TVA's Kingston Fossil Plant: An Economic Assessment of Replacement Alternatives

Prepared on behalf of the Southern Environmental Law Center (SELC)

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Economic and Policy Analysis of Energy, Environment and Equity

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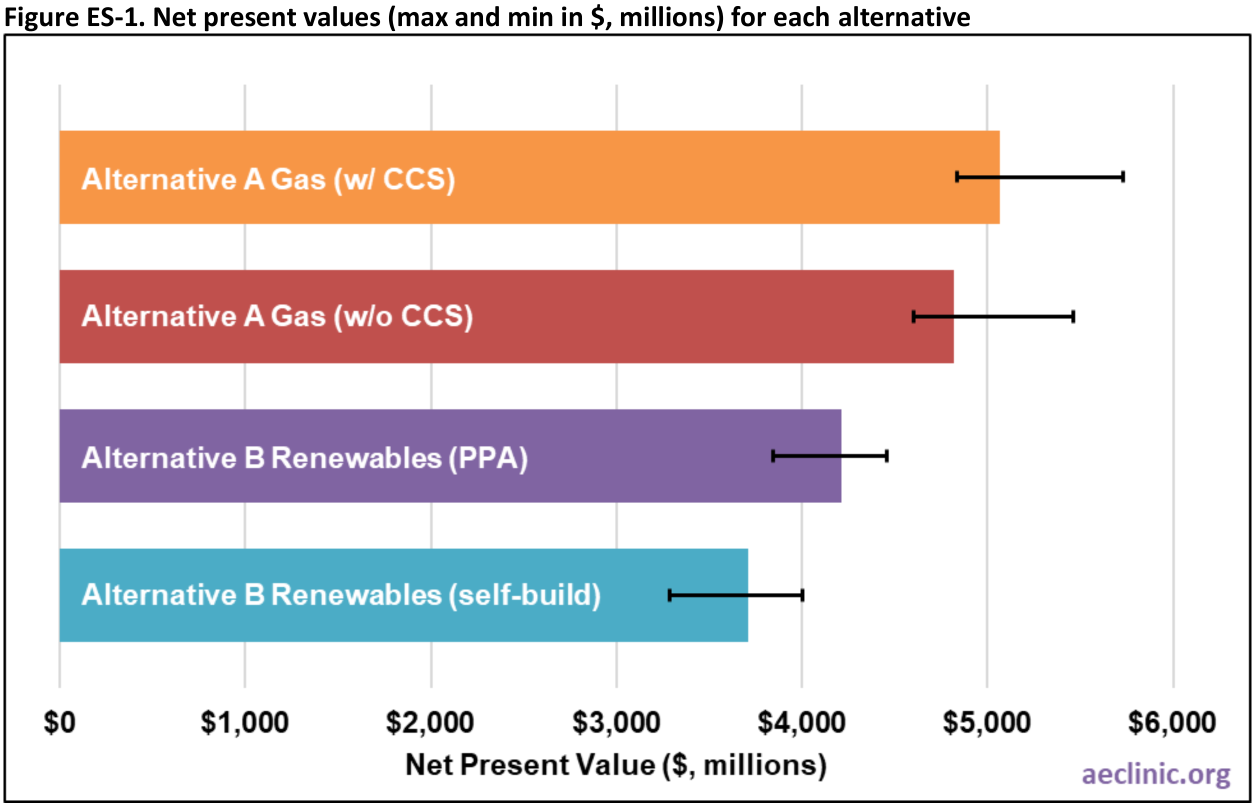
Executive Summary

The Tennessee Valley Authority (TVA) aims to retire all its coal-powered facilities by 2035 and to achieve emission reductions of 70 percent from 2005 levels by 2030, 80 percent by 2035, and achieving net-zero carbon emissions by 2050. To support these commitments, TVA released its *Aging Coal Fleet Evaluation* in 2021 to assess the end-of-life dates for its aging fossil units. Despite being similar in age, TVA's evaluation identified the Kingston Fossil Plant—located in Harriman, Tennessee—to be in worse material condition than some of its other coal-fired plants, such as Shawnee and Gallatin, warranting an earlier retirement. In February 2024, TVA released its Final Environmental Impact Statement (FEIS), which evaluates three alternatives related to the retirement and replacement of Kingston: (1) a "no action" alternative in which Kingston continues operation; (2) replacing Kingston with a gas-heavy portfolio that constructs gas combined cycle (CC) and combustion turbine (CT) plants (Alternative A); and (3) replacing Kingston with a clean energy portfolio that focuses on solar and battery storage resources (Alternative B). TVA indicated in the FEIS that it prefers Alternative A.

To fully understand the most cost-effective replacement alternative, TVA must evaluate a range of resources across different cost futures. In the absence of a more comprehensive assessment, this Applied Economics Clinic (AEC) report evaluates the net present value (NPV) costs associated with the two replacement alternatives identified by TVA in the Kingston FEIS. For Alternative A, AEC examined the potential pairing of gas-powered facilities with carbon capture and storage (CCS) infrastructure. For Alternative B, AEC evaluated a "self-build" scenario where TVA builds the solar and storage capacity itself and an additional scenario where TVA purchases capacity from private developers through a power purchase agreement (PPA).

Figure ES-1. Net present values (max and min in $, millions) for each alternative



Source: AEC calculations, see Methodology Appendix for description of assumptions and data sources.

AEC finds that the Alternative B self-build option has the cheapest NPV of the four alternatives assessed. The self-build option's NPV is $3.7 billion, compared to $4.2 billion for the Alternative B PPA option (see Figure ES-1 above). Both are cheaper than the NPVs of Alternative A w/ CCS ($5.1 billion) and Alternative A w/o CCS ($4.8 billion). While these costs are sensitive to gas prices and interconnection costs, a clean energy replacement remains the lower-cost option when capturing a range of these uncertainties. The costs of the gas-heavy alternatives are consistently higher due to fuel costs and the costs of the pipeline that would be required to provide gas to the Kingston site.

AEC constructed its analysis based on TVA's stated alternatives for Kingston. While they contradict TVA's claim that Alternative A is the lowest-cost option, it is not clear how TVA selected the amounts of solar and storage capacity in Alternative B. The storage capacity in Alternative B alone (2,200 MW) is exorbitant compared to the size of Kingston. Nor is it clear why the amount of proposed solar capacity—itself larger than Kingston (1,500 MW)—must be additional to solar capacity TVA is already scheduled to build. These irregularities are partly attributable to TVA's failure to synchronize its site-specific resource assessments with an IRP that provides a full range of plausible alternatives into which site-specific replacements can integrate.

As such, AEC provides the following recommendations for TVA's 2024 IRP:

- Conduct an all-resource RFP that assesses the range of resources that could reasonably be constructed.
- Consider the full set of resources that could facilitate decarbonization of TVA's grid, including transmission and distribution, distributed energy resources, energy efficiency, demand response, and others.
- Conduct optimization modelling on all potential resources instead of on pre-selected portfolios.
- Ensure site-specific planning does not contradict TVA's most recent IRP.
- Ensure the IRP provides plausible schedules for the installation and decommissioning of capacity.
- Use transparent assumptions and modeling inputs.

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I. Introduction

The Kingston Fossil Plant is a 1,398-megawatt (MW) plant located in Harriman, Tennessee that is owned and operated by the Tennessee Valley Authority (TVA).[1] TVA is a government-owned corporation that provides power to the Tennessee Valley region and is largely funded by sales of electricity, including to local distribution companies. The Kingston plant began operation in 1955. Because the plant is nearly 70 years old, TVA has noted the effect of wear and tear on its operation.[2] The units have been subject to more intense start-up and shutdown events, which are more frequent than intended for the plant.[3] Partly as a result of these challenges, TVA has recently proposed retiring, decommissioning, and replacing the generation of the Kingston plant with at least 1,500 MW of "firm, dispatchable" power—which it claims is consistent with its own 2019 Integrated Resource Plan (IRP).[4]

Since its last IRP in 2019, TVA has also committed to emission reductions of 70 percent from 2005 levels by 2030, 80 percent by 2035, and achieving net-zero carbon emissions by 2050.[5] As part of this goal, TVA plans to retire its entire coal fleet by 2035.[6] Meanwhile, TVA is required by law to conduct a "least-cost" planning program that evaluates "the full range of existing and incremental resources (including new power supplies, energy conservation and efficiency, and renewable resources)."[7] Regarding the Kingston site, in its 2024 Final Environmental Impact Statement (FEIS), TVA considered three futures: (1) keeping the coal plant running; (2) replacing it with mostly natural gas generation; and (3) replacing it with all solar photovoltaics (PV) and battery storage.[8]

This Applied Economics Clinic (AEC) report, prepared on behalf of the Southern Environmental Law Center (SELC), investigates which of TVA's preferred alternatives achieves the lowest net present value of customer costs using a cash flow analysis. The report begins in Section II with a more detailed overview of TVA's proposed alternatives. Section III describes the results of AEC's cashflow analysis and compares both the customer costs over a 20-year analysis period and the net present value of those costs between TVA's two replacement alternatives. AEC finds that the portfolio of solar and storage resources is the lowest-cost option for consumers. Section IV presents a sensitivity analysis on those results by varying key model inputs such as gas prices and interconnection costs. Section V concludes the report with key takeaways from this analysis for TVA's ongoing IRP process, which speak to both the least cost alternative and how TVA can further integrate its site-specific planning processes to a broader systemic assessment of its needs. The Appendix documents the methodology and data sources used to conduct the cash flow analysis presented in this report.

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[1] TVA. "Kingston Fossil Plant." Available at: https://www.tva.com/energy/our-power-system/coal/kingston-fossil-plant.
[2] Tennessee Valley Authority (TVA). February 2024. *Kingston Fossil Plant Retirement: Final Environmental Impact Statement*. Available at: https://www.tva.com/environment/environmental-stewardship/environmental-reviews/nepa-detail/kingston-fossil-plant-retirement. p. iv.
[3] Ibid, p. iv.
[4] Ibid, p. v; TVA. 2019. *2019 Integrated Resource Plan: Volume I — Final Resource Plan.* Available at: https://tva-azr-eastus-cdn-ep-tvawcm-prd.azureedge.net/cdn-tvawcma/docs/default-source/default-document-library/site-content/environment/environmental-stewardship/irp/2019-documents/tva-2019-integrated-resource-plan-volume-i-final-resource-plan.pdf?sfvrsn=44251e0a_4
[5] TVA. 2022 TVA Federal Sustainability Plan. Available at: https://www.sustainability.gov/pdfs/tva-2022-sustainability-plan.pdf. p. 1.
[6] TVA. "Coal." Available at: https://www.tva.com/energy/our-power-system/coal
[7] U.S. House. 16 USC 831m-1: Tennessee Valley Authority least-cost planning program. Available at: https://uscode.house.gov/view.xhtml?req=granuleid:USC-prelim-title16-section831m-1&num=0&edition=prelim#
[8] TVA FEIS, pp. iv-v.

II. Overview of Kingston Fossil Plant Retirement

The Kingston plant as it stands is one of the oldest coal plants operating in the United States and has had repeated technical struggles. In its 2019 Integrated Resource Plan (IRP),[9] TVA committed to a near-term action to evaluate end-of-life dates for aging fossil units, leading to the release of the *Aging Coal Fleet Evaluation* in 2021.[10] The 2021 evaluation showed that despite being similar in age, Kingston was in worse material condition than some of TVA's other coal-fired plants, such as Shawnee and Gallatin, warranting an earlier retirement.[11] TVA found that the current issues with the aging machinery of the plant were not able to be easily addressed and would require a more substantive repair.[12] As noted in the 2019 IRP, coal units operating beyond their lifetime also have a greater risk of higher operating costs.[13] At nearly 70 years old, Kingston is exhibiting a high rate of unplanned outages as its condition deteriorates, as well as more frequent shutdowns and startups, presenting a costly challenge to TVA in terms of its ability to meet generation and capacity demands.[14]

In February 2024, the Tennessee Valley Authority (TVA) published a FEIS, which evaluated the environmental and social impacts associated with the retirement, demolition, and replacement of its coal-fired Kingston Fossil Plant. In its FEIS, TVA evaluated a "No Action" Alternative, in which Kingston is not retired as planned, as well as two "Action" Alternatives where Kingston is retired and replaced with at least 1,500 megawatts (MW) of generating capacity; one alternative mostly involves replacement with natural gas generation (Alternative A) while the other mostly includes solar PV and battery storage (Alternative B).

TVA's preferred alternative is Alternative A—or mostly gas replacement.[15] TVA's analysis found that the total system costs of the No Action alternative and Alternative B were $488 million and $972 million more expensive than Alternative A, respectively.[16] TVA argued that Alternative A has the cheapest production costs and fixed costs of the three alternatives.[17] It has the most expensive fuel supply infrastructure costs and a higher transmission infrastructure cost than the No Action Alternative.[18] But TVA finds its transmission costs are lower than those of Alternative B.[19] TVA further justified this preference by claiming that a gas combined cycle (CC) gas plant with additional combustion turbine (CT) units would be "the best overall solution to supply low-cost, reliable, and cleaner energy to TVA's power system consistent with the 2019 IRP."[20] TVA argues that gas replacement could be built and made operational sooner than the clean energy option, which would further reduce costs.[21] In November 2023, TVA filed an air permit application for a combined cycle

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[9] TVA. 2019. *2019 Integrated Resource Plan: Volume I — Final Resource Plan*, ES-5. Available at: https://tva-azr-eastus-cdn-ep-tvawcm-prd.azureedge.net/cdn-tvawcma/docs/default-source/default-document-library/site-content/environment/environmental-stewardship/irp/2019-documents/tva-2019-integrated-resource-plan-volume-i-final-resource-plan.pdf?sfvrsn=44251e0a_4
[10] TVA. May 2021. *Aging Coal Fleet Evaluation*. Available at: https://tva-azr-eastus-cdn-ep-tvawcm-prd.azureedge.net/cdn-tvawcma/docs/default-source/environment/aging-coal-fleet-evaluation2eeb5bd7-1983-4d03-ac5b-c105e2686d07.pdf?sfvrsn=3425c191
[11] Ibid, p. 12.
[12] Ibid, p. 10.
[13] TVA. 2019. *2019 Integrated Resource Plan: Volume I — Final Resource Plan,* pp. 8-16
[14] TVA FEIS, p. 7.
[15] Ibid, p. x.
[16] Ibid, Appendix B, p. 28.
[17] Ibid, Appendix B, p. 28.
[18] Ibid, Appendix B, p. 28.
[19] Ibid, Appendix B, p. 28.
[20] Ibid, p. x.
[21] Ibid, p. xi.

facility at the Kingston Fossil Plant that would replace the current coal-fired units.[22]

Our economic analysis in this report relies on TVA's proposed solutions for replacement generation at the Kingston site. We have conducted our own cash flow analysis using more reasonable data assumptions, and incorporated tax credits. We have also updated key information provided in the more recent air permit application filed by TVA. We ultimately find that the clean energy portfolio is the lower-cost option. This is contrary to TVA's own assessment which favors the natural gas portfolio.

No Action Alternative

In the No Action Alternative evaluated by TVA, Kingston's nine coal-fired units would remain part of TVA's generation portfolio with required modifications to maintain compliance with the U.S. Environmental Protection Agency's Coal Combustion Residuals (CCR) rules and Effluent Limitation Guidelines (ELGs).[23] But in its FEIS, TVA determined that this option would not meet its generation and capacity needs going forward due to the costly repairs and maintenance needed to ensure that the aging coal units remained functional:

> *…based on the age, material condition, and cost required to ensure reliability of the KIF Plant [TVA's acronym for the Kingston Fossil Plant], this alternative of continuing to operate KIF for the long-term would not meet the purpose and need of TVA's Proposed Action.*[24]

TVA also notes its skepticism of the viability of the No Action Alternative as anything other than a baseline for assessment and that actual implementation would impact other proposed resource additions and retirements:

> *In addition, operation of the KIF Plant beyond 2027 is likely to result in cascading delays for the later planned retirements in TVA's phased 2035 coal fleet retirement plan and cause delay in TVA's plans to integrate more solar assets onto the system...*[25]

TVA also provided little information on how it modeled this portfolio—or when the units would retire in this portfolio. The proposed EPA greenhouse gas standards would require carbon capture and storage (CCS) systems, low-greenhouse-gas hydrogen co-firing, or natural gas co-firing be utilized on fossil-based generation resources that continue to operate.[26] Facilities with CCS must achieve a 90 percent capture rate.[27] This rule, which will likely be finalized later this year, could lead to further coal retirements on TVA's system. Based on the Kingston plant's age, mechanical issues, environmental compliance risks as well as TVA's assumption in the FEIS that these units are unlikely to operate much longer, AEC did not model the No Action Alternative.

[22] TVA. October 2023. Kingston Fossil Plant Combined Cycle Project Air Permit-To-Construct Application, p. 3-1.
[23] TVA FEIS, p. 33.
[24] Ibid, p. 38.
[25] Ibid, p. 7.
[26] EPA. 2023. *Greenhouse Gas Standards and Guidelines for Fossil Fuel-Fired Power Plants Proposed Rule.* Available at: https://www.epa.gov/system/files/documents/2023-05/FS-OVERVIEW-GHG-for%20Power%20Plants%20FINAL%20CLEAN.pdf ., p. 1.
[27] Ibid, p. 5.

Action Alternative A – Gas-Heavy Replacement

Under Action Alternative A, Kingston's nine coal-fired units would be decommissioned and demolished by the end of 2027.[28] In place of the lost generation, TVA proposes to build a 763-MW gas-fired combined cycle (CC) plant paired with an 888-MW dual-fuel aeroderivative combustion turbine (CT) plant.[29] In addition, Action Alternative A includes a 3- to 4-MW solar PV site and a 100-MW battery energy storage system (BESS), both to be located on the Kingston site.[30] This is TVA's preferred plan because "the proposed CC/Aero CT Plant could be built and made operational…and reduce economic, reliability, and environmental risks."[31] TVA also stated that Action Alternative A helps advance its system-wide goals:

> *TVA has also selected Alternative A as its Preferred Alternative because the proposed CC/Aero CT Plant would facilitate the flexibility needed to bring 10,000 MW of solar onto the system by 2035 and enables the [Kingston] coal-fired units to be retired by the projected end-of-life estimates for those units.* [32]

Other major infrastructure changes needed to serve the new gas plant will include on- and off-site transmission upgrades and connections, as well as the construction of an approximately 8-mile gas pipeline[33] equipped with a compressor station, and a 120-plus mile gas pipeline project being undertaken by East Tennessee Natural Gas (ETNG) for an upfront capital cost of over $1.1 billion.[34]

For the analysis presented in Section 0, AEC developed capital costs, operating costs, and characteristics for the new gas, solar, and battery projects using many sources, such as the National Renewable Energy Laboratory (NREL) and Energy Information Administration (EIA) projections of resource costs as well as past performance from TVA's natural gas fleet. AEC also used ETNG's filing for FERC approval of the new gas pipeline to determine the costs that would be passed on to TVA—and by extension its ratepayers.

AEC considered two scenarios for gas replacement where: (1) TVA would install carbon capture and storage (CCS) in 2035 to comply with the EPA's proposed greenhouse gas rule, achieving 90 percent carbon dioxide removal and getting access to the Inflation Reduction Act (IRA) tax credits for this technology; or (2) TVA would not need to install carbon capture and storage (CCS) and therefore not incur those costs or receive the corresponding tax credits.[35]

We recognize that the economics of this gas-heavy portfolio are contingent on the costs of the fuel itself. With that in mind, AEC also provides sensitivity modeling (presented in Section 0) that shows the costs of the portfolio under a low and high natural gas price (as opposed to the base forecast used currently) to determine how the results are impacted by different gas prices.

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[28] TVA FEIS, p. 40.
[29] TVA. October 2023. *Kingston Fossil Plant Combined Cycle Project Air Permit-To-Construct Application* p. 2-1, 2-2.
[30] TVA FEIS, p. 33.
[31] Ibid, p. 102.
[32] Ibid, p. ii.
[33] Ibid, p. 46, 48.
[34] Ibid, p. 48; FERC. Docket No. CP23-516-000, 20230823-5107_VOL I_Ridgeline Application, Exhibit K, p.2.
[35] The EPA rule would require CCS technology installed by 2039 but in order to access the IRA tax credits, the construction must begin by 2032. Therefore, we assumed that the technology would be installed by 2035. See EPA. 2023. *Greenhouse Gas Standards and Guidelines for Fossil Fuel-Fired Power Plants Proposed Rule.* Available at: https://www.epa.gov/system/files/documents/2023-05/FS-OVERVIEW-GHG-for%20Power%20Plants%20FINAL%20CLEAN.pdf.

Action Alternative B – Clean Energy Replacement

Similar to Action Alternative A, Kingston's nine coal-fired units would be decommissioned and demolished under Action Alternative B.[36] TVA would then procure approximately 1,500 MW of solar PV and 2,200 MW of 4-hour battery storage (BESS) facilities that would be developed under Power Purchase Agreements (PPAs), albeit not entirely in Tennessee.[37] According to TVA, transmission system upgrades and new transmission line rights-of-ways will be a necessary supplement to Alternative B.[38] The 1,500 MW of solar PV needed for Action Alternative B would be in addition to the 10,000 MW of solar planned by TVA over the next decade.[39] The solar PV and BESS sites are anticipated to require over 11,000 acres of available land.[40]

Action Alternative B was not chosen by TVA as the preferred replacement option for Kingston based on TVA's claim that it "would require substantial transmission upgrades and lengthy timeframes for the transmission work such that Alternative B would not meet the need to provide replacement generation by the end of 2027 when the KIF units would be retired."[41] To address the concerns of the costs, we modeled a wide range of interconnection costs for this portfolio.

For the analysis presented in Section 0, AEC modeled the portfolio as described by TVA in the FEIS, but with more reasonable cost assumptions (provided in further detail in the Appendix). AEC also modeled this option in two scenarios: (1) where renewable and BESS are built and financed by TVA; or (2) these resources are built by developers and acquired by TVA through power purchase agreements (PPAs). We also modeled the tax credits available from the IRA, including the full production tax credit (PTC) for solar PV and investment tax credit (ITC) for battery storage; and we considered variations in tax credits and interconnection costs. We ultimately find that, regardless of these variations in cost—including whether TVA builds or buys—the renewables and battery portfolio is the lower-cost option.

We modeled the clean energy portfolio's capacity as specified by TVA; but importantly it is not clear why TVA selected the above amounts of solar and storage capacity. The amount of storage capacity is exorbitant when compared to both the size of the Kingston plant, available information on planned storage buildouts in similar jurisdictions, and the scale of solar capacity in this portfolio. It is also unclear why the additional 1,500 MW of solar proposed in this alternative is additional to the 10,000 MW of solar to which TVA is already committed.[42]

[36] TVA FEIS, p. 34.
[37] Ibid, p. 34.
[38] Ibid, p. 34.
[39] Ibid, p. 71.
[40] Ibid, p. 71.
[41] Ibid, p. 102.
[42] Ibid, p. 71.

III. Economic Analysis of Replacement Alternatives

TVA's preferred alternative is Alternative A: the natural gas replacement for Kingston.[43] TVA had various criteria that informed its decision. It needed resources that could meet its planned phased retirement of the coal fleet by 2035, and hence it chose 1,500 MW as its target capacity.[44] TVA deemed in its FEIS that the replacement resources would have to be online by 2027 to replace the nine retiring Kingston units.[45] TVA argued that the gas option would be best for providing "low-cost, reliable, and cleaner energy to the TVA power system."[46] In this section, AEC presents its assessment of the gas and clean energy alternatives. In particular, AEC assesses "net annual customer costs," a measure which sums all expected "new" costs to be passed on to the ultimate customers in order to construct and operate the replacement resource, including (where applicable):

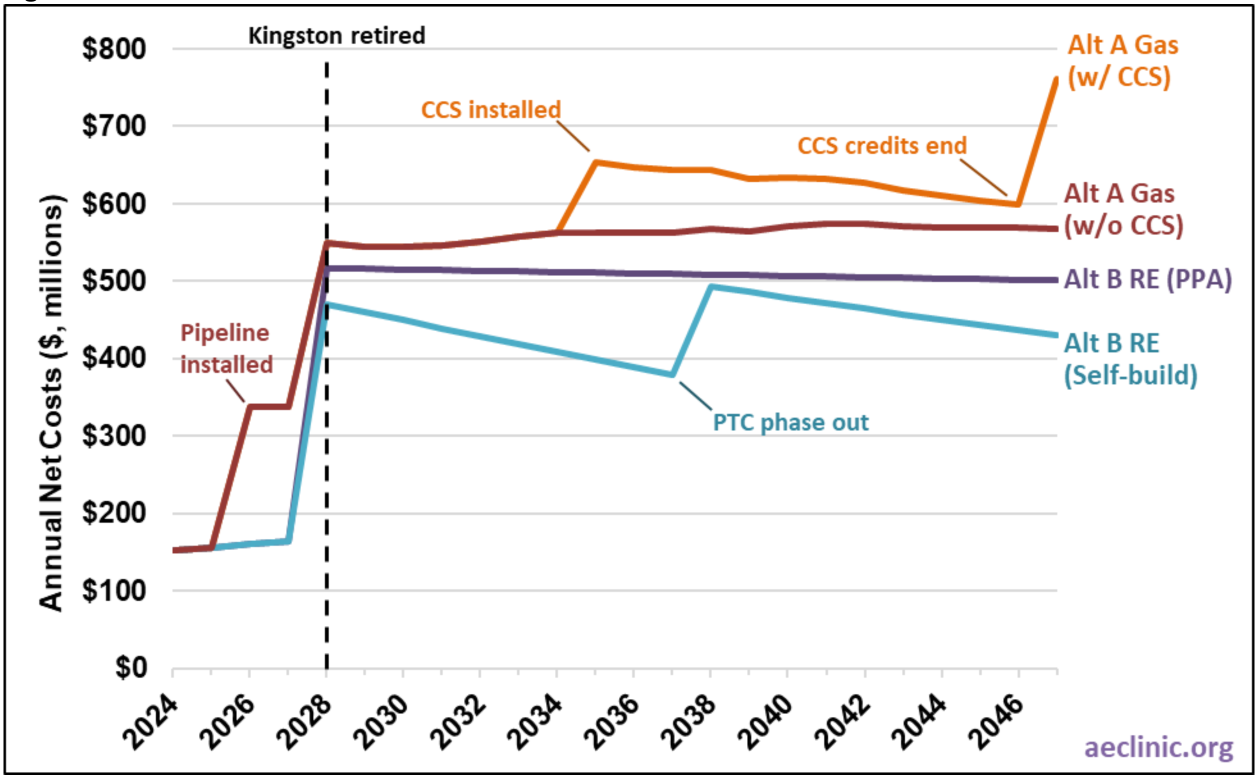
- Fuel costs;
- Fixed and variable operations and maintenance (O&M) costs;
- Costs of carbon capture and storage (CCS);
- Costs of financing (principal and debt service) the construction of new resources and any other new capital equipment needed to comply with regulatory requirements;
- Pipeline costs; and
- Interconnection costs.

Natural gas fuel, CCS and pipeline costs are only applicable to Alternative A's net annual customer costs, while interconnection costs are only applicable to Alternative B. For each portfolio, the "net" annual customer costs are an estimate of the costs and revenues (i.e., tax credits) that would flow to the ultimate customer of TVA. These do not include capital investments already made at Kingston, which are assumed to be "sunk costs" that would be recovered by TVA regardless of the future replacement options.

Our analysis of TVA's "Action" plans shows that clean energy replacement is far preferable to gas-heavy replacement from the point of view of costs faced by TVA customers. When we project the costs of clean energy replacement (Alternative B), it is consistently cheaper in annual net customer costs compared to gas-heavy replacement (Alternative A) – see Figure 1 below. This conclusion holds whether or not TVA installs CCS on the gas combined cycle plant; or whether TVA self-builds and finances the clean energy projects itself or procures them through a PPA. Moreover, regardless of the clean energy procurement strategy or greenhouse gas requirements, the costs of the gas-heavy alternative are consistently higher due to fuel costs and the $1.1 billion pipeline required to provide gas to the Kingston site. (Please refer to Appendix: Methodology and Assumptions for a more detailed description of assumptions and data sources.)

[43] Ibid, p. x.
[44] Ibid, p. iv; 7.
[45] Ibid, p. 8.
[46] Ibid, p. x.

Figure 1. Annual net costs to customers of TVA alternatives

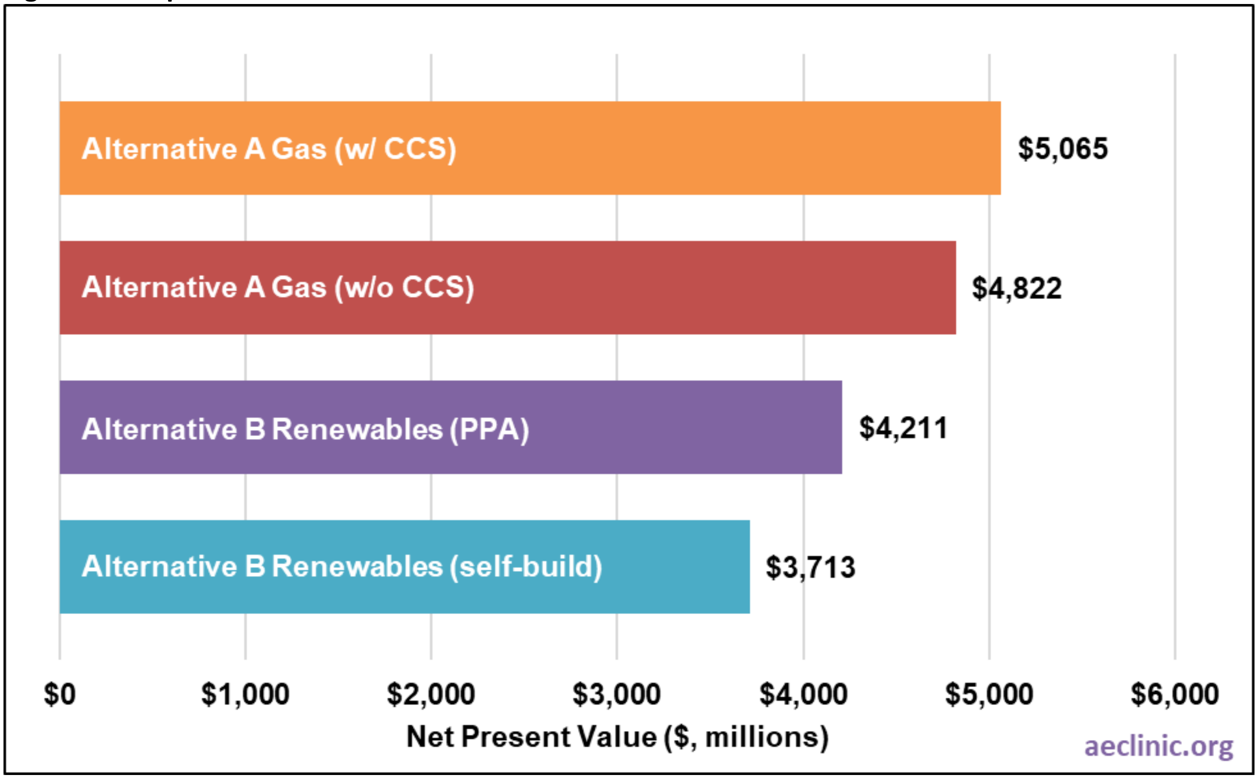


Source: AEC calculations, see Methodology Appendix for description of assumptions and data sources.

The net customer costs shown above reflect a summation of all those forward-going costs that would be passed on to TVA customers, including capital, operating, and financing costs, along with cash inflows from applicable tax credits. Large spikes or decreases in annual net customer costs from year-to-year reflect the end or start of tax credits, respectively. In Alternative A there are also spikes in costs when major infrastructure is added in the form of pipeline and carbon capture retrofits. Note that Alternative B's PPA option does not decrease at the same rate as the self-build option because the private developer selling generation through the PPA is assumed to pick one flat price that incorporates expected output, fixed costs, a higher cost of capital to that developer (relative to TVA which uses all debt financing), and the tax credits received by that developer who effectively distributes those costs and credits out in setting a PPA price.

The self-build and PPA options for clean energy replacement are substantially cheaper than gas-heavy replacement on aggregate level, as shown in the net present value (NPV) of customer costs (see Figure 2 below). The NPV of customer costs is a commonly used metric that utilities use to evaluate resource decisions. The calculation "discounts" the costs in each year to account for the time value of money, and sums that discounted value to enable the comparison of different plans on equal footing. We find that the NPV of the self-build option is approximately $3.7 billion relative to $4.2 billion for the PPA option (which TVA is more likely to choose); compared to $5.1 billion for Alternative A with CCS and $4.8 billion without CCS. Thus, customers save roughly between $600 million to $1.35 billion with clean energy compared to gas-heavy replacement. As we show later, these NPVs are sensitive to gas prices, interconnection costs, and other parameters; but the conclusion that clean energy is lower cost does not change.

Figure 2. Net present value of TVA's alternatives



Source: AEC calculations, see Methodology Appendix for description of assumptions and data sources.

Both alternatives contain multiple resources: Alternative A includes natural gas, a small-scale solar resource, and some battery storage, while Alternative B includes only solar and battery storage. These resources affect net present value differently because their technical specifications are different in each scenario. Alternative A utilizes small-scale distributed solar instead of large-scale utility solar. As noted above, the capital costs in the two versions of Alternative B are different because one (self-build) represents TVA's capital costs that would be funded by debt and the other represents the developer's higher financing costs (PPA) that would be a mix of debt and equity.

Another way to compare resource costs is on a "levelized" basis—which normalizes total costs by a unit of generation or capacity—and can help distinguish the various component resource costs of these alternatives. For ease of comparison, we show these in terms of either levelized energy ($/MWh) for solar and gas CC resources; or levelized capacity ($/kW-mo) for battery and gas CT resources that primarily provide capacity rather than energy. As shown in Table 1 below, the levelized cost of energy for solar is substantially lower than new gas on an energy-basis and battery storage is a cheaper capacity resource than a gas CT.

Table 1. Levelized costs of TVA's alternatives

Replacement Alternative	Resource Type	Levelized cost of energy ($/MWh)	Levelized cost of capacity ($/kW-mo)
Alt A Gas (w/ CCS)	Gas CC	$113	
	Solar DG	$92	
	Battery		$10
	Gas CT		$15
Alt A Gas (w/o CCS)	Gas CC	$111	
Alt B RE (PPA)	Battery		$13
	Solar large-scale	$53	
Alt B RE (Self-build)	Battery		$12
	Solar large-scale	$43	

Source: AEC calculations, see Methodology Appendix for description of assumptions and data sources.

The storage costs are consistent across scenarios, remaining between $10 to $13 per kW-month; slightly cheaper than the gas CTs as a capacity resource option. Alternative B's self-build iteration sees the cheapest solar costs at $43 per MWh, while Alternative A has the highest solar costs at $92 per kWh due to the solar project's much smaller scale. The gas CC, however, constitutes the most expensive levelized cost of energy among the proposed generation options at $113 per MWh. Note that the gas CC with CCS costs are likely on the low-end because it was assumed that CCS would achieve 90 percent removal, which is optimistic, and that it would receive the full tax credits for storage and transportation of carbon. The modeling period also captures the full 12-year period where the plant would receive tax credits (2035-2046) but when not receiving these credits it is extremely expensive to install CCS.

IV. Sensitivity Analysis

Cash flow analysis depends on specific assumptions or parameters that, if varied sufficiently, alter results. In this report, these parameters reflect characteristics such as the price of fuel, technological performance, and economic or infrastructural circumstances encountered during development. As such, we subject our assessments above to "sensitivity analysis" in which we vary key parameters to assess how or if the most favored scenario in net present value terms changes. AEC then compared the resulting NPV changes to determine how or if the chosen parameters affected the status of the clean energy scenario as the cheaper selection for TVA.

The results in the previous section reflect a "base" case. But in this section, AEC tests several parameters for sensitivity: gas prices, interconnection costs, and the "energy community" tax credit (see Table 2). The former affects the costs of gas replacement. Higher fuel costs should increase the lifetime NPV and the annual net customer costs of replacing Kingston with a gas plant. On the other hand, higher interconnection costs impact the clean energy portfolio due to the geographic dispersion of solar and storage resources and the requirements for connecting this network of new resources. Finally, the energy community would apply to sites that qualify under the IRA for additional tax credits. We assume that the solar and battery in Alternative A already receive this credit because they will be connected at the Kingston site. But for the full clean energy portfolio, it is unclear at this time where all of these projects would be located. Most likely, some resources would qualify, and some would not as they are expected to be spread throughout the region. Thus, the low-cost range of the clean energy portfolio assumes all would receive the extra credit, while the base and high costs assume no extra credit.

Table 2. Cost sensitivity assumptions for each replacement alternative

Replacement Alternative	Sensitivity Assumptions		
	Low Cost	Base	High Cost
Alt A Gas (w/ CCS)	Low Gas	Base Gas	High Gas
Alt A Gas (w/o CCS)	Low Gas	Base Gas	High Gas
Alt B RE (PPA)	Low interconnection, energy community adder	Base interconnection	High interconnection
Alt B RE (self-build)	Low interconnection, energy community adder	Base interconnection	High interconnection

Source: AEC calculations, see Methodology Appendix for description of assumptions and data sources.

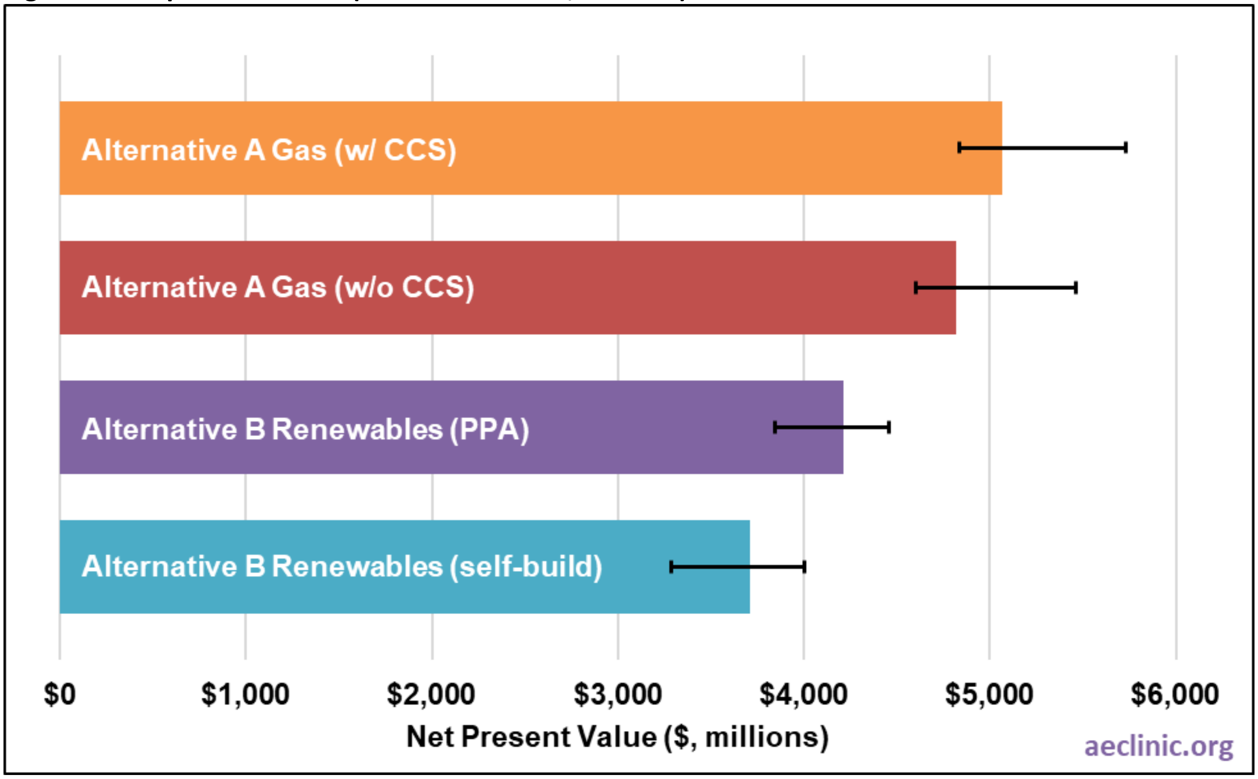
As shown in Table 3 below, the lowest-cost portfolio remains with the clean energy, self-build alternative which remains cheaper than the PPA alternative under all three interconnection costs. In turn, the PPA clean energy alternative is also cheaper than the gas scenario with the lowest NPV (low gas prices without CCS). Figure 3 below shows the minimum and maximum calculated NPV in each scenario relative to the base case.

Table 3. Net present value ($, millions) of each replacement alternative under different sensitivities

Replacement Alternative	Net Present Value ($, millions)		
	Low Cost	Base	High Cost
Alt A Gas (w/ CCS)	$4,833	$5,065	$5,732
Alt A Gas (w/o CCS)	$4,603	$4,822	$5,464
Alt B RE (PPA)	$3,788	$4,211	$4,502
Alt B RE (self-build)	$3,344	$3,713	$3,960

Source: AEC calculations, see Methodology Appendix for description of assumptions and data sources.

Figure 3. Net present values (max and min in $, millions) for each alternative



Source: AEC calculations, see Methodology Appendix for description of assumptions and data sources.

It is important to note that these sensitivities do not alter AEC's concerns noted above on TVA's specification of Alternative B. TVA has not justified the substantial solar and battery resource requirements in the clean energy portfolio. [47]

[47] AEC also ran an analysis where Kingston retired at the end of 2028 and the replacement resources came on-line starting in 2029; this analysis showed even higher savings for the clean replacement portfolios versus gas. This timeline is consistent with the Effluent Limitation Guidelines from EPA that allow coal units to retire by the end of 2028 to avoid additional compliance costs.

V. Key Takeaways

A new IRP for all of TVA's resources is expected in 2024. AEC does not intend this report to make a specific recommendation on which of TVA's self-defined alternatives it should pursue. Nevertheless, the results do indicate broadly that a clean energy strategy is preferable to a gas-heavy replacement given the exorbitant costs of infrastructure required to have gas generation at the Kingston site. TVA also did not provide sufficient data or explanation to illustrate: (1) why it chose the particular alternatives that it did; (2) why other alternatives consisting of different amounts of renewables or storage resources were not considered; (3) why Alternatives A or B were given the specific timelines or schedules that they were; or (4) how TVA assessed the feasibility of technological choices such as the use of carbon capture technologies, how it considered interconnection costs, or determined regulatory compliance costs. These omissions make it impossible to evaluate whether TVA's self-defined alternatives are realistic indications of the range of what is possible over the coming decades once Kingston is retired.

These issues with TVA's analysis are symptoms of a bigger problem: TVA's IRP process does not sufficiently synchronize with its site-specific analyses of proposed alternatives and does not assess the full range of plausible alternatives. These conclusions were reached in an earlier AEC report from July 2023, *Assessing TVA's IRP Planning Practices,* which assessed TVA's previous three IRPs as well as its site-specific analysis of the Cumberland Plant.[48] Based on that report's recommendations and the analysis conducted in this report, AEC will echo specific takeaways for TVA's 2024 IRP process:

1. TVA should conduct an all-resource RFP for potential resources or a similar process that can assess the range of resources that could be reasonably constructed and begin operation during TVA's selected analysis period.
2. An all-resource RFP process should consider the full set of resources that could facilitate decarbonization of TVA's grid while also impacting the scale of new generation and storage options that would need to be constructed: transmission and distribution, distributed energy resources, energy efficiency, and demand response among others.
3. TVA should undertake optimization modelling on potential resources rather than pre-select portfolios for analysis.
4. TVA must ensure that site-specific planning does not contradict its IRP.
5. TVA must ensure that its IRP provides plausible schedules for the installation and decommissioning of capacity and that such schedules reflect rigorous assessments of its expected demand.
6. TVA must be more transparent with its assumptions and modeling inputs.

[48] Lala, C. T., E. Seliga, E. A. Stanton. 2023. *Assessing TVA's IRP Planning Practices.* Applied Economics Clinic. Available at: https://aeclinic.org/publicationpages/7/2023/assessing-tvas-irp-planning-practices.

Appendix: Methodology and Assumptions

AEC assesses and compares TVA's proposed alternatives using a net cash flow analysis, which involves comparing all "new" costs that accrue to TVA because of pursuing its selected alternatives. Costs include the capital costs of purchasing new generation, storage, retrofits, interconnection, and pipelines. They also include fixed and variable operating costs (where appropriate), and the cost of debt used to finance capital expenditure. The net cash flow analysis also assesses cost subsidies associated with each alternative—namely the tax credits from the Inflation Reduction Act (IRA) that incentivize investments in zero-emission generation and storage resources as well as in carbon capture and storage (CCS) infrastructure.

AEC projects all relevant costs for the years 2024 through 2047. AEC then adds together all costs and cost subsidies to calculate the net present value of customer costs. AEC also calculates levelized costs on both an energy and capacity basis over the years of each resource's operation during this analysis period.

A list of general modeling assumptions is provided below:

- All alternatives are modeled from 2024 to 2047, with operating conditions for new generating resources assumed to start in 2028. From 2024 through 2027, all portfolios include the costs of continued coal generation at Kingston.
- Construction for new resources under Alternatives A and B is assumed to occur from 2024 through 2027.
- The useful lives of new resources are based on TVA's assumptions in the FEIS: 30 years for new gas, and 20 years for solar PV and battery storage.
- AEC uses the 8 percent discount rate from TVA's 2019 IRP to estimate the NPV of costs.
- Costs are all adjusted for inflation assuming a 2.5 percent annual rate.
- AEC estimates a cost of debt of 4.66 percent using a weighted average of long- and short-term debt based on the same mixture of long- and short-term debt on TVA's balance sheet as described in TVA's 2024 10-Q.[49]
- Capital costs for specific upgrades are calculated using overnight costs of capital with additional interest for the construction period. All capital investments made by TVA are assumed to be entirely debt-financed and assumed to be paid off over the useful life of the asset (see above).
- To qualify for the IRA tax credits, we assume that TVA meets prevailing wage and apprenticeship requirements and that it either meets the domestic content requirements necessary to qualify for the credits or receives a safe-harbor exemption under forthcoming Treasury Department rules.

[49] TVA. 2024 10Q filing p. 9, 47. TVA's long-term bond rates have typically been close to those of Treasury and AAA rated bonds (https://tva.q4ir.com/investment-opportunities/tva-power-bonds/default.aspx). Therefore, we estimated a long-term bond rate was based on the average of a 20-year Treasury rate and Moody's AAA rating (https://fred.stlouisfed.org/series/AAA) for January 2024. The short-term rates were provided in TVA's 10Q filing.

Modeling assumptions specific to each scenario are listed below:

Action Alternative A

- Costs of the new gas units:
    - AEC assumes that TVA will build a new 763 MW NGCC and 888 MW of aeroderivative combustion turbines (CT) for operation in 2028. Overnight costs are taken from the EIA's 2023 Annual Energy Outlook (AEO) for each unit type.[50] The interest during construction is calculated using the National Renewable Energy Laboratory (NREL) Annual Technology Baseline (ATB) from 2023.[51] The final capital cost is approximately $1,250 per kW for the NGCC and $1,320 per kW for the aeroderivative CTs (in 2022 dollars).
    - In one scenario, we assume that TVA will build carbon capture technology at the NGCC for operation in 2035 to comply with the proposed EPA greenhouse gas rule. The capital costs of this retrofit (roughly $1,499 per kW in 2021 dollars) are based on the incremental cost of a new NGCC with CCS and without, as shown in the AEO 2023.[52]
    - The heat rate and operations and maintenance (O&M) costs are based on NREL ATB 2023's estimates for an H-Frame NGCC under the "moderate" cost scenario.
    - Costs of natural gas rely on the AEO 2023 reference case forecast of Henry Hub gas prices.[53] The low gas price sensitivity is based on the AEO's "high oil and gas supply" case; and the high gas price is based on the "low oil and gas supply" case.
    - The capacity factor of the NGCC is assumed to be 60 percent based on the mode of the capacity factors across TVA's existing NGCCs in the past five plus years (2018 through May 2023).[54]
    - The capacity factor of ten percent for the CT is based on TVA's 2019 modernization study for combustion turbines, which provides an illustrative capacity factor range of 10 to 45 percent for aeroderivative CTs.[55] Based on this report, we utilized a CT capacity factor of 10 percent.
- Costs of the pipeline:
    - Capital costs are $1.1 billion, based on the ETNG filing with FERC and assuming operation by 2026.[56] These costs are assumed to be financed using ETNG's reported costs of debt and equity and their reported capital structure. AEC also calculated a pre-tax weighted average cost of capital (WACC) of 12.32 percent using the company's reported 24.37 percent tax rate.
    - The pipeline is assumed to be depreciated over a 50-year period per ETNG's FERC filing.

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[50] EIA. AEO 2023, Table 55. Available at: https://www.eia.gov/outlooks/aeo/tables_ref.php.
[51] NREL. ATB 2023. Available at: https://atb.nrel.gov/electricity/2023/data
[52] EIA. AEO 2023, Table 55, Available at: https://www.eia.gov/outlooks/aeo/tables_ref.php.
[53] EIA. AEO 2023, Table 13. Available at: https://www.eia.gov/outlooks/aeo/tables_ref.php.
[54] EIA. Form 860 and 923--reported capacity and generation. Available at: https://www.eia.gov/electricity/data/eia860/ and https://www.eia.gov/electricity/data/eia923/
[55] TVA. 2019. *Aging Fossil Unit Evaluation: Oldest Combustion Turbines (CT),* p. 10.
[56] FERC. Docket No. CP23-516-000, 20230823-5107_VOL I_Ridgeline Application, Exhibit P.

- Ultimately, we estimate that the costs of the pipeline, which include annual depreciation, rate of return, operating costs, and taxes would be a total of $175 million in the first year and slightly decline thereafter. This is very close to the initial tariff filed by ETNG at FERC.[57] These costs are assumed to be recovered in rates paid by TVA's ultimate customers.
- We ran a sensitivity in which the pipeline was not installed until 2028, to coincide with the gas plant, and in this case the plan's costs would decrease by $174 million NPV, which is nowhere near enough to make up for the cost savings with the clean energy replacement plan.

- Carbon capture operations:
  - AEC assumes that a renovated Kingston Gas Plant would achieve a capture efficiency of 90 percent.
  - We assume that TVA pays for transportation and storage of carbon dioxide on a per ton basis[58] and receives the $85 IRA tax credit (adjusted for inflation) for every per metric ton captured.[59]
  - The O&M costs for CCS are from NREL ATB 2023's estimates for a 90 percent removal CCS retrofit.
  - Per NREL ATB, there is a 10 percent increase in the unit's heat rate after CCS is installed, and there is a decrease in power output of 11 percent relative to pre-CCS operations.
- Solar and battery installations:
  - Per TVA's plan, we assume a 4 MW solar PV and 100 MW battery storage project will be built by 2028.
  - AEC assumes the accompanying battery and solar systems on the site both qualify for the 40 percent investment tax credit (ITC) for capital costs, assuming the additional "energy community" adder due to the location at the Kingston site.
  - We assume no new interconnection costs are required as the resources are tied into the grid at the existing Kingston interconnection.

Action Alternative B

- AEC assumes that TVA constructs a utility solar PV system of 1,500 MW and a battery system consisting of 2,200 MW of 4-hour lithium-ion batteries. Capital and operating costs are taken from the NREL ATB 2023 "moderate" scenario.

[57] Ibid

[58] National Energy Technology Laboratory (NETL). *Quality Guidelines for Energy System Studies Carbon Dioxide Transport and Storage Costs in NETL Studies*, p.36. Available at: https://www.osti.gov/biblio/1567735

[59] Clean Air Task Force (CATF). *The Inflation Reduction Act creates a whole new market for carbon capture*. Available at: https://www.catf.us/2022/08/the-inflation-reduction-act-creates-a-whole-new-market-for-carbon-capture/. We assume a dollar base year of 2025, see: https://cdn.catf.us/wp-content/uploads/2023/02/16093309/ira-carbon-capture-fact-sheet.pdf

- We assume the 30 percent ITC for battery storage and a 10-year payment of $27.50 per MWh (escalating with inflation) for the production tax credit (PTC) applied to the solar PV resources. We also model the energy community adder of 10 percent ITC or an additional 10 percent PTC payment under the "low" cost range for this portfolio.
- In our base case, we assume $100 per kW interconnection costs for all new solar and battery projects, based on the costs of actual projects completed in the PJM region in 2020 through 2022 and those of the MISO region from 2019 to 2021.[60] The low case interconnection costs are $50 per kW; the high case costs are $200 per kW.
- Interconnection costs include or account for various technologies such as advanced inverters.
- We assume that the solar PV operates at a 25 percent capacity factor per the EIS, with an annual degradation of 0.5 percent.
- Per the NREL ATB, we assume 85 percent roundtrip efficiency for the battery storage and that it operates once every day of the year.

[60] (1) Lawrence Berkeley Lab (LBL). 2023. *PJM Data Show Substantial Increases in Interconnection Costs,* completed projects. Available at: https://emp.lbl.gov/news/pjm-data-show-substantial-increases; (2) Lawrence Berkely Lab (LBL). 2022. *Data from MISO Show Rapidly Growing Interconnection Costs.* Available at: https://emp.lbl.gov/news/data-miso-show-rapidly-growing.