8. Transmission Assessment

8.1 Introduction

Transmission analysis plays an important role in the overall MLGW IRP process. Currently TVA supplies all the power to meet MLGW's demand under an All Requirements Contract. As previously discussed, if MLGW were to leave TVA and terminate the contract, there are a series of implications (refer to Section 2 of this report) including TVA's position that TVA will not provide wheeling services to MLGW through its transmission system to MISO and TVA will also require MLGW disconnect from its facilities and build an independent transmission system connecting it to MISO. As was presented in Section 2, we refer to this situation as the "No Deal" scenario where no middle ground can be found, not even for providing mutual support during emergencies.

Since there are no existing transmission connections between MLGW and MISO, reliable and adequate transmission projects would have to be constructed for MLGW to take advantage of the MISO market.

This section describes the transmission expansion plans and local reliability reinforcements proposed by Siemens in order for MLGW's system to be fully interconnected with MISO and to be able to meet all the MLGW's future demand in a reliable, secure, and economic way. The least cost portfolio screening analysis determined the lowest cost portfolios from a given transmission investment. The only way to fully evaluate the trade-offs between transmission and generation investments were to determine least cost portfolios for different levels of transmission investments.

As a result, the transmission analysis both supported and received input from the generation portfolio screening process. Thus, multimillion-dollar transmission investment levels for Strategy 4 (All MISO Strategy) could become valid alternatives if they generated savings on the generation investments. We describe these alternative transmission configurations and their investments in the following sections.

The total transmission investments were initially estimated for a generation portfolio consisting of three 1x1 combined cycle gas turbines with a summer capacity of 414 MW each, one combustion turbine at 215 MW, and 600 MW solar PV (in line in 2025) connected to MLGW system. The required investments amount is approximately $700 million (2018 $) including a 10% contingency, which can be divided into four main components:

- Transmission expansion costs of $376 million; this investment is largely independent of the size of the local generation portfolio.
- Local reliability reinforcement costs of $184 million; this investment is directly related with the local generation portfolio.
- Generation interconnection transmission costs of $88 million; this amount is a function of the units in the portfolio.

- Reimbursements to TVA (to reconnect the Allen combined cycle plant and for reliability upgrades near South Haven generation plant) of $47 million.

The total capital expenditure given above is for the portfolio outlined, and it varies somewhat among different Strategy 3 portfolios due to various levels of transmission requirements and or the number of generation sites. If there is a need for higher import capability from MISO, as in Strategy 4, the all MISO Strategy, it requires more transmission capital investments. Portfolios with reduced amounts of local generation, typically as a function of the number of thermal generation plants in the portfolio, will also require more transmission capability. Hence, Siemens' analysis considers both the generation cost and the transmission cost in determining the least cost portfolio.

Steady state power flow analysis, transfer analysis, stability analysis, and production cost economic analysis are the main transmission analyses performed and discussed in this section.

The Siemens transmission team developed the transmission plans in collaboration with the MLGW team to identify any constraints and challenges in designing the transmission plan. Siemens also worked with MISO to ensure the reasonableness of the assumptions used to develop the transmission plan. Collectively the process ensures the transmission plan is not only feasible, adequate, and reliable, but also efficient.

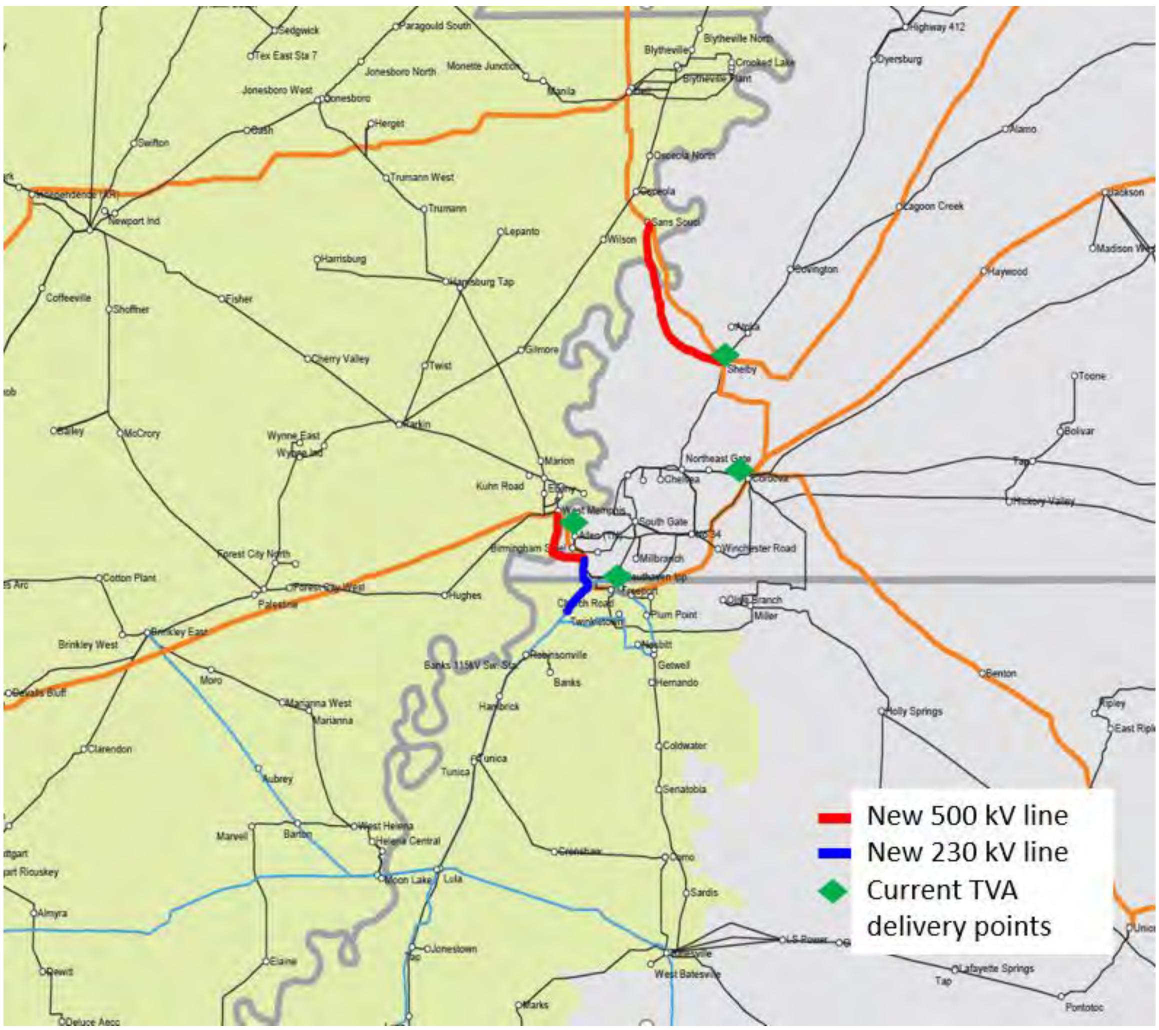
8.2 Transmission Expansions

The transmission expansions required for Strategy 3 under reference case assumptions will serve as the backbone for MLGW to interconnect with MISO systems and replace the four current TVA delivery points (Shelby, Cordova, Allen, and Freeport) if MLGW were to join MISO. Based on the transmission network topology in the region and the considerations of various constraints, three (3) new interconnections are proposed:

1. San Souci-MISO to Shelby-MLGW Interconnection consisting of:
   a. New San Souci-MISO to Shelby-MLGW 500 kV line: 2598/2598 MVA summer rating (approximately 26 miles), and
   b. New Shelby-MLGW 500/161 kV substation with two new 500/161 kV transformers, 1300 MVA each.
2. West Memphis-MISO to New Allen-MLGW Interconnection consisting of:
   a. New West Memphis-MISO to New Allen-MLGW 500 kV line: 2598/2598 MVA summer rating (approximately 8.5 miles), and
   b. New 500/230/161 kV substation, New Allen-MLGW with two new 500/161 kV transformers, 1300 MVA each.
3. Twinkletown-MISO to New Allen-MLGW interconnection consisting of:
   a. New Twinkletown-MISO to New Allen-MLGW 230 kV line: 1991/1991 MVA summer rating (approximately 8 miles), and
   b. Two new 230/161 kV transformers, 1000 MVA each.

The three interconnection projects above interconnect with MISO South – with the 500 kV system in eastern Arkansas and the 230 kV system in northern Mississippi – these systems are relatively close to MLGW's service territory to optimize the economic balance between local generation investments and capital investments on transmission. The transmission expansions are shown on the MISO geographic map below, where MLGW's transmission systems are represented by the lines inside of the current TVA delivery points (shown as green diamonds) at the center of the map, and the MISO South systems are represented by the yellow area covering the western portion of the map.

Exhibit 82: Transmission Expansions Geographic Map



Source: MISO

The total capital expenditure for the proposed baseline transmission expansion is estimated to be $376 million (2018$) including a 10% contingency. The cost estimation of each project is as follows:

1. $199 million for Shelby (MLGW) to San Souci (MISO) 500 kV line and new Shelby-MLGW 500/161 kV substation and transformers
2. $130 million for West Memphis (MISO) to New Allen (MLGW) 500 kV line and New Allen (MLGW) 500/230/161 kV substation and transformers
3. $47 million for Twinkletown (MISO) to New Allen (MLGW) 230 kV line and transformers

These are greenfield projects with only preliminary routings within the scope of this IRP. However, the development risks associated with these three projects are believed to be low. It should take approximately 3 to 5 years to complete the project assuming all interconnections can be developed simultaneously. Final cost estimations are subject to refinement during detailed engineering design prior to implementation.

Existing connections at the four delivery points between MLGW and TVA would be opened under the "No Deal" assumption. There will be no direct connection between MLGW and TVA in the proposed future configurations, not even for emergency backup. However, should TVA be willing to keep the remaining delivery points connected, MLGW would enter the negotiations with TVA and share cost obligations. Siemens refers to it as the "Deal" scenario if TVA is willing to remain connected with MLGW after the departure of MLGW. Siemens views the "Deal" scenario as mutually beneficial to both parties (under the circumstance where MLGW exits the TVA relationship) and the connection would provide valuable and undeniable reliability and resiliency benefits for the entire eastern interconnection of the U.S. power grid.

8.3 Reliability Reinforcements

Siemens performed steady state power flow analysis on the 2025 summer peak conditions following NERC TPL-001-4 reliability standards on N-0, N-1, and N-1-1 contingencies. The local MLGW generation, as discussed above, was based on the generation portfolio with three 1x1 combined cycle gas turbines at 414 MW each, one combustion turbine at 215 MW, and 600 MW solar PV dispatched at 30% capacity. Approximately 145 miles of local 161 kV MLGW owned transmission lines were identified for upgrades to avoid any potential reliability violations under the proposed transmission expansion plan. The estimated total upgrade costs are approximately $164 million (all costs are in 2018$). Also, a list of facilities appeared to be terminal limited and were recommended to be upgraded with an estimated cost of $3.5 million. In addition, one of the Entergy-MISO owned Freeport to Twinkletown 230 kV lines needs to be rebuilt/reconductored at an estimated cost of $16.5 million. These reliability reinforcements result in a total cost of $184 million.

Implementation of these reliability upgrades appears to be very low risk, as no new right-of-way is required, and these upgrades are included in the baseline transmission portfolio. However, final determination on the list of facilities to be reinforced and associated cost estimates is subject to full detailed engineering review prior to implementation.

8.4 Transfer Analysis

Siemens performed the First Contingency Incremental Transfer Capability (FCITC) analyses using a Single Transfer option in PSS®MUST on the power flow case with proposed transmission expansion and necessary reliability reinforcements in place. Summer peak load conditions were used to determine the maximum import capability required. Generation in MISO South, specifically Entergy Arkansas and Mississippi, are economically dispatched along with generators inside MLGW. MISO-MLGW Interface is defined as the group of the three new transmission interconnection lines and transfer levels are assessed under N-1 contingencies (P1) in the entire study footprint (including TVA).

Based on the analysis performed on the baseline transmission configurations, approximately 2,568 MW of power can flow on the MISO-MLGW interface without thermal violations under N-1 conditions.

Upon further review of the FCITC results, Siemens determined that all the thermal overloads identified are on MLGW internal transmission lines. Therefore, it is possible to upgrade those lines to achieve higher import capability to allow the specific LTCE portfolio to meet all its import requirements.

Incremental transmission investments are shown in Exhibit 83, along with the increased transfer levels those investments facilitate. For example, for $36.7 million in upgrades, it is possible to increase the import capability from 2,568 MW to 2,774 MW. Higher import capabilities can ensure resource adequacy for MLGW by taking advantage of the resources in MISO and at the same time maximizing the capability of integrating new renewable generation. During the analysis, the incremental costs for the upgrades required to meet each LTCE portfolio transfer capability requirement was added to the baseline transmission portfolio costs. For example, if the LTCE portfolio requires 2,950 MW of import capability (therefore requiring $70 million in upgrade costs), the total estimated transmission capital expenditure would be approximately $770 million.

Exhibit 83: Incremental Transfer and Associated Upgrade Costs

FCITC (MW)	Interface Transfer (MW)	Incremental Cost ($M)	Total Upgrade Cost ($M)
897	2568	13.4	13.4
1067	2738	3.9	17.3
1078	2749	10.3	27.6
1103	2774	9.1	36.7
1132	2803	15.0	51.7
1252	2923	5.7	57.4
1253	2924	8.2	65.6
1280	2951	4.5	70.1
1285	2956	11.1	81.2
1293	2964	10.6	91.8
1294	2965	7.1	98.9
1306	2977	7.1	106.0
1375	3046	7.4	113.4
1453	3124	1.2	114.5
1521	3192	7.6	122.1
1541	3212	4.7	126.9
1560	3231	2.6	129.5
1611	3282	4.3	133.7
1672	3343	4.4	138.2
1677	3348	3.6	141.8
1738	3410	4.1	145.9
1796	3467	2.5	148.5
1824	3495	6.4	154.8

Source: Siemens

The export (from MLGW to MISO South) limit under this proposed transmission plan is studied on light load conditions (1400 MW load level) where MLGW generation dispatches are at maximum. The export capability is approximately 1,600 MW. However, the export capability is not as critical as the import capability because MLGW is not expected to have much surplus generation available to export (perhaps only during limited high PV production hours with very low load).

8.5 Capacity Import Limits

For the resource adequacy assessment, Siemens, in coordination with MISO, assessed the capacity import capability (CIL) of MLGW using MISO procedures and its preferred tool, Transmission Adequacy and Reliability Assessment (TARA®). The results were almost identical to the results obtained with PSS® MUST. With baseline transmission configurations, the CIL for MLGW was found to be 2,579 MW (compared to 2,568 MW with PSS®MUST) and with $36.7

million in upgrades, it was identified that the import capability could be increased to 2,783 MW (compared to 2,774 MW with PSS® MUST).

Currently, to be conservative, a 2200 MW import limit and a 1500 MW export limit are used for all scenarios for Strategy 3 (the Self-Supply plus MISO Strategy) analysis.

8.6 Steady State Analysis/Interconnection Assessment

Siemens performed numerous steady state contingency analyses based on the proposed transmission expansion plan using NERC TPL-001-4 reliability standards. Unlike the transfer analysis described above that identified the capacity import capability that would support the system in case of generation outages, this analysis considers the impact of simultaneous contingencies of the transmission system that would affect the reliability under various operating conditions. The limits from this study should be equal to or larger than the 2200 MW import limit and 1500 MW export limit given to the zonal AURORA LTCE models for the Self-Supply plus MISO Strategy analysis.

8.6.1 Assumptions

MISO MTEP19 power flow cases are used as the starting base cases. Both day-peak and night-peak in the summer peak conditions are analyzed. The study year selected was 2025, though 2035 was also studied when all the planned generation is expected to be in service. Shoulder load conditions were also studied to ensure extended maintenance can be carried out during the off-peak (shoulder) months.

Bulk Electric System (BES) of 100 kV and above transmission facilities in MLGW, Entergy Arkansas, Entergy Mississippi as well as TVA were monitored for thermal and voltage violations under NERC Category P0 system intact and P1 through P7 contingencies.

Any reading 100% of Normal facility rating (Rate A) under system intact or over 100% of emergency facility rating (Rate B) under contingencies conditions may be considered thermal violations. Bus voltages must be maintained with 0.9 p.u. to 1.05 p.u. and must not deviate more than 0.08 p.u. under contingencies, otherwise may be considered voltage violations. Branch loadings and voltages are compared between base case and future changed case.

8.6.2 Cases Studied

Contingency analyses were performed on the following power flow cases with different generation dispatches or demand levels:

- 2025 Summer Day-Peak with normal dispatch (CC and PV online, no CT)
- 2025 Summer Night-Peak with normal dispatch (CC online, no PV)
- 2025 Summer Day-Peak max generation (all MLGW generation at max)
- 2025 Summer Day-Peak max import (reduced local generation to create max import)
- 2025 Shoulder Load with normal dispatch (CC and PV online, no CT)
- 2035 Summer Day-Peak with max generation

8.6.3 Results

No reliability violations were observed under system intact (N-0). In most of the cases assessed, there were no significant thermal or voltage reliability violations observed under either N-1 or N-1-1 contingent conditions. The system is believed to be reliable by meeting TPL-001-4 performance criteria under those conditions. The import limit was over the 2,200 MW used in AURORA and the export limit is over 1,500 MW as required.

In the two maximum generation dispatch cases, the system is believed to be reliable, however, some level of curtailment on renewable generation may be necessary to resolve some minor overloads. The actual curtailment would depend on the day-ahead and real-time system operations at the time. Conducting a full nodal production cost analysis will help to identify if this is the case and under what conditions.

In the 2025 Summer Day-Peak max import case, some minor overloads were identified under overlapping N-1-1 contingencies. N-2 events are very rare during summer peak conditions as most of the line maintenances are typically scheduled during off-peak months, and even more rare that MLGW local renewable generation would also be at low output. Otherwise most of the N-1-1 overloads can be mitigated by ramping up local generation. The system is believed to be reliable, and although load shedding is allowed per the TPL-001-4 standards, no load shedding is expected to be necessary.

There is one TVA 230 kV line from Freeport to South Haven that is overloaded under N-2 contingencies which cannot be fully mitigated by MISO or MLGW generation redispatch. The line is only 0.67-mile-long, and it should be upgraded at the expense of MLGW to TVA at approximately $2 million. These costs are included in the total required transmission investment. After that investment is made, the system is believed to be reliable.

8.7 Additional Transmission for the All MISO Strategy

An All MISO strategy (Strategy 4) has also been assessed in the IRP. The All MISO strategy requires that the entire MLGW demand is served by existing and future generation resources located in current MISO footprint, e.g. Arkansas, with no local generation allowed

This strategy was run to determine how high the transmission costs needed to be to supply the entirety of MLGW's load without the benefit of local generation. While local generation is the lowest cost generation available to MLGW, which ensures Strategy 4 is not least cost, PSAT wanted to determine the costs required to have an All MISO solution.

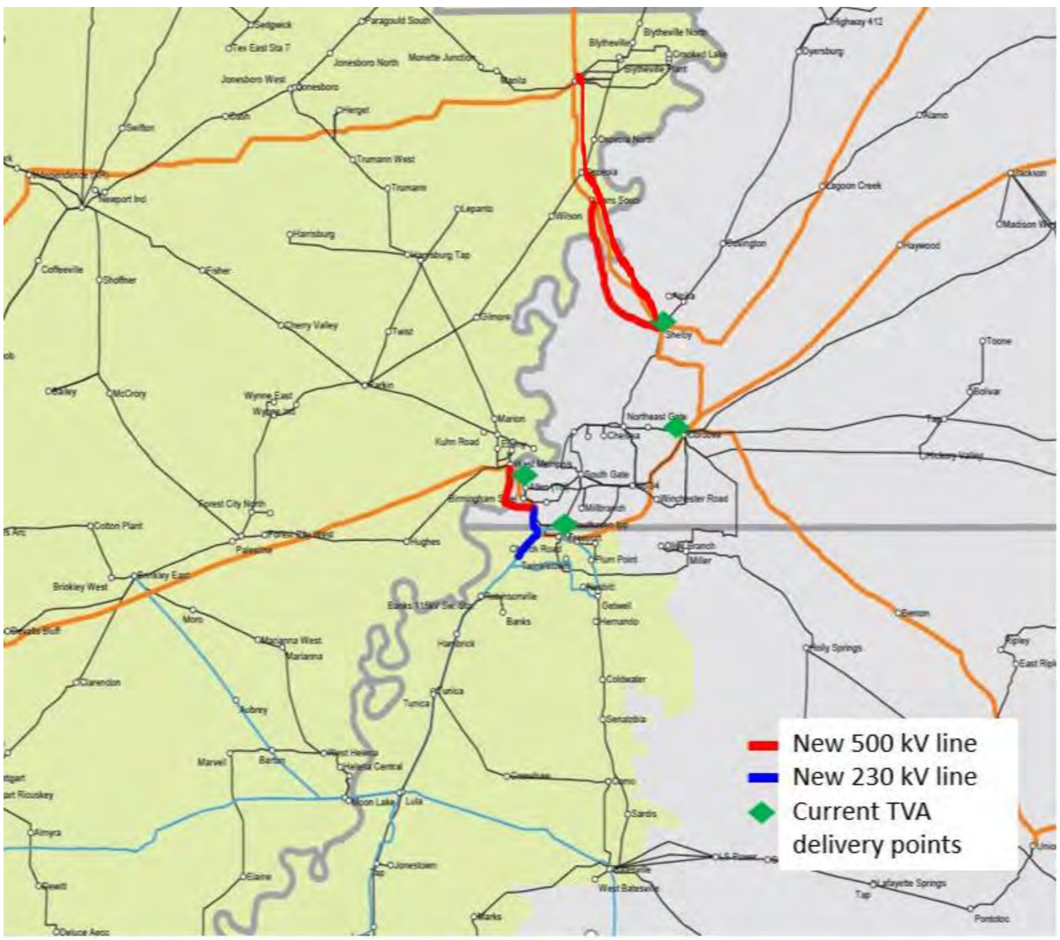
For this strategy to be feasible from the transmission perspective, additional interconnections to MISO are required in addition to the three interconnections in the baseline transmission plan; this is due to the risks associated with losing two or more interconnections. Because there is no local MLGW dispatchable generation under pre-existing contingency, at a minimum, N-2 events should be assessed to determine the applicable import capability. MLGW also needs to have a minimum firm import of 3500 MW under N-2 conditions without any reliability violations to meet MISO's 108.9% planning reserve margin resource adequacy requirement.

The base transmission plan, as currently proposed, does not provide this level of import capability, and as a result a fourth interconnection transmission project has been proposed as described below, followed by a geographic map showing all four interconnection lines.

Dell-MISO to Shelby-MLGW Interconnection consisting of:

a. New Dell-MISO to Shelby-MLGW 500 kV line: 2598/2598 MVA summer rating (approximately 44 miles), and
b. Two new 500/161 kV transformers, 1300 MVA each at the new Shelby 500 kV substation.

Exhibit 84: Transmission Expansions for All MISO Strategy



Source: MISO

The total capital expenditure for this additional project is estimated to be $248.3 million (2018$) including a 10% contingency.

In addition, a total of 140 miles of local 161 kV MLGW owned transmission lines were identified for upgrades to avoid any potential reliability violations to achieve a transfer capability of more than 3500 MW under N-2 conditions. The estimated costs to upgrade these lines are approximately $158.9 million (2018$).

For the All MISO strategy, the total additional transmission capital cost is $407.2 million. This includes costs for the 4th interconnection project, and the upgrade of the 140 miles of local transmission lines. When this additional cost for the All MISO strategy is added to the $700 million (2018$) needed as discussed in Section 8.1, the total capital investment on transmission system is approximately $1,014 million, excluding any applicable generation interconnection costs and well over $1.1 billion including the interconnection costs. These transmission investments, when expressed as a function of the present value of the load served, represent about $1.24/MWh of 2025-2039 NPV assuming 30-year repayment.

Full steady state contingency analysis has been performed for N-1 and N-1-1 contingencies under this topology and the system is found to be reliable with no thermal or voltage violations for the 2025 Summer Day-Peak condition without any local generation within MLGW.

8.8 Stability Analysis

Considering the limited interconnection points and local synchronous generations and reactive support within the future MLGW system if MLGW were to join MISO, it is necessary to evaluate the dynamic performance of the MLGW electric system under disturbances. The objective of the dynamic simulation analysis is to verify that the selected generation portfolio presents a secure operation from a transient stability perspective.

8.8.1 Portfolio Description

The analysis was carried out considering a generation portfolio with two CCGTs, two GTs and 600 MW of photovoltaic generation located inside of MLGW's footprint. However, the analysis is also applicable to portfolios with one CCGT and one CT.

Generation was assumed to be connected to the Chamber Chapel substation in the northeast side of Shelby County and consists of one combined cycle in 1x1 configuration (CCGT) and a combustion turbine (CT). The same generation arrangement was considered at Collierville substation in the southeast side of Shelby County.

The summer capacity of the combined cycle is 414 MW from which 89 MW are supplied by supplemental firing (duct firing). The combustion turbine capacity was estimated in 228 MW (F-class) while the steam turbine at 97 MW.

The gas turbine (F-class) was considered with a summer peak capacity of 215 MW.

The photovoltaic generation was modeled with a maximum capacity of 600 MW from which 300 MW were located at Austin Peay substation in the north of Shelby County and another 300 MW at New Allen substation in the southwest side of Shelby County.

8.8.2 Simulated Case

The 2025 summer peak maximum import case was created by reducing the internal generation of MLGW system to 350 MW of which 180 MW supplied by the two photovoltaic facilities operating at 30% of its capacity and the remaining 170 MW from Chamber Chapel combined cycle operating at minimum load. The generation at Collierville substation was assumed out of service as well as the CTs.

This resulted in a total import of approximately 2850 MW (3200 MW summer peak load minus 350 MW generation), presenting a highly stressed condition where most of the thermal resources are offline. The reactive power support is only provided by the photovoltaic power plants as well from the Chamber Chapel combined cycle.

8.8.3 Dynamic Models

The MTEP19 dynamic simulation package of 2024 summer peak MISO19_2024_SUM.sav provided by MISO was used for the base case dynamic setup. The dynamic models for the new MLGW generation units were added to the existing setup.

The combined cycle units and gas turbines were modeled with exciter model (ST6B) and provided with a power system stabilizer (PSS2B). The primary frequency response was considered with a 4% droop only on combustion turbines (GGOV1).

Photovoltaic generation was modeled with the latest WECC approved models (REGCA, REECA and REPCA).

8.8.4 Contingencies

The following contingencies were simulated to evaluate the dynamic performance against critical events. These contingencies are associated with the proposed new transmission interconnections between MLGW and MISO.

- Three-phase fault at Shelby MLGW 500 kV: trip of both 500/161 kV transformers
- Three-phase fault at New Allen 500 kV: trip of New Allen – Memphis 500 kV line
- Three-phase fault at New Allen 230 kV: trip of New Allen – Twinkletown 230 kV line
- Loss of the Chamber Chapel combined cycle (three-phase fault at the point of interconnection)

The three-phase faults were assumed to be cleared after 6 cycles by removing the faulted elements.

Voltages at 161 kV and 115 kV were monitored for all MLGW buses. Shelby 500 kV, New Allen 500 kV and 230 kV buses were also monitored. All internal generation were also monitored.

8.8.5 Simulation Results

In the following Exhibits, the simulation results are provided, and it shows fast voltage recovery for the MLGW power system and no instabilities. The generation show adequate damped response. Reactive power compensation devices such as Static Synchronous Compensator (STATCOM) or Static VAR Compensator (SVC) to provided dynamic voltage support are not deemed necessary for the conditions modeled.

Exhibit 85: Fault at Shelby 500/161 kV Transformers (2025 summer peak) – Bus Voltage [p.u.]

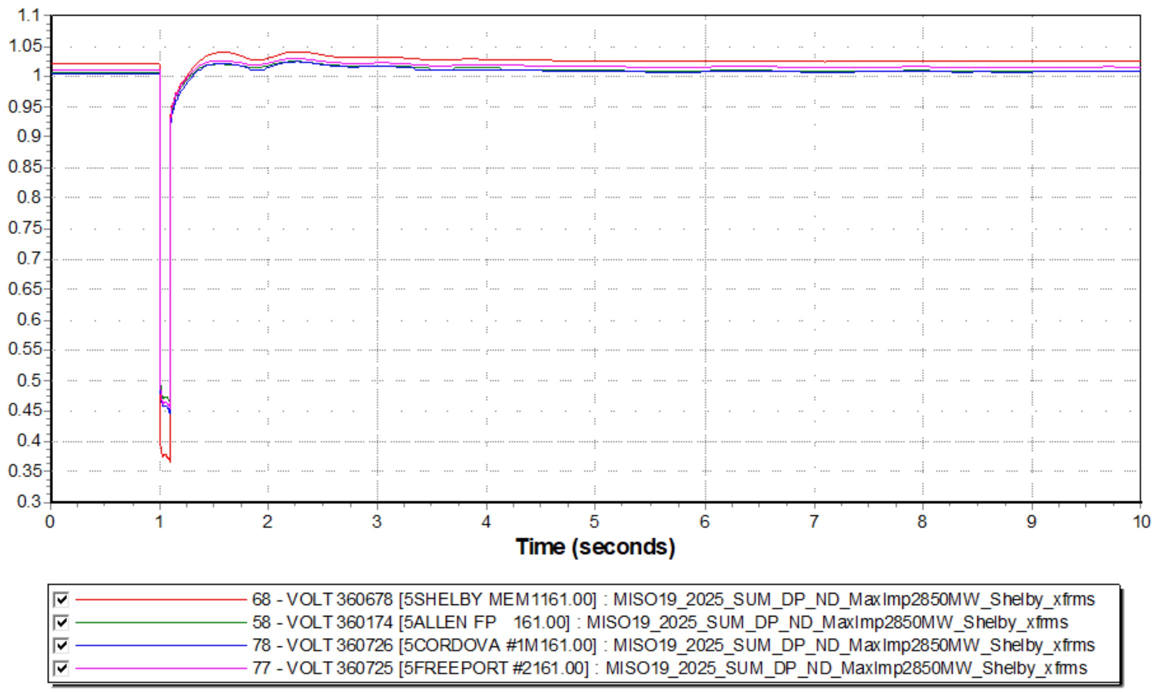
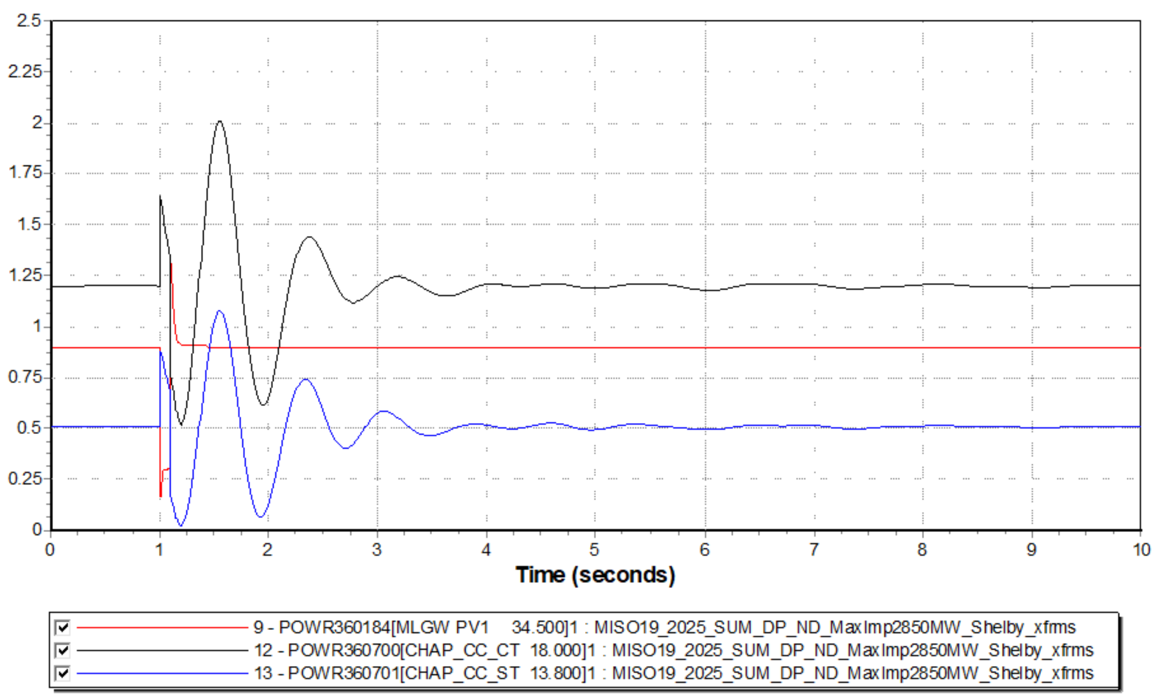


Exhibit 86: Fault at Shelby 500/161 kV Transformers (2025 summer peak) – PV and C. Chapel CC Active Power [p.u.]



Source: Siemens

Exhibit 87: Fault at New Allen 500 kV (2025 summer peak) – Bus Voltage [p.u.]

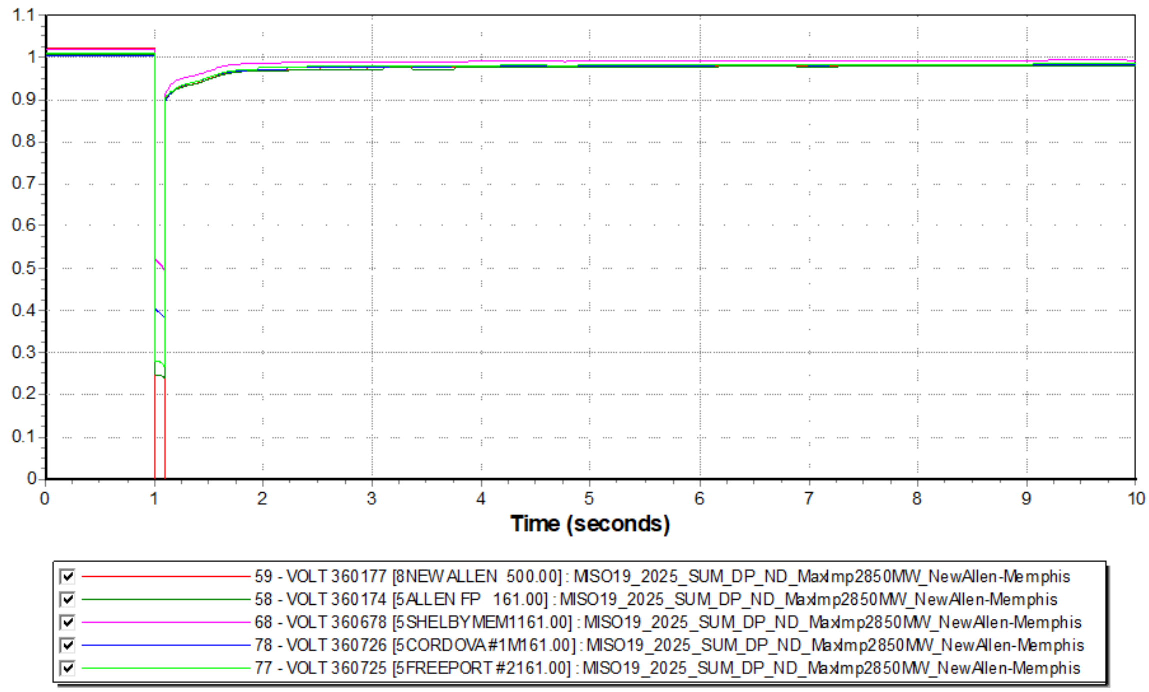
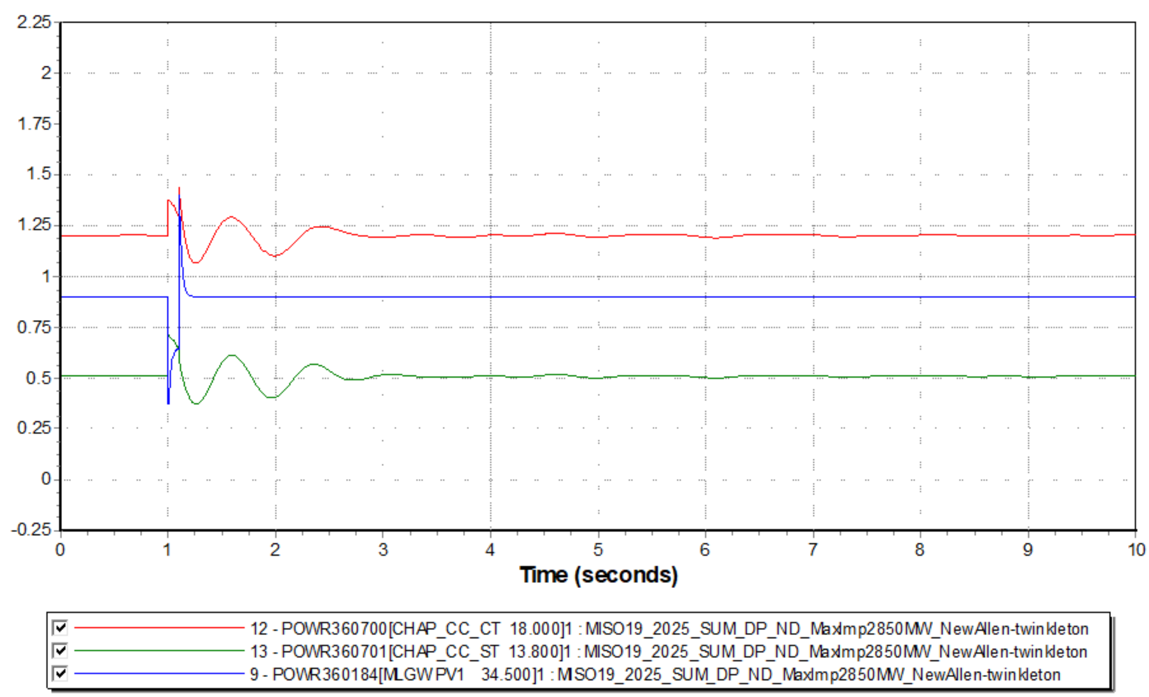
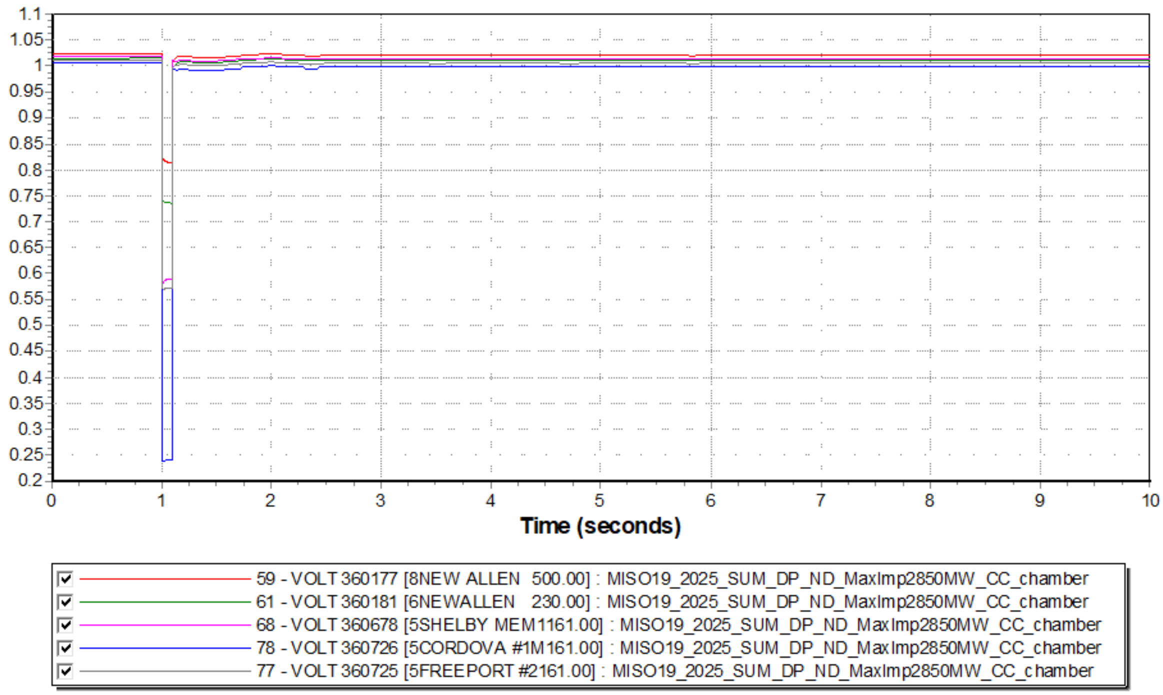


Exhibit 88: Fault at New Allen 230 kV (2025 summer peak) – PV and C. Chapel CC Active Power [p.u.]



Source: Siemens

Exhibit 89: Fault at C. Chapel CC (2025 summer peak) – Bus Voltage [pu].



Source: Siemens

8.8.6 Conclusions

The analysis was carried out considering a generation portfolio with two CCGTs, two GTs and 600 MW of photovoltaic generation located inside of MLGW's footprint. However, the analysis is applicable for any portfolios with 2 CCGTs and 1 CCGT. The MISO MTEP19 2024 summer peak dynamic package was used as the base case. The 2025 summer peak condition was simulated with a heavily stressed scenario with maximum import. The dynamic simulation analysis indicated a satisfactory performance of the MLGW system against critical faults under the selected expansion portfolio and maximum import conditions. Any Portfolios with more local generations or less import is expected to produce even more satisfactory dynamic performance results. Furthermore, the operation at reduced generation inside MLGW did not require any additional reactive power compensation devices.

8.9 Nodal Production Cost Analysis

Siemens is currently conducting a supplementary nodal production cost analysis using PROMOD® IV to fully evaluate the system congestion and economic performance of the preferred LTCE plans. MISO MTEP20 PROMOD Powerbase Databases were selected as the starting base cases. Studies will be carried out by staging the various resources from the final preferred LTCE plans over the years into the production cost models. Hourly nodal simulations are being conducted in 2025, 2030, and 2035. Various metrics including, but not limited to, total system production cost, flow-gate congestion, LMP prices, generator productions and revenue, market purchases and sales, renewable curtailment, fuel and environmental costs, etc. will be evaluated to attest to the efficacy of the analysis. This work is ongoing at the time of IRP this initial report and the result is expected to be included in the final IRP report. No congestion is expected; confirmed by a review of the independent studies carried out by MISO.

8.10 Capital Cost Estimation

Siemens provides transmission planning level cost estimation based on itemized scope of each transmission project as part of the transmission analysis in the scope of this IRP.

The estimated total transmission capital expenditure for three lines used in Strategy 3 is approximately $552 million without contingency based on the proposed baseline transmission expansion, local reliability upgrades, and the total generation interconnection related costs for three thermal sites are $80 million without contingency for a total of $632 million transmission related capital costs.

A 16% contingency covering areas such as scope changes, risks associated with right-of-way, permitting/approval and land acquisition, uncertainty to construct transmission projects out-of-state, material cost fluctuations, dispute and litigation, etc. was added on top of the base estimation. Also, a 5% cost saving was assumed to reflect synergies in developing multiple large transmission projects simultaneously and sharing on common services. The combined effect of the two resulted in a net 10% contingent, approximately, for cost overruns. Therefore, the total estimated transmission capital expenditure is approximately $696.5 million, or $2.11/MWh of 2025-2039 NPV assuming 30-year repayment schedule for the Base Strategy 3 investments.

Cost estimation was performed on every LTCE portfolio including the All MISO strategy based on the specific transmission needs. Portfolios which require higher import capabilities will see higher total transmission costs as discussed later in this report (Section 12).

8.11 Transmission O&M

Cost on transmission system operation & maintenance (O&M) is also a component of the “All-in” cost in the IRP. MLGW, as a current transmission owner/operator, carries a transmission O&M budget for maintaining its local transmission systems consisting mostly of 161 kV facilities and some 115 kV facilities. The newly proposed 500 kV and 230 kV high voltage transmission facilities in the baseline transmission portfolio will be foreign to the MLGW’s existing fleet and would significantly increase the O&M budget in the future as projected.

The incremental transmission O&M costs need to be captured appropriately in the overall costs. The general approach to estimate the annual O&M cost is based on a percentage of the transmission capital expenditure and is typically around 2-3%.

In this IRP, the incremental transmission O&M costs are assumed to be applicable on the capital costs of the new transmission expansion projects and a portion of the local upgrades, and if assuming a 2.5% factor, this cost is approximately $9.4 million on an annual basis 2025-2039, or $0.70/MWh of 15-year NPV for the baseline transmission plan. Finally, for the All MISO strategy, the 15-year NPV is approximately $0.89/MWh.

9. Other Costs

This section includes other costs that MLGW would have to cover if it were to give notice to TVA and become a MISO Member. These costs include:

a. Payments in Lieu of Taxes as a result of the new activities in power generation that MLGW will undertake
b. Continuation of services currently provided by TVA
c. MISO Membership costs

9.1 Payment in Lieu of Taxes

MLGW, as a non-profit municipal public utility, is responsible for compensating the state and local government by means of payment in lieu of taxes (PILOT) for some or all the property tax revenue lost due to its tax exemption status.

As a benefit to MLGW under the current All Requirements Contract with TVA, TVA paid a PILOT of approximately $18.2 million in fiscal year 2018 that would otherwise be the responsibility of MLGW[36].

If MLGW were to terminate the contract with TVA, MLGW would have to assume full PILOT responsibility to the state and local government. This is an important component that falls under the category for cost recovery for MLGW and needs to be properly estimated for an appropriate comparison to TVA.

MLGW would incur a PILOT imposed by the state and Shelby County, where the state PILOT is based on total power sales and the local PILOT is based on transmission and/or generation physical assets owned by MLGW in the county.

The estimated annual PILOT for MLGW would be approximately $4.1/MWh based on the NPV of the last 15 years of the planning period (2025-2039) after MLGW gives notice, divided by the NPV of the energy delivered. There is +/- $0.5/MWh variance in this value among different LTCE portfolios.

The PILOT factors used in the calculation were based on the information provided to Siemens by MLGW. Some of the assumptions could change based on future state and or local legislatures.

[36] Source: Memphis Summary of Benefits v3.pptx

9.2 PILOT Calculations

MLGW's PILOT responsibility is split into two categories, the state PILOT and the local PILOT.

9.2.1 State PILOT

Currently the state of Tennessee charges entities who wholesale electricity based on the power sales within the state under Section 4 of Public Chapter 475, Acts of 2009 and Public Chapter1035, Acts of 2010 passed by Tennessee General Assembly. If MLGW leaves TVA, it would be a wholesale electricity distributor in the state and thus would be required to pay the state PILOT.

In this IRP under Strategy 3, the cost of wholesale power from all sources is the cost of all generation resources plus all the power purchases from MISO markets, less market sales outside of the state.

Under current assumptions, if MLGW were to leave TVA, MLGW would pay a state PILOT factor of 5% on the costs from all resources; the amount varies among different LTCE portfolios.

For example, if the all resources costs for a given portfolio have an NPV of $9.5 billion for the last 15 years (2025-2039) of the planning horizon, the state PILOT would be $475 million, which would result in approximately $2.62/MWh, or roughly $35 million per year.

9.2.2 Local PILOT

The second category of PILOT is the local PILOT charged by the respective counties in which MLGW constructs and owns generation and/or transmission facilities, if MLGW were to leave TVA. In this IRP all generation facilities are assumed to be owned by third parties that would enter into a Power Purchase Agreement with MLGW, therefore the developer will be paying property and income taxes, and MLGW will not be subject to a PILOT. Transmission, on the other hand, will be developed by MLGW and will incur PILOT. As these new or reinforced assets will only be used and useful after separation from TVA, it is assumed that the counties will start to collect PILOT starting the first year when MLGW leaves TVA (2025).

We assume the same local PILOT factor will apply to Shelby as to other counties; the rate is based on the total transmission capital expenditures starting from 2025 in the last 15 years of the planning horizon (2025 to 2039). The PILOT factor will start from 4% in 2025 and decrease 1/30th every year thereafter (4.00%, 3.87%, 3.73%, 3.60%...).

For example, if there were $700 million worth of new transmission assets starting in 2025, MLGW would have to pay local PILOT for 4% x $700 million = $28 million, and if no more transmission was built, the local PILOT for 2026 would be $27.1 million. Levelized over the last 15 years (2025-2039) of the planning horizon, the PILOT is estimated to be approximately $1.50/MWh.

As mentioned above, MLGW is not expected to pay PILOT on the generation facilities developed in local counties, as we assume all generation will be developed by 3rd parties who will own the generation plants and pay property taxes. However, if MLGW were to build and own generation plant(s) in local counties, then MLGW would be required to pay the local PILOT. However, there would be offsetting economies as MLGW, as a non-profit municipal public utility has a lower cost of capital than for profit developers.

9.3 TVA Services

9.3.1 Summary

TVA, as the wholesale power supplier, has been providing economic benefits to its local power companies (LPC) and their communities. These benefits include direct spending by TVA such as investments, grants, energy efficiency programs, PILOT, etc., and indirect benefits such as economic growth, job creation, and business attraction.

TVA has provided Siemens with a high-level summary of benefits [37] for the Memphis communities. If MLGW were to leave TVA, these benefits are expected to be discontinued by TVA. For continuity for communities in the Memphis area, MLGW will have to at least maintain the same level of benefits to the communities; for this MLGW will incur additional costs.

The total direct spending by TVA on economic benefits to Memphis communities was between $67.97 to $72.97 million in fiscal year 2018. Excluding PILOT (which is calculated separately) and excluding revenue from transmission leases (which is not applicable), the net benefits spending provided by TVA was between $12.67 to $17.67 million in 2018. If MLGW were to leave TVA, it is expected that MLGW would spend similarly if not more on benefits to the communities in the next 20 years. In this remainder of this section, we will break down each item and estimate the necessary costs for MLGW to maintain these benefits in the future.

For high level estimation purpose, if MLGW were to leave TVA, at a minimum, MLGW is expected to spend $13 to $15 million per year as economic benefits to the communities in the Memphis area for the next 20 years, or about $1/MWh on the NPV basis for the planning period.

9.3.2 Economic Development Benefits

Current economic development benefits provided by TVA include investment credits, performance grants, etc. to the Memphis communities, as well and TVA's direct spending, which ranged between $10 to $15 million in fiscal year 2018. If MLGW were to leave TVA, MLGW should expect to replenish/continue these benefits, and should expect the cost to be at least $10 million per year.

9.3.3 PILOT

As discussed in the PILOT section, TVA is paying state and local PILOT on behalf of MLGW. If MLGW were to leave TVA, it would assume all PILOT costs on its own. The cost of future PILOT for MLGW has been estimated in the PILOT section in the report.

[37] Memphis Summary of Benefits v3.pptx

9.3.4 Community Benefits

This category of benefits mainly includes the Home Uplift (weatherization) program and other energy efficiency programs. TVA's direct spending on these programs was $2.2 million in fiscal year 2018. If MLGW were to leave TVA, MLGW would be expected to spend on new energy efficiency programs for system-wide customers, starting the first year after giving TVA contract termination notice. Total average annual energy efficiency cost for MLGW is estimated to be $6 to $7 million as discussed in the section of energy efficiency as a separate cost component. To simplify the estimation, we assume $2.2 million per year to be spent by MLGW in this category.

9.3.5 Community Investments

This category of benefits includes TVA's investments in local schools, local organizations, and non-profits. TVA's direct spending was in these areas was $0.33 million in fiscal year 2018. If MLGW were to leave TVA, MLGW would be expected to spend on the same level or more per year to continue these programs.

9.3.6 Revenue from Transmission Lease

TVA leases the use of some of the MLGW's 161 kV transmission lines in the area and claimed about $37 million in revenue to MLGW for this purpose. If MLGW were to leave TVA, as the departure of MLGW would cause electrical separation between MLGW and TVA, this revenue will go away, but MLGW will incur no cost for this item.

9.3.7 Comprehensive Services Program (CSP)

TVA provides matching funds for the Comprehensive Services Program (CSP) related to energy audits and energy saving measures in Memphis. This cost is split 50/50 with MLGW and TVA, each contributing $0.14 million per year. If MLGW were to leave TVA, MLGW would be expected to be responsible for the full cost for the remaining life of the program or implement other programs for additional financial incentives.

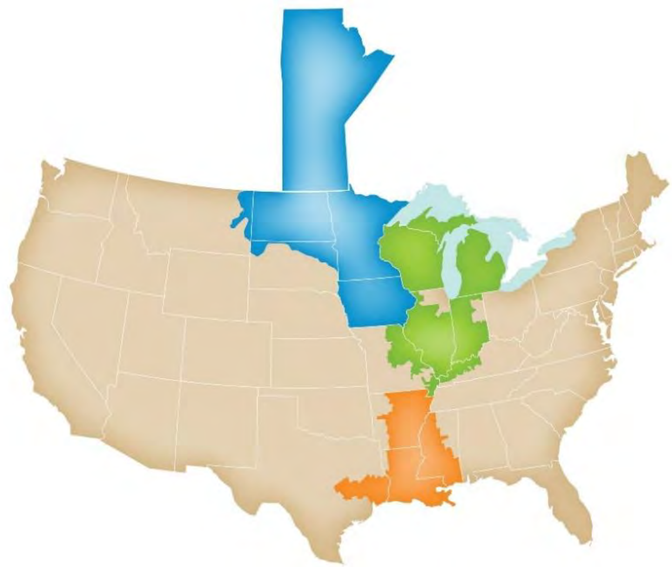
9.4 MISO Membership Cost

9.4.1 About MISO

The Midcontinent Independent System Operator (MISO)[38] is an Independent System Operator (ISO) and Regional Transmission Organization (RTO), a non-profit organization formed with the approval of Federal Energy Regulatory Commission (FERC), providing open-access transmission service and monitoring the high-voltage transmission system as well as operating one of the world's largest energy markets. MISO was established as an ISO since 1998 and as the nation's first RTO since 2001 to deliver safe, cost effective electric power and provide nondiscriminatory access to the bulk transmission network. MISO's footprint spans across 15 states in the U.S., mostly in the Midwest and Canadian province of Manitoba.

[38] https://www.misoenergy.org/

Exhibit 90: MISO Coverage Area



Source: MISO

9.4.2 Membership Process

MISO is a member-based organization, the core of which includes 51 transmission owners with more than 65,800 miles of transmission lines. New members may apply for membership with the submittal of an application which will be actioned upon at the next MISO Board meeting. A new member may join as a transmission owner (TO) if the member 1) owns operates, or controls facilities used for the transmission of electricity in interstate commerce that are physically interconnected with the facilities of an existing owner; and 2) Agrees to sign the MISO Transmission Owner's Agreement and to be bound by all its terms.

MISO provided MLGW with the detailed membership process and estimated costs and MLGW shared this with Siemens.

The total costs to MLGW associated with being a TO member in MISO are estimated to be $6.73 million by the time MLGW would join MISO (2025) based on the estimated energy demand of MLGW. This translates into an NPV (2025-2039) of $0.45/MWh in 2018$ and consists of the three components: membership costs, share of MISO administrative costs, and MLGW's Schedule 10 FERC charges.

Membership Costs

The first component is the initial membership application fee of $15,000 and an additional fee of $1,000 every year thereafter to maintain the membership.

Share of MISO Administrative Costs

MISO's tariff authorizes it to charge fees designed to allow the full and complete recovery of MISO administration costs through formula rates. Specifically, these are:

- Schedule 10 – ISO Cost Recovery Adder
- Schedule 16 – Financial Transmission Right (FTP) Cost Recovery Adder
- Schedule 17 – Energy Market Cost Recovery Adder

MISO's estimated annual operating expenses are $330.5 million. MISO has estimated that by 2025 its energy demand will be 750 million MWh and based on this the cost per MWh is estimated to be $0.44/MWh.

MLGW's estimated 2025 annual energy demand is 13.7 million MWh, and thus MLGW's share of MISO Administrative costs is approximately $6 million.

MLGW's Schedule 10 FERC Charges

MISO estimated the MLGW's Schedule 10 FERC charges to be approximately $0.73 million; this was determined based on MLGW's 2025 annual energy demand multiplied by the estimated FERC Charge Recovery Rate (FCRR) of $0.053/MWh.

10. Gap Analysis

10.1 Introduction

As a part of the IRP, Siemens evaluated options and a pathway for MLGW to terminate its contract with TVA and to join MISO as a Local Balancing Authority (LBA). This included a gap analysis and cost estimate for MLGW to become an LBA in MISO. This section summarizes the results of the gap analysis, cost estimates and provides assumptions used.

The gap analysis referenced NERC reliability standards assigned to Balancing Authorities (BAs). Although an individual LBA is not registered with NERC for compliance (MISO is registered as the BA for all of its LBAs), each LBA is obligated by the LBA operating agreement with MISO to operate in a manner consistent with and in support of overall compliance of the MISO BA function. The gap analysis also examined NERC's operations readiness (BA Certification) document for questions typically used by NERC to evaluate BA operational readiness and capabilities. Additionally, the review included an analysis of the MISO Operating Agreement, last amended in January 2019.

From the analysis of these reference documents, Siemens prepared a questionnaire addressing items Siemens felt would be essential for enabling MLGW to perform required planning and operating functions as a MISO LBA. The questionnaire was provided to MLGW, who shared the questions among applicable staff. The responses indicating the current status and capabilities of MLGW were compared to the requirements and gaps identified. Siemens then estimated resources and capital projects necessary to close the gaps identified. The cost estimates were then integrated into the overall transition plan along with the capital expenditures and annual operating, planning and maintenance costs over the period of the study.

Siemens has determined the least cost approach is to rely on the experience of an existing BA/LBA services provider. This approach allows MLGW to limit the number of new permanent operating staff and to minimize risks. The cost of this service is estimated to be $800,000 annually. Detail on this and other operating costs and capital for infrastructure upgrades are detailed below.

10.1.1 Capital Costs for Infrastructure Upgrades

Assuming the LBA function is managed by a third-party vendor, MLGW will still be required to make several capital investments. MLGW will be required by MISO to provide real-time pulsing of generators under its control to follow signals provided to MLGW for market dispatch. This will require the addition of an Automatic Generation Control (AGC) software program to the control center capabilities. The estimate of $800,000 assumes an off-the-shelf AGC application with the capability to pulse generators and maintain the LBA balance between load and resources, including scheduled interchange. AGC programs are available from major suppliers of energy management systems, such as Siemens, ABB, Alstom, and GE. The dispatch signals would come from the LBA desk at the vendor but would require MLGW equipment to communicate with and control the generators.

The AGC function will also require establishment of Inter-Control Center Communications Protocol (ICCP) communications systems and protocols between the AGC software and the generators under MLGW control, in addition to a real-time ICCP communications link with the LBA service provider. The cost also includes a real-time ICCP link with MISO so that the MLGW control center personnel can monitor MISO conditions related to the MLGW generators. Total capital costs for these communications links is assumed to be $1,200,000. This cost estimate includes:

- Replace/upgrade control center communications equipment (e.g., routers, switches, bridges, cabling, etc.) to meet requirements for generation control and real-time reliability analysis, and to meet NERC CIP requirements at Medium level critical asset ($200,000) due to the addition of 230 kV transmission and new generation in the MLGW LBA.
- Provide control center communications software installation, integration and testing to meet MLGW requirements ($200,000).
- Procure, install and test communications circuits to controllable generation resources, including communications equipment at each site ($500,000).
- Procure, install and test communications with MISO, LBA service provider, and neighboring BA/LBA systems ($100,000).
- Backup control center communications upgrade and links ($200,000).

The MLGW control center currently serves to monitor and control the distribution system and sub transmission facilities owned and operated by MLGW. Adding major generating and transmission facilities (230 kV and 500 kV) will require control center upgrades regarding computer systems, workstations, communications, and physical and cyber security controls. The control center upgrade is estimated to cost $1,000,000. Elements of the assumed cost include:

- Control center construction and remodeling to accommodate new positions in operations and support staff ($300,000)
- Operator workstations ($75,000)
- Dynamic map board ($100,000)
- Additional servers and equipment ($200,000)
- Upgraded HVAC for control center and computer room ($75,000)
- Backup control center upgrades ($250,000)

Oversight of the new transmission facilities will require MLGW to begin performing real-time contingency analysis, which was performed previously by TVA. A simple but compliant real-time contingency analysis program is estimated at $800,000. The cost is based on purchase price of the software license and the integration and testing services provided by the vendor. This amount is in addition to the capital expense of the new lines, substations, protection systems, and communications included in the CapEx estimates for the design, engineering and construction of the facilities themselves. The estimate of $800k for real time contingency analysis is in addition to the six bulleted items above for general upgrades to the control center.

Addition of 230kV transmission lines and substations and greater than 1500 MW of generation are criteria for MLGW to move from lower to medium cyber security requirements, which are more stringent. Capital upgrades for critical infrastructure protection (CIP) are estimated at $800,000. These costs include:

- Design and construction of a six-wall perimeter for cyber critical assets in the control center ($250,000)
- Upgrading control center access and logging systems to meet NERC requirements for a Medium level Critical Cyber Asset ($150,000)
- Upgrading building physical security features and monitoring systems at critical stations ($250,000)
- Security upgrade of backup control center ($150,000)

The capital expenditure estimates for the transition to become an LBA are summarized in Exhibit 91.

Exhibit 91: Estimated Capital Expenditures to Become an LBA

Fixed Capital Cost	(2018 $M)
AGC for MLGW controlled units	$0.8
Data communications to generators and LBA service provider	$1.2
Control center facility upgrade	$1.0
Real-time contingency and reliability analysis	$0.8
CIP compliance upgrade	$0.8
TOTAL	**$4.6**

Source: Siemens

Total capital costs are estimated to be $4.6 million. Although there is some discretion on timing of these expenditures, a base assumption would be to begin these projects upon execution of the letter of intent to separate from TVA. There could be flexibility to spread these costs over several years with careful planning to ensure capabilities are in place before commercial operations date.

10.1.2 Annual Operations and Maintenance Costs

The least cost solution for MLGW to qualify as a MISO LBA is to contract with a service provider to act as the MISO LBA on MLGW's behalf. Siemens contacted a leading BA/LBA service company (Gridforce Energy Management, LLC) and developed an estimate for the annual cost of this service, which is $800,000 per year. The role of the service provider for MLGW would be to provide 24/7 real-time generation control under the MISO market dispatch, including the following functions:

- Operate as a 24/7 real-time LBA on behalf of MLGW within MISO
- Receive real-time generator and meter scanned values from MLGW

- Calculate and maintain the MLGW LBA Area Control Error (ACE) within limits to balance load, generation and interchange in real-time
- Record MWhr values for the MISO market
- Provide 24/7 voice communications with neighboring BAs, transmission operators, reliability coordinators, MLGW, and MISO in support of coordinating real-time balancing operations, operating reserves, and reliability
- Provide for compliant communications protocols and training of LBA operators
- Maintain and implement plans to respond to capacity shortages, such as deployment of operating reserves and participation in reserve sharing
- Manage dynamic interchange over pseudo-ties for MLGW resources outside the metered boundary of the LBA

This approach allows MLGW to minimize staff additions that would be required for a full-time generation dispatch and LBA function in the control room with 24/7 operations. The estimate under this scenario is that MLGW would need to add two staff positions to perform generation operations planning for seasonal, monthly, and weekly resource commitment and scheduling, and for managing MLGW inputs to the MISO market operator. Having the real-time control of the LBA at MLGW would require five or six additional personnel above the estimates presented here. The annual cost for staffing and the service provider is addressed in a later section below.

MLGW will need to augment technical staff at the control center to address the addition of AGC and real-time contingency analysis and associated communications. This staff addition is estimated to be $400,000 per year. This effort covers control center technical support staff (technicians, network administrators, engineers and administrative staff needed to support additional operating positions), expanded systems and communications, and databases. Annual vendor/supplier cost estimates for communications and control center maintenance are $400,000 each.

The ongoing upkeep and tracking of NERC compliance will add $200,000 in addition to existing NERC compliance program costs supported by MLGW. This estimate is based on increased workload for the MLGW NERC compliance staff to capture increased compliance information and more frequent certification and compliance data requests from NERC and the regional entity.

Three additional control room staff will be required. Two will be focused on generator operational planning and scheduling and working with the real-time LBA operators provided by the vendor. These two personnel will manage the economic and reliable scheduling of resources for the seasonal, monthly, and weekly time horizons to optimize the value of MLGW resources for its customers and the MISO market. They will also coordinate planned resource outages with neighboring systems.

The third control room staff addition will oversee reliability monitoring and real-time contingency analysis. This position will be responsible for performing offline load flows and stability analysis to identify critical contingencies and operating limits for input and management of the online real-time contingency analysis tools. This position, an engineer, will also provide instructions, procedures and guides to operators in managing system contingencies. This reliability engineer will also maintain awareness of outages and reliability issues on neighboring systems that could impact MLGW.

These three positions (two generation scheduling and one reliability engineer) are expected to be dayshift jobs supported by existing MLGW 24/7 operating staff. Cost is estimated at $800,000 which is determined as $266,000 per position including labor, benefits, rents, workstations and other overhead costs with each position. The assumption is that these new positions will be salaried at approximately $133,000 per year and that all overheads will result in $266,000 per year.

Costs estimated as annual operating and maintenance costs are summarized in Exhibit 92.

Exhibit 92: Estimated Annual Operating Costs as LBA

Annual O&M Costs	(2020 $M)
Annual LBA service vendor	$0.8
LBA service technical support at MLGW	$0.4
Expanded CIP Scope	$0.2
Staff (+3) and training	$0.8
Additional communications maintenance and fees	$0.4
Additional control center systems maintenance	$0.4
TOTAL	**$3.0**

Source: Siemens

The increase in annual operations and maintenance costs are expected to be $3 million in 2020 dollars. It is assumed these costs will ramp in over a period of 18-36 months before commercial operation. Real annual escalation of costs is expected in the range of 2 to 3%.

With an increase in new workload and additional NERC standards, MLGW may need to supplement its workforce with contracted experts until internal subject matter experts are trained and knowledgeable in the standards.

10.1.3 Annual Transmission/Generation Planning and Procurement Resources

The resources for transmission and generation long-term planning and procurement are expected to build and peak in the years of the system expansion and then settle into a steady state resource requirement following the buildout. Annual costs for transmission and generation planning and procurement are provided below. These staff estimates are considered a minimum and may require consideration of additional staff for redundancy and evolving job requirements. Staffing costs are estimated at $133,000 base salary for system operators and engineers and a 2X factor that includes benefits, rent, facilities, workstations and other overheads for the positions. Actual costs will be determined by market compensation factors for these critical control center positions.

Exhibit 93: Estimated Annual Costs for Transmission and Generation Planning

	YR 1	YR 2	YR 3	YR 4	YR 5	YR 6	YR 7	YR 8	YR 9	YR 10	Steady State
Resource Planning Staff	1	2	2	2	2	2	2	2	2	2	2
Transmission Planning & Interconnection Studies	1	2	2	2	2	2	2	2	2	2	2
Procurement Staff	1	2	2	2	2	2	2	2	1	1	1
Total Staff	3	6	6	6	6	6	6	6	5	5	5
Staffing Costs $266,000/FTE	$0.8	$1.6	$1.6	$1.6	$1.6	$1.6	$1.6	$1.6	$1.3	$1.3	$1.3
Contractor Costs	$0.5	$0.8	$1.0	$1.0	$1.0	$1.0	$1.0	$0.5	$0.5	$0.3	$0.3
Total Cost*	**$1.3**	**$2.4**	**$2.6**	**$2.6**	**$2.6**	**$2.6**	**$2.6**	**$2.1**	**$1.8**	**$1.6**	**$1.6**

*$ millions; Source: Siemens

Additional planning staff are expected to include two new resource planning positions. These will be complemented in the early years of rapid system expansion by external contractors. Transmission planning and interconnection studies are expected to require two additional positions as well, also supplemented through year 8 by contractors. Procurement staff is estimated at two new positions through year 8 and then decreasing to one position once most expansion needs are complete.

10.1.4 Additional O&M Cost Considerations Not Included in LBA Gap Analysis

Operations and maintenance costs for the added transmission facilities and generator switchyards and interconnections that are part of the system expansion plan were not included in the LBA gap analysis. These estimates are built into the production cost simulation. The rate for new facility O&M is estimated in the simulation to be 2.5% of new capital costs or $0.77/MWh. Therefore, additional cost estimates were not developed as part of the LBA gap analysis, and double counting of resource requirements is avoided.

However, as a result of its assessment, Siemens believes MLGW should consider expanding O&M and construction positions to recognize the added workload from the new electrical facilities, transmission substations and lines, as well as new generation switchyards. Not only are additional personnel needed for the expanded design, testing and maintenance of new facilities, but also certain skillsets are also needed that do not exist at MLGW today; this is due to the higher voltage facilities and more complex protection and control systems that will be coming. MLGW should consider the following additions to their annual O&M budget:

- One additional crew for substation O&M & construction (5 positions)
- Test technicians (2)
- System protection and control technicians (2)
- Maintenance shop workers (2-4)
- Design and construction engineers (2)

Consideration should be given to building an alternative location for maintenance and construction personnel to provide separation and improved security for the control center.

11. Stochastics

11.1 Introduction

Probabilistic modeling incorporates several market variables and probability distributions into the analysis, allowing for the evaluation of a portfolio's performance over a wide range of market conditions. Quantitative data is extracted from the results and is the foundation for the balanced scorecard. Probabilistic modeling begins with the development of 200 sets of future pathways for coal prices, natural gas prices, carbon prices, peak and average load (at the Memphis, MISO Local Resource Zone 8 [LRZ-8], and MISO levels), and capital costs for a range of technologies. Each of these stochastic variables is propagated to the end of the study period, typically 1,000 to 3,000 times. A stratified sampling of the runs is taken, which allows the sample set to be reduced to 200 iterations. These 200 iterations of each stochastic variable are then loaded as inputs into the dispatch model. These inputs thus allow for the testing of each portfolio's performance across a wide range of market conditions.

All portfolios were subjected to each of the 200 iterations (scenarios) using AURORA in dispatch mode where the Memphis portfolios are fixed but other MISO members can make decisions under each market scenario.

The risk analysis (based on the probabilistic modeling) of each of the portfolios was developed by Siemens PTI using the AURORA dispatch model. There were several steps to this process:

- The first step was to develop the input distributions for each of the major market and regulatory drivers, including average and peak load growth and shape, natural gas prices, coal prices, carbon prices, and technology capital costs. This was done by considering volatility of each factor in the short-term, medium-term, and long-term.
- The second step was to run a probabilistic model (Monte Carlo) which selected 200 possible future states over the 20-year study planning period. This also formed the basis for the scenario inputs development.
- Each candidate portfolio was then run through simulated dispatch for the 200 possible future states using the AURORA production cost model. AURORA dispatches the candidate portfolio for each sampled hour over the planning horizon. For this risk analysis procedure, AURORA assumes that each candidate portfolio is constant but allows for builds and retirements to occur throughout the region based on economic criteria. MLGW generation, costs, emissions, revenues, etc. are tracked for each iteration over time.
- Next, values for each metric are tracked across all 200 iterations and presented as a distribution with a mean, standard deviation, and other metrics as needed.
- These measures are used as the basis for evaluation in the risk analysis.

The results of the risk analysis can be found in Sections 12.6, 13.4 and 14.7 for each of the considered strategies.

11.2 Overall Procedure for Identification of Preferred Portfolio

The risk analysis includes scenario modeling, probabilistic modeling, sensitivity and other analyses to inform judgment in the selection of the preferred portfolio. In addition, a key part of selecting the preferred portfolio was based on how well each portfolio met multiple objectives under 200 iterations representing different, but internally consistent and plausible market condition scenarios. The selection process consisted of several comparisons illustrating each candidate portfolio's performance measured against competing objectives. The goal is to create the right balance between satisfying the competing objectives. The preferred portfolio delivered the best balance of performance across all competing metrics when viewed across the full range of 200 iterations, while also maintaining reliability and providing resource diversity/system flexibility. This procedure is used and presented in the sections below where each portfolio is assessed.

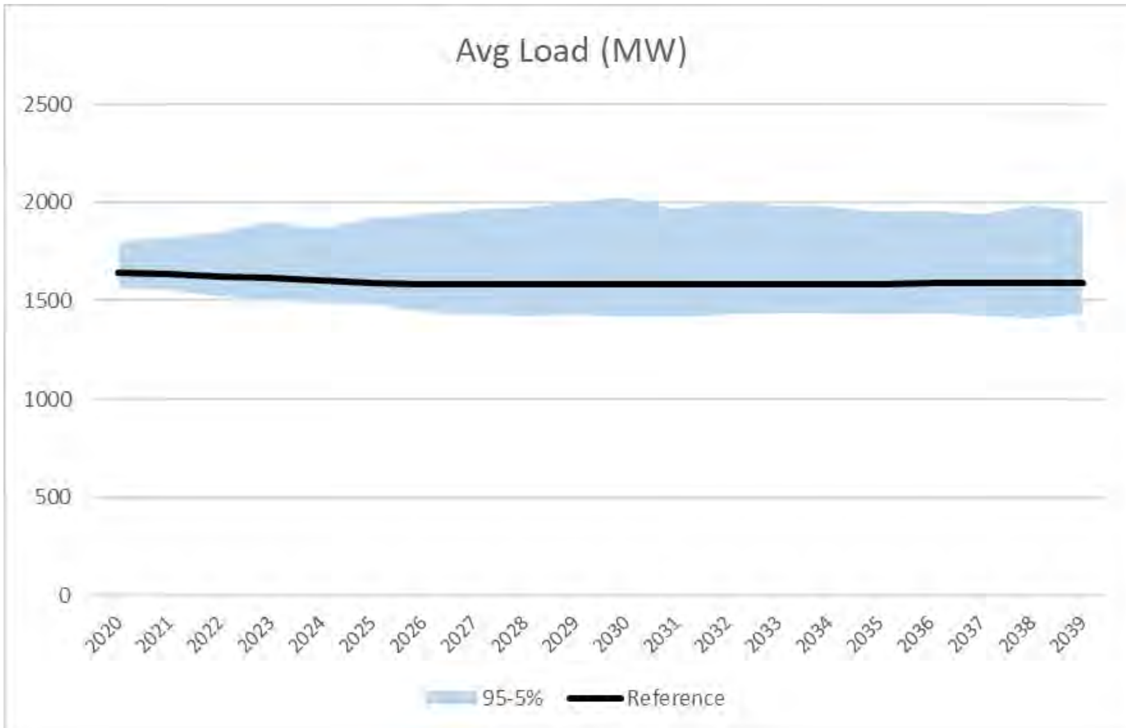
11.3 Stochastic Distributions

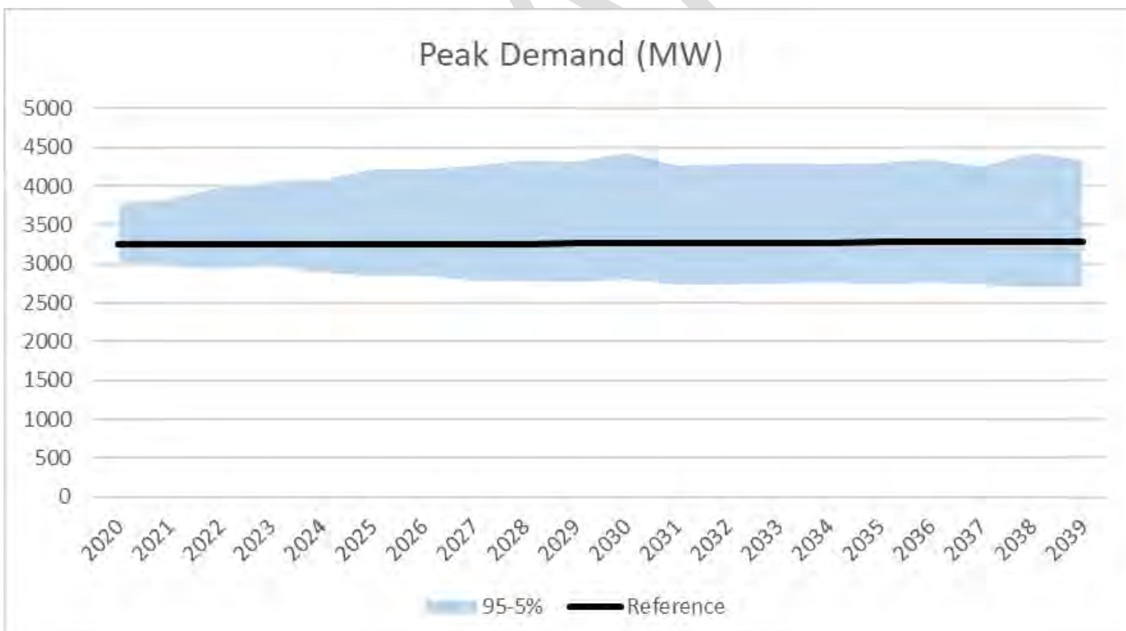
In order to perform the probabilistic modeling, also known as stochastic analysis, a set of probability distributions was required for each of the key market driver variables described above (fuel, emissions, load, and capital costs). These probability distributions were developed from a simulation that creates 200 future paths for each stochastic variable. The following sections describe the methodologies for developing these stochastic variables, with additional detail explained in Appendix C: Model Description.

11.3.1 Load Stochastics

To account for electricity demand variability that derives from economic growth, weather, energy efficiency, and demand side management measures, Siemens PTI developed stochastics around the load growth expectations for the MLGW control area and the neighboring ISO zones, including MISO, PJM, and utilities not served by an ISO in SERC. Siemens PTI benchmarked the MISO-wide projections against MISO-sponsored load forecasting studies that are conducted by independent consultants, institutions, and market monitors and then released into the public domain.

Exhibit 94: MLGW Load (MW) Distribution



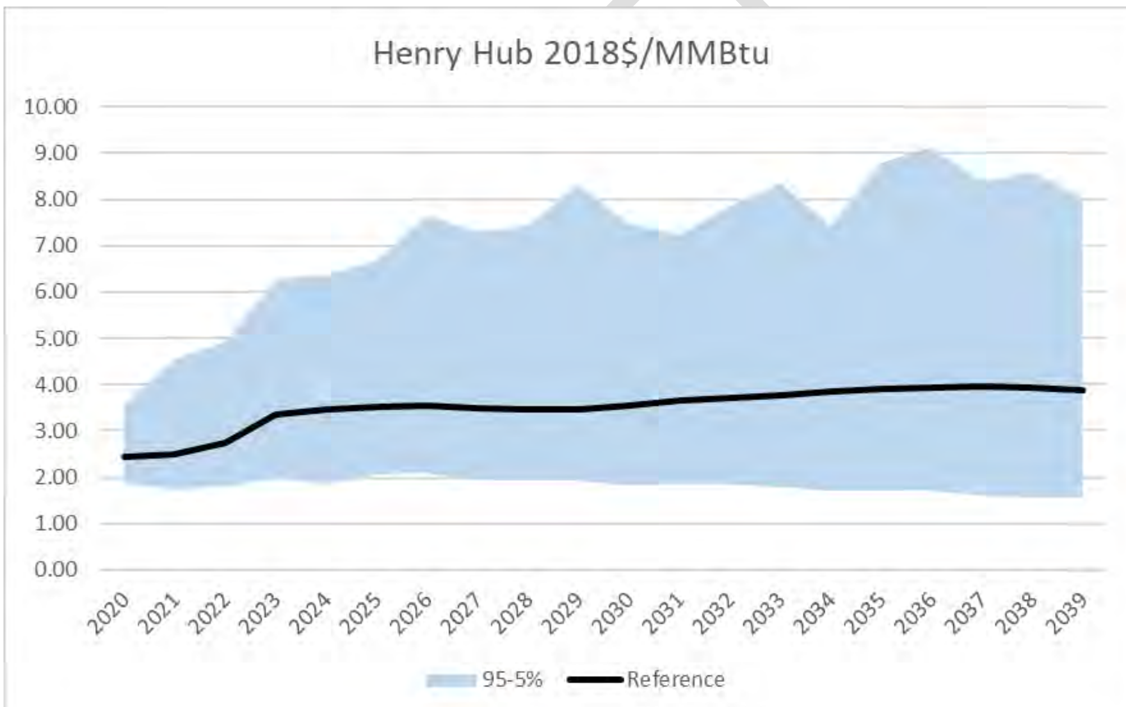


Source: Siemens

11.3.2 Gas Stochastics

Siemens PTI developed natural gas price stochastic distributions for the benchmark Henry Hub market point. These stochastic distributions are first based on the Reference Case view of natural gas prices with probability bands developed then based on a combination of historical volatility and mean reversion parameters as well as a forward view of expected volatility. For the period 2019-2022, volatility calculated from the past three years of price data is used. For 2023-2025, volatility calculated from the past five years is used. For 2026-2039, volatility calculated from the past 10 years is used. This allows gas price volatility to be low in the short-term, moderate in the medium-term and higher in the long-term in alignment with observed historical volatility. The 95th percentile probability bands are driven by increased gas demand (e.g., coal retirements) and fracking regulations that raise the cost of producing gas. Prices in the 5th percentile are driven by significant renewable development that keeps gas plant utilization relatively low as well as few to no new environmental regulation around power plant emissions.

Exhibit 95: Natural Gas (Henry Hub) Price Distribution (2018$/MMBtu)

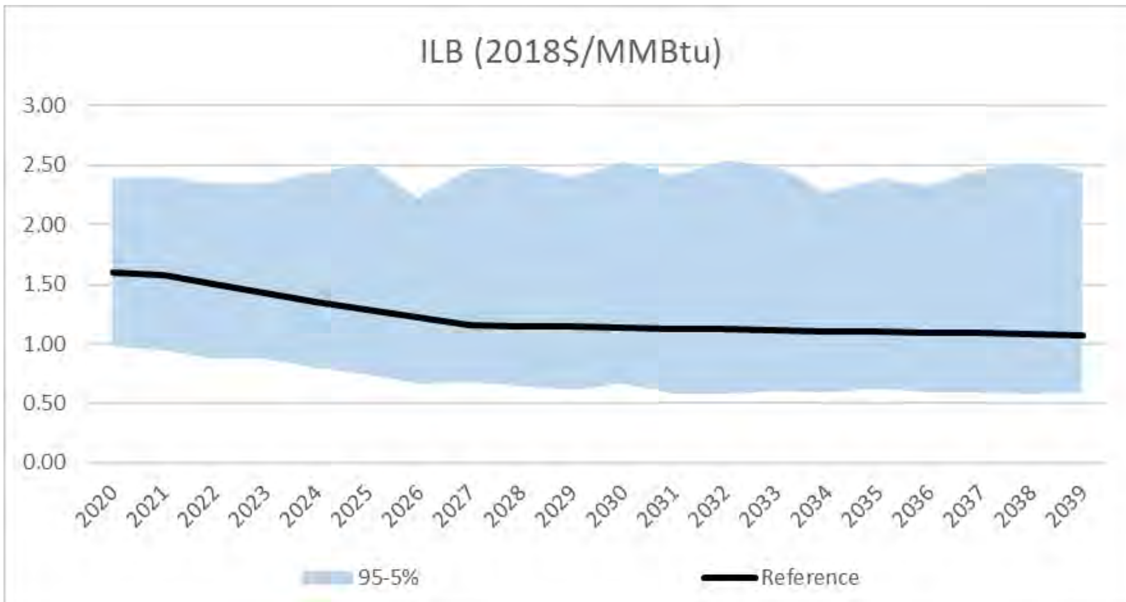


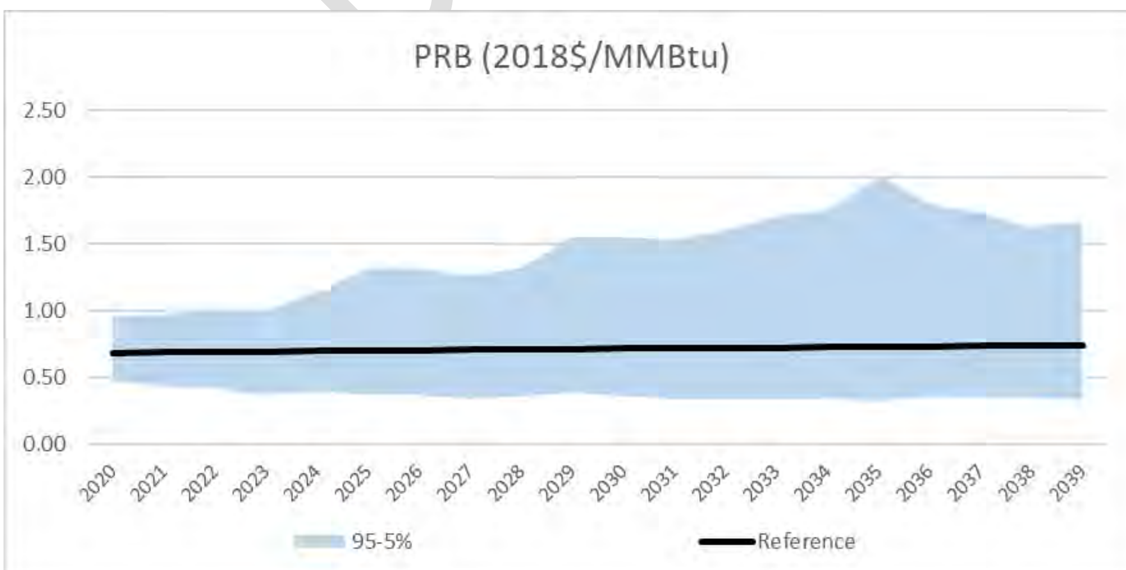
Source: Siemens

11.3.3 Coal Stochastics

Siemens PTI developed coal price stochastic distributions for the CAPP, NAPP, ILB and PRB basins. These stochastic distributions are first based on a Reference Case view of coal prices with probability bands developed then based on a combination of historical volatility and mean reversion parameters. It should be noted that most coal contracts in the U.S. are bilateral and only approximately 20% are traded on the New York Market (NYMEX) Exchange. The historical data set that is used to calculate the parameters is comprised of the weekly traded data reported in NYMEX.

Exhibit 96: Coal Price Distribution (2018$/MMBtu)



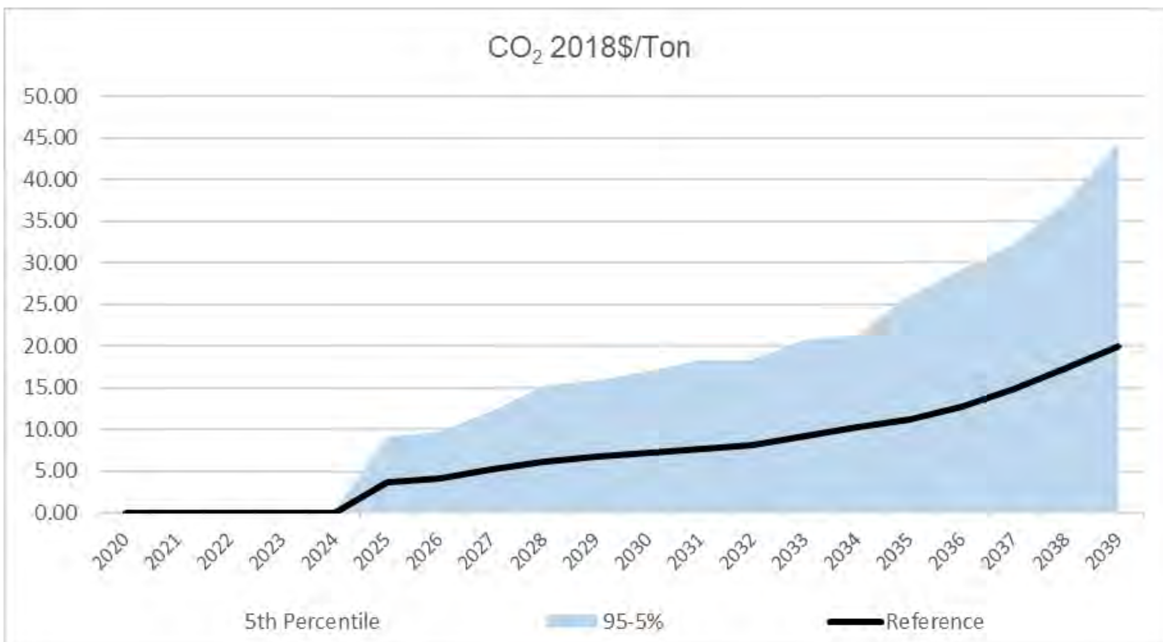


Source: Siemens

11.3.4 Emission Price Stochastics

Siemens PTI developed uncertainty distributions around carbon compliance costs, which were used in AURORA to capture the inherent risk associated with regulatory compliance requirements. The technique to develop carbon costs distributions, unlike the previous variables, is based on projections largely derived from expert judgment, as there are no national historical data sets (only regional markets in California and the northeast) to estimate the parameters for developing carbon costs distributions. The reference case reflects a view that some type of legislation will likely occur in the mid-2020s to provide incentives for faster shifts from fossil to renewable generation. Previous studies of a proposed trading mechanism showed prices rising to about $20/ton. The bottom end of the distribution assumes no future regulation. The top end reflects the social cost of a carbon emission program.

Exhibit 97: CO_2 Price Distribution (2018$/ton)



Source: Siemens

11.3.5 Capital Cost Stochastics

Siemens PTI developed the uncertainty distributions for the cost of new entry units by technology type, which was used in AURORA for determining the economic new builds based on market signals. These technologies included gas peaking units, gas combined cycles units, solar, wind, and battery storage resources. The methodology of developing the capital cost distributions is a two-step process: (1) a parametric distribution based on a Reference Case view of future all-in capital costs, historical costs, and volatilities, and a sampling of results to develop probability bands around the Reference Case; and (2) a quantum distribution that captures the additional uncertainty with each technology that factors in learning curve effects, improvements in technology over time, and other uncertain events such as leaps in technological innovation.

Exhibit 98: Solar Capital Costs Distribution (2018$/kW)

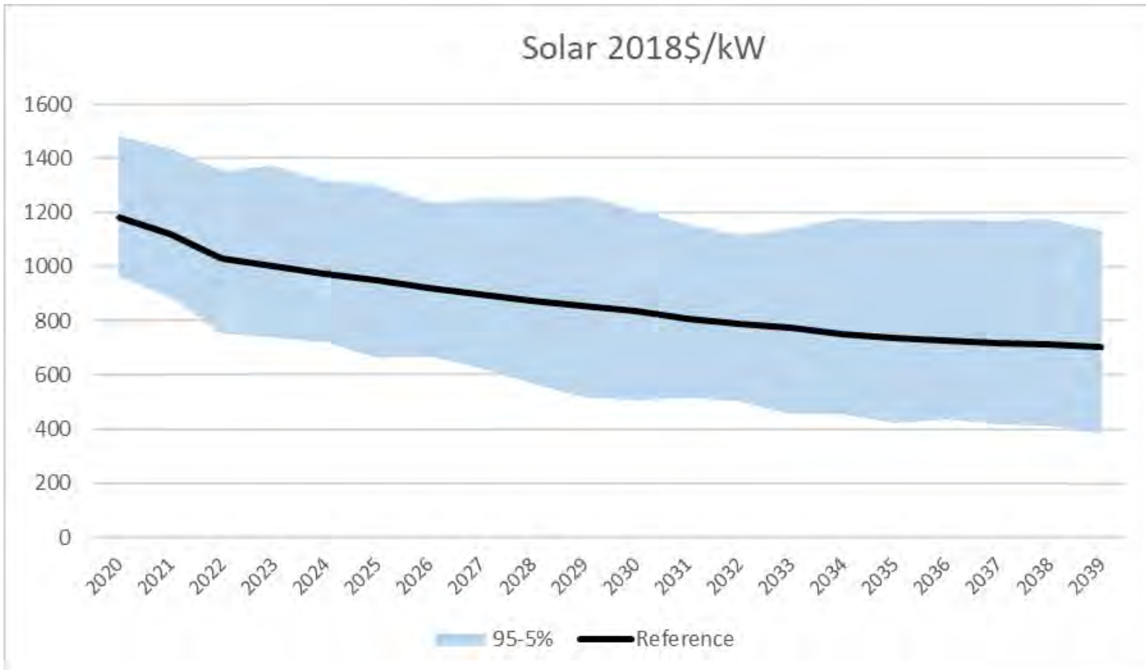
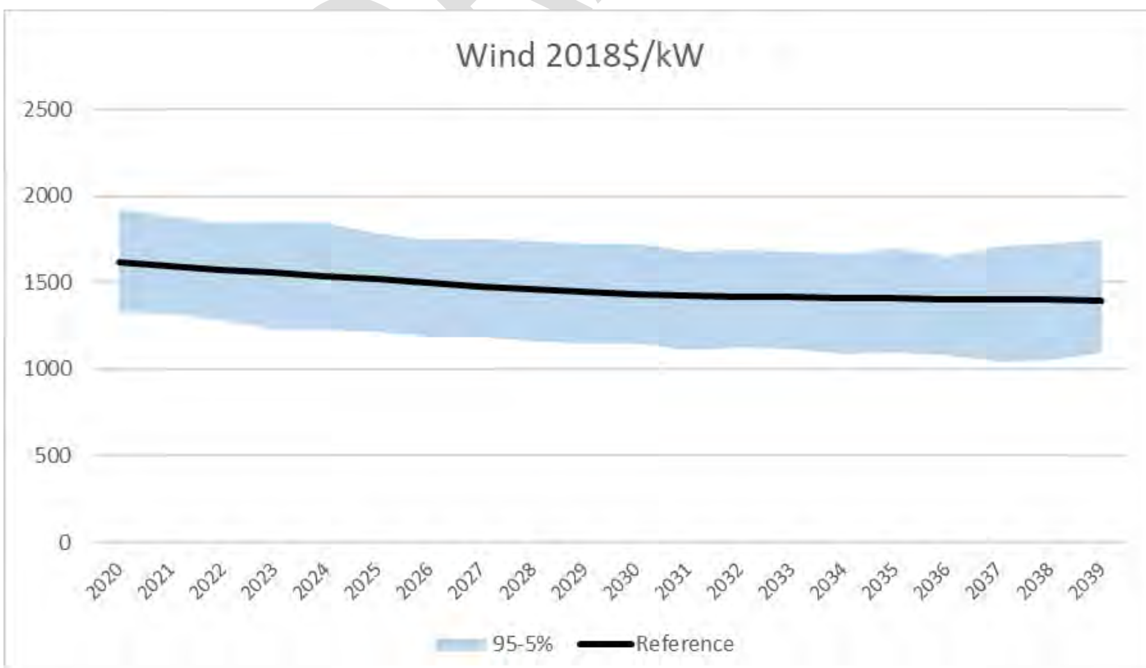


Exhibit 99: Wind Capital Costs Distribution (2018$/kW)



Source: Siemens

Exhibit 100: Lithium-Ion 4-hour Battery Storage Capital Costs Distribution (2018$/kW)

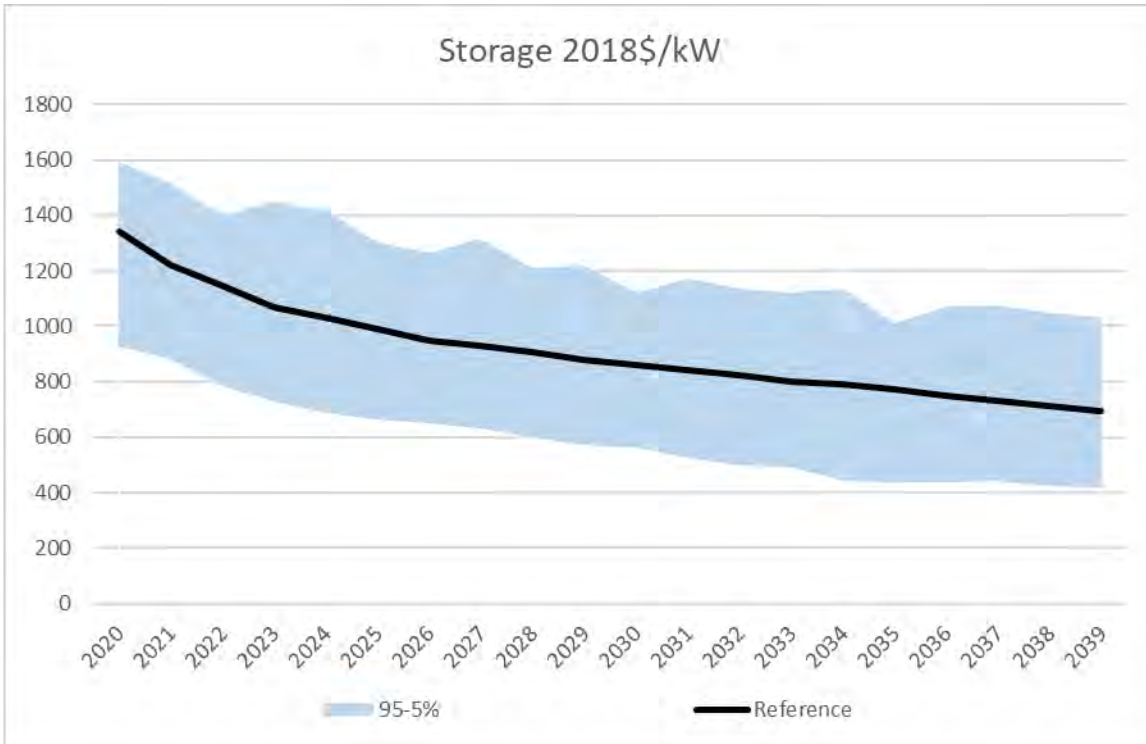
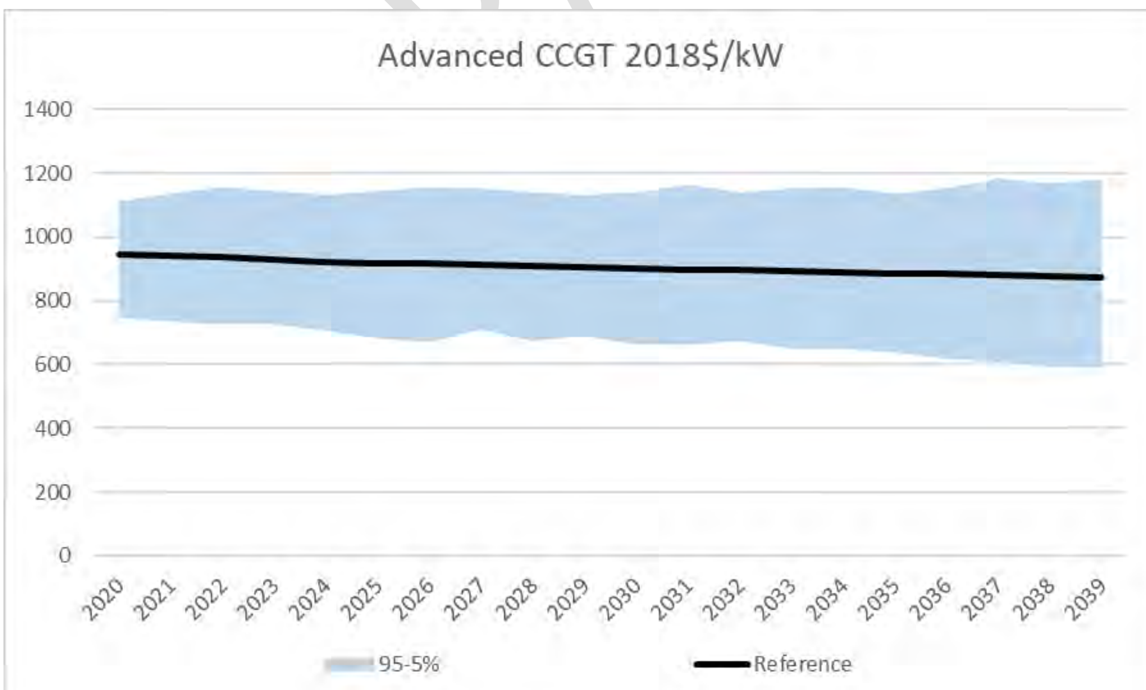
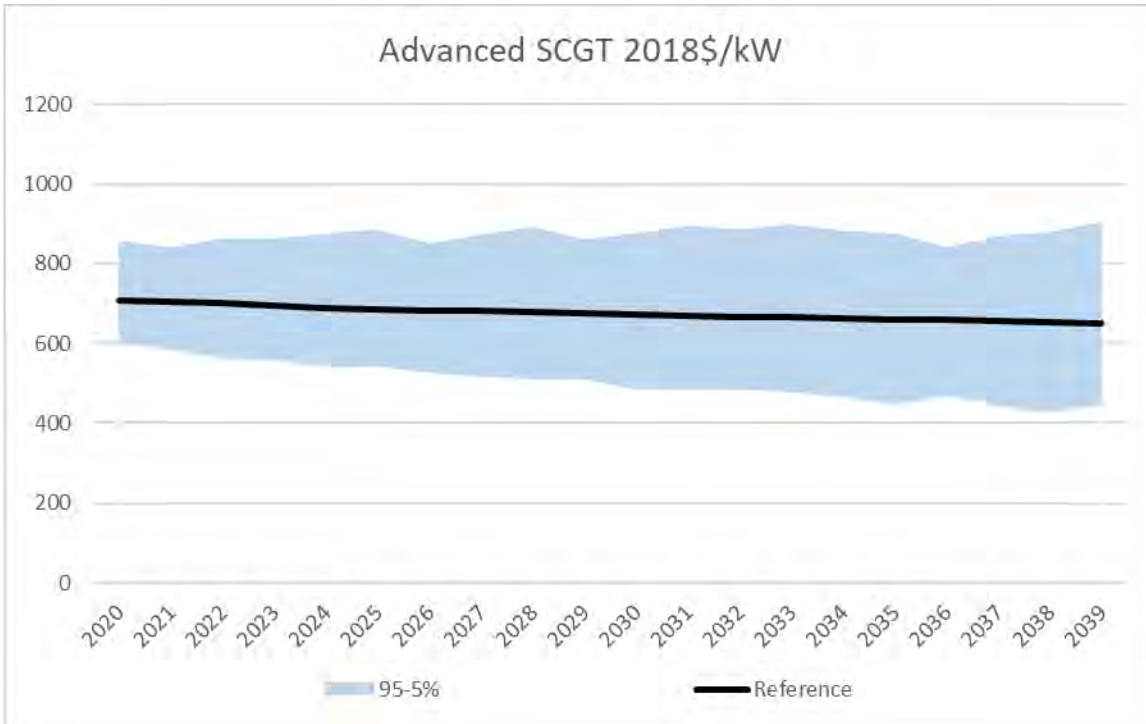


Exhibit 101: Advanced 2x1 Combined Cycle Capital Costs Distribution (2018$/kW)



Source: Siemens

Exhibit 102: Advanced Simple Cycle Frame CT Capital Costs Distribution (2018$/kW)



Source: Siemens

11.3.6 Cross-Commodity Stochastics

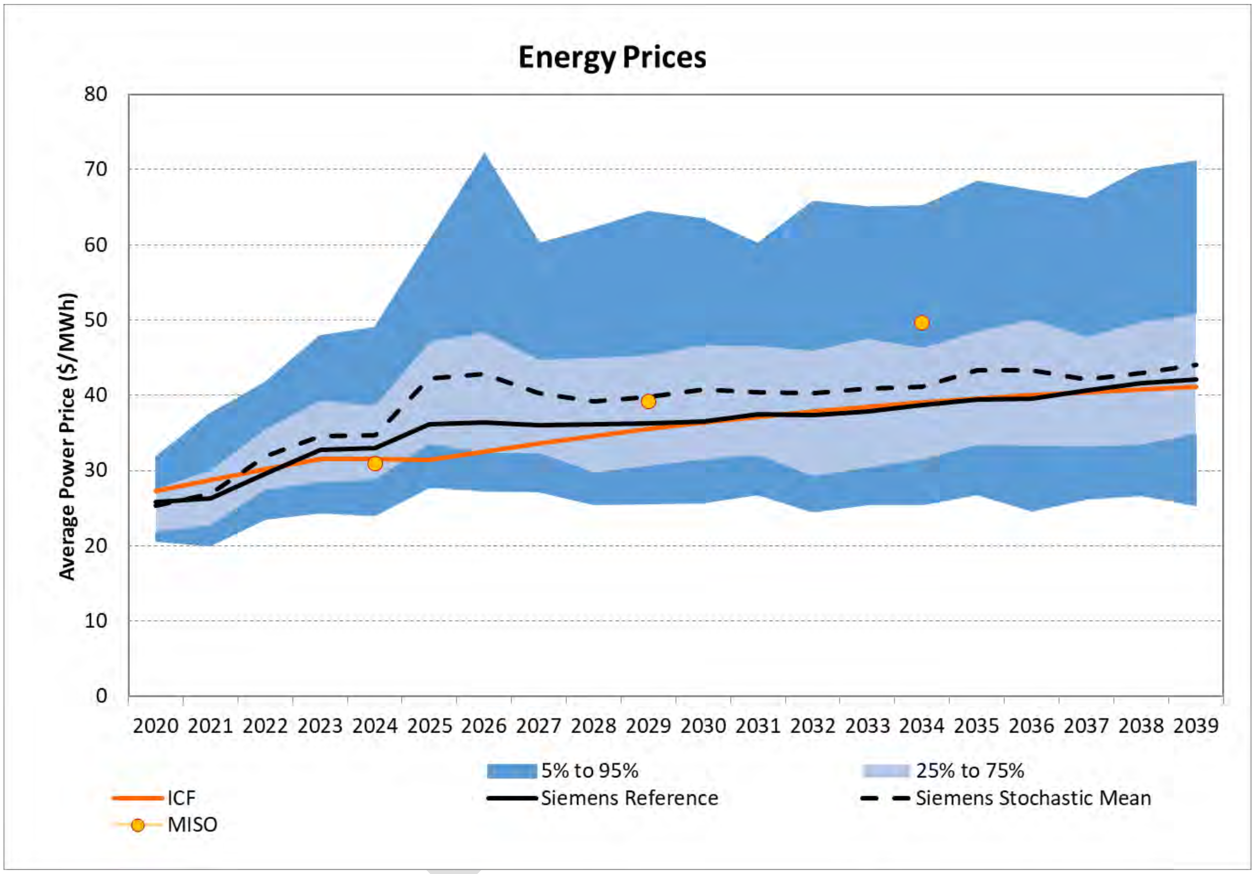
Siemens PTI captured the cross-commodity correlations in the stochastic process, which is a separate stochastic process from those for gas, coal and CO_2 prices. The feedback effects are based on statistical relationships between coal and gas switching and the variable cost of coal and gas generators. Siemens PTI conducted a fundamental analysis to define the relationship between gas and coal dispatch costs and demand. The dispatch costs of gas and coal were calculated from the gas and coal stochastics and CO_2 stochastics, along with generic assumptions for variable operation and maintenance costs. Where the gas-coal dispatch differential changes significantly enough to affect demand, gas demand from the previous year was adjusted to reflect the corresponding change in demand. A gas price delta was then calculated based on the defined gas demand. This gas price delta was then added to the gas stochastic path developed from historic volatility to calculate an integrated set of CO_2 and natural gas stochastic price forecasts.

11.4 Energy Price Distribution

Siemens produces a stochastic distribution of energy prices as a result of running the input distributions through AURORA (200 times). AURORA not only determines the build decisions for the region but also the resulting prices. The Exhibit below displays these prices.

For comparison purposes we have superimposed the ICF and MISO forecasts on the same graph as our distribution. They are well within the range of prices we include in our 200 iterations. In the near term both MISO and ICF are below Siemens forecasts, which in the case of MISO is due to an assumption that all builds prior to 2028 are renewable, where Siemens has a mix of renewables and gas. After 2028, MISO's forecast exceeds Siemens and ICFs is approximately the same as Siemens.

Exhibit 103: Stochastic Inputs – Market Forecast



Source: Siemens

12. Self-Supply plus MISO Analysis

12.1 Introduction

This section presents the portfolio selection and assessment of the Self-Supply plus MISO Strategy considering the Scenarios presented in Section 2.

This section describes the development of the 21 initial Strategy 3 portfolios, the selection of the ten final Strategy 3 Portfolios, and the performance of the ten from both deterministic assessment and stochastic on each of the selected metrics.

12.2 Portfolio Selection

As discussed in Section 2 of this report, three power supply strategies were considered in the IRP, Strategy 1 is the business as usual strategy with TVA, Strategy 3 is the combination of local supplies with builds or purchases from MISO, and Strategy 4 is the all builds and purchases from MISO with no local builds inside MLGW's footprint.

A Portfolio is a unique generation buildout under a specific combination of a strategy (e.g. TVA or MISO) and a scenario. As discussed in Section 2of this report, 7 different scenarios were considered in this IRP with the aim to producing seven or more distinct Strategy 3 Portfolios. The determination of these Portfolios is a two-step process:

- First a base capacity expansion is produced using the Long-Term Capacity Expansion (LTCE) module of the optimization software (AURORAxmp® or AURORA). Siemens recognizes that the least cost portfolio may not be the only combination worth considering given differences in reliability or other objectives. Hence a second step was added.
- Expert judgement is used to adjust the initial expansion plan and the AURORA LTCE was re-run with these adjustments in place, resulting in a unique Portfolio that is better suited to manage risks, such as reduced dependence on remote resources or improved reliability. Therefore, it is possible to have multiple portfolios associated with a single Strategy and Scenario combination.

This section explains how a total of 21 portfolios were produced through this two-step LTCE process under Strategy 3 and how the final 10 Portfolios were selected for the detailed deterministic and stochastic analysis.

Note in some of the comparisons, Portfolio 10 which was derived from the All MISO Strategy by moving some of the MISO resources to local resources is added to the analysis in this section so that all the Self-supply and MISO combination portfolios are compared together. The details of the Portfolio 10 will be discussed separately.

12.3 Portfolio Analysis and Selection.

We present below the procedure followed for the selection of the 9 portfolios under Strategy 3 evaluated in this section. This provides a view of how they were created and hence the underlying objectives that they were intended to address.

The exhibit below presents the main buildout and results of the set of 20 portfolios produced in this IRP. The Portfolio ID provides a reference on how the Portfolio was derived. For example, S3S1, indicates Strategy 3, Scenario 1 (reference case). If this name is followed by a letter it references a modification to the base plan.

The Portfolio NPV in the exhibit is the direct deterministic result of the LTCE process energy costs based on the reference scenario and does not include the impact of the other costs discussed in the previous sections (e.g. transmission or the PILOT, etc.).

Exhibit 104: Main Results for the Initial Portfolio Set

Portfolio ID	Final Portfolio	Load	Gas Price	Total Thermal 2039	Local Renew 2039	Battery 2039	Total Local Nameplate 2039	MISO Renew 2039	MISO Cap 2039	950 MW CC	450 MW CC	237 MW CT	343 MW CT	NPV Demand (MWh)	Portfolio NPV Cost ($000)	Demand Weighted NPV ($/MWh)
S3S1	No	Base	Base	1137	1000	0	2137	2200	1761	0	2	1	0	181,088,154	9,054,690	50.00
S3S1_P	Portfolio 1	Base	Base	1137	1000	0	2137	2200	1761	0	2	1	0	181,088,154	9,089,087	50.19
S3S7_BB	Portfolio 6	Base	Base	1137	1000	0	2137	2200	1761	0	2	1	0	181,088,154	9,214,886	50.89
S3S1_2CT	Portfolio 7	Base	Base	1374	1000	0	2374	2200	1550	0	2	2	0	181,088,154	9,125,223	50.39
S3S7_2CT	Portfolio 8	Base	Base	1374	1000	0	2374	2200	1550	0	2	2	0	181,088,154	9,251,110	51.09
S3S1_M	No	Base	Base	1930	650	0	2580	1050	1342	0	3	1	1	181,088,154	9,410,590	51.97
S3S1_MP	No	Base	Base	1587	750	0	2337	1800	1487	0	3	1	0	181,088,154	9,342,020	51.59
S3S1_F	Portfolio 2	Base	Base	1587	1000	0	2587	1550	1487	0	3	1	0	181,088,154	9,300,273	51.36
S3S1_A	No	Base	Base	1587	1000	0	2587	1150	1554	0	3	1	0	181,088,154	9,373,917	51.76
S3S2	No	High	Base	1824	1000	0	2824	1350	1746	0	3	2	0	210,203,674	10,770,685	51.24
S3S2_BB	Portfolio 3	Base	Base	1824	1000	0	2824	1350	1308	0	3	2	0	181,088,154	9,341,806	51.59
S3S3	No	Low	Base	1350	1000	0	2350	1550	1655	0	3	0	0	172,550,350	8,793,587	50.96
S3S3_BB	Portfolio 4	Base	Base	1350	1000	0	2350	1550	1697	0	3	0	0	181,088,154	9,126,137	50.40
S3S4	No	High	Low	1824	1000	25	2849	700	1849	0	3	2	0	210,203,674	9,140,036	43.48
S3S5	Portfolio 5	Base	Base	1398	1000	100	2498	3450	1183	0	1	4	0	181,088,154	8,980,510	49.59
S3S5_YD	Portfolio 9	Base	Base	1398	1000	100	2498	3450	1186	0	1	4	0	181,088,154	9,073,691	50.11
S3S6_N	No	Base	Base	900	1000	475	2375	2200	1505	0	2	0	0	181,088,154	9,414,739	51.99
S3S6	No	Base	Base	900	1000	475	2375	2200	1505	0	2	0	0	181,088,154	9,201,548	50.81
S3S7	No	Low	High	1137	1000	0	2137	2200	1718	0	2	1	0	172,550,350	9,965,303	57.75
S3S10	Portfolio 10	Base	Base	950	1000	0	1950	2250	1909	1	0	0	0	181,088,154	8,532,493	47.12

Source: Siemens

12.3.1 Reference Case Derived Portfolios

There are three derived portfolios for Strategy 3, Scenario 1 (Reference Case). The S3S1 LTCE from AURORA had one CT installed in 2039 in the expansion plan, which would result in heavier dependence on transmission in early years of the planning horizon.

S3S1_P advanced the CT to 2025 with a minor effect on the NPV. In fact, when the transmission costs are accounted for, the Portfolio with the CT advanced becomes more economic. Hence the adjusted Portfolio (S3S1_P) was selected for detailed analysis and named Portfolio 1.

For Portfolio 2, we also noted that in both the low load and the high load Scenarios a solution with three combined cycle units (CCGTs) was being selected, so we identified portfolios under reference case assumptions with 3 CCGTs. This expansion plan was labeled as S3S1_M which was further adjusted by advancing the CT from 2039 to 2025 (S3S1_MP) and accelerating the local solar (S3S1_F). As can be observed changes improved the NPV and S3S1_F was selected for final analysis and named Portfolio 2.

Finally, during the resource adequacy assessment of the initial Portfolio set, it was found that S3S1_P, i.e. Portfolio 1 could have issues for meeting the resource adequacy requirement so one more CT was added mainly for capacity (S3S1_2CT) and the resulting capacity expansion plan was labeled Portfolio 7.

12.3.2 High Load/Base Gas Derived Portfolio

S3S2 is a Portfolio with high forecasted load Scenario under Strategy 3. The load is about 16% higher than the base load assumption when comparing the NPV of the energy demand. This analysis produced a unique expansion plan with 3 CCGTs and 2 CTs. The extra CT is basically to cover the additional load from capacity perspective. Because of the unique buildout, it was selected as the Portfolio 3. (As mentioned above, the different Scenarios, e.g. changing load, gas assumption, are aimed to produce different generation expansion portfolios for further analysis.)

This Portfolio was run with the reference case load for proper comparison with other Portfolios.

12.3.3 Low Load/Base Gas Derived Portfolio

S3S3 is a Portfolio with low forecasted load Scenario under Strategy 3. The load is about 5% less than the base load assumption on an NPV basis. It produced a unique buildout plan which consists of only 3 CCGTs and no CT. This expansion plan was selected as the Portfolio 4 for detailed analysis.

This Portfolio was run on the reference load scenario for comparison with other Portfolios.

12.3.4 High Transmission Derived Portfolio

S3S5 was designed to test whether adding transmission capacity to acquire more MISO resources was a viable option. It tested if reduced generation costs of the portfolio could justify the additional transmission investments to achieve higher import/export capability.

In this run, we assumed 3,500 MW import limit from MISO to MLGW and 2000 MW limit from MLGW to MISO. The import limit is about 300 MW more than the MLGW's peak forecasted load and 1300 MW more than the import limit assumption in the reference base at 2200 MW. It did produce a unique expansion plan with 1 CCGT and 4 CTs in the later years with 3,450 MW of external solar in MISO and 1,000 MW of local solar. Substantial amounts of remote renewables were made possible by taking advantage of the increased transmission import capability. Because of the unique buildout and relatively low generation portfolio NPV of revenue requirements, it was selected as the Portfolio 5 for further study.

Because CTs came online after 2030, this Portfolio resulted in reliability, resiliency against extreme events, and resource adequacy concerns in the early years of the planning horizon. A new portfolio was developed to address these concerns by advancing all the four CTs to be built in first year 2025 so that the reliability was maintained to the similar level as other Portfolios. The capital costs increased, but there are savings from high transmission costs. Case S3S5_YD was created, and the resulting portfolio was named as Portfolio 9 for further analysis.

12.3.5 Low Load/High Gas Derived Portfolios

S3S7 is the Scenario with low load and high natural gas price under Strategy 3. It was designed to mimic higher energy efficiency penetration and higher energy prices, which is a proxy to the Climate Crisis Scenario. Only 2 CCGTs were selected, and the renewable generation was maximized as early as possible to address the expensive fuel costs. This case was identified as Portfolio 6 for further analysis.

This Portfolio was run using the Reference load forecast for comparison with other Portfolios. As with Portfolio 7, one more CT was added to the Portfolio 6 in 2025 to ensure capacity needed for resource adequacy and therefore Portfolio 8 was created for further analysis. Portfolio 8 is the same as Portfolio 7 but with earlier renewable generation builds.

12.3.6 Portfolios with Battery Energy Storage

Scenario 6 was created to test the economics on battery energy storage system (BESS) as BESS was not selected in any of the LTCE runs (except for 100 MW in Portfolio 5 or Portfolio 9). In this Scenario, we did not offer the option to build any CT units to see if any BESS will be selected.

When CTs were not offered as options, the LTCE program selected to build 475 MW of BESS, i.e. S3S6_N, which is equal to about the capacity of 2 CTs. However due to the relatively high levelized cost of BESS compared to CT, the NPV of the S3S6_N case is the highest among all cases.

Next, we lowered the cost of BESS by 2 standard deviations from the mean value which is a substantial reduction. The NPV result of this case, i.e. S3S6, is still higher than most of the other cases. Therefore, no portfolio with substantial BESS build was selected as a final portfolio for further analysis. The only BESS build is in Portfolios 5 or 9 (S3S5 & S3S5_YD), which were selected for further analysis.

12.3.7 Portfolios Derived from All MISO Strategy

In the analysis of Strategy 4, All MISO, where all generation resources were built within the current MISO footprint, the portfolio consisted of a large CCGT (950 MW) along with 3200 MW MISO solar and no CTs. Significant amounts of transmission investment were required to achieve a more reliable transmission configuration with much higher transfer capability.

In contrast with other Portfolios under Strategy 3, no resources were built inside of MLGW territory, even though local resources are cheaper than remote resources for the same generation type. Under the assumption that adequate land is available locally, a new portfolio was developed by relocating the large CCGT and 1000 MW solar from MISO to MLGW to create the S3S10 case. This creates a unique buildout and produced very competitive deterministic results on NPV and thus was selected as Portfolio 10 for further analysis. Transmission investments were kept the same as in the Portfolio All MISO so that the large CCGT can be a viable option.

This completed the portfolio selection process.

12.3.8 Final Portfolios Selected for Stochastic Analysis

The exhibit below shows the total of ten Portfolios which were selected under Strategy 3 for the stochastic analysis (risk assessment). The range of the deterministic NPV costs on generation supply (still not adding the remaining transmission and other costs) was all compared on the same reference case Scenario (base load base gas) and varies from $47/MWh $51.6/MWh; although this is not a large variation, it does represent more than $800 to million differences in costs on a 15-year NPV basis.

This summarizes the deterministic analysis of portfolios against the reference scenario. All the Portfolios were then subjected to 200 stochastic variations to identify the best performing Portfolio with minimum risks.

Exhibit 105: Final Portfolio List under Strategy 3

Portfolio ID	Final Portfolio	Total Thermal 2039	Local Renew 2039	Battery 2039	Total Local Nameplate 2039	MISO Renew 2039	MISO Cap 2039	950 MW CC	450 MW CC	237 MW CT	NPV Demand (MWh)	Portfolio NPV Cost ($000)	Demand Weighted NPV ($/MWh)
S3S1_P	Portfolio 1	1137	1000	0	2137	2200	1761	0	2	1	181,088,154	9,089,087	50.19
S3S1_F	Portfolio 2	1587	1000	0	2587	1550	1487	0	3	1	181,088,154	9,300,273	51.36
S3S2_BB	Portfolio 3	1824	1000	0	2824	1350	1308	0	3	2	181,088,154	9,341,806	51.59
S3S3_BB	Portfolio 4	1350	1000	0	2350	1550	1697	0	3	0	181,088,154	9,126,137	50.40
S3S5	Portfolio 5	1398	1000	100	2498	3450	1183	0	1	4	181,088,154	8,980,510	49.59
S3S7_BB	Portfolio 6	1137	1000	0	2137	2200	1761	0	2	1	181,088,154	9,214,886	50.89
S3S1_2CT	Portfolio 7	1374	1000	0	2374	2200	1550	0	2	2	181,088,154	9,125,223	50.39
S3S7_2CT	Portfolio 8	1374	1000	0	2374	2200	1550	0	2	2	181,088,154	9,251,110	51.09
S3S5_YD	Portfolio 9	1398	1000	100	2498	3450	1186	0	1	4	181,088,154	9,073,691	50.11
S3S10	Portfolio 10	950	1000	0	1950	2250	1901	1	0	0	181,088,154	8,532,493	47.12

Source: Siemens

12.4 Portfolio Deterministic Analysis under Reference Conditions

This subsection addresses the relative strengths and weaknesses of the ten selected portfolios and their performances in accordance to the selected metrics (see Section 2).

First, we describe each of selected metrics used to compare portfolios and how they are measured. Then a balanced scorecard is used to compare all final Portfolios together to visually rank these 10 Portfolios. This is followed by a discussion of what are the best or worst performing Portfolios within each metric. All results are presented using the Reference Case load scenario and gas price forecast for comparison purposes.

12.4.1 Portfolio Overview

The performances of the ten Portfolios were measured on six metrics including Least Cost, Sustainability, Reliability, Resiliency, Market Risk, and Economic Growth. Detailed quantitative measures are explained as follows.

Least Cost is measured as the NPV of total revenue requirements from 2020 to 2039, including the supply side costs from LTCE and all the other component costs, including capital and O&M costs of new transmission, PILOT, the costs of replacing TVA's benefits, the cost to perform functions that were not previously required (Gap analysis costs), MISO Admin costs and costs of replacing TVA's energy efficiency program. This is presented both in real 2018$ and levelized based on the NPV demand in energy (MWh) from 2025 to 2039 to calculate the $/MWh NPVRR. A real discount rate of 1.37% was used based on MLGW projected cost of capital of 3.5% and an assumed 2.1%/year inflation rate. Portfolios were ranked from lowest to highest NPVRR cost.

Sustainability is measured on three metrics: (a) the total CO_2 emissions in Millions of Tons, of both MLGW alone and Shelby County in total (snapshot in 2025 was selected when local thermal generation is maximum), (b) the total water consumption for thermal power plant cooling in Millions of Gallons, of both MLGW alone and Shelby County in total in 2025 (same reason as above), and (c) the renewable portfolio standards (RPS) or zero carbon measured by the percentage of energy from renewable resources or zero carbon technology to the total energy consumed by 2039 (the year of full deployment of the Portfolio). The lower the emission and water consumption are, the more sustainable the portfolio is, while the higher the RPS % is, the more sustainable the portfolio is, and therefore the higher the portfolio is ranked. All portfolios met the RPS target of 15% by 2039.

Reliability is measured as the sum of the total unforced generation capacity (UCAP) and firm capacity import limit (CIL) from the resource adequacy analysis divided by the summer peak demand of MLGW in 2025. The higher this percentage is, the more likely MLGW's total demand can be met reliably. It also suggests there is more flexibility in system planning and operations to allow for both scheduled and unscheduled maintenance outages.

Resiliency is measured on how the system can sustain the most extreme but very rare events, where two of the three MLGW to MISO transmission interconnection lines are out of service simultaneously. In this situation, the import capability will be severely impaired and load shedding may be required if there is insufficient local firm generation under peak demand conditions. Resilience is determined by taking the total unforced generation capacity (UCAP), (that is the emergency rating of the remaining interconnection line) subtracted from the summer peak load 3197 MW in 2025. The higher this number is, the less resilient the system will be against extreme events.

Market Risks are measured as the percentage of total energy that needs to be obtained from MISO market purchases and sales. Under Strategy 3 (Self-Supply plus MISO), MLGW is expected to procure some of the energy needs from the MISO market for both reliability and economic purposes. This dependency creates a potential market risk for MLGW for both energy availability and market price volatility. The less dependent MLGW is on the MISO market, the better MLGW is equipped to maintain price stability. This metric is calculated based on 2039 to allow the Portfolio to be fully deployed.

Economic Growth is calculated based on the total generation and transmission investment capital expenditure in the region expressed in million dollars of 2018. More capital investments could mean more job creation for both temporary construction jobs and permanent plant operation jobs. This metric only includes direct spending by MLGW, but there could be additional indirect capital investments and state and local tax revenue for the region.

Exhibit 106 shows the overall balanced scorecard for the final ten Portfolios under reference conditions (base load growth, base gas prices, base emissions, etc.). The balanced scorecard provides the ranking of each Portfolio according to each metric, and the color bands also provide an overview of the performance of each Portfolio. Green indicates scoring well relative to its peers in a metric and red indicates scoring poorly relative to its peers. The color scheme itself is purely for illustrative purposes to show the differences between the best performing Portfolio and the worst performing one for that metric. Portfolio performance within each of the metrics is discussed in detail in the following subsection.

Exhibit 106: Strategy 3 Portfolios Balanced Scorecard (Reference Case Conditions)

Category	Measure		Unit	Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4	Portfolio 5	Portfolio 6	Portfolio 7	Portfolio 8	Portfolio 9	Portfolio 10
				2 CC + 1 CT	3 CC + 1 CT	3 CC + 2 CT	3 CC + 0 CT	1 CC + 4 CT	2 CC + 1 CT	2 CC + 2 CT	2 CC + 2 CT	1 CC + 4 CT	1 CC + 0 CT
Least Cost	NPVRR 2025 - 2039		$ Millions	10,770	10,961	11,004	10,792	10,785	10,902	10,784	10,916	10,730	10,571
			% to Lowest Case	1.9%	3.7%	4.1%	2.1%	2.0%	3.1%	2.0%	3.3%	1.5%	0.0%
	Levelized Cost of Energy		$/MWh	59.5	60.5	60.8	59.6	59.6	60.2	59.5	60.3	59.3	58.4
			% to Lowest Case	1.9%	3.7%	4.1%	2.1%	2.0%	3.1%	2.0%	3.3%	1.5%	0.0%
Sustainability	2025 CO_2 Emission	MLGW Gen	Million Ton	3.0	4.2	4.5	4.2	1.4	3.0	3.2	3.2	1.4	2.7
		All Local Gen	Million Ton	6.1	7.3	7.6	7.3	4.5	6.1	6.3	6.3	4.5	5.8
		All Local Gen	% to Lowest Case	34.7%	61.4%	67.7%	61.1%	0.0%	34.5%	39.4%	39.0%	0.3%	27.7%
	2025 Water Consumption	MLGW Gen	Million Gallon	1,685	2,449	2,504	2,542	859	1,680	1,692	1,687	679	1,796
		All Local Gen	Million Gallon	4,788	5,551	5,607	5,645	3,961	4,782	4,795	4,789	3,782	4,899
		All Local Gen	% to Lowest Case	27%	46.8%	48.2%	49.3%	4.7%	26.5%	26.8%	26.6%	0.0%	29.5%
	Energy from Renewable Sources 2039 (RPS)		% of Energy	57%	46%	41%	47%	75%	55%	57%	55%	75%	53%
			% to Lowest Case	39.4%	13.3%	0.0%	16.2%	85.0%	34.8%	39.4%	34.8%	85.0%	29.4%
	Energy from Zero Carbon Sources 2039		% of Energy	57%	46%	41%	47%	75%	55%	57%	55%	75%	53%
			% to Lowest Case	39.4%	13.3%	0.0%	16.2%	85.0%	34.8%	39.4%	34.8%	85.0%	29.4%
Reliability	2025 (UCAP+CIL)/PEAK		%	126.6%	130.8%	137.3%	126.7%	126.0%	126.6%	127.2%	127.2%	127.8%	148.6%
			% to Lowest Case	0.5%	3.8%	9.0%	0.6%	0.0%	0.5%	1.0%	1.0%	1.4%	18.0%
Resiliency	Max Load Shed in 2025 under Extreme Event		MW	8	0	0	0	622	8	0	0	0	0
			% to Highest Case	1.4%	0.0%	0.0%	0.0%	100.0%	1.4%	0.0%	0.0%	0.0%	0.0%
Market Risk	% Energy Purchased from MISO		%	16.7%	7.0%	7.7%	7.4%	31.2%	17.4%	15.6%	16.2%	31.2%	23.0%
			% to Lowest Case	137.7%	0.0%	9.8%	5.4%	345.3%	148.1%	122.6%	131.5%	345.3%	227.8%
	% Energy Sold to MISO		%	10.5%	6.7%	5.6%	7.6%	22.6%	9.7%	10.6%	9.7%	22.6%	17.0%
			% to Lowest Case	86.5%	19.7%	0.0%	35.4%	301.7%	71.9%	88.0%	73.0%	301.7%	201.9%
Economic Growth	Total New T&G CapEx		$ Millions	2,811	3,299	3,404	3,138	2,989	2,845	2,932	2,965	2,864	2,984
			% to Highest Case	82.6%	96.9%	100.0%	92.2%	87.8%	83.6%	86.1%	87.1%	84.1%	87.6%

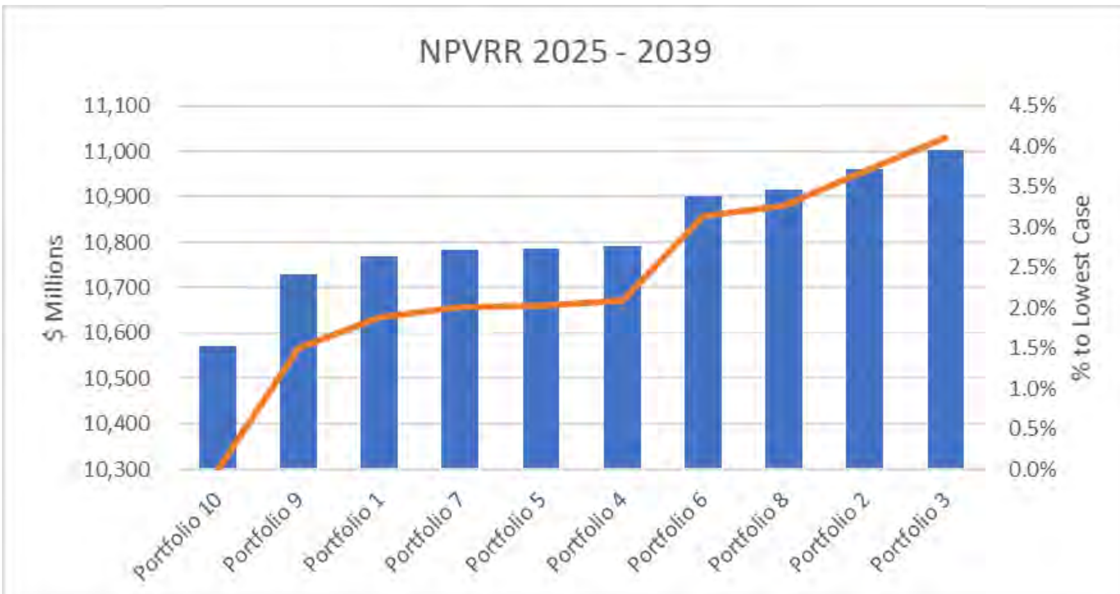
All $ in 2018 | Local = Shelby County, TN

Source: Siemens

12.4.2 Least Cost (NPVRR)

The NPVRR only varies by about 4% among all ten portfolios, with Portfolio 10 (derived from Portfolio All MISO) showing a slight advantage over the rest (even with higher amount of transmission investments than other Portfolios), followed by Portfolio 9 and Portfolio 1. Portfolio 5 is ranked 5th, behind Portfolio 7. The highest NPVRR is from the Portfolio 3 due to the largest local generation buildout (3CCGTs + 2CTs), which resulted in higher costs from generation supply side for just over $11 billion on the 15-year NPVRR basis.

Exhibit 107: Least Cost NPVRR



Note that the total NPV differences are very small for the Portfolios that one CT was added to reduce transmission costs (Portfolio 7 with respect to Portfolio 1, and Portfolio 8 with respect to Portfolio 6).

12.4.3 Sustainability

Portfolios 5 and 9 with one CC unit and heavy renewable buildout have the lowest CO_2 emission, water consumptions, and the highest RPS, all by a significant margin.

The total CO_2 and water emissions are linearly correlated with the total capacity of CCGT units.

All the portfolios met RPS targets with at least 40% in 2039. However, the high renewable Portfolios 5 and 9 surpassed 75% in 2039, which is the key driver on other component costs due to the local solar PV 1000 MW constraint assumed.

The exhibits below provide a visual comparison of the ten Portfolios.

Restrictí

Exhibit 108: 2025 CO_2 Emission

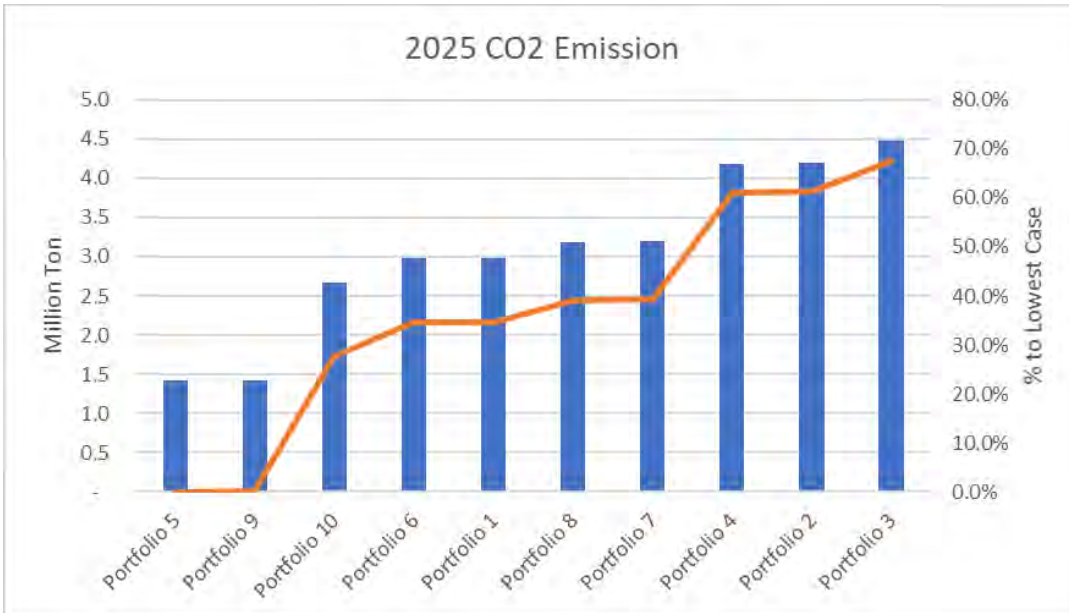
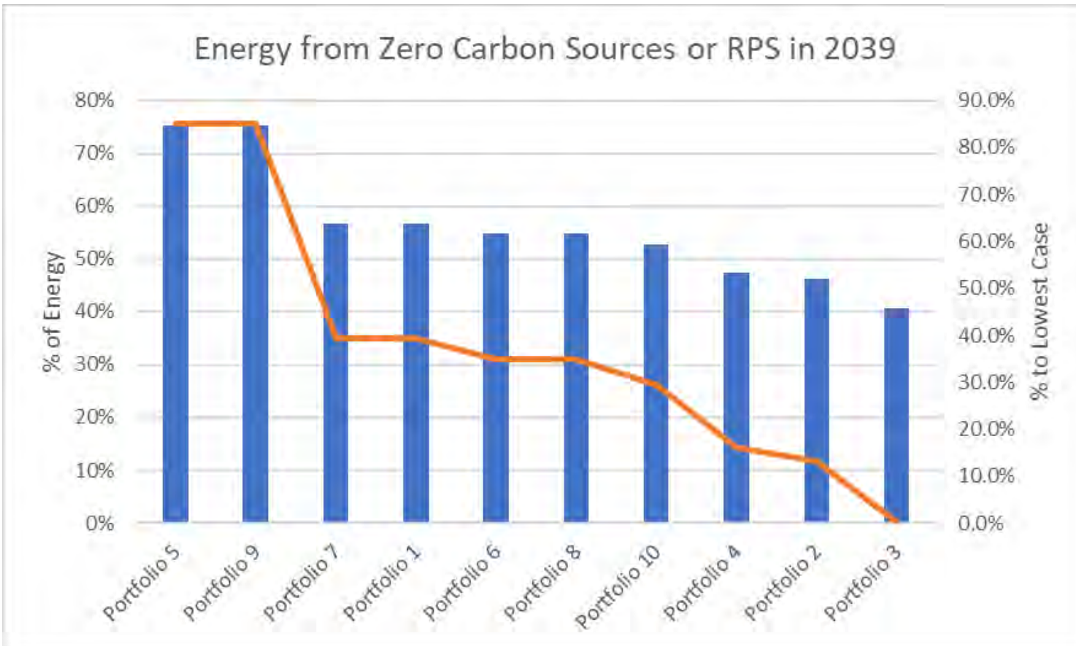


Exhibit 109: 2025 Water Consumption

Source: Siemens

Exhibit 110: Energy from Zero Carbon Sources or RPS in 2039

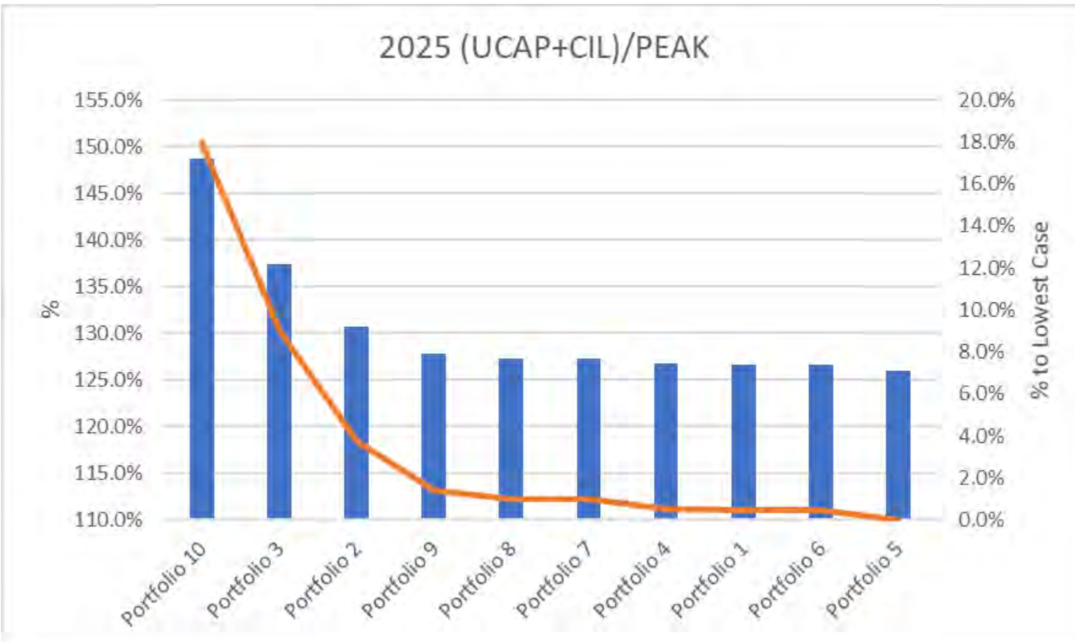


Source: Siemens

12.4.4 Reliability

Portfolio 10 ranked the highest score in the Reliability metric due to the preservation of high transmission integration with MISO for the All MISO Strategy with 148% (with the only caveat that with only one CCGT in the service territory this portfolio does require high transmission integration to address the extended outage of the CCGT and be able to address N-1-1 contingencies without load shedding). Portfolio 3 ranked the 2nd highest score at 137% which means the MLGW's load can increase up to 137% of the currently forecasted amount and still avoid load shedding. Portfolio 3 has the largest amount of local generation: 3 CCGTs and 2 CTs mainly because the original portfolio was determined based on the high load Scenario (it is also one of the higher cost portfolios for the same reason). The minimum scores are about 126%~127% because that is the requirement to meet the one day in 10 years LOLE from the resource adequacy analysis. The more local UCAP or more transmission investments the Portfolio has, the higher the Reliability metric score will be. Because MLGW's system must be reliable on day one of integration with MISO as the Strategy 3 implies, this metric was calculated based on the year 2025.

Exhibit 111: Reliability Metric



Source: Siemens

12.4.5 Resiliency

The Resiliency is assessed on the potential load shed amount by MLGW under N-2 conditions. These are the extreme but very rare events and if these occur, could mean extended power outages. All final Portfolios perform well except the Portfolio 5 which shows a possibility of more than 600 MW of load shed under extreme events. This is because the CTs were developed only in the later years and were not able to provide support to the capacity needs from the beginning. That is why we derived a modified Portfolio (Portfolio 9) by advancing all four CTs to first year 2025. As a result, Portfolio 9 is not expected to incur any load shed under N-2 extreme events.

12.4.6 Market Risk

Portfolios 5 and 9 have the highest Market Risk due to their dependency of energy import/purchase from the MISO market compared with other Portfolios. About 31% of the energy for these Portfolios is from imports, as compared to 7% from Portfolio 2 or Portfolio 3 with 3 CCGTs. Portfolios 5 and 9 are more vulnerable to the uncertainty in market prices and the cost of renewables. These are also heavily dependent on MLGW's ability to secure large amounts of renewables via bi-lateral power purchase agreements (PPAs). The more local generation MLGW acquires via PPAs (or builds), the more independent MLGW is of the outside (MISO) market.

The Market Risk of energy sales is not as significant as the risk from energy purchases, given that the nature of the energy surplus coming from MLGW is mostly energy from renewable generation. Market purchases mostly at night, when renewable is not available, represent a higher risk due to price volatility.

Exhibit 112: Market Risk-Energy Purchases

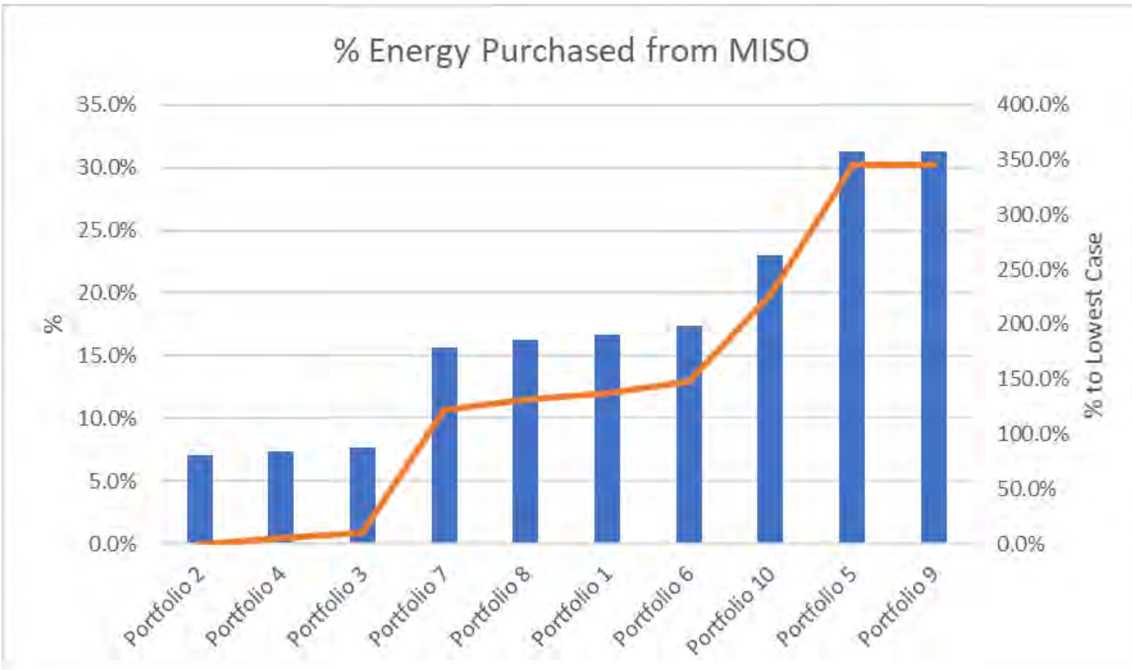
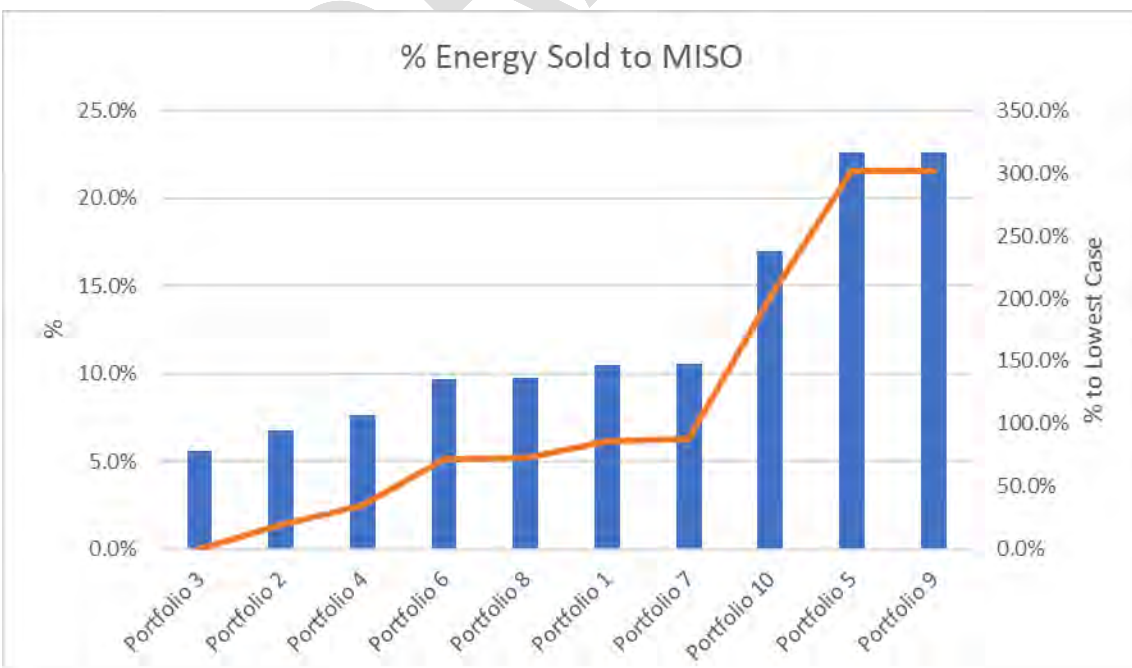


Exhibit 113: Market Risk-Energy Sales



Source: Siemens

12.4.7 Economic Growth

Substantial amounts of capital investments are expected should MLGW decided to leave TVA and join MISO. The capital investments include approximately $700 million to $1 billion for transmission and $2 to $2.7 billion for new generation for a total of $2.8 to $3.4 billion depending on the specific Portfolio. The total capital investment is balanced between transmission and generation investments. The main difference is related to the amount of local generation, where the Portfolio 3 with locally built 3 CCGTs and 2 CTs in the expansion plan will cost approximately $2.7 billion in capital from generation side, which requires the minimum investment on transmission at $700 million.

The Economic Growth is measured by total capital expenditure which is directly contributing to the economic growth in the region. It also means job creation, more state and local tax revenue as well as attracting other businesses, directly or indirectly related to the power infrastructure sector.

Exhibit 114: Local Economic Growth T&G CapEx

Source: Siemens

12.5 Selected Portfolios Deterministic Results

Appendix D: Portfolio Details contains the detailed generation buildout by year and by technology type for each of the ten selected final Portfolios as well as various key performance metrics. These are presented under Reference Scenario conditions.

12.6 Risk Assessment (Stochastic)

After selecting the portfolios for further consideration and completion of the deterministic (Scenario based) risk assessment and sensitivities, the remaining step is to conduct the 200 iterations or stochastic risk assessment and complete the balanced scorecard, consider "other" relevant factors and select the preferred portfolio given all of that information.

The comprehensive risk analysis using 200 iterations or scenarios provides a more comprehensive assessment of how the portfolios are likely to perform under a wide range of conditions. As with any analysis, the risk analysis and the balanced scorecard that is developed from it, does not provide MLGW with an answer, but rather they are intended to provide insights into the pluses and minuses and risks associated with a variety of portfolios over a range of future conditions.

The relevant information is provided in many of the metrics in the balanced scorecard. The benefit of conducting the stochastic risk assessment is that MLGW can get a clearer picture of the tradeoffs between least cost (the portfolio that has the lowest deterministic NPVRR may not have the best risk profile), cost uncertainty (measured by the 95th percentile of cost outcomes over the planning horizon), regret (measured as the difference between a portfolio outcome and the best portfolio for a given future), the carbon emissions profile of the portfolios, and the percentage dependence on energy and capacity purchases and sales of the portfolios.

After this comparison we will also discuss other factors that must be considered, such as diversity, flexibility, and optionality to adapt to conditions that might cause stranded or uneconomic assets.

A summary of how the portfolios performed against each of the above risk metrics is provided in Exhibit 115, including the color code described earlier. Portfolio 5 and 9 have the best performance from a least cost (affordability) point of view, followed by Portfolio 6 and Portfolio 8. All cases with 3 CCGTs perform worse in general. This greater risk of thermal generation is linked to the fuel risks are presented later. The results below are derived from the stochastic runs and Portfolio 10 (derived from All MISO) would rank third (if adjusted by the savings in fixed costs of developing the resources locally).

Exhibit 115: IRP Portfolio Balanced Scorecard (Risk Elements)

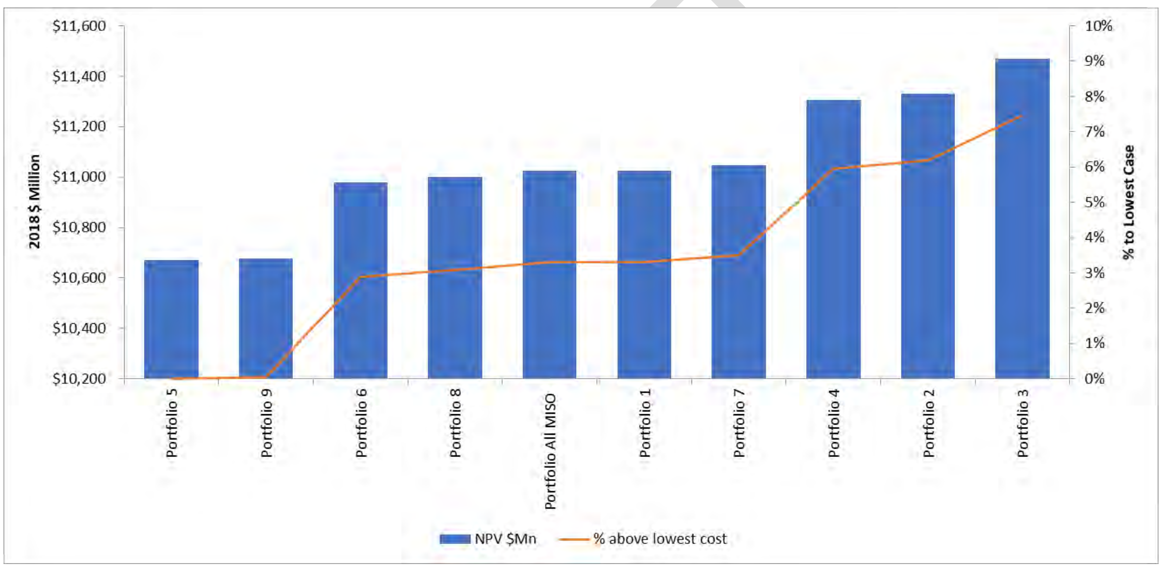
Objective	Measure	Unit	Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4	Portfolio 5	Portfolio 6	Portfolio 7	Portfolio 8	Portfolio 9	Portfolio All MISO
			2 CC + 1 CT	3 CC + 1 CT	3 CC + 2 CT	3 CC + 0 CT	1 CC + 4 CT	2 CC + 1 CT	2 CC + 2 CT	2 CC + 2 CT	1 CC + 4 CT	1 CC + 0 CT
Least Cost	Stochastic Mean 2025 - 2039 NPVRR	$ millions	11,025	11,332	11,468	11,306	10,671	10,980	11,045	11,000	10,677	11,024
		% to Lowest Case	3.3%	6.2%	7.5%	5.9%	0.0%	2.9%	3.5%	3.1%	0.1%	3.3%
Risk / Regret Minimization	95th Percentile Value of NPVRR	$ millions	13,429	13,948	14,227	14,172	13,001	13,270	13,454	13,268	12,952	13,605
		% to Lowest Case	3.7%	7.7%	9.8%	9.4%	0.4%	2.5%	3.9%	2.4%	0.0%	5.0%
	Regret (NPVRR - Best NPVRR)	$ millions	462	769	905	743	108	417	482	437	114	461
		% to Lowest Case	327%	610%	736%	586%	0%	285%	346%	304%	6%	326%
Min Envr. Risk	CO_2 Emissions Mean 15-Year	Tons CO_2	1,930,578	2,895,274	2,896,460	2,894,089	965,011	1,930,578	1,931,764	1,931,764	969,439	2,254,723
		% to Lowest Case	100%	200%	200%	200%	0%	100%	100%	100%	0%	134%
Energy Market Risk Minimization	% Energy Purchased in Market	%	29.9%	23.4%	28.0%	26.3%	35.1%	27.3%	29.9%	27.3%	35.0%	31.0%
		% to Lowest Case	27.8%	0.0%	19.9%	12.2%	49.9%	16.8%	27.7%	16.8%	49.7%	32.5%
	% Energy Sold in Market	%	10.8%	9.8%	6.7%	8.2%	23.7%	15.3%	10.8%	15.3%	23.7%	16.3%
		% to Lowest Case	62.1%	47.3%	0.0%	23.0%	255.9%	129.2%	62.1%	129.2%	256.0%	143.9%
Min Cap. Mkt Risk	Portfolio Capacity Market Purchases 2020-2039	MW	1931	1655	1509	1943	1885	1808	1720	1598	1270	2082
		% to Lowest Case	52%	30%	19%	53%	48%	42%	35%	26%	0%	64%

Each of the metrics are discussed in detail in the following section.

12.6.1 Least Cost (Affordability)

The Mean of the Net Present Value is one of the most important attributes, as it represents the financial viability of the portfolio. The following NPV portfolio cost ranking shows that Portfolio 5 is the lowest in cost, closely followed by Portfolio 9. These two Portfolios have the highest renewable component. Portfolio 5 depends heavily on transmission as there is only one CCGT installed by 2025 and the CTs are not yet in the system. Meanwhile, Portfolio 9 has one CCGT, plus all four CTs installed in 2025. The next lowest cost portfolio was Portfolio 6, which is 2.9% more expensive than Portfolio 5, closely followed by Portfolios 8, All MISO, 1, and 7 whose NPVRRs were within 1% of each other. All these portfolios have two 1x1 CCGTs, or one 2x1 CCGT (Portfolio All MISO). Portfolios 2 and 4 are about 6% more expensive than the lowest cost portfolio, where Portfolio 3 ends up being the highest cost portfolio, which is 7.5% higher than the lowest cost portfolio. These last portfolios have 3 CCGTs and Portfolio 3, in addition, has 2 CTs. The exhibit below shows the ranking according to this metric.

Exhibit 116: Mean of NPVRR



12.6.2 Price Risk Minimization

In addition to the expected NPVRR of portfolio cost, the cost stability plays an important role in determining the preferred portfolio, especially when considering the worst-case outcome of a portfolio. Among the selected portfolios (see below), Portfolio 5 and 9 have the lowest price risk, closely followed by Portfolios 1, 6, 7, and 8. Exhibit 117 shows the 95th percentile of NPVRR for each portfolio. The 95th percentile costs of the Portfolio 2, 3, and 4 are over 7% higher than the lowest cost Portfolios. In general, as noted above, the portfolios with more CCGTs have higher portfolio cost and price risk, due to the exposure to fuel risk as presented later.

Exhibit 118 shows the trade-off of NPVRR and variability (Standard Deviation) of NPVRR. Portfolio 5 shows the best cost-risk trade-off, while Portfolio 3 (3 CCGTs + 2 CTs) has poorest expected cost-risk tradeoff compared with other portfolios. We also note clusters around 1 CCGT (Portfolio 5, 9), 2 CCGTs (Portfolios 1, 6, and 7) and 3 CCGTs (Portfolios 2, 3, and 4).

Exhibit 117: 95th Percentile of NPVRR

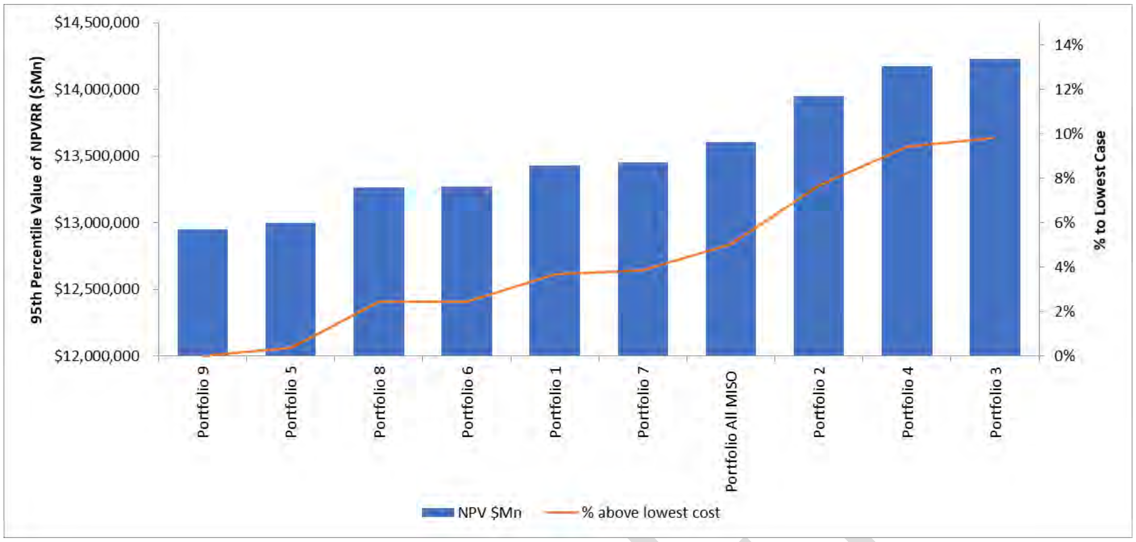
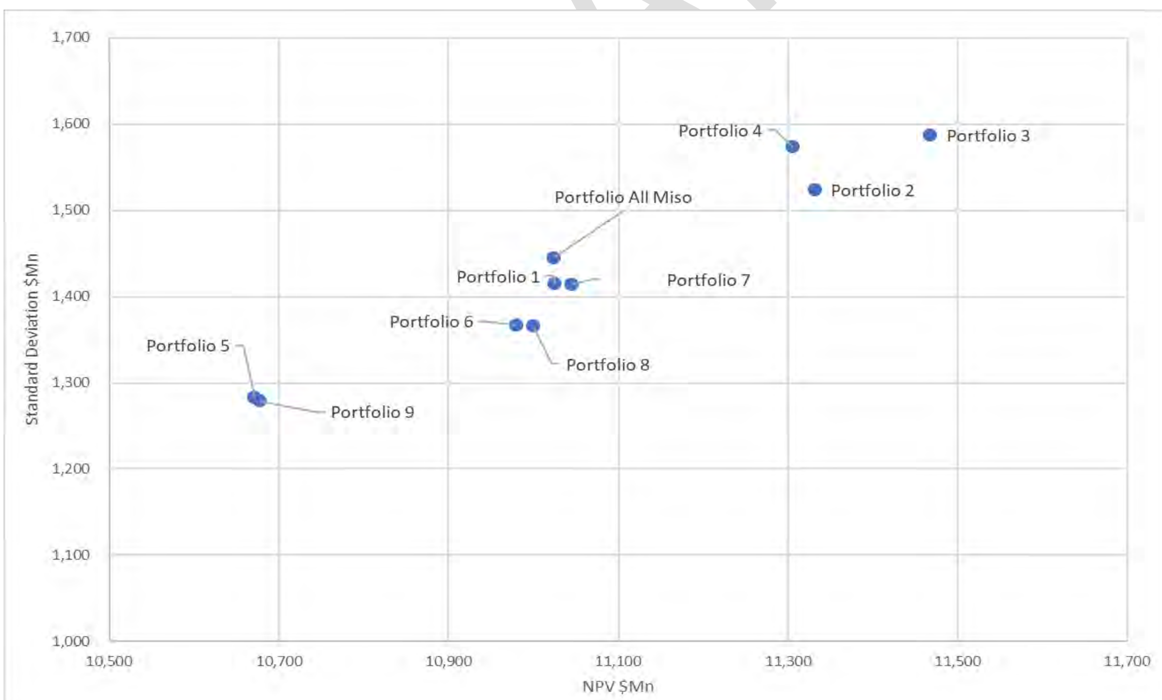


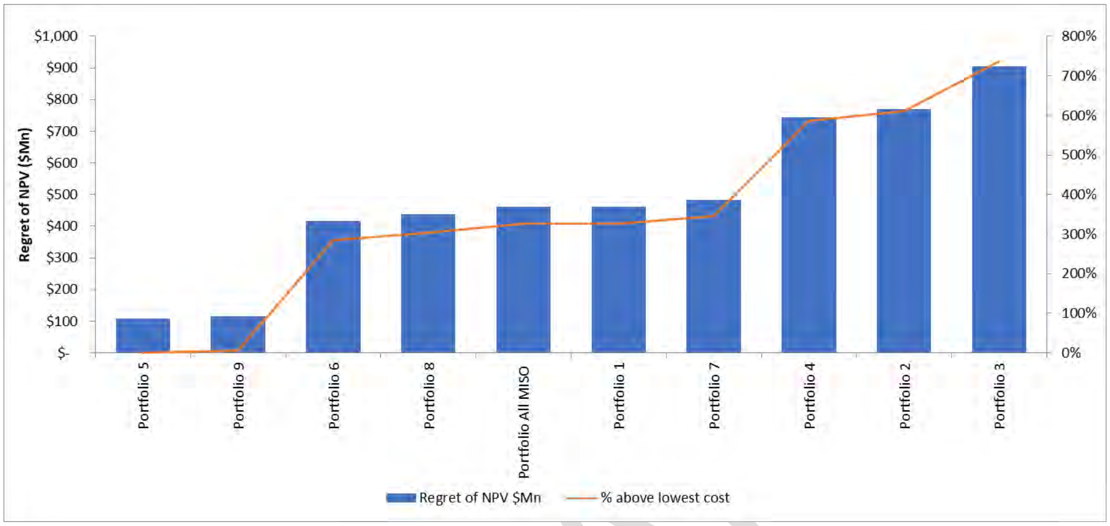
Exhibit 118: Cost-Risk Trade-off



Source: Siemens

Another measure for price risk is regret, which illustrates the level by which MLGW would regret having chosen a Portfolio in case of an adverse future. Similarly, Portfolio 5 and 9 have the least regret in terms of NPV of revenue requirements and could be considered a minimum regret Portfolio in this respect. Portfolio 3, on the other hand, has the most regret. Exhibit 119 shows the regret by Portfolio.

Exhibit 119: NPVRR Regret



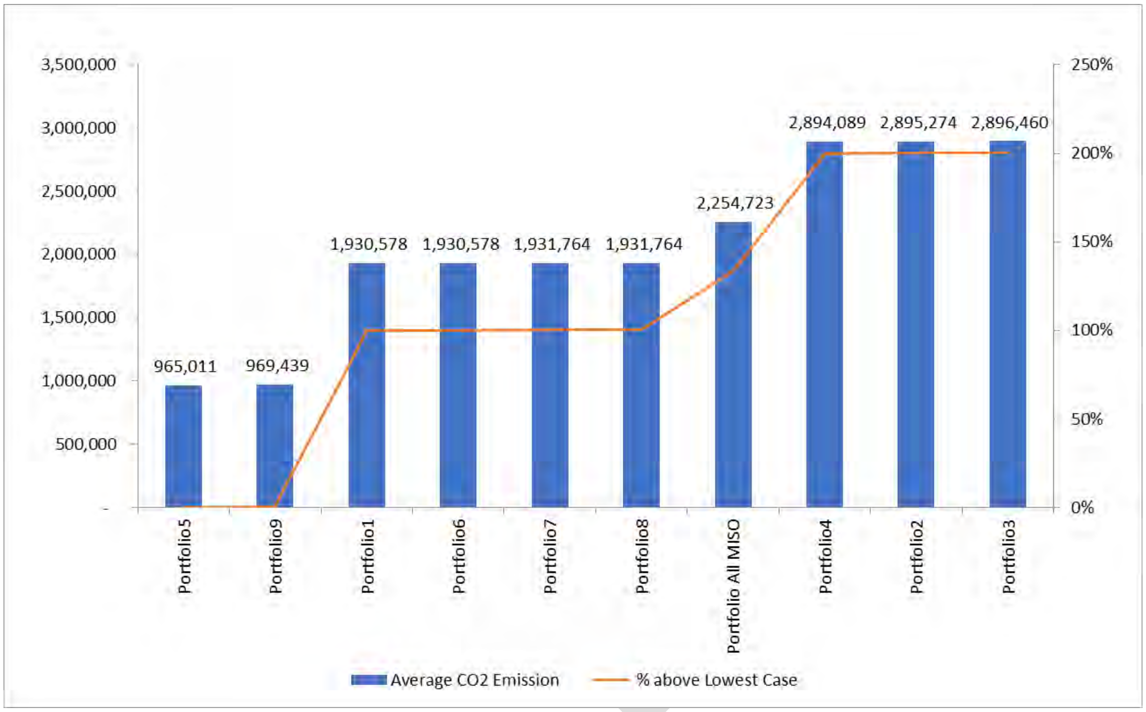
Source: Siemens

12.6.3 Environmental Risk Minimization

The environmental risk is measured as average annual portfolio carbon emissions. Less natural gas and more renewables will result in lower carbon emissions for the portfolio. Combined cycle units specifically will result in higher emissions due to their higher utilization (higher capacity factors). Because combustion turbines (CT) operate at much lower overall utilization, the resulting emissions have a lower impact to the overall portfolio emissions. Portfolios 5 and 9 have one combined cycle unit and the lowest emissions. Portfolios 1, 6, and 7 have two combined cycle units and emissions are around two times that of Portfolio 5. Portfolio All MISO has one large 2x1 combined cycle unit, so it has slightly more emissions. The other portfolios (Portfolios 2, 3, and 4) have 3 combined cycle units and total carbon emissions are the greatest at just under 3 million tons (see Exhibit 120).

All portfolios would result in lower emissions relative to that expected, if MLGW continues with TVA supply, as will be shown in Section 13.

Exhibit 120: Average CO_2 Emissions from 2025 to 2039 (tons)



Source: Siemens

12.6.4 Market Risk Minimization

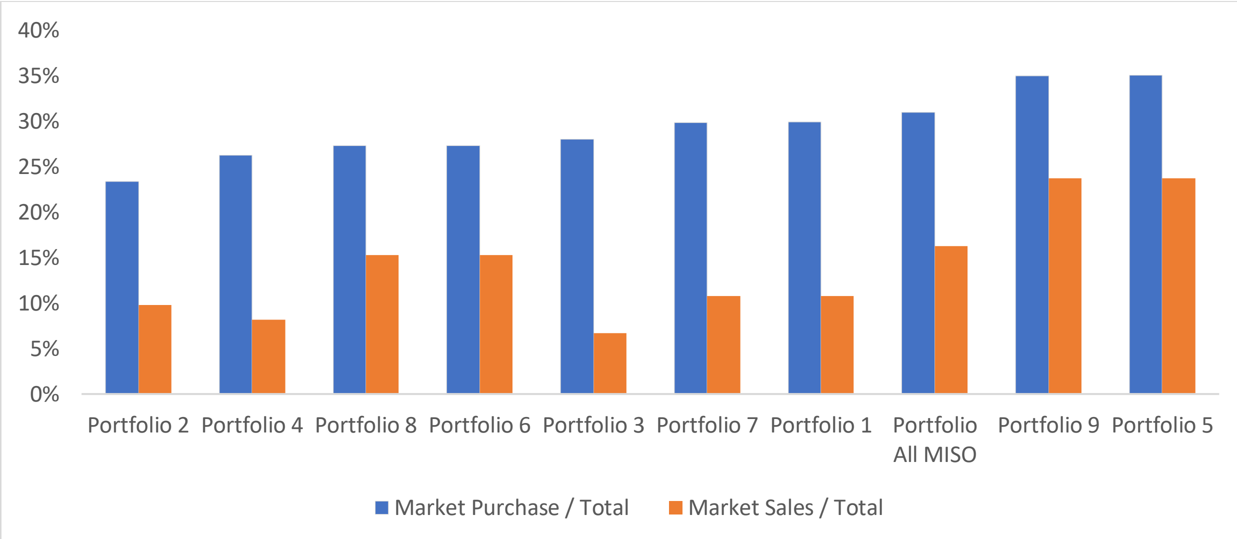
If MLGW were to join MISO, a significant portion of MLGW's energy and capacity need may come from the MISO energy market and capacity market. The amount of spot energy purchases depends on MLGW's total energy need, as well as the least cost dispatch of MISO resources, and the amount of capacity needs depends on the forecasted peak demand. Therefore, the amount needed for each portfolio varies depending on the market conditions and MLGW's load forecast.

Energy Market Risk Minimization

Thermal resources perform differently under different market conditions, affected by gas prices, CO_2 prices, and the supply / demand balance of the region. Exhibit 121 shows the average percentage of energy exposed to market purchases and market sales, respectively. The higher the percentage is, the market risk is higher, and the portfolio cost is more likely to be affected by the volatility in MISO market prices. When generation mix from the selected portfolio is more aligned with MLGW's load shape, the portfolio is less exposed to the market. Therefore, relying heavily on a technology that is only available during certain hours of the day, i.e., solar PV for Portfolio 5, will bring more market risk for the portfolio.

Due to this time limitation of solar technology, MLGW must rely on the MISO market to sell the excess energy during the day and buy energy to serve load during the night, resulting in higher exposure to market prices.

Exhibit 121: Market Purchase and Sales as Percentage of Load

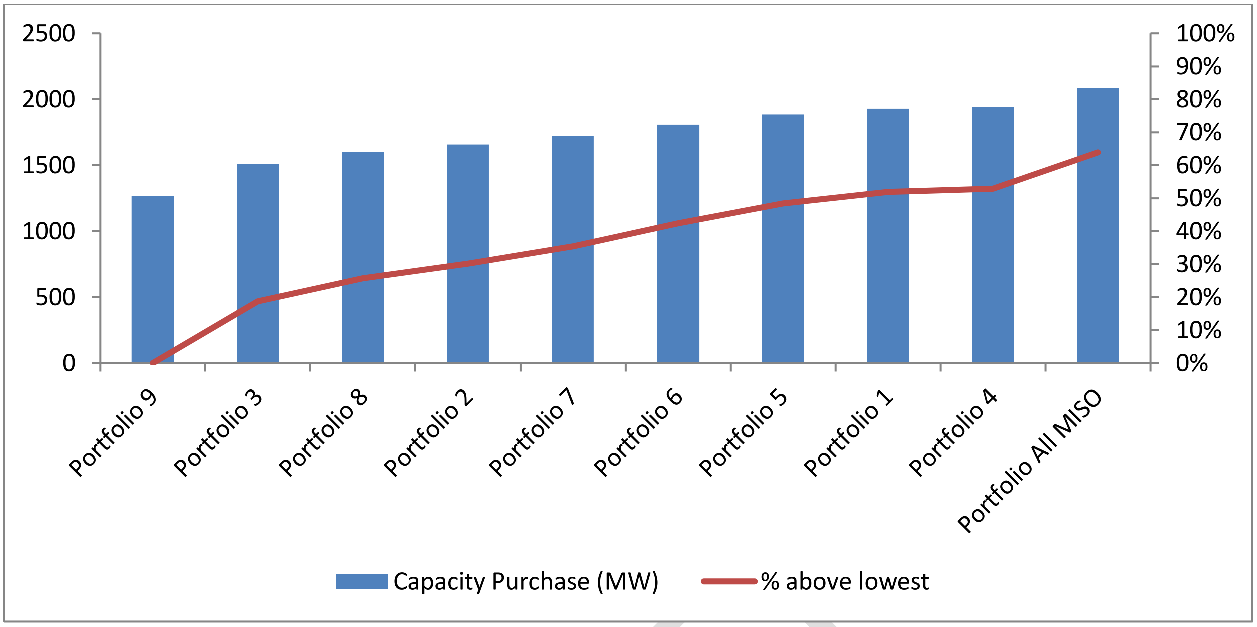


Source: Siemens

Capacity Market Risk Minimization

The amount of MISO capacity purchases varies slightly between each portfolio, based on the capacity and timing of each technology. Having more power plants built early in the study period will reduce the market exposure risk. MISO capacity purchase is calculated based on MLGW's peak demand for each iteration, averaged from 2025 to 2039 Portfolio 9 is the least exposed to the capacity market, because it has the most thermal plants, which contribute fully to the reserve margin. Portfolio 4 has higher capacity purchase risk because a large amount of solar generation does not come online until 2030, and solar unforced capacity (UCAP) also declines over time.

Exhibit 122: MISO Capacity Purchase



Source: Siemens

12.6.5 NPV Correlation with Inputs

In order to understand the drivers behind the results just presented, it is necessary to assess how market changes drive the NPV of each portfolio. For the input parameters that vary stochastically across each iteration, some have more correlated impact on the portfolio cost (such as gas prices and load), others do not. The following section elucidates the impact of several important inputs.

NPV Correlation with Gas Prices

As illustrated in Section 11, gas prices are quite volatile, with a wide range of outcomes in the medium to long term, which could be driven by increased gas demand, fracking regulation, environmental regulation, etc. In our forecast, the standard deviation expressed as a function of the mean of annual gas prices is about 40%; i.e. it is quite uncertain. Fuel cost is a large portion of total portfolio cost. Therefore, there is a strong correlation between average Henry Hub gas prices, and the NPVRR of each portfolio. Three representative portfolios with different number of CC units are presented in the following exhibit to illustrate this correlation.

Exhibit 123: NPVRR with Henry Hub Gas Price Correlation (Portfolio 3)

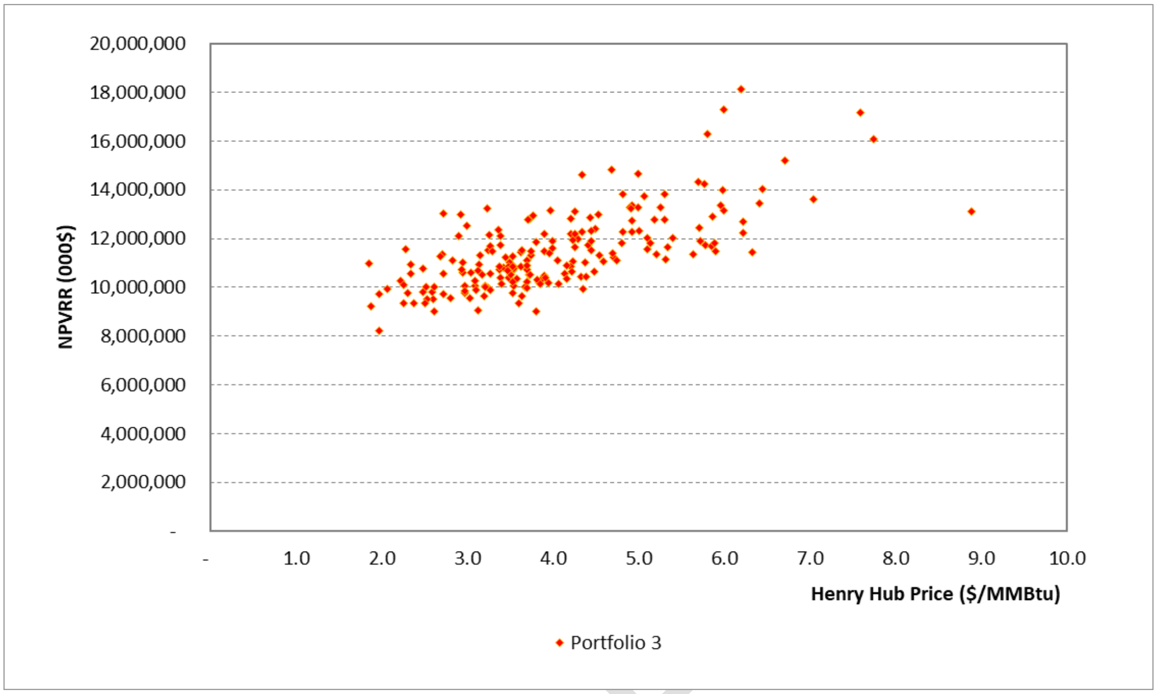
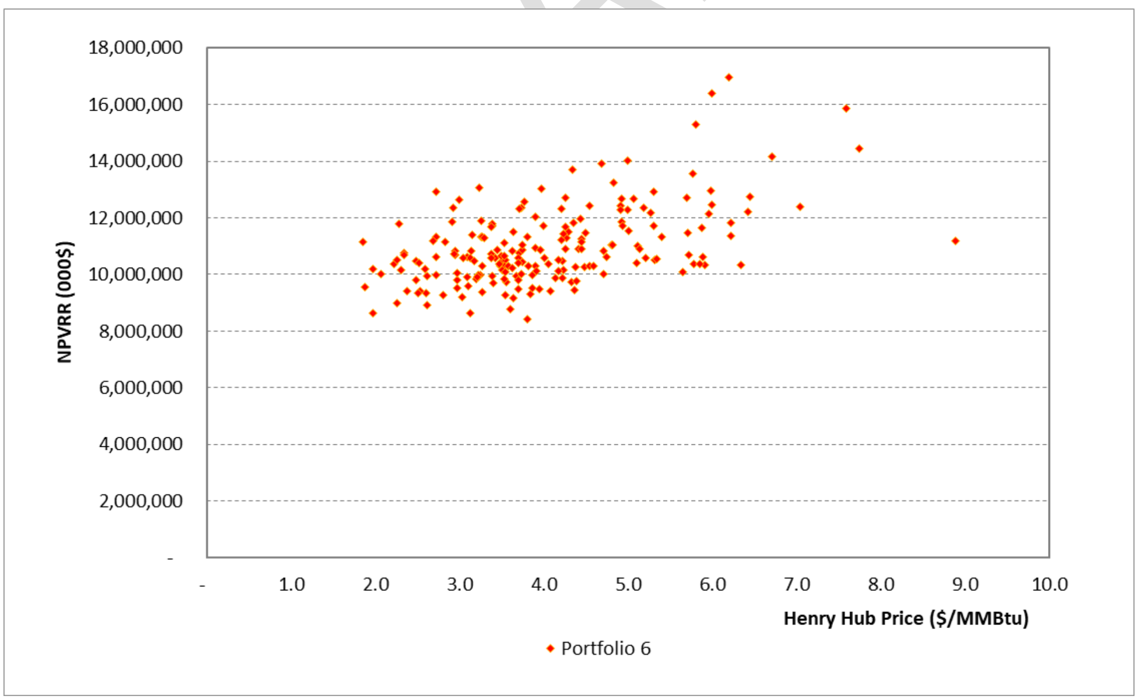
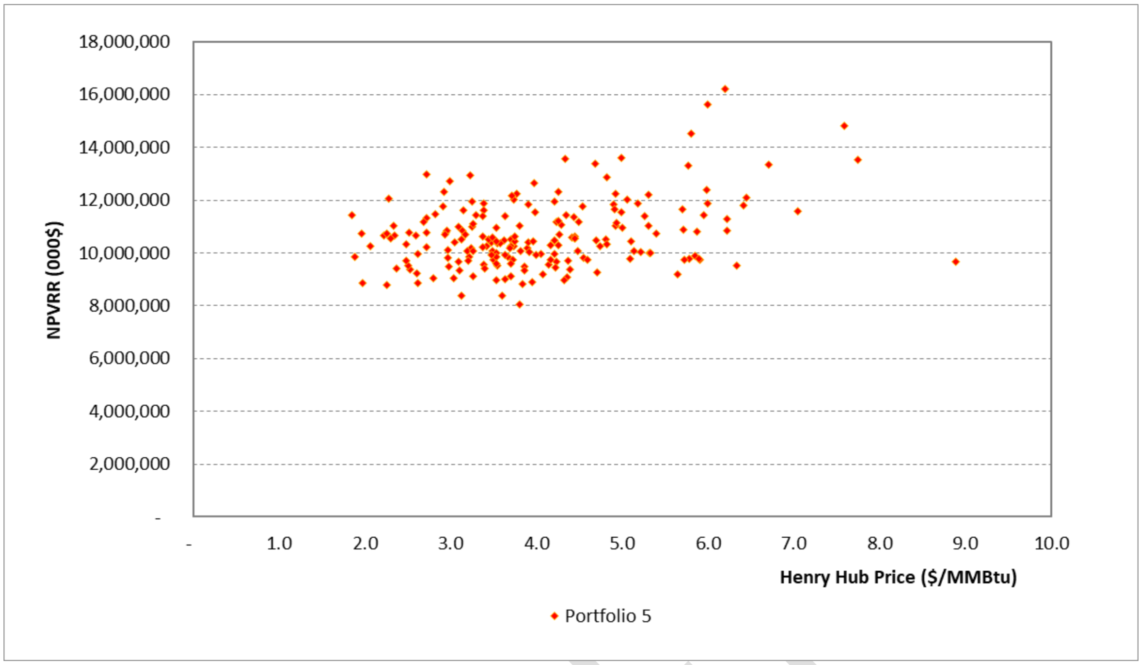


Exhibit 124: NPVRR with Henry Hub Gas Price Correlation (Portfolio 6)



Source: Siemens

Exhibit 125: NPVRR with Henry Hub Gas Price Correlation (Portfolio 5)



Source: Siemens

The exhibit above shows that Portfolio 3 (3 CCGTs) has a strong positive correlation between average Henry Hub prices and NPVRR, while Portfolio 6 (2 CCGTs) has a positive correlation. For Portfolio 5 (1 CCGT), there is not much correlation.

NPV Correlation with Load

Load is a large driver of the NPVRR. Using Portfolio 6 as an example, Exhibit 126 shows a strong and tight positive correlation between the NPV of annual energy and NPVRR However, if we take out the impact of the absolute value of the load from the NPV and only show the $/MWh cost for the NPV, there is no correlation.

Exhibit 126: NPVRR with Load (Portfolio 6)

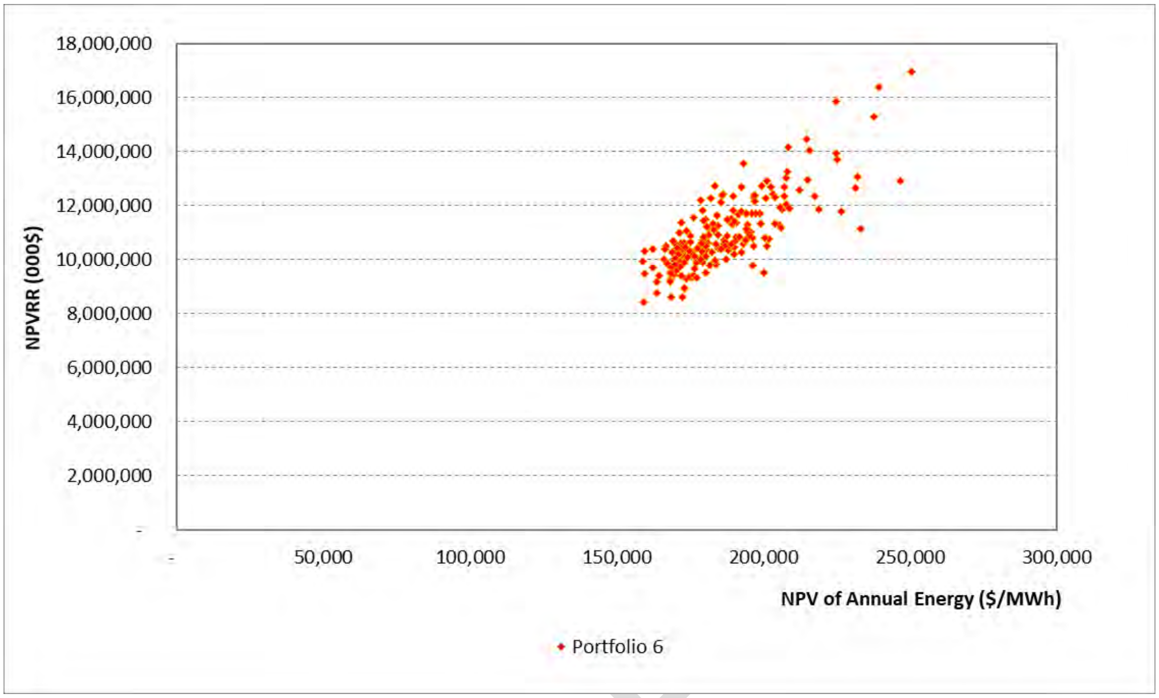
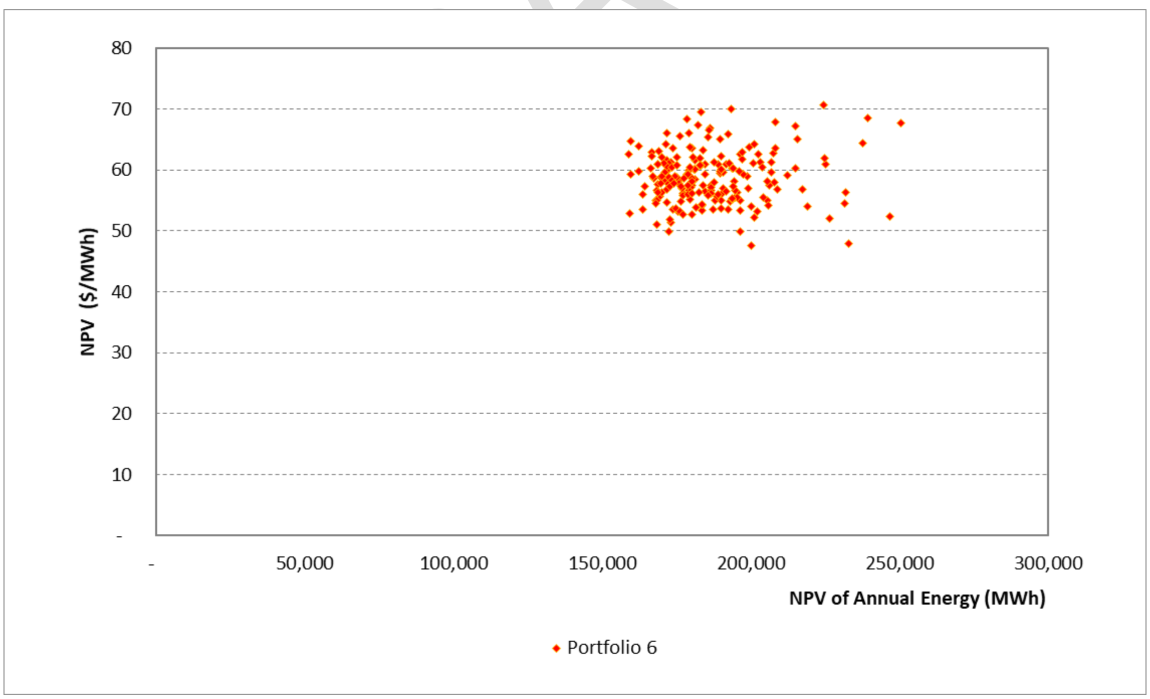


Exhibit 127: NPVRR per MWh with Load (Portfolio 6)



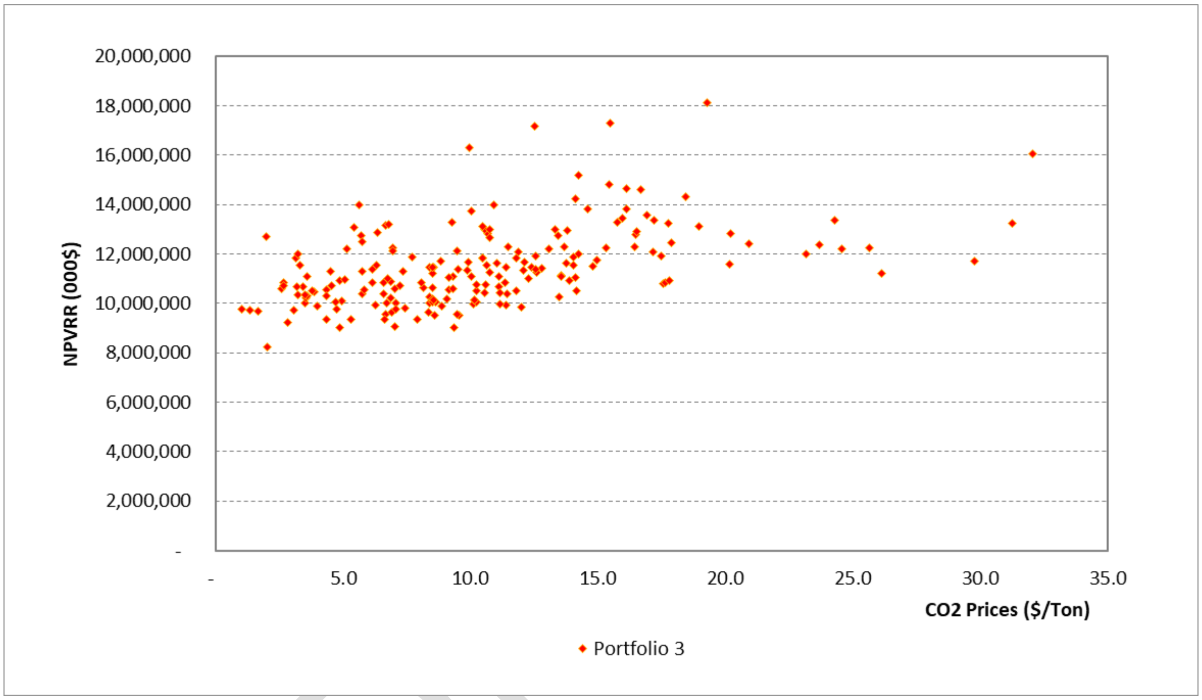
Source: Siemens

Restricted

NPV Correlation with CO_2 Prices

Emissions cost accounts for a small portion of the total portfolio cost. Therefore, although CO_2 price has a wide range of future outcomes, its impact on the portfolio cost is very small. Using Portfolio 3, which is the highest emitting portfolio, as an example, Exhibit 128 shows weak correlation between the average CO_2 price and NPVRR.

Exhibit 128: NPVRR with CO2 Prices (Portfolio 3)



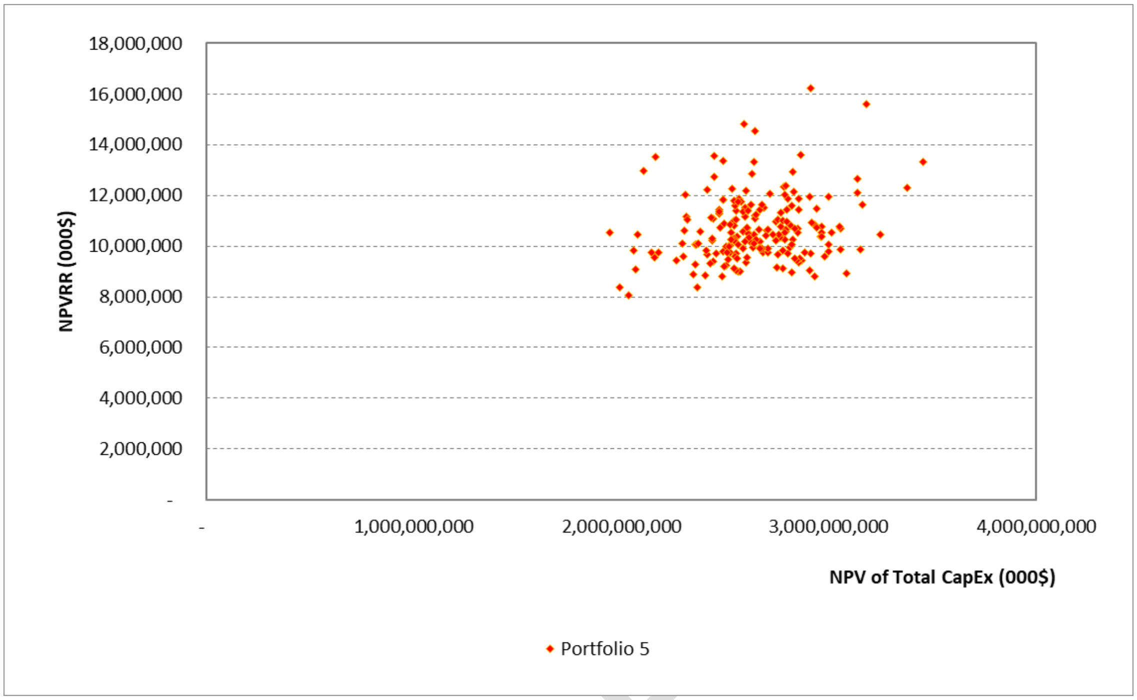
Source: Siemens

NPV Correlation with NPV of Capital Cost

As illustrated in Section 11, the distribution of capital cost is based on the view of future all-in capital costs, historical costs, and volatilities, and captures the additional uncertainty with each technology that factors in learning curve effects, improvements in technology over time, and other uncertain events such as leaps in technological innovation. In our forecast, the standard deviation over the NPV of total capital cost for each portfolio is about 10%, as compared with 40% for Henry Hub gas prices. Although capital costs a large portion of total portfolio cost, the low volatility of the aggregated capital costs, results in capital not being a good explanatory variable for the variability of the NPV, with other factors being better explanatory variables, as for example gas prices.

The weak correlation can be observed in the exhibit below for Portfolio 5 that has the largest capital cost. The trend is clearly in the positive direction, but the variability is not heavily correlated.

Exhibit 129: NPVRR with CapEx (Portfolio 5)



Source: Siemens

12.6.6 Strategy 3 Self-Supply Plus MISO Final Observations

Portfolio 5 with only one CCGT in year 2025 has the lowest expected value of the NPVRR and lowest risk as measured in 95th percentile and regret. It also has the best environmental performance. However, from a reliability point of view it complies but is below the other Portfolios and unless the CTs are advanced to 2025 (which makes it Portfolio 9), there is the risk of load shed under extreme events.

Portfolio 9 has similar as Portfolio 5; it is less than 1% more expensive and slightly higher emitting than Portfolio 5. With all four CTs installed by 2025, there would be no load shedding under the extreme event considered. Portfolios 6 and 8, that accelerate the installation of PV with two CCGTs and complemented with one or two additional CTs, have the next best performance on NPVRR. Portfolio 8 has adequate performance on reliability and there would be no load shed during the extreme event considered. The stochastics of Portfolio 10 were not assessed, but it is expected to behave the same as the All MISO portfolio with reduced fixed costs that would make it slightly worse than Portfolio 9. The estimated results of Portfolio 10 are provided in Section 15 and the Executive Summary.

Exhibit 130: Summarized Scorecard

Objective	Measure	Unit	Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4	Portfolio 5	Portfolio 6	Portfolio 7	Portfolio 8	Portfolio 9	Portfolio All MISO
			2 CC + 1 CT	3 CC + 1 CT	3 CC + 2 CT	3 CC + 0 CT	1 CC + 4 CT	2 CC + 1 CT	2 CC + 2 CT	2 CC + 2 CT	1 CC + 4 CT	1 CC + 0 CT
Least Cost	Stochastic Mean 2025 - 2039 NPVRR	$ millions	11,025	11,332	11,468	11,306	10,671	10,980	11,045	11,000	10,677	11,024
		% to Lowest Case	3.3%	6.2%	7.5%	5.9%	0.0%	2.9%	3.5%	3.1%	0.1%	3.3%
Risk / Regret Minimization	95th Percentile Value of NPVRR	$ millions	13,429	13,948	14,227	14,172	13,001	13,270	13,454	13,268	12,952	13,605
		% to Lowest Case	3.7%	7.7%	9.8%	9.4%	0.4%	2.5%	3.9%	2.4%	0.0%	5.0%
	Regret (NPVRR - Best NPVRR)	$ millions	462	769	905	743	108	417	482	437	114	461
		% to Lowest Case	327%	610%	736%	586%	0%	285%	346%	304%	6%	326%
Minimum Environmental Risk	CO_2 Emissions Mean 15-Year	Tons CO_2	1,930,578	2,895,274	2,896,460	2,894,089	965,011	1,930,578	1,931,764	1,931,764	969,439	2,254,723
		% to Lowest Case	100%	200%	200%	200%	0%	100%	100%	100%	0%	134%
Energy Market Risk Minimization	% Energy Purchased in Market	%	29.9%	23.4%	28.0%	26.3%	35.1%	27.3%	29.9%	27.3%	35.0%	31.0%
		% to Lowest Case	27.8%	0.0%	19.9%	12.2%	49.9%	16.8%	27.7%	16.8%	49.7%	32.5%
	% Energy Sold in Market	%	10.8%	9.8%	6.7%	8.2%	23.7%	15.3%	10.8%	15.3%	23.7%	16.3%
		% to Lowest Case	62.1%	47.3%	0.0%	23.0%	255.9%	129.2%	62.1%	129.2%	256.0%	143.9%
Minimum Capital Market Risk	Portfolio Capacity Market Purchases 2020-2039	MW	1931	1655	1509	1943	1885	1808	1720	1598	1270	2082
		% to Lowest Case	52%	30%	19%	53%	48%	42%	35%	26%	0%	64%

Source: Siemens

Currently, the Portfolios with three CCGTs all appear to be the least desirable, while the best portfolios include one CCGT.

13. All MISO Strategy

13.1 Introduction

Strategy 4 – the All MISO Strategy in this IRP consists of MLGW procuring all its supply needs from resources that are located within MISO's current footprint. The energy and capacity needs are procured via PPA contracts new resources, as in other portfolios, but all resources are in MISO, supplemented by MISO Capacity purchases via bi-lateral contracts and market purchases. Any combination of resources within MISO was available including MISO Capacity purchases, energy market purchases or new resources to be contracted via PPAs.

No new local generation inside of the MLGW footprint was an option in this strategy. Due to this restriction, this Strategy was not expected be a least cost option, because local thermal generation or renewable generation is expected to be less expensive than their remote counterparts.

The least cost Portfolio for Strategy 4 was developed and subjected to the full range of stochastics as were other Portfolios under Strategies 1 and 3.

Strategy 4 requires the largest transmission buildout to be fully interconnected with MISO, compared to any of the Portfolios under Strategies 1 and 3. Because there is no local generation to be developed, the whole system load has to rely on the transmission interconnections to MISO, and various transmission analyses have to be assessed based on (N-2) outage conditions. As discussed in Section 8 of this report, for Strategy 4, an additional high voltage interconnection line must be constructed, and the total transmission expenditure is more than $1 billion; over $400 million more than the baseline plan on the capital expenditure on transmission. Siemens prepared the transmission plan for Strategy 4 and provided it to MISO for independent feasibility review and cost estimation.

13.2 Portfolio Selection and Analysis

The LTCE module of AURORA was used to determine the generation expansion plan under Strategy 4. The only exception was that under this Strategy, no local resources were offered as options for the program to select, and thus we force the program to select resources in MISO only.

The simulation was performed on the Reference Scenario with base load and base gas price forecasts to ensure equal comparison with Portfolios under Strategy 3. Unlimited transmission import capability was given to the program to ensure the program can select as many resources as optimally needed. Thus, only one portfolio was selected under this Strategy as the final Portfolio for further analysis, named Portfolio All MISO, or All MISO for short.

The least cost portfolio consisted of one large CCGT (950 MW), 3200 MW in total of MISO solar, and procured approximately 1700 to 2300 MW of MISO Capacity throughout the planning horizon, as shown in the exhibit below.

Exhibit 131: Portfolio All MISO

Final Portfolio	Load	Gas Price	Total Thermal 2039	Local Renew 2039	Battery 2039	Total Local Nameplate 2039	MISO Renew 2039	MISO Cap 2039	950 MW CC	450 MW CC	237 MW CT	NPV Demand (MWh)	Portfolio NPV Cost ($000)	Demand Weighted NPV ($/MWh)
Portfolio All MISO	Base	Base	950	0	0	0	3200	1909	1	0	0	181,088,154	8,778,702	48.48

Source: Siemens

As discussed in Section 12, based on the buildout above, a modified portfolio was created by moving the large CCGT and 1000 MW solar to local MLGW; this was called Portfolio 10, and was studied along with other Portfolios under Strategy 3.

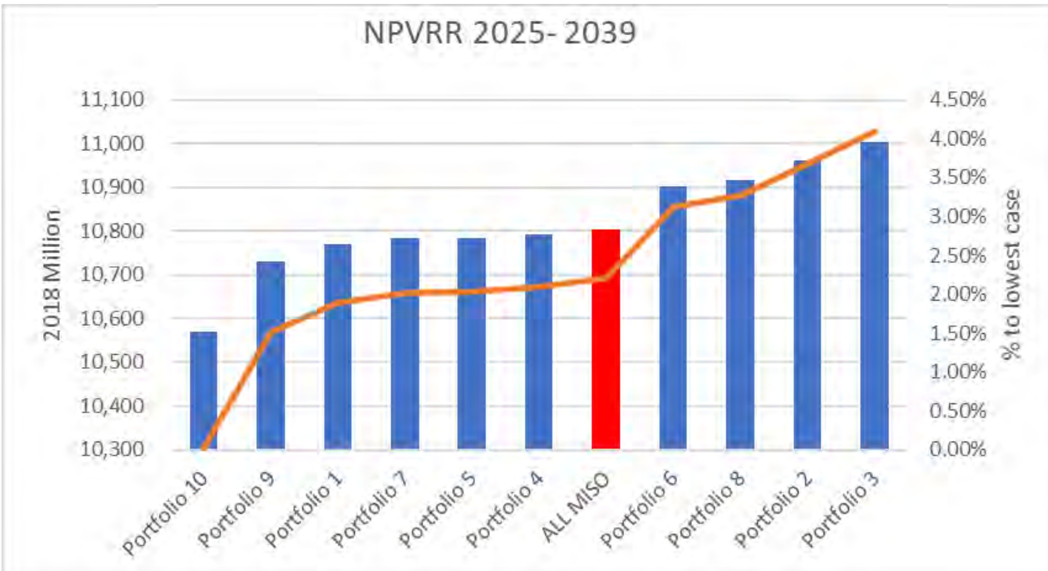
13.3 Portfolio Deterministic Results

We present next the results of this portfolio under reference conditions (base load growth, base gas prices, etc.) for the key selected metrics.

13.3.1 Least Cost

The All MISO Portfolio does produce a relatively lower NPV from the generation supply side compared to other Strategy 3 Portfolios at $8.78 billion on the 15-year NPV basis or $48.48/MWh as weighted by NPV demand in energy. However, when other cost components are added, especially the $1 billion transmission cost, the All MISO Portfolio's NPVRR increases to $10.8 billion on the 15-year NPV basis or $59.66/MWh as weighted by NPV demand in energy. This place the All MISO Portfolio about in the middle among all final Strategy 3 Portfolios, more costly than the Portfolios with 1 CCGT or some with 2 CCGTs. This is shown in the exhibit below.

Exhibit 132: NPV of Revenue Requirements



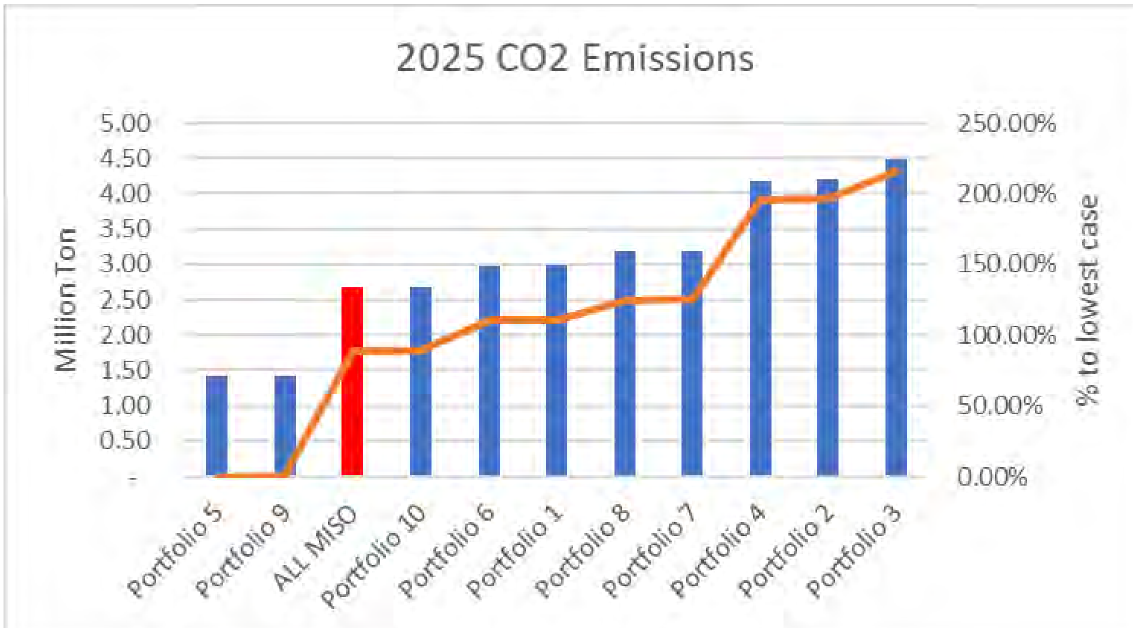
Source: Siemens

13.3.2 Sustainability

Although the All MISO Portfolio does not produce CO_2 emissions in Shelby County, CO_2 is a global issue and it does emit 2.67 million tons of CO_2 in MISO Arkansas and requires about 1800 million gallons of water to cool the combined cycle unit in 2025

According to the emissions the All MISO portfolio has fewer emissions than most portfolios with the exception Portfolio 5 and 10 as shown below.

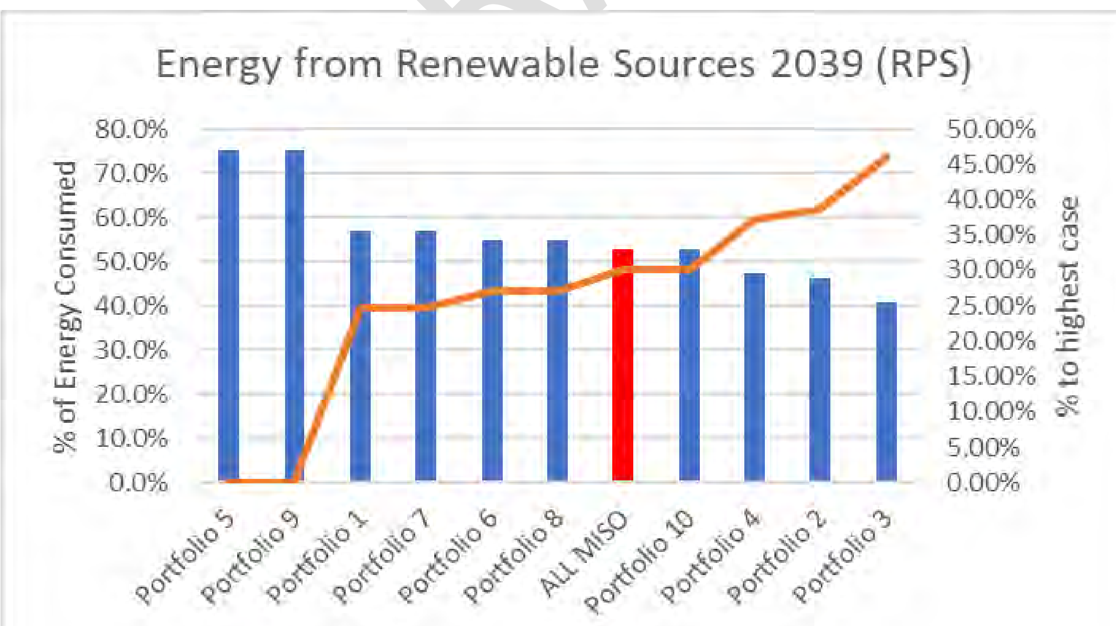
Exhibit 133: CO_2 Emissions



Source: Siemens

This portfolio has similar levels of renewable zero carbon generation as other portfolios with two CCGTs, and at about 50% renewable it is in the middle of the group.

Exhibit 134: Energy from Zero Carbon Sources or RPS in 2039

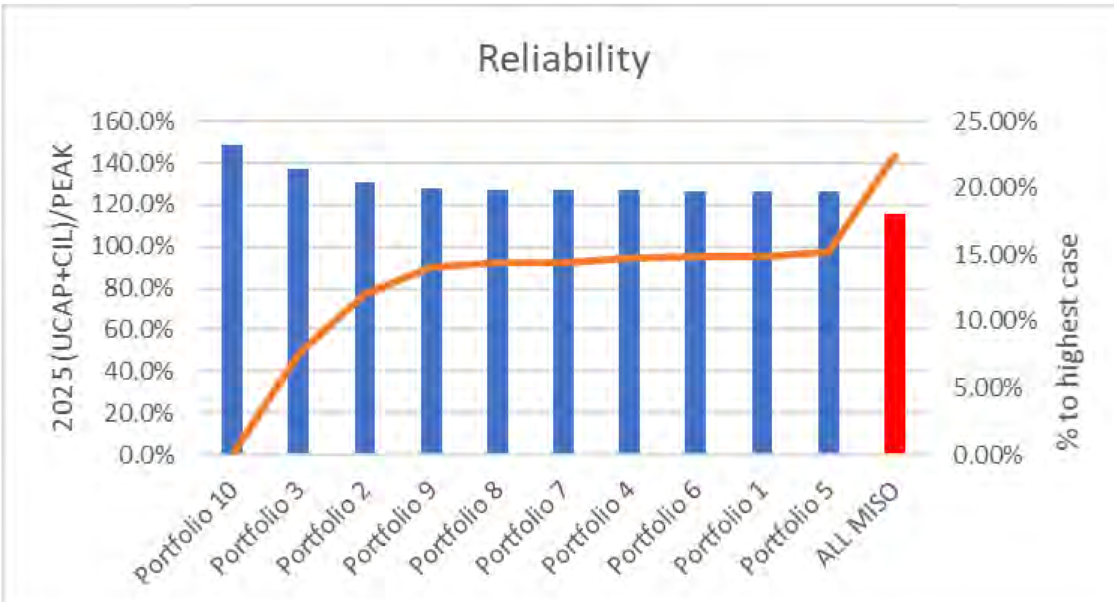


Source: Siemens

13.3.3 Reliability

This Portfolio does include over $1 billion on transmission investments, however, with no local generation providing UCAP, the reliability score solely relied on the CIL, which in this case was assessed based on N-2 transfer analysis. The CIL was calculated to be 3690 MW or 115.4% of the 2025 summer peak load. Although the CIL is more than the peak load value, this reliability score is the lowest among the final Portfolios with all the other Portfolios achieving least 126%.

Exhibit 135: Reliability Metric



Source: Siemens

13.3.4 Resiliency

The resiliency metric of Portfolio All MISO is estimated to be good, due to a total of 4 high voltage interconnection lines into MISO. No load shedding is normally expected under extreme events.

13.3.5 Market Risks

In this portfolio the MISO market purchases are about 23% and sales are about 17% of load by 2039, which is in between the other Portfolios with 1 CCGT and 2 CCGTs, and higher than the ones with 3 CCGTs. This is consistent with the Portfolio makeup of one large CCGT.

Restricted

Exhibit 136: Market Purchases

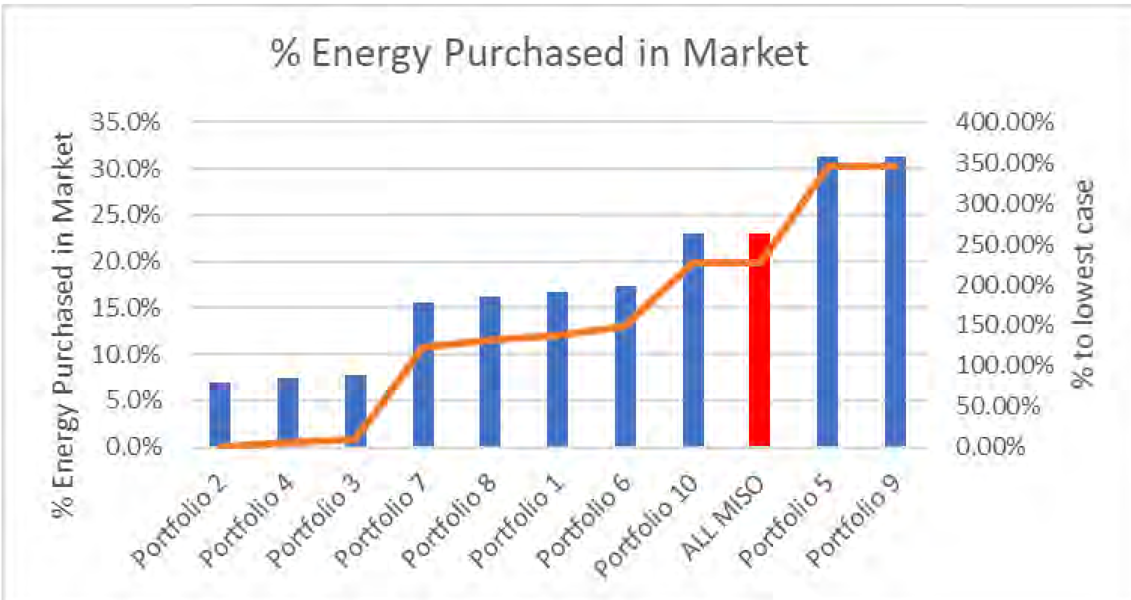
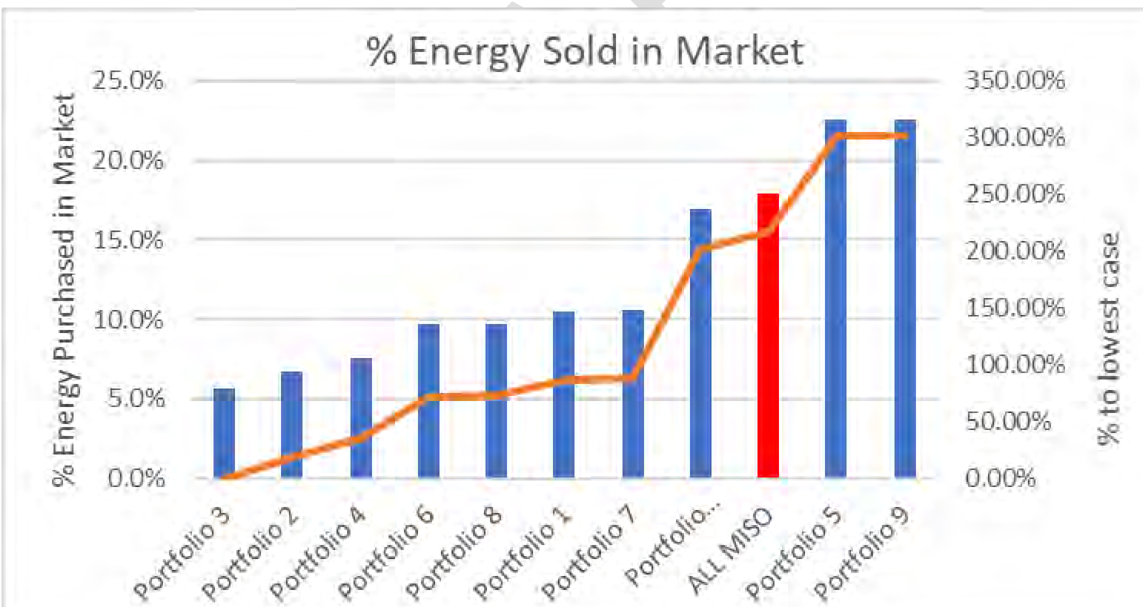


Exhibit 137: Market Sales



Source: Siemens

13.3.6 Economic Growth

Because all new generation will be developed within the MISO footprint, the only growth that fits the economic growth criteria is the local transmission investments. As stated previously, the transmission investments are about $1 billion for the All MISO Portfolio, which is significantly less than $3 billion in investments for other Strategy 3 Portfolios.

13.3.7 Selected Deterministic Results

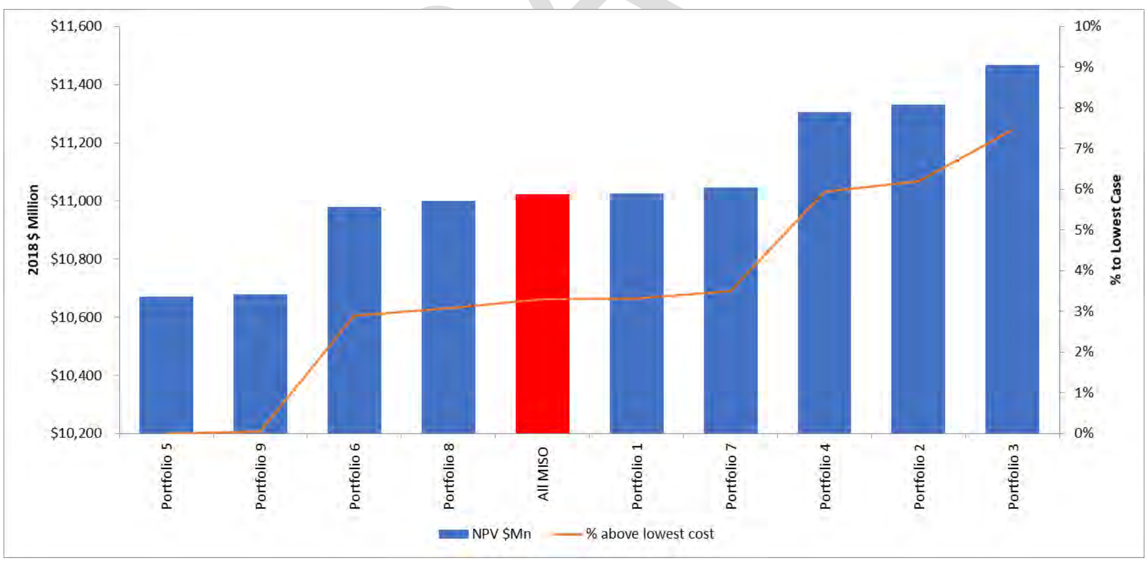
Appendix D: Portfolio Details contains the generation buildout by year and by technology type for this All MISO Portfolio, as well as various key performance metrics.

13.4 Portfolio Stochastic Results

13.4.1 Least Cost

The Mean of the Net Present Value is one of the most important attributes, as it represents the financial viability of the portfolio. As show below the All MISO portfolio ranks in the middle of portfolios analyzed, behind portfolios with one CCGT and some with two CCGTs, due to its exposure to gas prices.

Exhibit 138: Mean of NPVRR



Source: Siemens

13.4.2 Price Risk Minimization

Cost stability plays an important role in determining the preferred portfolio, especially when considering the worst-case outcome of a portfolio. The All MISO Portfolio has higher risk than most portfolios except for those portfolios with three CCGTs and has greater regret than portfolios with one CCGT and some with two CCGTs, as shown below.

Exhibit 139: 95th Percentile of NPVRR

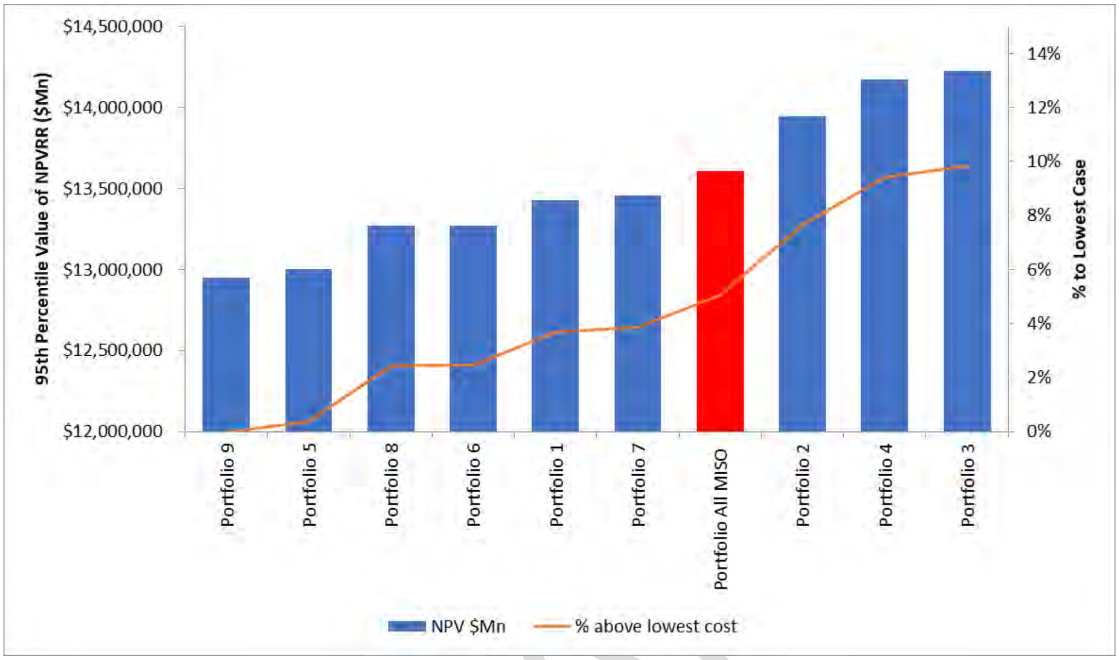
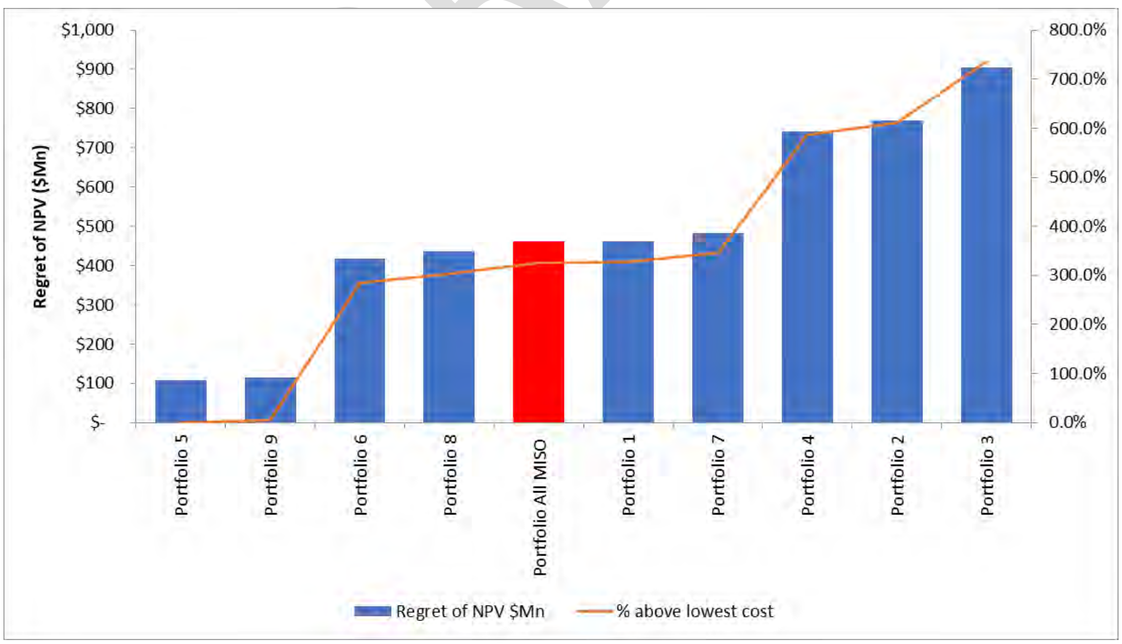


Exhibit 140: NPVRR Regret

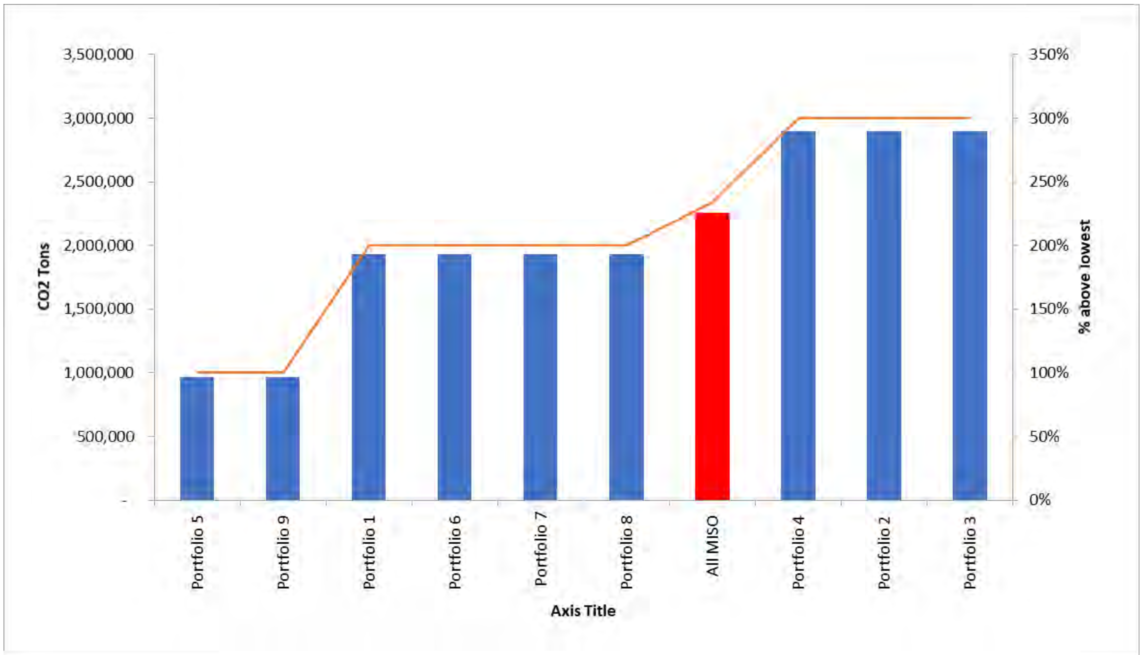


Source: Siemens

13.4.3 Environmental Risk

The environmental risk is measured as average annual portfolio carbon emissions. Less natural gas and more renewables will result in lower carbon emissions for the portfolio. Combined cycle units, specifically, will result in higher emissions due to their higher utilization (higher capacity factors). This affects the All MISO Portfolio; it ranks just before those portfolios with three CCGTs.

Exhibit 141: Average CO_2 Emissions from 2025 to 2039 (tons)



Source: Siemens

13.4.4 Market Risk Minimization

If MLGW were to join MISO, a significant portion of MLGW's energy and capacity needs may come from the MISO energy market and capacity market. The Portfolio All MISO has higher risk, as measured in terms of energy purchases and sales, than most portfolios, with the exception of Portfolio 5 and 9. It also has greater dependence on capacity purchases in the market than all other Portfolios, as shown in the exhibit below.

Exhibit 142: Market Purchase and Sales as Percentage of Load

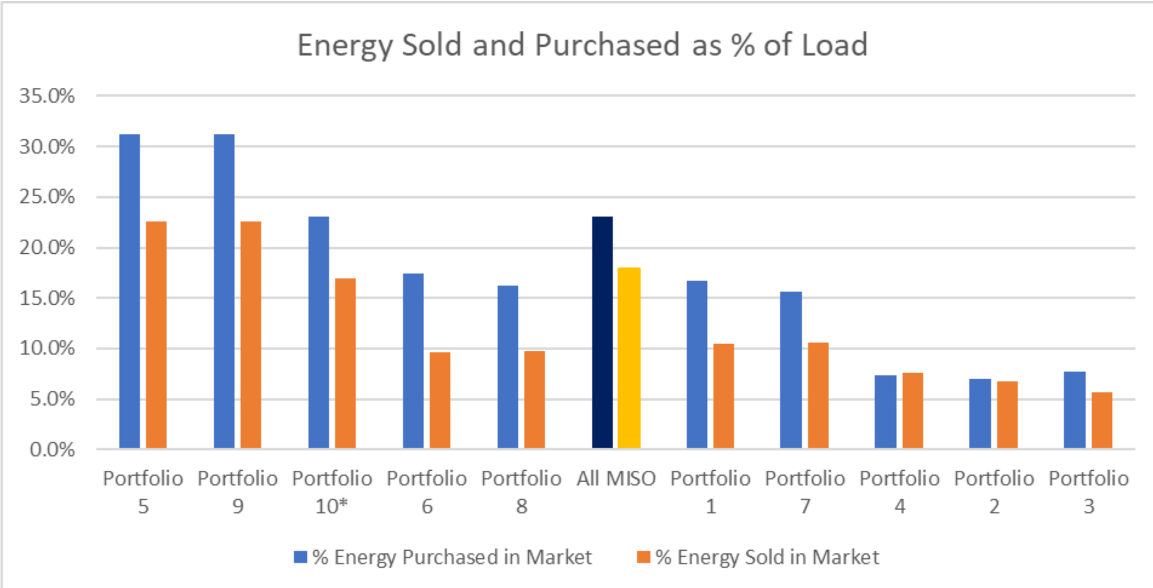
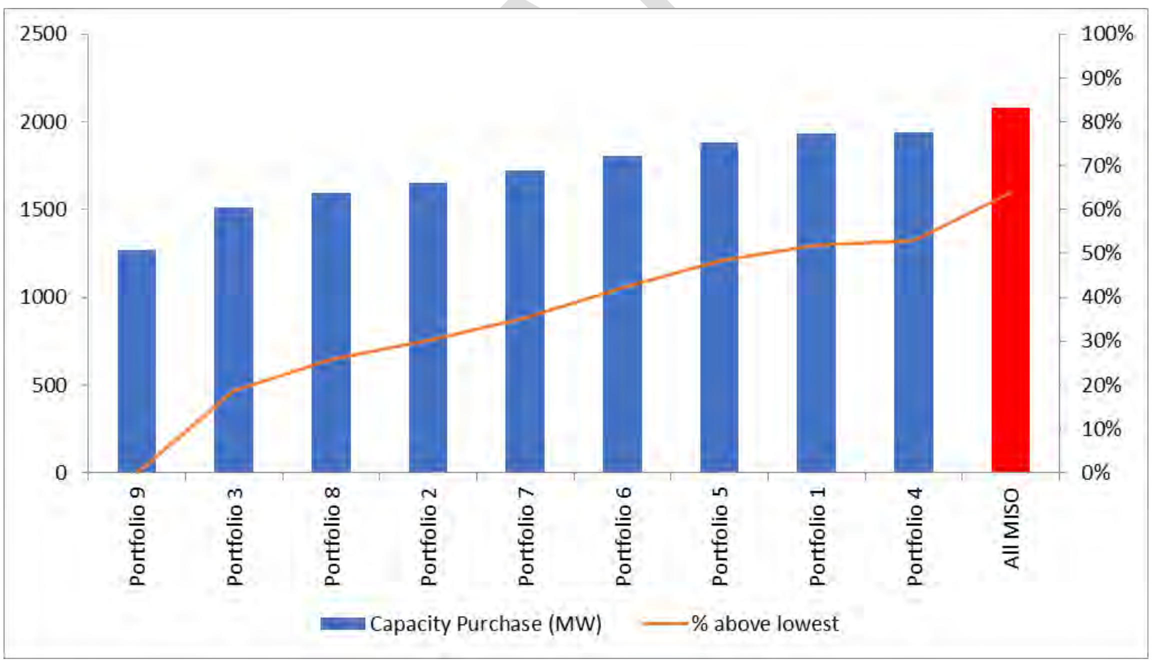


Exhibit 143: MISO Capacity Purchase



Source: Siemens

14. TVA – Status Quo Analysis

Strategy 1 of this IRP consists of continuing with TVA, either in the current contract model that maintains going forward the option to give notice with 5 years, or the Long-Term Partnership model that extends the notice period to 20 years. In this section we provide an assessment of the expected costs that MLGW would be likely to face under Strategy 1. The assessment is based in our review of TVA's rate methodology and uses it to assess the costs that MLGW is likely to incur.

14.1 TVA's Rate Methodology

In setting the base rates, TVA uses the Debt-Service Coverage (DSC) methodology to derive annual revenue requirements. Using this methodology, rates are calculated so that TVA will be able to cover its operating costs and to satisfy its obligations to pay principal and interest on debt outstanding. TVA's revenue requirements are based on the following cost categories:

- Fuel and Purchased Power
- Operations and Maintenance (O&M)
- Base Capital
- Interest
- Tax Equivalents (Payment in Lieu of Taxes)
- Debt Paydown, and
- Other

While categories such as fuel and purchased power, O&M, and interest expense are self-explanatory, the other cost categories require further explanation and are described below:

- "Base Capital" is the maintenance capital for TVA's assets that is funded through rates as opposed to being funded through debt.
- As a federal agency, TVA is exempt from taxation at the federal and state level. Instead of direct taxes, TVA makes "Tax Equivalent" payments to the states and counties in which TVA conducts power operations. This is also known as Payments in Lieu of Taxes (PILOT) and was discussed earlier in this report.
- The "Debt Paydown" category consists of two distinct cost categories: (i) strategic capital, and (ii) net annual change in the total financing obligations. The strategic capital category covers capital expenditures for capacity expansion and environmental matters. The second category is the net position considering payoff of existing long- and short-term debt and assumption of new long- and short-term debt in a given year.

- All remaining proceeds and uses of cash, as well as non-cash adjustments required to arrive at cash available for debt principal reduction (e.g. other revenue), are covered under the “Other” cost category.

14.2 TVA’s Revenue Requirement Model

For the past 80 years, MLGW has received all its power supply under an All Requirements Contract (also referred to as the WPC) with TVA. Under the contract, TVA supplies all the energy and capacity required by MLGW customers. In order to estimate the future rate that MLGW will need to pay TVA for its wholesale supply needs, Siemens created a pro forma financial model of TVA’s revenue requirements that is further described in this section.

In order to do so, Siemens developed future estimates of the cost components described in TVA’s Rate Methodology section above. Siemens independently developed future estimates of cost elements such as fuel and purchased power, O&M, and capital expenditures for capacity expansion, whereas for other cost components Siemens relied upon projections provided by TVA.

In addition to the cost components described in TVA’s Rate Methodology section above, Siemens added one additional cost component to the revenue requirements calculations; this component is “TVA's Direct Spend to Benefit all Local Power Companies (LPCs).” The components that make up this expenditure include:

- Economic Development Benefits
- Community Benefits, e.g. Home Uplift
- Community Investments
- Comprehensive Services Program
- 161kV Transmission Line Lease Payment (for Memphis-only)

The exhibit below provides correlation between the revenue requirement cost components and the data sources.

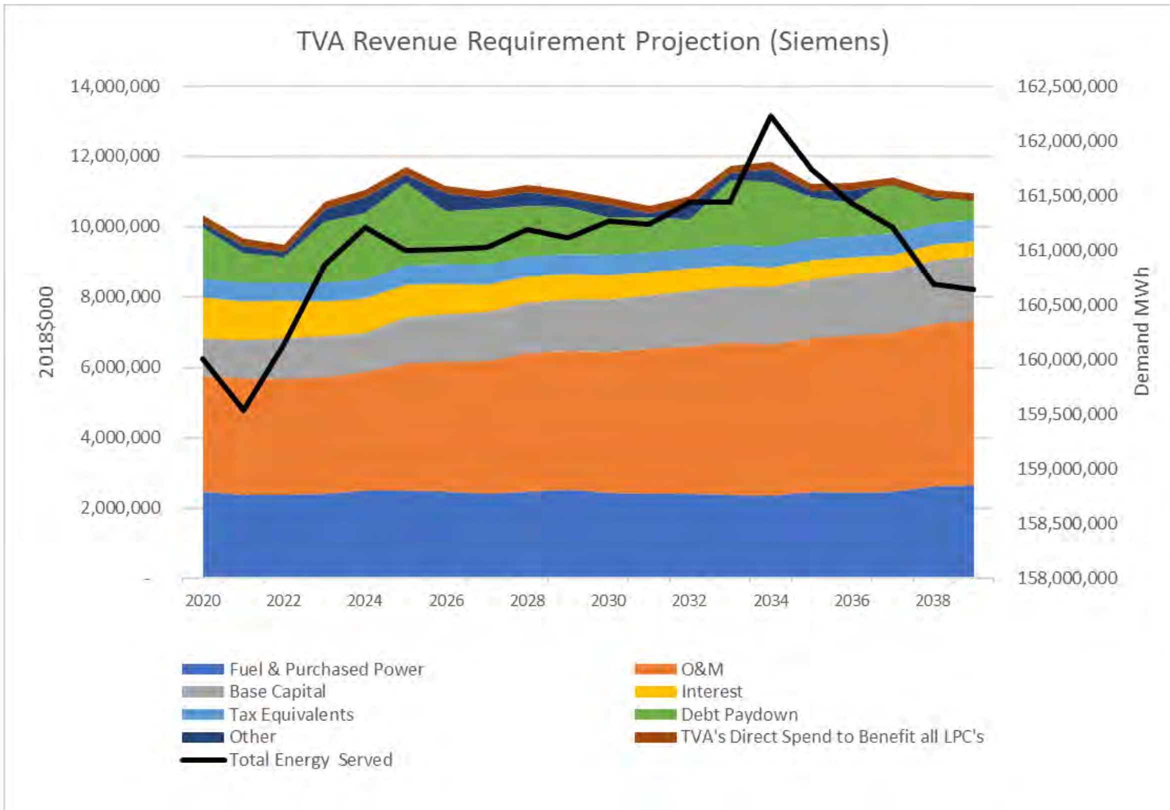
Exhibit 144: Revenue Requirement Cost Components and Data Sources

Revenue Requirement Cost Component	Data Sources
Fuel & Purchased Power	Siemens fuel and power cost projections given TVA's existing generation fleet and future capacity expansions based on TVA's published IRP
O&M	Siemens O&M cost projections given TVA's existing generation and transmission assets and future additions based on TVA's published IRP
Base Capital	TVA projections
Interest	TVA projections
Tax Equivalents	TVA projections
Strategic Capital	Siemens capital cost estimates for capacity expansions based on TVA's published IRP
Annual Change in Total Financing Obligations	TVA projections
Other	TVA projections
TVA's Direct Spending on programs Benefiting all LPCs	TVA's Fiscal Year 2018 estimated expenditures for Memphis projected forward in real terms and scaled to cover all the other LPCs served by TVA based on Memphis' share of the overall TVA revenue

Source: Siemens

Siemens built a pro forma financial model to calculate TVA's revenue requirements using the above mentioned sources. In the chart below, the revenue requirements build up (in 2018 real dollars) is on the left vertical axis along with the projection of total energy served at the TVA system level on the right vertical axis. Note that for this and future exhibits, the Debt Paydown component shown is an aggregation of the Strategic Capital and Annual Change in Total Financing Obligation line items.

Exhibit 145: TVA Revenue Requirement Projection



Source: Siemens

Siemens used a real discount rate of 1.37% to calculate the net present value (NPV) of the revenue requirements in the year 2025 for a period spanning 2020 to 2039. This rate corresponds to MLGW cost of capital of 3.5% in real terms considering 2.1% inflation. Using a similar discounting mechanism for the total energy served, the levelized cost of energy based on the 2020 to 2039 period is computed and given in the table below.

Exhibit 146: TVA's Net Present Value of Revenue Requirements (NPVRR) and Levelized Cost of Energy (LCE) – Siemens Forecast

Revenue Requirement Cost Component	NPVRR (2018 $000)	Levelized Cost of Energy ($/MWh) Based on the 2020 to 2039 Period
Fuel & Purchased Power	42,560,142	15.20
O&M	68,296,233	24.40
Base Capital	24,975,204	8.92
Interest	13,213,532	4.72
Tax Equivalents	9,856,420	3.52
Debt Paydown	23,259,015	8.31
Other	4,134,865	1.48
TVA's Direct Spend to Benefit all LPCs	3,715,947	1.33
Total	**190,011,359**	**67.88**

Source: Siemens

The levelized cost of energy based on the 2020 to 2039 period as shown above is slightly lower than the corresponding value for 2025 onwards (2018$ 69.39/MWh) due to the inclusion of the few low-cost years in the beginning of the study period.

For comparison, the table below provides the corresponding values using TVA's revenue projections, that we note result in a slightly higher value for the levelized cost of energy. Siemens' projections are used for assessing Strategy 1 in this IRP.

Exhibit 147: TVA's Revenue Requirement Net Present Value and Levelized Cost of Energy (TVA's Forecast)

Revenue Requirement Cost Component	NPVRR (2018 $000)	Levelized Cost of Energy ($/MWh) Based on the 2020 to 2039 Period
Fuel & Purchased Power	58,988,443	21.07
O&M	58,524,235	20.91
Base Capital	24,975,204	8.92
Interest	13,213,532	4.72
Tax Equivalents	9,856,420	3.52
Debt Paydown	25,043,164	8.95
Other	4,134,865	1.48
Total	**194,735,865**	**69.56**

Source: Siemens

14.3 MLGW's Rate Derived from TVA's Revenue Requirements

TVA's Revenue Requirement Model section above described the methodology used to arrive at TVA's revenue requirements. These revenue requirements form the basis for computing the revenue requirement that MLGW will need to collect, should it choose to continue being served by TVA. Siemens used 2 different methods to estimate MLGW's levelized cost of energy should it stay with TVA and these are described below.

14.4 Allocation Based on Variable and Fixed Components

TVA's cost components making up its revenue requirements can be broken down into variable and fixed cost components. The variable components such as fuel & purchased power and O&M vary proportionately with the amount of energy served and can be allocated based on the energy that MLGW is forecasted to consume. All the other components are fixed costs that can be considered as a demand charge that is levied to compensate TVA for ensuring the capacity and infrastructure is available to satisfy MLGW's energy demand.

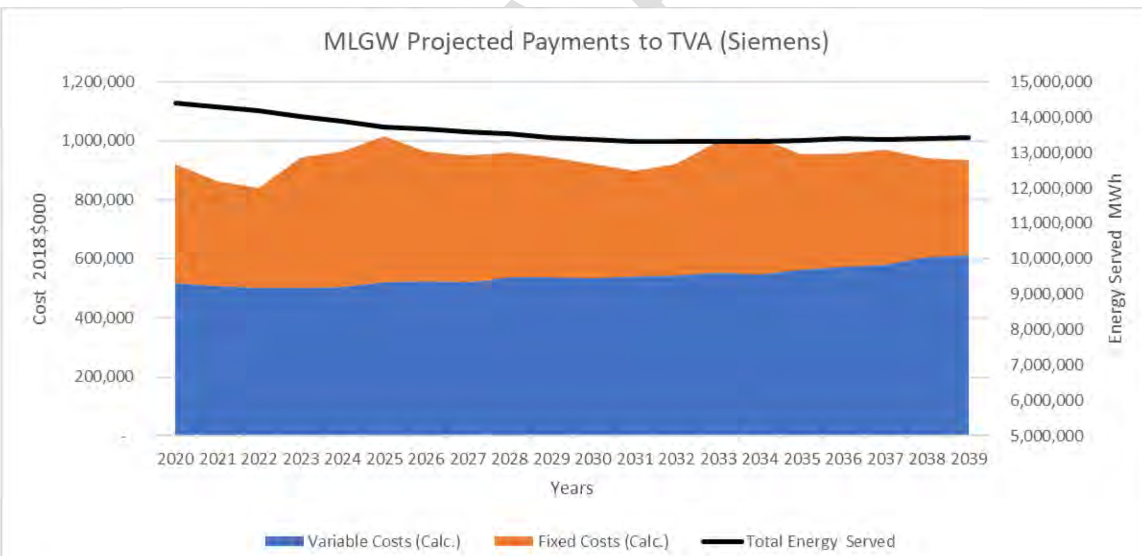
Allocation of the variable component is straightforward and is merely the variable rate ($/MWh) multiplied by MLGW's energy forecast (MWh). Base Capital, Interest payments, Tax Equivalents, Debt Paydown, TVA's Direct Spend to Benefit all LPCs, and Other payments together constitute the fixed component of TVA's revenue requirements.

These costs can be allocated considering MLGW's contribution to the system peak that drives such fixed costs. The "Highest 200 Hours" methodology is used to allocate the fixed component of TVA's revenue requirement to MLGW. With this methodology, the 200 highest peaks are used instead of just the single system peak to account for (a) the volatility of this single value, and (b) the fact that TVA could implement temporary measures to address a single very short duration peak.

Using the TVA load during the top 200 demand hours of the reference year, and the corresponding values of MLGW load during the same hours, the ratio of MLGW load to TVA load is calculated, thus identifying MLGW's contribution to those peaks. The average of all the 200 ratios is then used to calculate the fixed component of MLGW's cost of service. A ratio of 8.9% was determined, thus according to this method MLGW is responsible for 8.9% of TVA's fixed costs.

The exhibit below shows the projected revenue requirement ($2018) that MLGW would be required to collect in case it elected to continue with TVA under the existing contract using the pro forma model developed. The graph also shows the demand considered (MWh), which is the base case demand.

Exhibit 148: MLGW projected Payments to TVA (Method 1)



Source: Siemens

Siemens then used a real discount rate of 1.37% to calculate the net present value (NPV) of the variable and fixed components of MLGW's cost of service in the year 2020 for a period spanning 2020 to 2039. Using a similar discounting mechanism for MLGW's total energy needs, the levelized cost of energy to MLGW based on the 2020 to 2039 period is computed. Values for variable and fixed components are given in the exhibit below.

Exhibit 149: MLGW's Revenue Requirement Net Present Value and Levelized Cost of Energy (Siemens Projection)

MLGW's Cost of Service Component	NPV 2018 $000	Levelized Cost of Energy ($/MWh) Based on the 2020 to 2039 Period
Variable Costs	9,373,532	39.53
Fixed Costs	7,016,009	29.59
Total	**16,389,540**	**69.12**

Source: Siemens

The above rate represents a 1.8 % increase over TVA's corresponding levelized cost of energy for the same period.

We note that the levelized rate of 2018$ 69.12 /MWh when expressed in 2020$ results in 2020$ 71.94/MWh; this is somewhat lower than the average rate that MLGW paid in 2019 ($74.45/MWh) and thus it is estimated to be a conservative value. Also, it is consistent with TVA's pledge not to increase rates for ten years in the LTP agreement.

Using TVA's revenue requirement forecast an allocating it to MLGW (using the Top 200 Hours methodology described above), we compute the NPV and levelized cost of energy, as shown in the exhibit below.

Exhibit 150: MLGW's Revenue Requirement Net Present Value and Levelized Cost of Energy (TVA Forecast)

MLGW's Cost of Service Component	NPV 2018 $000	Levelized Cost of Energy ($/MWh) Based on the 2020 to 2039 Period
Variable Costs	9,922,450	41.84
Fixed Costs	6,844,781	28.87
Total	**16,767,232**	**70.71**

Source: Siemens

In this case the levelized rate of 2018$ 70.71 /MWh, when expressed in $2020, results in 2020$ 73.60/MWh; this is close to the average rate that MLGW paid in 2019 ($74.45/MWh).

14.5 Allocation Based on Historical Relationship

For the second method to estimate MLGW's levelized cost of energy, Siemens used the historical relationship between TVA's overall effective rate for serving LPCs, Direct Serve Companies, and Federal Agencies, and MLGW's net power cost paid to TVA. MLGW's final rate is reduced by the transmission credit it receives from TVA for leasing its transmission lines. The overall calculation is illustrated in the exhibit below.

Exhibit 151: MLGW Rate based on the TVA rate 2019

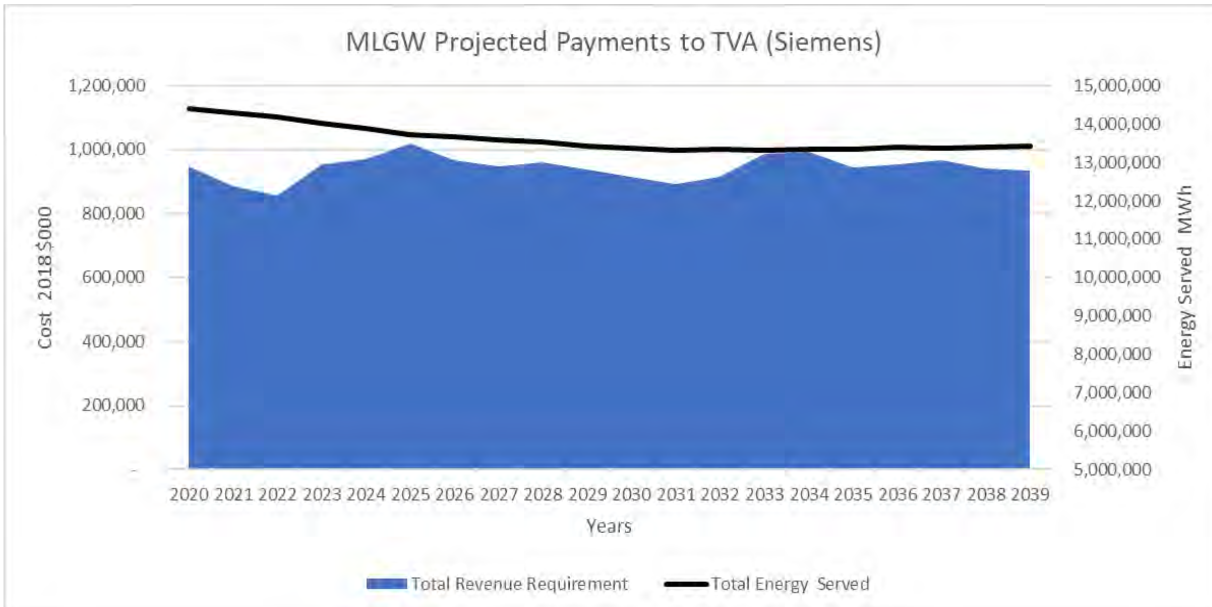
	Revenue (millions)	GWh	cents/KWh
Local Power Companies	10,351	138,928	7.45
Direct Serve Companies	686	17,363	3.95
Federal Agencies	122	2,152	5.67
Total TVA	**11,159**	**158,443**	**7.04**
MLGW	1,036	13,920	7.45
Less Transmission Credit	-36	13,920	-0.26
Net Power Cost	**1,001**		**7.19**
MLGW Ratio to TVA as a whole			**102.07%**

Source: MLGW

As can be seen from the exhibit above, MLGW's net power cost is 2.07% higher than the overall TVA rate; the overall TVA rate is affected by the lower cost of the energy supplied to the Direct Serve Companies and Federal Agencies.

The exhibit below shows the projected revenue requirement ($2018) that MLGW would need to collect, calculated using this allocation method (note that there is no distinction between fixed and variable costs).

Exhibit 152: MLGW Projected Payments Made to TVA (Method 2)



Source: Siemens

Using the discount rate of 1.37%, the net present value (NPV) of revenue requirements for 2020 to 2039 and the levelized cost of energy to MLGW is calculated and are given in the exhibit below.

Exhibit 153: MLGW's Revenue Requirement Net Present Value and Levelized Cost of Energy (Siemens Projection)

MLGW's Revenue Requirement for TVA	NPV 2018 $000	Levelized Cost of Energy ($/MWh) Based on the 2020 to 2039 Period
All Costs (Fixed & Variable)	16,411,372	69.21
Total (same as above)	**16,411,372**	**69.21**

Source: Siemens

We note that in this case the levelized rate expressed in 2018 of $69.21/MWh, when expressed in $2020, results in $72.03/MWh; this is closer to the average rate that MLGW paid in 2019 ($74.45/MWh).

Using TVA's revenue requirement forecast and allocating it to MLGW using the highest 200 hours method we have the following NPV and levelized costs of energy as shown in the following exhibit.

Exhibit 154: MLGW's Revenue Requirement Net Present Value and Levelized Cost of Energy (TVA Forecast)

MLGW's Cost of Service Component	NPV 2018 $000	Levelized Cost of Energy ($/MWh) Based on the 2020 to 2039 Period
All Costs (Fixed & Variable)	16,818,784	70.93
Total (Same as above)	**16,818,784**	**70.93**

Source: Siemens

In this case the levelized rate of 2018$ 70.93/MWh, when expressed in $2020, results in 2020$ 73.82/MWh; again, this is close to the average rate that MLGW paid in 2019 ($74.45/MWh).

14.6 Strategy 1 Deterministic Revenue Requirement Forecast

Considering the above Method 2 was selected for the forecast and given that the stochastic (risk) assessment can only be carried out using Siemens' independent projections, Siemens' projections are also used for the deterministic assessment.

Results are presented for the reference conditions (base load growth, base gas prices, etc.) for the key selected metrics

14.6.1 Long Term Partnership

As mentioned in Section 2, TVA has proposed a Long-Term Partnership (LTP), through which, in exchange for extending the notice for termination to 20 years, TVA offered a credit of 3.1% of the Wholesale Standard Service non-fuel component. This is equivalent to approximately $22.5 million per year with a present value of $391 million using a real discount rate of 1.37% for the period 2020 to 2039. Considering this the exhibit below shows the Revenue Requirement NPV and the levelized costs of energy before and after the Long-Term Partnership (LTP) benefits, using Method 2 above and Siemens projections. We also note that the projected rates are below current rates and the provision in the LTP of not having a rate increase in 10 years is also fulfilled.

Exhibit 155: Effect of the Long-Term Partnership on the MLGW's TVA Costs

MLGW's Cost of Service Component	TVA (Base)	TVA (LTP)
NPV of Revenue Requirements $2018	16,411,372	16,020,128
Levelized Cost of Energy ($/MWh)	69.21	67.56

Source: Siemens

14.6.2 Balanced Score Card

Exhibit 156 presents the balanced score card for Strategy 1, should MLGW decide to maintain TVA's All Requirements Contract under current conditions (the TVA Base column in the score card) and with the LTP (the TVA LTP column in the score card), and for reference we provide a comparison with the eight Portfolios selected for analysis. We discuss next these results. The corresponding values for the Strategy 3 portfolios are also included for comparison, with the NPV of revenue requirements for the period 2020 to 2039 determined considering that during the notice period MLGW would remain with TVA under the existing contract.

Exhibit 156: Balanced Scorecard TVA and Portfolios

Objective	Measure		Unit	TVA (Base)	TVA (LTP)	Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4	Portfolio 5	Portfolio 6	Portfolio 7	Portfolio 8	Portfolio 9	Portfolio 10	ALL MISO
						2 CC + 1 CT	3 CC + 1 CT	3 CC + 2 CT	3 CC + 0 CT	1 CC + 4 CT	2 CC + 1 CT	2 CC + 2 CT	2 CC + 2 CT	1 CC + 4 CT	1 CC + 0 CT	1 CC + 0 CT
Least Cost	NPVRR 2020 - 2039		$ Millions	16,411	16,020	14,490	14,668	14,709	14,511	14,504	14,614	14,503	14,627	14,453	14,304	14,522
			% to Lowest Case	14.7%	12.0%	1.3%	2.5%	2.8%	1.4%	1.4%	2.2%	1.4%	2.3%	1.0%	0.0%	1.5%
	Levelized Energy Cost		$/MWh	69.2	67.6	61.1	61.9	62.0	61.2	61.2	61.6	61.2	61.7	60.9	60.3	61.2
			% to Lowest Case	14.7%	12.0%	1.3%	2.5%	2.8%	1.4%	1.4%	2.2%	1.4%	2.3%	1.0%	0.0%	1.5%
	Levelized Savings per Year (with respect to LTP) 2025 -2039		$ Millions			121.5	107.4	104.1	119.9	120.4	111.7	120.5	110.7	124.5	136.3	119.0
			% to Highest Case			10.8%	21.2%	23.6%	12.0%	11.7%	18.0%	11.6%	18.8%	8.6%	0.0%	12.7%
Sustainability	2025 CO2 Emission	MLGW Gen	Million Ton	4.25	4.25	2.99	4.20	4.48	4.18	1.42	2.98	3.20	3.18	1.43	2.67	2.67
		All Local Gen	Million Ton	3.11	3.11	6.10	7.31	7.59	7.29	4.53	6.09	6.31	6.29	4.54	5.78	3.11
		MLGW Gen	% to Lowest Case	200.1%	200.1%	111.0%	196.4%	216.4%	195.4%	0.0%	110.3%	125.9%	124.7%	0.9%	88.7%	88.7%
	2025 Water Consumption	MLGW Gen	Million Gallon	1,388	1,388	1,685	2,449	2,504	2,542	859	1,680	1,692	1,687	679	1,796	1,796
		All Local Gen	Million Gallon	3,103	3,103	4,788	5,551	5,607	5,645	3,961	4,782	4,795	4,789	3,782	4,899	3,103
		All Local Gen	% to Lowest Case	0.0%	0.0%	54.3%	78.9%	80.7%	81.9%	27.7%	54.1%	54.5%	54.4%	21.9%	57.9%	0.0%
	Energy from Renewable Sources 2039 (RPS)		% of Energy Consumed	6.5%	6.5%	56.8%	46.1%	40.7%	47.3%	75.3%	54.9%	56.8%	54.9%	75.3%	52.7%	52.7%
			% to Highest Case	91.4%	91.4%	24.6%	38.8%	45.9%	37.2%	0.0%	27.1%	24.6%	27.1%	0.0%	30.1%	30.1%
	Energy from Zero Carbon Sources 2039 (RPS)		% of Energy Consumed	58.6%	58.6%	56.8%	46.1%	40.7%	47.3%	75.3%	54.9%	56.8%	54.9%	75.3%	52.7%	52.7%
			% to Highest Case	22.3%	22.3%	24.6%	38.8%	45.9%	37.2%	0.0%	27.1%	24.6%	27.1%	0.0%	30.1%	30.1%
Reliability	2025 (UCAP+CIL)/PEAK		%	134%	134%	126.6%	131%	137%	127%	126%	127%	127%	127%	128%	149%	115%
			% to Highest Case	10.0%	10.0%	14.8%	12.0%	7.6%	14.8%	15.2%	14.8%	14.4%	14.4%	14.0%	0.0%	22.4%
Resiliency	Max Load Shed in 2025 under Extreme Event		MW	0	0	8.4	0.0	0.0	0.0	622.4	8.4	0.0	0.0	0.0	0.0	0.0
			% to Highest Case	0.0%	0.0%	1.4%	0.0%	0.0%	0.0%	100.0%	1.4%	0.0%	0.0%	0.0%	0.0%	0.0%
Market	% Energy Purchased in Market		%	10.9%	10.9%	16.7%	7.0%	7.7%	7.4%	31.2%	17.4%	15.6%	16.2%	31.2%	16.7%	16.7%
			% to Lowest Case	55.4%	55.4%	137.7%	0.0%	9.8%	5.4%	345.3%	148.1%	122.6%	131.5%	345.3%	137.7%	137.7%
	% Energy Sold in Market		%	8.7%	8.7%	10.5%	6.7%	5.6%	7.6%	22.6%	9.7%	10.6%	9.7%	22.6%	10.5%	10.5%
			% to Lowest Case	55.0%	55.0%	86.5%	19.7%	0.0%	35.4%	301.7%	71.9%	88.0%	73.0%	301.7%	86.5%	86.5%
Economic Growth	Local T&G CapEx		$ Millions	0	0	2,811	3,299	3,404	3,138	2,989	2,845	2,932	2,965	2,864	2,984	1,014
			% to Highest Case			17.4%	3.1%	0.0%	7.8%	12.2%	16.4%	13.9%	12.9%	15.9%	12.4%	70.2%

Source: Siemens

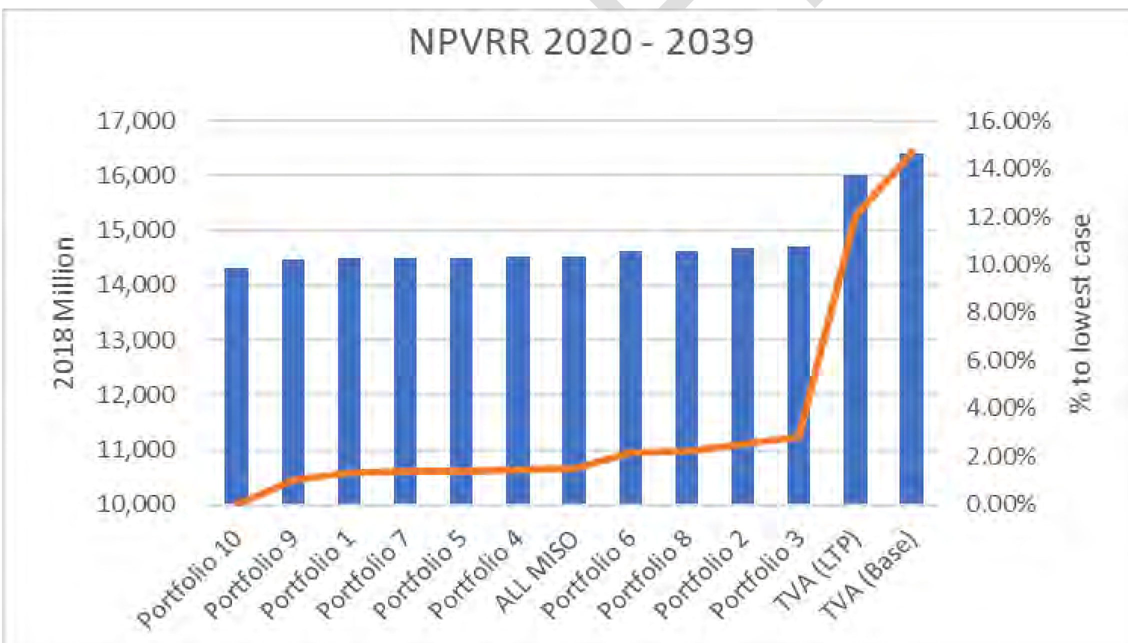
Least Costs

We observe in Exhibit 157 that with the TVA Base option, MLGW's NPV of the Revenue Requirements (NPVRR) for the 2020 to 2039 period at 1.37% discount is higher than any of the Portfolios analyzed under Strategy 3. With the TVA LTP option, the NPVRR is 12% higher than the least cost portfolio from a deterministic point of view (Portfolio 10) and 8.9% higher than the highest cost Portfolio 3. The levelized energy cost also reflects this with a cost of 2018$ 67.6/MWh under the LTP, compared with about $61/MWh for the best performing portfolios.

Finally, we observe there could be levelized savings in the order of $120 to $136 million per year (2018$). The levelized savings are determined by taking the difference between the two NPVRRs and making it an annuity starting in 2025.

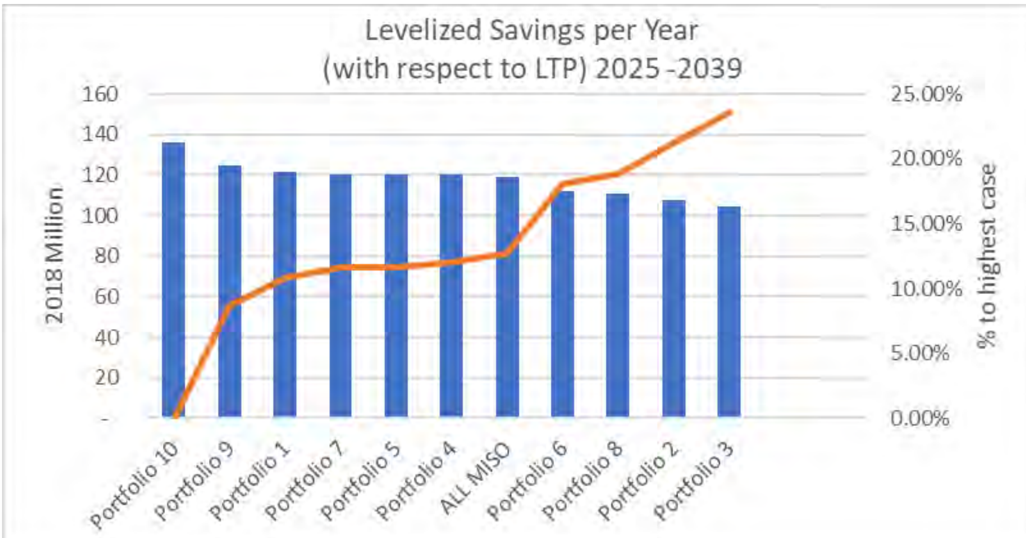
The exhibit below shows graphically the NPVRR for both TVA options and all Portfolios. This is followed by the levelized savings by portfolio.

Exhibit 157: NPVRR of 2020 – 2039



Source: Siemens

Exhibit 158: Levelized Savings 2025 - 2039



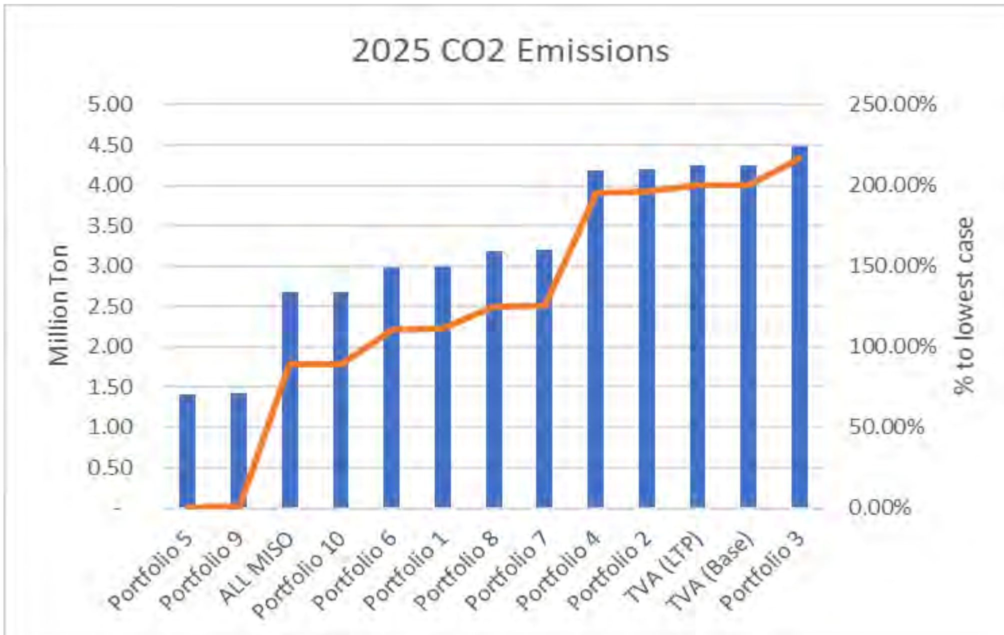
Source: Siemens

Sustainability

Sustainability, as described earlier, is measured according to various metrics: CO2 emissions, energy from zero carbon sources, the final RPS achieved considering only solar and wind (no large hydro), and water consumption. For the TVA options we assigned the overall metrics of CO_2 emissions and water consumed by the CCGTs and the CTs, using the percentage of TVA energy delivered to MLGW (8.5% approximately). Additionally, we provide for water consumption a metric that assesses the water consumed inside Shelby County; in the case of TVA this is our estimation of the consumption of the Allen power plant.

As can be observed in Exhibit 156 the CO_2 emissions attributable to TVA are similar to those in the Portfolios with three CCGTs and higher than in those Portfolios with two or fewer CCGTs. This is shown graphically Exhibit 159. We also assessed the CO_2 emissions within Shelby County as shown in Exhibit 156 but this is less relevant as CO_2 is a global problem.

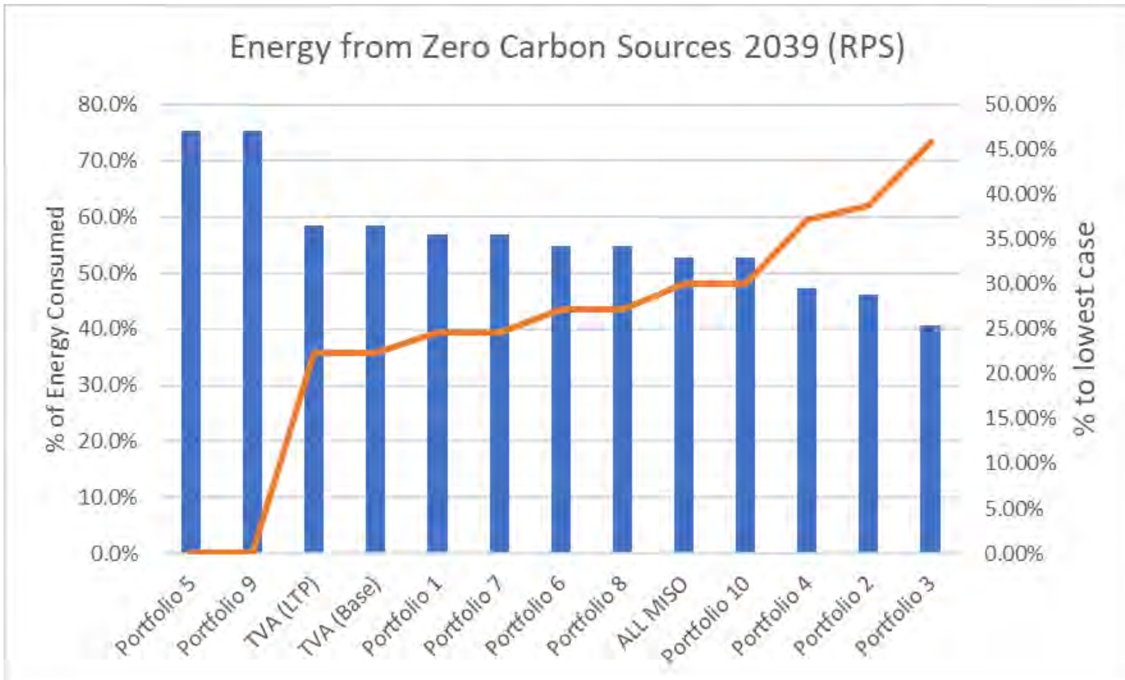
Exhibit 159: 2025 CO_2 Emissions



Source: Siemens

For TVA we measured the generation from zero carbon sources that, in the case of TVA, includes nuclear and large hydro. Considering this the TVA options have substantial levels of zero carbon generation, only surpassed by those in Portfolio 5 and its derivation Portfolio 9. See Exhibit 160 below.

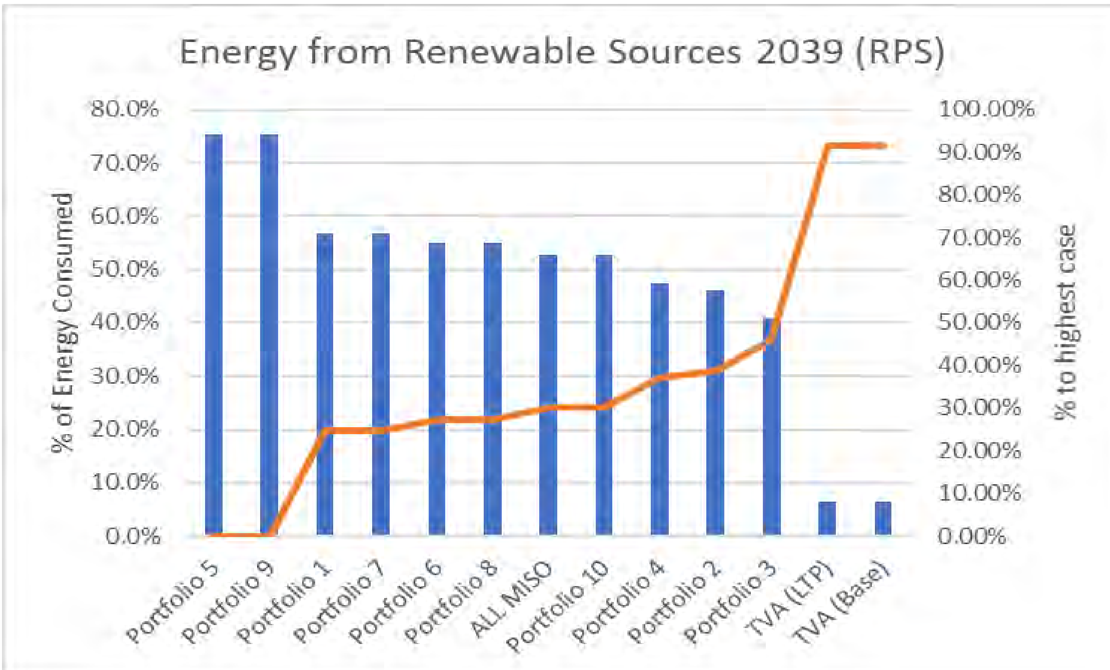
Exhibit 160: 2039 Generation from Zero Carbon Sources



Source: Siemens

Considering a renewable portfolio standard (RPS) centered on load coverage considering only PV and wind (and not including nuclear nor large hydro) the TVA options would rank last and fairly low as illustrated Exhibit 160 below. Even if large hydro is included, the RPS value would increase to only 16%.

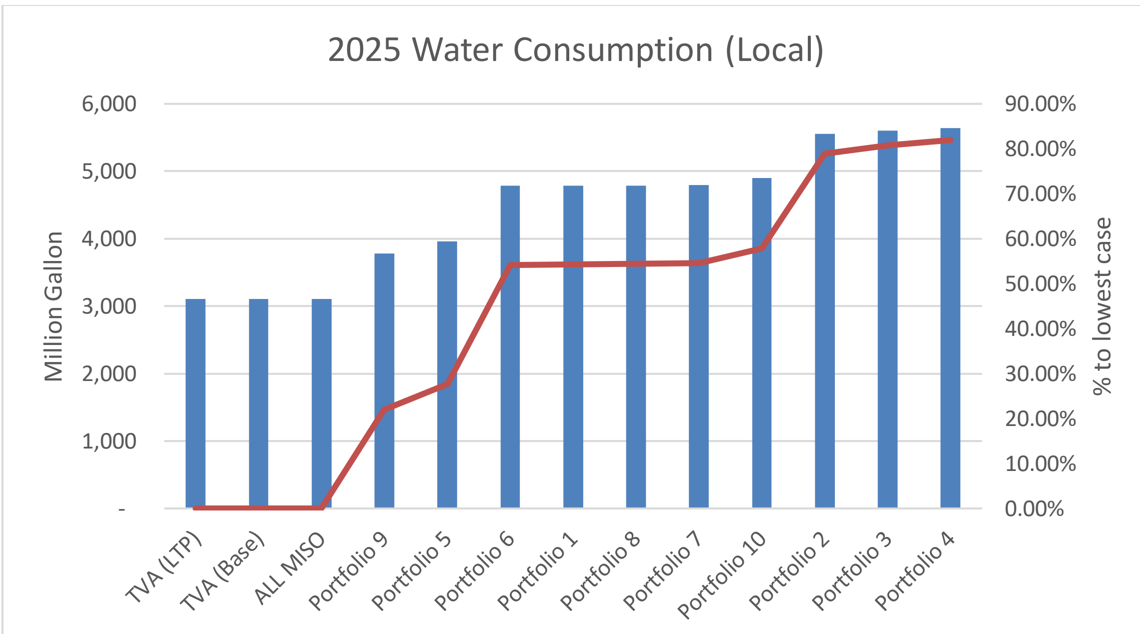
Exhibit 161: 2039 Renewable Generation Percentage



Source: Siemens

With respect to local water consumed, estimated using the same approach presented earlier for the Portfolios, we see in Exhibit 162 that the TVA options have the lowest impact in water consumed when the local impact in Shelby County is considered, as all other options would increase the need for local water, with the exception of the All MISO, that has thermal resources outside Shelby County. This is shown in the exhibit below.

Exhibit 162: 2025 Local Water Consumption



Source: Siemens

Reliability

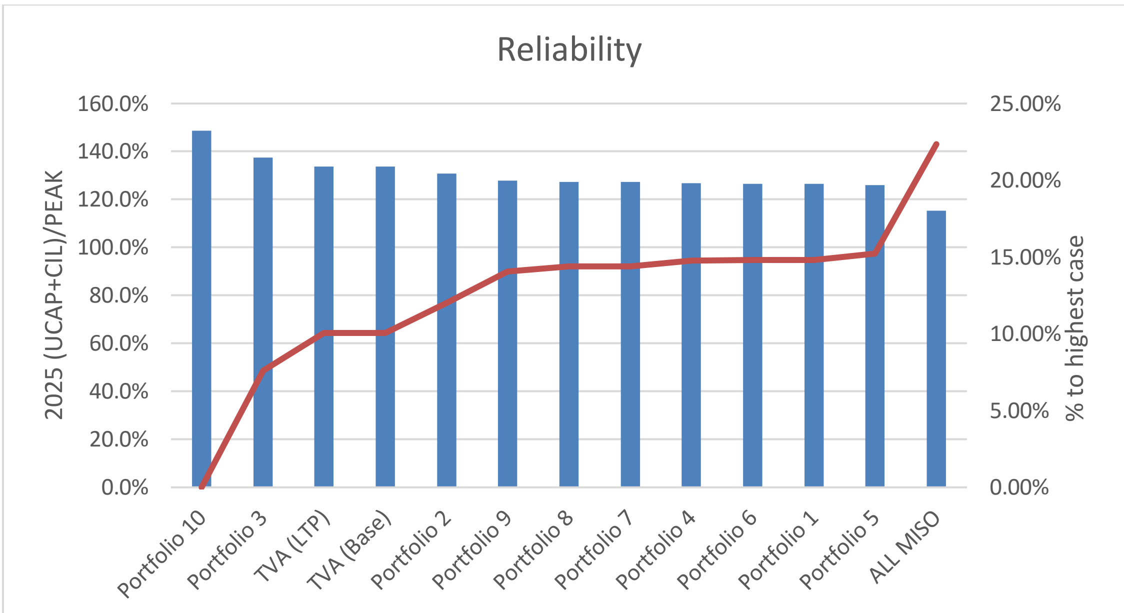
Reliability is measured as the percentage of coverage of MLGW peak load from local resources unforced capacity (UCAP) plus the transmission system Capacity Import Limit (CIL). The TVA options are among the best, only slightly worse than Portfolio 3 and Portfolio 10. Portfolio 3 has significant local generation (3 CCGTs and 2 CTs) and was derived considering a high load scenario, thus under base load it has high reliability. Portfolio 10 has high values according to this metric, but as mentioned earlier has the drawback of having only one large CCGT in MLGW and heavily dependent on transmission to avoid load shed under N-1-1 conditions.

This metric for the TVA case was assessed considering the existing system and no local generation and the CIL was estimated at 4,275 MW.

It should be noted that as indicated earlier all Portfolios, except one, meet the reliability standards with respect to this metric; its value is at or over the 126% threshold as presented in the Resource Adequacy section of this report. The only exception is the All MISO portfolio, as it does not have any local generation, and in this case the requirement is to meet reliable supply under N-1-1 conditions.

The exhibit below presents the results of this metric.

Exhibit 163: Reliability



Source: Siemens

Resiliency

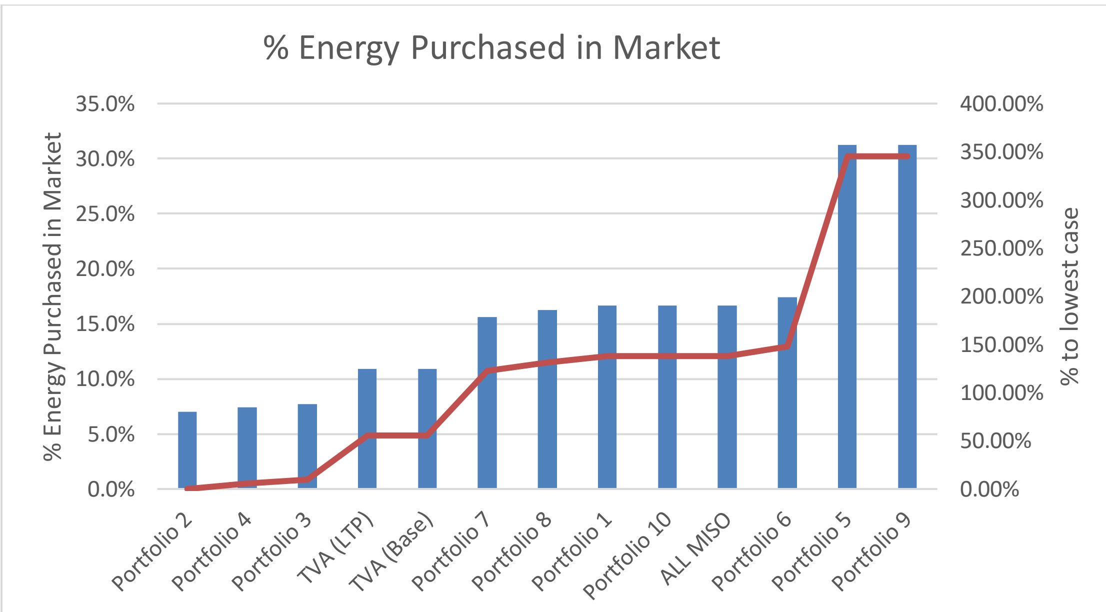
Resiliency in this case is measured as the amount of load that would need to be shed to prevent overloads in the case that the two 500 kV lines that interconnect MLGW to MISO were to both outage by a storm, or by one being in forced maintenance when the other failed. This event is unlikely but possible. However, for load shed to be required in this situation, in addition MLGW would need to be at or close to peak load. Note that the amount of load shed is the value by which the peak load exceeds the maximum load that could be sustained.

In the case of TVA there would be zero load shed, as the system would have enough remaining interconnections at 500 kV to survive this event. As mentioned earlier, only in Portfolio 5 this risk is material.

Market Risk

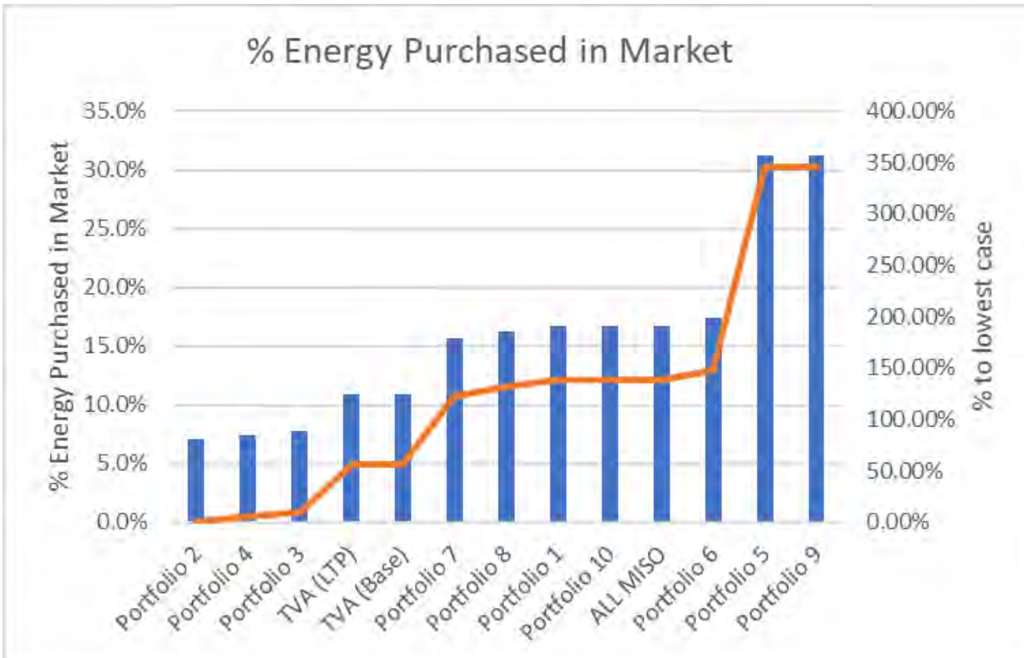
Market risk with the TVA options are very small as TVA is not expected to purchase or sell a significant percentage of its energy (expressed as a function of the load) in the surrounding markets (e.g. MISO) and this risk is comparable with that of the portfolios with 3 CCGTs, as shown in exhibit below. In summary the market risk with TVA is considered negligible.

Exhibit 164: Percentage of Energy Purchased in Market



Source: Siemens

Exhibit 165: Percentage of Energy Sold in Market



Source: Siemens

Economic Growth

With the TVA options, no new generation development is expected within Shelby County and the current situation is expected to remain largely unchanged.

14.7 Strategy 1 Risk Assessment (Stochastics)

The risk assessment of Strategy 1, status quo with TVA was carried out using Siemens' independent projections, using the same set of inputs as described in Section 9. This is compared with the Self-Supply + MISO strategy (Strategy 3) and the All MISO strategy (Strategy 4).

14.7.1 Balanced Scorecard

Exhibit 166 presents the balanced score card for the risk analysis, comparing MLGW maintaining TVA's All Requirements Contract under current conditions (TVA Base), MLGW maintaining TVA's All Requirements Contract with the LTP (TVA LTP) and all selected portfolios for detailed analysis, including the All MISO. In this exhibit the corresponding results for Strategy 3 portfolios and the All MISO (Strategy 4) are presented.

Affordability

The mean of the NPVRR for maintaining the All Requirement Contract with TVA (Strategy 1) for the 20-year study period is calculated using Method 2 for the allocation of TVA cost to MLGW. The NPVs of each portfolio includes the first 5 years (2020 to 2025) during the notice period and are assessed considering the conditions of the current contract. Therefore, the NPVRR for the entire 20-year planning horizon is presented in Exhibit 166. The NPVRR ranking shows that staying with TVA under the existing contract (TVA Base) is 13% higher than the least cost portfolio, and with the LTP this cost is 11% higher.

The levelized savings per year with respect to the TVA LTP option range from $122 million under Portfolio 5 and Portfolio 9, to $62 million under the least preferred Portfolio 3 (all in 2018$).

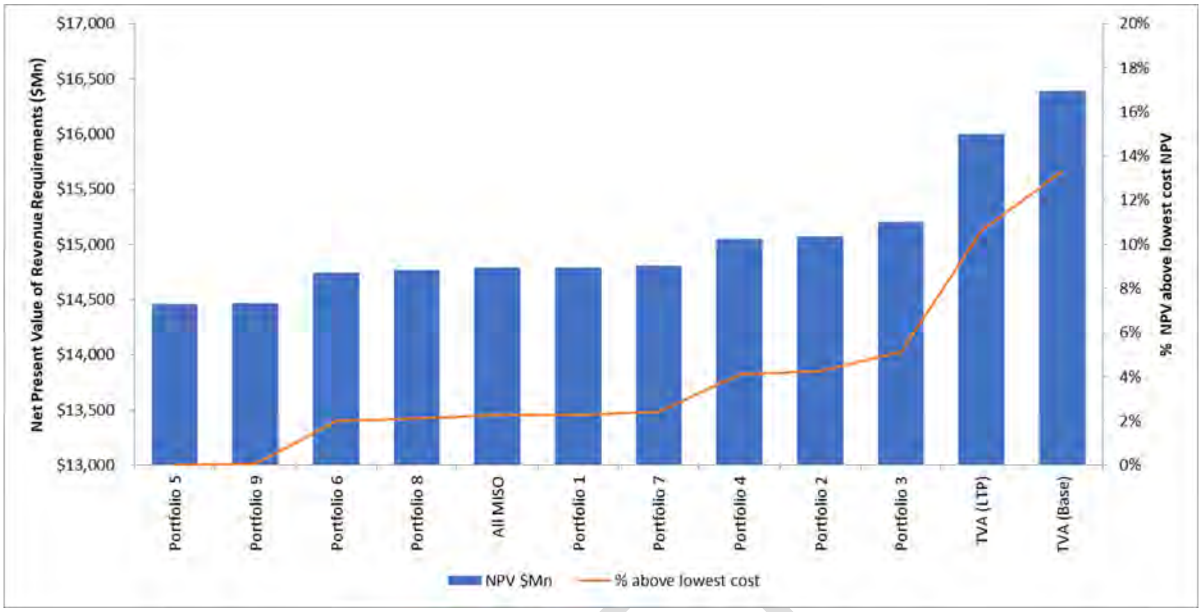
Exhibit 167 shows the NPVRR for both TVA options and the selected portfolios.

Exhibit 166: Stochastic Balanced Scorecard TVA and Portfolios

Objective	Measure	Unit	TVA (Base)	TVA (LTP)	Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4	Portfolio 5	Portfolio 6	Portfolio 7	Portfolio 8	Portfolio 9	All MISO
					2 CC + 1 CT	3 CC + 1 CT	3 CC + 2 CT	3 CC + 0 CT	1 CC + 4 CT	2 CC + 1 CT	2 CC + 2 CT	2 CC + 2 CT	1 CC + 4 CT	1 CC + 0 CT
Least Cost	Stochastic Mean NPVRR 2020 - 2039	$ millions	16,388	15,996	14,790	15,076	15,203	15,052	14,459	14,747	14,808	14,766	14,465	14,789
		% to Lowest Case	13.3%	10.6%	2.3%	4.3%	5.1%	4.1%	0.0%	2.0%	2.4%	2.1%	0.0%	2.3%
	Levelized Energy Cost 2020 -2039	$ / MWh	67.47	65.86	60.69	61.87	62.39	61.77	59.32	60.51	60.76	60.59	59.34	60.68
		% to Lowest Case	13.7%	11.0%	2.3%	4.3%	5.2%	4.1%	0.0%	2.0%	2.4%	2.1%	0.0%	2.3%
	Levelized Savings per Year (wrt LTP) 2025 -2039	$ Millions			95.9	73.1	63.0	75.0	122.1	99.2	94.4	97.8	121.7	96.0
		% to Highest Case			21.5%	40.1%	48.4%	38.6%	0.0%	18.7%	22.7%	20.0%	0.4%	21.4%
Minimum Risk	95th Percentile Value of NPVRR	$ millions	17,221	16,830	17,051	17,535	17,844	17,648	16,576	16,946	17,074	16,944	16,517	17,211
		% to Lowest Case	4.3%	1.9%	3.2%	6.2%	8.0%	6.8%	0.4%	2.6%	3.4%	2.6%	0.0%	4.2%
	Regret	$ millions			462	769	905	743	108	417	482	437	114	461
		% to Lowest Case			326.9%	610.4%	736.2%	586.2%	0.0%	284.9%	345.6%	303.5%	5.7%	326.0%
Minimum Environmental Risk	CO_2 Emissions Mean 20-Year	Tons CO_2	3,805,017	3,805,017	2,571,297	3,294,819	3,295,708	3,293,929	1,847,121	2,571,297	2,572,186	2,572,186	1,850,442	2,814,405
		% to Lowest Case	106%	106%	39%	78%	78%	78%	0%	39%	39%	39%	0%	52%

Source: Siemens

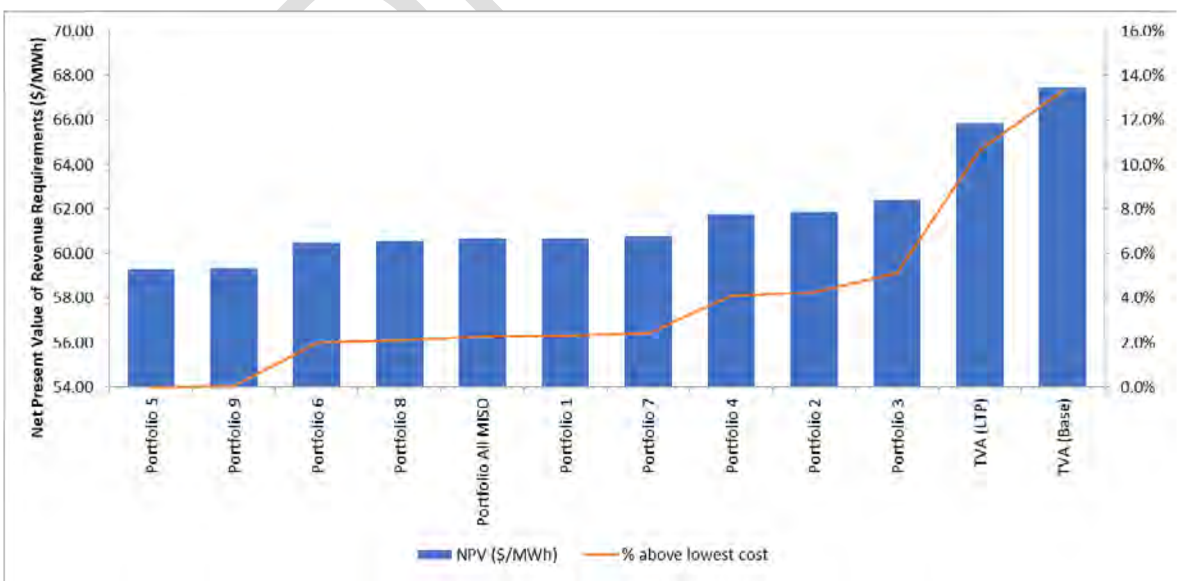
Exhibit 167: NPVRR 2020-2039



Source: Siemens

Similarly, as shown in Exhibit 168, TVA Base has the highest portfolio cost, which is about 8.2 $/MWh higher than the least cost alternative portfolio considered (Portfolio 5), and 5.1 $/MWh higher than the most costly portfolio (Portfolio 3).

Exhibit 168: NPVRR 2020-2039 ($/MWh)

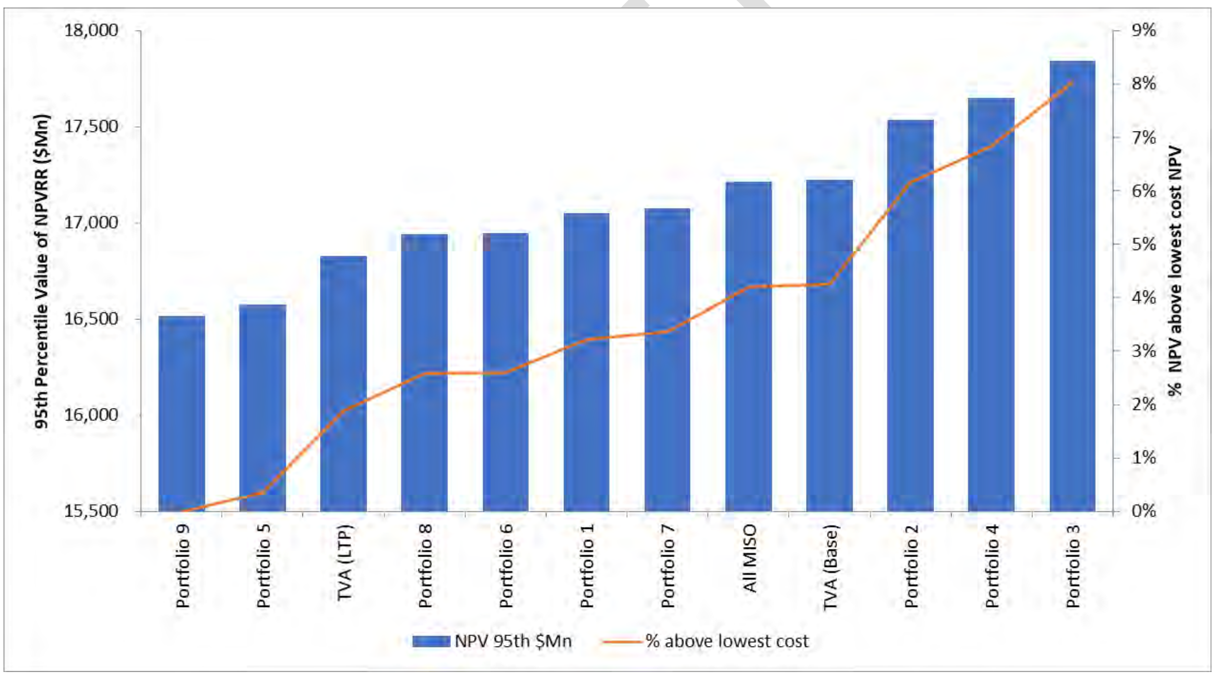


Source: Siemens

Risk Minimization

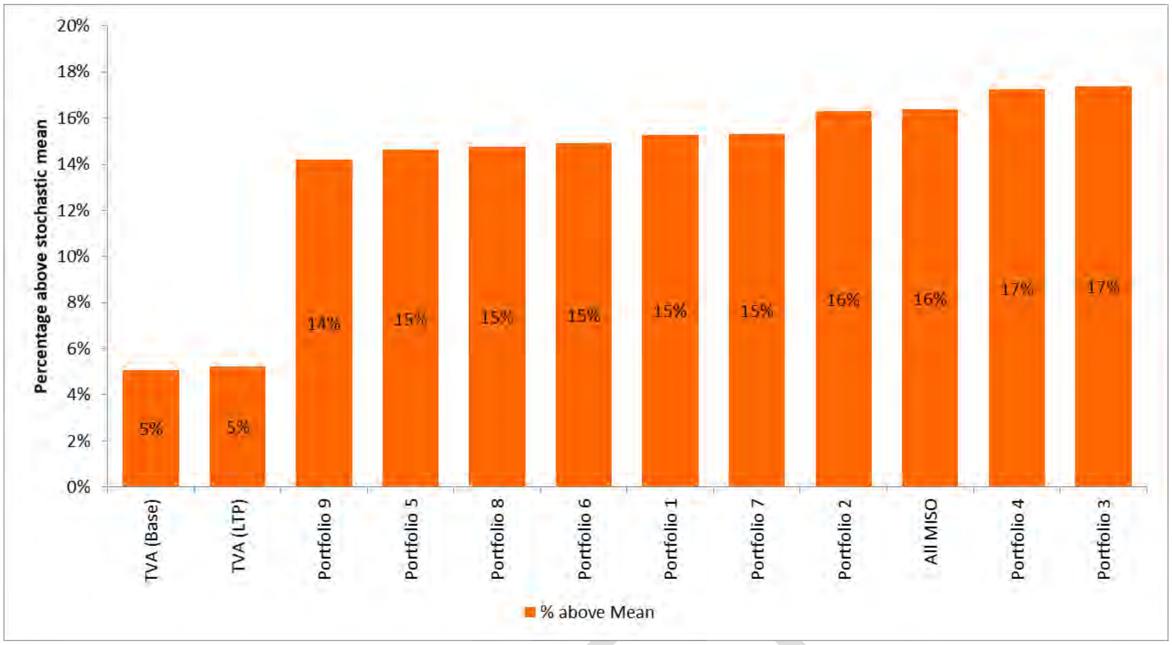
TVA's Base portfolio cost shows a moderate price variability as expressed in terms of the 95th percentile costs as shown in the figure below, and it is less variable than any of the alternative portfolios considered; the TVA 95th percentile is only 5% above the mean while in Portfolio 3 it is 17% higher due to its high dependence of gas (see exhibits below). This result was expected as TVA's generation fleet is very diversified and about half of the generation mix is comprised of hydro and nuclear, which have a relatively stable generation profile. Gas plants account for only around 15% of the generation in TVA's fleet, and although there is good correlation with gas prices, as shown in Exhibit 171, this is not enough to introduce large variability in the NPVRR. We note that considering the 95th percentile results, i.e. the outcome for which only 5% of the results are worse, only Portfolio 9 and Portfolio 5, that also share low dependence on fuel, have a better outcome than the TVA LTP. This highlights the importance of managing the fuel price exposure of the supply.

Exhibit 169: 95th Percentile of NPVRR



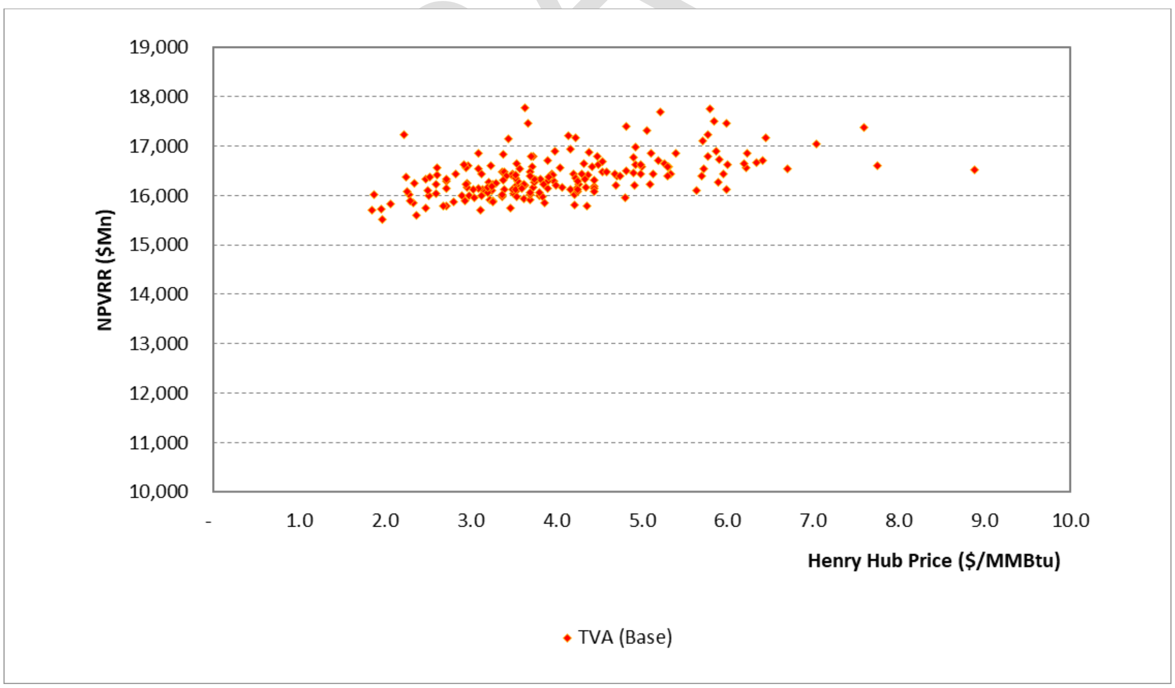
Source: Siemens

Exhibit 170: Increase of the 95th Percentile of NPVRR with Respect of the Mean NPVRR



Source: Siemens

Exhibit 171: NPVRR Correlation with Henry Hub Price



Source: Siemens

On the other hand, Portfolios 2, 3, and 4 have higher upward price risk because a large portion of generation and cost come from new combined cycle plants in the portfolio, which is susceptible to the higher volatility and wide range of gas prices. The portfolios with more renewables, such as Portfolio 5, have lower upward price risk.

Environmental Risk Minimization

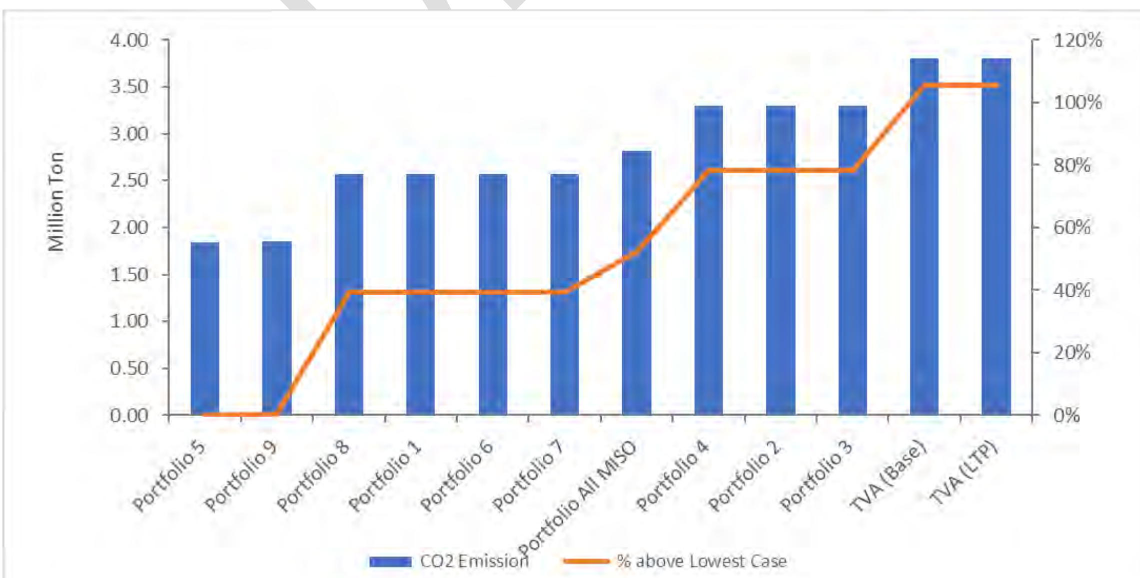
In TVA's generation fleet, coal plants account for about 25% of the generation, including several aged coal plants that stay on throughout the study horizon, and gas plants account for about 15% of the generation. TVA has plans to retire some coal units in coming years but at this time is expected to continue to operate coal generating units including Cumberland, Gallatin, Kingston, and Shawnee. Coal generation emits roughly two times as much carbon emissions as new, efficient natural gas per unit of generation. Coal generation also releases other pollutants including particulates and sulfur dioxide, pollutants to which natural gas's contributions are negligible.

Nuclear and large hydro plants account for about 50% of the TVA generation mix, which though non-emitting, both have environmental risk associated with them. Strategy 3 and Strategy 4 Portfolios are comprised of new and thus more efficient CCGTs, and renewables. Therefore, there will be more environmental impact associated with Strategy 1.

Exhibit 172 below shows the comparison of average CO_2 emissions for the 20-year study period.

Based on the stochastic simulation of potential outcomes, the mean of CO_2 emission impact of Strategy 1 is higher than any of the portfolios considered, and Portfolios 5 and 9 have the lowest emissions.

Exhibit 172: Average CO_2 Emissions 2020-2039



Source: Siemens

15. Recommendations and Findings

Siemens conducted an extensive analysis of the options available to MLGW to supply its energy needs for the next 20 years. The analysis included conventional and renewable generation, both in its footprint and more remotely in the MISO footprint, energy and capacity purchases in the MISO market, along with programs for energy efficiency and distributed generation. The analysis also covered a detailed study of the transmission system and the adequacy of the resources selected in order to ensure that all Portfolios for analysis are in compliance with NERC reliability requirements.

The analysis used over two hundred different forecasts (scenarios) in the stochastic representation of future market conditions to ensure that the Portfolios selected would perform well under a wide variety of future conditions. In the following, whenever we refer to "stochastic" results we are referring to this analysis and, unless otherwise indicated, to the mean of the obtained distribution of results.

The following Portfolios are determined to be among the preferred if MLGW decides to exit the TVA contract and join MISO.

Portfolio 5 (see Exhibit 173), which is based on heavy investment in transmission to secure the maximum amount of renewable generation and only has one CCGT in MLGW footprint, exhibited the lowest expected cost; i.e. it had the lowest mean of the NPV of Revenue Requirements (NVPRR) on the stochastic runs, and it is the most environmentally sustainable portfolio of the group. While Portfolio 5 meets all reliability and resource adequacy requirements, it one of the least reliable of all the Portfolios as evidenced by significant load shedding and is also more dependent on market purchases and MISO capacity purchases than the other Portfolios.

To improve the reliability of Portfolio 5 to align it more with the reliability of the other Portfolios, and at the same time reduce the need for higher transmission investments, Siemens moved four CTs from the 2030s to 2025, creating Portfolio 9. Portfolio 9 with the earlier CTs and reduced transmission became one of the best performing Portfolios among all Portfolios that entailed a mix of local plus MISO resources. It is second with respect to NPVRR on both deterministic and stochastic evaluations.

Portfolio 10 (see Exhibit 173), which was derived from the All MISO Portfolio but shifted MISO renewables to local renewables at a lower cost, also performed well, but slightly worse than Portfolio 9 on the NPVRR stochastics results. The key tradeoff of Portfolio 10 is between investments in transmission that allowed a much larger and efficient CCGT than other Portfolios.

This could be a possible future path that could be evaluated in an RFP. Proponents should be encouraged to provide CCGT's of various sizes for which a corresponding optimized transmission system would be designed allowing the selection of the best combination. This portfolio was the best on the deterministic analysis, before the greater exposure to gas move it to the third position according to the NPVRR on the stochastic analysis.

Portfolios 6 and 8 require less investments in transmission and add more local generation, which resulted in higher generation costs and higher emissions, but reduced transmission capital and O&M costs, and resulted in slight improvements in reliability and resiliency. While Portfolios 5, 9 and 10 had only one combined cycle unit in MLGW service territory, these Portfolios had two CCGTs in service by 2025 and one or two CTs: one in Portfolio 6 and two in Portfolio 8. The second CT in Portfolio 8 results in slightly higher costs but better reliability. Portfolio 6 ranked 4th according to NPVRR in the stochastics and was selected as part of the final set for analysis.

Strategy 4 (Portfolio All MISO), resulted in a Portfolio that ranked according to the NPVRR 6th in the stochastic analysis and 7th on the deterministic cost analysis. One key observation from this analysis is that the optimization process selected the development of new MISO located resources, rather than supplying the load from purchases in the day ahead energy market.

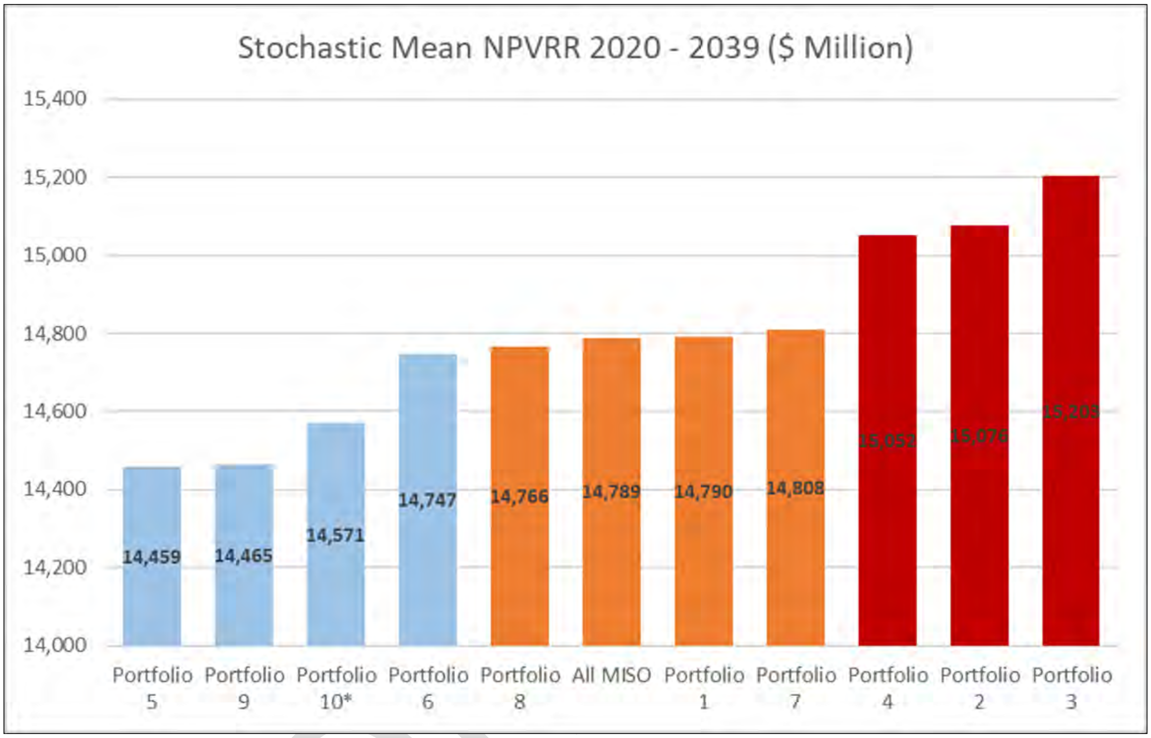
MLGW is too large to depend exclusively on the volatile day ahead energy market. The main drawbacks of this Portfolio are that: (a) all resources are outside MLGW and the entire load is dependent upon transmission that could be affected under extreme events, (b) it requires more transmission than any of the other Portfolios resulting in greater construction costs and development risks, and (c) locally developed resources are more economic as they would not incur point to point transmission costs in MISO. This was demonstrated with Portfolio 10, which is identical to the All MISO portfolio but with 1000 MW of local PV and the large combined cycle unit also locally developed (see Exhibit 173). Due to all the above the All MISO portfolio is not included in the final group for analysis.

Exhibit 245 shows the ranking of the Portfolios according to the NPVRR. In this exhibit we observe three distinct groups, largely as a function of the number of CCGTs in MLGW service territory: best with one CCGT, next with two CCGTs (All MISO being the only exception), and last with three CCGTs. Additionally this exhibit shows the risk associated with these portfolios measured as the 95th percentile result and we note that Portfolio 9 has slightly less risk than Portfolio 5, possibly due to the flexibility added by the 4 CTs advanced, and Portfolio 10 and the All MISO portfolio have slightly higher risk than the other portfolios, possibly due to the dependence on one large CCGT[39].

[39] The stochastics of Portfolio 10 were derived from those for the All MISO Portfolio, as the only difference between these portfolios are the fixed costs (developed outside versus inside MLGW) and capital did not have a significant impact on the risks (less than 3% of the NPV variability is explained by its changes).

Exhibit 9 shows a balanced scorecard for the total supply options analyzed, where the overall results for all portfolios are presented. As indicated above Portfolio 5, Portfolio 9, Portfolio 10 and Portfolio 6 are selected for contrasting the results with respect to the TVA option.

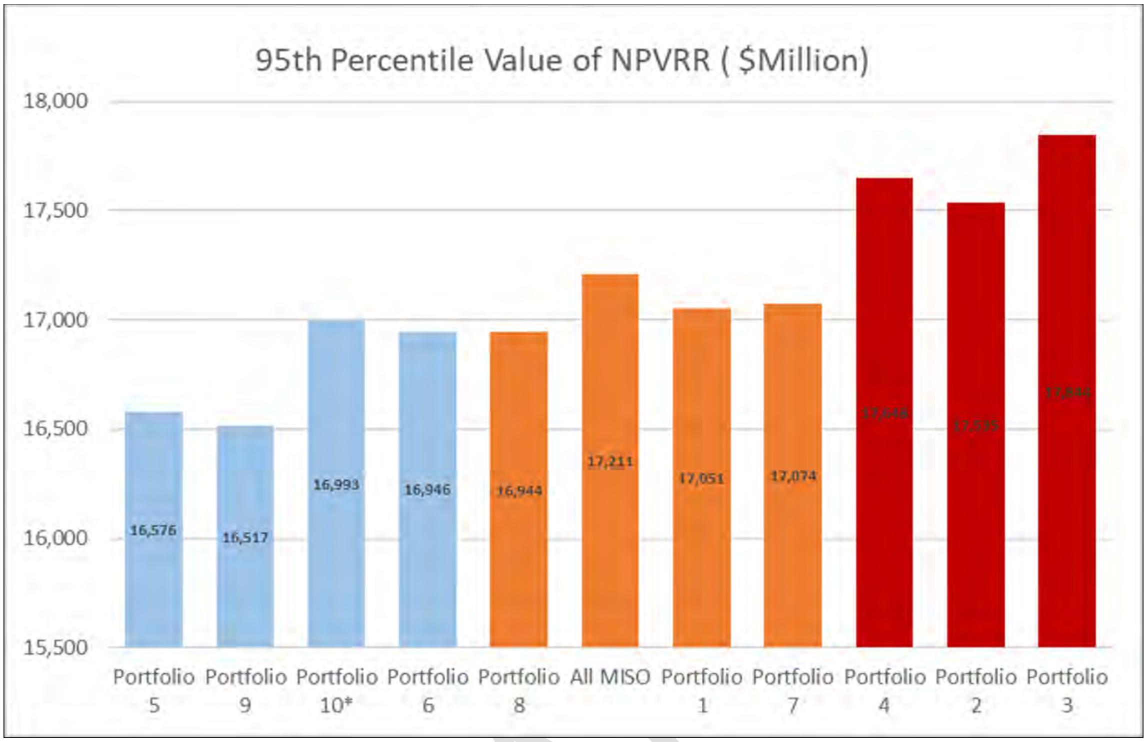
Exhibit 173: Ranking of Portfolios According to NPVRR



Blue = Best Performing and selected for comparison; Red = Worst Performing

Source: Siemens

Exhibit 174: Portfolio Risk



Blue = Best Performing or selected for comparison; Red = Worst Performing
Source: Siemens

15.1 Comparisons with TVA

Exhibit 175 displays the Balanced Scorecard, which shows all the metrics for all the portfolios. It is a complicated figure, but to make it easier to digest, we have added colors for the rows to show which portfolios performed best on each measure (green is best and red is worst performing).

The columns represent how well each portfolio did in all measures. A predominance of green is favorable, and a predominance of red is unfavorable. Portfolios 5, 9 and 10 have the most greens and the fewest reds of the group, including the TVA portfolios. Portfolio 6 has fewer greens but also fewer reds.

Below each metric is looked at separately.

Exhibit 175: Summary of Overall Results

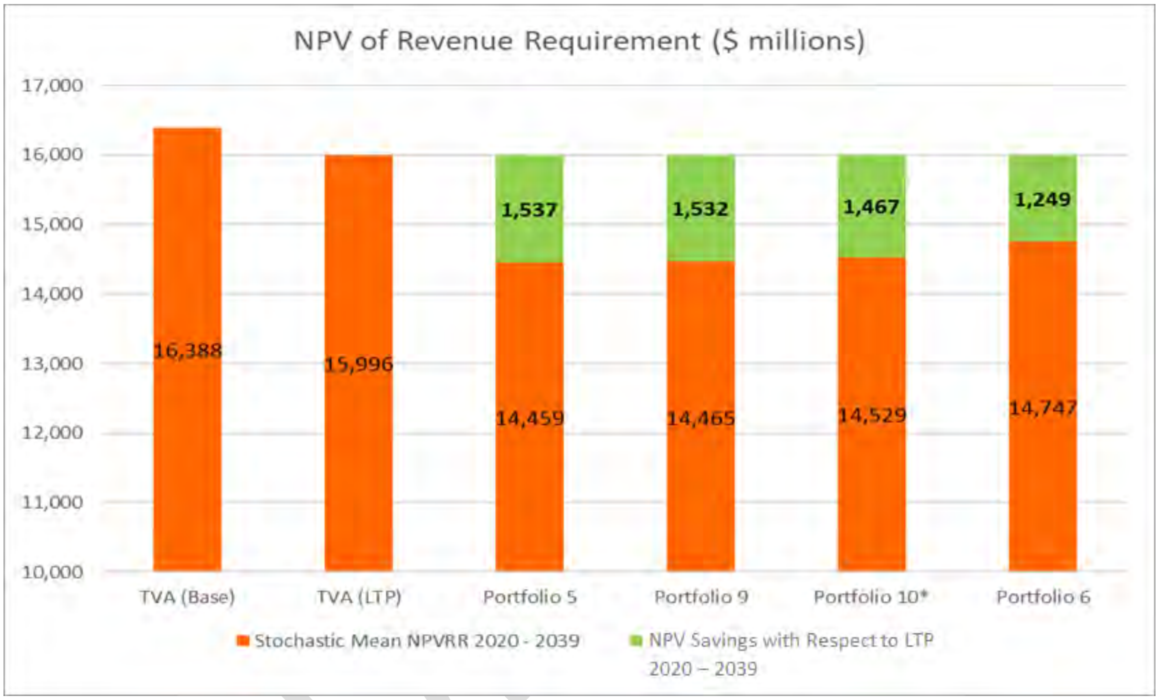
Objective	Measure	Unit	TVA (Base)	TVA (LTP)	Portfolio 5	Portfolio 9	Portfolio 10	Portfolio 6	Portfolio 8	All MISO	Portfolio 1	Portfolio 7	Portfolio 4	Portfolio 2	Portfolio 3
					1 CC + 4 CT	1 CC + 4 CT	1 CC + 0 CT	2 CC + 1 CT	2 CC + 2 CT	1 CC + 0 CT	2 CC + 1 CT	2 CC + 2 CT	3 CC + 1 CT	3 CC + 2 CT	3 CC + 0 CT
Least Cost	NPVRR 2020 - 2039	$ Millions	16,411	16,020	14,504	14,453	14,304	14,614	14,627	14,522	14,490	14,503	14,511	14,668	14,709
	Stochastic Mean NPVRR 2020 - 2039	$ millions	16,388	15,996	14,459	14,465	14,571	14,747	14,766	14,789	14,790	14,808	15,052	15,076	15,203
	Levelized Cost of Energy	$ / MWh	67.47	65.86	59.32	59.34	59.48	60.51	60.59	60.68	60.69	60.76	61.77	61.87	62.39
	NPV Savings with respect of LTP (wrt LTP) 2020 -2039	$ Millions			**1,537.4**	**1,531.7**	**1,425.9**	**1,249.3**	**1,230.5**	**1,207.8**	**1,206.8**	**1,188.0**	**944.7**	**920.2**	**793.0**
	Levelized Savings per Year (wrt LTP) 2025 -2039	$ Millions			**122.1**	**121.7**	**113.3**	**99.2**	**97.8**	**96.0**	**95.9**	**94.4**	**75.0**	**73.1**	**63.0**
	Levelized Savings per Year (wrt Base) 2025 -2039	$ Millions			**153.2**	**152.8**	**144.4**	**130.3**	**128.8**	**127.0**	**127.0**	**125.5**	**106.1**	**104.2**	**94.1**
Min Risk	95th Percentile Value of NPVRR	$ millions	17,221	16,830	16,576	16,517	16,993	16,946	16,944	17,211	17,051	17,074	17,648	17,535	17,844
Min Envr. Risk	CO_2 Emissions Mean 20-Year	Million Tons CO_2	3.8	3.8	1.85	1.85	2.81	2.57	2.57	2.81	2.57	2.57	3.29	3.29	3.30
	Energy from Renewable Sources 2039 (RPS)	% of Energy Consumed	6.5%	6.5%	75.3%	75.3%	52.7%	54.9%	54.9%	52.7%	56.8%	56.8%	47.3%	46.1%	40.7%
	Energy from Zero Carbon Sources 2039	% of Energy Consumed	58.6%	58.6%	75.3%	75.3%	52.7%	54.9%	54.9%	52.7%	56.8%	56.8%	47.3%	46.1%	40.7%
	2025 Local Water Consumption	Million Gallon	3,103	3,103	3,961	3,782	4,899	4,782	4,789	3,103	4,788	4,795	5,645	5,551	5,607
Reliability	2025 (UCAP+CIL)/PEAK	%	133.7%	133.7%	126.0%	127.8%	148.6%	126.6%	127.2%	115.4%	126.6%	127.2%	126.7%	130.8%	137.3%
Resiliency	Max Load Shed in 2025 under Extreme Event	MW	0	0	622.4	0.0	0.0	8.4	0.0	0.0	8.4	0.0	0.0	0.0	0.0
Min Market Risk	% Energy Purchased in Market	%	10.9%	10.9%	31.2%	31.2%	23.0%	17.4%	16.2%	16.7%	16.7%	15.6%	7.4%	7.0%	7.7%
	% Energy Sold in Market	%	8.7%	8.7%	22.6%	22.6%	17.9%	9.7%	9.7%	10.5%	10.5%	10.6%	7.6%	6.7%	5.6%
Econ. Grwth	Local T&G CapEx	$ Millions			2,989	2,864	2,984	2,845	2,965	1,014	2,811	2,932	3,138	3,299	3,404

Source: Siemens

15.1.1 Affordability

Portfolios 5, 9 and 10 NPVRR is estimated to be approximately $1.5 billion (real 2018 $) lower than the option of remaining with TVA under the long-term partnership. Lastly, with Portfolio 6 (that has 2 CCGTs) the savings are reduced to $1.2 billion, as compared to the TVA LTP option.

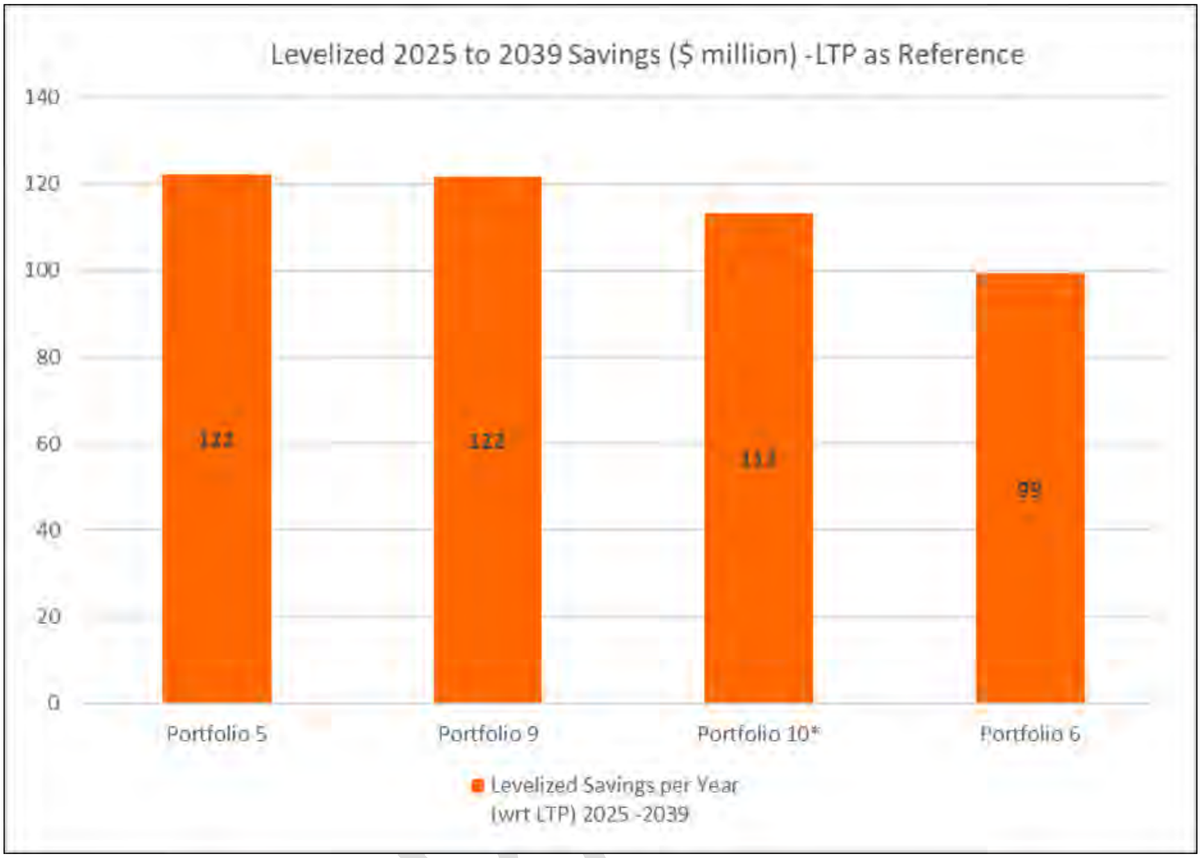
Exhibit 176: Affordability



Source: Siemens

When annualized, these savings relative to TVA's LTP option range from $99 to $122 million per year over the period 2025 to 2039. Note that these levelized savings are determined converting the difference between the 2020 -2039 NPVs into a real (levelized) annuity for the period 2025 to 2039. The values are lower from 2020 because MLGW can reduce its prices immediately if it accepts the LTP option. The actual yearly savings using the existing contract (without the effect of the LTP) are higher.

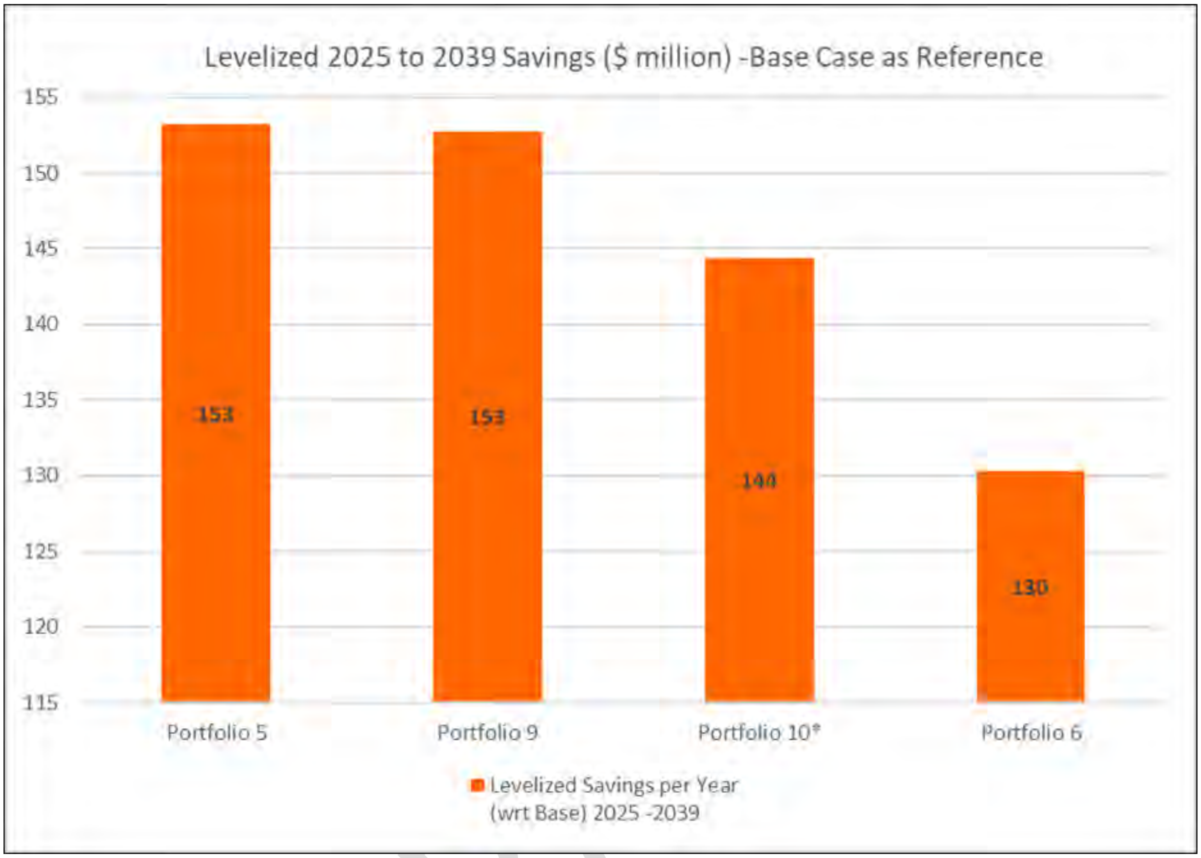
Exhibit 177: Levelized Savings per Year with Respect to the LTP



Source: Siemens

As a reference, if the LTP is not considered then the savings increase to $130 to 153 million per year as shown in the exhibit below.

Exhibit 178: Levelized Savings per Year with Respect to the Base TVA Contract

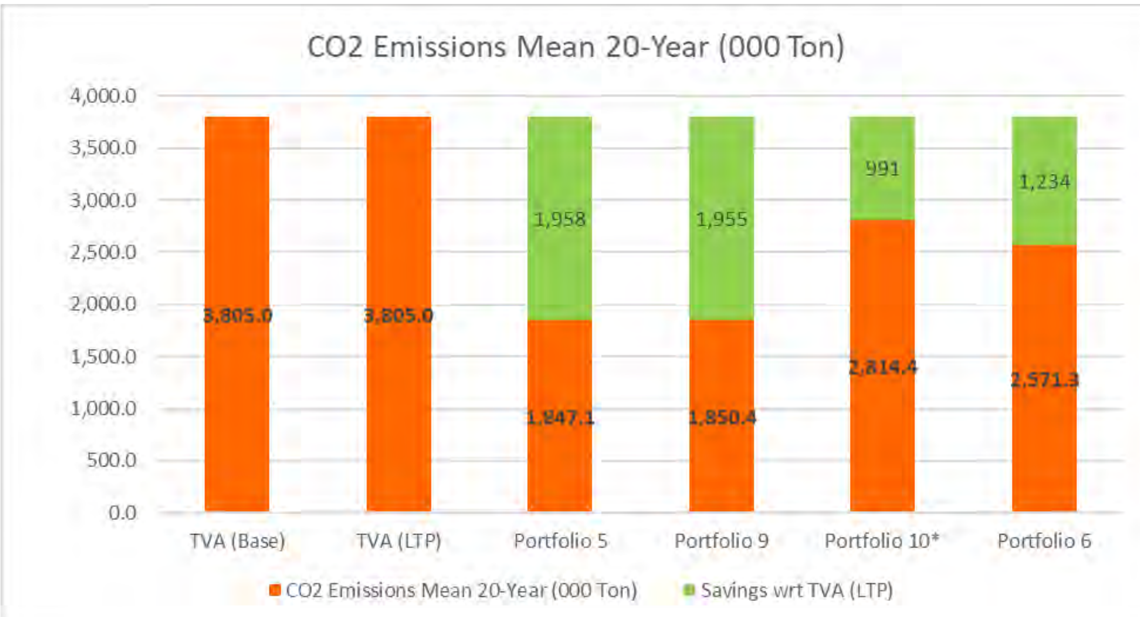


Source: Siemens

15.1.2 Sustainability Metric

Exhibit 179 shows that Portfolios 5 and 9, with their high levels of renewable generation, have significantly lower carbon emissions than the TVA options. For TVA the fleetwide CO_2 production by year was allocated to MLGW as a function of the ratio of MLGW load to total TVA load. Portfolio 10 and Portfolio 6 are also lower emissions but to a lesser degree due to the larger size of the thermal CCGT and less renewables.

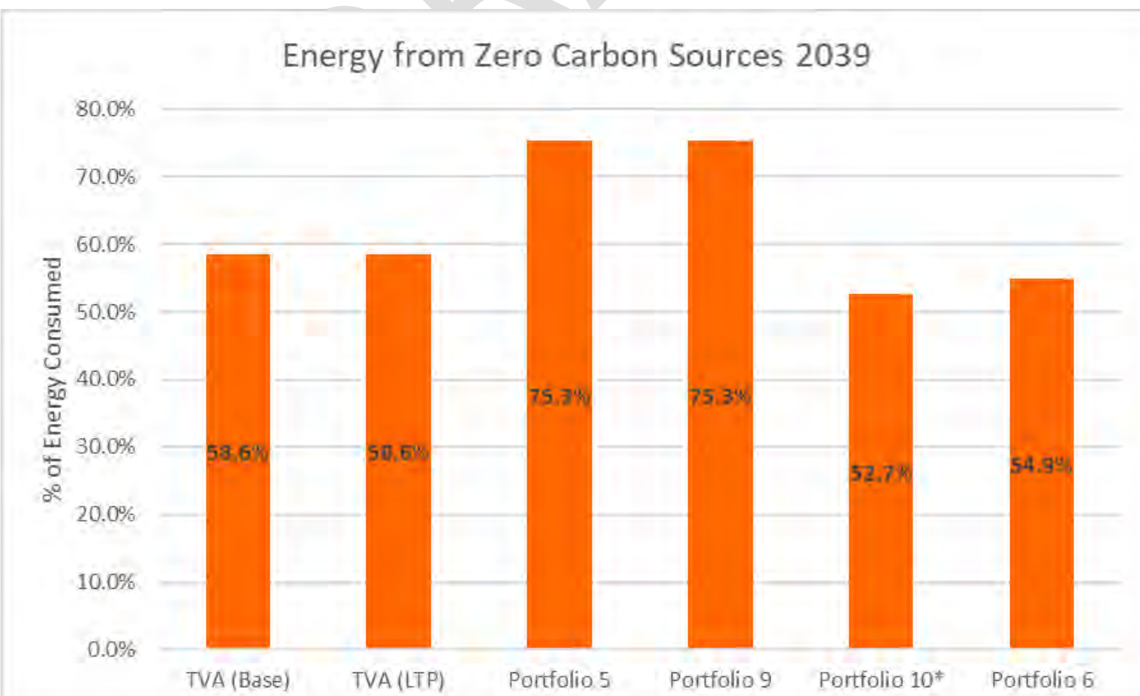
Exhibit 179: Sustainability Metric (CO_2 Emissions)



Source: Siemens

Portfolio 9 and 5 also have larger amounts of carbon free resources than the TVA options Portfolio 10 and Portfolio 6 are slightly above the TVA options due to the larger combined cycle generation (see Exhibit 180).

Exhibit 180: Zero Carbon Sources

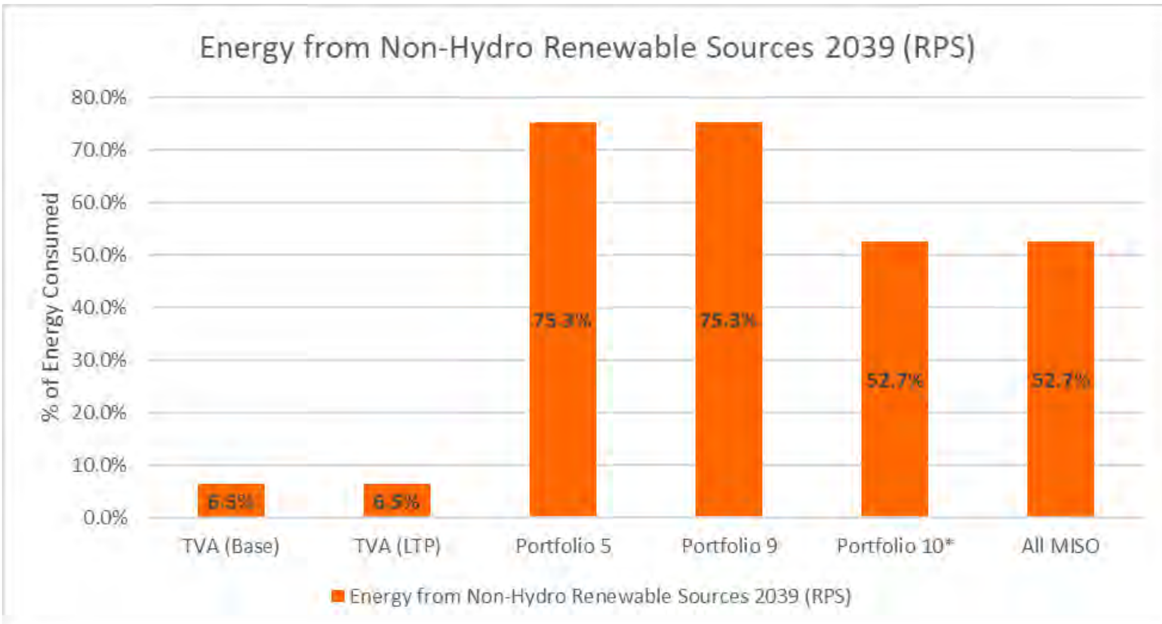


Source: Siemens

Restricted

Considering only photovoltaic and wind generation in the RPS, TVA fares poorly on an RPS measure. Even if large hydro were considered, this value would only increase to 16%. Exhibit: 181 displays a comparison of renewable energy as a percentage of total energy.

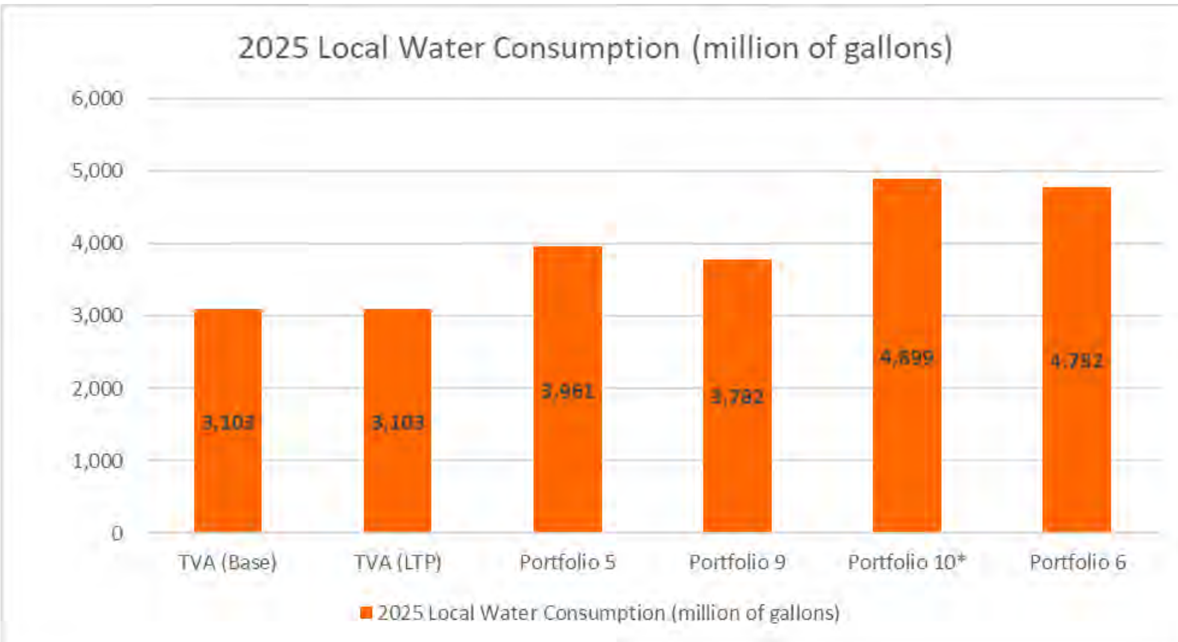
Exhibit: 181 RPS



Source: Siemens

Another important consideration is the use of water in Shelby County, which in the case of TVA is limited to the Allen CCGT. In this measure, TVA performs best. All Portfolios increase the water consumption with Portfolio 10 (with one large CCGT) and Portfolio 6 (with two CCGTs) being the worst performing. See Exhibit 182.

Exhibit 182: Water Consumption



Source: Siemens

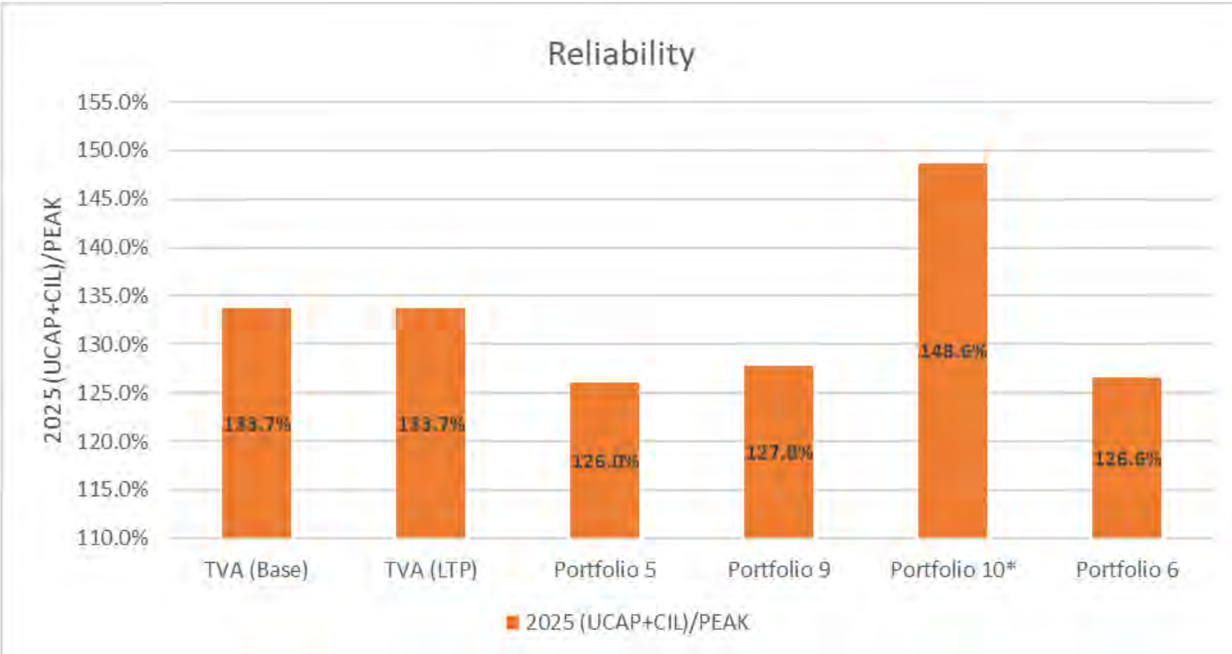
15.1.3 Reliability

From a reliability perspective all Portfolios meet and surpass NERC standards, which are among the highest in the world. As presented in the resource adequacy section of this report, the combination of the Unforced Generation Capacity (UCAP) + Capacity Import Limit (CIL) must be more than 126% of the peak demand to achieve a loss of load expectation of one day of missed load in every 10 years, when MLGW is treated as a separate Load Resource Zone (LRZ).

Portfolio 5 meets these requirements, however unlike other Portfolios with only one CCGT in the short term (the first GT is installed in 2035), during an extreme event that trips the two 500 kV lines linking MLGW with MISO there would be a need to shed load in MLGW system. (NERC allows for load shed during extreme events.) With Portfolio 9, 10, and 6, there would be no need to shed load during this extreme event.

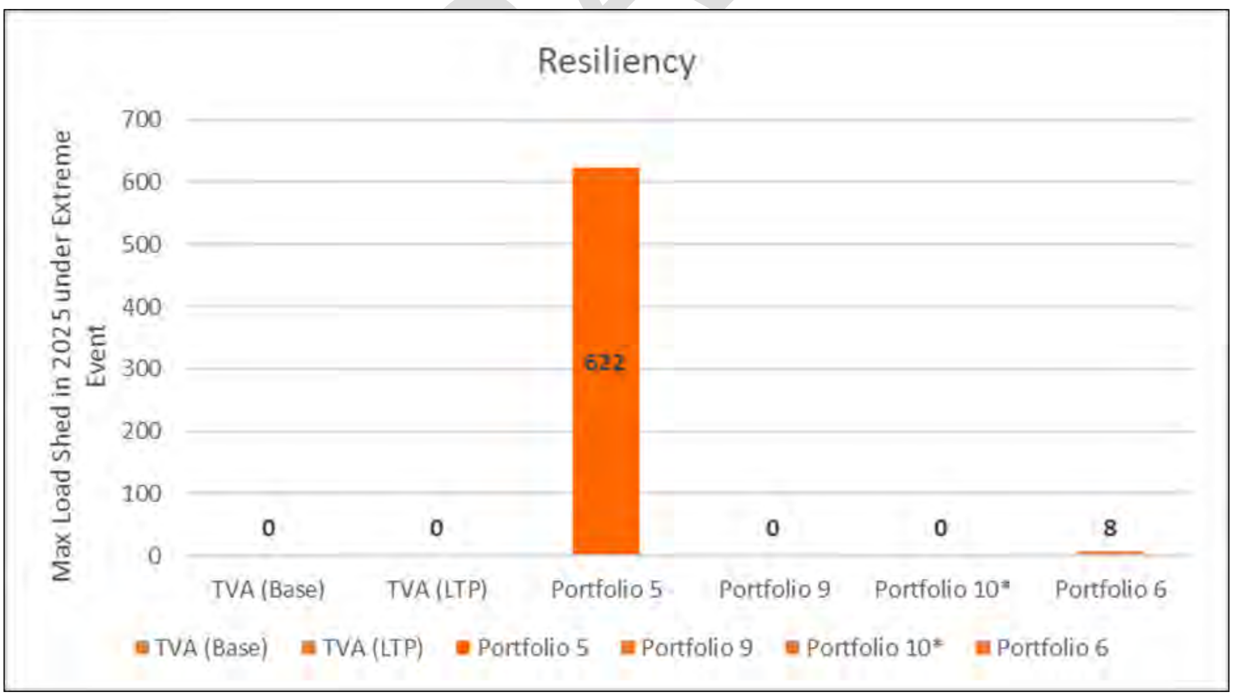
We also note that Portfolio 10 has the highest value according to this metric, but it can be misleading as this portfolio has only one large CCGT and its extended outage could lead to dependence exclusively on transmission, similar to Portfolio 5, but in this case it was reinforced allowing the incorporation of this large CCGT and preventing load shed during N-1-1 events. Portfolio 6 (with only one CT instead of two) has a very small amount of load shed that would occur only if the N-1-1 event were to occur at the time of the yearly peak and if desired to be eliminated it could be addressed with Portfolio 8 that is similar to 6 but with one more CT.

Exhibit 183: Reliability



Source: Siemens

Exhibit 184: Resiliency

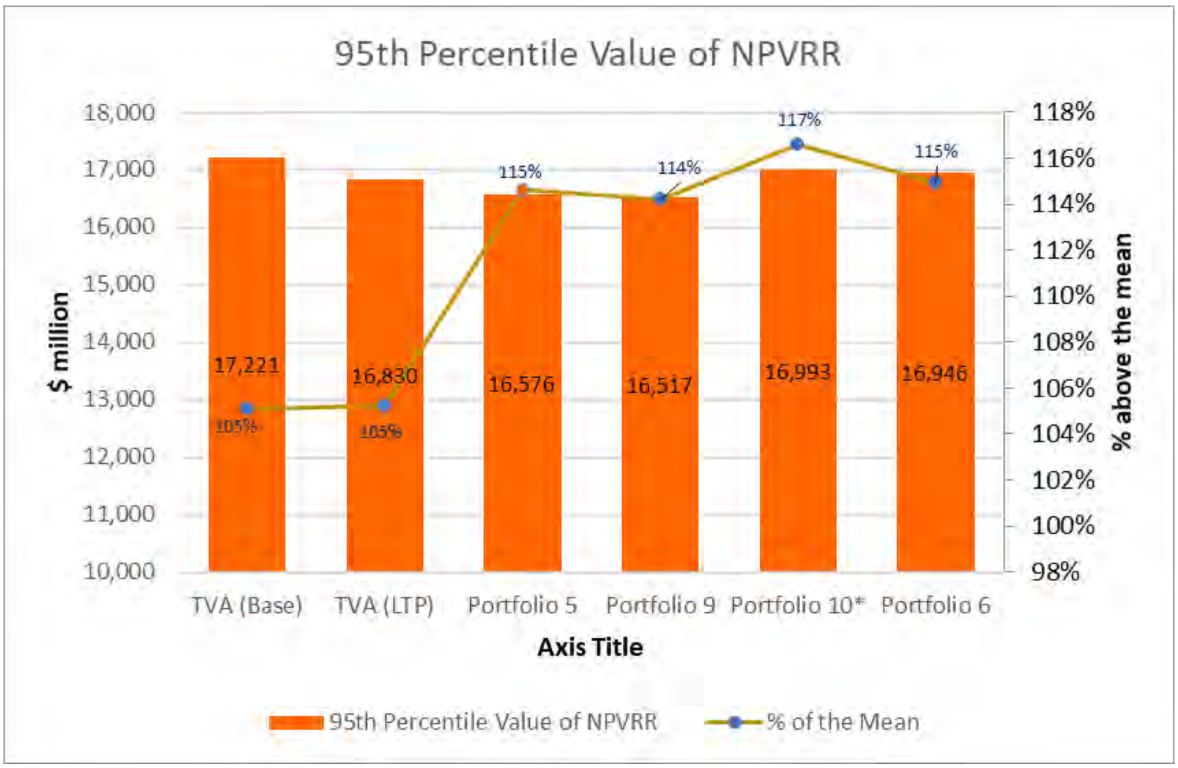


Source: Siemens

15.1.4 Price Risk

TVA's portfolios costs have moderate price variability as expressed in terms of the 95th percentile and it is less variable than any of the alternative portfolios considered. We note that the TVA 95th percentile is only 105% times the stochastic mean, Portfolio 5, 9 and 6 while in Portfolio the 95th percentile is 114% to 115% times the mean and in Portfolio 10 it is 117% times. 17% higher due to its high dependence of gas (see exhibits below). The relative stability of TVA prices is expected as TVA's generation fleet is very diversified and about half of the generation mix is comprised of hydro and nuclear. MLGW should asses options achieve fuel price volatility mitigation as part of its assessment to leave TVA.

Exhibit 185: 95th Percentile of Revenue Requirements and Changes with Respect of the Mean

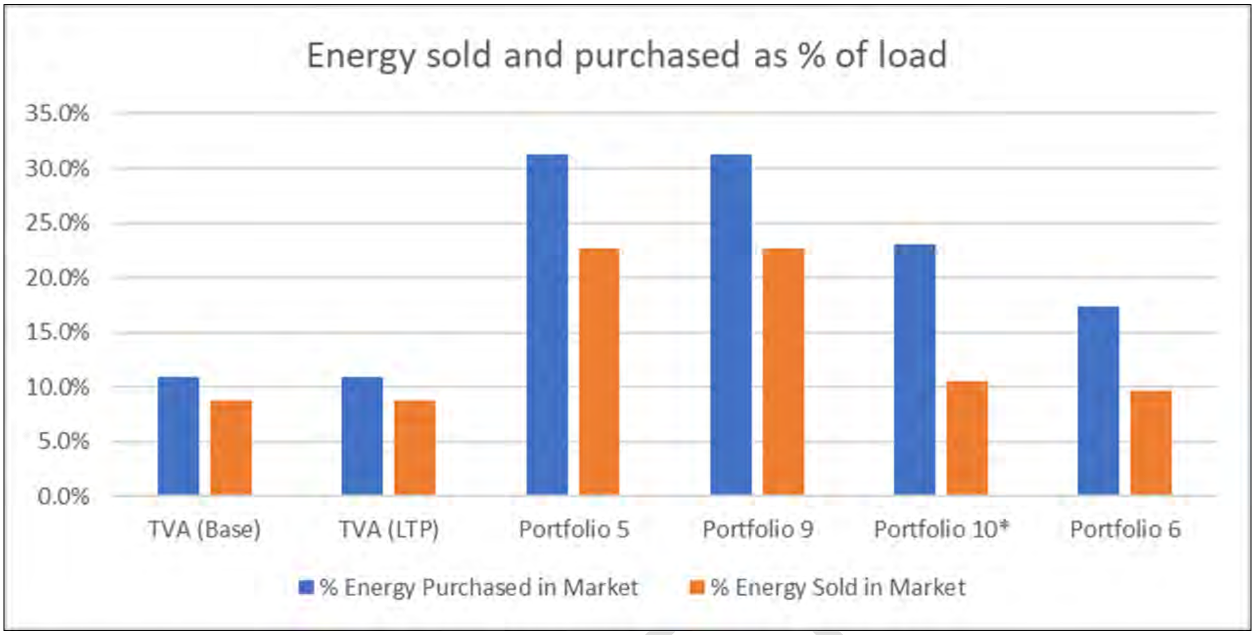


Source: Siemens

15.1.5 Market Risk

Market risk is measured as a function of the percentage of the energy that is sold and purchased in the MISO market as a percentage of the total load. As can be observed below, with TVA this risk is very small as TVA exchanges only a small amount of its energy. However, Portfolio 5 needs to sell large amounts of energy in the MISO market during the daytime and purchase some of it back at night. Portfolio 10 and Portfolio 6 have a reduced risk particularly on energy purchases due to the incorporation of the large CCGT on 10 and the two CCGTs on 6.

Exhibit 186: Market Risk



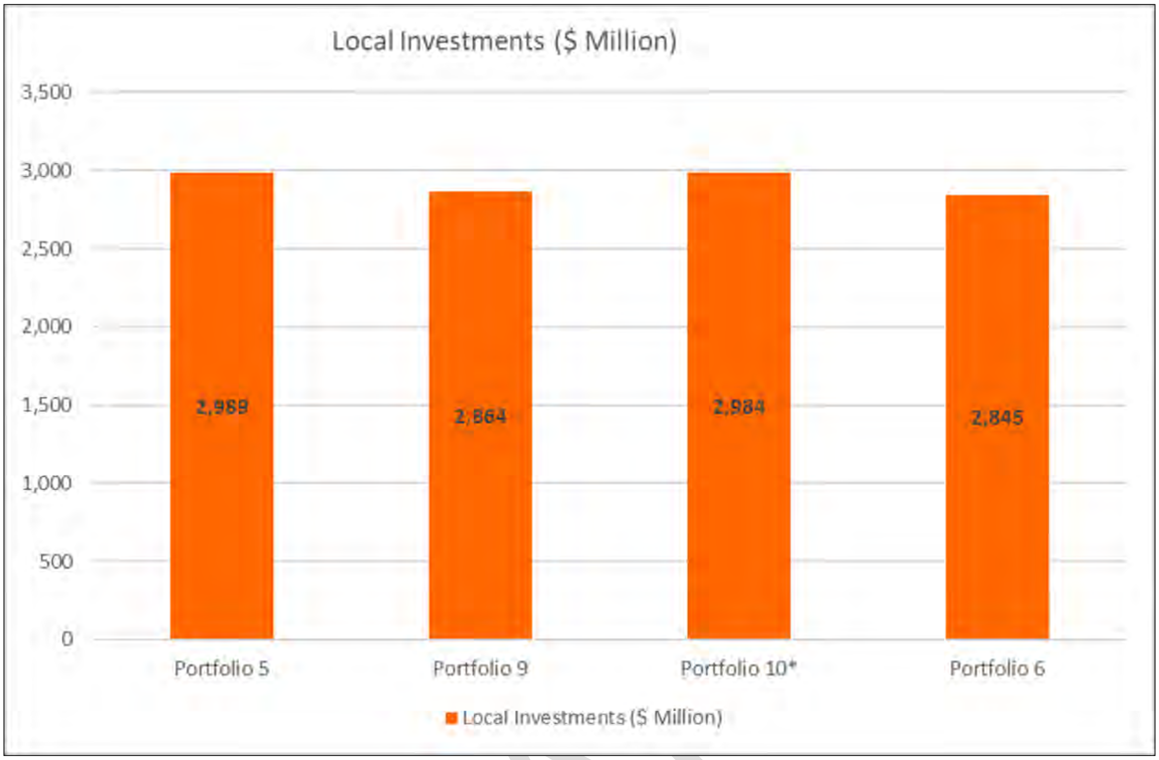
Source: Siemens

15.1.6 Local Economic Development

Local economic development is measured using the total local capital expenditures per Portfolio as a proxy. This is presented just for portfolios ranking purposes.

As shown in Exhibit 187 all portfolios are very similar, with Portfolio 5 and 10 slightly ahead largely due to the transmission investments.

Exhibit 187: Economic Development



Source: Siemens

15.1.7 Findings and Recommendations

Siemens IRP report is designed to provide MLGW with the information needed to decide on the tradeoffs associated with the Self-Supply plus MISO options and the TVA options. In addition, there are several tradeoffs among the MISO and local supply options to consider.

The selection of the best portfolios for MLGW is not simply a cost-based decision. It factors in risk, sustainability, resilience, reliability, and economic impacts. Hence, no final recommendation is made here. Rather we developed a series of no regret strategies and actions to be taken by MLGW to make its final determination.

The key findings of our study are:

- There are levelized cost savings of about $90 to $122 million in real 2018$ per year on an expected basis (probability weighted) associated with exiting the TVA contract and joining MISO under the LTP for the 2020 to 2039 period. These savings increase to $127 to 153 million per year for the current TVA contract.
- The TVA option provides a somewhat higher level of reliability as a percentage of load, though all Portfolios meet NERC requirements, and except for Portfolio 5, all can avoid load shedding under extreme conditions. While Portfolio 5 shows savings of $122 million per

year, it has the potential for significant load shedding during double outage conditions and is the worst of the selected portfolios regarding reliability.

- If MLGW chooses to exit the TVA agreement and join MISO, MLGW should:
  - Maximize the amount of local renewable generation, which provides local support and is not affected by transmission. This is a no regret decision, i.e. it is present in all best performing Portfolios and should be pursued. The 1000 MW limit was used in the study set to increase the likelihood of success, but if more local generation can be procured, this will only result in a reduced need to acquire MISO footprint generation.
  - Build or secure one combined cycle unit (450 MW). It is present in all preferred solutions; thus, this is a no regret decision. However, its size could be subject to further optimization. As was identified from the analysis of Portfolio 10 there are tradeoffs between the larger investments in transmission necessary to integrate a larger and efficient CCGT and the associated savings in generation costs. It is recommended a future RFP should consider CCGTs of various sizes for which a corresponding optimized transmission system would be designed, allowing the selection of the best combination of CCGT, transmission investments, and the renewable generation being acquired.
  - Consider the option of two CCGTs and reduce the need for transmission investments and MISO procured renewable generation. The decision between one or two CCGTs is a function of the expected reliability of the transmission system and the amounts of economic renewable generation that MLGW can procure both locally and within MISO. At this moment, pursuing two CCGTs does not seem to be a no regret decision.
  - Install at least two combustion turbines (237 MW CT) in 2025, which also appears to be a no regret solution. This is present in Portfolio 9 that requires four CTs and it is the best overall performing portfolio, Also, if two CCGTs are selected (as in Portfolio 6) the risk of load shed under N-1-1 is minimized with two CTs.
  - MLGW should asses options achieve fuel price volatility mitigation as part of its assessment to leave TVA.
  - MLGW should seek to become part of MISO Local Resource Zone 8 rather than becoming an independent zone. Both MLGW and the current members stand to gain from this given the diversity between the loads and the larger size of the new zone.

- In case MLGW decides to stay with TVA, MLGW should
  - Explore options to increase the amount of local renewable generation (which would be limited to 5% even under the 20-year exit option).
  - Assess further the LTP option. On one hand there will be a reduction on the costs and the NPVRR with the LTP is approximately $400 million lower than without it. On the other hand, MLGW will be locked for 20 years and unable to control or take advantage of developments in the electric power industry such as, for example, deeper drops in the cost of renewable generation and storage that could increase the economic savings for

reconsidering exiting TVA and joining MISO at a later date. This analysis can be performed at a later date and only needs to be performed if MLGW chooses to stay with TVA.

- The Payments in Lieu of Taxes (PILOT) is a payment that goes to both local and state government and directly or indirectly benefit the citizens, which are the same constituency of MLGW. Thus, the nature of who pays these costs is different than other costs. For example, payments to a generation developer, fuel costs, or investments in transmission may be treated differently and hence its impact should be considered separately. This cost is an important component of the total costs and savings. For example, in Portfolio 9 it represents approximately $720 million of the total NPVRR and it is likely larger than the payments that TVA would make in the case that MLGW decides to continue with the existing contract. MLGW should consider ways to minimize the differences between what TVA and MLGW pays for equivalent services where possible.
- An RFP should be undertaken by MLGW to confirm all estimated savings before making a final decision. The IRP can be utilized to determine the general mix of assets and locations of interest in the RFP and the orders of magnitude of transmission required. Differences between Portfolios 5, 9, 6, and 8 can be reassessed with bids provided by potential suppliers.

15.1.8 Magnitude of Savings for Exiting TVA

The following exhibit explains why the savings from exiting the TVA agreement are closer to $130 million per year (in real 2018$) than the $450 million per year (which may include inflation) figures floated by some consultants in prior studies and quoted in the press.

We chose Portfolio 9 as the representative portfolio for the following comparison but the waterfall in the exhibit would be similar in any of the most preferred strategies. For the estimation of the levelized annual savings in this case we used the difference in the NPVRR for the period 2025 to 2039, to show results not affected by the first 5 years and comparable to the results presented by others.

Exhibit 188: Portfolio 9 Levelized Yearly Costs for 2025 to 2039 with Respect to TVA LTP (2018$)

Source: Siemens

Expressing the above in terms of levelized costs in $/MWh.

Exhibit 189: Portfolio 9 Levelized Energy Costs for 2025 to 2039 with Respect to TVA LTP

Source: Siemens

A similar comparison with respect to the current contract shows savings in the order of $160 million per year.

Exhibit 190: Portfolio 9 Levelized Costs for 2025 to 2039 with Respect to TVA Current Contract

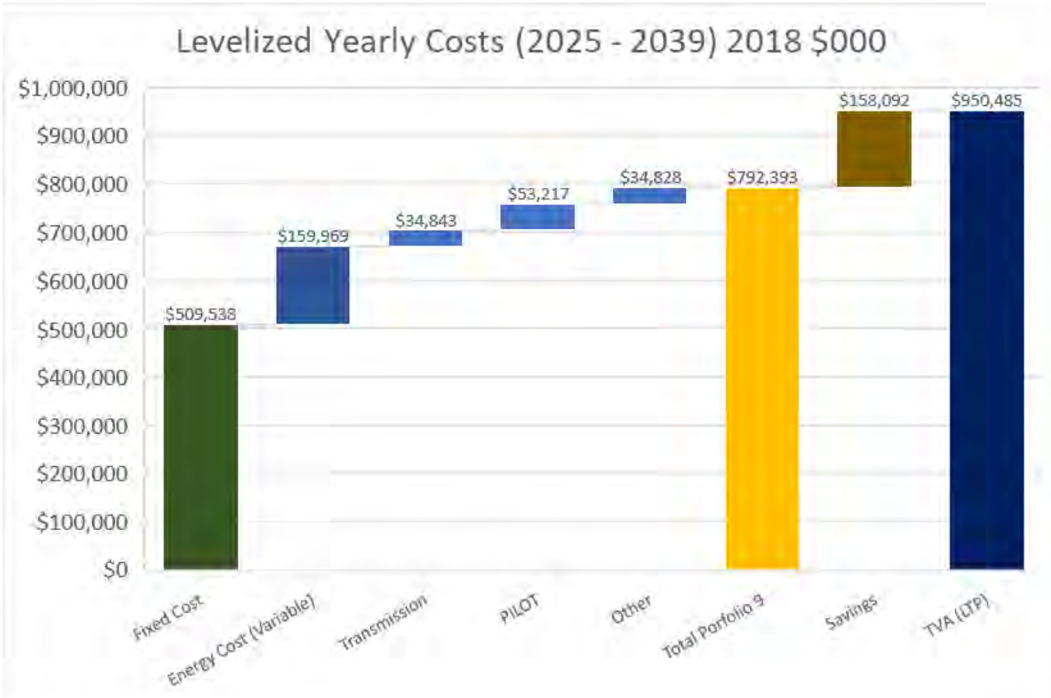


Exhibit 191: Portfolio 9 Levelized Energy Costs for 2025 to 2039 with Respect to TVA

Source: Siemens

In this last case the payments for transmission, PILOT and Others (Gap analysis costs, MISO membership, energy efficiency programs, and matching TVA community benefits) are an important cost for direct comparison to TVA because they account for approximately $122 million of costs per year.

Siemens estimated TVA's costs will decline to about $71 MWh in the future. If TVA were unable to achieve these costs, as they are about $76 / MWh in 2019 the savings would be greater

In summary, while the energy savings are substantial, MLGW will have to pay for several additional items that need to be taken into consideration. These include:

- Payments for fixed costs for entering long-term contracts as MLGW could not simply purchase energy and capacity in the open MISO market
- Transmission investments interconnecting with MISO
- PILOT currently paid by TVA but would have to be paid by MLGW
- Benefits provided to MLGW customers by TVA today that would have to be replaced
- Gap analyses costs (balancing authority, additional staff for planning and operations, etc.)
- MISO Membership

One of the most important factors that reduce the savings are the transmission costs and the PILOT. Transmission costs are very significant because TVA claims that they do not have to share their transmission facilities with MLGW, and it is not in their best interest to do so. We have attached the documents TVA provided that support their position in Appendix A: TVA Letters. Hence Siemens had to assume that TVA would not share facilities and would not allow MLGW to wheel power through their system. This substantially raised the transmission costs.

If MLGW gives notice to TVA, there could be a win – win opportunity that could increase the savings for MLGW but that will not be determined until a later date. It was prudent to assume that "No Deal" could be struck with TVA in the event MLGW exits the agreement.

Second, some of the PILOT costs TVA pays today might be borne by developers as actual taxes included in the prices, they charge MLGW on energy costs. In Siemens analysis, the state will collect more from Strategy 3 than in Strategy 1. If those costs were equal the savings for exiting the agreement could be larger.

Appendix A: TVA Letters

TVA's Long-Term Partnership Proposal
Talking Points

The TVA Board approved the terms of the Long-Term Partnership Proposal (LTPP) in August 2019. Below are the relevant talking points for distribution.

STANDARD ELEMENTS OF THE LONG-TERM PARTNERSHIP OPTION

- MLGW termination notice under the wholesale power contact will be changed to 20 years
- TVA will commit to providing enhanced flexibility for distribution solutions between 3-5% of load by October 1, 2021
- A Partnership Credit that reflects the opportunity to align TVA's debt retirement with the longer-term commitment of customers
    - The Partnership Credit is 3.1% of wholesale standard service (non-fuel)
    - The credit will be applied monthly to demand, non-fuel energy, GAC charges

RATE TRAJECTORY

- No base rate increases for 10 years (current TVA Financial plan approved by the Board in August)

Updated September 2019

PARTNERSHIP BENEFITS AND TVA PUBLIC POWER

Benefits of TVA Public Power

Annual Benefit 5-Year Contract | Annual Benefit Partnership Agreement | Potential Options for Consideration*

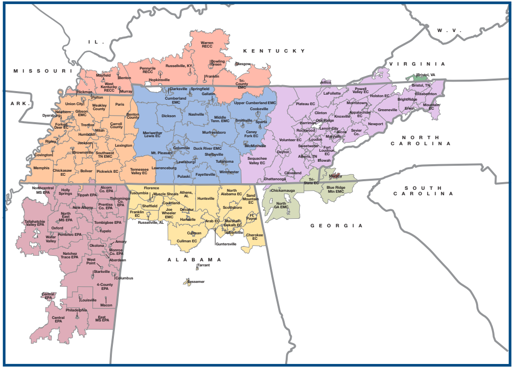
- As a part of the partnership agreement, TVA has offered a 3.1% credit on wholesale power rates to all Local Power Companies (LPCs); for MLGW, this credit is approximately $22.5 million per year, or $400 million over 20 years.
- LPCs that commit to the partnership agreement also gain additional access to the TVA planning process and an opportunity to self-generate some renewable energy (up to 5%) to meet local needs.
- All 154 LPCs are offered the same contract terms and benefits.
- Potential options for consideration may include but are not limited to $700M Transmission Prepay, $200M Gas Prepay and $100M Electric Prepay.*
- TVA is also commited to support future port development at the former Allen Fossil Plant site.*

Description	Annual Benefit 5-Year Contract	Annual Benefit 20-Year Partner Contract
Transmission Lease TVA lease of MLGW's 161kV system on an annual basis	$35M	$35M
PILOT Payments Payments in lieu of taxes distributed via the State of TN	$18.3M	$18.3M
Economic Development Benefits TVA's Investment Credit program rewards companies for new/expanded operations Numbers are specific to Memphis area	$13.8M	$13.8M
Programs to Reduce Energy Burden Includes weatherization programs like Share the Pennies and Home Uplift Provides incentives to homes, businesses, and local industries	$3.2M	$3.2M
Memphis Community Support Includes grants to Mid-South Food Bank, Memphis in May, Library, Museums, NAACP Awards, Urban League, School Programs / STEM, etc.	$0.3M	$0.3M
Partner Credit 3.1% wholesale bill credit	Not Included	$22.5M
Total Per Year	**$71M**	**$93M**
Items below and prepays are for further consideration.		
Transmission Lease Prepay TVA lease of MLGW's 161kV system on an annual basis	Not Included	Available prepay up to $700M
Gas JAA Prepay Bank and MLGW enter into a Joint Action Agency to prepay gas, TVA converts gas to electricity through tolling arrangement	Not Included	Available prepay up to $200M
Electric Prepay MLGW issues tax exempt bonds to prepay electric service, TVA repays with floating credit	Not Included	Available prepay up to $100M
		$1B Potential Benefits in Year One

** For discussion purposes only and does not constitute a binding offer and shall not form the basis for an agreement under any legal or equitable theory.*

TVA Public Power

TVA works with **154 local power companies** to keep safe, clean, reliable and affordable public power flowing to homes and businesses throughout the seven-state region. As of April 2020, 138 of the 154 local power companies have signed the TVA Partnership Agreement, including **Electric Power Board** (Chattanooga, TN), **Nashville Electric Service** (Nashville, TN) **Huntsville Utilities** (Huntsville, AL), and **Knoxville Utilities Board** (Knoxville, TN).



What happened to LPCs that left TVA?

Paducah and Princeton, Kentucky

History: Paducah and Princeton left in 2009 due to concern over TVA rates. They formed the Kentucky Municipal Power Agency (KMPA) to invest in a coal mine and build a large, new coal plant.

Challenge: Plant costs came in 75% higher than expected. In five years, their rates rose to the highest in KY, and KMPA carried $500M+ in debt while losing $300k per month.

Result: Paducah and Princeton wanted to return to TVA, but are unable due to outstanding debt.

Bristol, Virginia

History: Bristol Virginia Utility (BVU) left TVA in 1997 looking for lower rates. They switched to AEP in 2005 and returned to TVA in 2008 seeking rate stability.

Challenge: Reliability and price stability were significantly worse at other power providers, despite lower advertised prices. After a 40% rate hike with AEP, BVU negotiated a deal to re-join TVA.

Result: Bristol returned to TVA 10 years later.

TVA's Position on the Implications of A Customer Giving Notice to Terminate

INTRODUCTION

TVA currently serves 154 local power companies (LPCs). In the event that one of the LPCs gave notice that they would terminate their wholesale power contract (WPC), TVA has mapped out the implications and actions that it is prepared to take. This memorandum describes those implications prior to and after the termination, including whether TVA could be compelled to wheel power. The purpose of this document is to help customers evaluate the costs of giving notice without taking a stance on the risks or benefits to that customer.

IMPLICATIONS OF AN LPC GIVING NOTICE

During the notice period, which is typically 5 years, the following implications become relevant to a departing LPC:

- **Special Wholesale Rates:** The WPC does not allow TVA to accelerate cost recovery through increased rates to the departing customer. Nothing precludes TVA from offering special wholesale rates to other customers (e.g., for extending existing terms), and there is no requirement that TVA make such special rates available to departing customers.
- **Full Requirements:** The existing provisions of the WPC remain in effect during the notice period.
- **Notification to other LPCs:** TVA 2004 policy is designed to protect existing customers that did not give notice.
- **No New Projects:** Under the WPC, TVA is not obligated to undertake new projects absent agreement with the departing LPC on cost reimbursement.
- **Asset Retirement:** TVA policy would remove the departing LPC from TVA's power supply planning; subsequent retirements may flow from such removal.
- **Economic Development:** TVA's economic development efforts are discretionary; certain programs may require termination notice.
- **LPC-Sourced Services:** TVA's use is within its discretion, subject to existing contractual provisions.

After the notice period, should the LPC terminate their contract, TVA has evaluated the following implications:

- **Wheeling:** Wheeling power into the TVA service area is within TVA's discretion. FERC is precluded from ordering TVA to wheel power that will be consumed within the TVA service area.
- **Delivery Points/Back-up Power:** Existing delivery points with departing customers may need to be reconfigured/opened. Stand-by/back-up arrangements would be subject to negotiations, but the LPC would face obligation to pay the costs of maintaining delivery points.

- **Stranded Costs:** Some WPCs specifically preclude any stranded cost recovery. Others do not, but no precedent for such recovery exists.
- **Unrecoverable Investments:** TVA would avoid making any investments that could be stranded, consistent with existing policies.
- **PILOTs/ED:** Programs are within TVA's discretion. Termination of the WPC would terminate any existing programs with the departing LPC.
- **Potential Direct Serve Customers:** Upon termination of the WPC, restrictions on TVA's ability to serve customers within the LPC' service area also terminate, and state territory laws do not apply to TVA. Acquisition of new direct serve customers would hinge on the location of the potential customer relative to TVA transmission facilities absent "transmission service" on an LPC system.
- **LPC-Sourced Services:** TVA's use is within its discretion, subject to existing contractual provisions.

LIST OF ABBREVIATIONS

ED: Economic Development

FERC: Federal Energy Regulatory Commission

LPC: Local Power Company

PILOT: Payment in Lieu of Taxes

TVA: Tennessee Valley Authority

WPC: Wholesale Power Contract

LONG-TERM PARTNERSHIP PROPOSAL TERM SHEET

TENNESSEE VALLEY AUTHORITY (TVA)
CURRENT VERSION 05-05-2020
PROPRIETARY AND CONFIDENTIAL MATERIAL

THIS TERM SHEET DOES NOT CONSTITUTE A BINDING OFFER AND SHALL NOT FORM THE BASIS FOR AN AGREEMENT UNDER ANY LEGAL OR EQUITABLE THEORY.

GENERAL TERMS	
Parties:	Tennessee Valley Authority ("**TVA**") and [*local power company]* "**Distributor**"
Objective:	The Valley Public Power Model is unique and has an enduring legacy of improving life in the Tennessee Valley region. At present, there is an opportunity to secure the long-term success of the Valley Public Power Model by lengthening and strengthening the contractual relationship between Local Power Companies and TVA. These enhanced relationships will safeguard long-term access to the key elements of the model and can materially change the financial profile for the Valley, the benefits of which can be shared with participating Local Power Companies and consumers.
Documentation:	The transaction to be documented as an amendment ("**Amendment**") under the existing Wholesale Power Contract ("**WPC**") between Distributor and TVA.
Partnership Credit:	Long-term partnerships benefit TVA's financial risk profile. Benefits will be shared with Distributor in the form of a bill credit of 3.1% of wholesale standard service demand, non-fuel energy, and grid access charges. The bill credit will start the first full billing month after signature. If notice is given, the credit will be phased out over the next 10 years in equal annual percentages.
Full Requirements Commitment:	TVA commits to provide all the power supplied in the Distributor's service area and Distributor commits to ensuring that all power supplied in Distributor's service area is TVA power, unless otherwise agreed to by the Parties.
Termination Notice:	The Termination Notice under the WPC will be changed to 20 years.
Commitment to Explore Expanded Flexibility with Long-Term Partners:	TVA will commit to collaborate on flexibility solutions with long-term partners for addressing customer and system needs as well as provide research value. TVA will commit to providing enhanced flexibility for distribution solutions between 3-5% of load by October 1, 2021, with pricing and planning considerations mutually agreeable between Distributor and TVA. If TVA does not fulfill this commitment, Distributor may terminate this Amendment, return 50% of Program Credits received, and revert to the termination notice effective prior to this Amendment.
Additional Partnership Benefits:	During the term of this Amendment, TVA may provide additional benefits to long-term partners. Distributor would be eligible to receive any such additional benefits that are applicable to it. TVA will establish a practice of strong engagement with long-term partners for strategic resource and financial planning decisions.

Rate Adjustment Protection:	In the event that TVA implements rate adjustments that increase wholesale base rates by more than 5% within the next 5 years (ending FY2024) or 10% over any 5-year period, the Parties will endeavor to negotiate new terms for 180 days after which Distributor may reduce WPC notice provision to 10 years, which will immediately terminate this Amendment.
Events of Default:	TVA Defaults A sale or transfer of all, or substantially all, of TVA's power properties, including generation or transmission properties, to a non-public entity that results in Distributor paying higher rates that are not based on the current TVA Act. TVA assigns the WPC without the consent of the Distributor. Distributor Defaults A sale or transfer of all, or substantially all, of Distributor's assets to any entity that results in a reduction in load served by TVA. Distributor sells or supplies non-TVA power. Distributor assigns the WPC without the consent of TVA.
Remedies:	TVA Default In the event of a TVA default, TVA would pay Distributor actual and potential losses over the remaining term of the WPC due to the increased rates charged by a new power provider or as required by TVA under any new law that would be higher than those otherwise charged by TVA in accordance with the current TVA Act. Distributor Default In the event of a Distributor default, Distributor would pay TVA actual and potential losses over remaining term of the WPC due to loss of TVA revenue and load due to either sale of non-TVA power to end-use customer(s) in Distributor's service area or sale or transfer of all or substantially all of Distributor's assets.