

**McIntosh Upgrades Cost-Benefit Analysis**

2025 Integrated Resource Plan

# Overview

Georgia Power Company (“GPC” or the “Company”) routinely evaluates forecasted conditions and resource improvements to identify opportunities that can provide customers with clean, safe, reliable, and affordable energy from a diverse fleet of generation resources. For the 2025 Integrated Resource Plan (“IRP”), the Company has identified beneficial upgrades for several of its existing thermal generation resources located at Plant McIntosh. These resources include both the simple cycle Combustion Turbines (“CT”), Plant McIntosh Units 1A-8A (eight in total), and Natural Gas Combined Cycle (“NGCC”) units, Plant McIntosh Units 10-11 (two 2x1 units). Given the extraordinary economic growth in the state of Georgia, the Company has significant forecasted capacity needs that require additional firm generation to ensure reliability. The upgrades at Plant McIntosh present a unique opportunity to leverage existing resources and meet the growing needs of customers. The cost-benefit analyses presented in this technical appendix clearly demonstrate that executing these upgrades at Plant McIntosh is in the best interest of customers.

# Upgrade Opportunity

The upgrade opportunity being evaluated for the combined cycles at Plant McIntosh Units 10-11 is the General Electric (“GE”) 7FA.05 upgrade. The scope of this upgrade includes replacing rotating blades and stationary vanes in the CTs (two CTs per combined cycle), combustor replacement, increasing firing temperature and shaft limits, and additional operating mode flexibility. The result of these replacements will be increased capacity and improved heat rate for some operating modes. In addition, the GE 7FA.05 upgrade will give these NGCCs the ability to operate power augmentation (admission of steam to the combustion turbine to increase mass throughput and power output) and peak firing in winter conditions, as well as the ability to operate peak fire and power augmentation simultaneously. Table 1 shows the expected performance for both NGCC units, based on performance data provided by GE.

Table 1. Combined Cycle Expected Performance

|  |  |  |
| --- | --- | --- |
| Season | Capacity Increase  (Base + Peaking, MW)  Unit 10-11 | Heat Rate Improvement (Base Load) |
| Winter | 194 | -0.2% |
| Shoulder | 200 | -- |
| Summer | 68 | -0.7% |

The upgrade opportunity being evaluated for Plant McIntosh Units 1A-8A, or the simple cycle CTs, also includes replacing existing turbine components, which will allow each unit to operate at a higher capacity. In addition to increasing capacity, these replacement components are of lower cost than the in-kind replacement parts, leading to a reduction in the capital budget moving forward. This reduction can be explained by changing market conditions and reduction in the availability of in-kind replacement parts. The following table shows the capacity increase, per unit, for the CTs.

Table 2. Simple Cycle Expected Performance

|  |  |
| --- | --- |
| Season | Capacity Increase (Base + Peaking, MW) |
| Winter | 9 |
| Shoulder | 15 |
| Summer | 14 |

Cost and performance for both upgrade opportunities are based on indicative proposals from GE. These estimates are closely aligned with the expectations of the Company's technical experts and plant subject matter experts. While expectations are that these estimates will be very close to the final figures, the final commercial commitments will not be available at the time of the IRP filing.

# Methodology

The Company’s analysis methodology includes a detailed comparison of the units at Plant McIntosh with and without the proposed upgrades, providing a direct economic comparison of the two versions of the plant. This approach is applied to both the NGCC and CT upgrade opportunities.

The evaluation of the upgrade opportunity for Plant McIntosh Units 10-11 reflects a higher cost to complete the upgrades, as well as the associated benefits. The benefits include a capacity benefit, representative of the larger facility, as well as production cost savings due to the improved heat rate and increased size, although heat rate improvements are not anticipated in all operating modes. The cost accounts for the operation and maintenance of the upgraded version of the units as well as the cost to upgrade the resources. A consistent set of applicable costs and benefits are then modeled for a version of the Plant McIntosh Units 10-11 without upgrades. This version of Plant McIntosh Units 10-11, consistent with its current operating condition, has less capacity value and a higher heat rate than the upgraded version. However, the cost to continue operating Plant McIntosh Units 10-11 without upgrades is lower as it does not include costs associated with the upgrade. By directly comparing these two versions of Plant McIntosh Units 10-11, the analysis determines the most economic pathway for continued operations.

Similarly, for the Plant McIntosh Units 1A-8A upgrades, the same comparative approach is utilized. The capacity and energy benefits of the upgraded Plant McIntosh Units 1A-8A, along with the costs to operate these units, are modeled. Likewise, the costs and benefits of the simple cycle CTs without the upgrades are also modeled. The two versions of the CTs are then directly compared to identify the most cost-effective strategy for their operation.

The cost-benefit analyses for the upgrades were performed by comparing the existing cost and performance to the upgraded units’ cost and performance. The analyses were performed this way for both the NGCC and the simple cycle CT.

# Key Analysis Assumptions

The following sections outline key assumptions used in the cost-benefit analysis. The analysis results were evaluated on a net present value basis in 2025 dollars. The analysis for Plant McIntosh Units 10-11 assumed an in-service date for the upgrade of January 1, 2029, with the study running through the current retirement assumption of December 31, 2050. For Plant McIntosh Units 1A-8A, the in-service dates are staggered in the study starting in 2026 and carrying through 2033, with one unit upgrade occurring per year, with the study running through December 31, 2054.

## Upgrade Schedule

The tables below summarize the upgrade schedule for Plant McIntosh Units 1A-8A and Plant McIntosh Units 10-11.

Table 3. Capacity Addition Schedule for NGCC and CT Upgrades.

|  |  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| *Incremental Capacity (MW)* | *Outage Year[[1]](#footnote-2)* | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034+ |
| MCINTOSH 1A | 2029 | *-* | *-* | *-* | *-* | 9.3 | 9.3 | 9.3 | 9.3 | 9.3 |
| MCINTOSH 2A | 2028 | *-* | *-* | *-* | 9.3 | 9.3 | 9.3 | 9.3 | 9.3 | 9.3 |
| MCINTOSH 3A | 2031 | *-* | *-* | *-* | *-* | *-* | *-* | 9.3 | 9.3 | 9.3 |
| MCINTOSH 4A | 2033 | *-* | *-* | *-* | *-* | *-* | *-* | *-* | *-* | 9.3 |
| MCINTOSH 5A | 2032 | *-* | *-* | *-* | *-* | *-* | *-* | *-* | 9.3 | 9.3 |
| MCINTOSH 6A | 2026 | *-* | 9.3 | 9.3 | 9.3 | 9.3 | 9.3 | 9.3 | 9.3 | 9.3 |
| MCINTOSH 7A | 2027 | *-* | *-* | 9.3 | 9.3 | 9.3 | 9.3 | 9.3 | 9.3 | 9.3 |
| MCINTOSH 8A | 2030 | *-* | *-* | *-* | *-* | *-* | 9.3 | 9.3 | 9.3 | 9.3 |
| **Total CT** |  | **-** | **9** | **19** | **28** | **37** | **47** | **56** | **65** | **74** |
|  |  |  |  |  |  |  |  |  |  |  |
| *Incremental Capacity (MW)* | *Outage Year* | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034+ |
| MCINTOSH 10 | 2028 | *-* | *-* | *-* | 97.1 | 97.1 | 97.1 | 97.1 | 97.1 | 97.1 |
| MCINTOSH 11 | 2028 | *-* | *-* | *-* | 97.1 | 97.1 | 97.1 | 97.1 | 97.1 | 97.1 |
| **Total NGCC** |  | - | - | - | **194** | **194** | **194** | **194** | **194** | **194** |

## Deferred Generation Capacity

Deferred Generation Capacity Benefit, also referred to as capacity value, represents the amount of generation capacity that can be deferred or avoided by the incremental addition of capacity. The amount of generation capacity deferred or avoided is based on a summer target reserve margin of 20% and a winter target reserve margin of 26%. As described in the 2025 IRP Main Document, the Company continues to experience substantial load growth and has increasing capacity needs. Therefore, the analysis assumes all incremental capacity receives full capacity value starting at the year of need of 2028. This forecasted capacity value is valued at the economic carrying costs of a generic combustion turbine (“ECC of a CT”).

## Energy Benefit or Production Cost Savings

Production cost savings represent the variable cost savings (predominantly fuel savings) associated with generating energy from the units under evaluation. The Company quantifies these savings using the Aurora production cost model, and these analyses were performed with Budget 2025 (“B2025”) assumptions and scenarios. The Aurora model is used to compare total production cost with and without the upgraded resource. The difference between these two production cost totals is production costs savings or energy benefit of the project. A material portion of production cost savings results from fuel cost savings associated with higher efficiency resources operating at higher capacities. Other variable costs, such as variable O&M and emissions, are also included in production cost savings.

## Scenarios

Production cost savings were determined for seven planning scenarios, as shown in Table 4. As further described in Chapter 3 of the 2025 IRP Main Document, the scenarios reflect a range of natural gas prices and greenhouse gas pressure (“GHG”). In addition, two 111 GHG Rules-specific scenarios were used for the analyses.

Table 4. Planning Scenarios Included in Analyses

|  |  |  |
| --- | --- | --- |
| Scenario Name | Fuel View | Greenhouse  Gas Pressure View |
| MG0 | Moderate | $0 |
| HG0 | High | $0 |
| LG0 | Low | $0 |
| MG20 | Moderate | $20 |
| MG50 | Moderate | $50 |
| 111-MG0 | Moderate | $0 + 111 |
| 111-MG50 | Moderate | $50 + 111 |

## Upgrade Capital Costs

For the NGCC units, capital costs include expenses paid to the Original Equipment Manufacturer (“OEM”), which in this case is GE, during the upgrade planned outages. In addition, these costs include required improvements to the balance of plant (“BOP”) equipment, apart from the combustion turbines. These BOP improvements include the Heat Recovery Steam Generator (“HRSG”), the Selective Catalytic Reduction (“SCR”) portion of the hot gas path, and the Generation Step-Up (“GSU”) transformers. The following table shows the evaluated in-service capital costs for the combined cycle upgrades.

Table 5. In-Service Capital Cost for Combined Cycle Upgrades (Units 10&11)

|  |  |
| --- | --- |
| Cost Category | In-Service Capital  *(values reflect rounding)* |
| GE Capital Cost | **REDACTED** |
| BOP Capital Cost | **REDACTED** |
| Total | **REDACTED** |

The simple cycle combustion turbine upgrades do not require up front capital expenditures exceeding the budgeted capital for maintenance.

## Capital for Maintenance

Maintenance capital costs are the budgeted capital expenditures necessary to maintain reliable operation. These costs include, but are not limited to, capital replacements and improvements to existing resources. The NGCC maintenance capital budgets will be increased in the first major inspections after the upgrade outages to cover the cost to refurbish the upgraded turbine parts. This increase amounts to **REDACTED** projected for 2032. The simple cycle CT maintenance capital budget will be reduced by over **REDACTED** per outage where a major inspection will be performed.

## Operating & Maintenance (“O&M”) Costs

O&M costs are broken out between fixed and variable O&M for each study. Fixed O&M is directly reflected in the valuation spreadsheet model. Variable O&M, Fuel Costs, and Emissions Costs are netted out of each unit’s energy benefits and are derived by the production cost model. Fixed O&M costs include, but are not limited to, labor, materials, engineering and support services, overhead costs, and other necessary activities to operate a power plant. Fixed O&M is not expected to be materially impacted by the upgrades in either analysis.

## Firm Transportation

The NGCC units require firm transportation of natural gas (“FT”) to secure pipeline capacity, allowing the plant to access natural gas on a reliable basis. Therefore, the cost-benefit analysis includes an incremental cost for the upgrades associated with Plant McIntosh Units 10-11. This incremental cost is as shown in the following table.

Table 6. Firm Transportation for Combined Cycle Upgrades

|  |  |
| --- | --- |
| Volume  (MMBtu/day) | Cost  ($M/year) |
| 30,000 | **REDACTED** |

The simple cycle units at McIntosh do not require FT due to the availability of sufficient onsite fuel oil storage and infrastructure.

## Transmission

Transmission considerations for new resources or capacity additions at existing generation sites, as is the case with the McIntosh upgrades, require evaluation of transmission-related costs. The two primary categories of transmission-related costs are costs associated with delivery of the generation and the cost associated with interconnection of the generator to the transmission system. After evaluation, the NGCC upgrades will require the advancement of two prior-planned transmission projects. The incremental cost of advancement has been included in the analysis. The stability portion of the transmission evaluation has not been completed at time of filing for the NGCC or CT upgrade opportunities. In the event stability analysis identifies any additional costs, the analysis will be updated as appropriate. There are no incremental costs for the CT upgrade opportunity, either for delivery or interconnection.

## Environmental

Environmental analysis is completed for material changes to unit operation or performance to determine whether permitting is feasible and any incremental costs associated with environmental compliance. The evaluation performed as part of the McIntosh upgrade analysis resulted in no major permitting concerns. In addition, there are no incremental environmental compliance costs associated with the upgrade.

# Summary of Results

The results from each analysis demonstrate that the proposed unit upgrades are cost-effective for all scenarios evaluated, when compared with the existing unit configurations, as shown in Table 7. These results also demonstrate that these upgrades are a low-risk investment. Positive values in the following table indicate a net benefit to customers resulting from the evaluated upgrades. All results demonstrate that the upgrades are in the best interest of customers.

Table 7. Thermal Upgrade Cost-Benefit Results

|  |  |  |  |
| --- | --- | --- | --- |
| 2025 NPV (M$) | Combined Cycles (Units 10&11) |  | Simple Cycles (Units 1-8)  With Incremental Capacity |
| MG0 | **REDACTED** |  | **REDACTED** |
| HG0 | **REDACTED** |  | **REDACTED** |
| LG0 | **REDACTED** |  | **REDACTED** |
| MG20 | **REDACTED** |  | **REDACTED** |
| MG50 | **REDACTED** |  | **REDACTED** |
| 111-MG0 | **REDACTED** |  | **REDACTED** |
| 111-MG50 | **REDACTED** |  | **REDACTED** |

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1. Outage year reflects calendar year in which the unit is upgraded during a planned maintenance outage. The years in the columns to the right represent incremental capacity in January of the stated year. [↑](#footnote-ref-2)