by We Energies to obtain all necessary federal, state and local permits for the stated work (i.e., ACM abatement, lead abatement, WDNR demolition notification, etc.).

We Energies has applied for the following permits to decommission and demolish the facilities:

- Chapter 30 – Wetland permit
- WPDES (Wastewater Pollution Discharge Elimination System) discharge permit
- NR-216 Temporary stormwater runoff permit
- EPA Title V permit

- ACOE (Army Corps of Engineers) Army General GP/LOP-98-WI permit
- Ozaukee County Department of Environmental Health zoning permit

We Energies will retain a third party environmental inspector to observe and report on contractor's performance to the Company. We Energies will provide full-time site support during demolition for environmental and safety monitoring and contract compliance. The contractor will be required to have a full-time Department of Health and Family Services certified asbestos supervisor available throughout the entire demolition work as well as a Safety Supervisor.

We Energies contracted to have a Hazardous Materials Survey (including ACM inventory and characterization) performed, and provided copies to the contractors for their use in the bidding process and completion of the work.

Environmental and safety requirements included in the bid requests by We Energies for the contractor included:

- Follow work procedures that ensure no spills during contract activities and shall have a written plan to mitigate if a spill were to occur.
- Notify We Energies immediately if contaminated or hazardous materials are encountered during the demolition process.
- Proceed with demolition of a building and its contents only after Pre-Cleaning, ACM Abatement, Lead Abatement, Removal of Other Regulated Materials, and Equipment Decontamination and Removal have been completed within that building, and physical separation of all piping, cabling, and conduits from the remaining portions of the building have been completed.
- Verify, by walkdown that the conduit, cables, and piping have been physically disconnected to the area undergoing demolition.
- Observe and verify that all applicable We Energies' environmental, safety and plant operating rules, including protective tag procedures, and all security procedures are followed.
- Maintain documentation of all training provided to contractor employees and subcontractors.
- Maintain all records and documentation required by the work including laboratory, shipment and sales records and make them available for We Energies review and copying for five (5) years.
- Maintain and update its environmental management activities as required by legal permits, regulations or internal requirements. The contractor will allow Environmental Management Services audits on at least an annual basis during the duration of this Agreement. The ISO 14001 EMS standard will be used as the audit protocol.
- Must successfully pass an environmental certification audit conducted by We Energies.
- Take boring samples to verify the extent and type of contamination when dealing with possible ground contamination

During operation the fly ash is removed through an electrostatic precipitator (ESP), collected by a vacuum operated system, and stored in a silo. The fly ash is transferred into enclosed trucks for disposition to a company owned and operated landfill or transported to other company facilities to be reburned. The bottom ash and boiler slag is removed from the boilers via water blasting or air lancing. This material is collected and stored in a bottom ash de-watering pit for later transfer to a We Energies owned and operated landfill. For decommissioning purposes, the fly ash silo shall be emptied and vacuumed clean prior to turnover to the demolition contractor. The bottom ash de-watering pit shall be dredged as thoroughly as possible prior to turnover to the demolition contractor. Soil borings will be collected to measure the extent of remediation necessary.

Remediation and filling will be necessary for the coal pile runoff pond, bottom ash de-watering pit, tertiary pond, and the coal dock area. During the Units 1-3 demolition, the only area to be addressed by the contractor is the de-watering pit as the other areas are to be kept in service or used as lay down for the construction phase. When construction is complete, closure, remediation, and filling will be performed on these remaining areas.

All hazardous material including asbestos, lead, mercury, petroleum hydrocarbons, and PCB contaminates will be abated and removed from the pre-specified demolition areas prior to the start of demolition and equipment removal within such area. All Regulated Materials that are found or generated during abatement and demolition will be appropriately handled and disposed in accordance with all federal, state, and local requirements. Additional materials of concern include light ballasts, computer equipment with monitors, lead acid batteries, radioactive type exit signs, smoke detectors, CFC and HCFC containing equipment, halon fire protection systems, etc. Disposal sites and associated organizations to be contacted for removal of all materials were outlined by We Energies. All disposal options for any regulated materials must be approved by We Energies.

ACM is expected to be found in electrical and control wiring, electrical transite panels, lighting, insulation, gaskets and window glazing.

A "no visible emission" standard will be strictly held during the project for all contractor activities.

The Port Washington Power Plant's close proximity to the downtown area of the City of Port Washington and its marina, make it essential that any noise due to the Work be minimized. A noise curfew for the hours between 7 p.m. and 7 a.m. will be enforced.

The contractor will implement and coordinate a Project Safety and Health Program applicable to all employees and subcontractors at the project site. The Project Safety and Health Program will be an administrative process that generally follows the requirements of the Occupational Safety and Health Act (OSHA) of 1970. The contractor will need to develop an Emergency Action Response Plan. This plan will require interface with the appropriate civil parties involved (e.g. Port Washington Police and Fire Departments).

The building or enclosure foundations, footings, and sills will be removed or excavated, then cleaned and crushed on site for use as designed fill. Any excavation requires clean fill to return the excavation to grade. Fill will be screened so as to not include any rebar, structural steel, equipment, organic material, or demolition debris. No rebar, reinforcing steel or demolition debris will remain in crushed concrete.

Waste oils and hydraulic fluids may be present in process equipment, machinery, and oil sumps or reservoirs associated with machinery. The contractor will remove all waste oils and fluids before disassembly or removal of any equipment. If waste oil or other liquids are spilled during the equipment removal, the excess liquid will be recovered and any impacted surfaces cleaned by steam cleaning, pressure washing or other methods as approved by We Energies. Special care is required in the old turbine hall and boiler room footprints as there are drains and openings directly into the circulating water intake and discharge tunnels. No oil or other liquids will be permitted to enter these waterways.

Polychlorinated biphenyls (PCBs) in oil have been identified in each of the transformers at concentrations less than 50 parts per million (ppm). The contractor is responsible for proper disposal of PCBs. The contractor will be responsible for testing the transformer containment basin concrete for PCB contamination and for disposing of the concrete as required. The contractor should assume that below ground concrete is contaminated and that above ground concrete can be recycled.

Mercury has been identified in various electrical switches, light sources, gauges, and gauge reservoirs.

Lead has been identified in the paint coatings on the structural steel. Loose paints and paint chips should be removed and collected for disposal as hazardous waste. Areas on structural steel where torching will occur will be abated prior to torching. The contractor will not perform activities that will generate lead dust above the OSHA Permissible Exposure Limit (PEL) without proper engineering controls. Lead roof drain rings will also be collected for proper disposal.

Asset Disposition

Any spare parts for use elsewhere will be removed by We Energies. Also, We Energies will remove the temporary waste water facility and auxiliary equipment. Any spare parts or equipment remaining on site at the start of the contract work shall be included as part of the lump sum base bid and disposed of by the demolition contractor.

The following items will be removed from the project site by We Energies prior to the initiation of the demolition scope of work.

- Quincy Air Compressors #21 and #31.
- Ingersoll-Rand Outside Air Compressor.
- Unit 1, Unit 2 & Unit 3 Continuous Emissions Monitor (CEM) buildings.
- CEM Computer.
- Coal Sampler Equipment and Controls SLC 500.
- Precipitator monitoring equipment.

- Flyash Unloader.
- Unit 3 Low Pressure Turbine Spindle.
- Liquid propane tanks.

Dismantlement Tasks

Demolition and equipment removal at the Port Washington Power Plant will include the removal of all equipment, piping, structures, foundations, electrical and control equipment on Units 1, 2 and 3, and demolition of the building enclosure and foundations except where We Energies has specified items to remain.

The external walls and roofing of the switch house are to remain intact and undamaged. The admin/service building, north of the remaining north wall, will remain and not be demolished. The auxiliary boiler building will remain along with the supporting equipment required.

All drain lines extending beyond the footprint of any roadway, slab, foundation or footing below excavation elevation will remain, provided they are below el. +4.0'. The existing roof drains from the switchhouse that flow directly into the circulating water tunnel inside the west turbine hall building wall will not be removed or damaged. The circulating water tunnels both inside and outside the generation building are to remain and be protected by the contractor from damage during the entire project.

Asbestos abatement and demolition will be proceeding together for some time and coordination and cooperation will be required. Both activities will be monitored.

Removal and demolition also includes the generation building structural east walls, south walls, a portion of the Unit 1 boiler room north wall, boiler and turbine rooms, roof, east yard buildings (including equipment and basins), #7 stack, and north coal handling area buildings and equipment. Controlled blasting will not be permitted as a means of dropping the stack.

Various internal areas of the switch house and selected areas of the switchyard will be demolished. The Generator Step-up transformers (GSUs) and other designated equipment in the switchyard area will be removed . Contaminated soil as well as any other underground materials and tanks will be removed from the switchyard area.

The area outside and east of the Units 1, 2, and 3 will have equipment removed. The precipitators, stacks, silos, DSI building, DSI systems, settling basins, ash handling equipment and buildings, WPDES System, various storage and tractor sheds, and coal handling equipment and enclosures will be demolished.

Equipment removal includes removal of all electrical devices, conduit, wire, etc. (much of which will contain asbestos) related to the operation of the equipment being removed, back to the main disconnects for that equipment. The contractor will be responsible for determining that all equipment has been de-energized prior to removal.

Building shell demolition includes the complete removal of all building elements located above its underlying concrete slab and/or foundation, including roofs, sidewalls, building columns, and all other structures currently located within the building interior unless otherwise indicated in the specification. As noted previously, demolition of Units 4, 5, and 6 was completed in 2003. Photographs which chronicle the demolition of the building shells for Unit 4 and Unit 5 are shown in Figures C-9 through C-17.

The building or enclosure foundations, footings, and sills will be removed or excavated, then cleaned and crushed on site for use as designed fill. Filling with clean fill and grading will be required. Any excavation requires clean fill to return the excavation to grade. Fill shall be screened and shall not include any rebar, structural steel, equipment, organic material, or demolition debris.

Plant decommissioning efforts will include items such as electrical and mechanical isolations, draining of bulk oils and fuels, and removal of bulk controlled materials. The asbestos abatement will proceed first and demolition will start as soon as the specified areas have been abated and all regulated materials removed in order to meet the schedule for erection of the new power plant. Asbestos abatement may begin simultaneously in the north and east yard areas, the switch house, switchyard, and inside the power plant. The timing of these abatements efforts will depend on the contractor's overall schedule. The demolition contractor will coordinate accordingly with the asbestos abatement subcontractor to expedite the demolition activities. After the outside yard asbestos abatement is complete, the demolition contractor will start outside the plant and proceed to follow the asbestos contractor through the powerhouse and switchyard.

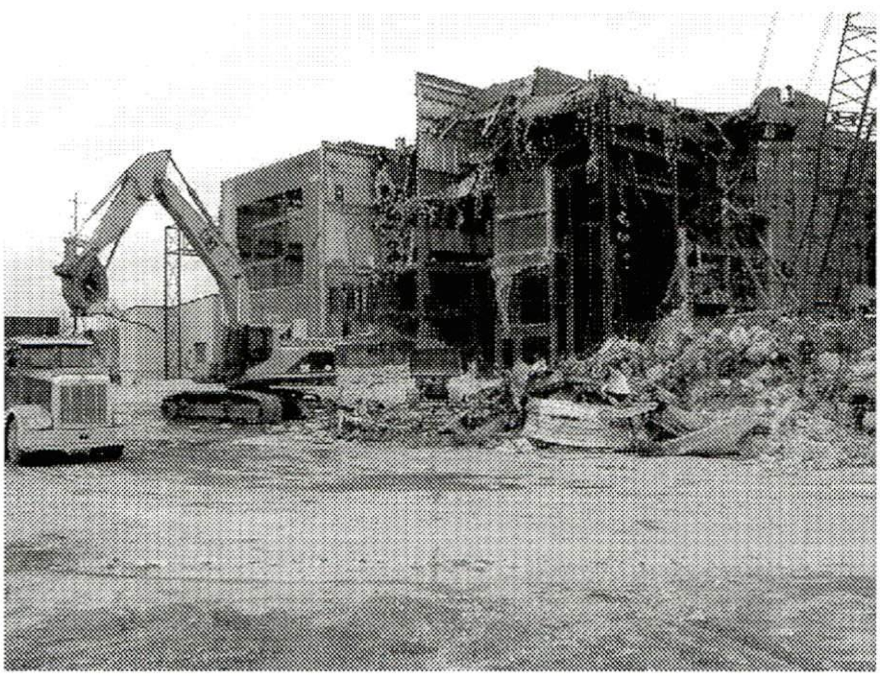

Figure C-9
Port Washington Power Plant – Demolition by February 2003, with Remaining North Wall of Unit 5 Coal Bunker

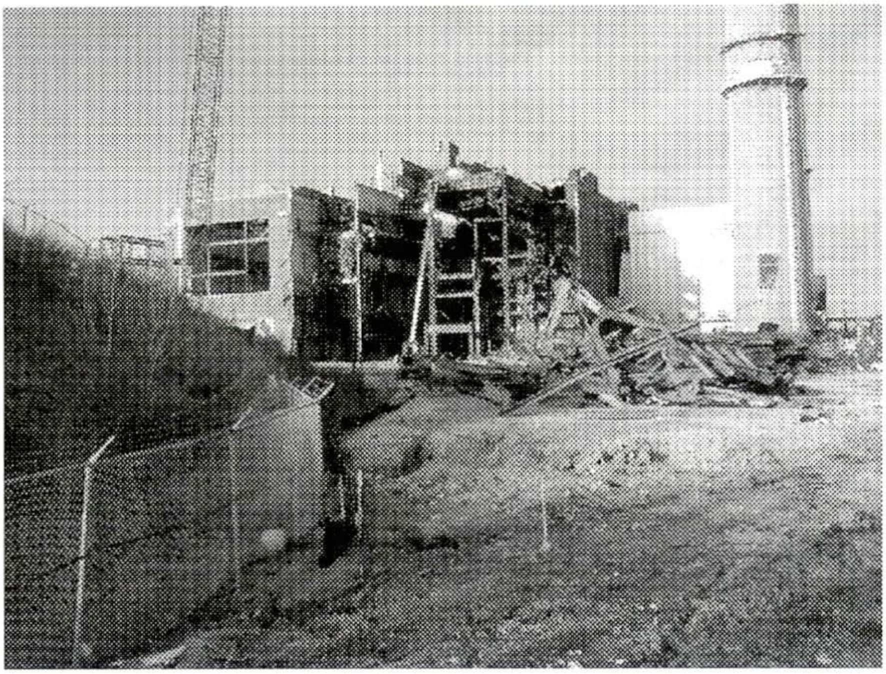

Figure C-10
Port Washington Power Plant - Demolition of Unit 5 Boiler House

Figure C-11
Port Washington Power Plant - Demolition of Unit 5 South Wall Brick with Wrecking Ball

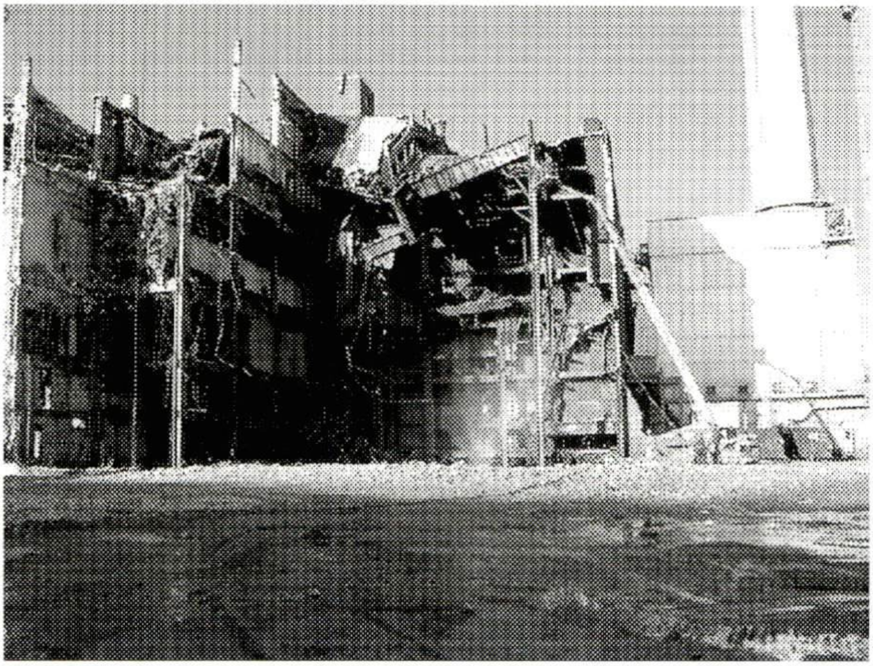

Figure C-12
Port Washington Power Plant - Removal of Structural Steel from Unit 5 Boiler House

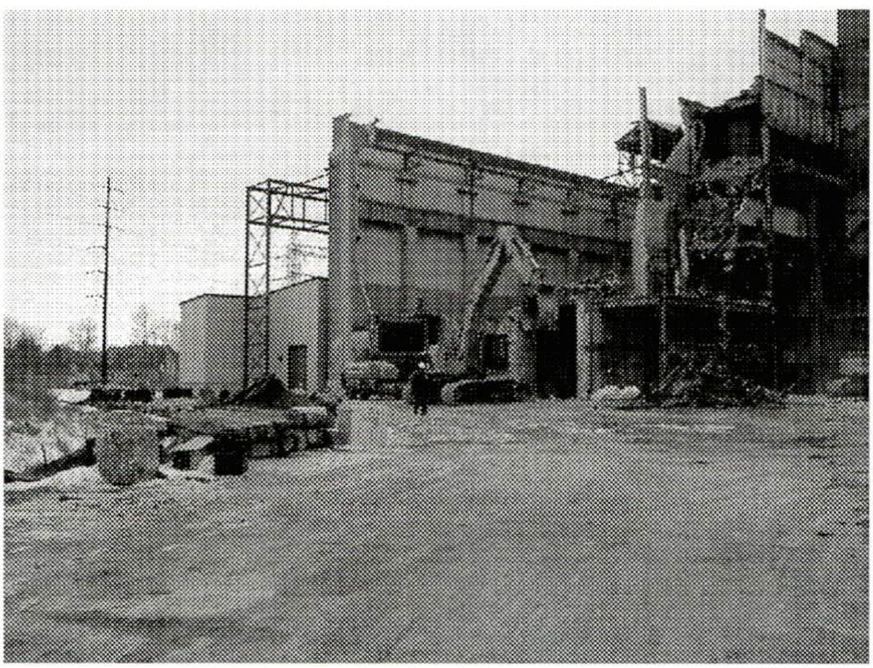

Figure C-13
Port Washington Power Plant - Demolition of Unit 5 Turbine Hall. Clean fill will be used to return any excavation to grade. No rebar, reinforcing steel, or demolition debris will remain in crushed concrete.

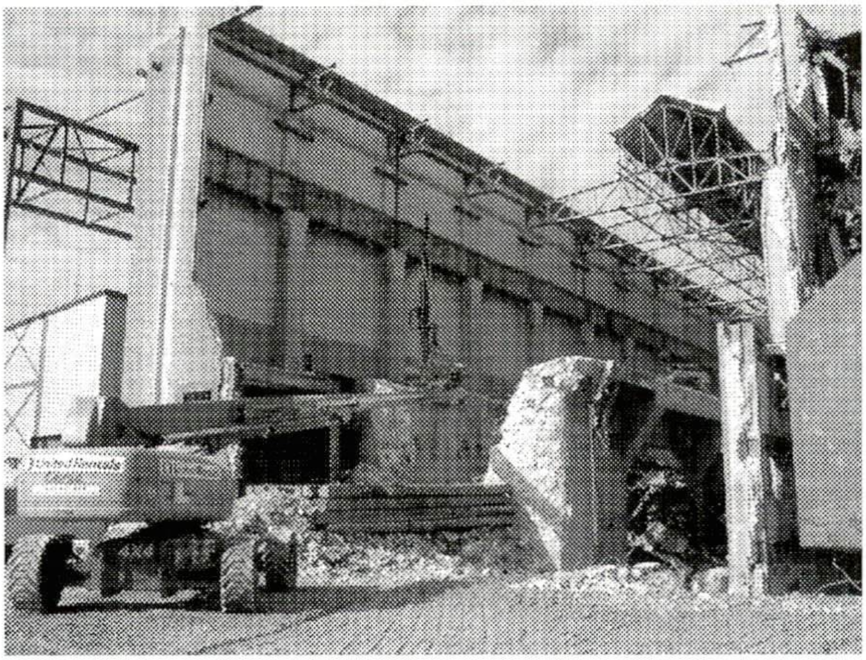

Figure C-14
Port Washington Power Plant – Drilling, in March 2003, of Southwest Turbine Pedestal for Demolition with Dynamite

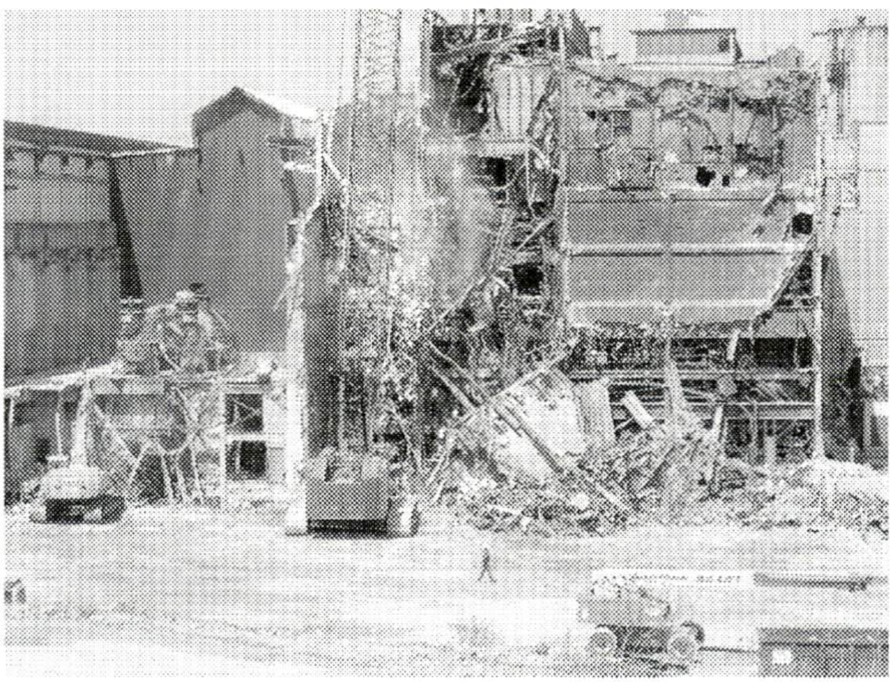

Figure C-15
Port Washington Power Plant - Demolition of Unit 4 Using the Wrecking Ball. Historical walls on the left will be retained.

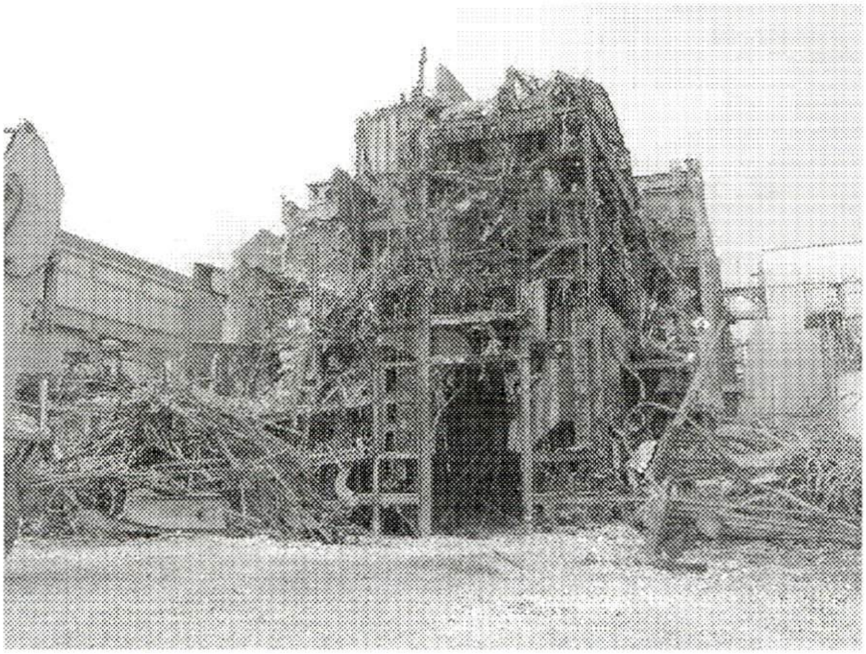

Figure C-16
Port Washington Power Plant – Demolition, in May 2003, of Unit 4 Boiler House

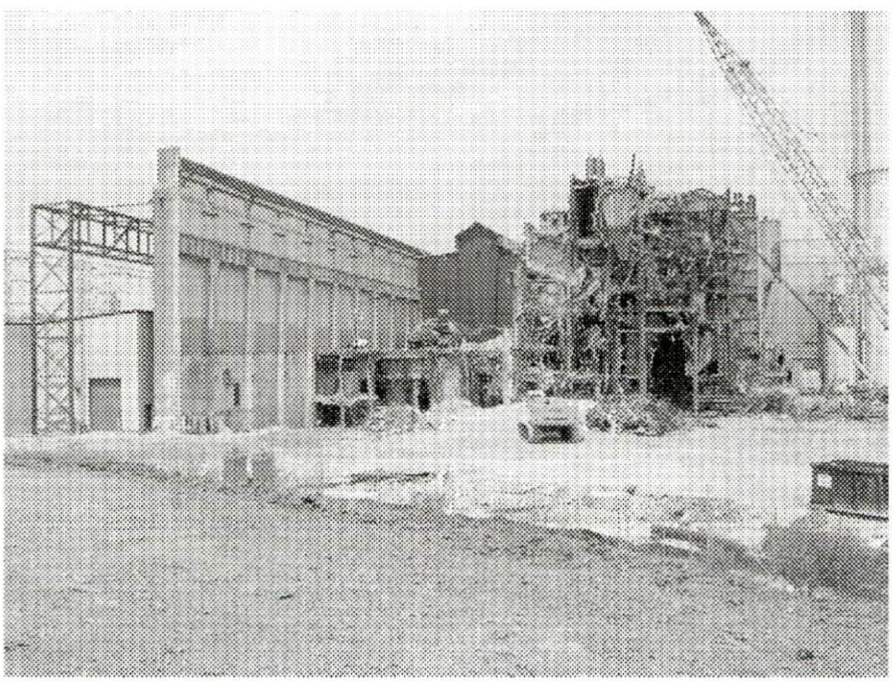

Figure C-17
Port Washington Power Plant - Wide Angle View, in May 2003, of Demolition Site

C

Schedule and Costs

We Energies requested the contractors to submit cost and schedule information in response to the bid proposals. The contractors were to provide a base schedule for completion of the work with a start date of November 1, 2004 and the latest date for completion being January 31, 2006.

The total cost for decommissioning Units 4, 5, and 6 was $12,400,000. Costs for separate tasks were as follows:

TASK	COST, $
Demolition	7,100,000
Asbestos & lead abatement	2,100,000
Asbestos disposal	75,000
Contaminated soil disposal	1,000,000
Decommissioning internal labor	800,000
System modifications & isolations	725,000
Environmental consulting	400,000
Engineering consulting	200,000
Total	12,400,000

The total cost for decommissioning Units 1, 2, and 3 and the balance of the plant (BOP) is estimated to be $17,000,000 to $22,000,000. Estimated costs for separate tasks are as follows:

TASK	COST, $
Demolition	6,000,000
Asbestos & lead abatement	3,000,000 - 5,900,000
Asbestos disposal	200,000 - 300,000
Hazardous material abatement	600,000
Hazardous material disposal	150,000
Demo debris disposal	750,000
Contaminated soil disposal	3,600,000
Decommissioning internal labor	900,000
System modifications & isolations	900,000
Temporary power requirements	300,000
Temporary WPDES	800,000
Environmental consulting	500,000
Engineering consulting	200,000
Contingency	3,000,000

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