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SOAH DOCKET NO. 473-21-0538
PUC DOCKET NO. 51415

APPLICATION OF SOUTHWESTERN	§	**BEFORE THE STATE OFFICE**
ELECTRIC POWER COMPANY FOR	§	**OF**
AUTHORITY TO CHANGE RATES	§	**ADMINISTRATIVE HEARINGS**
	§	
	§	

REDACTED VERSION

Direct Testimony of Devi Glick

On Behalf of Sierra Club

March 31, 2021

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1. INTRODUCTION AND PURPOSE OF TESTIMONY

Q Please state your name and occupation.

A My name is Devi Glick. I am a Senior Associate at Synapse Energy Economics, Inc. ("Synapse"). My business address is 485 Massachusetts Avenue, Suite 3, Cambridge, Massachusetts 02139.

Q Please describe Synapse Energy Economics.

A Synapse is a research and consulting firm specializing in energy and environmental issues, including electric generation, transmission and distribution system reliability, ratemaking and rate design, electric industry restructuring and market power, electricity market prices, stranded costs, efficiency, renewable energy, environmental quality, and nuclear power.

Synapse's clients include state consumer advocates, public utilities commission staff, attorneys general, environmental organizations, federal government agencies, and utilities.

Q Please summarize your work experience and educational background.

A At Synapse, I conduct economic analysis and write testimony and publications that focus on a variety of issues related to electric utilities. These issues include power plant economics, utility resource planning practices, valuation of distributed energy resources, and utility handling of coal combustion residuals waste. I have submitted expert testimony on unit-commitment practices, plant economics, utility resource needs, and solar valuation before state utility regulators in Texas, Arizona, Connecticut, Florida, Indiana, Michigan, New Mexico, North Carolina, South Carolina, Wisconsin, and Virginia. In the course

of my work, I develop in-house electricity system models and perform analysis using industry-standard electricity system models.

Before joining Synapse, I worked at Rocky Mountain Institute, focusing on a wide range of energy and electricity issues. I have a master's degree in public policy and a master's degree in environmental science from the University of Michigan, as well as a bachelor's degree in environmental studies from Middlebury College. I have more than seven years of professional experience as a consultant, researcher, and analyst. A copy of my current resume is attached as Exhibit DG-1.

Q On whose behalf are you testifying in this case?

A I am testifying on behalf of Sierra Club.

Q Have you testified previously before the Texas Public Utility Commission ("Commission")?

A Yes. I submitted testimony in PUC Docket No. 50997, Application of Southwestern Electric Power Company for Authority to Reconcile Fuel Costs, and PUC Docket No. 49831, Application of the Southwestern Public Service Company for the Authority to Change Rates.

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

A In this proceeding, I evaluate the economics of the coal units of Southwestern Electric Power Company ("SWEPCO" or the "Company"), with a particular focus on the Flint Creek and Welsh power stations. I assess three things with respect to SWEPCO's operation of its coal fleet: (1) the prudence of SWEPCO continuing to invest in and operate Flint Creek and Welsh; (2) the prudence retrofitting Flint

Creek to comply with the U.S. Environmental Protection Agency's ("EPA")Coal Combustion Residual ("CCR") and Effluent Limitation Guidelines ("ELG") regulations; and (3) the prudence of the proposed decision to convert Welsh to operate on gas.

Q How is your testimony structured?

A In Section 2, I summarize my findings and recommendations for the Commission.

In Section 3, I provide a summary of SWEPCO's coal fleet, and outline the test year expenses that the Company is requesting to recover in this current docket.

In Section 4, I evaluate the historical economic performance of the Flint Creek and Welsh plants and calculate the Company's net revenues during recent years. I also use the Company's own data to evaluate each unit's projected economic performance over the next decade.

In Section 5, I review the analysis that SWEPCO conducted to justify retrofitting Flint Creek to comply with the CCR Rule and ELG Rule rather than retire the plant by 2028. I evaluate the prudence of the retrofit decision relative to retirement and replacement.

In Section 6, I review the Company's proposal to retrofit Welsh to operate on gas. I evaluate the analysis that the Company has performed and outline my recommendation on what actions should be required to justify such a decision.

Q What documents do you rely upon for your analysis, findings, and observations?

A My analysis relies primarily upon the workpapers, exhibits, and discovery responses of SWEPCO witnesses. I also rely on public information from prior SWEPCO proceedings and other publicly available documents.

2. FINDINGS AND RECOMMENDATIONS

Q Please summarize your findings.

A My primary findings are:

1. SWEPCO incurred $153 million in net losses relative to the value of capacity and market energy at the Flint Creek Power Plant and incurred $144 million in net losses at the Welsh Power Plant over the past six years (2015–2020).
2. SWEPCO is projected to incur $161 million in net losses relative to the value of capacity and market energy by continuing to invest in and operate Flint Creek and incur $266 million in net losses at Welsh over the next decade (2021–2030).
3. SWEPCO has not demonstrated the prudence of continuing to invest in and operate its Flint Creek and Welsh coal plants through each of the plants' current retirement dates.
4. SWEPCO's recent decision to incur the avoidable ELG and CCR project costs at Flint Creek, rather than retire the plant in 2028, was imprudent.
5. Much of the $26.8 million that SWEPCO plans to spend to retrofit Flint Creek to comply with ELG and CCR requirements will be imprudently incurred over the next few years (2021–2023) if the Company goes ahead

with the project, especially in light of the fact that the company could operate Flint Creek until 2028 without incurring approximately $17.8 million of these retrofit costs.

6. The analysis that SWEPCO performed to justify the avoidable ELG and CCR retrofit projects at Flint Creek was flawed, relied on a simplified and inaccurate modeling methodology that did not evaluate an optimized resource mix, used overly conservative solar operational assumptions, omitted consideration of critical resource options, [redacted] and was not transparent on how, or whether, transmission costs were evaluated and included in the results.
7. SWEPCO has not conducted any analysis demonstrating the prudence of retrofitting Welsh to operate on gas.

Q Please summarize your recommendations.

A Based on my findings, I offer the following chief recommendations:

1. The Commission should disallow from the test year base rate all operations and maintenance ("O&M") and capital costs for Flint Creek and Welsh on the basis that the Company has not met the burden of demonstrating that those costs are reasonable and that it is prudent to continuing to invest in and operate the plants.
2. The Commission should find that SWEPCO's decision during the test year to undertake the avoidable ELG and CCR projects at Flint Creek, which could be avoided by a 2028 retirement, was imprudent.
3. The Commission should not permit SWEPCO to place into rate base and charge to Texas customers any costs incurred at Flint Creek for ELG and CCR project costs that could be avoided with a 2028 plant retirement date. To the extent that any ELG and CCR project costs are already included in

the test year rate base, SWEPCO should be required to complete an accounting of the ELG and CCR project costs at Flint Creek included in the test year and identify the costs that would be avoidable if the plant retired in 2028.

4. The Commission should not allow the recovery of future capital expenditures and fixed O&M costs at Flint Creek that are not necessary for the plant to operate beyond 2028.
5. Given that the current economic outlook for Welsh does not support converting the plant to gas, the Commission should require an analysis as part of the next rate case, or at the very least prior to any decision on whether to convert the plant to operate on gas.
6. The Commission should not allow the recovery of future capital and fixed O&M costs at Welsh associated with the plant's conversion to operate on gas until SWEPCO has presented robust analysis justifying the conversion and continued operation of the plant.
7. The Commission should require SWEPCO to conduct economic assessments of alternative retirement dates for Flint Creek and Welsh in its next rate case.

3. SWEPCO OWNS SIX SOLID-FUEL UNITS.

Q Describe SWEPCO's coal-fired fleet.

A The Company fully or partially owns four coal units. Units 1 and 3 at the Welsh Power Plant have a combined capacity of 1,053 megawatts ("MW") and are 100 percent owned by SWEPCO. Flint Creek is a one-unit plant with a capacity of 516 MW and is co-owned (50 percent each) with the Arkansas Electric

Cooperative Corporation. The John W. Turk Jr. Power Plant ("Turk") has a capacity of 650 MW and is 73.33 percent owned by SWEPCO.[1]

The Company also fully or partially owns two lignite plants. The Dolet Hills Power Station is a 650 MW mine-mouth lignite plant co-owned by SWEPCO (40.234 percent), Cleco Power LLC ("Cleco"), and two other nonaffiliated minority owners.[2] The Henry W. Pirkey Power Plant ("Pirkey") is a 675 MW, mine-mouth lignite plant operated by SWEPCO (85.936 percent) and co-owned with two other nonaffiliated minority owners.[3]

Q When does SWEPCO plan to retire or cease solid-fuel operations at each of these plants?

A Dolet Hills is scheduled to retire no later than December 2021[4] and Pirkey is scheduled to retire in 2023.[5] Under the current depreciation schedule, the Welsh units will retire in 2037 and 2042;[6] but SWEPCO has stated that it will cease coal operation at Welsh in 2028[7] and is currently considering whether to convert the units to gas or to retire them outright. Flint Creek has an estimated retirement year of 2038 and the Company is currently undertaking projects to comply with the

[1] Direct Testimony of Amy Jeffries, page 9 lines 1-9.
[2] *Id.*, Page 11 line 7-14.
[3] *Id.*
[4] Direct Testimony of A. Malcolm Smoak, page 5 lines 16-17.
[5] SWEPCO to End Coal Operations at Two Plants, Upgrade a Third. November 5, 2020. Accessible at https://www.swepco.com/company/news/view?releaseID=5847
[6] Schedule IV Plant Retire TX 2019.
[7] SWEPCO to End Coal Operations at Two Plants, Upgrade a Third. November 5, 2020. Accessible at https://www.swepco.com/company/news/view?releaseID=5847

ELG and CCR regulations that are at least partially avoidable if the plant retires by 2028.[8] Turk has an estimated retirement year of 2067.[9]

Q Which units do you address in this testimony?

A My testimony focuses on the economic performance and the operational and planning practices at the Flint Creek and Welsh units.

Although I have significant concerns with the uneconomic operational practices at Pirkey and Dolet Hills, the Company has announced near-term retirement dates for both plants. Therefore, I do not evaluate the units' recent or long-term economic performance. In addition, Turk is the newest coal unit in SWEPCO's fleet, so despite my concerns with the plant's long-term economics, I focus on the economics of SWEPCO's three older and most costly coal units in my testimony.

Q What is SWEPCO asking for in this rate case?

A SWEPCO is requesting an increase in base rates of 30.31 percent over adjusted Texas retail Test Year rate revenue.[10] The Company is using the historical period April 2019–March 2020 (adjusted for known and measurable change) for the Company's test year.[11]

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[8] Ex. DG-2, SWEPCO, Flint Creek APDES Permit Modification Application (Jan. 8, 2021); SWEPCO Response to Sierra Club Request 1-9(d); Direct Testimony of Monte McMahon, page 7 table 2.

[9] Schedule IV Plant Retire TX 2019.

[10] SWEPCO Petition and Statement of Intent to Change Rates, page 4.

[11] Direct Testimony of Thomas Brice, page 4 lines 10-12.

Q What power plant expenses is SWEPCO attempting to recover through this rate case?

A SWEPCO seeks to recover fixed and variable O&M expenses and ongoing capital expenditures, including a portion of spending on environmental retrofits.

Q What solid-fuel power plant O&M expenses and capital expenditures did SWEPCO include in the test year?

A SWEPCO's total test year O&M expenses totaled $91.9 million and capital expenditures totaled $34.6 million at its solid-fuel units (see Table 1).[12]

Table 1: Test year (April 2019–March 2020) O&M expenses and capital expenditures by plant

Plant	O&M Expenses ($Millions)	Capital Expenditures ($Millions)
Flint Creek	$9.8	$3.4
Turk	$19.0	$6.9
Welsh	$28.3	$6.8
Dolet Hills	$12.5	$1.5
Pirkey	$22.3	$16.0
Total	**$91.9**	**$34.6**

Source: Schedule H-1.2b, Schedule H-12c. SWEPCO Response to CARD Request 1-16, Supplemental Attachment 2.

[12] Schedule H-1.2b; Schedule H-12c; SWEPCO Response to CARD Request 1-16, Supplemental Attachment 2.

Q Does the Commission consider the reasonableness of capital expenditures through resource planning dockets in the state of Texas?

A No, Texas does not have an official resource planning process. Therefore, it is especially important for the Commission to address resource planning concerns through rate cases in test year spending.

Q What portion of the ELG and CCR project costs at Flint Creek are avoidable if the plant retires in 2028?

A It appears that around $17.3 million of SWEPCO's share of the total project costs are avoidable if Flint Creek retires in 2028.[13] The remaining $8.8 million will be incurred regardless to close the Primary Bottom Ash Pond.[14]

4. FLINT CREEK AND WELSH HAVE BEEN, AND ARE PROJECTED TO CONTINUE TO BE, UNECONOMIC.

Q Please summarize your findings on the economic performance of the Flint Creek and Welsh units.

A I find that SWEPCO incurred net losses of $153 million and $144 million at Flint Creek and Welsh respectively over the past six years. Further, the Flint Creek and Welsh units are projected to continue to incur net losses over the next decade of

[13] SWEPCO Response to Sierra Club Request 2-17, Attachment 1; SWEPCO Response to Sierra Club Request 1-9; SWEPCO Response to Sierra Club Request 3-2.

[14] The Company provided a total project cost of $26,793,000 in SWEPCO Response to Sierra Club Request 1-9, Attachment 1, but then a slightly different cost of $26,081,313 in SWEPCO Response to Sierra Club Request 2-17, Attachment 1. It is unclear which number is most current and accurate.

$161 million and $266 million respectively. In all my net loss calculations, I relied on projected unit costs provided by the Company, and the Company's own power market price forecast and capacity price forecast. I also ran a conservative sensitivity using the Southwest Power Pool's ("SPP") Cost of New Entry ("CONE") as a proxy for value of capacity in the region[15] and found that Flint Creek would still incur net losses of $27 million over the next decade, while Welsh would incur positive net revenues with this high capacity price assumption.

i. Flint Creek and Welsh incurred net losses of $153 million and $144 million respectively over the past six years.

Q Describe how the Company has been operating the Flint Creek and Welsh units over the past six years.

A Over the last six years, SWEPCO operated Flint Creek at an average capacity factor of 53 percent, and the Welsh Units at an average capacity factor of 52 percent. Capacity factors have been declining in recent years across all three units, with the plants' utilization dropping slightly in 2019 before plummeting in 2020.[16] These are low capacity factors for plants with such high fixed costs.

[15] In SPP, CONE is calculated based on the revenue needed to cover the capital and fixed costs of a hypothetical gas-burning peaking facility. This is a conservative estimate because unless a region is capacity constrained (which it is not, as evident by SWEPCO's incredibly low capacity price forecast), then capacity can generally be procured for less than the cost of building an entirely new peaking plant.

[16] EIA Form 923.

Q How did Flint Creek perform in recent years?

A At Flint Creek, SWEPCO incurred net negative revenues on a forward-looking[17] basis in every year over the past six years (2015–2020), totaling $153 million ($2020).[18] This works out to an average of $25 million in net losses relative to the market every year. Even excluding the $114 million associated with the installation of flue-gas desulfurization ("FGD") for compliance with the Mercury Air Toxics Standards ("MATS"),[19] SWEPCO's share of the unit incurred $35 million ($2020) in net negative revenues for an average of $6 million in losses annually. This shows exactly how poorly the unit has performed relative to the market value of the unit's energy and capacity.

[17] Forward-looking cost analysis looks at all costs that are incurred due to the continued operation of the plant, and therefore could be avoided by the retirement of the plant. All capital and fixed costs that had or have already been incurred, such as prior capital investments and fixed operating costs, are excluded from this analysis, as the decision to retire or operate the plant has no impact on their incursion.

[18] Schedule H-5-3.b; SWEPCO Response to Sierra Club Request 1-7 Attachment 2; SWEPCO Response to Sierra Club Request 1-7 Attachment 3; SWEPCO Response to Sierra Club Request 2-6, HS Attachment 1; SWEPCO Response to Sierra Club Request 2-13, HS Attachment 1; SWEPCO Response to CARD Request 1-16, Supplemental Attachment 2; SWEPCO Response to CARD Request 1-26, 1-26_2H2016_Base_Attachment_1, PUC Docket 50997, SOAH 473-20-4204 (filed Aug. 3, 2020); SWEPCO Response to CARD Request 1-26, 1-26_2H2018_Base_Attachment_2, PUC Docket 50997, SOAH 473-20-4204 (filed Aug. 3, 2020); SWEPCO Response to CARD Request 1-26,1-26_1H2019_Base_Attachment_3, PUC Docket 50997, SOAH 473-20-4204 (filed Aug. 3, 2020).

[19] Schedule H-5-3.b.

Table 2: HS historical net revenues of Flint Creek and Welsh Units 1 and 3, 2015–2020 (2020 $Million)

	2015	2016	2017	2018	2019	2020	Total
Flint Creek	[redacted]						($152.7)
Welsh 1&3	[redacted]						($143.9)

Source: Schedule H-5-3.b; SWEPCO Response to Sierra Club Request 1-7 Attachment 2; SWEPCO Response to Sierra Club Request 1-7 Attachment 3; SWEPCO Response to Sierra Club Request 2-6, HS Attachment 1; SWEPCO Response to Sierra Club Request 2-13, HS Attachment 1; SWEPCO Response to CARD Request 1-16, Supplemental Attachment 2; SWEPCO Response to CARD Request 1-26, 1-26_2H2016_Base_Attachment_1, PUC Docket 50997, SOAH 473-20-4204 (filed Aug. 3, 2020); SWEPCO Response to CARD Request 1-26, 1-26_2H2018_Base_Attachment_2, PUC Docket 50997, SOAH 473-20-4204 (filed Aug. 3, 2020); SWEPCO Response to CARD Request 1-26,1-26_1H2019_Base_Attachment_3, PUC Docket 50997, SOAH 473-20-4204 (filed Aug. 3, 2020).

Q How did Welsh Units 1 and 3 perform in recent years?

A At the Welsh Plant, SWEPCO incurred net negative revenues on a forward-looking basis over the years 2015–2020 totaling $144 million ($2020).[20] This works out to an average of $24 million in losses each year. Just as at Flint Creek, SWEPCO incurred a large capital expenditure at Welsh to install FGD to comply with MATS.

[20] Schedule H-5-3.b; SWEPCO Response to Sierra Club Request 1-7 Attachment 2; SWEPCO Response to Sierra Club Request 1-7 Attachment 3; SWEPCO Response to Sierra Club Request 2-6, HS Attachment 1; SWEPCO Response to Sierra Club Request 2-13, HS Attachment 1; SWEPCO Response to CARD Request 1-16, Supplemental Attachment 2; SWEPCO Response to CARD Request 1-26, 1-26_2H2016_Base_Attachment_1, PUC Docket 50997, SOAH 473-20-4204 (filed Aug. 3, 2020); SWEPCO Response to CARD Request 1-26, 1-26_2H2018_Base_Attachment_2, PUC Docket 50997, SOAH 473-20-4204 (filed Aug. 3, 2020); SWEPCO Response to CARD Request 1-26,1-26_1H2019_Base_Attachment_3, PUC Docket 50997, SOAH 473-20-4204 (filed Aug. 3, 2020).

While the plant appears to incur positive net revenues when the environmental capital expenditures are removed, as with all capital expenditures that the Company incurs each year, the project costs must be covered by the unit's energy market revenue and any capacity value over the lifetime of the project.[21] On average, if a plant is covering its annual capital expenditures (on top of its other fixed and variable costs) with its energy market revenue and capacity value, it makes sense to continue to operate the plant. But if the plants costs are consistently higher than its revenue and value over a sustained period, then ratepayers would be better off if the Company did not run the plant and instead purchased energy and capacity from the market.

With respect to Welsh, if the Company was projecting that it would earn significant net revenues at the plant over the next decade then it would be possible to recover the costs associated with prior large capital investments. But, as I will discuss in the next section, SWEPCO is, in fact, projected to incur net losses at Welsh over the next decade.

Q Explain how you calculated the values displayed in Table 2.

A I calculated the net revenues in Table 2 using the Company's own data on unit costs and revenues.

[21] SPP does not have a capacity market, but I still use SWEPCO's capacity price forecast as a proxy for the value of capacity in the region. I also ran sensitivities using SPP CONE as a proxy for the capacity value.

For costs, SWEPCO provided historical fuel costs[22] and total O&M costs[23] by unit for each historical year between 2015–2020. The Company also provided historical capital expenditures (including environmental projects)[24] for the period 2015–March 2020[25] but did not provide actual costs incurred for April–December of 2020.

The projected project cost data that SWEPCO did provide for 2020 on Schedule H-5-3.b[26] was incorrect and out of date. This was evident by the inclusion of $6.3 million for a dry-bottom ash conversion project at Welsh in 2020, and another $45.5 million over the subsequent three years, that the Company is not planning to spend. We know this because SWEPCO has filed a permit that reflects the Company's decision to cease coal combustion on or before December 31, 2028, and therefore to not proceed with the project.[27] [redacted].[28] Given this conflicting but limited data, I had to rely on the projections from Schedule H-5-3.b as the basis for capital expenditures for 2020, but I removed the large projected capital costs associated with the dry bottom ash project for Welsh.[29]

[22] SWEPCO Response to Sierra Club Request 1-7 Attachment 3.
[23] SWEPCO Response to Sierra Club Request 1-7 Attachment 2.
[24] Schedule H-5-3.b.
[25] Schedule H-5-3.b; SWEPCO Response to CARD Request 1-16, Supplemental Attachment 2.
[26] Schedule H-5-3.b.
[27] SWEPCO Response to Sierra Club Request 3-2(e).
[28] SWEPCO Response to Sierra Club Request 2-6, HS Attachment 1.
[29] Schedule H-5-3.b.

I add the capital expenditure costs to the fuel and O&M costs to get total unit costs.

For revenues, SWEPCO provided energy and ancillary market revenues[30] from selling the energy from each unit into the SPP market. Although SPP does not have a capacity market, and therefore the Company earned no capacity market revenues over the years 2015–2020, I included a capacity value calculated based on the Company's forward capacity price forecast produced between the years of 2016–2019.[31] I summed energy, ancillary, and capacity revenue to get total unit revenues.

Finally, I calculated the difference in each year between unit costs and revenues to produce the net revenues at each plant, shown in Table 2.

Q Did you also evaluate the units' operational performance?

A Yes, I looked Flint Creek and Welsh Units 1 and 3's operational performance in 2020 based on the Company's fuel[32] and O&M data,[33,34] and SPP Locational

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[30] SWEPCO Response to Sierra Club Request 2-13, HS Attachment 1.

[31] SWEPCO Response to CARD Request 1-26, 1-26_2H2016_Base_Attachment_1, PUC Docket 50997, SOAH 473-20-4204 (filed Aug. 3, 2020); SWEPCO Response to CARD Request 1-26, 1-26_2H2018_Base_Attachment_2, PUC Docket 50997, SOAH 473-20-4204 (filed Aug. 3, 2020); SWEPCO Response to CARD Request 1-26,1-26_1H2019_Base_Attachment_3, PUC Docket 50997, SOAH 473-20-4204 (filed Aug. 3, 2020).

[32] SWEPCO Response to Sierra Club Request 1-7 Attachment 3.

[33] SWEPCO Response to Sierra Club Request 1-7 Attachment 2.

[34] SWEPCO did not break out variable and fixed O&M in its historical data. I estimated historic VOM by finding the ratio of variable O&M to total O&M in the Company's

Marginal Prices.[35] I found that on a variable basis, Welsh Units 1 and 3 incurred net negative revenues in 2020, while Flint Creek incurred net positive revenues. But, critically, each unit incurred significant net revenue losses across many months in 2020: at Welsh 1, net losses were incurred during 4 of the 9 months the unit was operating, at Welsh 3 during 7 of 12 months, and at Flint Creek during 6 of the 11 months the unit was operating. In total, the three units incurred $14.5 million in losses across these uneconomic months, meaning that Texas ratepayers would have been $14.5 million better off if the units had not operated at all during these months and SWEPCO had instead purchased energy from the market.

ii. Flint Creek and Welsh are projected to continue to incur significant losses over the next decade of $161 million and $266 million respectively.

Q How does the Company project it will operate the Flint Creek and Welsh plants over the next decade?

A SWEPCO's own analysis projects dramatically decreasing utilization of the Flint Creek and Welsh units. Specifically, over the next decade (2021–2030) SWEPCO's modeling shows Flint Creek operating at only a [redacted] capacity factor and the Welsh units operating at only a [redacted] capacity factor.[36] These capacity factors roughly match those produced in the Company's Unit Disposition Study that was completed in February 2020.[37] As shown in Figure 1 below, this

projected costs provided in SWEPCO Response to Sierra Club Request 1-8, HS Attachment 1. I applied that ratio to the historic total O&M values.

[35] SPP Day Ahead Market LMPs available at https://marketplace.spp.org/pages/da-lmp-by-location.

[36] SWEPCO Response to Sierra Club Request 1-8, HS Attachment 1.

[37] SWEPCO Response to Sierra Club Request 2-2, HS Attachments 1–11; SWEPCO Response to Sierra Club Request 4-1.

represents a substantial decrease in utilization relative to the recent performance. These results indicate that there are lower-cost options that the Company can use to serve load and that Flint Creek and Welsh are relatively more expensive and less competitive than market energy and other Company resources. Given the significant deviation between the Company's projected capacity factors and its historical performance, I evaluated the units' projected revenues using both the projected, as well as historical, capacity factors. I will discuss the results of both sets of analysis below.

Figure 1: HS capacity factors by unit—historical and projected

Source: SWEPCO Response to Sierra Club Request 1-8, HS Attachment 1.
Note: The historical line shows the historical capacity factor assumption used for the capacity factor sensitivities.

Q What did you find regarding the forward-looking economics of Flint Creek over the next decade?

A As shown in Figure 2, I find that SWEPCO is projected to incur net losses at Flint Creek of $161 million (on a present value basis) over the next decade or an average of $21 million per year (2020$) at Flint Creek. These results are based on valuing capacity at SWEPCO's projected Capacity Price.[38]

Figure 2: HS projected net revenue at Flint Creek, 2021–2030 ($Million)

Source: Schedule H-5-3.b; SWEPCO Response to Sierra Club Request 1-8, HS Attachment 1; SWEPCO Response to Sierra Club Request 1-9, Attachment 1; SWEPCO Response to Sierra Club Request 2-6, HS Attachment 1; SWEPCO Response to Sierra Club Request 2-6, HS Attachment 2; SWEPCO Response to CARD Request 2-10, Supplemental Attachment 2; EPA CAMD data.

[38] SWEPCO Response to CARD Request 2-10, Supplemental Attachment 2.

Q What did you find regarding Flint Creek's performance under a different capacity price and capacity factor assumption?

A As shown in Table 3, I find that regardless of the capacity price and capacity factor assumptions, the unit is projected to incur net revenue losses. I conducted a sensitivity using a significantly higher capacity price represented by the SPP CONE.[39] CONE is "the total annual net revenue (net of variable operating costs) that a new generation resource would need to recover its capital investment and fixed costs, given reasonable expectations about future recovery over its economic life."[40] The CONE values are calculated based on the cost to build a new natural gas-fired peaking facility in SPP.[41] This is a very conservative capacity value estimate because unless a region is capacity constrained (which it is not, as evident by SWEPCO's incredibly low capacity price forecast) then capacity can generally be procured for less than the cost of building an entirely new peaking plant.

But even under this incredibly conservative capacity price assumption, Flint Creek is still projected to incur net losses of nearly $27 million in present value over the next decade, or $3.5 million annually (2020$).

I also evaluated the unit's net revenue assuming a higher capacity factor. Increasing the unit's capacity factor to 2019 levels has a very minimal impact on

[39] Southwest Power Pool – Open Access Transmission Tariff, Sixth Revised Volume No.1 – Attachment AA Resource Adequacy – Attachment AA Section 14. Cost of New Entry. Available at: https://spp.org/documents/58599/cone-effective%207-1-2018.pdf

[40] PJM Cost of New Entry, The Brattle Group. April 2018. Available at: https://www.pjm.com/~/media/committees-groups/committees/mic/20180425-special/20180425-pjm-2018-cost-of-new-entry-study.ashx.

[41] Southwest Power Pool – Open Access Transmission Tariff, Sixth Revised Volume No.1 – Attachment AA Resource Adequacy – Attachment AA Section 14. Cost of New Entry. Available at: https://spp.org/documents/58599/cone-effective%207-1-2018.pdf.

the unit's performance, with net revenue losses improving by only $1 million to total of $159.5 million (present value). In fact, I find that there is no capacity factor that would produce positive net revenue results at Flint Creek under either the AEP capacity price forecast or the SPP CONE capacity price.

Table 3: HS projected net revenues at Flint Creek with capacity price and capacity factor sensitivities (2020 $Million)

(Million $2020)	AEP Capacity Price		SPP CONE Capacity Price	
	Projected CF	Historical CF	Projected CF	Historical CF
2021	[redacted]	[redacted]	[redacted]	[redacted]
2022	[redacted]	[redacted]	[redacted]	[redacted]
2023	[redacted]	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]	[redacted]
2026	[redacted]	[redacted]	[redacted]	[redacted]
2027	[redacted]	[redacted]	[redacted]	[redacted]
2028	[redacted]	[redacted]	[redacted]	[redacted]
2029	[redacted]	[redacted]	[redacted]	[redacted]
2030	[redacted]	[redacted]	[redacted]	[redacted]
NPV Nominal	($159.5)	($160.6)	($25.64)	($26.76)
Annual Average ($2020)	($20.1)	($20.8)	($2.77)	($3.46)

Source: Schedule H-5-3.b; SWEPCO Response to Sierra Club Request 1-8, HS Attachment 1; SWEPCO Response to Sierra Club Request 1-9, Attachment 1; SWEPCO Response to Sierra Club Request 2-6, HS Attachment 1; SWEPCO Response to Sierra Club Request 2-6, HS Attachment 2; SWEPCO Response to CARD Request 2-10, Supplemental Attachment 2; EPA CAMD data.

Q What did you find regarding the forward-looking economics of Welsh over the next decade?

A As shown in Figure 3, I find that Welsh Units 1 and 3 are projected to incur net losses of $266 million over the next decade (on a present value basis) or an average of $35 million per year (2020$).

Figure 3: HS projected net revenue at Welsh, 2021–2030 ($Million)

Source: Schedule H-5-3.b; SWEPCO Response to Sierra Club Request 1-8, HS Attachment 1; SWEPCO Response to Sierra Club Request 1-9, Attachment 1; SWEPCO Response to Sierra Club Request 2-6, HS Attachment 1; SWEPCO Response to Sierra Club Request 2-6, HS Attachment 2; SWEPCO Response to CARD Request 2-10, Supplemental Attachment 2; EPA CAMD data.

Q Explain what the results at Welsh look like under an alternative capacity price?

A As shown in Table 4, the results of the net revenue analysis at Welsh are heavily dependent on how capacity is valued. For example, when capacity is priced using SPP CONE instead of SWEPCO's fundamental capacity price forecast, the plant nets positive revenues over the next decade.

Table 4: HS projected net revenues at Welsh with capacity price and capacity factor sensitivities (2020 $Million)

(Million $2020)	AEP Capacity Price		SPP CONE Capacity Price	
	Projected CF	Historical CF	Projected CF	Historical CF
2021	[redacted]	[redacted]	[redacted]	[redacted]
2022	[redacted]	[redacted]	[redacted]	[redacted]
2023	[redacted]	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]	[redacted]
2026	[redacted]	[redacted]	[redacted]	[redacted]
2027	[redacted]	[redacted]	[redacted]	[redacted]
2028	[redacted]	[redacted]	[redacted]	[redacted]
2029	[redacted]	[redacted]	[redacted]	[redacted]
2030	[redacted]	[redacted]	[redacted]	[redacted]
NPV Nominal	($416.0)	($266.4)	$130.4	$279.9
Annual Average ($2020)	($52.7)	($35.0)	$18.1	$35.8

Source: Schedule H-5-3.b; SWEPCO Response to Sierra Club Request 1-8, HS Attachment 1; SWEPCO Response to Sierra Club Request 1-9, Attachment 1; SWEPCO Response to Sierra Club Request 2-6, HS Attachment 1; SWEPCO Response to Sierra Club Request 2-6, HS Attachment 2; SWEPCO Response to CARD Request 2-10, Supplemental Attachment 2; EPA CAMD data.

I calculated a break-even capacity value for Welsh, that is the capacity price that would allow the plant to net zero dollars in both losses and revenues through 2030 and found a value of $132.43/MW-day. This price falls squarely in the middle between SWEPCO's capacity price forecast over this same period (2021–2030), which averages $31.66/MW-day,[42] and SPP CONE at $234.55/MW-day.[43]

[42] SWEPCO Response to CARD Request 2-10, Supplemental Attachment 2.

[43] Southwest Power Pool – Open Access Transmission Tariff, Sixth Revised Volume No.1 – Attachment AA Resource Adequacy – Attachment AA Section 14. Cost of New Entry. Available at: https://spp.org/documents/58599/cone-effective%207-1-2018.pdf

This means that in order for Welsh to provide net value to its customers, the value of capacity has to be more than quadruple from where the Company is forecasting capacity prices today. While this is not impossible, it is not a prudent assumption for system planning. As I will discuss in Section 6, this shows how important it is for SWEPCO to perform robust analysis to evaluate the cost of continuing to operate Welsh before it makes any significant investments in the unit that will lock ratepayers into more fixed and capital costs.

Q What happens to the results if the Welsh units operate more than projected?

A As shown in Table 4, when historical capacity factors are used and capacity is valued based on AEP Capacity prices, the plant still nets negative revenues of $416 million (present value). Further, there is no capacity factor that would make the Welsh plant incur positive net revenues with capacity valued at the AEP capacity price. As discussed above, when SPP CONE is used to value capacity, the plant incurs net positive revenues even at the Company's low projected capacity factors.

Q How did you calculate the net revenue values shown in Figure 2 (Flint Creek) and Figure 3 (Welsh)?

A I calculated the values shown in Figure 2 and Figure 3 using the Company's own projections of unit costs and operation over the next decade. SWEPCO provided the outputs from a recent run of its PLEXOS production cost model, which included capacity factors, fixed and variable O&M costs, fuel costs, and generation.[44] The Company also provided a schedule of planned capital

[44] SWEPCO Response to Sierra Club Request 1-8, HS Attachment 1.

expenditures[45] for the years 2021–2030 and the cost of its project to upgrade Flint Creek to comply with CCR and ELG regulations.[46] The itemized historical (2016–March 2020)[47] and projected (2021–2030)[48] capital expenditures schedule provided by the Company contained only approximately half of the $26.8 million[49] ELG and CCR project[50] costs. I calculated the amount that was unaccounted-for and spread it over the years 2021–2023 as an additional environmental capital cost. I added together the costs for fuel, fixed and variable O&M, capital expenditures and the outstanding ELG and CCR project costs to get total unit costs by year.

I calculated energy market revenue by multiplying the projected annual generation output from the PLEXOS model[51] by the Company's 2021 energy market power price forecast for the SPP Central Region.[52] I assumed that the ratio of peak to off-peak generation would be roughly the same over the next decade as it was over the past six years.[53] Even though SPP does not have a capacity market, I estimated a capacity value by applying the capacity prices for the SPP Central Region calculated by SWEPCO[54] to the Company's megawatt share of each unit's

[45] SWEPCO Response to Sierra Club Request 2-6, HS Attachment 1; SWEPCO Response to Sierra Club Request 2-6, HS Attachment 2.
[46] SWEPCO Response to Sierra Club Request 1-9, Attachment 1.
[47] Schedule H-5-3.b.
[48] SWEPCO Response to Sierra Club Request 2-6, HS Attachment 2.
[49] SWEPCO Response to Sierra Club Request 1-9, Attachment 1.
[50] Project "000020379 FLC U1 DBA Convert (CCR/ELG)" on Schedule H-5-3.b and in SWEPCO Response to Sierra Club Request 2-6, HS Attachment 2.
[51] SWEPCO Response to Sierra Club Request 1-8, HS Attachment 1.
[52] SWEPCO Response to CARD Request 2-10, Supplemental Attachment 2.
[53] I calculated the historical peak to off-peak ratio based on EPA's Clean Air Markets Division ("CAMD") hourly generation data.
[54] SWEPCO Response to CARD Request 2-10, Supplemental Attachment 2.

capacity. As a sensitivity, I also calculated the value of capacity at SPP's CONE, a highly conservative assumption.

I then found the difference between the projected revenues and costs for each unit in each year. These values represent the projected net revenues of the units.

Q What do you conclude regarding the economic status of the Flint Creek and Welsh units?

A As summarized in Table 5, I find that under any reasonable capacity value assumption, SWEPCO has incurred significant losses at both plants over the past six years and is projected to continue to incur significant losses at both plants over the next decade. Further, the Company's own analysis shows that the plants are projected to be operated at extremely low capacity factors moving forward.

Table 5: HS summary of historical and projected net revenue at Flint Creek and Welsh ($Million)

	2015-2020	2021-2030	
	Historical Net Revenue ($2020)	**Projected NPV (Nominal)**	**Projected Annual Average Cost ($2020)**
Flint Creek	($153)	($161)	($21)
Welsh	($144)	($266)	($35)

Source: Schedule H-5-3.b; SWEPCO Response to Sierra Club Request 1-7 Attachment 2; SWEPCO Response to Sierra Club Request 1-7 Attachment 3; SWEPCO Response to Sierra Club Request 1-8, HS Attachment 1; SWEPCO Response to Sierra Club Request 1-9, Attachment; SWEPCO Response to Sierra Club Request 2-6, HS Attachment 1; SWEPCO Response to Sierra Club Request 2-6, HS Attachment 2; SWEPCO Response to Sierra Club Request 2-13, HS Attachment 1; SWEPCO Response to CARD Request 1-16, Supplemental Attachment 2; SWEPCO Response to CARD Request 2-10, Supplemental Attachment 2; SWEPCO Response to CARD Request 1-26, 1-26_2H2016_Base_Attachment_1, PUC Docket 50997, SOAH 473-20-4204 (filed Aug. 3, 2020); SWEPCO Response to CARD Request 1-26, 1-26_2H2018_Base_Attachment_2, PUC Docket 50997, SOAH 473-20-4204 (filed Aug. 3, 2020); SWEPCO Response to CARD Request 1-26,1-26_1H2019_Base_Attachment_3, PUC Docket 50997, SOAH 473-20-4204 (filed Aug. 3, 2020); EPA CAMD data.

5. SWEPCO IS IMPRUDENTLY INVESTING $26.8 MILLION TO RETROFIT FLINT CREEK TO EXTEND THE LIFE OF THE PLANT BEYOND 2028.

Q What is SWEPCO's plan or proposal with regards to Flint Creek?

A SWEPCO has decided to retrofit the Flint Creek plant to comply with the Effluent Limitations Guidelines ("ELG") and Coal Combustion Residuals ("CCR") regulatory requirements, with the intention of operating the plant beyond 2028.[55]

Q What requirements of the ELG and CCR rules are most pertinent for SWEPCO's planning at Flint Creek?

A Under the ELG rule, EPA regulates the discharge of pollutants from bottom ash transport water. The rule requires steam electricity generating units such as Flint Creek to comply with best available technology requirements by December 31, 2025, or permanently cease the combustion of coal by December 31, 2028. This rule allows electricity generating units to continue operating until retirement without additional ELG-related retrofits.[56] The CCR rule, which regulates the disposal of coal ash from coal-fired power plants, requires that CCR impoundments close by October 15, 2023. But, it includes an option to continue operating CCR impoundments such as Flint Creek's primary ash pond as long as the plant commits to cease the combustion of coal and close impoundments by October 17, 2028 (this applies to impoundments greater than 40 acres).[57] Flint

[55] Ex. DG-2, Flint Creek APDES Permit Modification Application, Attachment 1 at 1-2.
[56] U.S. EPA, Steam Electric Reconsideration Rule, 85 Fed. Reg. 64,650, 64,661, 64,680 (Oct. 13, 2020); SWEPCO Response to Sierra Club Request 3-2(e).
[57] 40 CFR § 257.103(f); SWEPCO Response to Sierra Club Request 3-2(d).

Creek handles coal ash by wet sluicing bottom ash to the primary ash pond and is planning to convert to dry ash handling.[58] Currently, SWEPCO is in the preliminary engineering and design phase of the projects selected to comply with these avoidable ELG and CCR requirements. SWEPCO estimates the projects' will be completed by November 30, 2022 and February 28, 2023 respectively.[59] This means that the project is only just underway, and the majority of the project costs can still be avoided.

The estimated cost of the ELG and CCR projects are $26.8 million.[60] Because of the ELG and CCR rule exemptions for power plants that cease burning coal by 2028, SWEPCO could operate the plant through 2028 and avoid approximately $17.3 million of these costs, provided it commits to retire the plant by that time.[61]

Q What analysis did SWEPCO conduct to justify continued investment in, and operation of, the Flint Creek Power Plant?

A At the request of Counsel, SWEPCO conducted a Unit Disposition Study in February 2020 that compared the revenue requirement of (1) installing upgrades at the Flint Creek, Pirkey, and Welsh plants to comply with CCR and ELG regulations; (2) not installing the upgrades, and instead retiring the plants by the 2028 deadline, or in the case of Welsh, alternatively converting Unit 1 to operate on gas.[62]

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[58] Ex. DG-2, Flint Creek APDES Permit Modification Application, Attachment 1 at 1.

[59] Ex. DG-2, Flint Creek APDES Permit Modification Application, Attachment 2; SWEPCO Response to Sierra Club Request 3-2(d)-(e).

[60] SWEPCO Response to Sierra Club Request 1-9, Attachment 1.

[61] SWEPCO Response to Sierra Club Request 2-7, Attachment 1.

[62] SWEPCO Response to Sierra Club Request 1-5, HS Attachment 6; SWEPCO Response to Sierra Club Request 4-1.

Q What did SWEPCO find in these studies?

A At Pirkey and Welsh, SWEPCO found that it was [redacted]

Q Do you have concerns with the analysis performed by the Company?

A Yes. I have many concerns with the study. As a preliminary point, it is implausible to assume that a coal plant that is marginal today will somehow become more economic as its equipment ages, renewables come onto the grid, and the grid itself faces carbon constraints. Therefore, it is not surprising that the Company relied on flawed analysis to support its findings. I found the following issues with SWEPCO's study: (1) The savings SWPECO found that were used to justify retrofitting Flint Creek to comply with the CCR and ELG rules are [redacted] with more accurate assumptions; (2) the Company was not transparent around its assumptions and data inputs; (3) The Company did not utilize optimized capacity expansion and production cost modeling; (4) SWEPCO modeled solar with very conservative and low operational assumptions; (5) SWEPCO considered limited replacement options, [redacted]; and (6) it is unclear how or if SWEPCO included the cost of [redacted] at Flint Creek in the retirement analysis.

Q Explain your concerns with the small level of savings used to justify the decision to retrofit Flint Creek.

A SWEPCO asserts that its results [redacted][63] This level of savings could be significant in the short term provided the analysis is robust. But the number is relatively meaningless when the inputs and assumption are highly uncertain over an extended planning period, and there is lack of clarity on how the assumptions were developed, such as in this analysis.

Q Can you provide some examples of inputs assumption that appears uncertain or unclear?

Yes. First, the Company provided no details on the basis of the ongoing capital cost assumptions it used in each scenario (particularly the difference between costs used in each scenario). [redacted]

Second, as mentioned in the end of Section 3, certain ELG and CCR project costs will be incurred regardless of whether the plant retires in 2028 or operates

[63] SWEPCO Response to Sierra Club Request 1-5, HS Attachment 6.

beyond.[64] But, for the purposes of the Unit Disposition Study, SWEPCO did not provide its assumption on which costs were incurred regardless of retirement, and which were avoidable with a 2028 Flint Creek retirement.[65]

Finally, in this Unit Disposition Study, SWEPCO modeled O&M costs at Flint Creek that are [redacted] over the years 2021–2030[66] than the Company modeled in another study conducted more recently.[67] In the Flint Creek 2028 retirement scenario, the O&M costs are avoided in 2029–2030, therefore using low O&M costs will result in an underestimate of the benefits from retiring the unit. If the O&M cost from the more recent study are used instead, the savings SWEPCO asserts it will see from keeping Flint Creek online between 2021–2030 decrease by [redacted]

Q Explain your concerns with the Company's modeling approach.

A The Company did not perform optimized capacity expansion and production cost analysis to justify the decision to invest in Flint Creek and operate the unit beyond 2028. Instead SWEPCO relied on an oversimplified methodology that used a faulty baseline, assumed that each unit operated in isolation, and did not test or provide any information about optimized or least-cost retirement paths for the Company's solid-fuel units.

First, SWEPCO assumed that each unit operates in a vacuum, and that if one unit retires, it has zero impact on the operation of all the remaining units. [redacted]

[64] SWEPCO Response to Sierra Club Request 2-17, Attachment 1.
[65] SWPECO Response to Sierra Club Request 2-2, HS Attachment 12.
[66] SWEPCO Response to Sierra Club Request 1-5, HS Attachment 6; SWEPCO Response to Sierra Club Request 2-2, HS Attachment 13.
[67] SWEPCO Response to Sierra Club Request 1-8, HS Attachment 1.

[redacted] This representation of the plants operating in isolation is absolutely not accurate and does not represent how utilization and revenues can change as the fleet makeup changes.

Second, the Company utilized a baseline or reference scenario that does not represent reality. [redacted]

Third, SWEPCO did not do utilize optimized capacity expansion modeling to test which units would retire and which units would continue to operate in the optimal system. [redacted] There was no modeling in the near term of the cost to replace the units directly with alternatives such as solar PV and battery storage, and therefore the results do not reflect any analysis on the competitiveness of SWEPCO's existing fleet relative to alternative resources.

[68] It is unclear what this resource represents and why it was modeled by SWEPCO.

Q Do you have concerns with the way SWEPCO modeled the renewable resources that were available to the system?

A Yes, not only did SWEPCO limit the ability of the model to seriously consider these resources in the Company's Unit Disposition Study until later in the 2030s, but the Company also assigned an overly conservative capacity credit to solar PV. [redacted] These assumptions are extremely conservative and limit the ability for solar PV to contribute to energy and capacity needs on the system. SPP conducted a study of solar effective load carrying capacity ("ELCC")[70] on the SPP system in 2019 and found that at the level of solar on the system at that time (4,282 MW), solar should be valued with an ELCC of 62.4 percent.[71] [redacted] This decision to assign solar PV a low capacity credit significantly decreases its ability to meet any capacity needs in the model. This is a major problem in the retire-or-retrofit study because solar PV would likely be a key part of the lowest cost suite of resources to replace Flint Creek.

[69] SWEPCO Response to Sierra Club Request 2-2, HS Attachment 1.

[70] ELCC is defined by SPP as "the amount of incremental load a resource can reliably serve, while also considering probabilistic parameters of unserved load caused by forced outages, load uncertainty, and other factors." SPP uses ELCC to award facility's capacity accreditation.

[71] Southwest Power Pool, ELCC Solar Study Report. September 2019. Available at: https://www.spp.org/Documents/60747/2019%20ELCC%20Solar%20Study%20Report.docx

Q Explain your concerns with the Company's resource alternative available to the model.

A The Company did not consider a full range of alternative resources in its analysis. [redacted] [redacted][72] Solar PV was offered and was indeed selected. But as discussed above, it was modeled with a very low capacity credit. If the model faced a firm capacity constraint, such as could be met by battery storage (paired with solar PV or standalone), [redacted] These existing resources include the coal being considered for retirement. [redacted]

Q Why do you think the retirement of Flint Creek would have been a lower cost option if battery storage and solar PV were available to the model in the Company's analysis to replace Flint Creek when it retired in 2028?

A Battery storage (and solar PV) costs have been declining dramatically over recent years. These price declines for renewable and storage technologies have made standalone and paired projects viable and cost-effective replacement options for gas technologies. If SWEPCO had included these resources in the model with reasonable costs and operational assumptions and allowed the model to select them when Flint Creek was retired, it is very likely SWEPCO would have found

[72] SWEPCO Response to Sierra Club Request 2-2, HS Attachment 14.

retirement and replacement with a portfolio of solar PV and battery storage to be a lower cost option.

Lazard's *Levelized Cost of Storage—Version 4.0* states that there have been high cost declines for battery storage resources across most use cases and technologies, and that "sustained cost declines have exceeded expectations for lithium-ion technologies," specifically.[73] Bloomberg New Energy Finance ("BNEF") analyzed historical battery storage costs, finding that costs for lithium-ion batteries have fallen 76 percent between 2012 and the first half of 2019.[74] BNEF noted this was its most striking finding when looking at historical cost trends for both renewable and storage technologies.

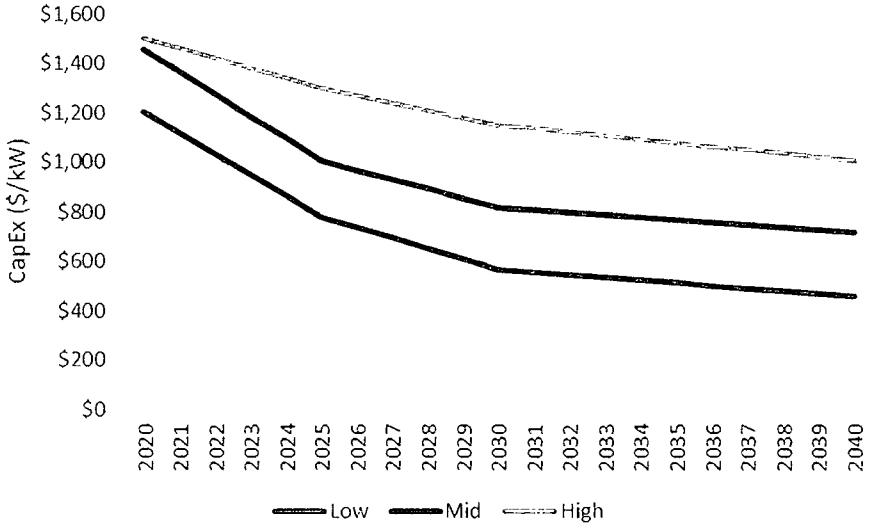
Battery storage costs are predicted to continue their cost decline. As a result, storage resources are and will become a cost-effective replacement resource for traditional peaking units. A 2018 report by GTM Research and Wood Mackenzie predicted that energy storage technologies will regularly compete head-to-head with new gas-fired peaking units by 2022, and that new gas peakers will be rare by 2028.[75]

[73] Lazard. 2018. *Levelized Cost of Storage Analysis—Version 4.0.* Available at: https://www.lazard.com/media/450774/lazards-levelized-cost-of-storage-version-40-vfinal.pdf.

[74] Utility Dive. 2019. *Electricity costs from battery storage down 76 percent since 2012: BNEF.* Available at: https://www.utilitydive.com/news/electricity-costs-from-battery-storage-down-76-since-2012-bnef/551337/.

[75] Greentech Media. March 1, 2018. "Will Energy Storage Replace Peaker Plants?" Available at: https://www.greentechmedia.com/webinars/webinar/will-energy-storage-replace-peaker-plants#gs.6JwDozs.

Figure 4: Projected capital cost for battery storage with 4-hour duration, 2018$



Source: NREL 2020 ATB. Available at: https://atb.nrel.gov/electricity/2020/data.php.

Q Explain your concerns around the Company's transmission upgrade assumptions. Specifically, did the Company incur transmission costs as part of any retirement scenario?

A It is unclear. [redacted][76] But the Company did not show in its input files if or how this cost was directly included in the Unit Disposition Study.

[76] SWEPCO Response to Sierra Club Request 2-2, HS Attachment 2; SWEPCO Response to Sierra Club Request 3-1, HS Attachment 4.

Q Would it be reasonable to include the full cost of the transmission project in a unit disposition analysis?

A No, it is not reasonable to include the full cost of the transmission project in this analysis. The Company has known since at least 2007 that it needs to address the load pocket in northwest Arkansas.[77] This concern has been ongoing, independent of any decision to retrofit or retire Flint Creek. Back in 2013, when the Arkansas Public Service Commission approved FGD upgrades at Flint Creek, it also ordered SWEPCO to study and address the load pocket in a timely manner.[78] The Company has clearly failed to do so.

Further, inclusion of these costs ignores the ability for replacement resources to serve as solutions themselves to the load pocket, or at least to mitigate the reliability concerns and reduce the scale of the needed solution. Battery storage coupled with solar (and not to mention increased energy efficiency investment) can be installed within the load pocket and directly replace the energy and capacity being retired at Flint Creek.

Q Did SWEPCO perform any other analysis at the time it was deciding to install upgrades at Flint Creek?

A SWEPCO provided no other substantive analyses that the Company performed to justify the decision to move forward with the avoidable CCR and ELG projects at Flint Creek.

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[77] Order No. 14, Ark. Pub. Serv. Comm'n, Docket 12-008-U, at 23 (July 10, 2013), available at: http://www.apscservices.info/pdf/12/12-008-u_227_1.pdf.

[78] Order No. 14, Ark. Pub. Serv. Comm'n, Docket 12-008-U, at 24 (July 10, 2013), available at: http://www.apscservices.info/pdf/12/12-008-u_227_1.pdf.

Q What is your conclusion with regards to the prudence of the Company's decision to invest in the CCR and ELG upgrades at Flint Creek?

A I find that SWEPCO acted imprudently in deciding to invest the $26.8 million to upgrade Flint Creek when at least $17.8 million of those costs could be avoided by retiring the unit in 2028. To demonstrate the prudence of the avoidable ELG and CCR projects, SWEPCO needs to show that, based on the information known at the time, it would be cheaper to retrofit Flint Creek and keep it operating beyond 2028 than to retire it and replace it with alternative resources. Such analysis would have required modeling a reasonable range of alternative resources, including gas, battery storage, wind, or solar PV—or at the very least testing a large number of distinct scenarios with various combinations of alternative resources. But SWEPCO provided no such analysis and therefore has not demonstrated the prudence of the decision to lock ratepayers into $26.8 million in project costs.

6. SWEPCO IS CONSIDERING CONVERSION OF WELSH TO OPERATE ON GAS, BUT THE COMPANY HAS YET TO PROVIDE ANY REASONABLE ECONOMIC ANALYSIS TO SUPPORT THE DECISION.

Q What is SWEPCO's plan or proposal with regards to the Welsh Plant?

A SWEPCO has announced its intention to cease burning coal at Welsh by 2028,[79] and therefore has decided it will not install upgrades necessary to comply with ELG and CCR requirements. The Company has indicated that it is considering

[79] SWEPCO to End Coal Operations at Two Plants, Upgrade a Third. November 5, 2020. Accessible at https://www.swepco.com/company/news/view?releaseID=5847

switching the unit to operate on gas, among other options.[80] The Company estimates that the cost of a conversion to gas at Welsh would be $32 million.[81]

Q What analysis has SWEPCO conducted to support converting the plan to operate on gas?

A The Company has not yet conducted any robust analysis on the option of converting the Welsh units to operate on gas. The Company did consider the [redacted] Unit Disposition Analysis, but for the reasons discussed in the section above, this analysis was not robust. Even if the analysis had been robust, [redacted].[82]

Q What type of analysis should the Company conduct to justify the decision to convert the unit to operate on gas?

A As part of the next rate case, or at the very least prior to making any investments in a conversion project, SWEPCO should be required to produce robust analysis that evaluates and compares the costs of converting the plant to the cost of retiring the plant and investing in alternatives. The analysis in the Unit Disposition Study is not sufficient; instead the Company should be required to produce optimized capacity expansion and production cost runs, or at the very least the results of specific scenarios that test retirement of Welsh and replacement with a reasonable range of alternative resources, including battery storage, solar PV, wind, and increased energy efficiency deployment.

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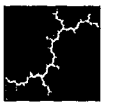
[80] *Id.*

[81] SWEPCO Response to Sierra Club Request 5-2.

[82] SWEPCO Response to Sierra Club Request 1-5, HS Attachment 6.

1 **Q Does this conclude your testimony?**

2 A Yes.



Devi Glick, Senior Associate

Synapse Energy Economics I 485 Massachusetts Avenue, Suite 3 I Cambridge, MA 02139 I 617-453-7050
dglick@synapse-energy.com

PROFESSIONAL EXPERIENCE

Synapse Energy Economics Inc., Cambridge, MA. *Senior Associate*, April 2019 – Present, *Associate*, January 2018 – March 2019

Conducts research and provides expert witness and consulting services on energy sector issues. Examples include:

- Modeling for resource planning using PLEXOS and Encompass utility planning software to evaluate the reasonableness of utility IRP modeling.
- Modeling for resource planning to explore alternative, lower-cost and lower-emission resource portfolio options.
- Providing expert testimony in rate cases on the prudence of continued investment in, and operation of, coal plants based on the economics of plant operations relative to market prices and alternative resource costs.
- Providing expert testimony and analysis on the reasonableness of utility coal plant commitment and dispatch practice in fuel and power cost adjustment dockets.
- Serving as an expert witness on avoided cost of distributed solar PV and submitting direct and surrebuttal testimony regarding the appropriate calculation of benefit categories associated with the value of solar calculations.
- Reviewing and assessing the reasonableness of methodologies and assumptions relied on in utility IRPs and other long-term planning documents in Arizona, Kentucky, New Mexico, Florida, South Carolina, North Carolina, South Africa, Newfoundland, and Nova Scotia for expert reports.
- Co-authoring public comments on the adequacy of utility coal ash disposal plans, and federal coal ash disposal rules and amendments.
- Analyzing system-level cost impacts of energy efficiency at the state and national level.

Rocky Mountain Institute, Basalt, CO. August 2012 – September 2017
Senior Associate

- Led technical analysis, modeling, training and capacity building work for utilities and governments in Sub-Saharan Africa around integrated resource planning for the central electricity grid energy. Identified over one billion dollars in savings based on improved resource-planning processes.
- Represented RMI as a content expert and presented materials on electricity pricing and rate design at conferences and events.
- Led a project to research and evaluate utility resource planning and spending processes, focusing specifically on integrated resource planning, to highlight systematic overspending on conventional resources and underinvestment and underutilization of distributed energy resources as a least-cost alternative.

Associate

- Led modeling analysis in collaboration with NextGen Climate America which identified a CO2 loophole in the Clean Power Plan of 250 million tons, or 41 percent of EPA projected abatement. Analysis was submitted as an official federal comment which led to a modification to address the loophole in the final rule.
- Led financial and economic modeling in collaboration with a major U.S. utility to quantify the impact that solar PV would have on their sales and helped identify alternative business models which would allow them to recapture a significant portion of this at-risk value.
- Supported the planning, content development, facilitation, and execution of numerous events and workshops with participants from across the electricity sector for RMI's Electricity Innovation Lab (eLab) initiative.
- Co-authored two studies reviewing valuation methodologies for solar PV and laying out new principles and recommendations around pricing and rate design for a distributed energy future in the United States. These studies have been highly cited by the industry and submitted as evidence in numerous Public Utility Commission rate cases.

The University of Michigan, Ann Arbor, MI. *Graduate Student Instructor*, September 2011 – July 2012

The Virginia Sea Grant at the Virginia Institute of Marine Science, Gloucester Point, VA. *Policy Intern*, Summer 2011

Managed a communication network analysis study of coastal resource management stakeholders on the Eastern Shore of the Delmarva Peninsula.

The Commission for Environmental Cooperation (NAFTA), Montreal, QC. *Short Term Educational Program/Intern*, Summer 2010

Researched energy and climate issues relevant to the NAFTA parties to assist the executive director in conducting a GAP analysis of emission monitoring, reporting, and verification systems in North America.

Congressman Tom Allen, Portland, ME. *Technology Systems and Outreach Coordinator*, August 2007 – December 2008

Directed Congressman Allen's technology operation, responded to constituent requests, and represented the Congressman at events throughout southern Maine.

EDUCATION

The University of Michigan, Ann Arbor, MI
Master of Public Policy, Gerald R. Ford School of Public Policy, 2012
Master of Science, School of Natural Resources and the Environment, 2012
Masters Project: *Climate Change Adaptation Planning in U.S. Cities*

Middlebury College, Middlebury, VT
Bachelor of Arts, 2007
Environmental Studies, Policy Focus; Minor in Spanish
Thesis: *Environmental Security in a Changing National Security Environment: Reconciling Divergent Policy Interests, Cold War to Present*

PUBLICATIONS

Eash-Gates, P., D. Glick, S. Kwok. R. Wilson. 2020. *Orlando's Renewable Energy Future: The Path to 100 Percent Renewable Energy by 2020.* Synapse Energy Economics for the First 50 Coalition.

Eash-Gates, P., B. Fagan, D. Glick. 2020. *Alternatives to the Surry-Skiffes Creek 500 kV Transmission Line.* Synapse Energy Economics for the National Parks Conservation Association.

Biewald, B., D. Glick, J. Hall, C. Odom, C. Roberto, R. Wilson. 2020. *Investing in Failure: How Large Power Companies are Undermining their Decarbonization Targets.* Synapse Energy Economics for Climate Majority Project.

Glick, D., D. Bhandari, C. Roberto, T. Woolf. 2020. *Review of benefit-cost analysis for the EPA's proposed revisions to the 2015 Steam Electric Effluent Limitations Guidelines.* Synapse Energy Economics for Earthjustice and Environmental Integrity Project.

Camp, E., B. Fagan, J. Frost, N. Garner, D. Glick, A. Hopkins, A. Napoleon, K. Takahashi, D. White, M. Whited, R. Wilson. 2019. *Phase 2 Report on Muskrat Falls Project Rate Mitigation, Revision 1 – September 25, 2019.* Synapse Energy Economics for the Board of Commissioners of Public Utilities, Province of Newfoundland and Labrador.

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Suphachalasai, S., M. Touati, F. Ackerman, P. Knight, D. Glick, A. Horowitz, J.A. Rogers, T. Amegroud. 2018. *Morocco – Energy Policy MRV: Emission Reductions from Energy Subsidies Reform and Renewable Energy Policy.* Prepared for the World Bank Group.

Camp, E., B. Fagan, J. Frost, D. Glick, A. Hopkins, A. Napoleon, N. Peluso, K. Takahashi, D. White, R. Wilson, T. Woolf. 2018. *Phase 1 Findings on Muskrat Falls Project Rate Mitigation.* Synapse Energy Economics for Board of Commissioners of Public Utilities, Province of Newfoundland and Labrador.

Allison, A., R. Wilson, D. Glick, J. Frost. 2018. *Comments on South Africa 2018 Integrated Resource Plan.* Synapse Energy Economics for Centre for Environmental Rights.

Hopkins, A. S., K. Takahashi, D. Glick, M. Whited. 2018. *Decarbonization of Heating Energy Use in California Buildings: Technology, Markets, Impacts, and Policy Solutions*. Synapse Energy Economics for the Natural Resources Defense Council.

Knight, P., E. Camp, D. Glick, M. Chang. 2018. *Analysis of the Avoided Costs of Compliance of the Massachusetts Global Warming Solutions Act*. Supplement to 2018 AESC Study. Synapse Energy Economics for Massachusetts Department of Energy Resources and Massachusetts Department of Environmental Protection.

Fagan, B., R. Wilson, S. Fields, D. Glick, D. White. 2018. *Nova Scotia Power Inc. Thermal Generation Utilization and Optimization: Economic Analysis of Retention of Fossil-Fueled Thermal Fleet to and Beyond 2030 – M08059*. Prepared for Board Counsel to the Nova Scotia Utility Review Board.

Ackerman, F., D. Glick, T. Vitolo. 2018. *Report on CCR proposed rule*. Prepared for Earthjustice.

Lashof, D. A., D. Weiskopf, D. Glick. 2014. *Potential Emission Leakage Under the Clean Power Plan and a Proposed Solution: A Comment to the US EP*A. NextGen Climate America.

Smith, O., M. Lehrman, D. Glick. 2014. *Rate Design for the Distribution Edge*. Rocky Mountain Institute.

Hansen, L., V. Lacy, D. Glick. 2013. *A Review of Solar PV Benefit & Cost Studies*. Rocky Mountain Institute.

TESTIMONY

Michigan Public Service Commission (Docket No. U-20804): Direct Testimony of Devi Glick in the application of Indiana Michigan Power Company for approval of a Power Supply Cost Recovery Plan and factors (2021). On behalf of Sierra Club. March 12, 2021.

Public Utility Commission of Texas (PUC Docket No. 50997): Direct Testimony of Devi Glick in the application of Southwestern Electric Power Company for authority to reconcile fuel costs for the period May 1, 2017- December 31, 2019. On behalf of Sierra Club. January 7, 2021.

Michigan Public Service Commission (Docket No. U-20224): Direct Testimony of Devi Glick in the application of Indiana Michigan Power Company for Reconciliation of its Power Supply Cost Recovery Plan (Case No. U-20223) for the 12-month period ending December 31, 2019. On behalf of Sierra Club. October 23, 2020.

Public Service Commission of Wisconsin (Docket No. 3270-UR-123): Surrebuttal Testimony of Devi Glick in the application of Madison Gas and Electric Company for authority to change electric and natural gas rates. On behalf of Sierra Club. September 29, 2020.

Public Service Commission of Wisconsin (Docket No. 6680-UR-122): Surrebuttal Testimony of Devi Glick in the application of Wisconsin Power and Light Company for approval to extend electric and natural gas rates into 2021 and for approval of its 2021 fuel cost plan. On behalf of Sierra Club. September 21, 2020.

Public Service Commission of Wisconsin (Docket No. 3270-UR-123): Direct Testimony and Exhibits of Devi Glick in the application of Madison Gas and Electric Company for authority to change electric and natural gas rates. On behalf of Sierra Club. September 18, 2020.

Public Service Commission of Wisconsin (Docket No. 6680-UR-122): Direct Testimony and Exhibits of Devi Glick in the application of Wisconsin Power and Light Company for approval to extend electric and natural gas rates into 2021 and for approval of its 2021 fuel cost plan. On behalf of Sierra Club. September 8, 2020.

Indiana Utility Regulatory Commission (Cause No. 38707-FAC125): Direct Testimony and Exhibits of Devi Glick in the application of Duke Energy Indiana, LLC for approval of a change in its fuel cost adjustment for electric service. On behalf of Sierra Club. September 4, 2020.

Indiana Utility Regulatory Commission (Cause No. 38707-FAC123 S1): Direct Testimony and Exhibits of Devi Glick in the Subdocket for review of Duke Energy Indian, LLC's Generation Unit Commitment Decisions. On behalf of Sierra Club. July 31, 2020.

Indiana Utility Regulatory Commission (Cause No. 38707-FAC124): Direct Testimony and Exhibits of Devi Glick in the application of Duke Energy Indiana, LLC for approval of a change in its fuel cost adjustment for electric service. On behalf of Sierra Club. June 4, 2020.

Arizona Corporation Commission (Docket No. E-01933A-19-0028): Rely to Late-filed ACC Staff Testimony of Devi Glick in the application of Tucson Electric Power Company for the establishment of just and reasonable rates. On behalf of Sierra Club. May 8, 2020.

Indiana Utility Regulatory Commission (Cause No. 38707-FAC123): Direct Testimony and Exhibits of Devi Glick in the application of Duke Energy Indiana, LLC for approval of a change in its fuel cost adjustment for electric service. On behalf of Sierra Club. March 6, 2020.

Texas Public Utility Commission (PUC Docket No. 49831): Direct Testimony of Devi Glick in the application of Southwestern Public Service Company for authority to change rates. On behalf of Sierra Club. February 10, 2020.

New Mexico Public Regulation Commission (Case No. 19-00170-UT): Testimony of Devi Glick in Support of Uncontested Comprehensive Stipulation. On behalf of Sierra Club. January 21, 2020.

Nova Scotia Utility and Review Board (Matter M09420): Expert Evidence of Fagan, B, D. Glick reviewing Nova Scotia Power's Application for Extra Large Industrial Active Demand Control Tariff for Port Hawkesbury Paper. Prepared for Nova Scotia Utility and Review Board Counsel. December 3, 2019.

New Mexico Public Regulation Commission (Case No. 19-00170-UT): Direct Testimony of Devi Glick regarding Southwestern Public Service Company's application for revision of its retail rates and

authorization and approval to shorten the service life and abandon its Tolk generation station units. On behalf of Sierra Club. November 22, 2019.

North Carolina Utilities Commission (Docket No. E-100, Sub 158): Responsive testimony of Devi Glick regarding battery storage and PURPA avoided cost rates. On behalf of Southern Alliance for Clean Energy. July 3, 2019.

State Corporation Commission of Virginia (Case No. PUR-2018-00195): Direct testimony of Devi Glick regarding the economic performance of four of Virginia Electric and Power Company's coal-fired units and the Company's petition to recover costs incurred to company with state and federal environmental regulations. On behalf of Sierra Club. April 23, 2019.

Connecticut Siting Council (Docket No. 470B): Joint testimony of Robert Fagan and Devi Glick regarding NTE Connecticut's application for a Certificate of Environmental Compatibility and Public Need for the Killingly generating facility. On behalf of Not Another Power Plant and Sierra Club. April 11, 2019.

Public Service Commission of South Carolina (Docket No. 2018-3-E): Surrebuttal testimony of Devi Glick regarding annual review of base rates of fuel costs for Duke Energy Carolinas. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. August 31, 2018.

Public Service Commission of South Carolina (Docket No. 2018-3-E): Direct testimony of Devi Glick regarding the annual review of base rates of fuel costs for Duke Energy Carolinas. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. August 17, 2018.

Public Service Commission of South Carolina (Docket No. 2018-1-E): Surrebuttal testimony of Devi Glick regarding Duke Energy Progress' net energy metering methodology for valuing distributed energy resources system within South Carolina. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. June 4, 2018.

Public Service Commission of South Carolina (Docket No. 2018-1-E): Direct testimony of Devi Glick regarding Duke Energy Progress' net energy metering methodology for valuing distributed energy resources system within South Carolina. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. May 22, 2018.

Public Service Commission of South Carolina (Docket No. 2018-2-E): Direct testimony of Devi Glick on avoided cost calculations and the costs and benefits of solar net energy metering for South Carolina Electric and Gas Company. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. April 12, 2018.

Public Service Commission of South Carolina (Docket No. 2018-2-E): Surrebuttal testimony of Devi Glick on avoided cost calculations and the costs and benefits of solar net energy metering for South Carolina Electric and Gas Company. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. April 4, 2018.

Resume updated March 2021

SOUTHWESTERN ELECTRIC POWER COMPANY

An AEP Company

January 8, 2021

Submitted via email

Dr. Robert Blanz
Water Division Manager
Arkansas Department of Environmental Quality
5301 Northshore Drive
North Little Rock, AR 72118

Re: Southwestern Electric Power Company
Flint Creek Power Plant
ADPES Permit Modification Application
AFIN: 04-00107
NPDES Permit No.: AR0037842

Dear Dr. Blanz:

Southwestern Electric Power Company (SWEPCO) is submitting this APDES Permit modification request for Flint Creek Power Plant, Permit No. ARR0037842. The following are included in the application:

- Form 1
- Attachment 1 – Description of Changes
- Attachment 2 – Bottom Ash Transport Water Schedule
- Attachment 3 – Site and Location Maps
- Attachment 4 – Water Flow Diagrams
- Attachment 5 – Financial Assurance
- Attachment 6 – 2019 Form 10K and 2020 Form 10-Q
- Attachment 7 – Previous Correspondences with ADEQ

The modification is to provide a justification as required by the Steam Electric Power Effluent Limitation Guidelines (ELGs) published in the *Federal Register* on October 13, 2020. SWEPCO is requesting an Applicability Date of November 30, 2022 to comply with the Best Available Technology requirements for Bottom Ash Transport Water.

If you have any questions, please do not hesitate to contact Steve Wells at (614) 716-2232 or sfwells@aep.com.

Sincerely,

Sara N. Vestfals
Plant Manager
Flint Creek Power Plant

Attachments

Southwestern Electric Power Company
Flint Creek Power Plant

Form 1

NPDES PERMIT APPLICATION

FORM 1

ARKANSAS DEPARTMENT OF ENERGY AND ENVIRONMENT
DIVISION OF ENVIRONMENTAL QUALITY - OFFICE OF WATER QUALITY
5301 Northshore Drive
North Little Rock, AR 72118-5317
www.adeq.state.ar.us/water

PURPOSE OF THIS APPLICATION

- ☐ INITIAL PERMIT APPLICATION FOR NEW FACILITY
- ☐ INITIAL PERMIT APPLICATION FOR EXISTING FACILITY
- X MODIFICATION OF EXISTING PERMIT
- ☐ REISSUANCE (RENEWAL) OF EXISTING PERMIT
- ☐ MODIFICATION AND CONSTRUCTION OF EXISTING PERMIT
- ☐ CONSTRUCTION PERMIT

SECTION A- GENERAL INFORMATION

1. Legal Applicant Name (The permit will be issued under this name. This is the entity that controls and is responsible for operations and compliance.):
   Southwestern Electric Power Company
   Please note: Arkansas Electric Cooperative is a 50% co-owner of power plant.
   Note: The legal name of the applicant must be identical to the name listed with the Arkansas Secretary of State.

2. Operator Type: Private ☐ Municipality ☐ State ☐ Federal ☐ Partnership ☐ Corporation X Other ☐
   State of Incorporation: Delaware

3. Facility Name: Flint Creek Power Plant

4. Is the legal applicant identified in number 1 above the owner of the facility? X Yes ☐ No

5. NPDES Permit Number (If Applicable): AR0037842

6. NPDES General Permit Number (If Applicable): ARG ____

7. NPDES General Storm Water Permit Number (If Applicable): ARR00B277

8. Permit Numbers and/or names of any permits issued by ADEQ or EPA for an activity located in Arkansas that is presently held by the applicant or its parent or subsidiary corporation which are not listed above:

Permit Name	Permit Number	Held by
Air	276-AOP-R9	Facility
Ash Landfill	273-S3N-R2	Facility

9. Give driving directions to the wastewater treatment plant with respect to known landmarks:
   From Hwy 59 in the City of Gentry, turn west on West 3rd Street (Hwy. 12). Turn south on Pioneer Lane, and then west on SWEPCO Road. Proceed to front gate of Flint Creek Power Plant.

10. Facility Physical Location: (Attach a map with location marked; street, route no. or other specific identifier)
    Street: 21797 SWEPCO Road

City: Gentry County: Benton State: AR Zip: 72734

11. Facility Mailing Address for permit, DMR, and invoice (Street or Post Office Box):

Name: Sara Vestfals Title: Plant Manager

Street: 21797 SWEPCO Plant Road, O1 P.O. Box

City: Gentry State: AR Zip: 72734

E-mail address*: snvestfals@aep.com Fax: 479-444-4719

* Is emailing all documents (permit, letters, DMRs, invoices, etc.) acceptable to the applicant? X Yes ☐ No

12. Neighboring States Within 20 Miles of the permitted facility (Check all that apply):

Oklahoma X Missouri X Tennessee ☐ Louisiana ☐ Texas ☐ Mississippi ☐

13. Indicate applicable Standard Industrial Classification (SIC) Codes and NAICS codes for primary processes (See Item #3 of the instructions for assistance in determining the correct SIC and NAICS Codes):

4911 SIC Facility Activity under this SIC or NAICS:

221112 NAICS Fossil Fuel Electric Power Station

14. Design Flow: 401-450 MGD Highest Monthly Average of the last two years Flow: _____ MGD

15. Is the outfall equipped with a diffuser? ☐ Yes X No

16. Responsible Official (as described on the last page of this application):

Name: Monte A. McMahon Title: VP, Generating Assets. SWEPCO

Address: 2400 FM 3251 Phone Number: 903-927-4930

E-mail Address: mamcmahon@aep.com

City: Hallsville State: TX Zip: 75650-9448

17. Cognizant Official (Duly Authorized Representative of responsible official as described on the last page of this application):

Name: Sara Vestfals Title: Plant Manager

Address: 21797 SWEPCO Road Phone Number: 479-444-4711

E-mail Address: snvestfals@aep.com

City: Gentry State: AR 72734

18. Name, address and telephone number of active consulting engineer firm (If none, so state):

Contact Name: Steve Wells

Company Name: American Electric Power Service Corporation

Address: 1 Riverside Plaza Phone Number: 614-716-2232

E-mail Address: sfwells@aep.com

City: Columbus State: OH Zip: 43215

19. Wastewater Operator Information

Wastewater Operator Name: Ivaunna Neigler License number: 011853

Class of municipal wastewater operator: I II ☐ III ☐ IV ☐

Class of industrial wastewater operator: Basic X Advanced ☐

Wastewater Operator Information

Wastewater Operator Name: Nichole Morrall License number: 011617

Class of municipal wastewater operator: I II ☐ III ☐ IV ☐

Class of industrial wastewater operator: Basic Advanced X

Wastewater Operator Information

Wastewater Operator Name: Chris Hubbell License number: 013499

Class of municipal wastewater operator: I II ☐ III ☐ IV ☐

Class of industrial wastewater operator: Basic X Advanced ☐

Wastewater Operator Information

Wastewater Operator Name: Trent Searle License number: 013600

Class of municipal wastewater operator: I II ☐ III ☐ IV ☐

Class of industrial wastewater operator: Basic X Advanced ☐

SECTION B: FACILITY AND OUTFALL INFORMATION

1. Facility Location (All information must be based on the **front door (gate)** location of the facility). A topographic map must be submitted. See Item #5 of the instructions for additional details.:

   Lat: 36 ° 15 ' 24.703 " Long: -94 ° 30 ' 59.407 "

2. Outfall Information (If more than two outfalls, add additional pages)

Outfall 001

End-of-Pipe Location: Latitude: 36 ° 14 ' 0.37 " Longitude: -94 ° 33 ' 5.944 "

Monitoring Location: Latitude: 36 ° 14 ' 0.37 " Longitude: -94 ° 33 ' 5.944 "

Description of outfall location: Discharge weir in Little Flint Creek

Name of Receiving Stream (i.e. an unnamed tributary of Mill Creek, thence into Mill Creek; thence into Arkansas River):

Discharge to Little Flint Creek, thence into Flint Creek, thence to Illinois River, thence to the Arkansas River

Type of Treatment system (Include all components of the treatment system and attach the process flow diagram):
- Sedimentation occurs in the primary and Clearwater Pond, landfill truck wash station, landfill non-contact stormwater ponds (2), industrial stormwater pond, landfill contact water pond landfill, leachate collection pond, and reclaim water storage basin;
-Bioreactor leachate treatment system to remove selenium and chromium, and pH neutralization;
- Ecology pit to remove oil and sediment;
-pH adjustment by CO2 injection occurs in the neutralization basin at the discharge weir from the Clearwater Pond; and
-NID oil/water separator removes oil.
A flow diagram showing these treatment systems is included in Attachment B.

How are effluent samples collected?

Grab as required by NPDES Permit.

How is flow measured, i.e., v-notch weir, totalizing meter, Parshall flume, etc.?

Continuous recorder with ultrasonic meter system.

Outfall 101

End-of-Pipe Location: Latitude: 36 ° 14 ' 57.80 " Longitude: -94 ° 31 ' 35.14 "

Monitoring Location: Latitude: 36 ° 14 ' 57.80 " Longitude: -94 ° 31 ' 35.14 "

Description of outfall location: Discharge weir from the Clearwater Pond into Lake SWEPCO.

Name of Receiving Stream (i.e. an unnamed tributary of Mill Creek, thence into Mill Creek; thence into Arkansas River):

Dicharge from the Clearwater Pond into Lake SWEPCO, thence through Outfall 001 into Little Flint Creek

Outfall 401
End-of-Pipe Location: Latitude: 36 ° 15 ' 27.01 " Longitude: -94 ° 31 ' 33.16'
Monitoring Location: Latitude: 36 ° 14 ' 27.01 " Longitude: -94 ° 31 ' 35.16

Description of outfall location: Left descending bank immediately below discharge from seal well to Lake SWEPCO

Name of Receiving Stream (i.e. an unnamed tributary of Mill Creek, thence into Mill Creek; thence into Arkansas River):

Dicharge from nto Lake SWEPCO, thence through Outfall 001 into Little Flint Creek.

Type of Treatment system (Include all components of the treatment system and attach the process flow diagram):

See above for Outfall 001.

How are effluent samples collected?

Grab sample as required by NPDES Permit. A portable ISCO sampler is used for biomonitoring.

How is flow measured, i.e., v-notch weir, totalizing meter, Parshall flume, etc.?

Ultrasonic flow meter

3. Is the proposed or existing facility located above the 100-year flood level? X Yes ☐ No

NOTE: FEMA Map must be included with this application. Maps can be ordered at www.fema.gov .

If "No", what measures are (or will be) used to protect the facility? _____

4. Population for Municipal and Domestic Sewer Systems: N/A

5. Backup Power Generation for Treatment Plants

Are there any permanent backup generators? Yes ☐ No X

If Yes, how many? _____ Total Horsepower (hp)? _____

If no, check one of the following.

☐ Portable generator is available.

☐ The WWTP does not require power to operate.

☐ Operations at the facility will cease if power is not available.

☐ The WWTP has sufficient capacity to hold influent until power is restored.

☐ Other, please explain _____

SECTION C – WASTE STORAGE AND DISPOSAL INFORMATION

1. Solids/Sludge Disposal Method (Check as many as are applicable):

☐ **Solids are not produced at this facility.**

X **Landfill:**

Landfill Site Name Flint Creek Landfill ADEQ Solid Waste Permit No. 273-S3N-R2

The facility does not generate typical wastewater plant sludge (biosolids); however, "bottom ash" is sluiced to the primary ash pond where it is separated from the wastewater via sedimentation. The facility dredged and disposed 48,000 cu.yds. of bottom ash from the primary ash pond in 2010, dewaterd it, and place it in the landfill in 2012. All sanitary wastes are routed to the City of Gentry POTW.

☐ **Land Application:** ADEQ State Permit No. _____

☐ **Septic tank**: Arkansas Department of Health Permit No.: _____

☐ **Distribution and Marketing**: Facility receiving sludge:

Name: _____ Address: _____

City: _____ State: _____ Zip: _____ Phone: _____

Rail: ☐ _____ Pipe: ☐ _____ Other: _____

☐ **Subsurface Disposal** (Lagoon for which the sole purpose is storing sludge):

Location of lagoon _____ How old is the lagoon? _____

Surface area of lagoon: _____ Acre Depth: _____ ft Does lagoon have a liner? ☐ Yes ☐ No

☐ **Incineration:** Location of incinerator _____

☐ **Remains in Treatment Lagoon(s):**

How old is the lagoon(s)? _____ Has sludge depth been measured? ☐ Yes ☐ No

If Yes, Date measured? _____ Sludge Depth? _____ ft If No, When will it be measured? _____

Has sludge ever been removed? Yes ☐ No ☐ If Yes, When was it removed? _____

☐ **Other** (Provide complete description): _____

SECTION D - WATER SUPPLY

Water Sources which are downstream of the outfall location, i.e., those which could be affected by the discharge from this facility (check as many as are applicable):

☐ **None**

X **Private Well** - Distance from Discharge point: ☐ Within 5 miles X Within 50 miles

X **Municipal Water Utility** (Specify City): City of Gentry

Distance from Discharge point: ☐ Within 5 miles ☐ Within 50 miles

X **Surface Water-** Name of Surface Water Source: SWEPCO Lake

Distance from Discharge point: X Within 5 miles ☐ Within 50 miles

Lat: 36 ° 14 ' 00 " Long: -94 ° 33 ' 02 "

☐ **Other** (Specify): _____

Distance from Discharge point: ☐ Within 5 miles ☐ Within 50 miles

NOT APPLICABLE (N/A): ☐

SECTION E: TRUST FUND REQUIREMENTS AND DISCLOSURE STATEMENT

1. Ark. Code Ann. § 8-4-203(b)(1)(A) forbids the Arkansas Department of Energy and Environment – Division of Environmental Quality (DEQ) from issuing, modifying, renewing, or transferring a permit for a nonmunicipal domestic sewage treatment works without the applicant first fulfilling the trust fund requirements set forth in that section. Ark. Code Ann. § 8-4-203(b)(1)(B) defines "nonmunicipal domestic sewage treatment works" as a device or system operated by an entity other than a city, town, or county that treats, in whole or in part, waste or wastewater from humans or household operations and must continually operate to protect human health and the environment despite a permittee's failure to maintain or operate the device or system. NDSTW's can include, but are not limited to:

    - Sewer Improvement Districts;
    - Subdivisions,
    - Mobile Home Parks,
    - Property Owner' Associates,
    - RV parks, and
    - Apartments

    Exclusions Excluded from this application's Section E.1. requirements for trust fund contribution fees are:
    - State or federal facilities,
    - Schools,
    - Universities and colleges,
    - Public facilities boards and public water authorities,
    - Entities that continuously operate due to a connection with a city, town, or county, and
    - Commercial or industrial entity that treats domestic sewage from its operations and does not accept domestic sewage from other entities or residences.

    The trust fund form may be obtained from the DEQ web site at:

    http://www.adeq.state.ar.us/water/permits/npdes/individual/pdfs/ndstw-trust-fund-certification-form.pdf

2. Disclosure Statement:

    Ark. Code Ann. 8-1-106 requires that applicants for any type of permit or transfer of any permit, license, certification or operational authority issued by the DEQ file a Disclosure Statement with their application unless exempt for doing so under Ark. Code Ann. §8-1-106(b)(2). The filing of a Disclosure Statement is mandatory. No application can be considered administratively complete without a completed Disclosure Statement unless that facility is exempt. Publicly traded companies may submit the most recent 10k and 10Q filings to the Securities and Exchange Commission in lieu of the Disclosure Statement. The form may be obtained from the ADEQ web site at:

    https://www.adeq.state.ar.us/ADEQ_Disclosure_Statement.pdf

NOT APPLICABLE (N/A): ☐

SECTION F – INDUSTRIAL ACTIVITY

1. Does an effluent guideline limitation promulgated by EPA (Link to a Listing of the 40 CFR Effluent Limit Guidelines) under Section 304 of the Clean Water Act (CWA) apply to your facility?

   YES X (Answer questions 2 and 3)NO ☐

2. What Part of 40 CFR? 423

3. What Subpart(s)? NA

4. Give a brief description of all operations at this facility including primary products or services (attach additional sheets if necessary):

   Sub-bituminous coal is burned in a boiler to produce steam for electrical generation. Steam is condensed for reuse. Wastewaters include; boiler blowdown, demineralizer regenerate, miscellaneous wash waters, condenser and ancillary equip non-contact cooling water, truck wash water, ash transport water, stormwater, leachate collection and treatment, and coal yard runoff.

5. Production: (projected for new facilities)

Product(s) Manufactured	Last 12 Months lbs/day*		Highest Production Year of Last 5 Years lbs/day*	
(Brand name)	Highest Month	Days of Operation	Monthly Average	Days of Operation

* These units could be off-lbs, lbs quenched, lbs cleaned/etched/rinsed, lbs poured, lbs extruded, etc.

NOT APPLICABLE (N/A): ☐

SECTION G - WASTEWATER DISCHARGE INFORMATION

Facilities that checked "Yes" in question 1 of Section F are considered Categorical Industrial Users and should skip to question 2.

1. **For Non-Categorical Users Only**: List average wastewater discharge, maximum discharge, and type of discharge (batch, continuous, or both), for each plant process. Include the reference number from the process flow schematic (reference Figure 1) that corresponds to each process. [New facilities should provide estimates for each discharge.]

No.	Process Description	Average Flow (GPD)	Maximum Flow (GPD)	Type of Discharge (batch, continuous, none)

If batch discharge occurs or will occur, indicate: [New facilities may estimate.]

Number of batch discharges: _____ per day Average discharge per batch: (GPD)

Time of batch discharges _____ (days of week) at _____ (hours of day)

Flow rate: _____ gallons/minute Percent of total discharge: _____

Answer questions 2, 3, 4, and 5 only if you are subject to Categorical Standards.

2. For Categorical Users: Provide the wastewater discharge flows for each of your processes or proposed processes. Include the reference number from the process flow schematic (reference Figure 1) that corresponds to each process. [Note: 1) New facilities should provide estimates for each discharge and 2) Facilities should denote whether the flow was measured or estimated.]

No.	Regulated Process	Average Flow (GPD)	Maximum Flow (GPD)	Type of Discharge (batch, continuous, none)
001	Reservoir Discharge	7,380,000	9,760,000	Continuous
101	Low volume wastewater	5,430,000	6,470,000	Continuous
401	Once-through cooling water	342,700,000	406,080,000	Continuous

No.	Unregulated Process	Average Flow (GPD)	Maximum Flow (GPD)	Type of Discharge (batch, continuous, none)
N/A	Sanitary Wastewater	3,680	5,600	Continuous to Gentry POTW

No.	Dilution (e.g., Cooling Water)	Average Flow (GPD)	Maximum Flow (GPD)	Type of Discharge (batch, continuous, none)

If batch discharge occurs or will occur, indicate: [New facilities may estimate.] Reclaim Basin – Low Volume Wastewater

Number of batch discharges: ≤1 per day Average discharge per batch: 36,000 (maximum) (GPD)

Time of batch discharges ≤ at 24
(days of week) (hours of day)

Flow rate: 25 gallons/minute Percent of total discharge: 0.625 (of average daily discharge through Outfall 101)

3. Do you have, or plan to have, automatic sampling equipment or continuous wastewater flow metering equipment at this facility?

Current: Flow Metering X Yes Type: Ultrasonic flow meters at Outfalls 001 and 101 ☐ No ☐ N/A

Sampling Equipment X Yes Type: Portable ISCO sampler used for biomonitoring only. ☐ No ☐ N/A

Planned: Flow Metering ☐ Yes Type: _____ X No ☐ N/A

Sampling Equipment ☐ Yes Type: _____ X No ☐ N/A

If yes, please indicate the present or future location of this equipment on the sewer schematic and describe the equipment below:

4. Are any process changes or expansions planned during the next three years that could alter wastewater volumes or characteristics?

X Yes ☐ No (If no, skip Question 5)

5. Briefly describe these changes and their effects on the wastewater volume and characteristics:

See Attachment 1.

NOT APPLICABLE (N/A): ☐

SECTION H -TECHNICAL INFORMATION

Technical information to support this application shall be furnished in appropriate detail to understand the project. Information in this Part is required for obtaining a **construction permit** or for **modification** of the treatment system.

1. Describe the proposed construction activity. Include the types of control equipment to be installed along with their methods of operation and control efficiency.

   N/A – Another modification will be submitted in the future with design plans. Please refer to explanation in Attachments 1 and 7.

2. One set of construction plans and specifications, approved (signed and stamped) by a **Professional Engineer** (PE) registered in **Arkansas**, must be submitted as follows:

   a. The plans must show flow rates in addition to pertinent dimensions so that detention times, overflow rates, and loadings per acre, etc. can be calculated.
   b. Specifications and complete design calculations.
   c. All treated wastewater discharges should have a flow measuring device such as a weir or Parshall flume installed after the final treatment unit. Where there is a significant difference between the flow rates of the raw and treated wastewater, a flow measuring device should be provided both before and after treatment.

3. If this application includes a construction permit disturbing five or more acres, a storm water construction permit must be obtained by submitting a notice of intent (NOI) to DEQ.

SECTION I: SIGNATORY REQUIREMENTS

Cognizant Official (Duly Authorized Representative)

40 CFR 122.22(b) states that all reports required by the permit, or other information requested by the Director, shall be signed by the applicant (or person authorized by the applicant) or by a duly authorized representative of that person. A person is a duly authorized representative only if:

(1) the authorization is made in writing by the applicant (or person authorized by the applicant);
(2) the authorization specifies either an individual or a position having responsibility for the overall operation of the regulated facility or activity responsibility, or an individual or position having overall responsibility for environmental matters for the company.

The applicant hereby designates the following person as a Cognizant Official, or duly authorized representative, for signing reports, etc., including Discharge Monitoring Reports (DMR) required by the permit, and other information requested by the Director:

Signature of Cognizant Official: _____ Date: 1/6/2021

Printed name of Cognizant Official: Sara N. Vestfals

Official title of Cognizant Official: Plant Manager Telephone Number: 479-444-4711

Responsible Official

The information contained in this form must be certified by a ***responsible official*** as defined in the "signatory requirements for permit applications" (40 CFR 122.22).

Responsible official is defined as follows:

Corporation, a principal officer of at least the level of vice president
Partnership, a general partner
Sole proprietorship: the proprietor
Municipal, state, federal, or other public facility: principal executive officer, or ranking elected official.

"By my signature below, I certify that the cognizant official designated above is qualified to act as a duly authorized representative under the provisions of 40 CFR 122.22(b)." NOTE: If no duly authorized representative is designated in this section, the Division considers the applicant to be the responsible official for the facility and only reports, etc., signed by the applicant will be accepted by the Division.

"By my signature below, I certify that, if this facility is a corporation, it is registered with the Secretary of State in Arkansas. Please provide the full name of the corporation if different than that listed in Section A above."

"I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information including the possibility of fine and imprisonment for knowing violations. I further certify under penalty of law that all analyses reported as less than detectable in this application or attachments thereto were performed using the EPA approved test method having the lowest detection limit for the substance tested."

Signature of Responsible Official: _____ Date: 1/6/2021

Printed name of Responsible Official: Monte McMahon

Official title of Responsible Official: VP Generating Assets SWEPCO Telephone Number: 903-927-4930

Attachment 1

Southwestern Electric Power Company
Flint Creek Power Plant

Description of Changes

Southwestern Electric Power Company (SWEPCO) Flint Creek Power Plant (Flint Creek) submits this modification in response to the 2020 Steam Electric Power Generating Effluent Guidelines Reconsideration Rule (2020 ELG Rule) that was published in the *Federal Register* on October 13, 2020. The Best Available Technology (BAT) requirements apply to the discharge of bottom ash transport water (BATW) at Flint Creek. SWEPCO presents the following information as justification for an as soon as possible Applicability Date for the elimination of bottom ash transport water.

The renewal NPDES Permit is currently under Appeal and stayed; however, it contains an ELG BATW Applicability Date of December 31, 2023 based on the 2015 Effluent Limitations Guideline Rule (2015 ELG Rule).

The 2020 ELG Rule stipulates that the new BAT limits do not apply until, at the earliest, October 13, 2021. The rule affords permittees the opportunity to demonstrate that the new limits should not apply until a later date, although no later than December 31, 2025. The demonstration is to be based on waste stream-specific facts and analyses and the burden to provide this information rests with the permittee. If the permitting authority receives relevant information from the permittee, the permitting authority must consider, among others, the following factors, which define "as soon as possible" under the rule:

1. Time to expeditiously plan (including to raise capital), design, procure, and install equipment to comply with the requirements of the final rule;

2. Changes being made or planned at the plant in response to greenhouse gas regulations for new or existing fossil fuel-fired power plants under the Clean Air Act, as well as regulations for the disposal of coal combustion residuals under subtitle D of the Resource Conservation and Recovery Act;

3. Other factors as appropriate, [such as grid reliability, the timing and progress of § 316(b) compliance, planned shut-down and maintenance periods to allow for equipment installations; and any other relevant factor that may affect the ability to implement the necessary facility retrofits].

To address BATW, a number of technologies were evaluated. The evaluation of different technologies was on-going during the postponement of the 2015 ELG Rule by USEPA. Based on the evaluation of technologies, SWEPCO has chosen a Dry Bottom Ash Handling (DBAH) system using a traditional under-boiler drag chain conveyor (UBDC) for the bottom ash system and dry flight conveyors for the economizer ash system. This will eliminate the use of BATW to sluice CCR material to the ponds. The DBAH will have a discharge of quench water to a wastewater sump in the bottom ash area of the Plant. Quench water is used to cool the bottom ash for handling and not used to transport bottom ash. It is classified by USEPA as a "low

volume waste source". SWEPCO is currently working with Burns and McDonnell (B&M) to provide engineering, design and procurement services for this system.

Attachment 2 provides a schedule of activities to occur in regards to the installation of the DBAH system. As the schedule indicates, ongoing closure of the Primary Settling Basin by removal of CCR material, for compliance with the CCR Rule, will be done concurrently with DBAH system installation. Upon removal of CCR material, the Primary Ash Pond will be renamed as "Wastewater Pond". We request that the permit reflect this change. The installation of the DBAH system will require a significant amount of supporting balance-of-Plant work and includes installing a new storage bunker, conveyor, electrical upgrades, and controls. Based on the work that needs to be completed in the Plant, the Unit needs to be taken out of service to complete installation under and around the boiler. The earliest this is achievable will be after completion of the rest of the supporting balance-of-Plant work in the Fall of 2022. Based on this information and schedule presented in Attachment 2, Flint Creek will meet the ELG BATW requirements by November 30, 2022.

Attachment 4 contains the current water balance and a future water balance. Additional work at Flint Creek is not addressed in this modification, but an additional modification(s) will be submitted for a new coal pile runoff pond, reclaim area, and potential demineralization wastewater treatment system. This work was previously mentioned to ADEQ in correspondence (copies enclosed in Attachment 7).

In addition, SWEPCO requests proposed language be included in the NPDES Permit:

A. The 2020 Steam Electric Power Generating Effluent Guidelines contain provisions in §423.13(o) to allow for the transfer between applicable limitations in a permit by certain, specified deadlines. EPA's intent is to allow for such transfers without the need for further permit modifications, as long as the transfer option is included in the permit and certain notification requirements in §423.19(i) are met. Consistent with that approach we request the following optional transfers be recognized and included in the permit using the language proposed below:

BATW – Transfer to Cessation of Coal Combustion:

The discharge of bottom ash transport water generated on and after November 30, 2022 is prohibited unless the permittee elects to permanently cease coal combustion in a generating unit by December 31, 2028 and complies with the following provisions:

(a) *Submit a Notice of Planned Participation (NOPP) by October 13, 2021 as outlined in §423.19(f).*

(b) *Permanently cease coal combustion in that unit on or before December 31, 2028.*

(c) There shall be no discharge of bottom ash transport water generated after December 31, 2028 for that unit.

(d) Any compliance schedule for the installation of bottom ash management technologies will be deemed to be in compliance with this NPDES permit upon timely submittal of the NOPP.

(e) The permittee shall submit annual progress reports starting on October 13, 2022 as outlined by §423.19(f)(3). These annual progress reports shall detail the completion of any interim milestones listed in the NOPP since the previous progress report, provide a narrative discussion of any completed, missed, or delayed milestones, and provide updated milestones. The annual progress reports will be due no later than October 13 of each year.

(f) Bottom ash transport water generated prior to the cessation of coal combustion date specified in the NOPP is permitted to be discharged in accordance with the limits established for Outfall 101.

B. Since bottom ash transport water (BATW) generated before the Applicability Date for this categorical wastewater will still need to be discharged, we are requesting the NPDES permit recognize this and authorize the discharge of any BATW generated before the Applicability Date of November 30, 2022. We propose the following permit language:

The discharge of bottom ash transport water generated on and after November 30, 2022 is prohibited. Any bottom ash transport water generated before November 30, 2022 is permitted to be discharged in accordance with the limits established for Outfall 101.

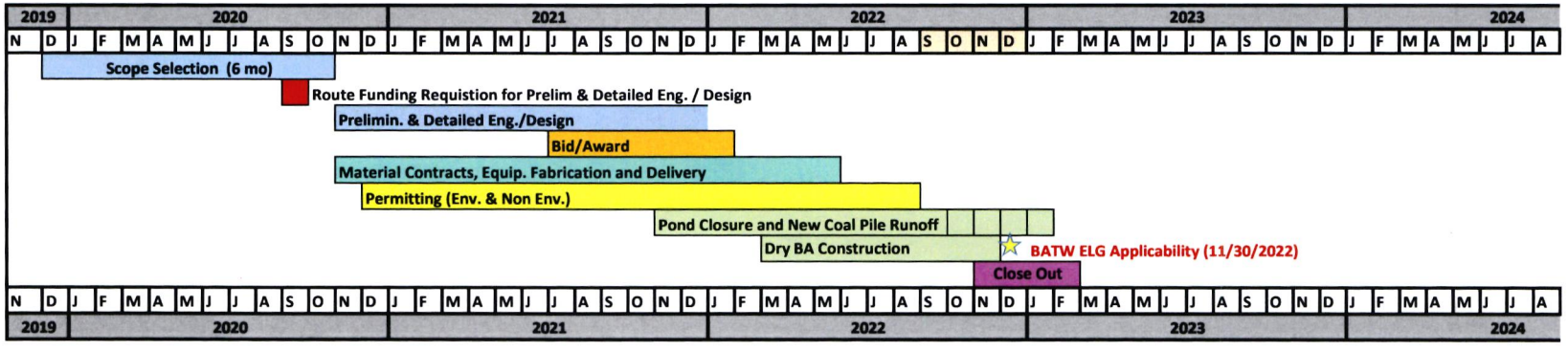
C. The 2020 Steam Electric Power Generating Effluent Guidelines states that permit conditions listed in § 423.18 must be included in all NPDES Permits. We propose that this be accomplished by reference using the following language:

§ 423.18 is incorporated by reference into this permit. If the Permittee needs to implement a provision included in § 423.18, the permittee shall submit information to the Director as required by § 423.19(g) within the necessary timeframes.

Attachment 2

Southwestern Electric Power Company
Flint Creek Power Plant

Bottom Ash Transport Water Schedule


2019
2020
2021
2022
2023
2024
N D J F M A M J J A S O N D J F M A M J J A S O N D J F M A M J J A S O N D J F M A M J J A S O N D J F M A M J J A S O N D J F M A M J J A
Scope Selection (6 mo)
Route Funding Requistion for Prelim & Detailed Eng. / Design
Prelimin. & Detailed Eng./Design
Bid/Award
Material Contracts, Equip. Fabrication and Delivery
Permitting (Env. & Non Env.)
Pond Closure and New Coal Pile Runoff
Dry BA Construction
BATW ELG Applicability (11/30/2022)
Close Out
N D J F M A M J J A S O N D J F M A M J J A S O N D J F M A M J J A S O N D J F M A M J J A S O N D J F M A M J J A S O N D J F M A M J J A
2019
2020
2021
2022
2023
2024

Attachment 3

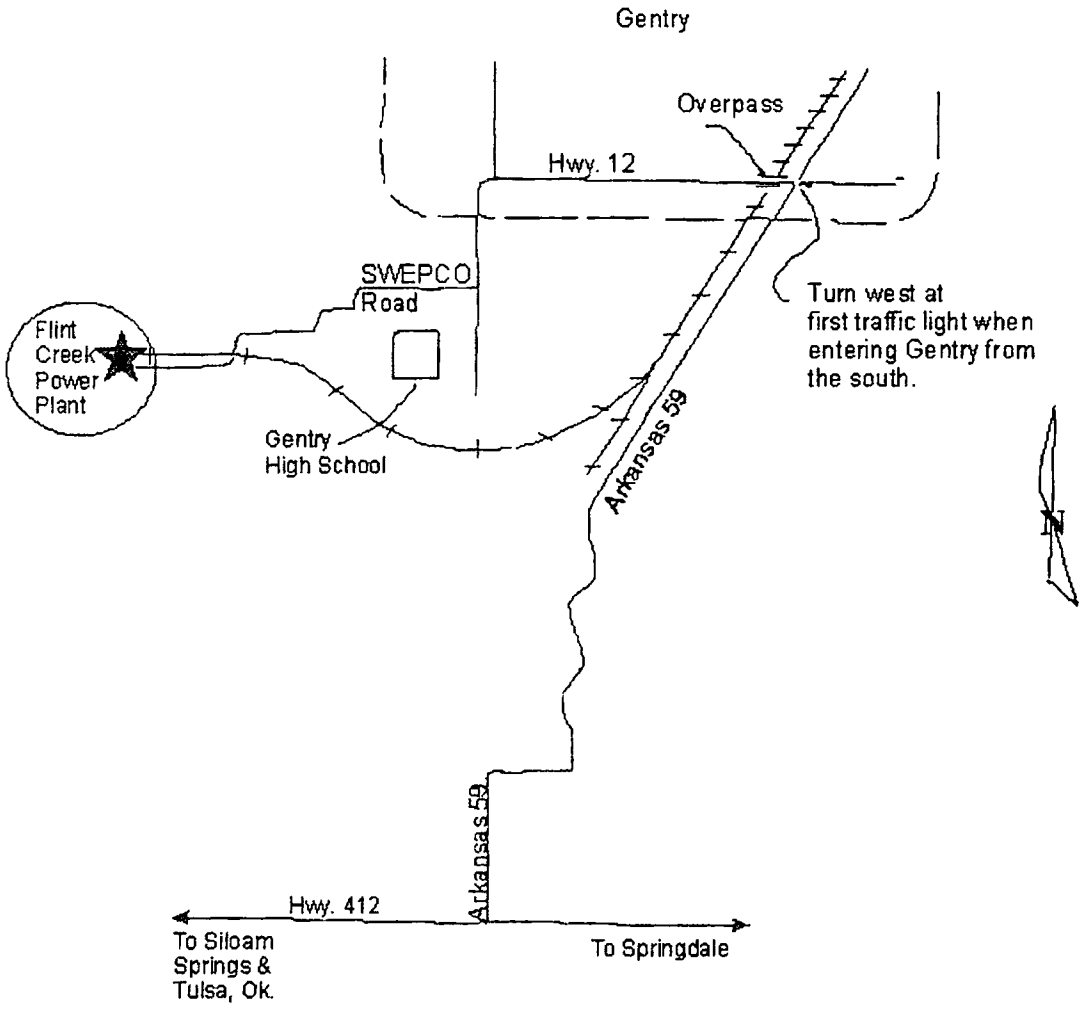
Southwestern Electric Power Company
Flint Creek Power Plant

Site and Location Maps

Southwestern Electric Power Company

Flint Creek Power Plant

Location Map



Flint Creek Power Plant is located west of the City of Gentry, Arkansas, on SWEPCO Road.

Address: 21797 SWEPCO Road
Gentry, Arkansas 72734

Phone: 479-444-4700

Southwestern Electric Power Company
Flint Creek Power Plant

Water & Ecological Resource Services

Aerial View

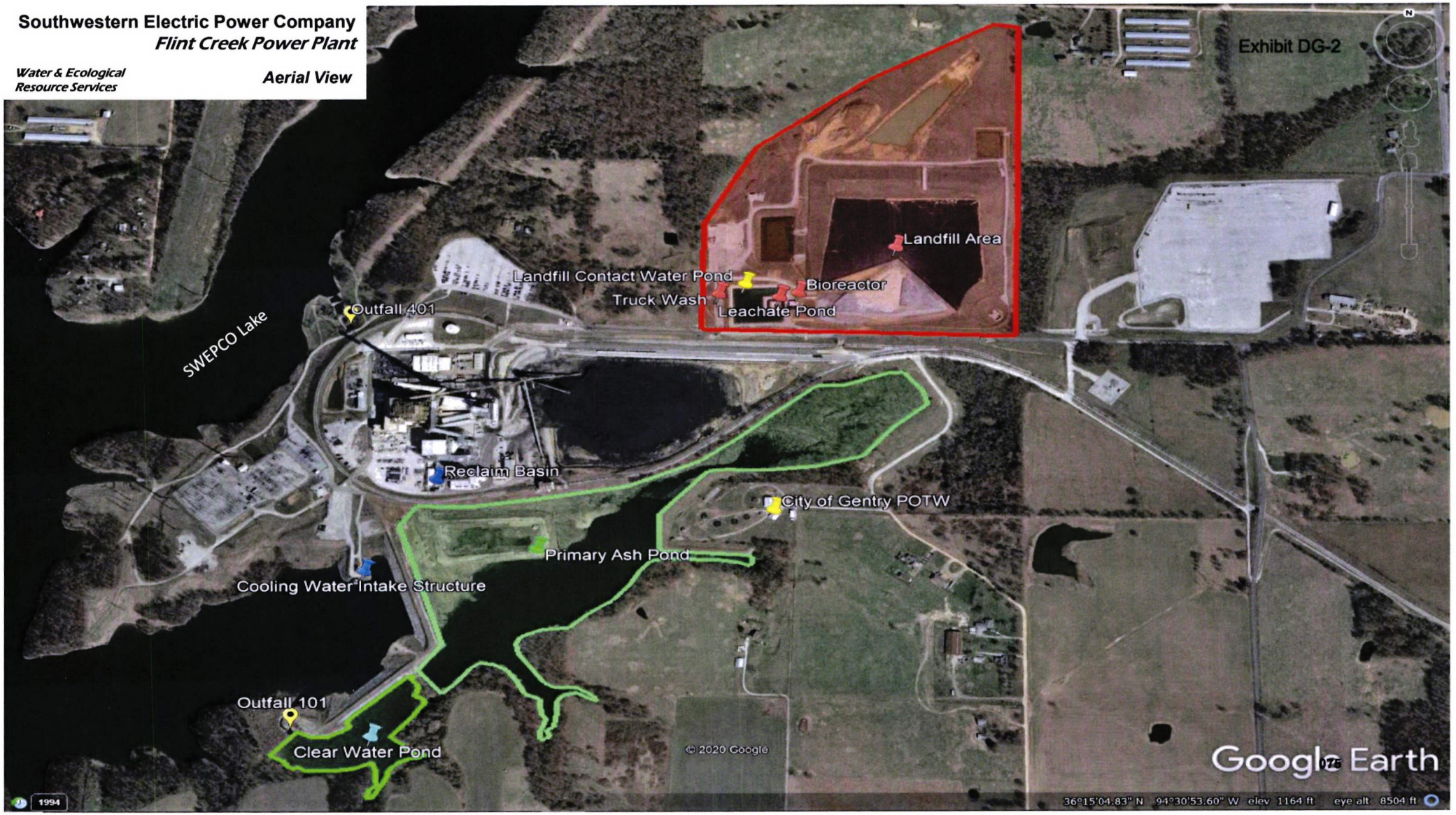
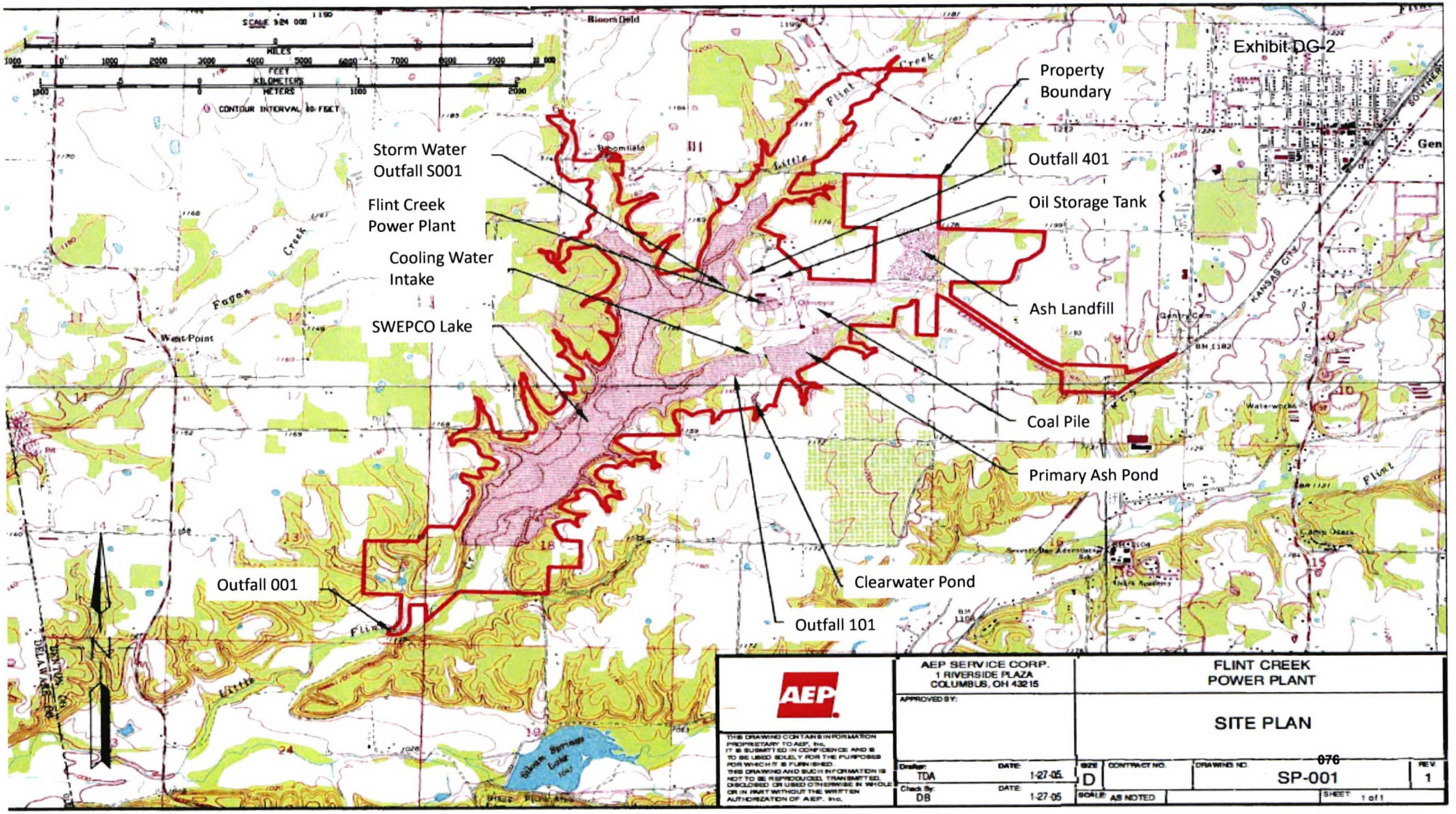


Exhibit DG-2


Property Boundary
Outfall 401
Oil Storage Tank
Ash Landfill
Coal Pile
Primary Ash Pond
Clearwater Pond
Outfall 101
Outfall 001
Storm Water Outfall S001
Flint Creek Power Plant
Cooling Water Intake
SWEPCO Lake
AEP SERVICE CORP.
1 RIVERSIDE PLAZA
COLUMBUS, OH 43215
APPROVED BY:
FLINT CREEK POWER PLANT
SITE PLAN
THIS DRAWING CONTAINS INFORMATION PROPRIETARY TO AEP, Inc. IT IS SUBMITTED IN CONFIDENCE AND IS TO BE USED SOLELY FOR THE PURPOSES FOR WHICH IT IS FURNISHED. THIS DRAWING AND SUCH INFORMATION IS NOT TO BE REPRODUCED, TRANSMITTED, DISCLOSED OR USED OTHERWISE IN WHOLE OR IN PART WITHOUT THE WRITTEN AUTHORIZATION OF AEP, Inc.
Drafter: TDA DATE: 1-27-05
Check By: DB DATE: 1-27-05
SIZE D
CONTRACT NO.
DRAWING NO. 076 SP-001
REV 1
SCALE AS NOTED
SHEET 1 of 1

NOTES TO USERS

LEGEND

PANEL 0105J

FIRM
FLOOD INSURANCE RATE MAP
BENTON COUNTY, ARKANSAS
AND INCORPORATED AREAS

PANEL 195 OF 560

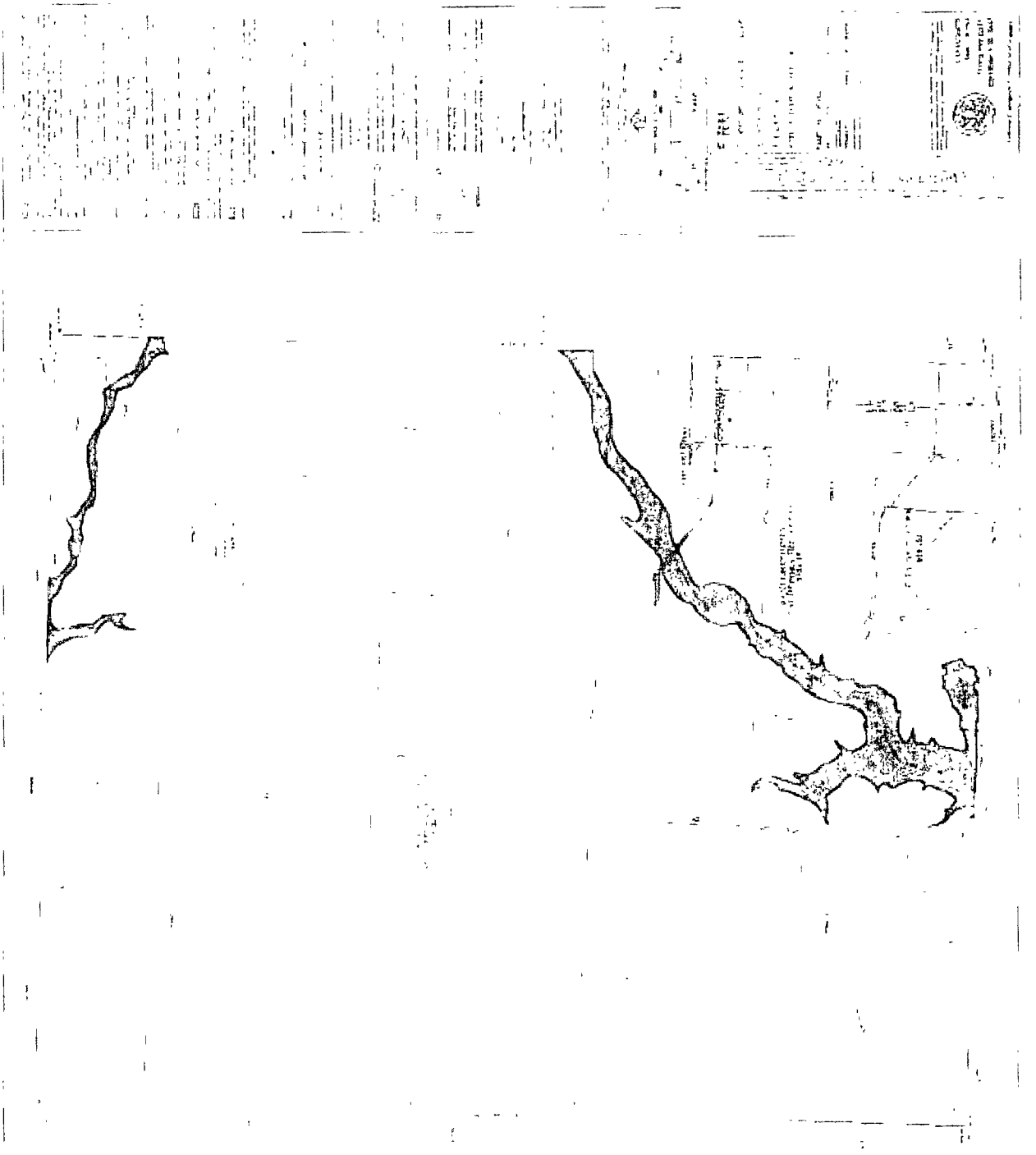
MAP NUMBER 05007C0195J

EFFECTIVE DATE SEPTEMBER 28, 2007

Federal Emergency Management Agency

Exhibit DG-2

Exhibit DG-2



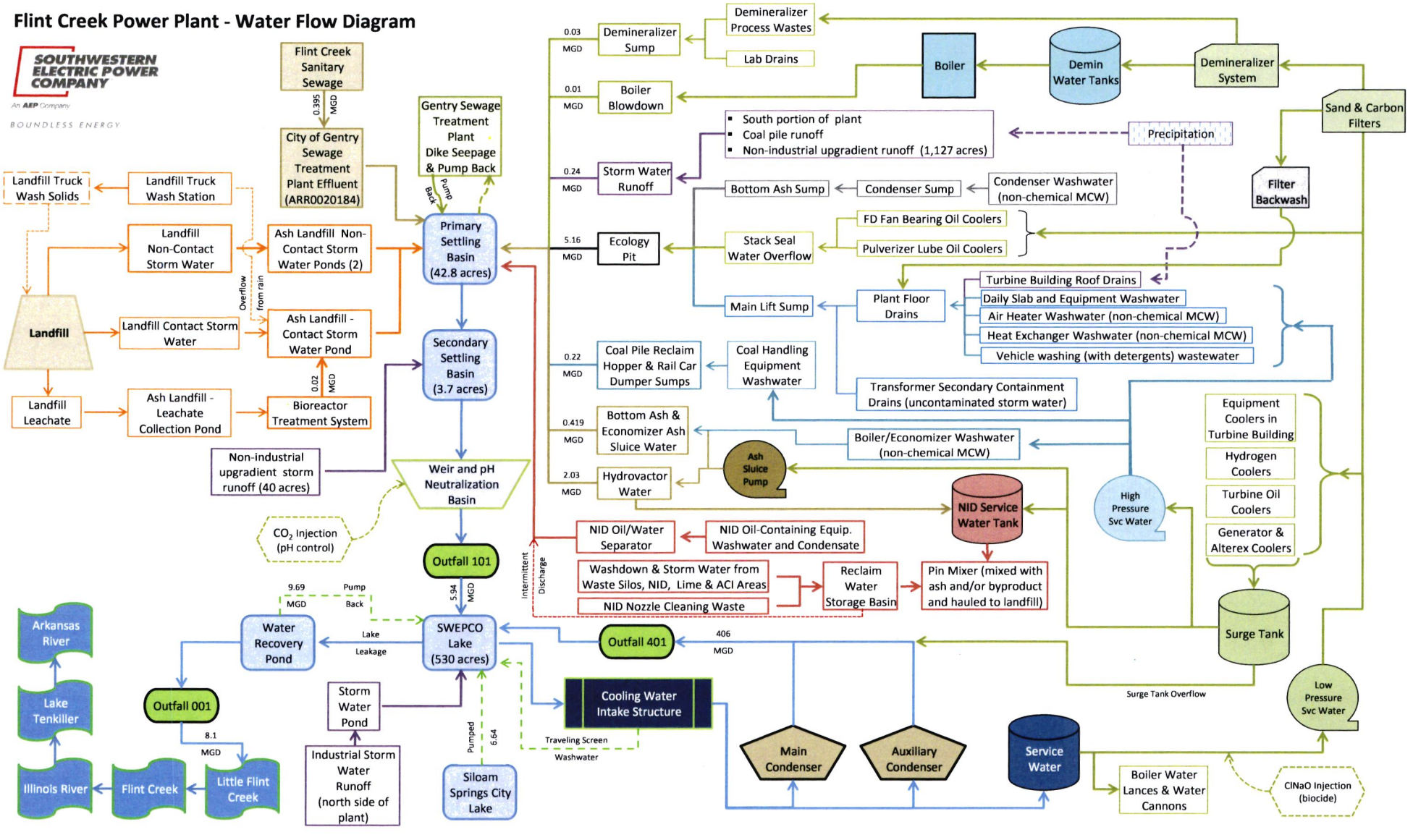
Attachment 4

Southwestern Electric Power Company
Flint Creek Power Plant

Water Flow Diagrams

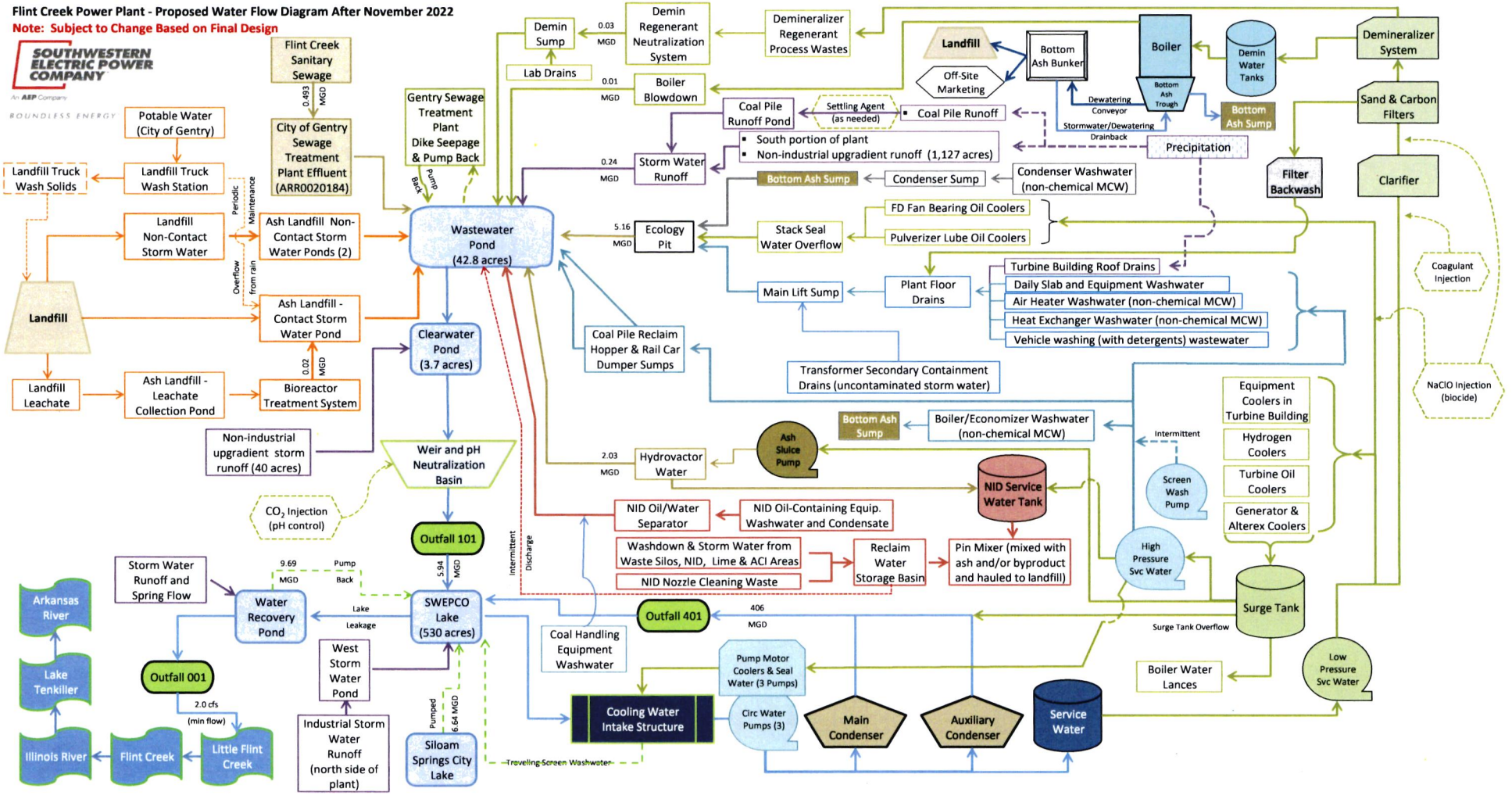
Flint Creek Power Plant - Water Flow Diagram

SOUTHWESTERN ELECTRIC POWER COMPANY
An AEP Company
BOUNDLESS ENERGY



Flint Creek Power Plant - Proposed Water Flow Diagram After November 2022

Note: Subject to Change Based on Final Design



Attachment 5

Southwestern Electric Power Company
Flint Creek Power Plant

Financial Assurance

American Electric Power
2019 Annual Report

The AEP 2019 Annual Report may be located at the following Web address:

https://aep.com/assets/docs/investors/AnnualReportsProxies/docs/19annrep/2019AnnualReportAppendixAtoProxy.pdf

Attachment 6

Southwestern Electric Power Company
Flint Creek Power Plant

American Electric Power
2019 Form 10-K
First Quarter 2020 Form 10-Q
Second Quarter 2020 Form 10-Q
Third Quarter 2020 Form 10-Q

The AEP Security Exchange Commission, 2019 Form 10-K may be located at the following Web address:

https://www.aep.com/assets/docs/investors/AEP201910K.pdf

The AEP Security Exchange Commission, First Quarter 2020 Form 10-Q may be located at the following Web address:

https://aep.com/assets/docs/investors/AEP10Q20201Q.pdf

The AEP Security Exchange Commission, Second Quarter 2020 Form 10-Q may be located at the following Web address:

https://aep.com/assets/docs/investors/AEP10Q20202Q.pdf

The AEP Security Exchange Commission, Third Quarter 2020 Form 10-Q may be located at the following Web address:

https://aep.com/assets/docs/investors/AEP10Q20203Q.pdf

Attachment 7

Southwestern Electric Power Company
Flint Creek Power Plant

Previous Correspondences with ADEQ

SOUTHWESTERN ELECTRIC POWER COMPANY
An AEP Company

May 20, 2020

Electronic Mail: cusher@adeq.state.ar.us

Ms. Annette Cusher
Office of Land Resources
Facility Permits
Arkansas Department of Environmental Quality
5301 Northshore Drive
North Little Rock, AR 72118

leamons@adeq.state.ar.us

Mr. Brian Leamons, PE
Senior Operations Manager / Water Permits
Office of Water Quality
Arkansas Department of Environmental Quality
5301 Northshore Drive
North Little Rock, AR 72118

Re: Southwestern Electric Power Company
Flint Creek Power Plant
NPDES Permit No.: AR0037842; AFIN: 04-00107
EPA RCRA Id.: ARD084938455
Follow-up: elementary neutralization of demineralizer regeneration wastes and subsequent discharge

Dear Ms. Cusher and Mr. Leamons,

In the ADEQ's May 6, 2020, response to SWEPCO's letter dated March 23, 2020, additional information was requested from SWEPCO to determine if the treatment of the demineralizer regeneration waste would meet the proposed exclusion under APC&EC Regulation No. 23 for an elementary neutralization unit. The facility is requesting that ADEQ evaluate the attached process description, waste sampling plan and flow diagram and subsequently provide tentative approval for our plan to treat the demineralizer regeneration waste stream, should it be confirmed to be D002 corrosive only, in a RCRA elementary neutralization unit for subsequent discharge to the primary ash pond and Outfall 101 under a modified NPDES permit. The facility recognizes that this tentative approval includes the following provisions which will require future actions under the applicable regulations:

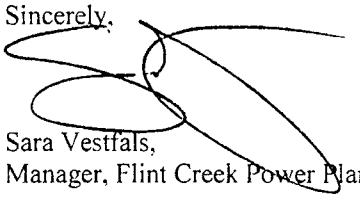
1. Confirmation that the demineralizer regeneration waste streams are only characteristically hazardous for corrosivity, and that no RCRA metal toxicity limits are exceeded.
2. The facility will provide the results of the sampling/analyses of the composite demineralizer regeneration wastes to ADEQ.
3. The facility will submit an NPDES wastewater modification/construction permit application that includes the details of the elementary neutralization unit and associated equipment, as well as an updated flow diagram and other documents as may be required for adequate evaluation by ADEQ.

With tentative approval, SWEPCO will proceed with implementing the sampling plan followed by engineering and design of the elementary neutralization unit.

If ADEQ requires any additional information to allow for consideration of our request, we will expedite the response to the extent possible. AEP/SWEPCO and the Flint Creek Power Plant appreciate the consideration of this request by ADEQ.

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

Sincerely,



Sara Vestfals,
Manager, Flint Creek Power Plant

Cc: Al Wood (ec)
Brian Whatley (ec)
Scott Carney (ec)
Ivaunna Neigler (ec)
Randy Solomon (ec)
File: FLC 180.05.2020

Jason Bolenbaugh, Manager, Compliance Branch, OWQ (ec)
Jessica Sears, P.E., Engineer Supervisor, Permits Branch, OWQ (ec)
Guy Lester, P.E., Engineer, Permits Branch, OWQ (ec)
Jay Rich, Manager, Permits Branch, Regulated Waste Operations, OLR (ec)

Attachments:
1) Process description (pretreatment, demineralizer, demineralizer regeneration).
2) Process flow diagram (pretreatment, demineralizer, demineralizer regeneration).
3) Sampling plan for demineralizer regeneration waste.
4) ADEQ reply letter dated May 6, 2020.
5) SWEPCO request letter dated March 23, 2020

Attachment 1

Process description (pretreatment, demineralizer, demineralizer regeneration)

Water Treatment System for Making Steam-Grade Water

(Pretreatment, Demineralizer, and Demineralizer Regeneration Processes)

Water obtained from SWEPCO Lake is used for making ultrapure water suitable for use in the steam-generating electric utility boiler. This water must be treated to remove all impurities that would cause corrosion, mineral deposition, or other detrimental chemical reactions within the boiler and stream turbine. To produce this pure water, the following treatments are applied:

Pretreatment

The cooling water intake structure screens large items from the lake water such as tree branches, leaves, aquatic vegetation, fish, debris, and other similar items. First, the stationary bar screen prevents larger objects from entering the intake structure. After passing the bar screens, water passes through the traveling screens, which provide for screening of much smaller items. Any removed items are properly disposed off-site.

The water from the cooling water intake structure that is diverted for boiler water make-up (the majority of this water is used elsewhere in the plant) is dosed with bleach (Sodium hypochlorite) to kill algae and/or bacteria. It is then temporarily stored in the Chlorine Retention Tank before being dosed with a coagulant while being transferred to the Pre-mix Tank. The partially treated water then travels through the Clarifier (functionally a flow-through tank) to the Clearwell Tank before passing through three sand filters and two activated carbon filters. The water is then stored in the Filtered Water Tank awaiting processing in the demineralizer system.

Demineralizer Process

Filtered water from the pretreatment process is pumped through three sequential beds of demineralizer resin beads. First, the water passes through the cation resin bed where the cation resin exchanges hydrogen for raw water cations, such as calcium, magnesium, and sodium; removing them from the water as it passes through. Next, the water is treated in the anion resin bed where the anion resin exchanges hydroxide ions for raw water anions, such as sulfate and silica; removing them from the water as it passes through. Finally, the water passes through the mixed bed which contains both cation and anion resin. The mixed bed functions as a "polishing" unit to remove trace ions that may remain in the otherwise "demineralized" water. The demineralized water is then stored in the Demineralized Water Storage Tanks awaiting use as make-up water in the steam boiler.

Demineralizer Regeneration Process

The demineralizer resins are designed to be periodically regenerated by removal of the accumulated cations and anions, respectively. When the cation resin bed nears exhaustion, it must be regenerated to remove the cations and replace them with hydrogen ions to restore their effectiveness. The cation bed is regenerated in a multi-step process using several rinses of filtered water and two different dilute sulfuric acid solutions (2% and 4% concentrations), producing regeneration wastewater flows of varying pH ranging from 3.4 to < 1 standard units (SU). Likewise, when the anion resin bed nears exhaustion, it must be regenerated to remove the anions and replace them with hydroxide ions to restore their effectiveness. The anion bed is regenerated in a multi-step process using several rinses of filtered

water, warm filtered water and a dilute solution (5% concentration) of sodium hydroxide, producing regeneration wastewater flows of varying pH ranging from 7.9 to > 13 SU. The regeneration of both the cation and anion beds are conducted simultaneously in one automated process. The cation and anion beds are typically regenerated every 1 – 4 days, depending on water demand for steam make-up. Regeneration of the cation and anion resin beds typically generates a total of approximately 62,275 gallons of effluent with a pH of less than 2.0. Because the mixed bed is fed by already highly-purified water from the cation and anion beds, it is much slower to be exhausted than the cation and anion resin beds, and therefore is regenerated as a reduced frequency, typically once per 25 anion/cation regeneration events, or approximately every 75 days. However, regeneration of the mixed bed does occur in a similar fashion and typically generates approximately 9,500 gallons of effluent. The demineralizer regeneration process takes place as depicted in the attached process flow diagram and waste sampling plan.

Elementary Neutralization Unit (Future)

Currently, all demineralizer regeneration waste is routed to a sump and then to the primary ash pond with no prior treatment. This is conducted under provision of the EPA's January 13, 1981, "Dietrich Letter" (subsequently codified at 40 CFR 261.4(b)(4)(i) and (ii)), which exempts the demineralizer waste streams, and other wastewaters, from hazardous waste regulation if co-disposed with coal ash, which is conducted at Flint Creek. Due to the final rules for Coal Combustion Residual (CCR – 40 CFR 257) and updated Effluent Limit Guidelines (40 CFR 423), the continued wet sluicing of coal ash to the primary ash pond will end no later than December 31, 2023. With the end of wet sluicing of ash to the primary ash pond will come the end of the facility's reliance on the §261.4(b)(4) relief from hazardous waste regulation of demineralizer regeneration waste (no co-disposal with coal ash).

The facility is currently in the engineering and design phase of a project that will allow the plant to comply with these new regulations. Part of that project will transition the handling of coal ash (bottom ash and economizer ash) from wet sluicing to the primary ash pond to "dry handling" as it is generated in the boiler. Another part of the project is to provide for treatment of the demineralizer regeneration waste in a RCRA elementary neutralization unit. In general, the elementary neutralization unit will provide for adequate tank capacity to accumulate the entire volume of the demineralizer regeneration waste (cation, anion, and/or mixed bed) process and neutralizing chemicals. The neutralization unit will also include the necessary pumps, probes, chemical tanks, and other ancillary equipment for ensuring proper treatment (2.0 < pH < 12.5 SU) prior to discharge to the primary ash pond and NPDES Outfall 101.

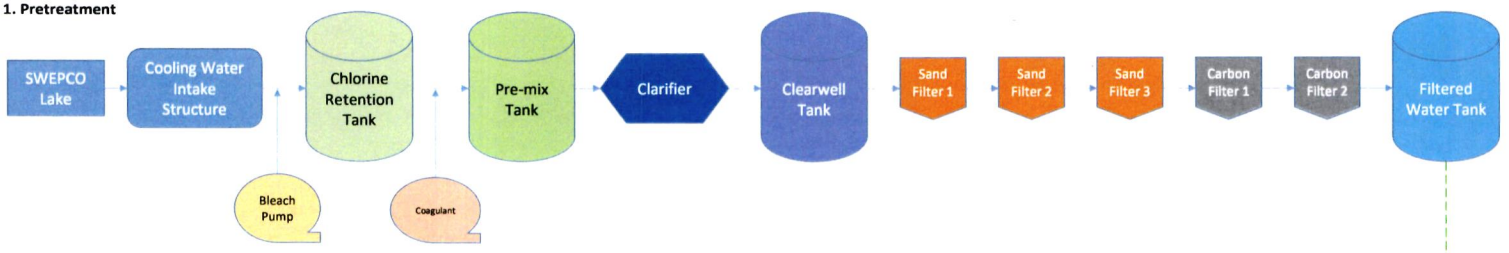
As the facility has not had cause to evaluate the demineralizer regeneration waste in the past for hazardous waste characeristics due to the referenced relief, we now are taking steps to make such an evaluation. Due to the facility's process knowledge, we anticipate that the demineralizer regeneration waste streams could only exhibit hazardous waste characteristics due to corrosivity and/or toxicity from metals (potentially D002 and D004 through D011). Although RCRA metal toxicity is not anticipated, testing will be conducted to document and confirm this assumption. Accordingly, we have developed a sampling plan (attached) that will comprehensively allow for characterization of the waste stream. This characterization will allow the facility to design and implement the appropriate treatment methodology for the demineralizer regeneration wastestream.

Attachment 2

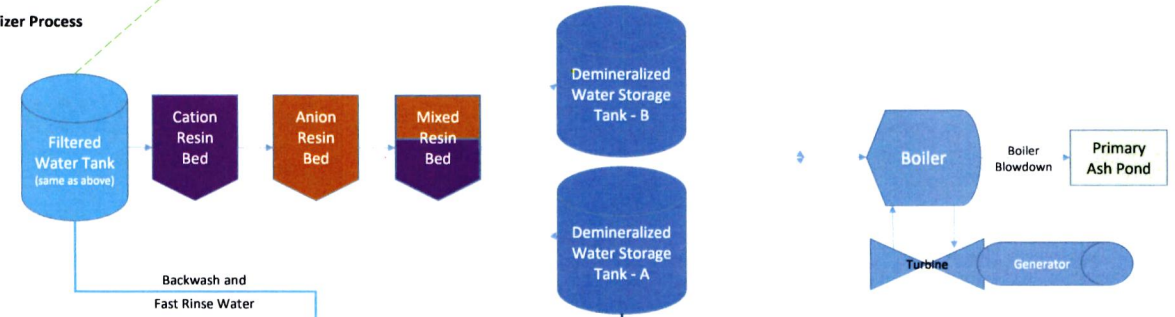
Process flow diagram (pretreatment, demineralizer, demineralizer regeneration)

Steam Make-up Water Process (Pretreatment, Demineralizer Process, Demineralizer Regeneration Process)

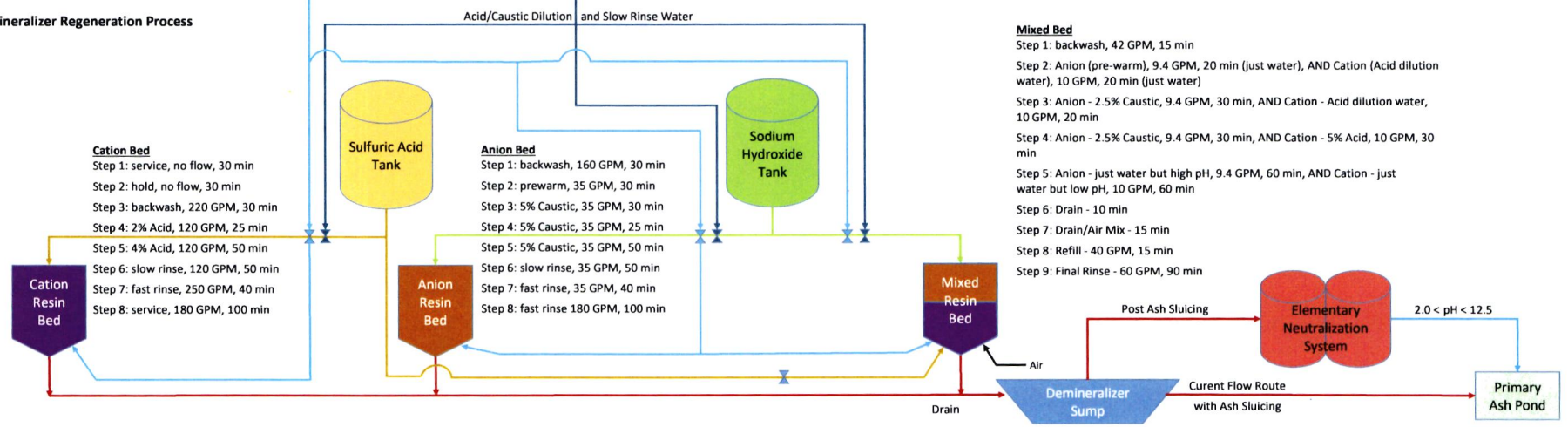
1. Pretreatment



2. Demineralizer Process



3. Demineralizer Regeneration Process



Cation Bed

Step 1: service, no flow, 30 min
Step 2: hold, no flow, 30 min
Step 3: backwash, 220 GPM, 30 min
Step 4: 2% Acid, 120 GPM, 25 min
Step 5: 4% Acid, 120 GPM, 50 min
Step 6: slow rinse, 120 GPM, 50 min
Step 7: fast rinse, 250 GPM, 40 min
Step 8: service, 180 GPM, 100 min

Anion Bed

Step 1: backwash, 160 GPM, 30 min
Step 2: prewarm, 35 GPM, 30 min
Step 3: 5% Caustic, 35 GPM, 30 min
Step 4: 5% Caustic, 35 GPM, 25 min
Step 5: 5% Caustic, 35 GPM, 50 min
Step 6: slow rinse, 35 GPM, 50 min
Step 7: fast rinse, 35 GPM, 40 min
Step 8: fast rinse 180 GPM, 100 min

Mixed Bed

Step 1: backwash, 42 GPM, 15 min
Step 2: Anion (pre-warm), 9.4 GPM, 20 min (just water), AND Cation (Acid dilution water), 10 GPM, 20 min (just water)
Step 3: Anion - 2.5% Caustic, 9.4 GPM, 30 min, AND Cation - Acid dilution water, 10 GPM, 20 min
Step 4: Anion - 2.5% Caustic, 9.4 GPM, 30 min, AND Cation - 5% Acid, 10 GPM, 30 min
Step 5: Anion - just water but high pH, 9.4 GPM, 60 min, AND Cation - just water but low pH, 10 GPM, 60 min
Step 6: Drain - 10 min
Step 7: Drain/Air Mix - 15 min
Step 8: Refill - 40 GPM, 15 min
Step 9: Final Rinse - 60 GPM, 90 min

Attachment 3

Sampling plan for demineralizer regeneration waste,

The tables below outline the steps involved in the regeneration of the demineralizer system. The total time of each step has been divided to create a representative composite sampling plan that provides for incorporation of differing characteristics of each step through time. Each collected aliquot will be monitored upon collection for pH, and the identified volume will be added to a composite bucket (pre-cleaned 5-gallon plastic bucket) from which samples intended for TCLP analysis of the eight RCRA metals will be collected. A composite pH measurement will also be taken with a calibrated pH probe from the composited sample.
Note: the Cation-Anion bed regeneration is conducted as an automated process. The Mixed bed regeneration is conducted separately from the Cation-Anion bed regeneration and will therefore be monitored and sampled separately. Sample aliquots from each of the regeneration process (Cation-Anion and Mixed bed) are designed to create a composite sample totaling 10 liters each.

Cation-Anion Bed Regeneration Sampling Plan

Step 1 Cation in Service

Flow rate: 0 gpm
Total time: 30 min

Time (min)	pH	Sample Aliquot (mL)	Total to Drain	Percent of Total
5	X	0		
15	X	0	0	0.000
25	X	0		

Step 2 Cation Idle

Flow rate: 0 gpm
Total time: 30 min

Time (min)	pH	Sample Aliquot (mL)	Total to Drain	Percent of Total
5	X	0		
15	X	0	0	0.000
25	X	0		

Step 3 Cation Backwash

Flow rate: 220 gpm
Total time: 30 min

Time (min)	pH	Sample Aliquot (mL)	Total to Drain	Percent of Total
5		353		
15		353	6,600	0.106
25		353		

Step 4 2% Acid Injection

Flow rate: 120 gpm
Total time: 25 min

Time (min)	pH	Sample Aliquot (mL)	Total to Drain	Percent of Total
5		96		
10		96		
15		96	3,000	0.048
20		96		
25		96		

Step 5 4% Acid Injection

Flow rate: 120 gpm
Total time: 50 min

Time (min)	pH	Sample Aliquot (mL)	Total to Drain	Percent of Total
5		96		
10		96		
15		96		
20		96		
25		96		
30		96	6,000	0.096
35		96		
40		96		
45		96		
50		96		

Step 6 Slow Rinse

Flow rate: 120 gpm
Total time: 50 min

Time (min)	pH	Sample Aliquot (mL)	Total to Drain	Percent of Total
5		193		
15		193		
25		193	6,000	0.096
35		193		
45		193		

Step 7 Fast Rinse

Flow rate: 250 gpm
Total time: 40 min

Time (min)	pH	Sample Aliquot (mL)	Total to Drain	Percent of Total
5		401		
15		401	10,000	0.161
25		401		
35		401		

Step 8 Service

Flow rate: 0 gpm
Total time: 100 min

Time (min)	pH	Sample Aliquot (mL)	Total to Drain	Percent of Total
5	X	0		
15	X	0		
25	X	0		
35	X	0		
45	X	0	0	0.000
55	X	0		
65	X	0		
75	X	0		
85	X	0		
95	X	0		

Total (mL): 5,074 31,600 0.507

Anion Backwash

Flow rate: 160 gpm
Total time: 30 min

Time (min)	pH	Sample Aliquot (mL)	Total to Drain	Percent of Total
5		257		
15		257	4,800	0.077
25		257		

Anion Prewarm

Flow rate: 35 gpm
Total time: 30 min

Time (min)	pH	Sample Aliquot (mL)	Total to Drain	Percent of Total
5		56		
15		56	1,050	0.017
25		56		

5% Caustic Injection

Flow rate: 35 gpm
Total time: 30 min

Time (min)	pH	Sample Aliquot (mL)	Total to Drain	Percent of Total
5		28		
10		28		
15		28		
20		28	1,050	0.017
25		28		
30		28		

5 % Caustic Injection

Flow rate: 35 gpm
Total time: 25 min

Time (min)	pH	Sample Aliquot (mL)	Total to Drain	Percent of Total
5		28		
10		28		
15		28	875	0.014
20		28		
25		28		

5 % Caustic Injection

Flow rate: 35 gpm
Total time: 50 min

Time (min)	pH	Sample Aliquot (mL)	Total to Drain	Percent of Total
5		28		
10		28		
15		28		
20		28		
25		28	1,750	0.028
30		28		
35		28		
40		28		
45		28		
50		28		

Slow Rinse

Flow rate: 35 gpm
Total time: 50 min

Time (min)	pH	Sample Aliquot (mL)	Total to Drain	Percent of Total
5		56		
15		56		
25		56	1,750	0.028
35		56		
45		56		

Fast Rinse

Flow rate: 35 gpm
Total time: 40 min

Time (min)	pH	Sample Aliquot (mL)	Total to Drain	Percent of Total
5		56		
15		56	1,400	0.022
25		56		
35		56		

Fast Rinse

Flow rate: 180 gpm
Total time: 100 min

Time (min)	pH	Sample Aliquot (mL)	Total to Drain	Percent of Total
5		289		
15		289		
25		289		
35		289		
45		289	18,000	0.289
55		289		
65		289		
75		289		
85		289		
95		289		

Total (mL): 4,926 30,675 0.493

Final Sampling: composited monitoring and sampling from the 5-gallon bucket.

	pH	1 liter sample	1 liter replicate	Trip blank	Equipment blank
Composite pH (field):	✓				
Composite sample collected for TCLP RCRA metals analysis (Method 1311):		✓	✓		
Blanks obtained from ADEQ-certified lab (analyzed by Method 1311):				✓	✓

Mixed Bed Regeneration Sampling Plan

Step 1 Mixed Bed Backwash

Flow rate: 42 gpm
Total time: 15 min

Time (min)	pH	Sample Aliquot (mL)	Total Gallons to Drain	Percent of Total
5		332		
15		332	630	0.066

Step 2 Anion (pre-warm) and Cation (acid dilution water)

Flow rate Cation: 10 gpm
Flow rate Anion: 9.4 gpm
Total time: 20 min

Time (min)	pH	Sample Aliquot (mL)	Total Gallons to Drain	Percent of Total
5		136		
10		136	388	0.041
20		136		

Step 3 Anion (2.5% caustic injection) and Cation (acid dilution water)

Flow rate Cation: 10 gpm
Flow rate Anion: 9.4 gpm
Total time: 30 min

Time (min)	pH	Sample Aliquot (mL)	Total Gallons to Drain	Percent of Total
5		102		
10		102		
15		102		
20		102	582	0.061
25		102		
30		102		

Step 4 Anion (2.5% caustic injection) and Cation (5% acid injection)

Flow rate Cation: 10 gpm
Flow rate Anion: 9.4 gpm
Total time: 30 min

Time (min)	pH	Sample Aliquot (mL)	Total Gallons to Drain	Percent of Total
5		102		
10		102		
15		102		
20		102	582	0.061
25		102		
30		102		

Step 5 Anion (just water but high pH) and Cation (just water but low pH)

Flow rate Cation: 10 gpm
Flow rate Anion: 9.4 gpm
Total time: 60 min

Time (min)	pH	Sample Aliquot (mL)	Total Gallons to Drain	Percent of Total
5		102		
10		102		
15		102		
20		102		
25		102		
30		102	1,164	0.123
35		102		
40		102		
45		102		
50		102		
55		102		
60		102		

Step 6 Drain

Flow rate: gpm
Total time: 10 min

Time (min)	pH	Sample Aliquot (mL)	Total Gallons to Drain	Percent of Total
5	X	0	0	0.000
10	X	0		

Step 7 Drain and Air Mix Injection

Flow rate: 9.4 gpm
Total time: 15 min

Time (min)	pH	Sample Aliquot (mL)	Total Gallons to Drain	Percent of Total
5		50		
10		50	141	0.015
15		50		

Step 8 Refill

Flow rate: 40 gpm
Total time: 15 min

Time (min)	pH	Sample Aliquot (mL)	Total Gallons to Drain	Percent of Total
5		316	600	0.063
15		316		

Step 9 Final Rinse

Flow rate: 60 gpm
Total time: 90 min

Time (min)	pH	Sample Aliquot (mL)	Total Gallons to Drain	Percent of Total
5		2,846	5,400	0.569
15		2,846		

Total (mL): 10,000 9,487 1

Final Sampling: composited monitoring and sampling from the 5-gallon bucket.

	pH	1 liter sample	1 liter replicate	Trip blank	Equipment blank
Composite pH (field):	✓				
Composite sample collected for TCLP RCRA metals analysis (Method 1311):		✓	✓		
Blanks obtained from ADEQ-certified lab (analyzed by Method 1311):				✓	✓

Attachment 4

ADEQ reply letter dated May 6, 2020

ARKANSAS
ENERGY & ENVIRONMENT | ENVIRONMENTAL QUALITY

MAY 0 6 2020

Tommy Slater, VP of Generating Assets
Southwestern Electric Power Company - Flint Creek Power Plant
21797 SWEPCO Road
Gentry, AR 72734

Re: NPDES Permit Number AR0037842, AFIN 04-00107

Dear Mr. Slater:

The Arkansas Department of Energy & Environment – Division of Environmental Quality (DEQ) received a letter, dated March 23, 2020, requesting comments on proposed changes at the facility to comply with the requirements of 40 CFR § 257 concerning coal combustion residuals (CCR), and 40 CFR § 423 concerning bottom ash transport water (BATW). Comments were also requested on changes to the handling of waste streams from the water demineralization system. The Office of Water Quality (OWQ), and the Office of Land Resources (OLR), have reviewed the letter, and have the following comments:

OWQ comments

1. Continued use of the primary ash pond – OWQ has no objection to the future use of the primary ash pond for acceptable remaining waste streams after the elimination of all BATW. Based on current information available, no changes to the pond, or additional treatment will be required. OWQ acknowledges that the pond will be renamed after BATW is rerouted and all settled ash is removed from the pond in accordance with applicable rules.

2. New coal pile run-off ponds – Prior to construction of the two (2) proposed ponds (with the polymer system) for the treatment coal pile run-off, a complete application for a state construction permit must be received, and a state construction permit issued, by OWQ. A complete application includes plans and specifications stamped by an Arkansas Registered Professional Engineer.

   Coal pile run-off is a regulated process water waste stream [ref. 40 CFR § 423.12(b)(9)], and is not considered stormwater associated with industrial activity. Therefore, the requirement in Part II.7 of the NPDES permit for managing stormwater runoff commingling with other process wastewater is not applicable. Limitations for Total Suspended Solids (TSS) are included in the NPDES permit for Outfall 101, based partially on the volume of treated coal pile run-off reported in the permit renewal application. Any significant change in the volume of coal pile run-off (+/- 10% or more) may require modification of the NPDES permit.

3. Regulation of demineralizer waste streams – Deminerilizer waste streams fall under the definition of "low volume waste sources" in 40 CFR § 423.11(b), and are regulated under 40 CFR § 423.12(b)(3). Limitations for TSS and Oil & Grease (O&G) in the NPDES permit for Outfall 101 take into account the volume of deminerilizer waste streams reported in the permit

renewal application. Any significant change in the volume of these waste streams (such that the total quantity of low volume waste sources changes by +/- 10% or more) may require modification of the NPDES permit.

OLR comments

4. Continued use of the primary ash pond – Solid Waste Permit 0273-3N2-R2 allows the landfill to accept non-hazardous ash for disposal.

5. Regulation of demineralizer waste streams – There is not enough information to determine if the treatment of the demineralization water would meet the proposed exclusion under APC&EC Regulation No. 23. In order to make a determination regarding the demineralization water, additional specific information should be submitted on the treatment process, including information on storage of the waste stream, flow diagrams, etc.

If there are any questions concerning this submittal, please contact Guy Lester, P.E., of my staff at 501-682-0622.

Sincerely,

Bryan Leamons

Bryan Leamons, P.E.
Senior Operations Manager
Office of Water Quality

Annette Cusher

Annette Cusher, P.E.
Engineer Supervisor
Regulated Waste Operations
Office of Land Resources

cc: Electronic Filing (AR0037842, and 0273-3N2-R2)
Jason Bolenbaugh, Manager, Compliance Branch, OWQ
Jessica Sears, P.E., Engineer Supervisor, Permits Branch, OWQ
Guy Lester, P.E., Engineer, Permits Branch, OWQ
Jay Rich, Manager, Permits Branch, Regulated Waste Operations, OLR
Annette Cusher, P.E., Engineer Supervisor, Regulated Waste Operations, OLR

Sara Vestfals, SWEPCO email: snvestfals@aep.com
David Hall, SWEPCO email: dbhall@aep.com
Scott Carney, SWEPCO email: scarney@aep.com
Ivaunna P Neigler, SWEPCO email: ipneigler@aep.com
Randy Solomon, SWEPCO email: rbsolomon@aep.com

Attachment 5

SWEPCO request letter dated March 23, 2020

SOUTHWESTERN ELECTRIC POWER COMPANY
An AEP Company

March 23, 2020

Electronic Mail: lester@adeq.state.ar.us

Mr. Guy Lester
Office of Water Quality
Arkansas Department of Environmental Quality
5301 Northshore Drive
North Little Rock, AR 72118

Re: Southwestern Electric Power Company
Flint Creek Power Plant
NPDES Permit No.: AR0037842; AFIN: 04-00107
Dry Bottom Ash Conversion and Clean Closure of the Primary Ash Pond

Dear Mr. Lester,

SWEPCO is in the initial stages of engineering and design for modifications to the Flint Creek Power Plant's systems related to bottom ash management. The purpose of the modifications are for compliance with the pending finalization of the coal combustion residuals rule (40 CFR 257), and the prospective effluent limit guidelines for steam-electric power generating facilities (40 CFR 423). Overall, as currently envisioned the project would result in the installation of new equipment to remove bottom ash and economizer ash from the boiler by a submerged flight conveyor system, and to remove ash from the primary ash pond (CCR closure by removal). Ash sluicing to the primary ash pond would stop upon completion and connection of the submerged flight conveyor ash removal system.

In order for SWEPCO to continue with engineering and design of the project, certain regulatory aspects need to be determined. These aspects relate to how ADEQ will view/regulate the proposed changes envisioned to comply with the referenced regulations.

1- Continued use of the primary ash pond:

SWEPCO proposes to continue use of the primary ash pond as a settling basin for all waste streams currently entering the pond, with the exception of ash sluice water (bottom and economizer ash) which would end upon completion of construction and connection of the submerged flight conveyor system to remove ash from the boiler. Between now and October 2023, SWEPCO would begin removal of ash deposited in the primary ash pond in accordance with the pending finalization of the CCR regulations (40 CFR 257). During and following CCR pond closure activities and final certification of ash removal per the CCR regulations, SWEPCO would like to continue use of the primary ash pond as is, without any other substantive changes to the pond. The primary ash pond would continue to settle sediment received from industrial wastewater streams, storm water from industrial, residential, and agricultural land areas, as well as the treated effluent from the City of Gentry wastewater