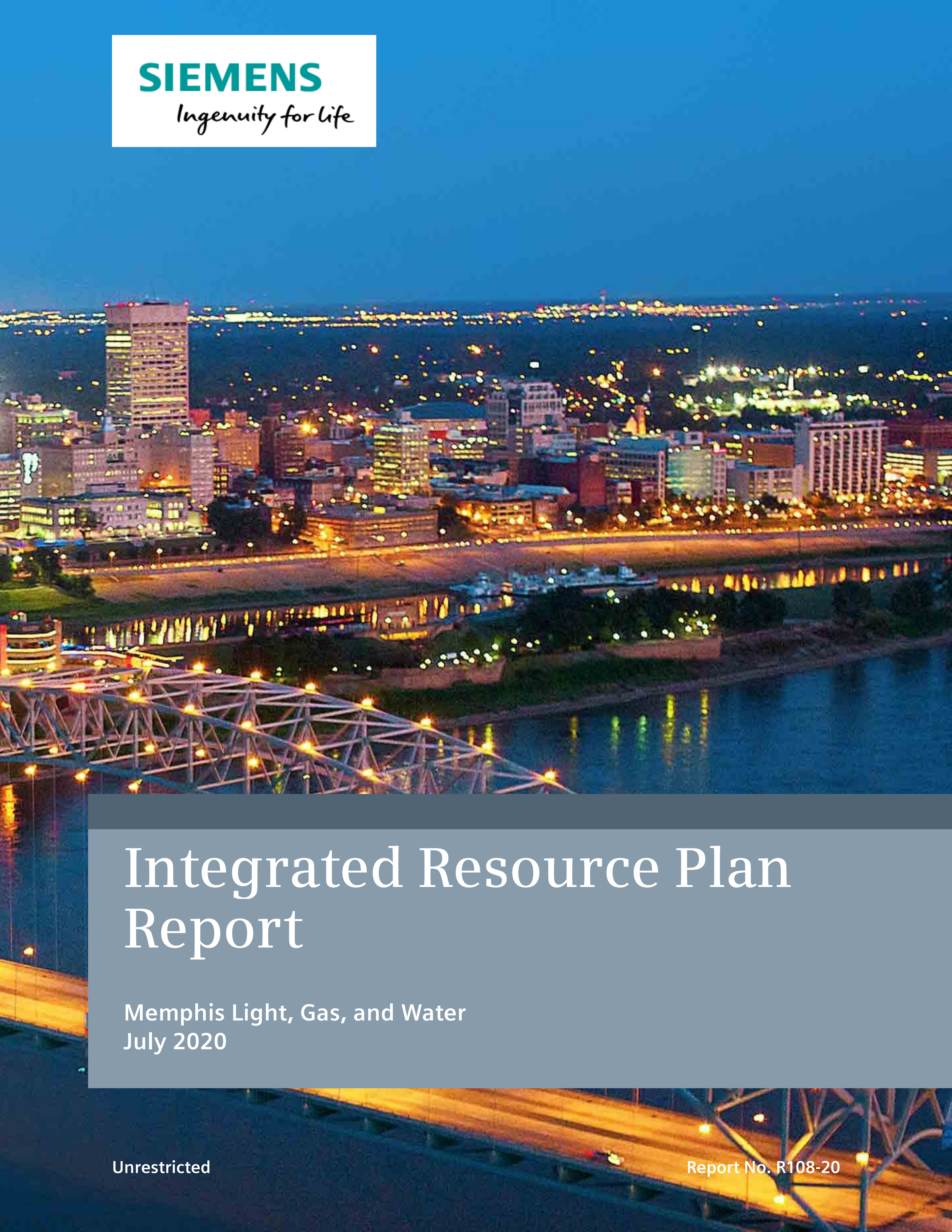

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Integrated Resource Plan Report

Memphis Light, Gas, and Water
July 2020

Unrestricted

Report No. R108-20

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1. Executive Summary

1.1 Introduction

Memphis Light, Gas and Water (MLGW) is the largest municipal utility in the State of Tennessee, serving approximately 431,200 electric customers in Shelby County. Its electrical demand (average load) in 2019 was 1,598 MW with a peak load of 3,161 MW.

MLGW currently purchases all its electric power needs from the Tennessee Valley Authority (TVA) under an All Requirements Contract. MLGW has the option of exiting its All Requirements Contract with TVA with 5 years of advance notice. TVA has the option of terminating the contract with 10 years of advance notice.

As an alternative to the current contract, TVA has offered to MLGW (and all the Local Power Companies it serves) an option of extending the notice period to 20 years, in exchange for a 3.1% discount on the Standard Service non-fuel components of the wholesale rate. In addition, TVA is offering the flexibility to MLGW to provide up to 5% of its load with local generation solutions other than TVA.

In addition to evaluating the two alternatives available from TVA, MLGW is evaluating the option of terminating its contractual relationship with TVA and developing its own resources and/or acquiring them from the neighboring Midcontinent Independent System Operator (MISO) market. The evaluation of these options is the central objective of this Integrated Resource Plan (IRP).

1.2 Strategies/Scenarios/Portfolios Analyzed

The overarching objective of this IRP is to identify a generation resource Portfolio (or Portfolios) that performs best across agreed performance metrics (least cost, reliability & resiliency, sustainability, etc.). The Strategies, representing the available options to MLGW to supply its load, are combined with Scenarios (i.e. future states of the world) to determine least cost Portfolios of Generation and Transmission Assets, which are subjected to a range of future outcomes, and then ranked using a balanced scorecard.

The Strategies, Scenarios and Portfolios derived are presented next.

MLGW initially identified four distinct supply strategies to be evaluated in the IRP. These consisted of

1. **Strategy 1:** All Requirements Contract with TVA (status quo), business as usual.
2. **Strategy 2:** Self-supply where MLGW self-serves all needs from local resources.
3. **Strategy 3:** Combination of self-supply (i.e. local supply) with procurement of resources in MISO market.
4. **Strategy 4:** Procure all resources from MISO.

Strategy 3 (Self-Supply plus MISO) is a lower cost strategy than Strategy 4 (All MISO). Local renewables are the least expensive option of all available resources for MLGW. Since purchasing all resources from MISO would preclude the least expensive source of generation to MLGW, Strategy 4 cannot be the least cost option for MLGW. In addition, Strategy 4 requires more transmission than is required for Strategy 3. Still, for the purpose of comparison, a Portfolio for Strategy 4 (All MISO) was developed and subjected to the full range of stochastics as requested by Power Supply Advisory Team (PSAT) members.

Strategy 2 is simply not achievable. There is not enough land available in MLGW's service territory and its vicinity to economically acquire the needed renewable resources, nor would there be adequate backup generation capacity to meet the reliability and resource adequacy requirements, without major investments in generation resources. For these reasons, Siemens focused our attention on Strategies 1, 3 and 4.

In the context of the IRP, Scenarios are plausible futures in which MLGW could find itself operating. Each Strategy is evaluated in combination with each Scenario to produce least cost Portfolios of resource options. Seven Scenarios were considered to produce the Portfolios for detailed risk analysis.

For Strategy 3, the seven Scenarios (future states of the world) are described below. Five of them can be considered typical scenarios (1, 2, 3, 4 and 7) and two were sensitivities to test for the impact of specific conditions (5 and 6).

- **Reference (Scenario 1)** – The Reference Scenario represents the "most likely" future market conditions based on what is known at this time. Key drivers were based on Siemens reference case outlook. These include:
  - Natural gas prices increasing in real terms from current levels through 2039.
  - Coal prices vary by basin with Illinois Basin coal prices declining slightly due to expected demand declines and Powder River Basin coal prices increasing slightly because of reserve depletion over the study period.
  - Load for markets surrounding MLGW increase at a moderate rate of less than one percent on average annually.
  - New build technology costs decline with fossil resources declining moderately and more pronounced declines for solar, battery storage and to a lesser extent onshore wind.
  - A moderate national price of carbon (beginning at about $3 per ton and rising over time to about $20 per ton) is assumed beginning in the mid-2020s.

- **High Load (Scenario 2)** – This scenario maintains the same assumptions as in the Reference Scenario, with the exception being higher levels of load growth. The objective of this scenario is to assess the need for increases in the amount of generation resources.

- **Low Load (Scenario 3)** – This scenario maintains the same assumptions as in the Reference Scenario, with the exception that load growth is slower. The objective of this scenario is to determine if there would be reductions in the amount of generation resources required if load growth is reduced.
- **High Load/Low Gas (Scenario 4)** – This scenario maintains the same assumptions as in the Reference Scenario, with the exception that load growth is faster and natural gas prices are lower. The objective of this scenario is to identify how the generation mix will change in a higher load future.
- **Reference with High Transmission (Scenario 5)** – This scenario maintains the same assumptions as in the Reference Scenario, but in this case the transmission capacity into MISO is increased to determine how greater access to MISO markets would affect the generation mix (e.g. as in an All MISO Strategy). Raising access to transmission would also raise the fixed cost for transmission to MISO.
- **Reference with Low Storage Costs (Scenario 6)** – This scenario maintains the same assumptions as in the Reference Scenario, but in this case the battery energy storage system (BESS) costs are projected to be very low and combustion turbines are excluded to force the selection of the BESS solution.
- **Low Load/ High Gas (Scenario 7) –** This scenario maintains the same assumptions as in the Reference Scenario, with the exception that load growth is slower and natural gas prices are higher. By the end of the planning horizon, gas price increased by 210% in real terms (2018 $)[1]. This scenario was expected to maximize the use of renewables and accelerate their implementation, while minimizing the thermal additions as the load is lower. This scenario is similar to the Climate Crisis case requested by PSAT since there are strong incentives to accelerate renewables and minimize thermal generation.

Strategy 1 (TVA) was assessed considering TVA's 2019 IRP plan (but with Reference Case assumptions) and Strategy 4 (All MISO) was assessed under Scenario 1 (Reference Case assumptions). Exhibit 1 below summarizes the base combinations of Strategies and Scenarios considered.

[1] The increase in gas prices could be directly due to an increase in the price of the commodity or a combination of increases in commodity plus CO_2 emissions costs $/Ton. In the base case the gas is modeled to increase by 59% by the end of the forecast period as compared with 210% in this scenario.

Exhibit 1: Portfolios Across Scenarios and Strategies

Scenarios / Portfolios		Strategy		
		Strategy 1 (TVA)	Strategy 3 Self + MISO	Strategy 4 All MISO
State of the World	Scenario 1 Reference	S1S1	S3S1	S4S1
	Scenario 2 (High Load)		S3S2	
	Scenario 3 (Low Load)		S3S3	
	Scenario 4 (High Load/Low Gas)		S3S4	
	Scenario 5 (High Transmission)		S3S5	
	Scenario 6 (Promote BESS)		S3S6	
	Scenario 7 (Low Load/High Gas)		S3S7	

Source: Siemens

In Siemens' structured approach the determination of the final Portfolios for detailed analysis is a two-step process:

- First a least cost capacity expansion plan is produced using the Long-Term Capacity Expansion (LTCE) module of the optimization software (AURORAxmp® or AURORA) for each combination of Strategy and Scenario. 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 judgment 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 to improve reliability. Therefore, it is possible to have multiple portfolios associated with a single Strategy and Scenario combination.

A total of 20 Portfolios under Strategy 3 resulted from the two-step process; Exhibit 2 describes these 20 Portfolios. Following this exhibit is a brief discussion of how the Portfolios were reduced from 20 to 10 under Strategy 3. In addition, there are two scenarios for Strategy 1 (TVA Status Quo and TVA under the Long-Term Partnership) and one Portfolio for Strategy 4 (All MISO).

Exhibit 2: Summary of the Selection of 11 Portfolios

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	Portfolio NPV Cost ($000)	Demand Weighted NPV ($/MWh)
S3S1	No	Base	Base	1137	1000	0	2137	2200	1761	0	2	1	0	9,054,690	50.00
S3S1_P	Portfolio 1	Base	Base	1137	1000	0	2137	2200	1761	0	2	1	0	9,089,087	50.19
S3S1_F	Portfolio 2	Base	Base	1587	1000	0	2587	1550	1487	0	3	1	0	9,300,273	51.36
S3S1_2CT	Portfolio 7	Base	Base	1374	1000	0	2374	2200	1550	0	2	2	0	9,125,223	50.39
S3S1_M	No	Base	Base	1930	650	0	2580	1050	1342	0	3	1	1	9,410,590	51.97
S3S1_MP	No	Base	Base	1587	750	0	2337	1800	1487	0	3	1	0	9,342,020	51.59
S3S1_A	No	Base	Base	1587	1000	0	2587	1150	1554	0	3	1	0	9,373,917	51.76
S3S2	No	High	Base	1824	1000	0	2824	1350	1746	0	3	2	0	10,770,685	51.24
S3S2_BB	Portfolio 3	Base	Base	1824	1000	0	2824	1350	1308	0	3	2	0	9,341,806	51.59
S3S3	No	Low	Base	1350	1000	0	2350	1550	1655	0	3	0	0	8,793,587	50.96
S3S3_BB	Portfolio 4	Base	Base	1350	1000	0	2350	1550	1697	0	3	0	0	9,126,137	50.40
S3S4	No	High	Low	1824	1000	25	2849	700	1849	0	3	2	0	9,140,036	43.48
S3S5	Portfolio 5	Base	Base	1398	1000	100	2498	3450	1183	0	1	4	0	8,980,510	49.59
S3S5_YD	Portfolio 9	Base	Base	1398	1000	100	2498	3450	1186	0	1	4	0	9,073,691	50.11
S3S6_N	No	Base	Base	900	1000	475	2375	2200	1505	0	2	0	0	9,414,739	51.99
S3S6	No	Base	Base	900	1000	475	2375	2200	1505	0	2	0	0	9,201,548	50.81
S3S7	No	Low	High	1137	1000	0	2137	2200	1718	0	2	1	0	9,965,303	57.75
S3S7_BB	Portfolio 6	Base	Base	1137	1000	0	2137	2200	1761	0	2	1	0	9,214,886	50.89
S3S7_2CT	Portfolio 8	Base	Base	1374	1000	0	2374	2200	1550	0	2	2	0	9,251,110	51.09
S3S10	Portfolio 10	Base	Base	950	1000	0	1950	2250	1901	1	0	0	0	8,532,493	47.12
S4S1	Portfolio All MISO	Base	Base	950	0	0	0	3200	1909	1	0	0	0	8,778,702	48.48

Source: Siemens

1.2.1 Reference Case Derived Portfolios

There are three derived Portfolios for Strategy 3, Scenario 1 (Reference Case or S3S1). The S3S1 LTCE from AURORA had one combustion turbine (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 Net Present Value (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 noted that in both the low load and the high load cases, a solution with three combined cycle turbines (CCGTs) was being selected. So, we identified least cost Portfolios under reference case assumptions with three CCGTs. This expansion plan was labeled as S3S1_M in Exhibit 2 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 in Exhibit 2 these 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 in Exhibit 2) and the resulting capacity expansion plan was named Portfolio 7.

1.2.2 High Load/Base Gas Derived Portfolio

S3S2 is a case with high forecasted load 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 three CCGTs and two CTs. The extra CT covers the additional load from a capacity perspective. Because of the unique buildout, it was selected as 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 scenario for proper comparison with other cases.

1.2.3 Low Load/Base Gas Derived Portfolio

S3S3 is a case with low forecasted load 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 3 CCGTs and no CT. This expansion plan was selected as Portfolio 4 for detailed analysis. This Portfolio was run on the base load scenario for comparison with other cases.

1.2.4 High Transmission Derived Portfolios

S3S5 was designed to test whether adding transmission capacity to acquire more MISO load was a viable Portfolio. It tested whether 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. S3S5 did produce a unique expansion plan with only one CCGT and four CTs in the later years with 3,450 MWs of external solar in MISO and 1,000 MWs 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

Portfolio 5 for further study. Additionally, considering that this Portfolio already included CTs in later years, another Portfolio was created by advancing the CTs from the 2030s to 2025, which also reduced the transmission and improved the reliability metrics to values similar to other Portfolios. Due to the timing of its formulation, this Portfolio was named Portfolio 9.

1.2.5 Low Load/High Gas Derived Portfolios

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

Portfolio 6 was run using the reference load forecast for comparison with other cases. As with Portfolio 7, one more CT was added in 2025 to ensure resource adequacy. Portfolio 8 is the same as Portfolio 7, but with earlier renewable generation builds.

1.2.6 Portfolios with Battery Energy Storage

Scenario 6 was created to test the economics of battery energy storage system (BESS), as BESS was not selected in any of the LTCE runs (except for 100 MW on Portfolio 5). 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, 475 MW of BESS were selected, which is equal to the capacity of 2 CTs (S3S6_N). However, due to the relatively high capital cost of BESS compared to CT, the NPV of the S3S6_N case is the highest among all reference cases[2].

Siemens tried to assess how low the capital cost of BESS had to be for BESS to become an economic option. Siemens lowered the capital cost of BESS by two 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 Portfolio 5 (S3S5) and subsequently Portfolio 9 (S3S5_YD), which were selected for further study.

1.2.7 All MISO Portfolio

In addition to the nine Portfolios, an All MISO (Strategy 4) Portfolio was developed. For this purpose, all local supply options were eliminated and then the LTCE module of

[2] BESS have multiple value streams, and this includes the energy shifting, i.e. moving renewable energy from daytime to nighttime. However, in the case of MLGW this service can also be provided by selling g energy to MISO during the daytime and purchasing it back at night. The optimization program found this later to be the preferred option. In addition to the above BESS also provides local reserves and peaking service that the optimization program found that it was more effective provided using CTs.

AURORA was run with no limits to transmission and giving the process the option to select any thermal resource or renewable generation to serve the load. Based on the amounts of generation resources selected, the remaining load was met by market purchases. Based on the All MISO Portfolio, a new Portfolio was created that replaced 1000 MW of MISO renewable capacity with an equivalent amount of local renewable generation, which became Portfolio 10.

Exhibit 3 provides an overview of the 10 selected Portfolios for analysis and the All MISO Portfolio. We note that Portfolio 5, 9, 10 and the All MISO Portfolio share the same overall characteristics: large amount of renewable generation and one combined cycle unit only.

Exhibit 3: Summary of the Final Portfolios Under Strategy 3 and Strategy 4

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
S3S1_P	Portfolio 1	1137	1000	0	2137	2200	1761	0	2	1
S3S1_F	Portfolio 2	1587	1000	0	2587	1550	1487	0	3	1
S3S2_BB	Portfolio 3	1824	1000	0	2824	1350	1308	0	3	2
S3S3_BB	Portfolio 4	1350	1000	0	2350	1550	1697	0	3	0
S3S5	Portfolio 5	1398	1000	100	2498	3450	1183	0	1	4
S3S7_BB	Portfolio 6	1137	1000	0	2137	2200	1761	0	2	1
S3S1_2CT	Portfolio 7	1374	1000	0	2374	2200	1550	0	2	2
S3S7_2CT	Portfolio 8	1374	1000	0	2374	2200	1550	0	2	2
S3S5_YD	Portfolio 9	1398	1000	100	2498	3450	1186	0	1	4
S3S10	Portfolio 10	950	1000	0	1950	2250	1901	1	0	0
S4S1	Portfolio All MISO	950	0	0	0	3200	1909	1	0	0

Source: Siemens

1.2.8 Other Considerations

In all Portfolios the difference between the actual load and the generation is met by purchases in the MISO market in the case of shortfalls, or sales in the case of a surplus. Also as can be observed in Exhibit 3, all Portfolios require some level of capacity purchases from MISO market and this capacity is assumed to be procured via bi-lateral contracts between MLGW and generation owners. The amount of market-based capacity required was determined by the total reserve requirement less the accredited capacity of the resources contracted by MLGW.

Additionally, each Portfolio has different levels of transmission requirements to reliably supply the load, which are met by system expansions and upgrades. The expanded system capability is measured as the Capacity Import Limit (CIL) and ranges from a low of 2,579 MW for cases with strong local generation (e.g. 3 CCGTs + 1 CT), to a maximum of 3,690 MW for the All MISO Portfolio.

1.3 Metrics

The IRP was centered on more than just costs. The "best" portfolio for MLGW will be the portfolio that performs best against all relevant objectives and metrics over a range of future conditions. There will be tradeoffs between the competing objectives of reliability, least cost, price risk, sustainability, market risk, economic growth, and resilience. The objectives and metrics used in the evaluation of alternative portfolios are summarized in Exhibit 4.

Exhibit 4: MLGW IRP Objectives and Metrics

OBJECTIVES	METRICS
Reliability	Meets or exceeds NERC reliability requirements and manages intermittency. All Portfolios meet NERC Standards; thus, the metric is designed to assess the level by which NERC levels are exceeded. The ratio of the Capacity Import Limit (CIL) + Reliable Generation (Unforced Capacity UCAP) to Peak Load was selected. ***Higher the better.***
Least Cost **(Affordability)**	Net Present Value (NPV) of revenue requirements. This NPV includes all costs in addition to the generation capital and operating costs, i.e. cost of transmission, MISO Membership, TVA costs, PILOT (payments in lieu of taxes), etc. ***Lower the better.***
Price Risk (Minimization/Stability)	Measured as: (a) 95% confidence interval (e.g. Worst Plausible Outcome) and (b) Regret: i.e. the level by which MLGW would regret having chosen a Portfolio in case of an adverse future condition. ***Lower Worst Plausible Outcome and Minimum Regret or No Regret (always optimal no matter the future) is the goal.***
Sustainability	Measured as (a) carbon (proxy for total emissions), (b) water consumption and (c) RPS limit – percentage of the energy coming from renewable resources (nuclear and large hydro, although "clean" on emission, do not count). ***For "a" and "b" Lower the better, for "c" Higher the better.***
Market Risk	Energy Market Purchases or Sales as a percentage of load; Amount of Capacity Purchases. ***Lower the better.***
Economic Growth	Job creation; Capital Expenditures in Shelby County and number of plants as a proxy. ***Higher the better.***
Resiliency	Amount of load shed during extreme events. ***Lower the better.***

Source: Siemens

Most of the metrics were reviewed by the PSAT committee and the general public. For the objective of sustainability, we added a carbon metric and a water metric in addition to the Renewable Portfolio Standard (RPS) metric because what is considered renewable may vary from state to state (For example, hydro and nuclear, while "clean" and carbon-free on emission are not counted as renewables in many states, including Tennessee).

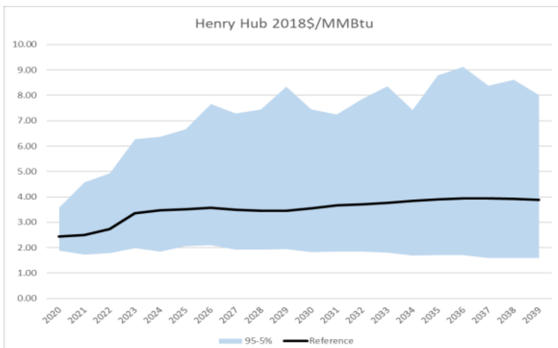
1.4 Key Inputs

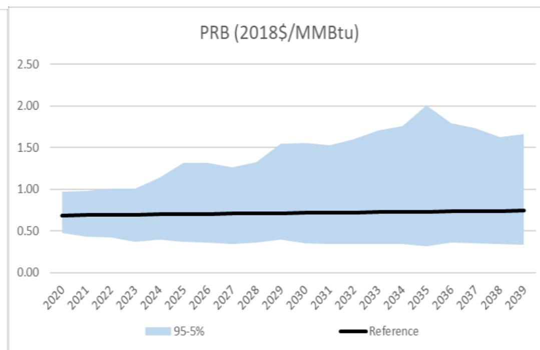
One of the critical reasons to utilize stochastics is that the analysis does not rely on a single point forecast for reaching the ultimate conclusions.

Siemens developed a range of forecasts for each of the key variables in the study, including coal, gas, emission prices, load forecasts, and the cost of new generation technologies. Exhibit 5 shows some of the distributions considered in the analysis.

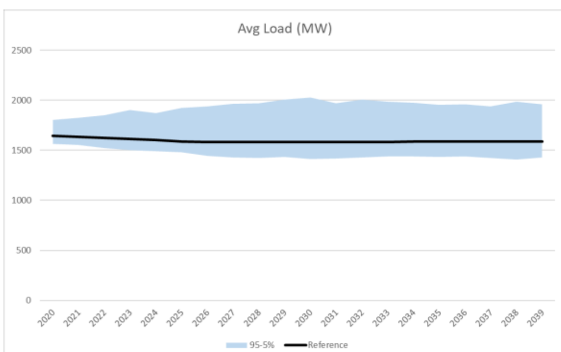
Exhibit 5: Stochastic Distributions

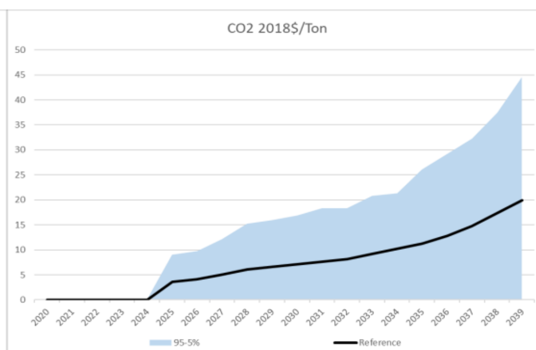
Fuels





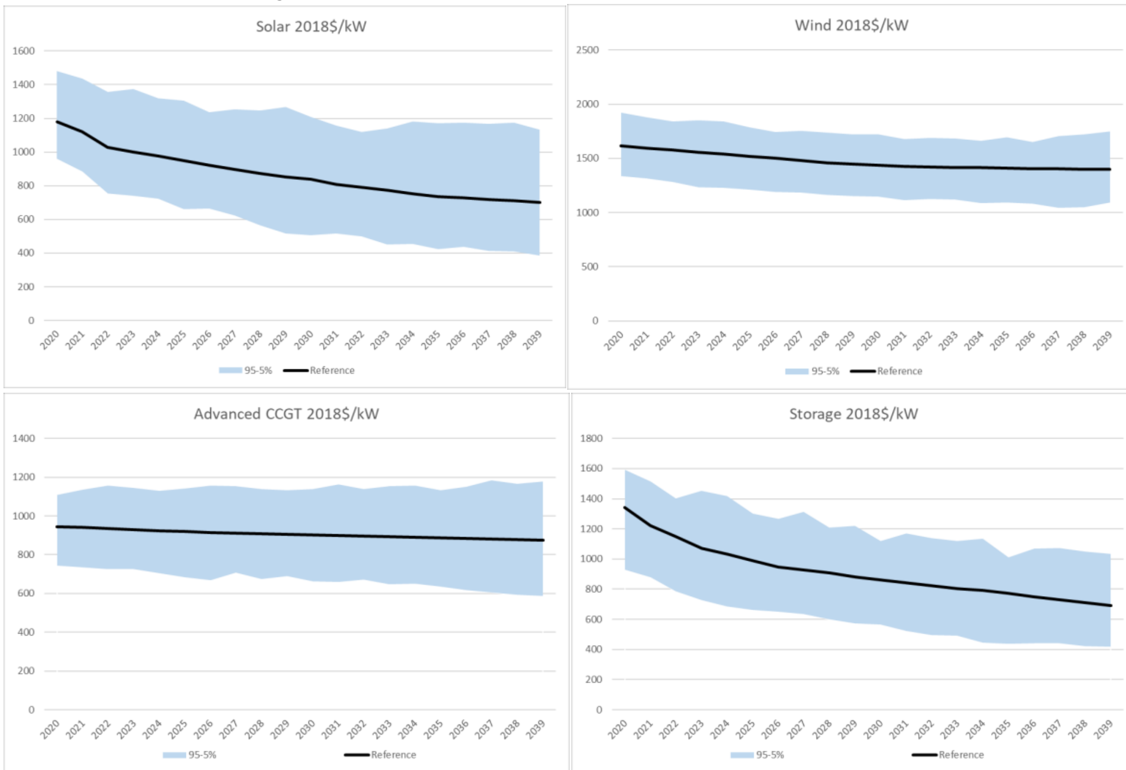
Load and CO_2





Source: Siemens

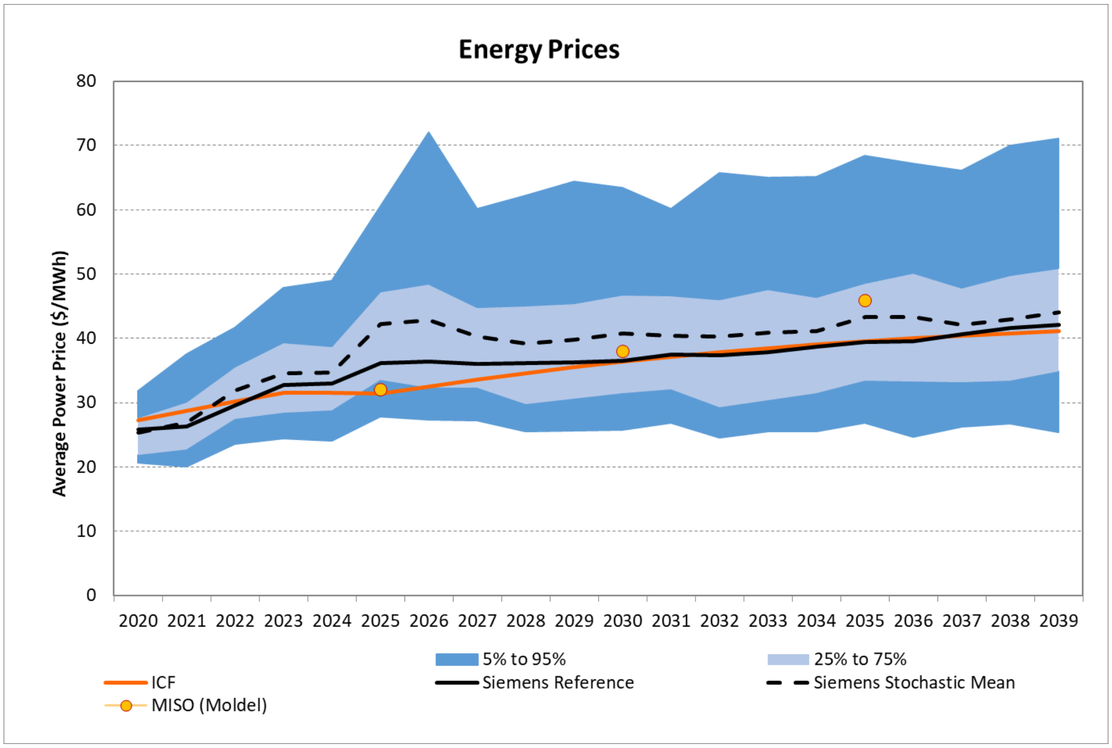
Generation Technologies



Source: Siemens

Siemens also produced a range of views on how energy prices will change over the planning horizon. AURORA was used with all the input distributions to calculate energy prices.

Exhibit 6: Energy Price Forecast for MISO Arkansas (Average LMP Load Hub)



Source: Siemens

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

For comparison purposes Siemens has superimposed the ICF and MISO forecasts on the same graph as Siemens' distribution. They are well within the range of prices Siemens included in the 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 had a mix of renewables and gas. After 2028, MISO's forecast exceeded Siemens' and ICF's forecast is approximately the same as Siemens.

1.5 Results and Recommendations

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 comply with NERC reliability requirements.

The analysis used over 200 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. 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 3), which is based on heavy investment in transmission to secure the maximum amount of renewable generation and only has one CCGT in MLGW's 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 is the most environmentally sustainable portfolio of the group. While Portfolio 5 meets all reliability and resource adequacy requirements, it is 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 and align the reliability of Portfolio 5 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 3), 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 moved 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's 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 3). Due to all the above the All MISO Portfolio was not included in the top four Portfolios used for final comparison with TVA.

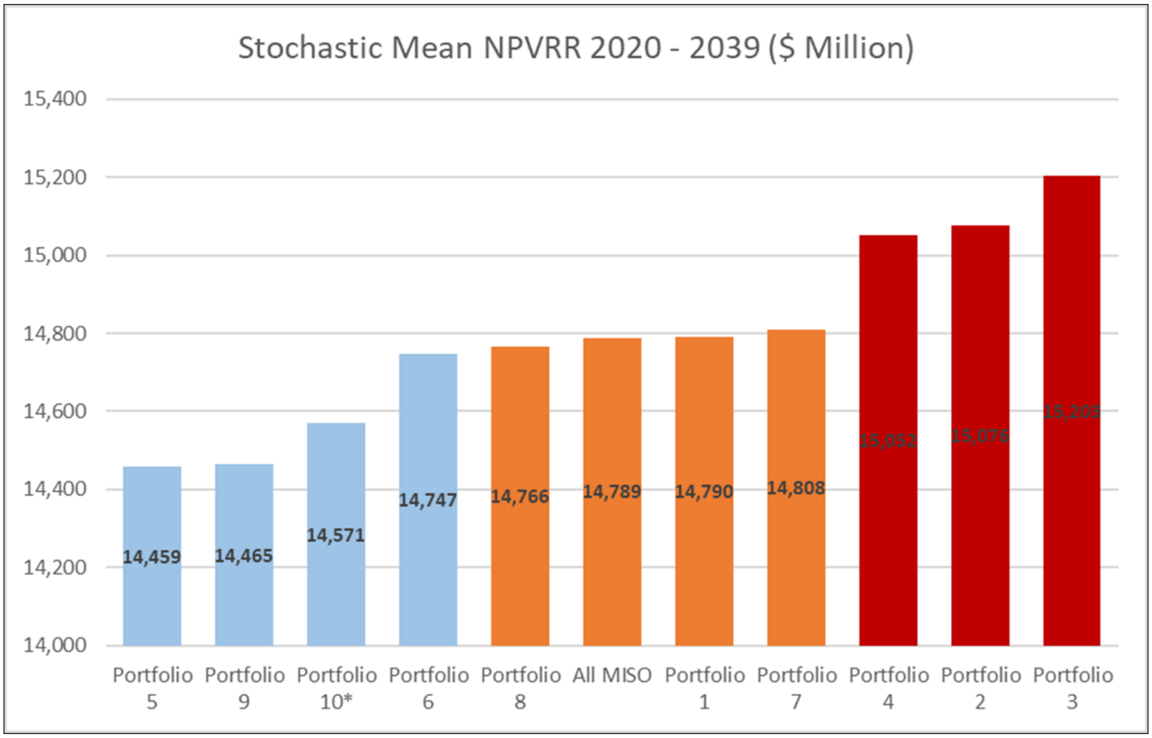
Exhibit 7 shows the ranking of the Portfolios according to the NPVRR. In this exhibit we observe three distinct groups, largely as a function of the number of CCGTs in MLGW's service territory: best with one CCGT, next with two CCGTs (All MISO being the only exception), and last with three CCGTs. Exhibit 8 shows the risk associated with these Portfolios measured as the 95th percentile result. 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[3].

As a reference Exhibit 9 shows the total capital expenditure by portfolio. Note that only the transmission CapEx is expected to be covered by MLGW as the generation capex is expected to be expensed by third parties and recovered via PPA payments from MLGW. The CapEx includes all costs to the commissioning of the project including interests during construction. This CapEx will be spent at different times over the development of the various portfolios as shown in Appendix D: Portfolio Details where the overnight CapEx at the year that the project comes in service is shown. It can be observed that the highest overnight CapEx ($7.18 billion) occurs in Portfolio 5, followed by Portfolio 9 ($ 7.0 billion) which is expected given the higher amounts of capital-intensive renewable resources.

Exhibit 10 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.

[3] 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).

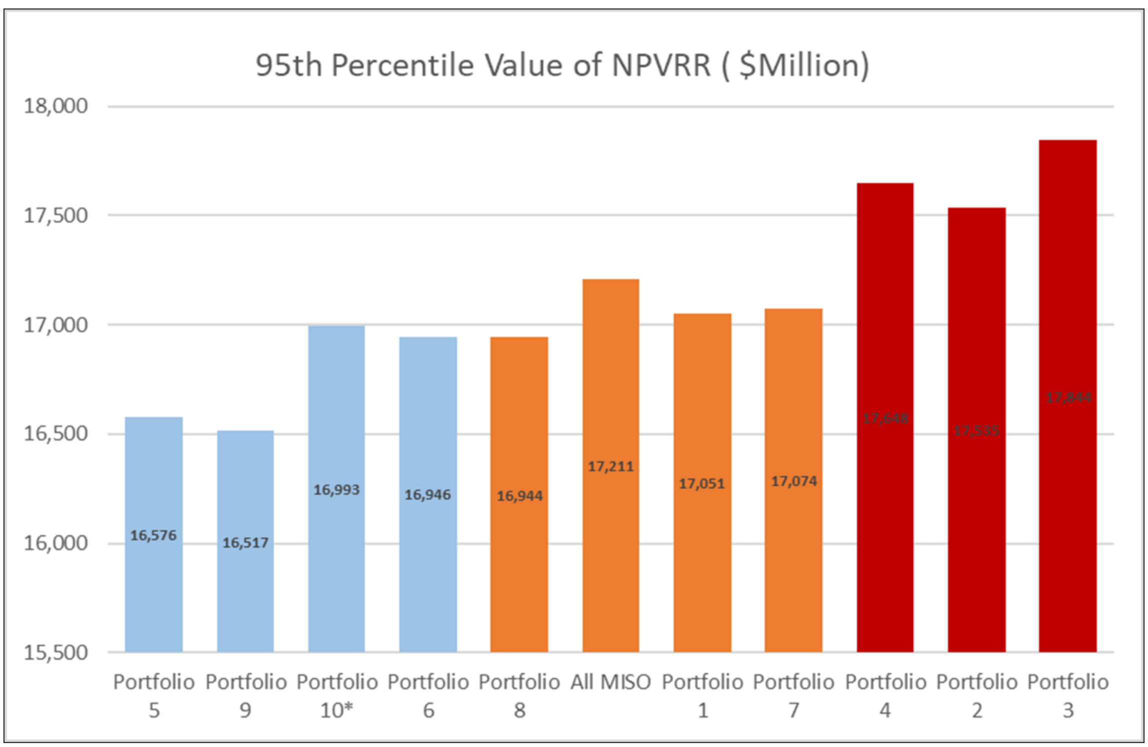
Exhibit 7: Ranking of Portfolios According to NPVRR



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

Source: Siemens

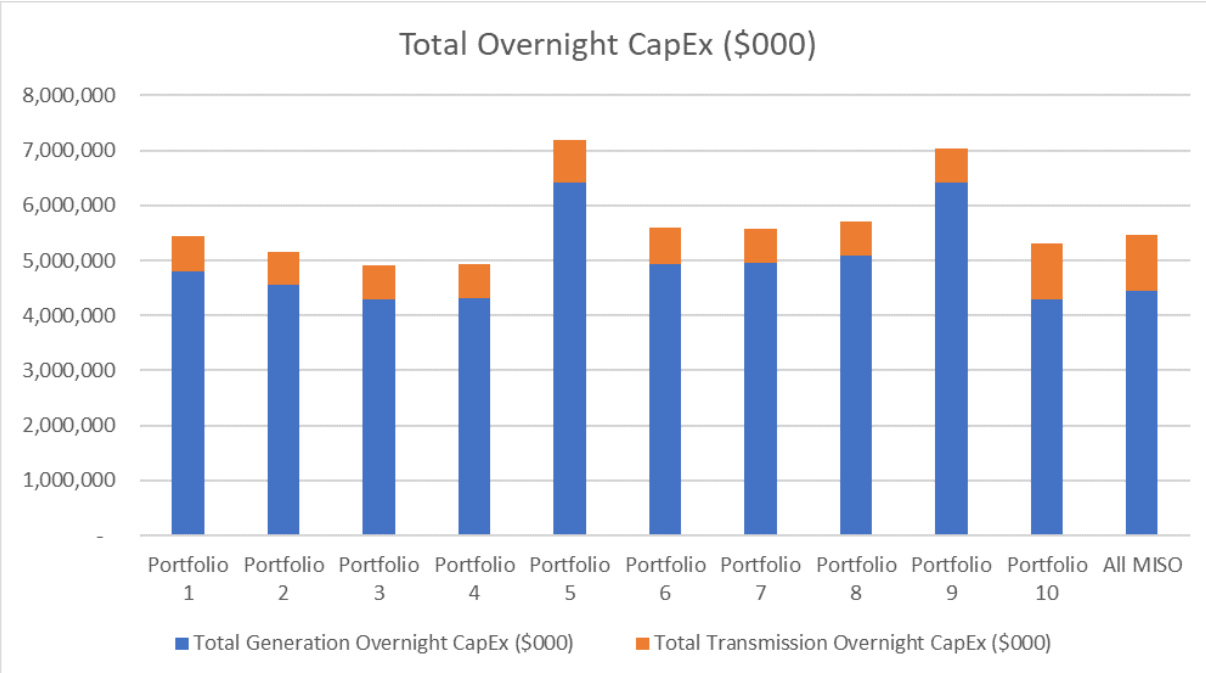
Exhibit 8: Portfolio Risk



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

Source: Siemens

Exhibit 9: Total Overnight T&G CapEx



Source: Siemens

1.6 Comparisons with TVA

Exhibit 10 displays the Balanced Scorecard, which shows all the metrics for all the Portfolios. To make this complex exhibit easier to visualize, 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.

Afterward, each metric is looked at separately.

Exhibit 10: Summary of Overall Results

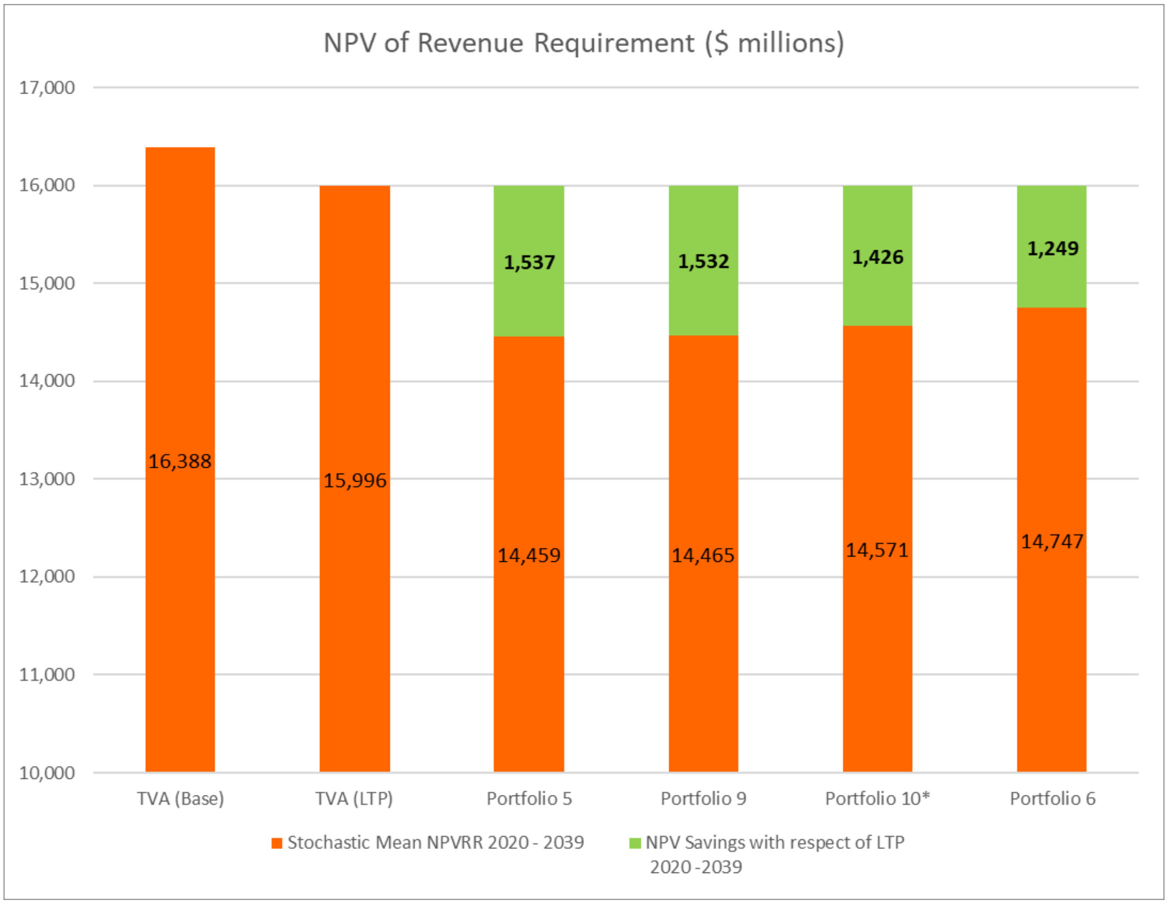
Objective	Measure	Unit	TVA (Base)	TVA (LTP)	Portfolio 5	Portfolio 9	Portfolio 10*	Portfolio 6	Portfolio 8	All MISO	Portfolio 1	Portfolio 7	Portfolio 4	Portfolio 2	Portfolio 3
					1 CC + 4 CT	1 CC + 4 CT	1 CC + 0 CT	2 CC + 1 CT	2 CC+2 CT	1 CC + 0 CT	2 CC + 1 CT	2 CC+2 CT	3 CC + 1 CT	3 CC + 2 CT	3 CC + 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	2.37	2.37	3.44	3.04	3.04	3.44	3.33	3.33	4.02	3.82	4.09
	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%
Reliable	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
Resilient	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%
	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%	23.0%	16.7%	15.6%	7.4%	7.0%	7.7%
	% Energy Sold in Market	%	8.7%	8.7%	22.6%	22.6%	17.0%	9.7%	9.7%	17.9%	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

1.6.1 Affordability

The NPVRR for Portfolios 5, 9 and 10 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 (which has 2 CCGTs) the savings are reduced to $1.2 billion, as compared to the TVA LTP option.

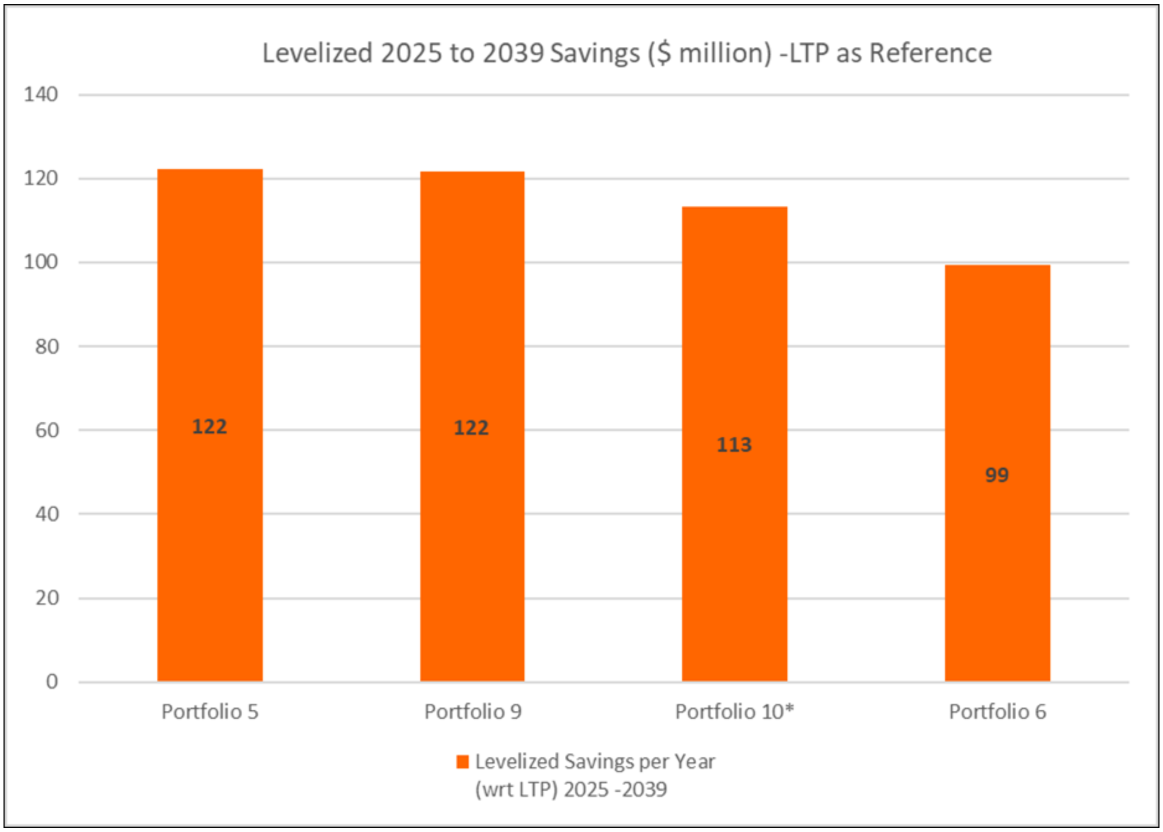
Exhibit 11: Affordability



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 by 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.

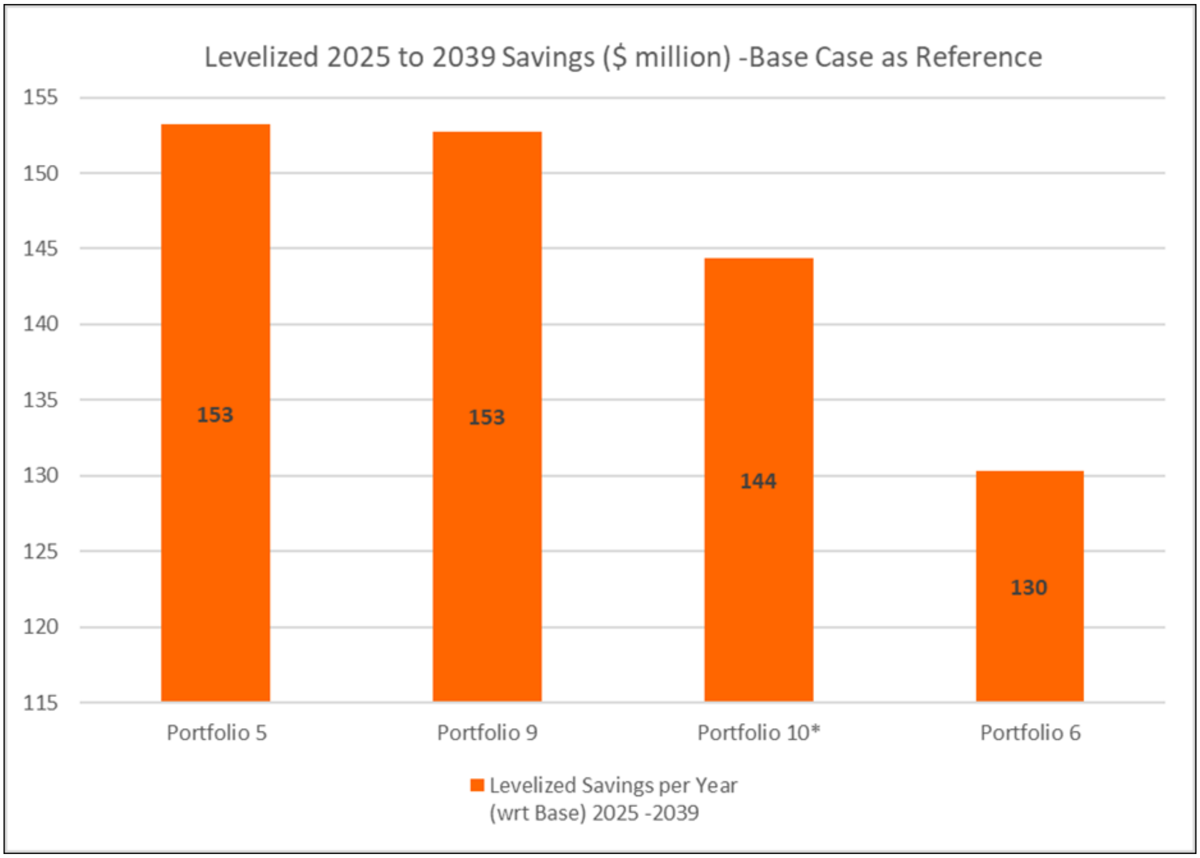
Exhibit 12: Levelized Savings per Year with Respect to the LTP



Source: Siemens

As a reference, if the LTP is not considered then the savings increase to $130 to $153 million per year, as shown Exhibit 13.

Exhibit 13: Levelized Savings per Year with Respect to the Base TVA Contract

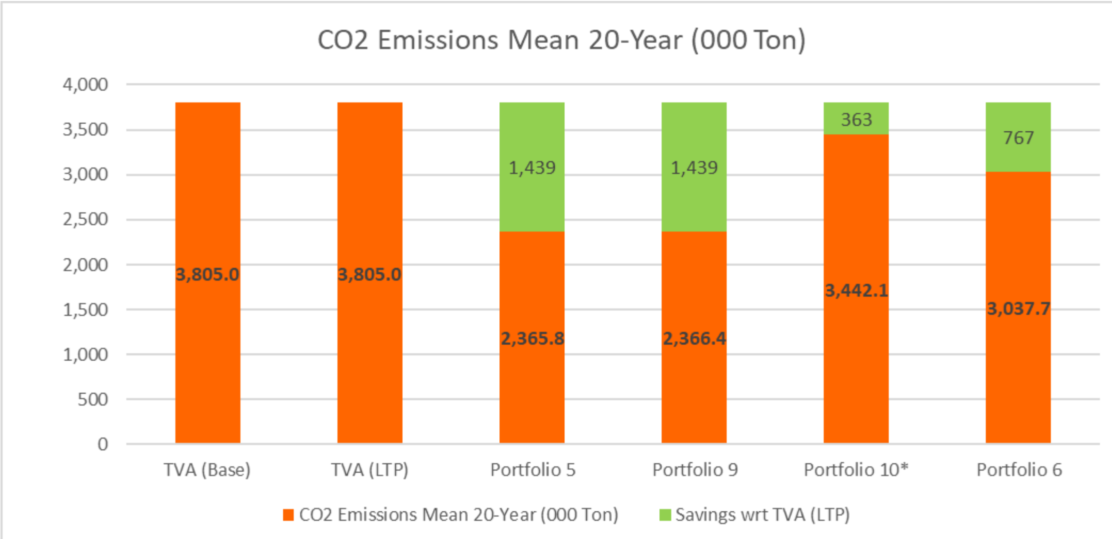


Source: Siemens

1.6.2 Sustainability Metric

Exhibit 14 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 have also lower emissions but to a lesser degree due to the larger size of the thermal CCGT and less renewables.

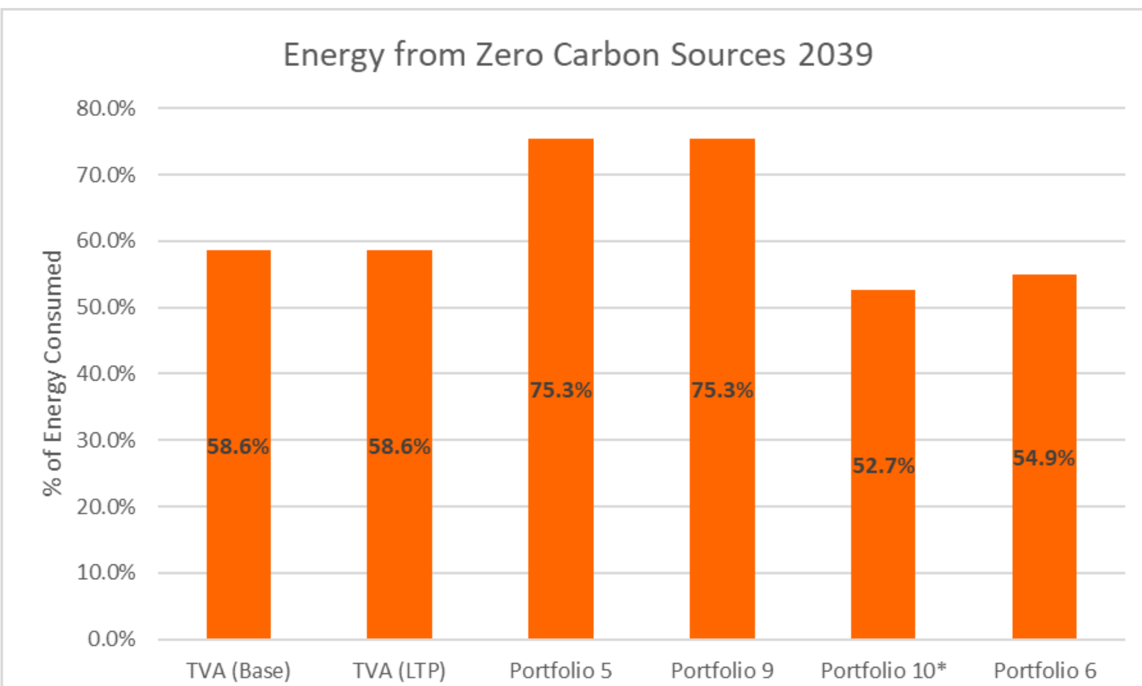
Exhibit 14: Sustainability Metric (CO_2 Emissions)



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 15).

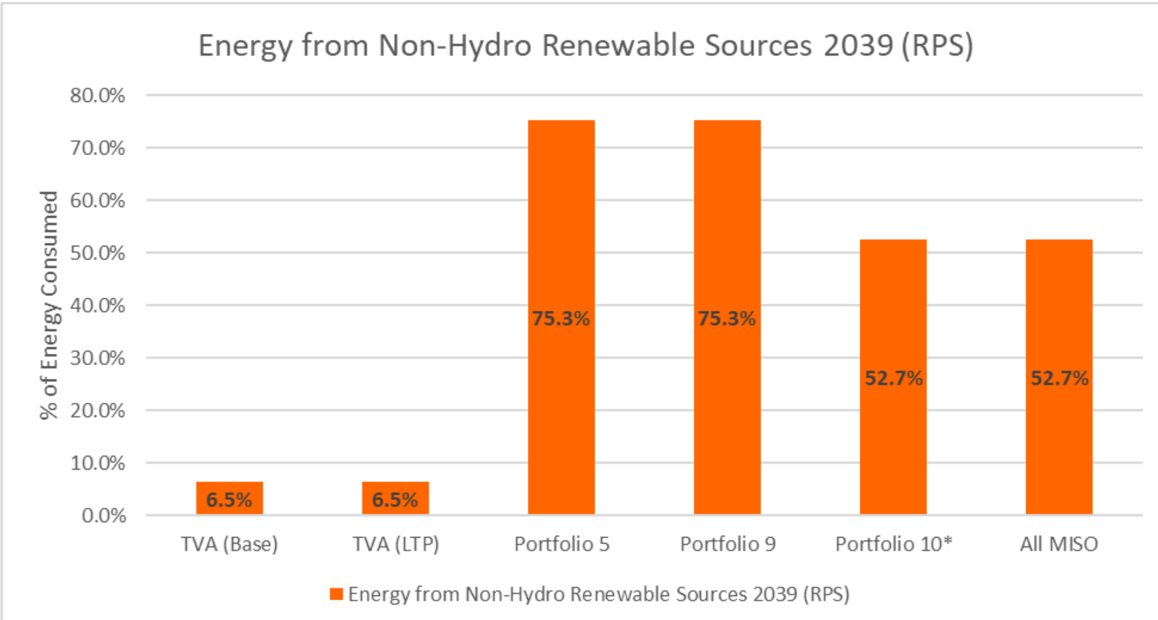
Exhibit 15: Zero Carbon Sources



Source: Siemens

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

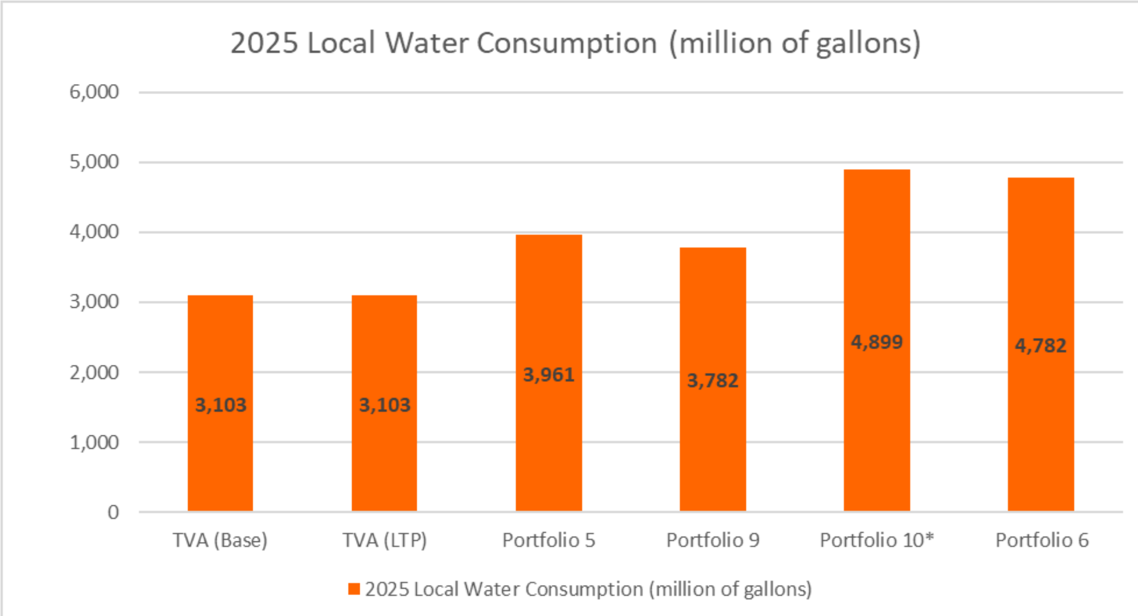
Exhibit 16: RPS



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 17 below.

Exhibit 17: Water Consumption



Source: Siemens

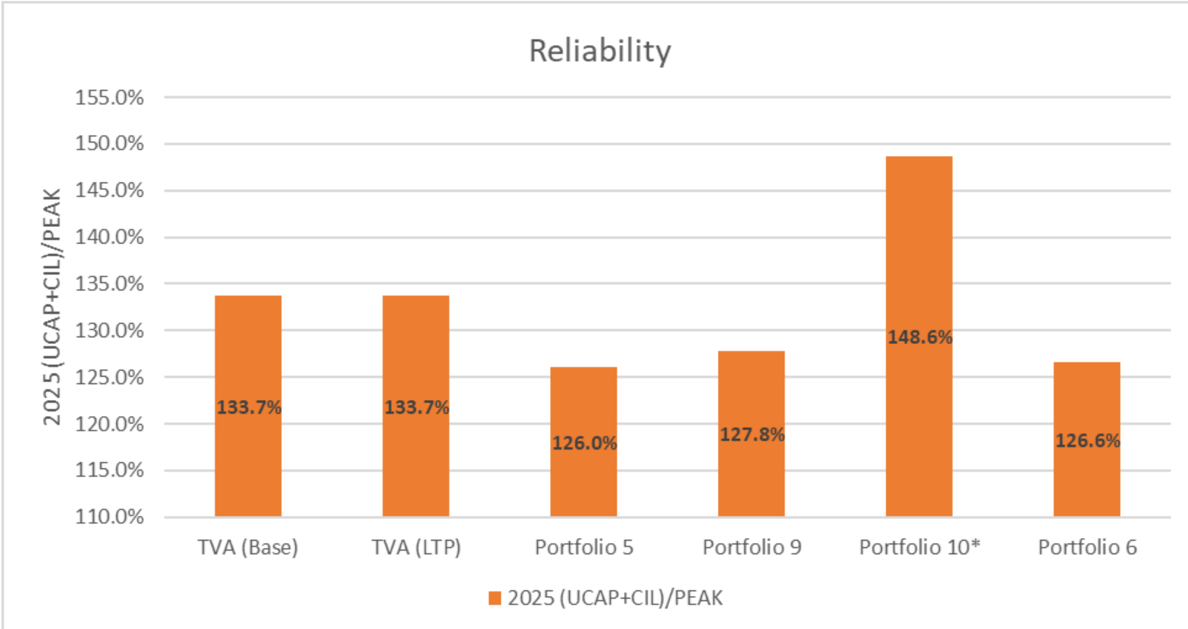
1.6.3 Reliability

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's 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.

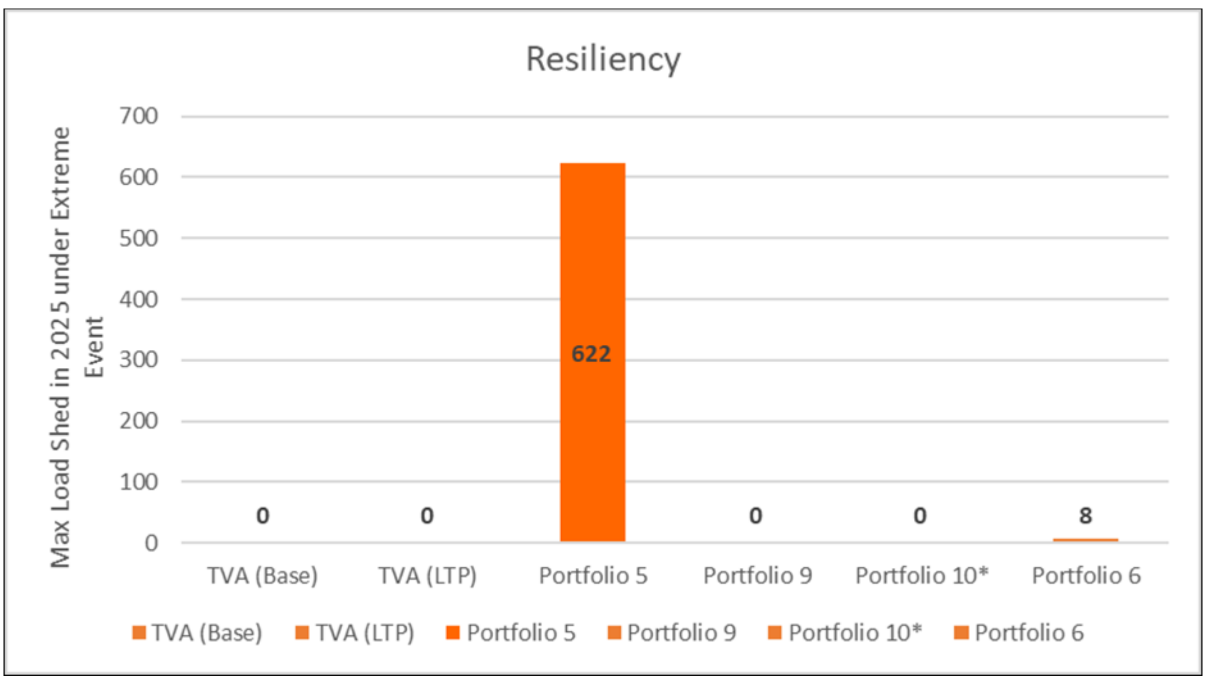
We also note that Portfolio 10 has the highest value according to this metric, but it can be misleading as this Portfolio has only one large CCGT and its extended outage could lead to dependence exclusively on transmission(similar to Portfolio 5) but, in this case, it was reinforced allowing the incorporation 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 18: Reliability



Source: Siemens

Exhibit 19: Resiliency



Source: Siemens

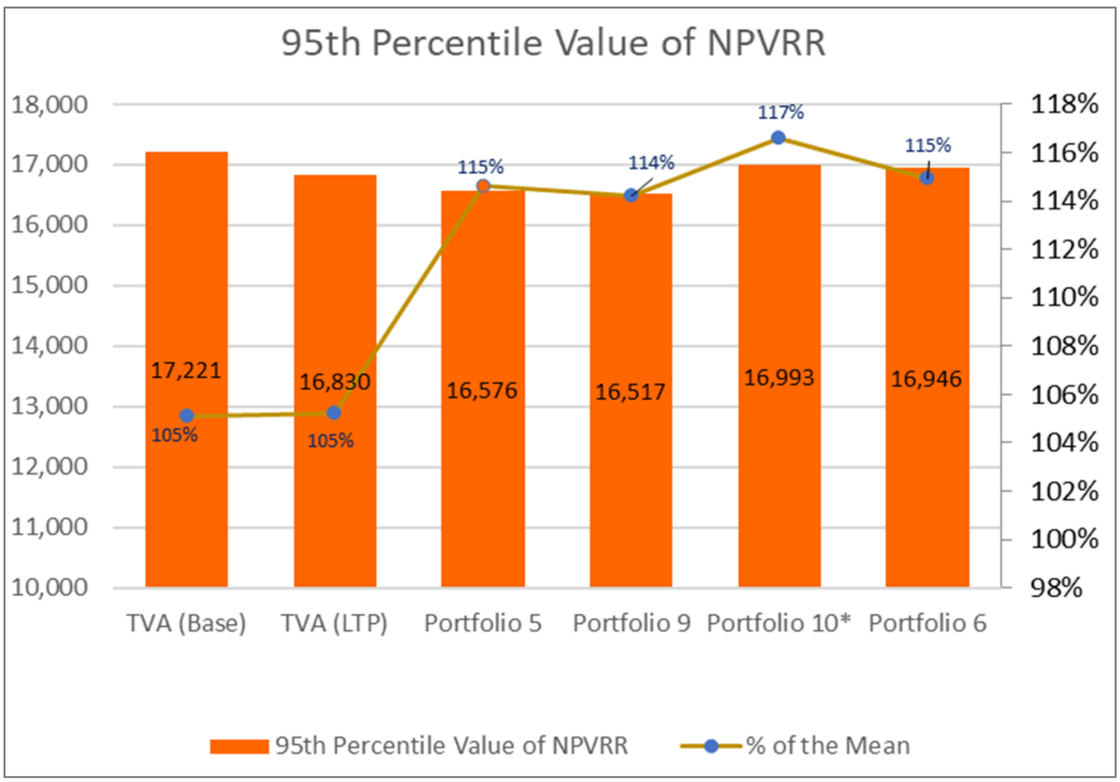
1.6.4 Price Risk

TVA's portfolio 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.

Siemens note that the TVA 95th percentile, i.e. the NPVRR that is exceeded only in 5% of the runs, is 105% times the stochastic mean (the average value). This means that 95% of the time the results are within 105% of the average, showing lower risk.

On the other hand, Portfolio 5, 9 and 6 the 95th percentile is within 114% to 115% times the mean and in Portfolio 10 it is 117%. This shows higher volatility of the outcomes and it is 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 assess options to achieve fuel price volatility mitigation as part of its assessment to leave TVA.

Exhibit 20: 95th Percentile of Revenue Requirements and Changes with Respect of the Mean



Orange bars are the NPVRR (left Y-axis), line % above the mean (right Y-axis).

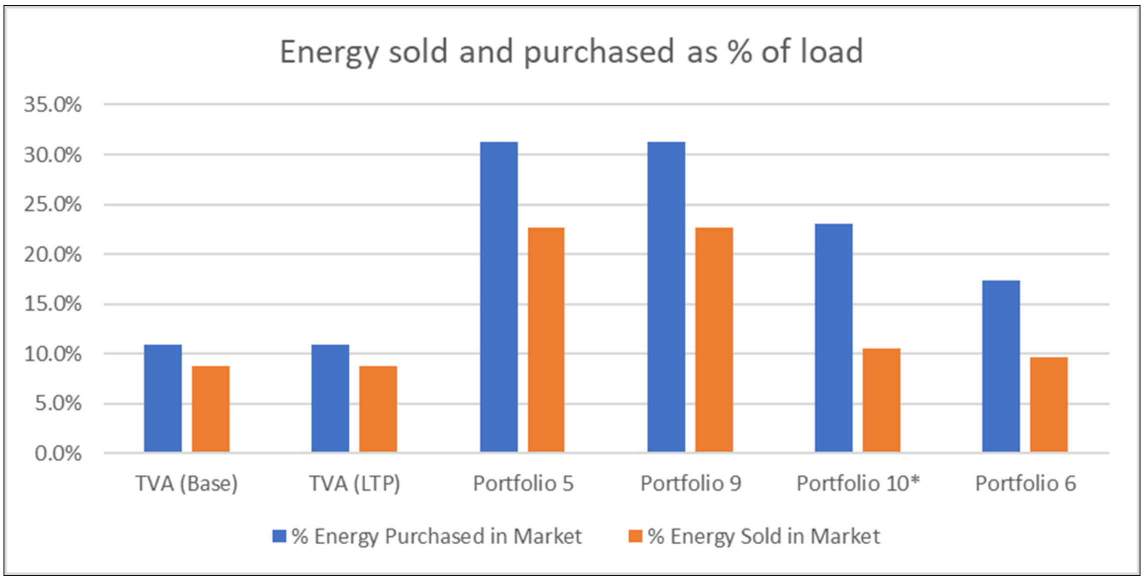
Source: Siemens

1.6.5 Market Risk

Market risk is measured as a function of the energy that is sold and purchased in the MISO market as a percentage of the total load. As portfolios have different development timelines and there tend to be higher purchases from MISO in the earlier years (e.g. 2025), in order to highlight the actual long term difference between portfolios, the value shown below and Exhibit 10 corresponds to the expected purchases and sales by 2039, when the portfolios are fully developed. Appendix D: Portfolio Details contains the actual MISO Purchases and Sales per Portfolio and year.

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 Portfolio 10 and the two CCGTs on Portfolio 6.

Exhibit 21: Market Risk

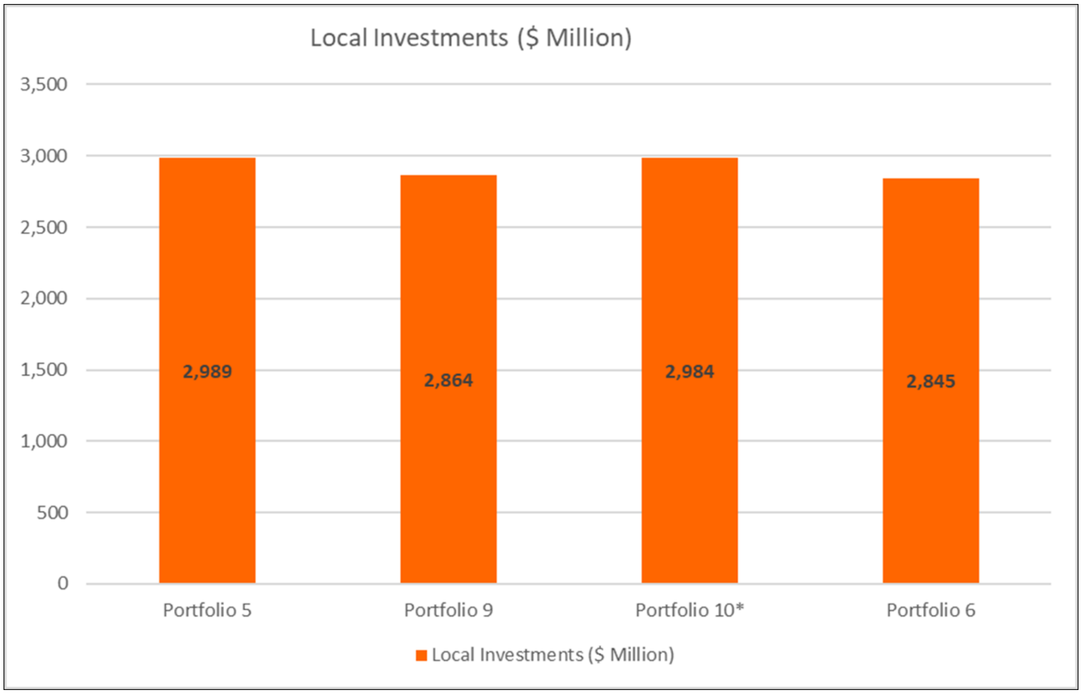


Source: Siemens

1.6.6 Local Economic Development

Local economic development is measured using the total local capital expenditures per Portfolio as a proxy (i.e. investments in local renewable, thermal power plants and transmission). This is presented just for portfolios ranking purposes. As can be observed below all Portfolios are very similar, with Portfolio 5 and 10 slightly ahead largely due to the transmission investments (it has the same amounts of local renewable generation as in other portfolios).

Exhibit 22: Economic Development



Source: Siemens

1.6.7 Municipality Departure Impact on Portfolio Cost

The studies conducted assume that all the Municipalities that are associated with MLGW will stay with MLGW in their transition to one of the select Portfolios. The question arises what happens to the Portfolio costs if some of them do not stay with MLGW. To assess this impact on Portfolio costs Siemens evaluated one of the preferred Portfolios (Portfolio 9) under the assumption that some of the Municipalities would choose to stay with TVA.

The analysis concluded that under a severe situation where about 12% of the total load that MLGW currently serves would separate from MLGW there would be increase in Portfolio costs is of about 0.8%. It is important to note that beyond the increase in Portfolio costs, there would be other impacts to MLGW that could be significant arising for example due to for example, impacts in operations and the loss of margin.

1.6.8 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 evaluated by MLGW to make its final determination.

The key findings of the study are:

- There are levelized cost savings of about $99 to $122 million per year on an expected basis (probability weighted) associated with exiting the TVA contract assuming under the LTP and joining MISO for the 2020 to 2039 period. These savings increase from $130 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 significant load shedding 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 assess options to 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 chooses 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). This generation should not be limited to distribution level solutions but must include the possibility of MLGW deploying utility scale renewable that has lower costs.
  - 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 future developments in the electric power industry, such as 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 in the future and only needs to be performed if MLGW chooses to stay with TVA.
  - Seek written guarantees from TVA that provide long term wholesale rate stability. This could take the form of a ceiling rate not to be exceeded for a clearly defined term to be followed by a cap on future rate increases.

- The Payments in Lieu of Taxes (PILOT) are payments made to both local taxing jurisdictions and state governments and directly or indirectly benefits the citizens, who are also customers of MLGW. This cost is an important component of the total costs and savings.

- 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, 10, 6, and All MISO can be reassessed with bids provided by potential suppliers.

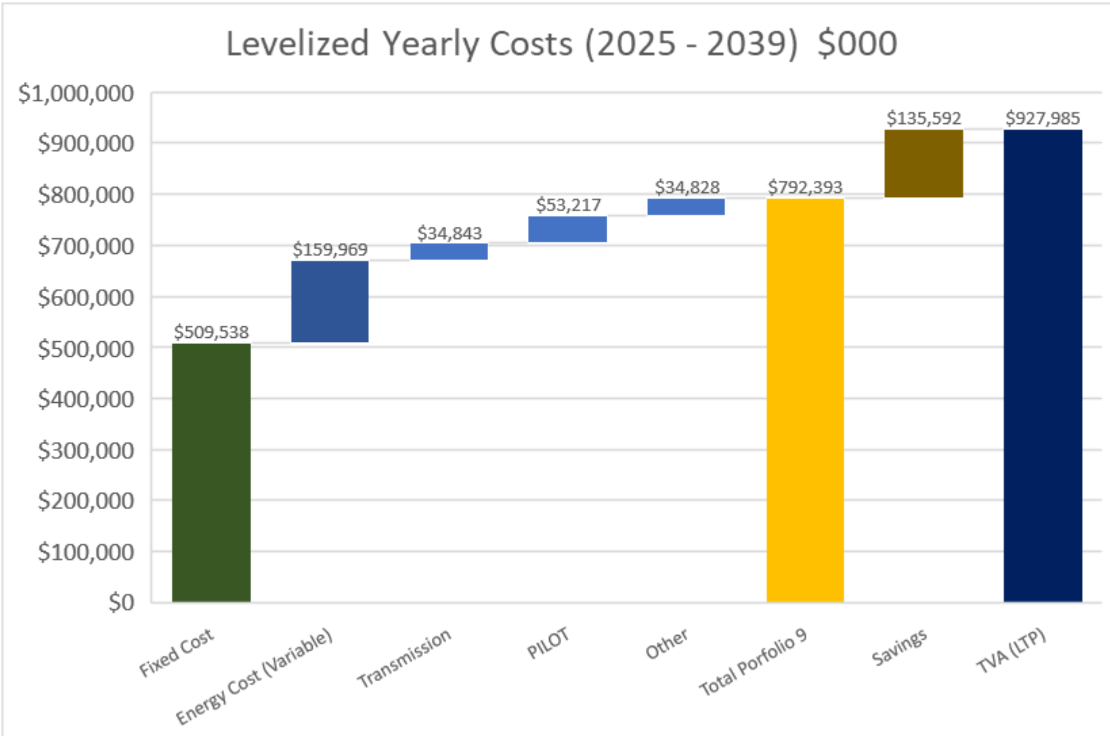
1.6.9 Magnitude of Savings for Exiting TVA

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 media.

Siemens 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. Note that because of this the savings below are higher than those in Exhibit 10.

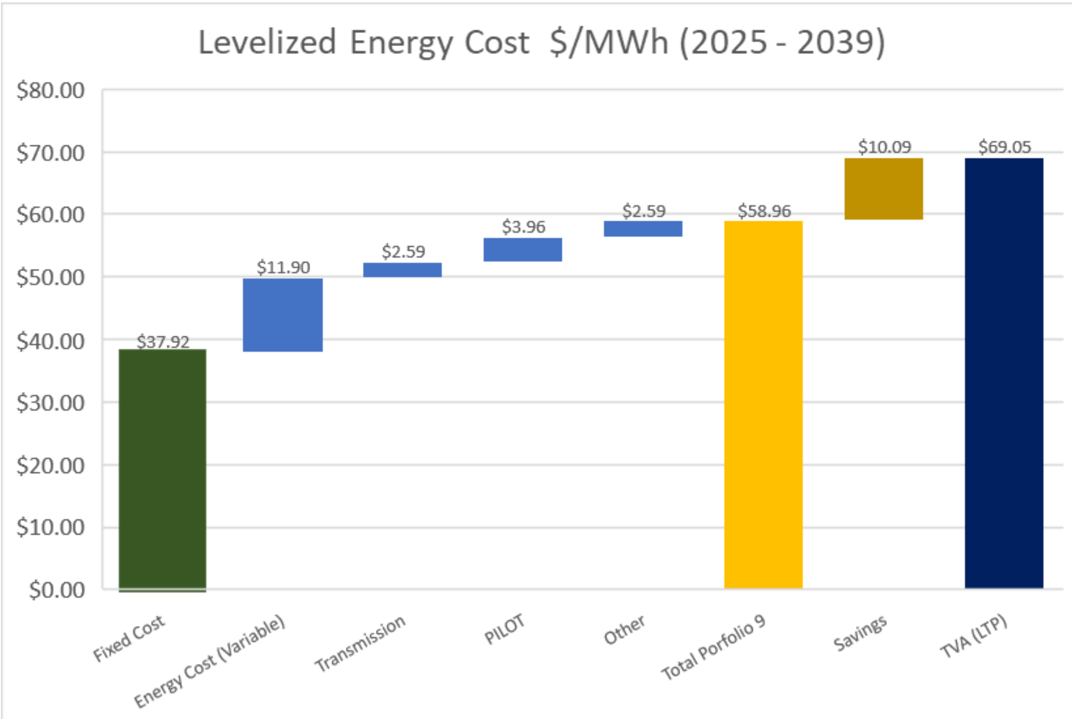
Exhibit 23: Portfolio 9 Levelized Yearly Costs for 2025 to 2039 with Respect to TVA LTP



Source: Siemens

Expressing the above in terms of levelized costs in $/MWh we have the following:

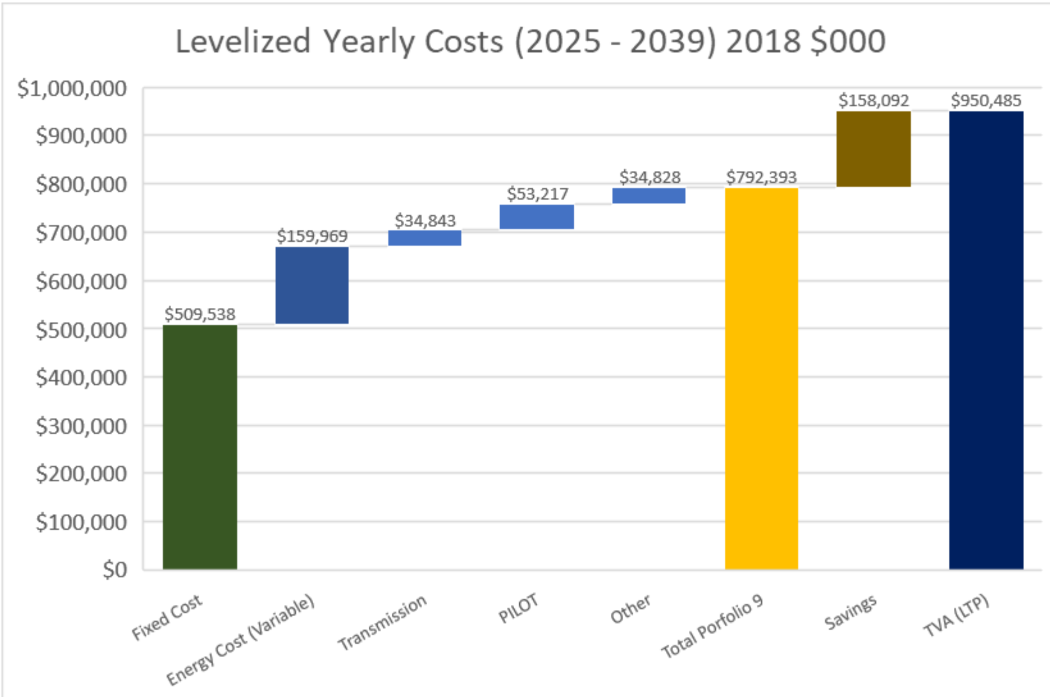
Exhibit 24: Portfolio 9 Levelized Energy Costs for 2025 to 2039 with Respect to TVA LTP (2018 $)



Source: Siemens

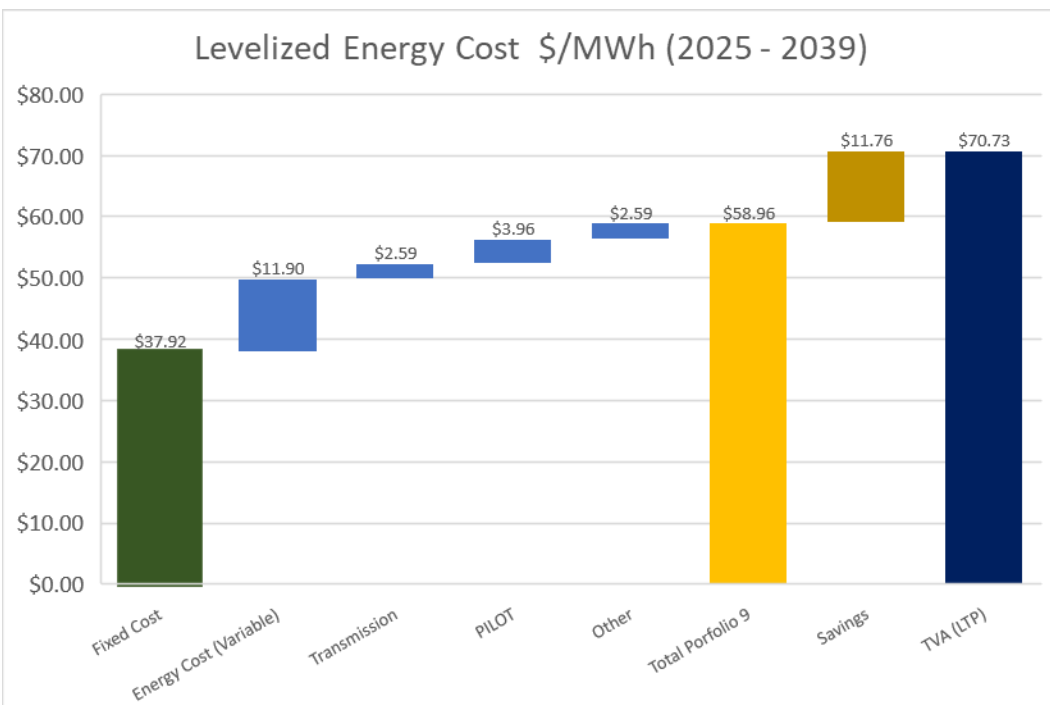
A similar comparison with respect to the current contract shows savings in the order of $160 million per year.

Exhibit 25: Portfolio 9 Levelized Yearly Costs for 2025 to 2039 with Respect to TVA Current Contract (2018 $)



Source: Siemens

Exhibit 26: Portfolio 9 Levelized Energy Costs for 2025 to 2039 with Respect to TVA Current Contract (2018 $)



Source: Siemens

In this last case the payments for transmission, PILOT and Others (which include 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 $123 million 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 or the generator provider
- 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

Two 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 . 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 will be paid by MLGW or third-party developers as actual taxes included in the prices, they charge MLGW on energy costs.

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2. Introduction

Memphis Light, Gas and Water (MLGW) is the largest municipal utility in the State of Tennessee, serving approximately 431,200 electric customers in Shelby County. Its electrical demand (average load) in 2019 was 1,598 MW with a peak load of 3,161 MW.

For the past 80 years, MLGW has received its power supply under an All Requirements Contract, also referred as the Wholesale Power Contract (WPC), with the Tennessee Valley Authority (TVA). TVA is one of the largest federally run utilities in the country. It serves over 150 different Local Power Companies (LPC) in Tennessee and portions of Alabama, Mississippi, Kentucky, Georgia, Virginia, and North Carolina. TVA was originally set up to provide large scale hydroelectric power to its members but over time has developed a mix of generation involving nuclear, fossil based, and renewable power in its Portfolio. MLGW comprises approximately 10% of TVA's load.

As an All Requirements customer of TVA, MLGW owns no generation nor transmission ties to outside entities other than TVA. MLGW sits on the southwestern edge of TVA's service territory. It is surrounded by TVA's transmission network, but it is very close to MISO's footprint, which is separated by the Mississippi River to the west and is immediately adjacent to the south across the border to Mississippi.

MLGW has the option of exiting its All Requirements Contract with TVA upon 5 years advance notice. Otherwise, the relationship continues in force. Under the contract, TVA supplies all the energy and capacity required by MLGW customers, and in addition, TVA provides a range of planning and operational services to MLGW. TVA also provides a range of programs to MLGW's customers for demand side management and energy efficiency, and in addition provides additional benefits to the City of Memphis. TVA also makes payments in lieu of taxes to the State of Tennessee, a portion of which is then allocated to Shelby County and the local municipalities.

TVA has offered MLGW the option of extending the notice period to 20 years, in return for receiving a 3.1% discount on the Standard Service non-fuel components of the wholesale rate and the ability to serve up to 5% of its load with generation solutions other than TVA. Several Local Power Companies in TVA's jurisdictions have accepted this offer.

Siemens was selected from an RFP conducted by MLGW to perform the IRP. This report presents the IRP findings on behalf of MLGW.

2.1 Approach

In order to make an informed decision, MLGW requires assessing the expected costs of staying with either the 5-year or the 20-year notice of termination provision of the TVA All Requirements Contract versus developing its own resources and/or acquiring them from the neighboring Midcontinent Independent System Operator (MISO) market. This assessment is the central objective of this IRP.

This is not a traditional IRP. For most electric utilities, an IRP is designed to consider changes to an existing portfolio of generation assets to account for changes in load, plant retirements or new capacity additions to meet existing or future regulations, or accounting for changes in technology. In this IRP, MLGW either stays with the TVA mix of assets as it evolves based on its latest IRP or it embarks on an entirely new path, building the necessary transmission access to MISO and developing an entirely new generation mix of assets to meet its load. Hence, should MLGW choose to exit TVA, it must consider the implications of joining MISO, including building the necessary transmission linkages to appropriate locations in the MISO footprint; meeting MISO reserve and resource adequacy requirements; and determining the best mix of local generation, MISO footprint generation, and MISO market purchases of energy and capacity to meet its load. This must all be accomplished in a five-year period, but some work can and most likely would be done prior to giving notice. This IRP process was designed to identify a preferred plan for MLGW to procure energy resources in the (local) Memphis and MISO footprints (primarily generation and demand side programs) and design transmission interconnections to MISO to reliably meet MLGW's future load, and to compare that portfolio with the TVA status quo option. The IRP is forward looking and reflects views of future regulations, market conditions and expectations of technology changes. The IRP is designed to suggest what portfolio of generating assets (power plants or Power Purchase Agreements), energy efficiency programs, and transmission adjustments best meets MLGW's future needs. The plan must meet existing and future regulatory requirements and provide for reliable supply of power as it is currently supplied to customers at lowest reasonable cost. Most importantly, the IRP process must be comprehensive, transparent, community focused, and reflective of the interests of all MLGW's customers and stakeholders.

The results and conclusions of the IRP presented in this document include several candidate future supply portfolios and a comparison of the leading portfolios relative to continuation of supply provided by TVA under the All Requirements Contract. This report provides information to be considered by MLGW in making its decision. MLGW will need to verify the conclusions of this report through an RFP before a final recommendation can be made to the Board of Commissioners. However, this report provides planning level estimates of prices and amounts of generation that can be procured for the Self-Supply plus MISO option and the cost of the TVA option so that all the relevant factors in the decision are properly considered.

2.2 IRP Central Considerations

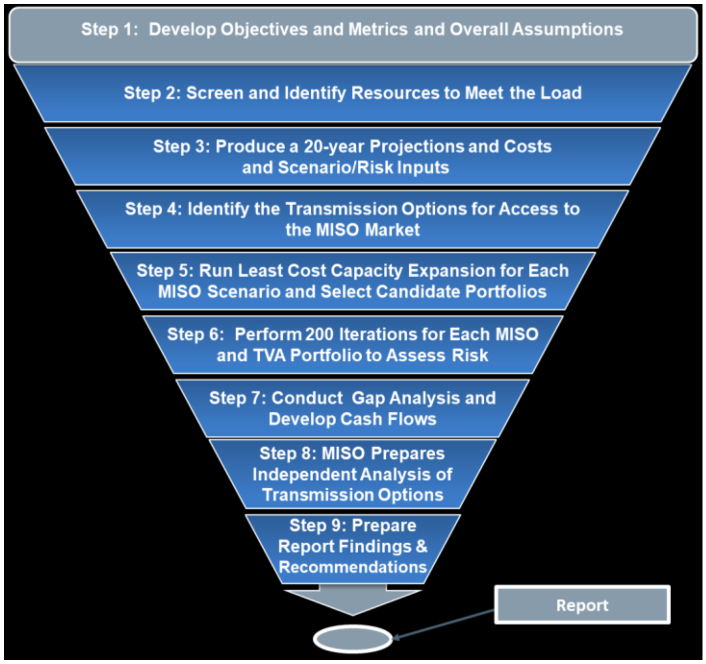
2.2.1 Structured Approach

For each of the principal strategic options (Status quo with TVA or Exit TVA) the IRP followed a process designed to identify the preferred course of action that balances least cost of supply with other key metrics such as environmental stewardship, price stability and risk mitigation.

The process followed is a process Siemens has used for clients across the US:

1. Develop objectives, metrics, and overall assumptions.
2. For the Self-Supply plus MISO option, identify resources that reasonably could be included in plans to meet the load including both supply and demand-side resources (screening).
3. Produce a 20-year load projection, fuel cost projections, emission costs, technology costs and performance (e.g. heat rates, capacity factors etc.) that will be applied to both the MISO and TVA options – also define alternative scenarios and distributions for input assumptions for the risk analysis.
4. Identify the transmission options that will provide access to the MISO market necessary to fully evaluate the Self-Supply plus MISO option (Strategy 3) and the MISO only option (Strategy 4).
5. Run least cost capacity expansion studies for each MISO scenario to identify the lowest cost portfolios for Self-Supply plus MISO option (Strategy 3) under each scenario. In parallel, evaluate the two TVA options (i.e. the 5-year and 20-year exit options for Strategy 1 which is defined further below) based on TVA's IRP, using common assumptions to those considered for the MISO options. Plan for adequate transmission to ensure reliability and resource adequacy requirements are met in the MISO only (Strategy 4) option. Then, select among the portfolios that represent the least cost option for each scenario and, using these candidate portfolios, perform additional risk analysis that subjects each portfolio to a wide range of future outcomes.
6. Perform 200 iterations (range of uncertainties) for each Self-Supply + MISO and TVA portfolio to assess how well each portfolio performs under a range of market, technology, and regulatory uncertainties.
7. Conduct a gap analysis and identify all of the relevant costs embedded in the TVA rate that must be considered for a proper comparison (including balancing authority, additional planning and operational resources, payments in lieu of taxes, and additional benefits provided by TVA) and develop cash flows for each option.
8. Have MISO prepare an independent analysis of the transmission options and ensure that all MISO requirements for transmission reliability and resource adequacy are met. Then reconcile differences between the MISO and Siemens analyses and adjust results.
9. Prepare a balanced scorecard using the objectives and metrics defined in step 1 to rank supply options based on the chosen objectives and metrics and select best portfolio.
10. Prepare a report with findings and recommendations for next steps.

Exhibit 27: Overall IRP Process



Source: Siemens

2.2.2 Access to MISO Market

The Self-Supply plus MISO option, which is a combination of local resources, and MISO resources plus purchases and sales in the MISO market, is designed to take advantage of the geographical location of MLGW and its proximity to one of the largest electric markets in North America: the MISO. Currently MLGW is electrically connected to MISO via TVA transmission assets. Consideration was given to whether MLGW could take advantage of TVA's connected transmission assets to MISO to supplement the direct interconnections that would need to be in place for MLGW to become a MISO member.

TVA has made it clear that it "TVA will not consider wheeling [allowing MLGW to use TVA's transmission assets as part of its connection to MISO] for MLGW or agree to any other power supply options that utilize any part of the TVA transmission system to deliver power to MLGW as those actions would erode the protections established by Congress for TVA's remaining customers and its ratepayers under current regulations TVA".

In this letter, TVA's position is based on Federal Legislation entitled the Anti-Cherry-picking Amendment to the Federal Power Act(Section 212) that prohibits FERC from ordering TVA to wheel power that would be consumed within the TVA Fence, as defined by TVA's existing service area as of July 1, 1957, with certain limited exceptions.

Considering the above statements by TVA, this IRP was designed under the conservative assumption that MLGW completely severs its interconnections to TVA and creates new connections to MISO. As a result, there inevitably will be significant duplication of existing transmission, and this severed connection forgoes the benefits that would accrue to all parties if the interconnection between the systems were to be maintained. This approach is referred in this document with the shorthand of "No Deal", to reflect that the separation is assumed to occur without reaching a mutually beneficial middle ground. TVA's position is based upon their view that granting MLGW the right to wheel through its system is not in TVA's best interest. Moreover, TVA believes it has the legal right to prevent wheeling through its transmission assets and, as stated above, this cannot be forced by FERC.

Hence, the IRP carefully considered options to interconnect with MISO assuming no access to TVA's transmission assets. The transmission analysis (TA) carried out in this IRP allows for the direct comparison of supply alternatives with the existing TVA All Requirement Contract, by conservatively estimating the required interconnection costs while maintaining comparable (not necessarily equivalent to TVA) levels of reliability to others in the MISO market.

The considerations above should not be construed to imply that the "No Deal" is the only option available to MLGW for leaving TVA with the implied unnecessary duplication of facilities. In case that TVA were to provide access to its transmission system and receive wheeling payments, the additional investments in transmission would be small as the current system would be fully capable to support the expected imports from MISO with adequate levels of reliability. In this case there would be limited transmission investments to meet MISO's requirement for MLGW to have a physical connection to its system, which could be for example a 161 kV line from Allen (MLGW) to Horn Lake (MISO).

2.2.3 TVA Long Term Partnership

TVA presented to each of the Local Power Companies (LPC) it serves the option of entering into a Long Term Partnership (LTP)[4] that will extend the termination notice to 20 years and that would reportedly allow TVA to refinance its debt and fund new capital requirements over a longer period of time than is currently the case and reduce the debt repayment component of its revenue requirements. In exchange for this partnership, TVA commits to:

a. Allow the LPC (in this case, MLGW) to install distribution level solutions (e.g. local generation) to between 3 to 5% of the energy sold under the category of "Wholesale Standard Service" by October 1, 2021, that is the energy that is delivered to customers whose electric demand is under 5 MW. For MLGW this represents up to 3-5% of about 85% of its load.

b. Provide a partnership credit of 3.1% of the Wholesale Standard Service non-fuel component. Not counting the fuel adjustment, this discount would apply to

[4] TVA Long Term Partnership Proposal Talking Points.pdf and FINAL Partnership Term Sheet.pdf (see Appendix A: TVA)

approximately 70% of a typical invoice to MLGW and would imply 2.1% reduction on such invoice equivalent to approximately $22.5 million per year.

c. 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 LTP allows MLGW to negotiate new terms for 180 days after which the LPC (MLGW) may reduce the notice provision from 20 to 10 years and terminate the LTP.

Additionally, the LTP includes an agreement that TVA would assure no base rate increases for 10 years. This option is evaluated for the TVA status quo strategy since it is the lowest direct cost option for MLGW. If MLGW chooses to stay with TVA, the optionality associated with keeping the 5-year exit provision needs to be assessed separately.

2.2.4 Considerations of Giving Notice

Once a Local Power Company gives notice to TVA[5] about its desire to terminate the All Requirements Contract, a few conditions are triggered, some of which are relevant to the IRP and are summarized below.

In the period leading to termination:

a. TVA will not be able to accelerate any cost recovery and rates will remain largely in line with status quo.
b. Existing provisions in the contract will stay in effect.
c. No new projects will be initiated unless TVA decides to do so for its own benefit.
d. Economic development efforts may be affected as these are discretionary.
e. TVA may use at its own discretion the LPC sourced services (no effect expected).
f. TVA may initiate the retirement of assets based on the notice (no effect expected).
g. TVA will notify other LPCs of the change.

After termination:

a. Wheeling within its area is at TVA's discretion. FERC cannot order TVA to provide wheeling to MLGW, but TVA could choose to allow it at its discretion. Although TVA said, as indicated above, that it will not offer wheeling, potentially it could be negotiated if both parties were to agree it is in their mutual best interest (probably only available as a mutual benefit if MLGW has given termination notice).

b. Delivery points, i.e. the points where MLGW is electrically interconnected and receives power from TVA, may need to be opened. However, TVA indicated that stand-by/ back-up arrangements could be in place with appropriate

[5] TVA's Position on the Implications of a Customer Giving Notice to Terminate (see Appendix A: TVA)

compensation. This would be of interest during extreme contingencies affecting two or more of the new supply points.

c. Stranded Costs/Unrecoverable Investments. There is no precedent on stranded costs being recovered from the departing LPC, however TVA will not make any new investment that could be stranded.

d. Payments in Lieu of Taxes (PILOT)/Economic Development (ED). Termination of the contract will also terminate all programs in effect with the departing LPC. These payments would become a requirement of MLGW.

e. TVA can target any customer within the LPC territory without restriction. Hence TVA can enter negotiations to supply MLGW's customers.

f. LPC Services can be used, at TVA's discretion, under existing contractual conditions.

In addition to the above considerations, TVA would require that TVA power plants (Allen CCGT) are not stranded but rather are reconnected to the grid. It is assumed that the cost to reconnect will be incurred at MLGW's expense.

2.2.5 Stakeholder Input

To incorporate input from MLGW's diverse customer base and other potentially impacted parties, a stakeholder engagement process was a core component of the IRP process. Siemens worked closely with MLGW, its Board of Commissioners, the Power Supply Advisory Team (PSAT) and community stakeholders to obtain input on objectives and limitations that should be considered in the development of the IRP.

The input from both the PSAT and the community was invaluable and helped to shape the IRP as is reflected in the selection of options, scenarios and inputs described in the sections below.

2.3 Strategies and Scenarios

2.3.1 Strategies

MLGW initially identified four distinct supply strategies to be evaluated in the IRP. These consisted of:

1. **Strategy 1:** All Requirements Contract with TVA (status quo), business as usual.
2. **Strategy 2:** Self-supply where MLGW self-serves all needs from local resources.
3. **Strategy 3:** Combination of self-supply (i.e. local supply) with procurement of resources in MISO market.
4. **Strategy 4:** Procure all resources from MISO.

Strategy 2 requires MLGW to identify and develop local resources (only) to reliably meet all its energy and capacity needs. This strategy was dropped after a preliminary analysis, for multiple reasons. First, it was unlikely to lead to a least cost solution; the long-term capacity expansion (LTCE) always resulted in a combination of local resources and MISO located supply, including capacity purchases in the MISO market. Second, renewable local generation that can be sited in and around Shelby County is limited due to land availability for development. In addition, this strategy would have required permitting approval for well over 3 GW of local resources by 2025, which is also a significant challenge.

Strategy 4 (MISO only) was also considered in the analysis although it was not expected to include the final recommended solution:

a. For this strategy to be implemented MLGW load would have to depend entirely on remote resources even though some local resources were shown to be most economic. In addition, it would have required very high levels of new transmission and interconnection into MISO to support the load under contingency conditions, including those affecting two or more transmission lines during maintenance or storms.
b. An artificial limit would have to be placed on the AURORA's Long-Term Capacity Expansion (LTCE) module preventing it from selecting local renewable generation and forcing the expansion plan to acquire it all of it from MISO. [6]
c. Discussions with MISO and a review of the existing resources showed that there are not enough resources currently in service in the MISO zones into which MLGW would interconnect (Arkansas Zone 8 and Mississippi Zone 10) to economically supply MLGW's load without major expansion of generation resources.

Based on the above analysis, the balance of this IRP was based on Strategy 1: status quo with TVA, Strategy 3: combination of MISO market transactions, MISO builds and MLGW builds, and review of how Strategy 4 would compare to Strategy 3. As previously discussed, the required levels of transmission investment were evaluated assuming that TVA would not allow any wheeling (under the "No Deal") with increasing levels of interconnection capacity.

2.3.2 Scenarios

Scenario analysis, using AURORA's Long-Term Capacity Expansion module, was used to identify potential Supply Portfolios (Portfolios) resulting from the application of the different strategies' performance across a range of reasonably expected future market conditions. A variety of scenarios were considered and discussed by MLGW and

[6] A test run without any transmission limitations into MISO still installed renewable generation first locally to MLGW as this is the cheapest resource and once the local generation limit was reached (see New Resources Section), the model started adding resources in MISO. That is, the optimization process found it to be uneconomic to only purchase energy in the MISO market.

stakeholders. The central objective of using scenarios is to produce distinct (different) Portfolios whose performance can then be further evaluated considering a wide range of uncertainties in the Risk (Stochastic) simulation component of the study. Any scenario that would not significantly change the mix of assets in the least cost portfolio was dropped from further consideration. The scenarios that were dropped were encompassed in the risk analysis that subjects each of the portfolios to a wide range of future outcomes (including the dropped scenarios) as described below.

The initial set of scenarios identified by MLGW, Siemens, the PSAT, and stakeholders included eight potential scenarios.

Exhibit 28: Initial Scenario Selection

Scenario	CO_2	Gas Regulations	Economy	Load	Gas Price	Coal Price	Renewables and Storage Cost	Energy Efficiency Cost
Reference (Base)	**Base**	**none**	**Base**	**Base**	**Base**	**Base**	**Base**	**Base**
High Technology	No longer an issue	none	Higher	Higher	Lower	Lower	Lower	Lower
High Regulation	High CO_2 Price	Fracking Ban	Lower	Lower	Higher	Lower (low demand)	Higher	Higher
No Inflation	None	none	Flat	Flat	Flat	Flat	Flat	Flat
Worst Historical	None	Highest	Highest	Highest	Highest	Highest	Base	Base
Best Historical	None	Lowest	Lowest	Lowest	Lowest	Lowest	Base	Base
Climate Crisis	High CO_2 Price	Fracking Ban	Lower	Lower	Higher	Higher	Much Lower	Lower
MISO Operational Changes	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD

Source: Siemens

Ultimately, some of these scenarios were not used or were modified for the development of portfolios because (i) the Reference Case maximized the use of local renewables or (ii) these scenarios would not lead to practical Portfolios. The Reference Case study identified that without limitations on land available for development for the local solar or transmission, the least cost capacity expansion plan would maximize a combination of renewable generation and capacity purchased in the MISO market.[7] Adding to the price of carbon or reducing the cost of renewable technologies, for example, would not change the resource mix. Hence, the inputs associated with these two scenarios were addressed in the wide range of outcomes covered in the 200-iteration risk assessment.

The High Technology scenario and the Climate Crisis scenario were replaced by a High Gas Price/Low Load scenario. This new scenario also favored high levels of renewables

[7] A Scenario with unlimited transmission into MISO built only renewable generation both locally and in MISO and procured all capacity needs from MISO.

and limited fossil-based generation. In addition, a high transmission scenario was added to consider the possibility of bringing additional renewable generation from more remote locations in MISO, further allowing for increased remote renewable penetration.

The Low Load/High Gas scenario has similar characteristics to the High Regulation scenario. The impact of raising the cost of renewables can be observed in the range of renewable costs captured in the risk (stochastic) assessment

Finally, the No Inflation and Worst and Best Historical scenarios were unlikely to produce viable Portfolios.

After discussion with MLGW and the PSAT group, both groups agreed that the scenarios discussed below were appropriate.

The Long-Term Capacity Expansion (LTCE) module of AURORA was run to determine the least cost portfolio for each of seven scenarios, which are described below. Five of them can be considered typical scenarios (1, 2, 3, 4 and 7) and two were sensitivities to test for the impact of specific conditions (5 and 6).

- **Reference (Scenario 1)** – The Reference scenario represents the "most likely" future market conditions based on what is known at this time. Key drivers were based on Siemens reference case outlook. These include:
  - Natural gas prices increasing in real terms from current levels through 2039.
  - Coal prices vary by basin with Illinois Basin coal prices declining slightly due to expected demand declines and Powder River Basin coal prices increasing slightly because of reserve depletion over the study period.
  - Load for markets surrounding MLGW increase at a moderate rate of less than 1% on average annually.
  - New build technology costs decline with fossil resources declining moderately and more pronounced declines for solar, battery storage and to a lesser extent onshore wind.
  - A moderate national price of carbon is assumed beginning in the mid-2020s.

- **High Load (Scenario 2)** – This scenario maintains the same assumptions as in the Reference scenario, except for higher levels of load growth (approximately 1% growth per year for the first 10 years as compared with flat for the reference case). The objective of this scenario is to assess the need for increases in the amount of renewable and thermal resources.

- **Low Load (Scenario 3)** – This scenario maintains the same assumptions as in the Reference scenario, with the exception that load growth is slower (about 1.4% lower per year for the first 10 years). The objective of this scenario is to identify if there would be reductions in the amount of generation resources in the resulting least cost portfolio.

- **High Load/Low Gas (Scenario 4)** – This scenario maintains the same assumptions as in the Reference scenario, with the exception that load growth is faster (as in Scenario 2) and natural gas prices are lower; prices are approximately flat in this scenario, as compared with the reference case where they increase by 60% in 2018 $ by the end of the planning period. The objective of this scenario is to identify how the generation mix would change, resulting in a Portfolio that would incorporate higher levels of thermal generation and potentially lower levels of renewable generation.

- **Reference with High Transmission (Scenario 5)** – This scenario maintains the same assumptions as in the Reference scenario, but in this case the transmission into MISO is increased to determine what greater access to MISO markets would do to the least cost portfolio (e.g. as in an All MISO option) and in particular the level of renewables. Raising access to transmission would also raise the fixed cost for transmission to MISO.

- **Reference with Low Storage Costs (Scenario 6)** – This scenario maintains the same assumptions as in the Reference scenario, but in this case the battery energy storage system (BESS) costs are projected to be very low and combustion turbines are excluded from the options offered to the expansion model to force the BESS solution.

- The objective of this scenario was to produce a Portfolio that maximized the use of storage, which was not being selected in the least cost capacity expansions in the Portfolios. This determined the additional cost associated with adding storage to the portfolios.

- **Low Load/High Gas (Scenario 7)** – This scenario maintains the same assumptions as in the Reference scenario, with the exception that load growth is slower and natural gas prices are higher; gas price increases in real terms (2018 $) by 210% by the end of the planning period[8]. This scenario was expected to maximize the use of renewables and accelerate their implementation, while minimizing the thermal additions as the load is lower. This scenario can be considered similar to the Climate Crisis as all incentives are there for renewables to be accelerated and thermal generation to be minimized.

Strategy 1 (TVA) was assessed considering TVA's IRP buildout of capacity (i.e. no least cost capacity expansion was required) and Strategy 4 (All MISO) was assessed under Scenario 1 (the Reference Scenario) as well. Only the least cost MISO expansion plan was required because local resources in Strategy 3 will always result in the least cost plan. Exhibit 29 below provides a summary of the strategies and scenarios considered.

[8] The increase in gas prices could be directly due to an increase in the price of the commodity or a combination of increases in commodity plus CO_2 emissions costs $/Ton. In the base case the gas is modeled to increase by 59% by the end of the forecast period as compared with 210% in this scenario.

Exhibit 29: Portfolios Across Scenarios and Strategies

Scenarios / Portfolios		Strategy		
		Strategy 1 (TVA)	Strategy 3 Self-Supply plus MISO	Strategy 4 All MISO
State of the World	Scenario 1 Reference	S1S1	S3S1	S4S1
	Scenario 2 (High Load)		S3S2	
	Scenario 3 (Low Load)		S3S3	
	Scenario 4 (High Load/Low Gas)		S3S4	
	Scenario 5 (High Transmission)		S3S5	
	Scenario 6 (Promote BESS)		S3S6	
	Scenario 7 (Low Load/High Gas)		S3S7	

Source: Siemens

2.4 Objectives and Metrics

Early in the process, Siemens worked with both MLGW and the PSAT to define their primary objectives for their future supply plan and define metrics that were measurable that could be tracked for all analyses. These objectives will serve as the components of the balanced scorecard against which supply alternatives identified through the IRP will be measured and ranked. MLGW selected and PSAT agreed to the identified objectives of reliability for customers, cost control, environmental stewardship, and economic growth in and around its service area. Siemens defined metrics to align with each objective to be tracked throughout the analysis. These were reviewed by MLGW and stakeholders and ultimately locked in the specific objectives and metrics to measure in the analysis as summarized in Exhibit 30.

Exhibit 30: MLGW IRP Objectives and Metrics

OBJECTIVES	METRICS
Reliability	Meets or exceeds NERC reliability requirements and manages intermittency. All Portfolios meet NERC Standards; thus, the metric is designed to assess the level by which NERC levels are exceeded. The ratio of the Capacity Import Limit (CIL) + Reliable Generation (Unforced Capacity UCAP) to Peak Load was selected. ***Higher the better.***
Least Cost **(Affordability)**	Net Present Value (NPV) of revenue requirements. This NPV includes all costs in addition to the generation capital and operating costs, i.e. cost of transmission, MISO Membership, TVA costs, PILOT (payments in lieu of taxes), etc. ***Lower the better.***
Price Risk (Minimization/Stability)	Measured as: (a) 95% percentile of the NPV distribution of costs (Worst) Outcome and (b) Regret: i.e. the level by which MLGW would regret having chosen a Portfolio in case of an adverse future. ***Lower Worst Outcome and Minimum Regret or No Regret (always optimal no matter the future) is the goal.***
Sustainability	Measured as: (a) carbon (proxy for total emissions), (b) water consumption, and (c) percentage of the energy coming from renewable resources (nuclear and large hydro, although "clean", do not count). ***For "a" and "b" Lower the better, for "c" Higher the better.***
Market Risk	Energy Market Purchases or Sales as a percentage of load; Amount of Capacity Purchases. ***Lower the better.***
Economic Growth	Capital Expenditures in Shelby County and number of plants as a proxy. ***Higher the better.***
Resiliency	Amount of load shed during extreme events. ***Lower the better.***

Source: Siemens

MLGW's planning objectives are in line with good utility practice and those commonly considered in IRPs across the country.

- Reliably meeting customer demands is a primary objective. As shown in Exhibit 30 above the ratio measures the amount the plan exceeds the minimum requirements defined by NERC. Portfolios not meeting these minimum requirements were not considered viable.
- Likewise, it is critical to develop the system cost with a supply strategy that minimizes risk to customers across a variety of potential future market conditions.
    - Cost objectives were measured as the net present value of revenue requirements under reference conditions (least cost objective).
    - The 95th percentile of the NPV (highest cost outcome) across alternate market outcomes was considered in the risk analysis (price stability risk).
    - Level of regret in case of adverse future conditions (e.g. low demand, high capital cost or high fuel prices) was evaluated.

- In addition, sustainability, measured as carbon emissions, water consumption and renewable penetration over the forecast period, was another objective considered.
- Economic growth impacts of supply alternatives are measured in terms of expected capital expenditures in Shelby County and number of generation plants.
- Resilience is measured by the amount of load shedding that could occur across the 200 iterations.

3. Load Forecast

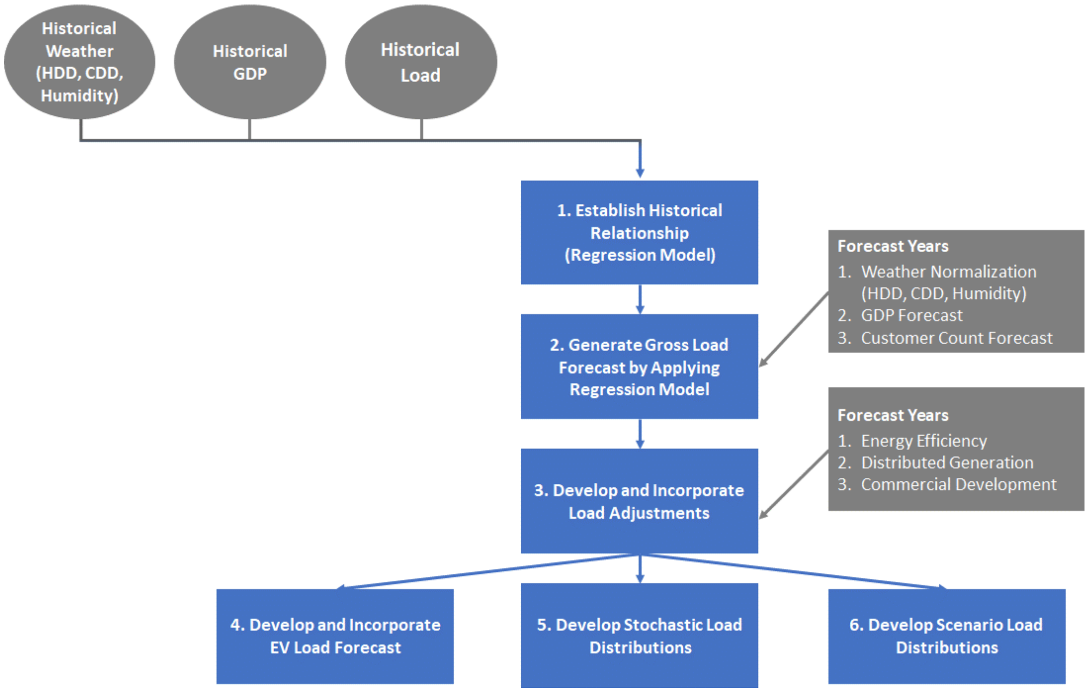
Siemens developed a reference case load forecast for the MLGW service territory. This section presents a 20-year net load forecast which is the gross system load forecast adjusted for energy efficiency (EE), distributed solar generation (DS), electric vehicles (EV) and other known future commercial loads under development.

3.1 Load Forecasting Methodology

Siemens used a deterministic load forecasting process, described in the flow chart in Exhibit 31, to develop a gross load forecast and adjusted the forecast to account for several load modifiers. The average and peak load regression models were generated separately using the same process. In summary, using historical weather data, customer counts, economic data (gross domestic product [GDP] for the region) and historical monthly system load data, Siemens developed separate linear regression models to fit the economic and weather data to the average and peak load data. Various weather parameters and historical GDP data were used as independent variables in the best-fitting models; customer counts did not contribute to the models' performance significantly, however.

Using historical data as the basis for the regression model resulted in a strong negative correlation between economic growth and load, which Siemens and MLGW believe is not likely to continue beyond the near term (next five years). As a result, for the long term, Siemens assumes a load growth rate of approximately 0.1% per year, consistent with TVA's long-term load growth rate assumption. Siemens specified a five-year transition period (2025-2029) to bridge the near-term (2020-2024) regression-based forecast with the TVA long term (2030-2039) growth rate.

Exhibit 31: Deterministic Load Forecasting Process



Source: Siemens

3.1.1 Historical System Load Profile

Exhibit 32 below shows a 20-year series of historical energy consumption and peak system load data for Memphis and Compounded Annual Growth Rates (CAGR) for select periods of time, as provided by MLGW. Over the past 20 years, energy has grown from 14,323 GWh to 15,869 GWh in 2007 but fell to 14,415 GWh by 2018, representing little difference between 1999 and 2018. Similarly, peak load increased from 3,234 MW in 1999 to an all-time high of 3, 533MW in 2007 but fell to 3,097 MW in 2018—one of the lowest peak levels over the 20-year period as shown in Exhibit 32 below.

Exhibit 32: Historical Energy (GWh) and Peak Load (MW)

Year	Energy (GWh)	Peak Load (MW)
1999	14,323	3,234
2000	14,898	3,334
2001	14,629	3,174
2002	14,927	3,211
2003	14,540	3,264
2004	14,866	3,269
2005	15,446	3,390
2006	15,374	3,466
2007	15,869	3,533
2008	15,164	3,336
2009	14,364	3,287
2010	15,434	3,444
2011	14,863	3,507
2012	14,660	3,256
2013	14,443	3,195
2014	14,297	3,062
2015	14,231	3,226
2016	14,396	3,155
2017	13,795	3,086
2018	14,415	3,097
Period	**CAGR**	**CAGR**
1999-2008	0.64%	0.35%
2009-2013	0.14%	-0.71%
2014-2018	0.21%	0.29%
1999-2018	0.03%	-0.23%

Source: MLGW

3.1.2 Establish Historical Relationships (Regression Model)

Siemens used a stepwise regression process in MATLAB to discover the relationship between historical weather data, economic data, customer data, and system energy and load. All available data from 2014-2019 were used for the regression analysis. The following input data sets were used to create historically based relationships between weather, economic, and system data:

1. **Historical weather data** – Monthly humidity data from Memphis International Airport, which MLGW provided. Monthly Heating Degree Days (HDD) and Cooling Degree Days (CDD) were sourced from Degreedays.net.
2. **Historical economic data** – Historical real per capita GDP for the Memphis metropolitan area was downloaded from The Federal Reserve Bank of St. Louis.[9]

[9] https://fred.stlouisfed.org/series/NGMP32820. Siemens expects the impact of the COVID 19 pandemic on markets to be temporary. Broader trends of softer demand for commercial.

3. **Historical load and energy data** –Monthly customer energy and peak data for MLGW's service territory since 2014. Siemens chose the past five years of data to reflect recent economic growth trends following the recessionary period that began in 2008.

Siemens found a positive relationship between HDD, CDD, and humidity with energy consumption, but found an inverse relationship between GDP and energy. Historically, economic variables such as GDP or personal income would have a positive relationship to the load growth. This relationship, however, has not been holding for many regions throughout the United States—especially in the residential sector since 2010.[10] Considering that MLGW's average load was relatively flat to decreasing from 2014-2018 during a period of economic growth, Siemens expected an inverse relationship between GDP and weather normalized load in the analysis. The adjusted R-squared values for each of the models exceeded 0.9.

For the energy forecast, the following relationship was specified as the best-fitting regression model:

Energy_per_Customer = f (HDD, CDD, Humidity, GDP, Calendar Variables)

Similarly, for the peak load forecast, the following relationship was specified:

Peak_Load_per_Customer = f (HDD, CDD, Calendar Variables)

Using the functions above, Siemens developed a forecast of gross energy and peak loads per customer for 2020 to 2025. Using the customer count forecast data, the MW per customer values were converted into gross service area energy and peak load forecasts.

3.1.3 Generate Gross Energy and Load Forecasts

Siemens specified gross system forecasts by applying the coefficients calculated in the regression model to their corresponding forecasted variables for the 2020-2025 period. The following input data sets were used as independent variables for specifying the gross energy and peak load models:

1. **Normal temperature data** – Siemens extrapolated average weather data from 2009-2018 by averaging HDD, CDD, and humidity, all aggregated on a monthly basis. Humidity data was sourced from the Memphis International Airport that as provided by MLGW, and HDD and CDD were sourced from Degreedays.net.
2. **Customer count forecast data** – Siemens extrapolated customer counts by averaging data that MLGW provided from 2008-2017. Siemens used an estimated annual customer growth rate of 0.1%.
3. **Economic forecast data** – For the purposes of forecasting load, Siemens assumed an average 1% annual GDP growth rate through 2025 to emulate the economic growth in the historical data with consideration for long-term forecasts. Long-term national economic forecasts call

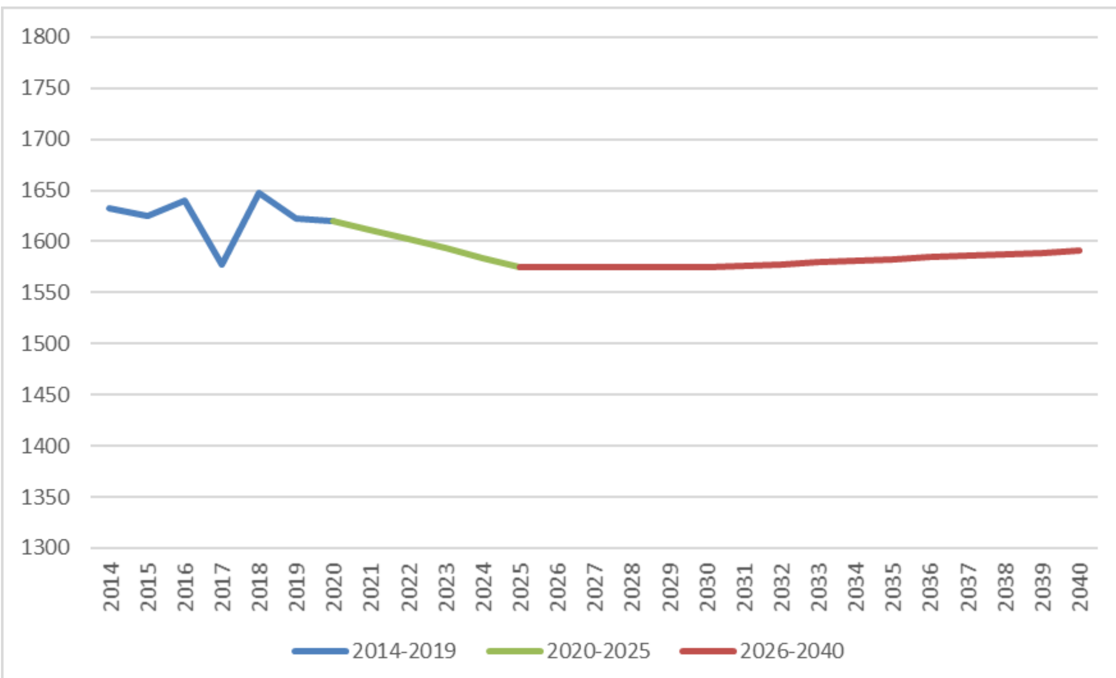
[10] https://www.eia.gov/todayinenergy/detail.php?id=14291 real estate, digitalization, and online commerce are already embedded in regional forecasts

for modest growth during this period[11], and historically Memphis has grown at a slower rate than the national average.

4. **Monthly calendar variables** – Because the model was fit to a monthly time series data set, both the average and peak load models were specified with dummy variables based on the month associated with each data series.

The historical and forecasted annual gross average load data are presented in Exhibit 33. Siemens views recent historical declines in energy usage to only be applicable in the short term, returning to modest growth over time, as reflected in the long-term forecast. Siemens applied the regression-based forecasts to the 2020-2025 period, and then transformed the forecast into gross average load by dividing by hours per year (green line). For future years, we assume gross average load will flatten in the medium term (2026-2030) as a transition period, followed by a period of slow load growth (in red) equal to 0.1%per year in the long term (2031-2040).

Exhibit 33: Historical and Forecasted Annual Gross Average Load (MW)

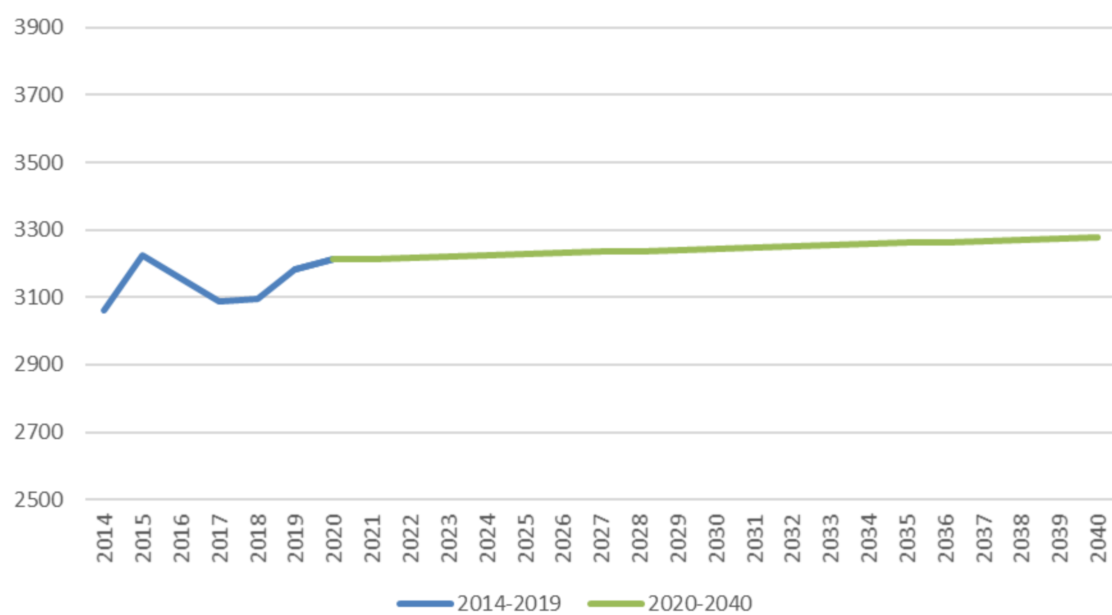


Source: Siemens

[11] https://www.cbo.gov/system/files/2019-03/54918-Outlook-3.pdf

The gross peak load forecast is shown in Exhibit 34. Peak load has been increasing historically, and Siemens views it appropriate to assume the regression-based peak load forecast growth rate throughout the entire period of the study. The average growth rate for the 2020 to 2040 period (in green) is 0.1%.

Exhibit 34: Historical and Forecasted Annual Gross Peak Load (MW)



Source: Siemens

Exhibit 35 shows the historical and forecasted values for gross annual average and peak loads from 2014 to 2039. As described above, the gross average load has generally been declining over the 2014-2019 period, continuing until 2025 to 1,575 MW, followed by a flat trend from 2025 to 2030, followed by a small annual increase (CAGR of 0.1%) to 2039, rising to 1,589 MW. The peak forecast continues the 2014 to 2019 trend of 0.1% growth to 2039, from 3,211 MW in 2020 to 3,274 MW in 2039.

Exhibit 35: Historical and Forecasted Gross Annual Average and Peak Load (MW

	Avg Load (MW)	Peak (MW)	Load Factor
2014	1633	3062	53%
2015	1625	3226	50%
2016	1640	3155	52%
2017	1577	3086	51%
2018	1647	3097	53%
2019	1622	3182	51%
2020	1620	3211	50%
2021	1611	3215	50%
2022	1602	3218	50%
2023	1593	3221	49%
2024	1584	3224	49%
2025	1575	3228	49%
2026	1575	3231	49%
2027	1575	3234	49%
2028	1575	3238	49%
2029	1575	3241	49%
2030	1575	3244	49%
2031	1576	3247	49%
2032	1578	3251	49%
2033	1580	3254	49%
2034	1581	3257	49%
2035	1583	3261	49%
2036	1584	3264	49%
2037	1586	3267	49%
2038	1587	3271	49%
2039	1589	3274	49%
	CAGR	**CAGR**	
2020-2025	-0.56%	0.10%	
2026-2030	0.00%	0.10%	
2031-2039	0.10%	0.10%	
2020-2039	-0.10%	0.10%	

Source: MLGW and Siemens

3.2 Net Load Modifier Forecasts

Adjustments to the gross load forecasts are needed to incorporate the future effects of energy efficiency/demand side load management, distributed solar generation, electric vehicle adoption, and known future commercial development loads. Energy efficiency and distributed solar generation reduce the gross forecasts while electric vehicles and known development loads add to the gross forecasts. Siemens developed average and peak load forecasts for each of these load variables, as explained below.

3.2.1 Energy Efficiency (EE) Impact

Currently, MLGW does not administer an EE portfolio, having utilized TVA's EnergyRight program instead. To forecast the estimated impacts of a prospective EE portfolio, Siemens used data from the U.S. Energy Information Administration (EIA) Form 861 for 2018. To develop a comparison group of utilities, Siemens considered the system size, annual energy savings, sales, customer characteristics, and geographic location. The following utilities provide a good basis for developing an estimate of potential EE savings for comparison and planning purposes.

- Entergy Mississippi LLC
- KCP&L Greater Missouri Operations Co.
- Southwestern Electric Power Co.
- Entergy New Orleans, LLC
- City Utilities of Springfield (MO)

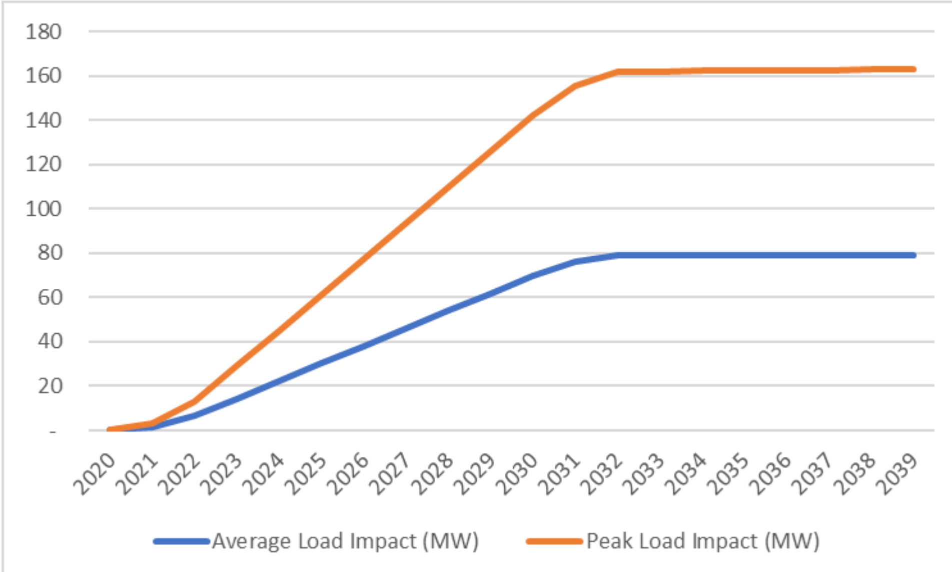
Siemens determined that the average contribution from EE for those utilities as a percentage of annual sales was 0.5%. By multiplying the 0.5% average by Memphis' forecasted load, Siemens estimated the overall impact of EE on average load. For peak load impacts, Siemens assumed that such a small portfolio would be primarily composed of heating and cooling EE programs, and most EE resources would be peak coincident.

It is important to note that these EE savings do not include those due to naturally occurring EE, i.e. the proportion of all equipment purchases that will flow to efficient products (in the absence of any programmatic incentives), changes in building codes or other energy use standards (e.g., national ENERGY STAR requirements). These naturally occurring EE savings are already included in the base load forecast and what is presented here are the additional savings due to the incentive programs to be put in place by MLGW.

As shown in Exhibit 36, Siemens assumes that Memphis will start funding EE projects by 2021 and that the useful life of the technology used in the programs will be 10 years. Therefore, the forecasted load reductions begin in 2021 and accumulate over time but flatten out after 2031. After 2031, programs will continue to replace the older technology stock, but EE as a resource will no longer result in additional net load reductions.

It is important to point out that this is a conservative assumption and if the EE gains continue beyond 2031 this will result in reduced net energy purchases from MISO and reduced amounts of MISO Capacity to be acquired via bilateral contracts.

Exhibit 36: Annual Average and Peak Load EE Reductions (MW)



Source: Siemens

The following table (Exhibit 37) shows Siemens estimates of average and peak load reductions resulting from an EE portfolio designed to achieve energy savings at 0.5% of annual consumption. Average load reductions begin at 2 MW in 2021, rising to 79 MW by 2032, and maintaining that level through 2039. Peak load reductions also begin in 2021 and rise to 163 MW by 2037.

Exhibit 37: Annual Average and Peak Load EE Reduction Estimates (MW)

	Avg. Load Reduction (MW)	Peak Load Reduction (MW)
2020	0	0
2021	2	3
2022	6	13
2023	14	29
2024	22	45
2025	30	61
2026	38	77
2027	46	94
2028	54	110
2029	62	126
2030	70	142
2031	76	155
2032	79	162
2033	79	162
2034	79	162
2035	79	162
2036	79	162
2037	79	163
2038	79	163
2039	79	163

Source: Siemens

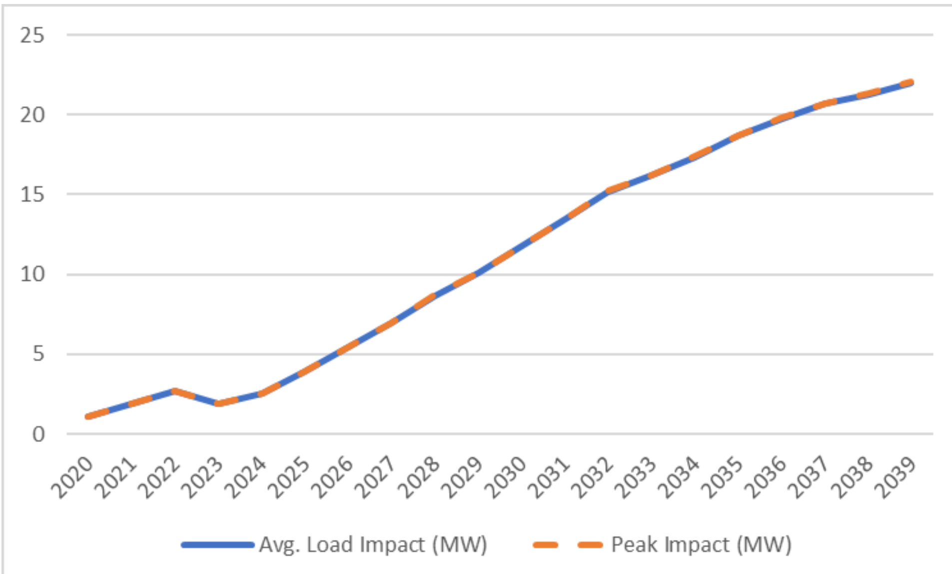
Siemens estimated the costs of administering an EE portfolio from historical data for other regional utilities. Drawing from 2018 U.S. EIA data for the same group of utilities in developing the reasonable expected portfolio savings rate, Siemens estimated the average cost of energy savings on a per KWh basis to be $0.10. Multiplying this by the expected annual EE portfolio savings rate of 0.5% of retail sales amounts to approximately $7 million annually by 2023, after a two-year ramp-up. After discounting the cost stream over the period of analysis, the resulting levelized cost estimate for administering an EE portfolio at that savings rate is $0.064/kWh. This value is in line with documented EE industry portfolio performance standards.[12]

[12] http://www.synapse-energy.com/sites/default/files/COSE-EIA-861-Database-66-017.pdf

3.2.2 Distributed Solar (DS) Generation Impact

To project the DS penetration, Siemens assumes that MLGW's DS penetration proportionally corresponds with TVA's projected DS penetration, at approximately 10% of TVA's total peak demand. Siemens developed a forecast of MLGW's DS penetration to match 10% of TVA's DS forecast. Siemens applied NREL's PV Watts[13] capacity factor for the Memphis geographic location to calculate an average load and peak load DS impact for MLGW, shown in Exhibit 38.

Exhibit 38: Annual Average and Peak Load Distributed Solar Generation (MW)



Source: Siemens

The following table (Exhibit 39) shows Siemens estimates of average and peak load reductions resulting from distributed solar generation. Average and peak load reductions amount to approximately 1.1 MW in 2020, rising to 22 MW by 2039. The average and peak load reductions vary slightly but appear equal in Exhibit 39 below by coincidence due to rounding.

[13] https://pvwatts.nrel.gov/

Exhibit 39: Annual Average and Peak Load Distributed Generation Estimates (MW)

	Avg. Load Impact (MW)	Peak Impact (MW)
2020	1.1	1.1
2021	1.9	1.9
2022	2.7	2.7
2023	1.9	1.9
2024	2.5	2.5
2025	3.9	3.9
2026	5.4	5.5
2027	7.0	7.0
2028	8.7	8.7
2029	10.1	10.1
2030	11.7	11.8
2031	13.5	13.5
2032	15.2	15.2
2033	16.2	16.2
2034	17.4	17.4
2035	18.7	18.7
2036	19.7	19.8
2037	20.7	20.7
2038	21.3	21.4
2039	22.0	22.0

Source: Siemens

3.2.3 Electric Vehicle Impact

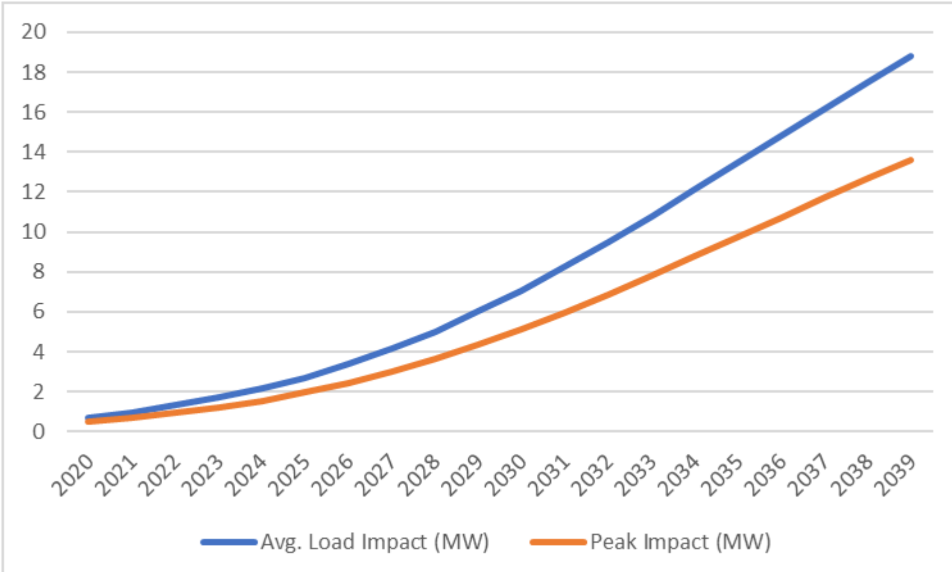
Siemens forecasted the average and peak load impacts of increased electric vehicle adoption within MLGW's service territory through the forecast period. To estimate the potential for EV adoption in MLGW's territory, Siemens applied our proprietary electric vehicle forecasting approach, which employs our market view, a leading Light Duty Vehicle (LDV) adoption tool, and our proprietary analytical models to project commercial vehicles adoption and load calculations.

The Siemens' reference case LDV adoption forecast leverages proprietary inputs and adjustments to the latest version of the best-in-class customer choice model (MA^3T Model[1]) developed by Oak Ridge National Labs (ORNL). This model generates forecasts for both battery electric vehicles (BEVs) and plug-in hybrid electric vehicles (PHEVs) by state. Siemens segmented the Tennessee forecast derived from this model into MLGW's LDV portion using MLGW's residential customer count. The commercial vehicle reference case forecast was derived from the Department of Energy's 2019 Annual Energy Outlook PEV adoption forecast, which we applied to the commercial vehicles operating in MLGW's service territory.

[1] https://www.ornl.gov/content/ma3t-model

As illustrated in Exhibit 40, average and peak load impacts from electric vehicle charging are very small in 2020 but rise gradually over the period of analysis through 2039. The peak impact for all electric charging is lower than the average impact because the peak most frequently occurs at 4-5 P.M., which is not when most customers are charging.

Exhibit 40: Annual Average and Peak Load Electric Vehicle Contribution (MW)



Source: Siemens

The following table (Exhibit 41) shows Siemens estimates of average and peak load increases resulting from electric vehicle charging. Average and peak load increases amount to approximately 1 MW in 2020 but rise to 14 MW at system peak, and account for a 19 MW increase to average system load by 2039.

Exhibit 41: Annual Average and Peak Load Electric Vehicle Charging Impact Estimates (MW)

	Avg. Load Impact (MW)	Peak Impact (MW)
2020	1	1
2021	1	1
2022	1	1
2023	2	1
2024	2	2
2025	3	2
2026	3	2
2027	4	3
2028	5	4
2029	6	4
2030	7	5
2031	8	6
2032	9	7
2033	11	8
2034	12	9
2035	13	10
2036	15	11
2037	16	12
2038	18	13
2039	19	14

Source: Siemens

3.2.4 Known Commercial Developments Impact

MLGW provided estimated peak load design data for known future commercial developments that will impact the MLGW system. MLGW reports increases in expected peak load from a FedEx Hub Expansion (25 MW), Amazon (5 MW), One Beale Project New Hotel (2.4 MW), and One Beale Project Dr. MLK (1.7 MW) beginning in 2020. Siemens applied an assumed industrial load factor of 70% to FedEx and Amazon, and a commercial load factor of 50% for the One Beale Projects to calculate their contribution toward average load increases. These development loads are expected to begin in 2020 and last through the period of analysis (2039). The estimated development load average impact totals 23 MW and the expected total peak load impact is 34 MW.

3.3 Long-Term Net Energy Reference Case Forecast

The long-term net energy forecast estimates for the reference case are presented below in Exhibit 42. This net energy forecast is the gross system energy forecast after accounting for separate forecasts of all load modifier impacts. Siemens is forecasting an overall decline in energy consumption over the 2020-2039 period. Most of this is driven from the penetration of distributed solar within the service territory and some additional energy reductions from EE programs. These load modifiers more than offset the expected modest growth in system load and EV penetration.

Exhibit 42: Forecasted Net Energy Estimates (GWh)

Year	GWh
2020	14,389
2021	14,294
2022	14,170
2023	14,032
2024	13,918
2025	13,735
2026	13,658
2027	13,582
2028	13,539
2029	13,433
2030	13,359
2031	13,313
2032	13,328
2033	13,312
2034	13,328
2035	13,342
2036	13,391
2037	13,375
2038	13,395
2039	13,414

Source: Siemens

3.4 Long-Term Net Peak and Average Reference Case Demand Forecasts

Exhibit 43 shows the forecasted reference case net peak load forecast for the 2020-2039 period. Following a similar process as for developing the net energy forecast, Siemens applied load modifiers during the peak hour for expected EE, distributed solar, and development loads. The impact of those load modifiers is modest over time, steadily decreasing peak loads by about 4% per year. The impact of EE and distributed solar in decreasing peak impacts overwhelms the impact of development loads on increasing peak load.

Exhibit 43: Forecasted Net Peak Load Estimates (MW)

Year	MW
2020	3,244
2021	3,244
2022	3,236
2023	3,224
2024	3,211
2025	3,197
2026	3,182
2027	3,168
2028	3,153
2029	3,139
2030	3,124
2031	3,113
2032	3,108
2033	3,110
2034	3,112
2035	3,114
2036	3,116
2037	3,118
2038	3,121
2039	3,123

Source: Siemens

Exhibit 44 displays the reference case net average load forecast for the 2020-2039 period. To calculate the net average load forecast, the forecast net energy is divided by the number of hours in that particular year.

Exhibit 44: Forecasted Net Average Load Estimates (MW)

Year	MW
2020	1,638
2021	1,632
2022	1,618
2023	1,602
2024	1,585
2025	1,568
2026	1,559
2027	1,550
2028	1,541
2029	1,533
2030	1,525
2031	1,520
2032	1,517
2033	1,520
2034	1,521
2035	1,523
2036	1,524
2037	1,527
2038	1,529
2039	1,531

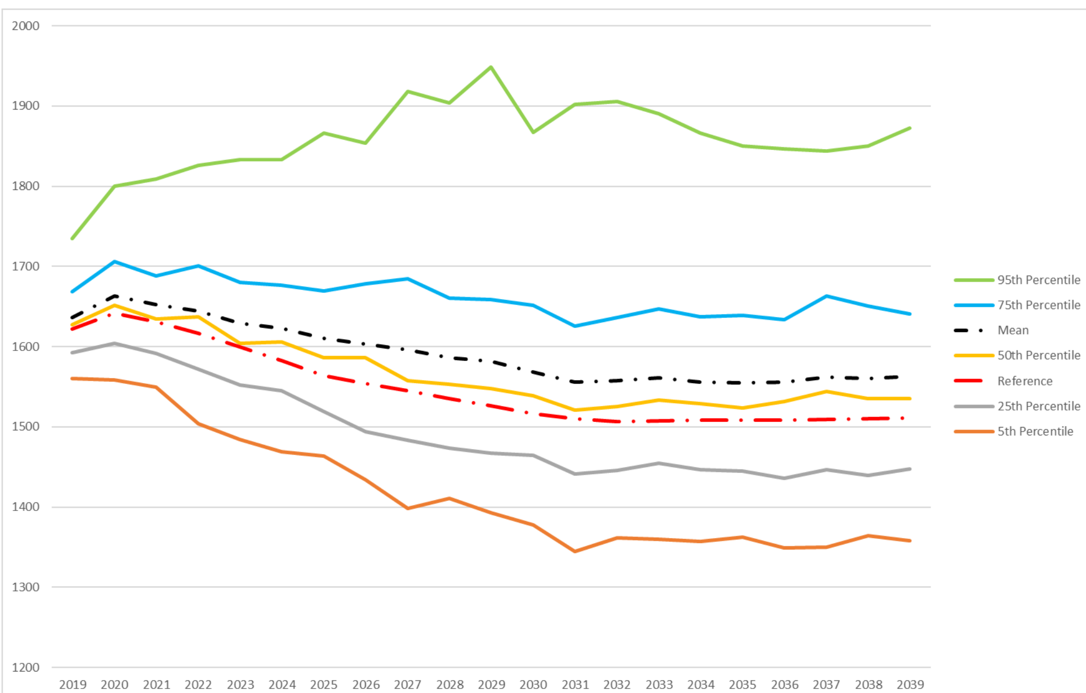
Source: Siemens

3.5 Stochastic Distribution Development

To reflect uncertainty in the forecast, Siemens developed stochastic distributions for the net average and peak loads for the period of analysis (2020-2039). The stochastic distributions are the net result of 200 random simulations for the reference case net load forecasts. Siemens calculated the distributions for the 5th and 95th percentiles (two standard deviations), quartiles (25th, 50th, and 75th) percentiles, and the average (mean) of the annual distributions over time. Siemens Stochastics Methodology is further explained in Appendix C: Model Description.

As shown in Exhibit 45, the overall distribution shows considerable uncertainty for future average load growth exceeding the reference case, and less uncertainty for future average load growth trending below the reference case. Significantly, annual estimates for the average and the 50th percentile of the stochastic distribution track above the reference case, implying with a probability greater than 50% that the reference case will not exceed those values. Moreover, the third quartile (75th percentile) estimates deviate more from the reference case than the first quartile (25th percentile) over the entire period, demonstrating the downside risk of unexpected load growth. Reference case used in the non-stochastic runs.

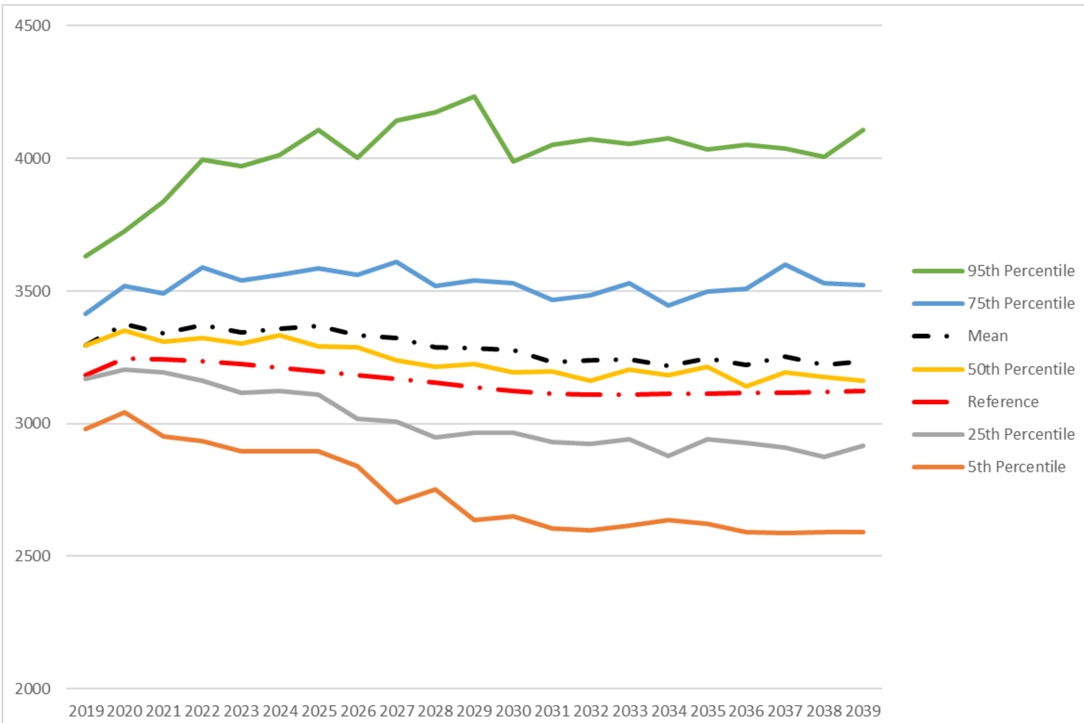
Exhibit 45: Stochastic Distribution of Average Load Forecast from 2019 to 2039 (MW)



Source: Siemens

Similarly, as shown in Exhibit 46, the stochastic distribution also shows considerable uncertainty that peak load will exceed the reference case over time. Both the mean and the 50th percentile estimates track above the Reference Case, and both the 5th and 25th percentile estimates deviate from the reference case by less than their 95th and 75th percentile counterparts. This also strengthens the case that the risk of load growth below the mean is less than the risk of it exceeding those estimates. Note the reference case used in the non-stochastic runs

Exhibit 46: Stochastic Distribution of Peak Load Forecast from 2019 to 2039 (MW)



Source: Siemens

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4. Environmental Considerations

4.1 Renewable Portfolio Standards (RPS)

The Memphis Area Climate Action Plan published in 2019 includes several strategies for reducing the City's emissions and contribution to climate change. The Memphis Area Climate Action Plan calls for decarbonizing the electric grid with renewable energy, increasing the percentage of carbon-free energy in electricity supply from the baseline of 60% in 2020 to 75% by 2035 and 100% by 2050, and focusing on renewable sources such as solar and wind. Noting this, there was a focus on considering low- and no-emitting resources in the IRP analysis, weighing these impacts with other objectives including reliable and cost-effective supply.

MLGW wanted to consider the cost associated with meeting Climate Action Plan goals rather than requiring they be met regardless of cost. A base RPS target of 5%-15% RPS from 2025-2039 was imposed as a floor, expecting that higher levels would be achieved. This percentage is expressed as a function of the energy consumed in a year.

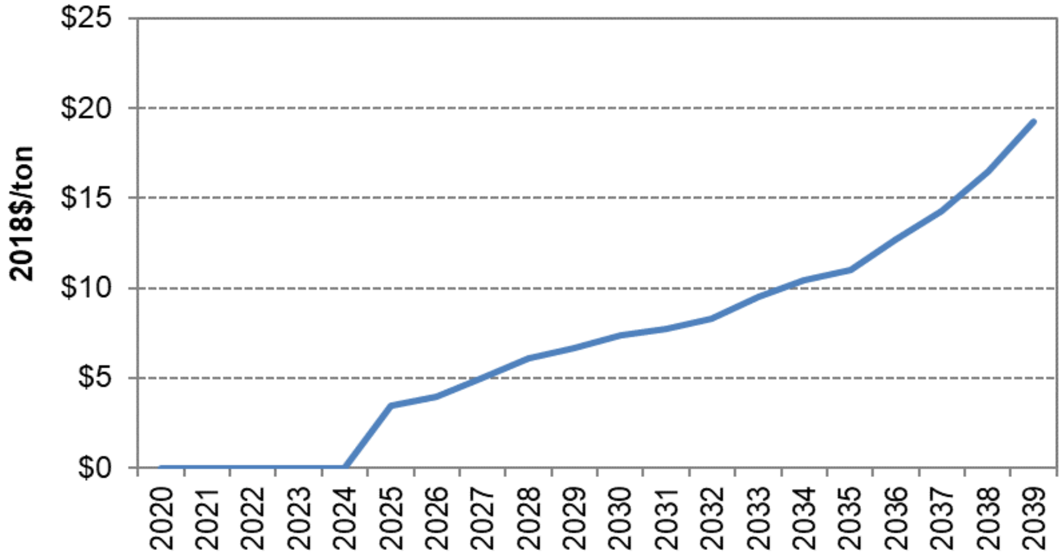
Siemens found that renewable builds including both wind and solar were economic and the base RPS target level above was always exceeded under all supply portfolios. As will be shown later in this report, the level of renewable generation coverage of the load ranged from a low of 42% to a high of 77%, with most of the Portfolios producing over 46% of the load by the end of the forecast period and 56% on average. Renewable percentages achieved were tracked as part of the balanced scorecard for all Portfolios.

4.2 CO_2 Pricing

No comprehensive national regulation of carbon emissions currently exists in the U.S. Efforts to enact policy covering carbon emissions from major sources has occurred over the years. This included efforts by the U.S. Congress to pass a national cap and trade regime, the EPA's regulation of GHG emissions from new and existing power generators, and more recently, proposals in Congress for carbon taxes and comprehensive clean energy targets.

Action to limit carbon emissions has increased in recent years with states taking the lead in defining low- and no-carbon generation requirements. Tennessee does not have a state policy covering carbon emissions from power generation. The potential for enactment of such regulation over the study period remains. To account for this uncertainty, a moderate price on CO_2 emissions from fossil generators is assumed in the Reference Case. This outlook includes a national carbon price to become effective in 2025, covering emissions from electric generating units in the U.S. Siemens CO_2 price projections in the Reference Case are presented in Exhibit 47.

Exhibit 47: Carbon (CO_2) Price Projections (2018 \$/ton)



Source: Siemens

Annual emissions targets were not modeled as a constraint in the IRP, but the costs associated with emissions were considered. Also, as presented in the Stochastic section of this report, a range of possible future carbon costs were included in the study.

4.3 Air Compliance

Tennessee is covered under the EPA's Cross State Air Pollution Rule (CSAPR). CSAPR was finalized in 2011 to ensure that emissions from generating units in upwind states did not adversely impact the ability of downwind states to meet their National Ambient Air Quality Standards for ozone and particulates. Fossil generators in Tennessee must surrender one allowance representing one short ton for emissions of SO_2 (traded in CSAPR group 1) and for NOx annual market and seasonal market extending from May to September. The Reference Case outlook for emission allowance prices under CSAPR are presented in Exhibit 48 (Emission Allowance Prices). Annual NOx and SO_2 prices are expected to remain low, under $5/ton, as the emission levels are expected to be below caps. Seasonal NOx markets are priced higher due to lowered caps beginning in 2017. Over time as additional fossil generators retire, pricing in this market is expected to decline.

Exhibit 48: Emission Allowance Price Outlook under CSAPR (2018 $/ton)

Source: Siemens

Major emissions sources with the potential to emit more than 100 tons per year of an air pollutant are required to obtain a Title V operating permit under the current Federal legislation of the Clean Air Act. Air permitting for new large sources is typically performed at the state level. Shelby County performs initial review of permits for new facilities at the county level. It is expected that subsequent to the IRP, if MLGW pursues local generation, MLGW will have discussion with the County on overall permitting strategy during the implementation process leading to an RFP.

4.4 Water Use

Water needs for future generation units were considered in the IRP. In 2017, high arsenic levels were detected in groundwater close to the TVA Allen coal plant ash ponds. The TVA Allen coal plant site on McKellar Lake southwest of downtown Memphis is undergoing full remediation following the coal plant closure in 2018. This contamination was considered a threat to the Memphis Sands aquifer which supplies drinking water to the City. TVA's Allen combined cycle plant developed at this site planned to use water from the aquifer as cooling water source. Due to concerns that the coal ash contamination could reach the aquifer, the plant found an alternative source.

Considering the Allen site contamination, cooling needs for natural gas-fired units are assumed to be water from municipal supply rather than local wells. Air cooling is another alternative, albeit a less preferable option due to higher costs and auxiliary load. CTs sited in Memphis would likely include some version of inlet cooling given the high summer temperatures. A CC would require wet cooling. Siemens estimates that water needs for a CC and CT unit on a peak summer day could reach 100,000 gallons per hour.

To better understand the implications of water supply for new build natural gas-fired generating units, MLGW water system engineers were consulted. At this time, it is expected that some water system upgrades would be required to supply 100,000 gallons of water per hour to new combined cycle generating stations. An actual expected consumption profile would be needed to assess the necessary design upgrades. This might include additional capacity or onsite storage to ensure water availability when needed. Additional assessment of water needs would be included in the permitting process. However, this initial consultation suggests that, with some additional upgrades, water supply is feasible from the municipal system, depending on specific unit siting.

5. New Resource Options

This section documents the methodology Siemens applied to develop the cost and performance assumptions for all new build generation technologies for MLGW. The assumptions used in the long-term capacity expansion modeling are summarized by resource type. Furthermore, Siemens capital cost forecasts are compared with public forecasts as references.

This section also reviews the additional capacity (reserves) MLGW would be responsible for providing in the event MLGW joined MISO and integrated into an existing Local Resource Zone (LRZ), rather than remaining as a separate zone.

5.1 Overview of New Generation Resources

Siemens maintains a technology cost and performance database that includes all applicable studies, projects, and announcements from over fifty public and confidential client sources. All sources in the database are maintained to be within three years of the current year to sustain up-to-date assumptions. Key public sources include annual reports such as the NREL Annual Technology Baseline (ATB), the EIA Annual Energy Outlook (AEO), the Lazard Levelized Cost of Energy, and the Lazard Levelized Cost of Storage. In addition, key subscription sources such as ThermoFlow, S&P Global, Energy Velocity, and Greentech Media are included.

The Siemens team screens each source for equipment type, model, project scope and location to develop qualified samples. These qualified samples are then modified using variables including location adjustments, inflation adjustments and owner's interest rate to develop comparable national samples. Siemens then uses statistical analysis from the comparable national samples and expert opinion to determine likely cost ranges for each technology.

The technology database provides the foundation for Siemens technology cost and performance forecasts. To develop longer term cost projections, Siemens considers several factors, including the recent and expected rates of technological improvements for existing technologies and new technologies that are under development. By varying assumptions (i.e. productivity, learning curves, technology obsolescence, cost escalations, etc.), Siemens develops a distribution of values for each technology over time, which we apply to define high and low values for each of the technologies.

5.2 Assumptions

For this analysis, generation options for the long term capacity expansion included advanced combined cycle gas turbine (CCGT), conventional CCGT with duct firing, simple cycle advanced frame combustion turbine (CT), simple cycle advanced frame CT, simple cycle aero derivative CT, river flow hydro, supercritical coal with carbon capture and storage (CCS), single-axis tracking solar PV, Li-ion battery storage, onshore wind, and nuclear small modular reactor (SMR).

5.2.1 Summarized Technology Comparison

This summary includes Siemens' national capital cost forecasts by technology class.[14] All capital cost assumptions are considered to be "all-in" capital costs which include EPC costs (engineering, procuring, construction), developer costs (i.e. land acquisition, permitting, legal, etc.), and financing interest during construction. However, these capital costs only include onsite costs up to the point of interconnection.[15]

- Budgetary estimates of unit performance and cost were provided in the IRP. According to the American Association of Cost Engineers (AACE), this is a Class 4 estimate appropriate for a study with an expected accuracy range of Low: -15% to -30%, to High: +20% to +50%. That said, given the modularity and experience building most generation technologies, Siemens believes the cost estimates we provide are closer to Class 3 estimates and within a tighter range of accuracy than AACE defines, i.e. Low: -10% to -20%, to High: +10% to +30%. Siemens uses different ranges for each technology.
- The estimates are for typical units of a class (i.e. Advanced class CT = G, H, J, or HA CT models depending upon the vendor), the unit models presented are typical for the class, and do not necessarily represent the specific models used as a basis for the estimate. Specific units may be chosen during a procurement process when vendors provide both unit performance and cost guarantees.
- Performance (e.g. heat rates) are based on ISO conditions. Only in extreme cases (i.e. high elevations or exceptional temperatures) does Siemens adjust performance estimates to locational specificity, which does not apply in Tennessee, though adjustments are made for local cost conditions.
- Capacity is provided for winter conditions. Winter ratings were adjusted to summer as needed for modeling purposes.
- Provided estimates are "inside-the-fence" estimates and account for all EPC and owners costs, including interest during construction, insurance and taxes. They do not include the cost of fuel, water, or waste pipelines, rail, or transmission upgrades since the exact location of the study plant is unknown. However, a standard cost of interconnection was added to the Portfolios as a function of the number of power plants interconnected, and a cost for fuel transport was also included. These costs are covered in the Transmission Section and the Fuel Section of this report.
- Technology cost and performance estimates are based on a combination of public and private sources which provide a range of potential inputs. No single budgetary estimate source will exactly represent the performance of a given unit when constructed. Vendors will assess site conditions during a procurement process and develop a specific offer which guarantees both performance and cost.
- Vendors operate in a highly competitive market and they continually improve unit performance and cost. As a result, a given turbine model (i.e. F-class) will perform better

[14] Regional capital cost forecasts are developed by applying regional multipliers from the EIA AEO to the Siemens national capital cost forecasts.

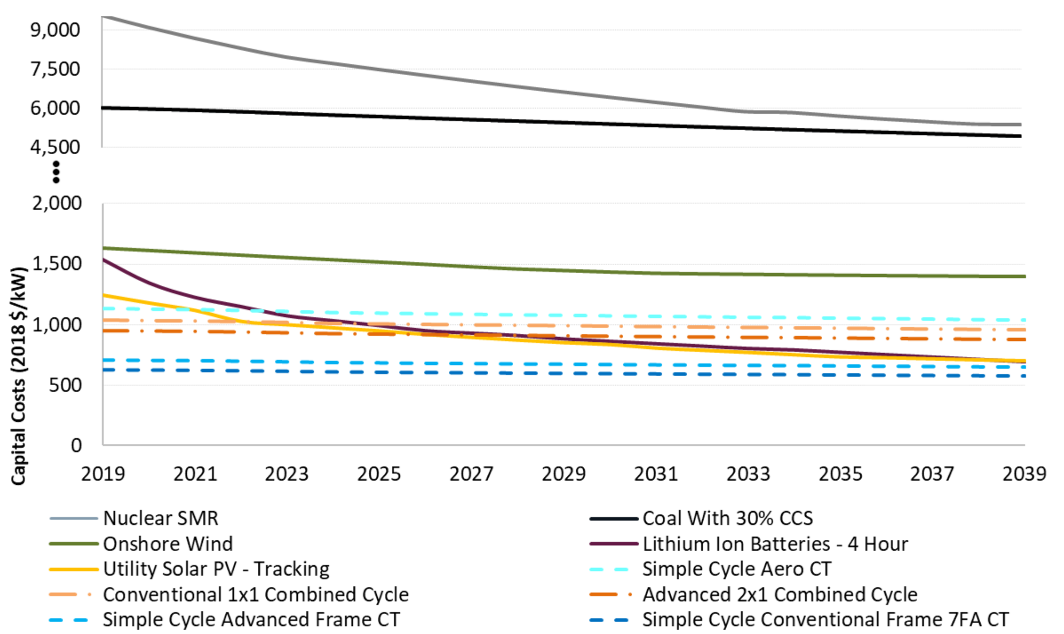
[15] Siemens "all-in" capital costs do not include additional transmission/interconnection costs past the busbar as these costs are highly variable and dependent on project specific details.

two to three years from now than today, while still being termed "F-class." Thus, the studies and tools used to develop the performance and cost estimates may not represent the exact characteristics of a new unit purchased today, though the difference will be small, and the characteristics will remain within the bounds provided. Even vendor websites often lag in presenting their latest performance.

- Even within a given equipment model, customers have choices which influence performance and costs and those choices are not always apparent. They may select wet or dry cooling, add evaporative cooling, require on-site gas compression, or add a range of duct firing capability, for example. This is one key reason Siemens does not use project announcements in establishing technology cost and performance estimates. Announcements typically lack a clearly delineated supply scope and condition definition.

Exhibit 49 depicts Siemens forecasted levelized cost for each of the utility scale technologies to be considered for new development.

Exhibit 49: Siemens New Resource Capital Cost Assumptions by Technology, 2018 $/kW



Source: Siemens

Siemens capital cost forecasts are assumed for the year of development rather than the year of commercial operation; thus, development timelines are considered for building new generation, and interest during construction is included in the estimation.

The new technology cost and performance estimates developed for this project and used to calculate the levelized cost of energy (LCOE) are presented in Exhibit 50. Note that two CCGT and three CT technologies were considered in the long-term capacity expansion plan (LTCE). Siemens applied a weighted average cost of capital (WACC) of 6.16% for developers to finance with the backing of a long term PPA with MLGW is the counterpart, and to be consistent with other utility-financed new builds in the SERC and MISO markets.

Exhibit 50: Siemens New Resource Technology Cost and Financial Assumptions[16]

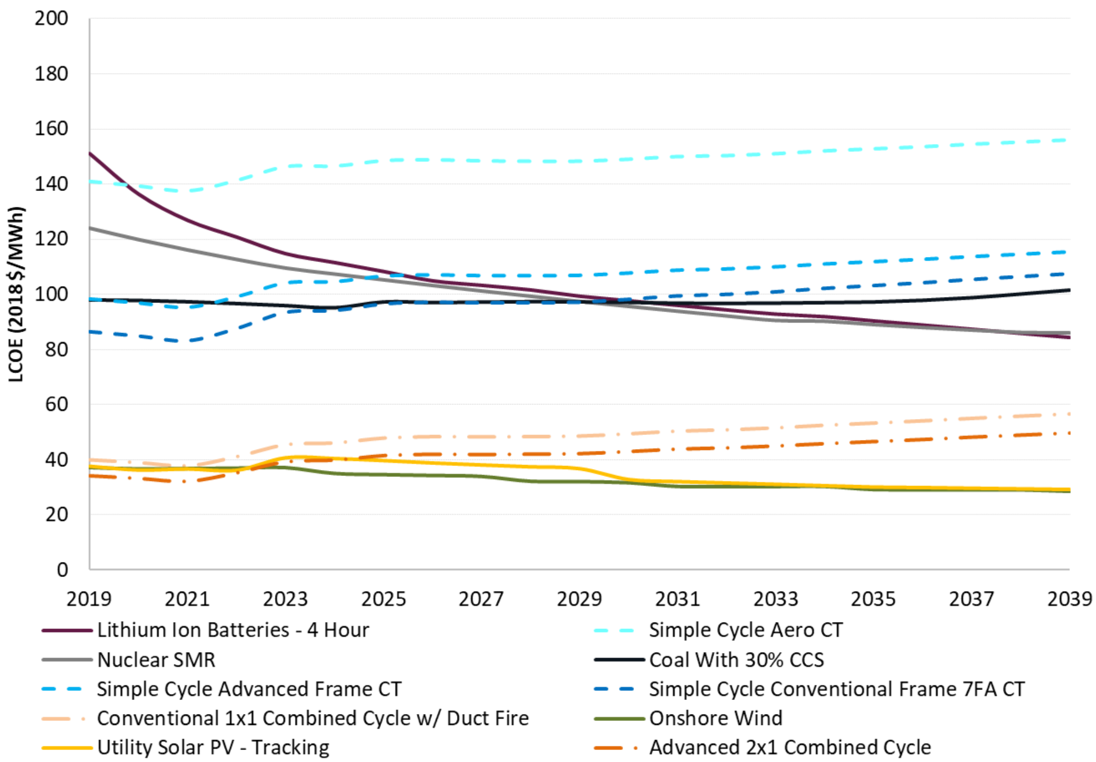
Technology	Advanced 2x1 CCGT	Conventional 1x1 CCGT, Fired	Simple Cycle Advanced Frame CT	Simple Cycle Conventional Frame 7FA CT	Simple Cycle Aero CT	Coal With 30% CCS	Utility Solar PV - Tracking	Onshore Wind	Lithium Ion Batteries (4 hrs.)	Nuclear SMR
Fuel	Nat. Gas.	Nat. Gas.	Nat. Gas.	Nat. Gas.	Nat. Gas.	Coal	Sun	Wind	Elec. Grid	Uranium
Construction Time (Years)	3	3	2	2	2	5	1	2	<1	7
Winter Capacity[17] (MW)	950	450 361 (Base) 89 (DF)	343	237	50	600	50	50	5 MW / 20 MWh	50-1,200
Average Heat Rate (Btu/kWh), HHV	6,536	7,011 (Base) 8,380 (Incr. DF)	8,704	9,928	9,013	9,750	N/A	N/A	N/A	N/A
VOM (2018 $/MWh)	1.81	2.49	7.13	5.05	6.50	7.14	0.00	0.92	1.39	14.79
FOM (2018 $/kW-year)	15.90	17.41	9.53	4.39	15.70	73.45	20.70	36.56	32.21	165.42
Range of Capital Cost (2018 $/kW)	947-874	1084-1003	711-652	626-578	1136-1041	6135-5027	1245-702	1636-1399	1534-693	9539-5365
Range of LCOE (2018 $/MWh)	35-51	42-58	95-112	88-110	140-155	98-101	38-29	37-28	151-84	124-86
Book Life	30	30	30	30	30	40	30	30	15	40
Debt Life	20	20	20	20	20	20	20	20	10	20
MACRS[18] Depreciation Schedule	20	20	15	15	15	20	5	5	7	15
Cost of Equity (Utility/ Merchant)	9.7% / 13.46%	9.7% / 13.46%	9.7% / 13.46%	9.7% / 13.46%	9.7% / 13.46%	9.7% / 13.46%	9.7% / 13.46%	9.7% / 13.46%	9.7% / 13.46%	9.7% / 13.46%
Cost of Debt (Utility / Merchant)	4.37% / 6.46%	4.37% / 6.46%	4.37% / 6.46%	4.37% / 6.46%	4.37% / 6.46%	4.37% / 6.46%	4.37% / 6.46%	4.37% / 6.46%	4.37% / 6.46%	4.37% / 6.46%
Equity Ratio (Utility / Merchant)	45% / 45%	45% / 45%	45% / 45%	45% / 45%	45% / 45%	45% / 45%	45% / 45%	45% / 45%	45% / 45%	45% / 45%
Debt Ratio (Utility / Merchant)	55% / 55%	55% / 55%	55% / 55%	55% / 55%	55% / 55%	55% / 55%	55% / 55%	55% / 55%	55% / 55%	55% / 55%
After Tax WACC[19] (Utility / Merchant)	6.16% / 8.71%	6.16% / 8.71%	6.16% / 8.71%	6.16% / 8.71%	6.16% / 8.71%	6.16% / 8.71%	6.16% / 8.71%	6.16% / 8.71%	6.16% / 8.71%	6.16% / 8.71%

Source: Siemens

[16] The Levelized Cost of Energy (LCOE) is determined by adding the annualized cost of capital + fuel costs + fixed and variable O&M and dividing by the expected energy to be produced in the year.
[17] Winter to summer capacity adjustment ratio is 0.92 for CCGT, 0.91 for SCCT, 0.99 for Coal, and 0.94 for Nuclear.
[18] Modified Accelerated Cost Recovery System (MACRS)
[19] MLGW's new builds are assumed at generic utility's WACC of 6.16%.

Exhibit 51 shows Siemens forecasted levelized cost of energy assumptions for each technology, where we observe that for base load service (energy) the conventional 1x1 CC and renewables (onshore wind and utility solar PV tracking) are the best options. The advanced 2x1 CC has the lowest cost but with a 950 MW capacity represents over 30% of MLGW peak load and would be too large for resource adequacy, unless large investments are made in transmission as is the case of the Portfolio 10 presented later in this report. For peaking service, the best option is the simple cycle conventional frame 7FA CT; however, all peaking options were offered to the model as their ranking also depends on the capacity factor as shown next.

Exhibit 51: Siemens New Resource Levelized Cost of Energy Assumptions by Technology, 2018 $/MWh



Source: Siemens

Siemens notes that the levelized cost of energy determinations for all thermal and storage technologies are highly dependent on capacity factor assumptions, which are outputs of the production cost model scenarios. Thus, the levelized cost of energy forecasts above for these technologies are valid for the expected capacity factors and Exhibit 52 (below) provides the selected capacity factors applied to develop the LCOE presented in Exhibit 51.

Exhibit 52: Assumed Capacity Factors

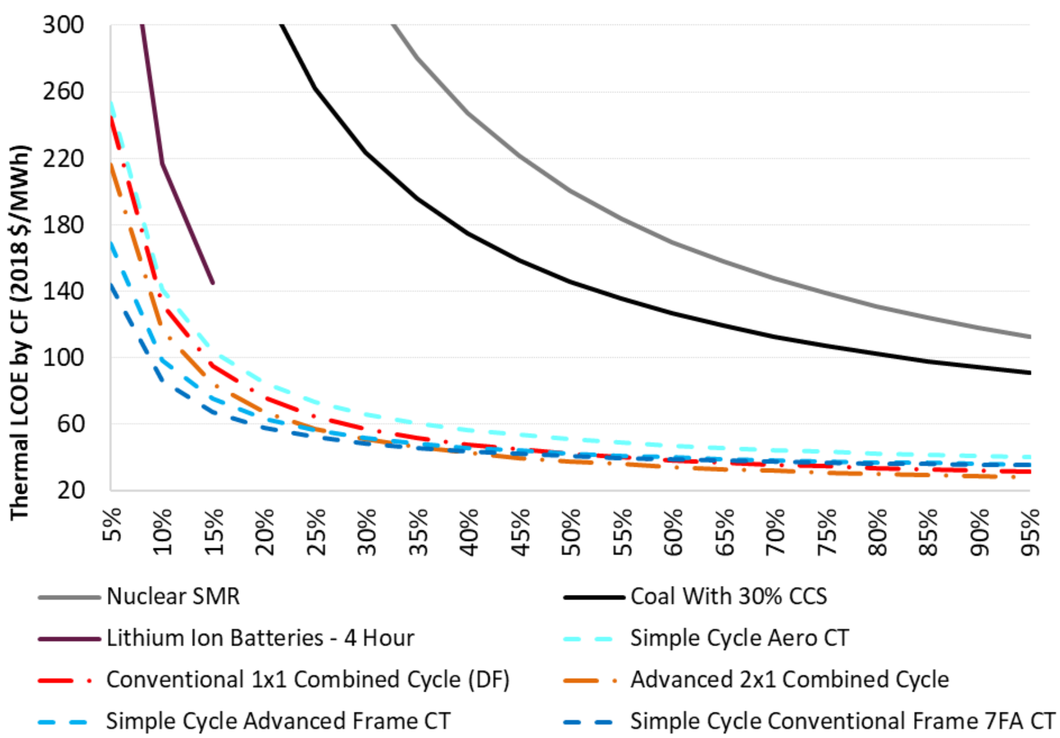
Technology	Advanced 2x1 Combined Cycle	Conventional 1x1 Combined Cycle	Simple Cycle Advanced Frame CT	Simple Cycle Conventional Frame 7FA CT	Simple Cycle Aero CT	Coal With 30% CCS	Utility Solar PV - Tracking	Onshore Wind	Lithium Ion Batteries - 4 Hour	Nuclear SMR
Assumed Capacity Factor (%)	60%	55%	10%	10%	10%	85%	23%	40%	15%	85%

Source: Siemens

Since capacity factors can vary, Siemens calculated the levelized energy cost of each resource type at various capacity factors. Results are presented in Exhibit 53.

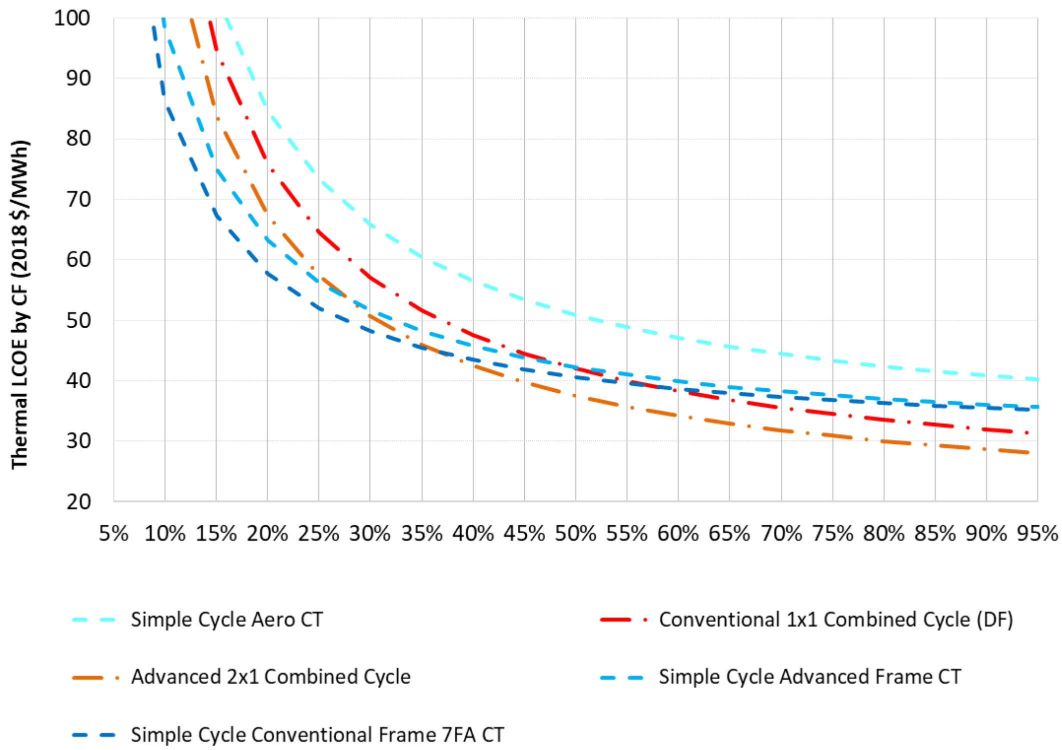
As can be observed in Exhibit 54, which focuses on CTs, for low capacity factors which are expected for peaking services, the simple cycle conventional frame 7FA CT and simple cycle advanced frame CT offer the lowest levelized cost, followed by the CCGT's and the aero CT. For base load services (higher capacity factors), the lowest levelized cost is observed for the advanced 2x1 CCGT, followed closely by the conventional 1x1 CCGT. For storage the capacity factor is determined by the number of cycles expected over the year.

Exhibit 53: Thermal & Storage Technology 2019 LCOE Assumptions by Capacity Factor, 2018 $/MWh



Source: Siemens

Exhibit 54: Thermal Technology 2019 LCOE Assumptions by Capacity Factor, 2018 $/MWh



Source: Siemens

5.2.2 Combined Cycle Gas Turbine

Combined cycle gas turbines (CCGTs) take advantage of the hot gasses leaving gas turbine to generate steam and drive a steam turbine generator. If there is one gas turbine and one steam turbine it is a 1x1, if there are two gas turbines and one steam turbine it is a 2x1 and so on.

CCGTS provide a reliable source of capacity and energy for relatively low plant capital investment. Relatively fast ramp rates and the ability to cycle daily allow CCGTs to integrate with the variable nature of renewable generation.

Advanced CCGTs can achieve operating efficiencies above 62%, compared to conventional generation technologies (including simple cycle CTs) that range from 30 to 44%. Generally, CCGTs are good replacement options for less efficient, higher-emitting fossil fuel resources.

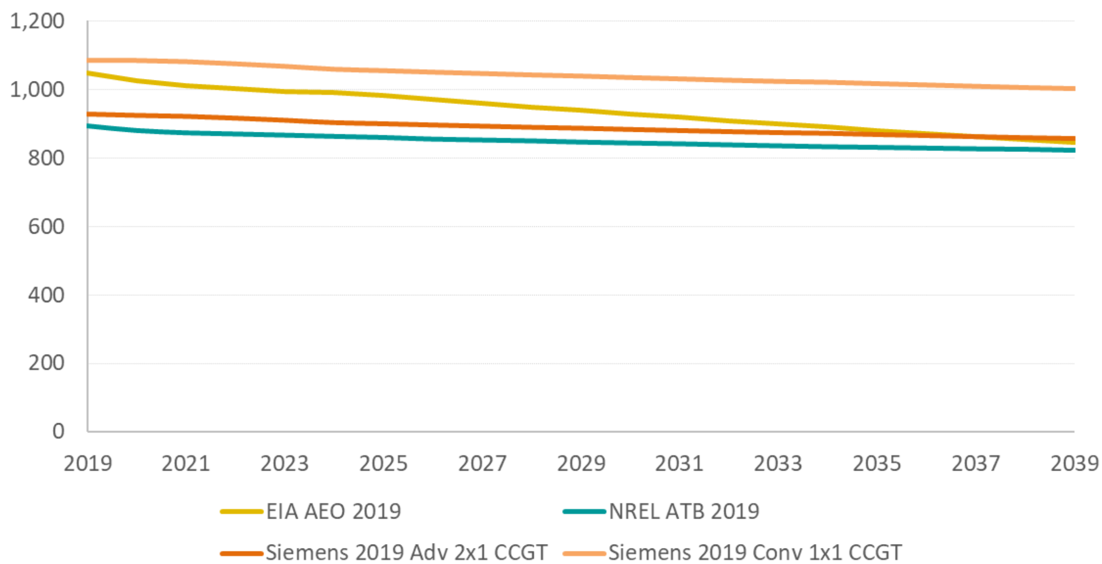
Favorable capital costs, operational flexibility, lower CO_2 emissions, and high plant efficiencies have allowed CCGTs to expand their role in power generation, serving as either baseload or intermediate generators.

Siemens compares our advanced frame 2x1 CCGT and conventional frame 1x1 CCGT capital cost assumptions to both NREL ATB and EIA AEO similar technologies in Exhibit 55.

Advanced CCGTs in a 2x1 configuration (950 MWs) generally offer the lowest cost of generation and in large markets, are often selected for their competitive costs. While these units are large, they represent a small portion of generation in a large market, so the impacts on reliability of a forced outage are manageable. However, the reliability impacts of a forced outage for a unit of this size operating in the comparably small market like MLGW would be infeasible, unless large investments in transmission are made as in Portfolio 10 presented later in this report. MLGW's peak load is expected to reach 3,200 MW and this unit would represent 30% of that peak demand. Further, during high import conditions (e.g. 2,200 MW from MISO), local generation would be 1,000 MW, and the 2x1 CCGT would represent 95% of this requirement making its trip a critical contingency which would force additional generation online. As a result, Siemens considered a smaller 1x1 configuration CCGT.

As discussed earlier in this document, Siemens optimized the 1x1 CCGT initially considered by adding duct firing (i.e. adding burners in the heat recovery steam generator [HRSG] to produce more steam). The duct firing portion increased the unit capacity which supported local reliability at a lower capital cost and better heat rate than a simple cycle gas turbine.

Exhibit 55: Advanced Combined Cycle Capital Cost Forecast, 2018 $/kW



Source: Siemens

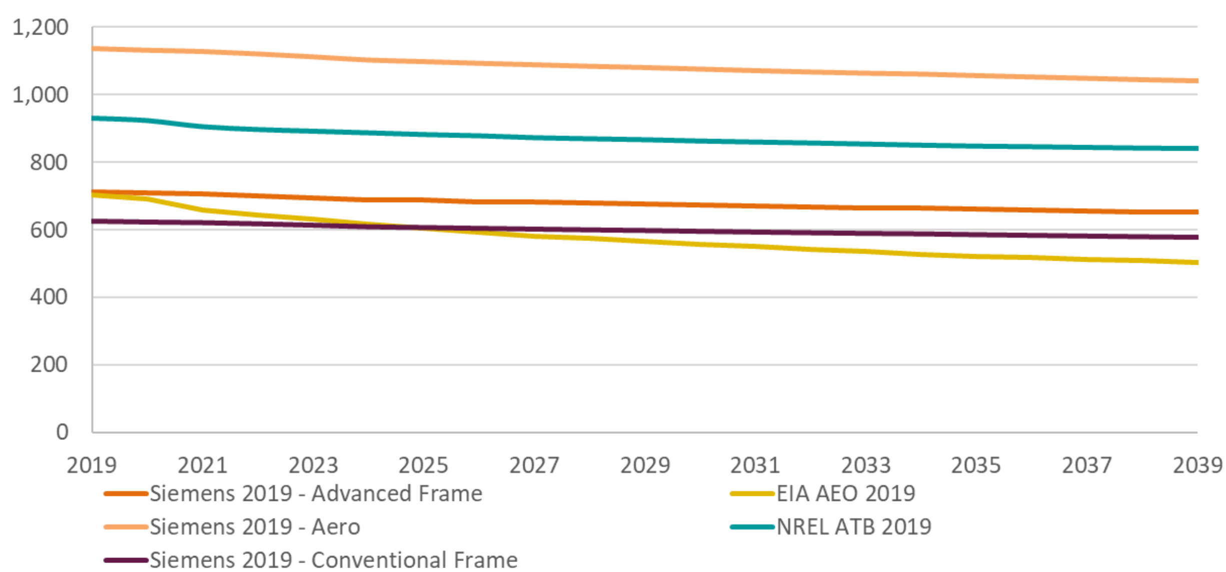
5.2.3 Simple Cycle Combustion Turbine

The high operating costs and low efficiency of CTs (around 40%) typically keep annual capacity factors below 10% and limit CTs primary use to load peaking purposes. However, CTs start and ramp quickly, and play a key role in grid stability, providing reserve capacity and ancillary services. The responsiveness of CTs make them viable candidates to manage intermittent resources such as renewables on a broad scale. Historically, frame CTs were used as peaking resources because of their low operating costs and economies of scale, and aero derivative CTs were also used for peaking service when smaller capacities were a better fit. Newer frame CT models offer higher capacities (300 to 400 MW) and increased efficiency (heat rates of 8,000 to 8,500 Btu/kWh) than earlier models. Aero derivative CTs are available in relatively small capacities with heat rates between 8,000 to 10,500 Btu/kWh, and higher unit costs.

An influx of intermittent energy resources and lower load growth, as well as the need for more flexible resources, has increased interest in aero derivative CT technologies to provide faster ramping capabilities. Newer models provide faster start up, higher ramp rates, and integration with other technologies, particularly battery energy storage.

Siemens compared our simple cycle combustion turbine capital cost assumptions to both NREL ATB and EIA AEO similar technologies in Exhibit 56. It is important to note that NREL does not disclose the size or type (frame vs. aero) for their combustion turbine assumptions in the ATB. For reference, Siemens presents our forecast for conventional frame (7FA technology) and advanced frame below.

Exhibit 56: Simple Cycle CT Capital Cost Forecast, 2018 $/kW



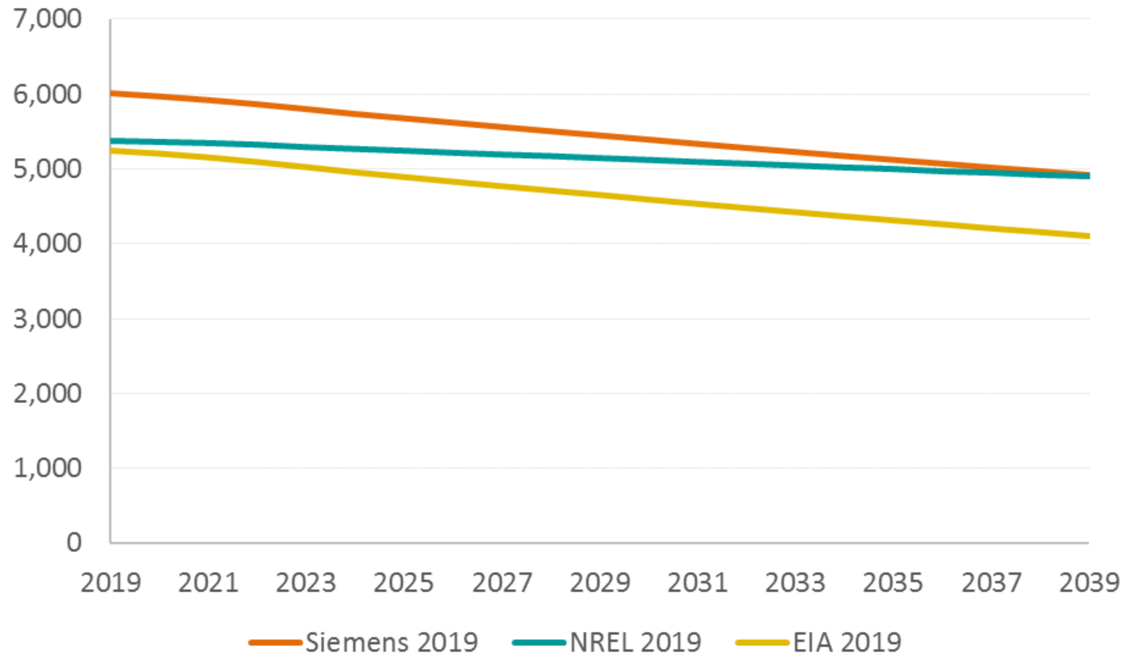
Source: Siemens

5.2.4 (Clean) Coal with CCS

In a conventional coal plant, post-combustion carbon capture and storage (CCS) captures CO_2 from the exhaust gases. Chemical solvents or other filtration separation techniques are used to absorb CO_2 from the exhaust, which is heated to separate the CO_2 for storage. These processes are energy-intensive and expensive to implement. Typically, these facilities are most economic when the CO_2 can be sold to industry for needs such as enhanced oil recovery.

Siemens compared our supercritical coal with carbon capture and storage capital costs to both NREL ATB and EIA AEO similar technologies in Exhibit 57.

Exhibit 57: Supercritical Coal with CCS Capital Cost Forecast, 2018 $/kW



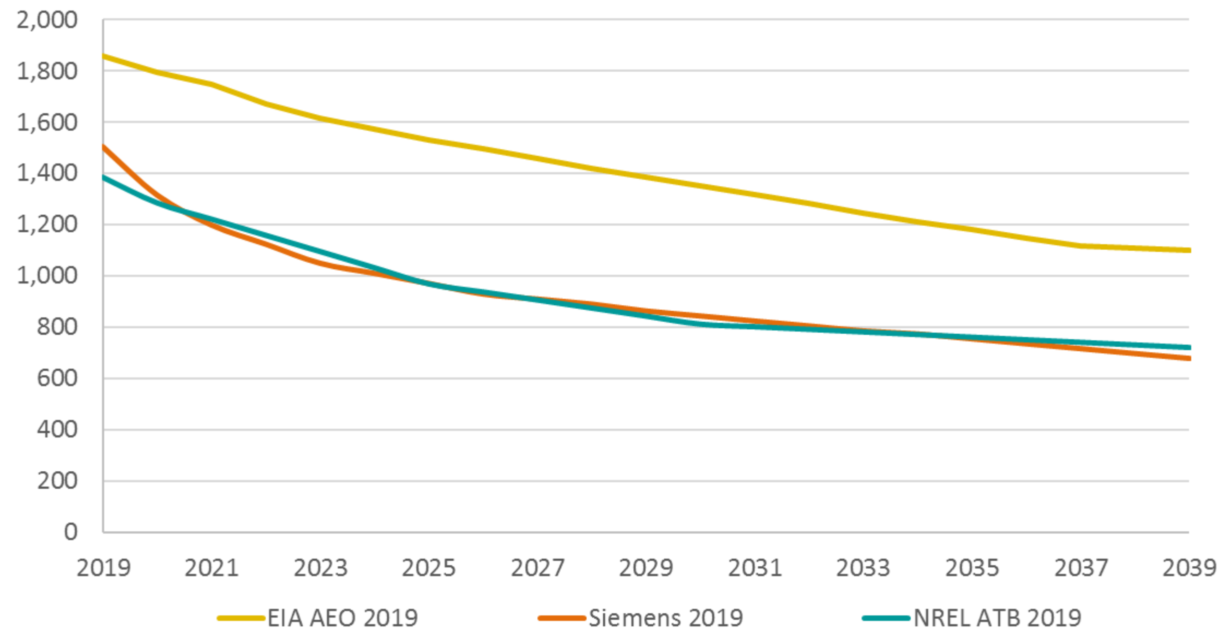
Source: Siemens

5.2.5 Battery Storage

In recent years, battery energy storage has become more important as a utility scale option to integrate non-dispatchable resources onto the energy grid. Lithium-ion (Li-ion) batteries are the most common type of storage used at the utility scale and can target location-specific applications unsuitable to pumped hydro or compressed air energy storage. Li-ion battery costs are rapidly declining as suppliers increase production, making them a popular choice for current energy storage needs. Manufacturing capacity is expected to grow to meet strong energy storage demand from mobile devices, medical devices, and electric vehicles. Li-ion batteries have accounted for 94% of all new energy storage capacity in the U.S. since 2012, growing at an average rate of 55% per year. Most of the installed Li-ion capacity provides frequency regulation, but recent projects in the U.S. have targeted alternative applications including peaking capacity, renewable integration (energy arbitrage), and peak shaving.

Exhibit 58 presents Siemens four-hour duration Li-ion battery capital costs, compared to both NREL ATB and EIA AEO similar technologies.

Exhibit 58: 4-Hour Li-ion Battery Capital Cost Forecast, 2018 $/kW



Source: Siemens

A key challenge of battery storage technology is capacity degradation. With every battery cycle, the ability of the battery to retain charge is diminished and after 10 years, for example, the capacity of a battery storage project may decline from 15% to 20%. For an owner wishing to maintain the capacity of a battery system over time, battery capacity must be replaced (augmented) under the following circumstances: (1) if the particular unit charges or discharges to a level less than its rated energy capacity (kWh) per cycle; (2) if the battery chemistry does not have the cycle-life needed to support the entire operating life of the use case; or (3) if the energy rating (kWh) of the battery chemistry degrades due to usage and can no longer support the intended application.

Siemens expects that MLGW would elect to maintain the capacity of any battery system installed and would need to account for the augmentation costs. Siemens assumed replacement of one third of the battery packs every eighth year, with battery packs comprising approximately 40% of the cost of the total battery system. In total, the replacement battery cost is about 13% of the total battery system cost.

5.2.6 Solar PV

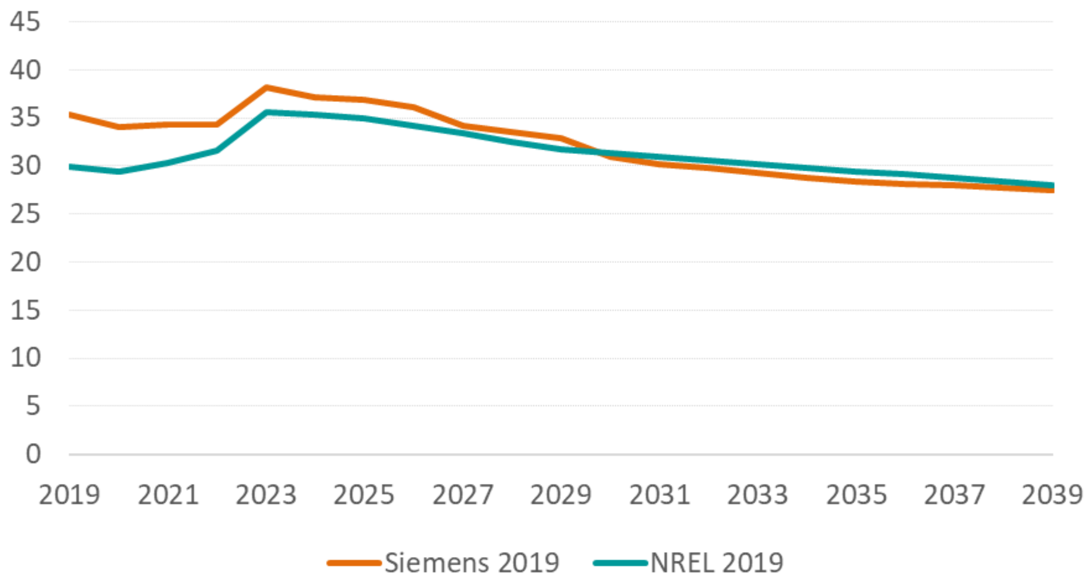
Solar PV generation has been rapidly expanding as a desirable form of renewable generation in recent years, with total U.S. installed capacity reaching 62.5 GW through 2018.[20] Single-axis tracking PV systems offer higher capacity factors and require less land for nearly the same unit cost as fixed-tilt systems. As a result, tracking solar installations now account for more than 50% of utility scale solar PV in the U.S. and are most common in the southwest.

Renewable energy incentives have played a critical role in supporting the development of solar PV, either in the form of renewable portfolio standards (RPS), feed-in tariffs, or tax credits. The investment tax credit (ITC) is set to decline to 10% of capital investment in 2022, remaining available post 2021. Developers can "safe harbor" solar equipment for up to four years to qualify for the ITC, past the deadline.[21]

Siemens single-axis tracking solar technology forecast accounts for the increasing application of bifacial solar cells. While monofacial cells dominate the market today, bifacial cells are expected to comprise most solar cells sold by 2030. While bifacial cells cost slightly more than monofacial cells[22], they can deliver impressive generation gains over monofacial cells, so Siemens forecast accounts for a phasing in of bifacial technology. Exhibit 59 compares Siemens utility scale, single-axis tracking, solar levelized cost of energy assumptions to those of the NREL ATB[23] similar technologies. Note that Siemens applied the same financial assumptions to both the Siemens and the ATB forecast using a utility WACC. The faster reduction in LCOE in Siemens forecast is driven by a combination of reduction of capital costs and the phasing in of bifacial panels that result in higher capacity factors.

[20] SEIA U.S. Solar Market Insight: Q2 2019
[21] Siemens assumes two years of safe harboring in Siemens LCOE calculations.
[22] Bifacial cells have photovoltaic cells on both sides and take advantage of reflection from the ground
[23] NREL forecasts five LCOE scenarios based on different locations in the U.S. The most similar NREL reference case is in Kansas City.

Exhibit 59: Single-Axis Tracking Solar PV Levelized Cost of Energy Forecast, 2018 $/MW



Source: Siemens

Siemens assumptions used to derive our single-axis tracking solar PV levelized cost of energy estimates are shown in Exhibit 60 below.

Exhibit 60: Single-Axis Tracking Solar PV Levelized Cost of Energy Assumptions Table

Year	Siemens Capital Cost (2018$/kW)	Siemens Capital Cost with Land Cost Adjusted (2018$/kW)	NREL Capital Cost (2018$/kW)	Capital Recovery Rate (%)	Siemens Fixed O&M (2018$/kW-yr)	NREL Fixed O&M (2018$/kW-yr)	Siemens Capacity Factor (%)	NREL Capacity Factor (%)	Siemens Variable O&M ($/MWh)	NREL Variable O&M ($/MWh)	Siemens LCOE (2018$/MWh)	NREL LCOE (2018$/MWh)
2019	1,245	1,343	1,096	4%	20	13	23%	22%	0	0	35	30
2020	1,180	1,278	1,076	4%	20	13	23%	22%	0	0	34	29
2021	1,119	1,217	1,054	4%	20	13	23%	22%	0	0	34	30
2022	1,028	1,126	1,032	5%	20	12	23%	22%	0	0	34	32
2023	1,001	1,099	1,010	6%	20	12	23%	22%	0	0	38	36
2024	975	1,073	988	6%	20	12	23%	22%	0	0	37	35
2025	950	1,048	966	6%	20	12	23%	22%	0	0	37	35
2026	921	1,019	945	6%	20	11	23%	22%	0	0	36	34
2027	897	995	923	6%	20	11	24%	22%	0	0	34	33
2028	874	972	901	6%	20	11	24%	22%	0	0	34	33
2029	853	951	879	6%	20	11	24%	22%	0	0	33	32
2030	837	935	869	6%	20	10	25%	22%	0	0	31	31
2031	808	906	860	6%	20	10	25%	22%	0	0	30	31
2032	790	888	850	6%	20	10	25%	22%	0	0	30	31
2033	772	870	840	6%	20	10	25%	22%	0	0	29	30
2034	753	851	830	6%	20	10	25%	22%	0	0	29	30
2035	735	833	821	6%	20	10	25%	22%	0	0	28	29
2036	728	826	811	6%	20	10	25%	22%	0	0	28	29
2037	720	818	801	6%	20	10	25%	22%	0	0	28	29
2038	711	809	791	6%	20	9	25%	22%	0	0	28	28
2039	702	800	782	6%	20	9	25%	22%	0	0	27	28

Source: Siemens

Land Constraints

One of the constraints associated with utility scale solar PV development that should not be ignored is land availability. Siemens worked with MLGW to identify local land available for utility scale PV build in this IRP. The prospective land for solar PV is typically limited to agriculture and/or large commercial and industrial parcels that are generally flat, not prone to flooding, and relatively affordable. Current solar PV technology requires approximately 6.33 acres [24] of land for every MW of PV capacity, i.e. a typical 100 MW PV project would require 633 acres of land. Further, developers try to select sites proximate to existing transmission to minimize interconnection costs. Solar PV development in Shelby County will be hampered by the limited availability of attractive land and the likely need to acquire multiple conjoined parcels for larger capacity plants. Siemens worked with MLGW to identify prospective land on the order of 24,000 acres; this acreage would, in principle, accommodate 3,800 MW of PV if all the land was successfully acquired and met the minimum requirements with respect to flooding, which may not be possible.

Considering all these factors, it was determined that the maximum amount of local utility scale solar PV would be 1,000 MW. This capacity would require about 6,330 acres of land which is equal to about 1.3% of total land of Shelby County or one- and one-half times the size of Shelby Farms Park and implies approximately 25% success in acquiring the identified available land. Siemens is also considering land that is slightly outside of Shelby County if a short gen-tie transmission line is an option, i.e. not all PV must be strictly in Shelby County which lowers the pressures on success in acquiring land within the county.

The cost of land was also reviewed in collaboration with MLGW for solar PV development in the specific region. Considering the limited availability of suitable land, the cost of land in Shelby County is expected to be higher than the national average. Siemens estimated the national average base cost of land assumed in the NREL ATB 2018 data to be $5,000/acre. For the MLGW IRP, a land cost of $17,000/acre was applied with the NREL ATB 2018 capital cost structure data to calculate the local capital cost of solar PV. This analysis resulted in a capital cost about 6.6% higher than the base or $98/kw-ac more than the base in 2018. Siemens added the difference to the Siemens Solar PV capital cost presented above, to be included as a candidate portfolio resource.

5.2.7 Onshore Wind

Wind generation is the second largest source of carbon-free electric generation in the US, accounting for 6.3% of power produced in 2017. Technology improvements coupled with lowered production costs have resulted in rapidly declining capital and operating costs, and improved performance resulting in increased unit energy output. In general, wind turbines are taller with larger wind-swept areas which allows them to produce more energy across a wider range of wind speeds, which drives up average capacity factors. [25] Further, the federal

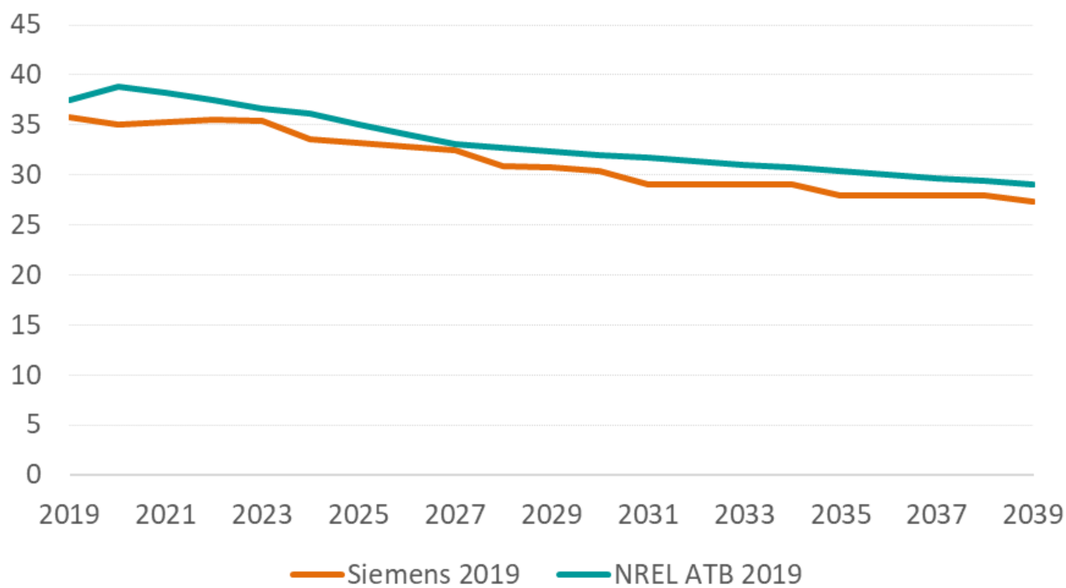
[24] NREL ATB 2018

[25] Siemens assumes MLGW will be able to build or procure wind generation in the SERC reliability corporation/gateway region.

production tax credit (PTC) has significantly lowered recent prices for wind power. However, the PTC is scheduled to phase out by 2020, which could affect near-term affordability for new wind resources. Developers can "safe harbor" wind turbine equipment for up to four years to qualify for the PTC past the deadline.[26]

Siemens compares our onshore wind levelized cost of energy assumptions to NREL ATB[27] similar technologies in Exhibit 61.

Exhibit 61: Onshore Wind Levelized Cost of Energy Forecast, 2018 $/MWh



Source: Siemens

Siemens assumptions applied to derive our onshore wind levelized cost of energy estimates are shown below.

[26] Siemens assumes two years of safe harboring in Siemens LCOE calculations.
[27] NREL forecasts ten Techno-Resource Groups (TRGs) to categorize types of wind projects across the US. The most similar NREL reference case for MLGW is TRG 6 due to wind speed ranges.

Exhibit 62: Onshore Wind Levelized Cost of Energy Assumptions Table

Year	Siemens Capital Cost (2018$/kW)	NREL Capital Cost (2018$/kW)	Capital Recovery Rate (%)	Siemens Fixed O&M (2018$/kW-yr)	NREL Fixed O&M (2018$/kW-yr)	Siemens Capacity Factor (%)	NREL Capacity Factor (%)	Siemens Variable O&M ($/MWh)	NREL Variable O&M ($/MWh)	Siemens LCOE (2018$/MWh)	NREL LCOE (2018$/MWh)
2019	1,636	1,502	5%	37	44	40%	38%	0.90	0	37	38
2020	1,616	1,474	6%	37	43	44%	38%	0.90	0	36	40
2021	1,596	1,446	6%	37	43	44%	39%	0.90	0	36	39
2022	1,576	1,418	6%	37	43	44%	39%	0.90	0	36	38
2023	1,557	1,390	6%	37	42	44%	40%	0.90	0	36	37
2024	1,538	1,362	6%	37	42	46%	40%	0.90	0	34	37
2025	1,519	1,334	6%	37	42	47%	41%	0.90	0	34	36
2026	1,500	1,306	6%	37	41	47%	41%	0.90	0	34	35
2027	1,479	1,278	6%	37	41	47%	42%	0.90	0	33	34
2028	1,461	1,266	6%	37	40	49%	42%	0.90	0	31	33
2029	1,448	1,255	6%	37	40	49%	42%	0.90	0	31	33
2030	1,436	1,244	6%	37	40	49%	42%	0.90	0	31	33
2031	1,425	1,232	6%	37	39	51%	42%	0.90	0	30	32
2032	1,421	1,221	6%	37	39	51%	42%	0.90	0	30	32
2033	1,417	1,209	6%	37	39	51%	42%	0.90	0	30	32
2034	1,413	1,198	6%	37	39	51%	42%	0.90	0	30	31
2035	1,409	1,186	6%	37	38	52%	42%	0.90	0	29	31
2036	1,406	1,174	6%	37	38	52%	42%	0.90	0	28	31
2037	1,403	1,162	6%	37	38	52%	42%	0.90	0	28	30
2038	1,401	1,150	6%	37	37	52%	42%	0.90	0	28	30
2039	1,399	1,138	6%	37	37	53%	42%	0.90	0	28	30

Source: Siemens

5.2.8 Small Modular Reactor

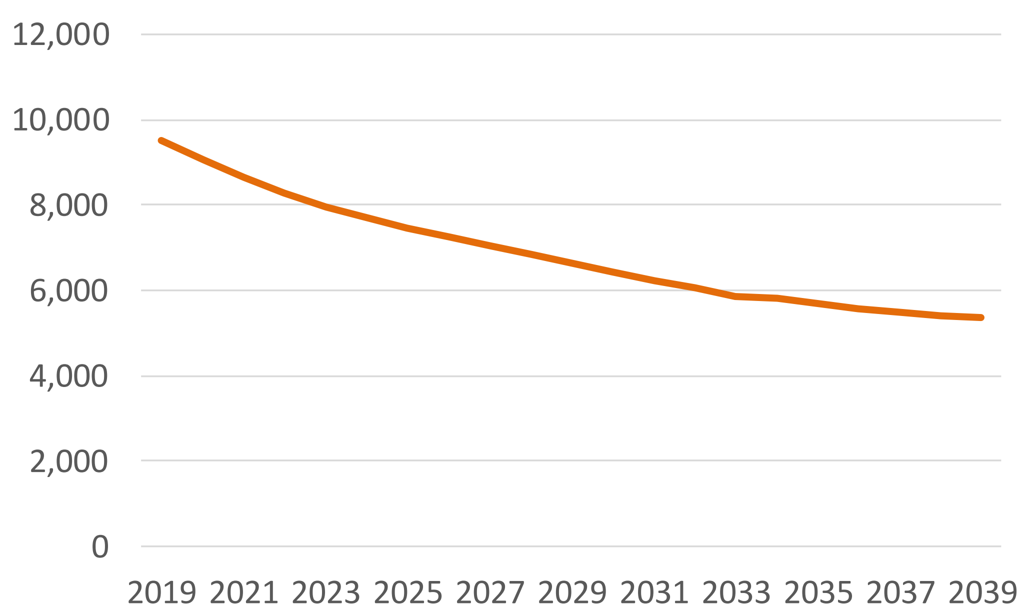
Small modular reactor (SMR) technology was initially developed for naval/shipping purposes and is being adapted for utility scale generation; however, it has not yet demonstrated commercial viability in the US. SMR modules range in size from 10 to 300 MW (compared to roughly 900 to 1,200 MW for conventional nuclear reactors), and modules can be scaled to meet loads. Some SMRs, by virtue of their smaller size and other operational features, can offer greater capability to conduct load following operations than larger nuclear power plants. SMRs have appeal as potential future carbon-free resources to complement renewable resources.

Much of the key equipment for SMRs can be manufactured off-site in controlled factory environments, reducing plant construction time by an expected 40% or more. They also provide potential improvements in safety from their underground containment designs and passive cooling systems. However, underground installations could make maintenance more challenging during a malfunction.

NuScale Power LLC is aiming to put an SMR into commercial operation in Utah, comprised of a dozen 50 MW reactors. It is the only company with an SMR design certification pending before the U.S. Nuclear Regulatory Commission (NRC). The NRC is also reviewing two SMR pre-applications from BWXT mPower, Inc. and SMR Inventec, LLC.

As shown in Exhibit 63, the expected capital costs of the SMRs put them at disadvantage relative to other base load technologies on a unit cost basis.

Exhibit 63: Small Modular Reactor (SMR), All-In Capital Cost, 2018 $/kW



Source: Siemens

5.2.9 River Flow Hydro

There are two forms of hydro generation which employ the energy from flowing river water to generate electricity, and neither are currently appropriate for the Mississippi river.

A traditional run-of-river hydro system diverts running water from a flowing river to turn a turbine, which drives a generator after which the water is returned to the river. Unlike traditional hydro systems, run-of-river systems do not dam the river to create a large reservoir. However, most will use a small dam, also known as a weir, to ensure sufficient water and use a small reservoir to store water for same-day-use only. Since run-of-river systems employ little storage, power generation is limited to and entirely dependent upon water flow. In dry seasons and droughts generation can become unreliable with degraded capacity factors impacting plant economics. These systems are most common in mountainous terrain where there is significant head to add potential energy to the flowing water.

The other option for extracting energy from flowing water is hydrokinetic technologies. These can be thought of essentially as propeller generators anchored to the river floor over which water flows. While there are a few projects in the US, the most notable of which is in the East River, high capital and operating costs have slowed development. A February 2019 FERC study for a 70-kW system in Alaska estimated levelized energy costs could exceed other local options by $322/ MWh with a total system energy cost of $787/MWh[28]. Such high costs are driven by the novelty of the technology, as well as the need to protect the equipment from common river debris (i.e. logs, ice, etc.). Recognizing the potential of this technology, as well as the high current cost, in June 2019 the U.S. Department of Energy Advanced Research Projects Agency (ARPA) released a Request for Information (RFI) seeking industry insight into hydrokinetic technologies[29]. High current costs coupled with a nascent effort from a research agency to understand the technology suggests that economic application of hydrokinetic technologies remains out of reach for the immediate future.

5.2.10 Wet vs. Dry Cooled Condenser Application

Thermoelectric power plants boil water to create steam. Once steam has passed through a turbine, it must be cooled back into water before it can be reused to produce more electricity. Colder water cools the steam more effectively and allows more efficient electricity generation. Since wet-recirculating systems are generally more efficient and less expensive than dry cooling systems, they have been the traditional choice for cooling steam. These systems use cooling towers to expose hot water to ambient air to reduce the water temperature, with water loss resulting from evaporation.

Dry cooling systems use air instead of water to cool the steam exiting the turbine thereby reducing plant water use substantially. While air-cooled systems cost more than wet systems and reduce plant efficiencies to a greater degree, they can be preferred where water is in short supply, expensive, or regulated in such a manner to incentivize minimizing its use. Siemens analysis indicates that plant capital costs are 2.8% higher, heat rates are 1.93% higher, and capacities are lower by 1.88% for 1x1 configuration combined cycle plants with dry cooling.

5.2.11 Load Carrying Capability/Unforced Capacity

The ISOs in general and MISO define the required reserve margin both as a function of the installed capacity (ICAP) and the unforced capacity (UCAP). The use of UCAP is becoming the preferred approach as this can be uniformly correlated with the load carrying capability of renewable resources, i.e. the level of perfectly reliably capacity that, when added to the study, results in the same level of reliability as when the renewable resource is modeled explicitly.

MISO studies indicate that for solar the UCAP changes with the amount of the respective generation in the case[30]. For wind generation there is also a reduction, but it is small and can be considered largely constant. Based on this the table below shows the factors for solar generation and wind generation used in this study to convert ICAP into UCAP, i.e. UCAP = Factor x ICAP.

[28] https://www.ferc.gov/industries/hydropower/enviro/eis/2019/P-13511-003-EA.pdf
[29] https://arpa-e-foa.energy.gov/FileContent.aspx?FileID=e5f68776-98a0-4088-8086-06e8f9de87e5
[30] See Renewable Integration Impact Assessment (RIIA) Assumption Document V-6 December 2018, MISO.

Exhibit 64: Wind Turbine Generation and Solar PV Adjustment Factors for UCAP

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Solar	30%	29%	29%	28%	27%	26%	26%	25%	24%	24%	23%	22%	21%	21%	20%
Wind	15.7%	15.7%	15.7%	15.7%	15.7%	15.7%	15.7%	15.7%	15.7%	15.7%	15.7%	15.7%	15.7%	15.7%	15.7%

Source: Siemens

For thermal generation, the definition is Unforced Capacity (UCAP) = Installed Capacity (ICAP) x (1 – EFOR), where EFOR is the equivalent forced outage rate and is assumed to be 2.5% in this study[31].

To calculate the UCAP for battery storage technology, Siemens researched the EFOR assumptions made by other entities in studies and resource plans. As a relatively new technology, there is little operating history. The research uncovered two sets of assumptions; one assumes an EFOR < 3% with a planned outage rate (POR) < 3%, and the other assumes EFOR + POR = (1- Unit Availability) < 2%. Both assumptions were developed by reputable engineering firms providing estimates for electric utility Integrated Resource Plans. Since the evidence suggests expected EFOR is between 1 and 3%, Siemens selected 2% for this assumption.

5.3 Capacity Price Forecasts

If the market is in balance, capacity prices reflect the additional margins required beyond energy prices to fully compensate for the cost of the marginal unit in an hour (the CONE[32]). If there is excess capacity in the market, capacity prices can clear at a discount to CONE. If there is a shortage, market prices can greatly exceed CONE. Historically this market has been volatile, though not in the last few years.

In the future, MISO has noted the possibility of capacity shortages and given the historical volatility of prices in a reasonably limited market, this poses a risk to rely heavily on the capacity market in the future despite recent capacity prices. Exhibit 65 shows Siemens forecast of capacity prices. Beginning in the mid-2020s, Siemens forecast is close to CONE.

The Forecast shown in Exhibit 65 below was developed by evaluating the availability of Capacity in LRZ-8 and LRZ-10. Over the planning horizon, the market is forecasted to become more in balance, so the capacity price moves towards the Cost of New Entry (CONE).

[31] Slightly higher values were used for the adequacy assessment in agreement with MISO.
[32] CONE = Cost of New Entry, typically a new peaking unit (e.g. CT) less expected energy revenues

Exhibit 65: Siemens Capacity Price Forecast

Year	$/kW-year	$/kW-month
2025	33.5	2.8
2026	34.4	2.9
2027	26.2	2.2
2028	30.7	2.6
2029	27.7	2.3
2030	34.2	2.9
2031	44.1	3.7
2032	46.2	3.9
2033	43.3	3.6
2034	40.2	3.4
2035	45.2	3.8
2036	45.3	3.8
2037	45.2	3.8
2038	45.2	3.8
2039	45.3	3.8

Source: Siemens

6. Fuel Infrastructure Forecast

For the development of the self-supply options, several natural gas thermal units, including combined cycle gas turbines (CCGTs) and combustion turbines (CTs), were offered for the long-term capacity expansion plan. In order to assess each gas-fired resource option, it is necessary to: a) identify to which pipeline(s) the units will interconnect, b) provide a delivered gas forecast, and c) identify where these units are likely to be located so the construction of gas laterals (connections between the plant location and existing pipeline infrastructure) is minimized.

For the location of the potential gas-fired units, it is useful to compare the existing distribution system delivery capacity to the expected gas supply rate of the various units that were considered. An examination of the distribution system is not within scope of this IRP report, but an understanding of fuel requirements is examined in this section. Exhibit 66 below shows the maximum gas consumption rate for each unit type in two common metrics: million British Thermal Units per hour (MMBtu/hr) and thousand cubic feet per hour (Mcf/hr).

Exhibit 66: Gas Consumption by Unit Type

Technology	Advanced 2x1 CCGT	Conventional 1x1 CCGT with Duct-Firing	Simple Cycle Advanced Frame CT	Simple Cycle Conventional Frame 7FA CT	Simple Cycle Aero CT
Fuel	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
Winter Capacity[33] (MW)	950	450 361 (Base) 89 (DF)	343	237	50
Average Heat Rate (Btu/kWh), HHV	6,536	7,011 (Base) 8,380 (Incr. DF)	8,704	9,928	9,013
Gas Consumption MMBtu/hour (100% CF)	6,209	2,531 (Base) 3,277 (w/ DF)	2,985	2,353	451
Gas Consumption Mcf/hour[34] (100% CF)	5,993	2,443 (Base) 3,163 (w/ DF)	2,882	2,271	435

Source: Siemens

For one or more interconnections to a natural gas pipeline, Siemens developed a view of the estimated available capacity on the three pipelines located within the MLGW service territory. This view took into account the physical location of the three natural gas pipelines that cross MLGW's service territory (ANR, Texas Gas, and Trunkline), the number of existing gates for each pipeline, the seasonal pipeline transmission rates during a recent 12 month period on the three pipelines, a monthly ANR transport cost estimate (using 157,000 dekatherms[35] per day (Dth/d)

[33] Winter to summer capacity adjustment ratio is 0.92 for CCGT, 0.91 for SCCT, 0.99 for Coal, and 0.94 for Nuclear.
[34] Using the EIA conversion of 1 thousand cubic feet (Mcf) to 1.036 MMBtu, per https://www.eia.gov/tools/faqs/faq.php?id=45&t=8
[35] 1 Dekatherm = 1 MMBtu ≈ 0.965 Mcf

for 16 hours as inputs), and estimates for a meter station upgrade together with a calculator for ANR's FTS-3 rate, which is the appropriate rate for power generators.

Discussions with pipeline representatives provided information on currently available capacity. For ANR, up to 181,000 Dth/day is available in the winter and up to 340,000 Dth/day is available in the summer; this is expected to be the case in five years but is subject to change. Texas Gas has 67,000 Dth/day available in the winter and 179,800 Dth/day in the summer; this is expected to be the case in five years but is subject to change. Trunkline has available capacity of 157,000 Dth/day in the winter and 430,000 Dth/day in the summer; this is expected to be the case in five years but is subject to change. An additional consideration for a potential gas-fired plant location is that Substation 86 on the MLGW system has access to fuel supply, sufficient land, and available transmission interconnection capacity for siting a CCGT or CT.

To assist in identifying the pipeline(s) to which the potential new gas-fired units could interconnect and the accompanying costs, Exhibit 67 provides the firm transportation service (FTS) tariffs for each of the three pipelines (ANR, Texas Gas, and Trunkline), which are also shown in Exhibit 76 at the end of Section 6. The ANR FTS-3 tariff plus 2-hour notice enhanced service from SE to ML-2 (the Southeast Area to Southeast Southern Segment) assuming 157,000 Dth/d has a unit rate of $0.8055/Dth. Using the same assumptions with Texas Gas tariff rates, we estimate a unit rate of $0.4965/Dth. Similarly, for Trunkline we estimate a unit rate of $0.3811/Dth.

Exhibit 67: Enhanced Firm Transportation Service Rates as of November 2019 ($/Dth)

Pipeline (Zone to Zone)	Tariff	Demand Rate ($/Dth)	Commodity Rate ($/Dth)	ACA Rate ($/Dth)	Equivalent Fuel Rate ($/Dth)	Unit Rate ($/Dth)
ANR (SE to ML-2)	FTS-3 w/ 2hr+balancing	$0.7257	$0.0347	$0.0013	$0.0438	$0.8055
Texas Gas (1-1)	FT+WNS+SNS	$0.4028	$0.0553	$0.0020	$0.0364	$0.4965
Trunkline (Field Zone to 1A)	QNT+FSS	$0.3364	$0.0080	$0.0013	$0.0354	**$0.3811**

Source: Pipeline published tariffs, MLGW, Siemens.

As seen in Exhibit 67, the unit rate of $0.3811/Dth is the least costly rate for enhanced firm transportation service, and therefore is the rate is used in the AURORA model.

Each of these three pipeline tariffs are approximately the same in terms of level of tariff design that is best able to service a power generator. This includes firm transportation service that is enhanced with no-notice service and seasonal storage and balancing services. Firm service is assumed for any combined cycle builds, whereas a simple cycle gas peaking unit would be more likely to incur a lower fuel supply cost, closer to the interruptible transportation service (ITS) tariff, which is shown in

Exhibit 68. Note that while ANR has an ITS-3 schedule, the maximum rate of $1.6266/Dth is much higher than the FTS-3 rate. Siemens confirmed with an ANR representative that capacity

is limited on their Southeast Mainline, so ITS-3 rates would be near to the maximum rate. For this reason, this Southeast Mainline is not included in Exhibit 68, although conditions could change in five years.

Exhibit 68: Interruptible Transportation Service Rates as of November 2019 ($/Dth)

Pipeline (Zone to Zone)	Tariff	Demand Rate ($/Dth)	ACA Rate ($/Dth)	Equivalent Fuel Rate ($/Dth)	Unit Rate ($/Dth)
Texas Gas (1-1)	IT	$0.1593	$0.0013	$0.0213	$0.1819
Trunkline (Field Zone to 1A)	QNIT*	$0.2845	$0.0013	$0.0354	**$0.3212**

*Quick Notice Interruptible Transportation
Source: Pipeline published tariffs, MLGW, Siemens.

As seen in Exhibit 68, the unit rate for interruptible transportation service is $0.3212/Dth for Trunkline, which had the cheapest rate for firm transportation and transportation availability. For consistency, this is the rate used in the AURORA model for interruptible transportation.

The FTS rates range from $0.3811/Dth to $0.8055/Dth. A reasonable assumption for enhanced FTS to CCGTs in MLGW's service territory would be to use the Trunkline rate of $0.3811/Dth, which is the input assumption used in the AURORA model. Trunkline is the pipeline with the most expected available capacity in five years (see Exhibit 69). Similarly, a reasonable assumption for enhanced ITS to gas peaking CTs in MLGW's service territory is to use the $0.3212/Dth rate offered by Trunkline, which is the input assumption used in the AURORA model. In addition, three other regions are being modeled, including Arkansas, Mississippi, and TVA's service territory. Siemens used the same Trunkline FTS and ITS rates for each of these three regions in order to provide internally consistent modeling assumptions for fuel transport rates.[36]

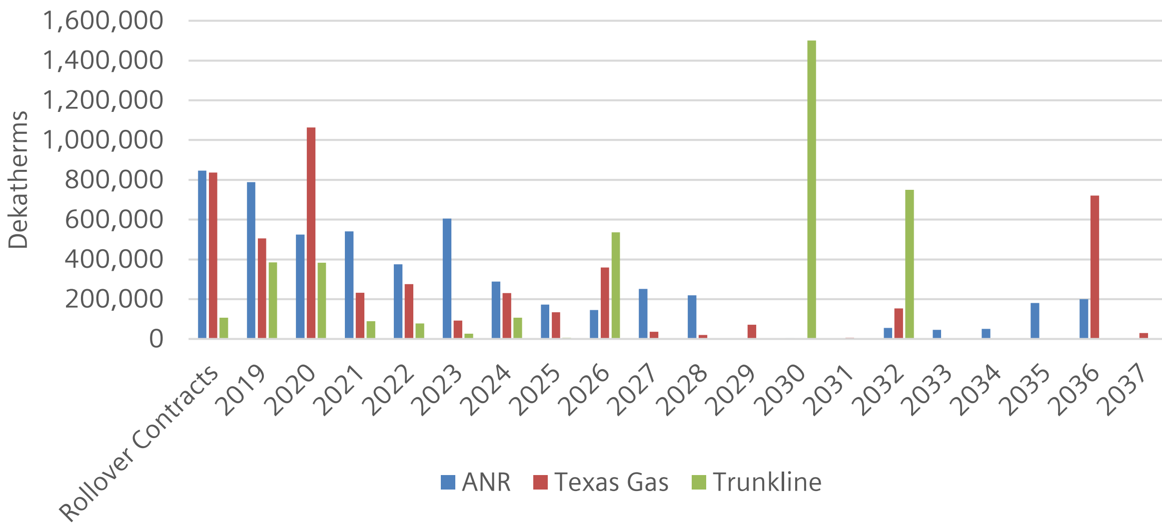
In addition, ANR (with one existing gate in MLGW's service territory) provided an estimate of $10 million for a meter station upgrade or replacement. It is unclear at this time if Trunkline (two existing gates) or Texas Gas (five existing gates) would also need a similar upgrade. Based on the tariff analysis above (and the capacity availability discussion below), any potential new gas-fired generation should be sited near Trunkline or possibly Texas Gas, if negotiated rates are similar to the tariffs shown in the exhibits above. Furthermore, the two gas hubs associated with Trunkline and Texas Gas (Trunkline Z1A and Texas Gas Z1, respectively) are expected to have lower basis (regional market differentials relative to prices at Henry Hub) to Henry Hub than ANR Patterson LA, meaning commodity costs will be lower in addition to lower firm transportation service rates.

As a check on available pipeline capacity, Siemens reviewed contract expirations as reported by S&P Global for 19Q3, as shown in Exhibit 69. ANR shows a steady decline in contract expirations

[36] Note that the lower cost Texas Gas FTS rate including WNS and SNS and Fayetteville Lateral access to provide supply into Arkansas is roughly equivalent to the Trunkline FTS rate.

through the 2020s, but not shown is 2,100,000 Dth of contract expirations post-2044. Texas Gas shows more than 2,000,000 Dth in contract expirations through 2022. Trunkline shows 935,000 Dth in contract expirations through 2022, with an incremental 675,000 Dth from 2023 to 2026 but with several large contract expirations in 2030 (1,500,000 Dth) and 2032 (750,000 Dth). These contract expiration figures represent total contracts and are not specified by pipeline zone, shipper, or delivery points.

Exhibit 69: Pipeline Contract Expirations

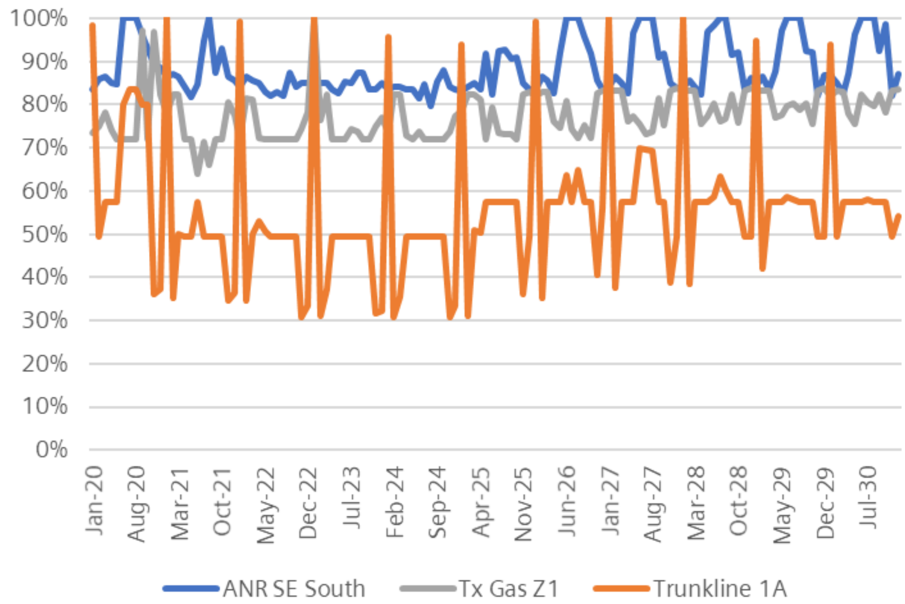


Source: Siemens, S&P Global. Note: Data is from 2019 Q3.

Siemens also reviewed reported daily pipeline deliveries to determine available pipeline capacity. During the winter months of December 2018 through February 2019 when demand was elevated, the average utilization rate on ANR's mainline segment through the adjacent Haywood County, TN (Shelby County was not listed) was 61% or 783,500 Dth/d out of 1,287,000 Dth/d. The average utilization rate on Texas Gas mainline at the Covington compressor station in Tipton County during these same months was 53% flowing north (882,000 Dth/d out of 1,670,000 Dth/d) and 74% flowing south (444,000 Dth/d out of 600,000 Dth/d). Texas Gas also lists a Shelby County Memphis Shipper delivery point with a 58% utilization rate (198,000 Dth/d out of 344,000 Dth/d). Finally, the average utilization rate on Trunkline to MLGW Division flowing north and south was 7% (30,000 Dth/d out of 400,000 Dth/d).

Because we are most interested in available pipeline capacity in 3-5 years, when a new-build CCGT or CT would enter into service, Siemens also reviewed the monthly pipeline capacity utilization factors in its national forecast model through 2030 (modeled using the Gas Pipeline Competition Model [GPCM], a commercial model as licensed by RBAC Inc. and adapted to Siemens' national market fundamentals outlook). The modeled average monthly capacity utilization factors are shown below in Exhibit 70. When looking at monthly utilization factors for the period of January 2020 to December 2030 (n=132 months), the ANR SE South zone shows an average monthly utilization factor at or above 90% in 43 of the months. The Trunkline 1A zone shows an average monthly utilization factor at or above 90% in 11 of the months. And the Texas Gas Z1 zone shows an average monthly utilization factor at or above 90% in only three (3) of the months. This analysis suggests that Trunkline is the pipeline most likely to have available capacity when a potential new CCGT or CT is brought online.

Exhibit 70: Modeled Monthly Average Pipeline Zone Capacity Utilization Factors



Source: Siemens.

6.1 U.S. Natural Gas Market Outlook

The U.S. natural gas market outlook is expected to see low prices at the benchmark Henry Hub market point in the short-term to 2021, despite increasing LNG demand and with higher storage refill requirements coming out of the 2018-19 and 2019-20 winters. Low prices are primarily due to excess production particularly with the ongoing natural gas production, increases out of the Permian Basin and the Marcellus Shale. The main drivers of Henry Hub pricing in the short-term are:

1. The drop in natural gas demand due to shelter-in-place responses to the COVID-19 pandemic, counterbalanced by the decline in associated gas production due to low oil prices stemming from an oversupply in global crude oil markets.

2. LNG export demand, which is expected to grow from 4.5 billion cubic feet per day (Bcf/d) in 2019 to 9-10 Bcf/d by 2021 from online or under construction projects, out of a total LNG export capacity of 10.6 Bcf/d. Furthermore, there were three Gulf Coast LNG projects reaching a go-forward Final Investment Decision in 2019, which are expected to add an additional 4 Bcf/d of LNG export capacity in the early- to mid-2020s, for a total of 14.6 Bcf/d by 2024.

3. U.S. production growth, most of which is coming from the Marcellus Shale and Permian Basin, albeit to a lesser extent in the latter with a decline in oil prices (and thus associated gas production).
4. Over 43 Bcf/d of U.S. pipeline projects under construction or expected to become operational through 2021 (of which 15.5 Bcf/d is Marcellus takeaway capacity and 8.6 Bcf/d is Permian takeaway capacity).

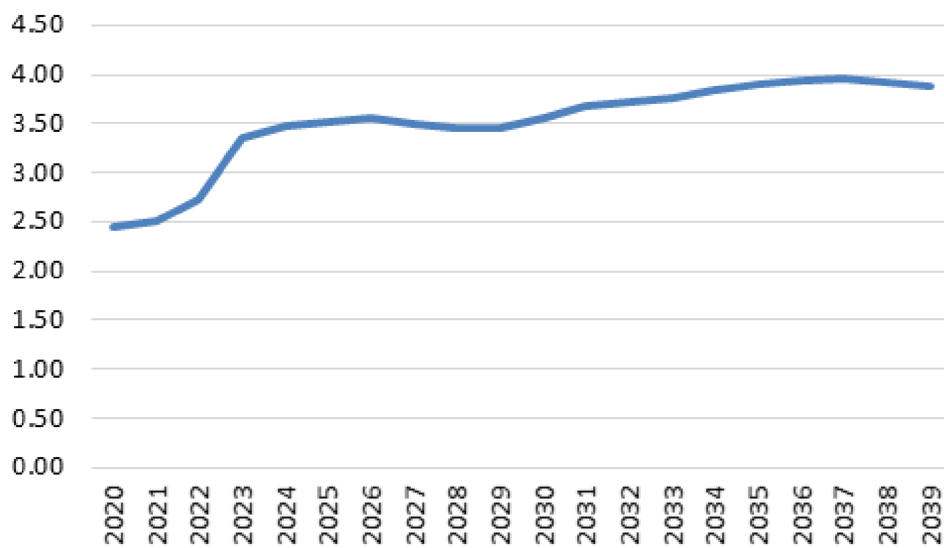
The 14.6 Bcf/d of LNG export capacity expected by 2024 is mostly under "take-or-pay" contracts, meaning demand for LNG feedstock gas will be baseload with liquefaction capacity expected to run at an 85% capacity factor or greater. LNG export demand is expected to put modest upward pressure on prices, despite low Asian LNG prices in early 2020. However, we expect the downward price pressure from supply/production growth and pipelines will largely moderate any such increase in prices.

Generally, a trend has emerged of increased gas usage in the power sector at the expense of coal burn. With natural gas prices still relatively cheap compared to historical levels and coal facing other economic and regulatory pressures, there has been some switching to gas-fired units from coal-fired units in the dispatch order in certain power regions, particularly during shoulder-season months. Utilities in regions where gas transportation costs are relatively low and coal transportation costs are high, for example the SERC region, have announced the shutdown of certain coal units in favor of increasing utilization at intermediate gas units. Annual electricity generation from coal declined 31% in the past decade (2009-2018) from 1,756 TWh to 1,204 TWh, while generation from natural gas increased 43% from 921 TWh to 1,319 TWh, with natural gas surpassing coal beginning in 2016.

Major uncertainties on the demand side include the power sector response to new environmental regulations and rapidly declining renewables costs and battery storage costs that can displace gas-fired generation. While a carbon regime is not likely to advance in the current U.S. government administration, the finalized Affordable Clean Energy (ACE) rule has been promulgated and is expected to lead to heat rate improvements for coal plants >25 MW that will in turn lead to greater dispatch of coal units. Nevertheless, utilities and other generators are beginning to plan for the rising probability of a carbon-constrained future.

On the supply side, shale gas accounted for over 70% of U.S. gas production in 2018, up from 17% in 2008. During this time, unconventional gas production (primarily shale gas) has changed the perception of gas markets and has been the primary driver of Henry Hub pricing, causing prices to drop from the 2008 records that topped $13/MMBtu. The cost of production in 2019 ranges widely, from core Marcellus Shale play acreage able to generate breakeven returns at only $0.80/MMBtu compared to higher-cost conventional or non-core shale that might require prices of $4/MMBtu or more to break even. U.S. gas production is influenced to a relatively substantial degree by oil prices. When oil prices are high, incentivizing producers to drill for oil and natural gas liquids, a significant amount of associated gas can be produced as a by-product. Associated gas now accounts for 20% of total U.S. production, with notable recent growth in associated gas in areas such as the Permian Basin in West Texas. In addition, the nature of drilling in shale plays is that, while initial production can be strong, the production curve declines very rapidly. A sustained or growing level of production requires ongoing drilling programs. This has resulted in U.S. supply becoming more responsive to market conditions, with shale wells acting as virtual storage to adapt quickly to changes in the market. It also means that a decline in oil prices, as occurred in early 2020, can lead to a decline in associated gas production. Producers typically hedge a significant portion of their forward production, but a sustained decline in oil prices will result in less associated gas production growth out of regions such as the Permian Basin. Exhibit 71 shows increasing real prices over time as declining associated gas production is coupled with rising marginal costs of production and extraction.

Exhibit 71: Annual Henry Hub Natural Gas Forecast (2018 $/MMBtu)



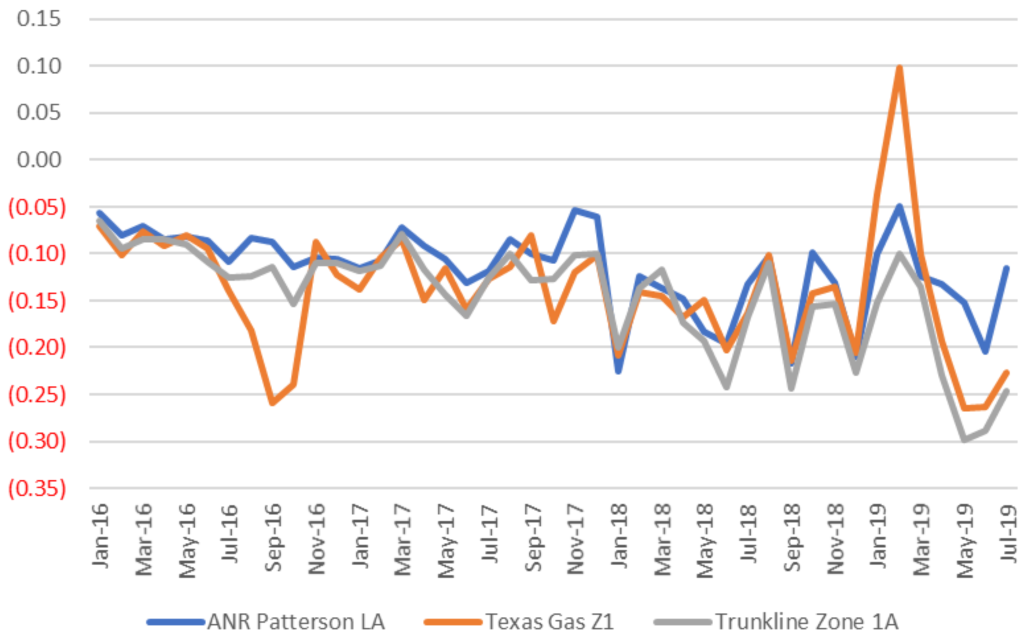
Source: Siemens

The Stochastic sections of this report (Section 11) present Siemens view on possible ranges of future prices under different views of regulations (e.g. fracking), markets (e.g. exports) and technology advance.

6.2 MLGW Regional Outlook

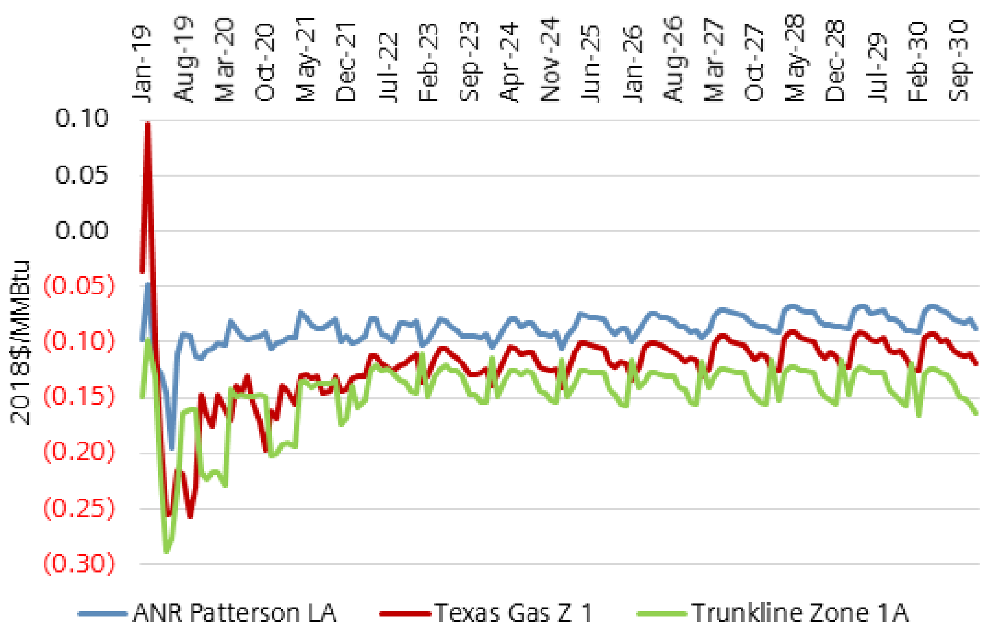
On a regional level, MLGW receives supply via three long-haul natural gas transmission pipelines that cross its service territory: Texas Gas, Trunkline, and ANR. The corresponding natural gas hubs include Texas Gas Zone 1, Trunkline Zone 1A, and ANR Patterson LA. In the past several years, these gas hubs have seen a trend downward in basis to Henry Hub, due to increasing supplies from natural gas production. Each of these pipelines sends supplies northward toward the Marcellus Shale play, a play where production has grown dramatically in the past decade. Accordingly, Marcellus supply is displacing the need for south-to-north supply deliveries, increasing the supply at these gas hubs and driving down basis. Exhibit 69 shows the monthly average historical gas basis (regional market differential) of three key market points relative to benchmark Henry Hub prices. Exhibit 72 shows the monthly forecasted gas basis to the Henry Hub for the next decade.

Exhibit 72: Monthly Average Historical Gas Basis to Henry Hub (Nominal$/MMBtu)



Source: Siemens, S&P Global

Exhibit 73: Monthly Forecast Gas Basis to Henry Hub (2018 $/MMBtu)



Source: Siemens

Exhibit 73 shows historical basis differentials (relative to Henry Hub). Prices are historically lower than Henry Hub. However, as shown in Exhibit 46, over the next decade to 2030, these same three hubs are expected to see a moderation in the basis decline seen during the last few years, with basis climbing up toward between -$0.06/MMBtu and -$0.15/MMBtu. This moderation is expected as most U.S. Gulf Coast LNG export projects come online through 2021, helping to alleviate the downward price and basis pressure from natural gas oversupply. Trunkline Zone 1A is expected to remain the most competitive natural gas pricing point among these three gas hubs (from the point of view of the consumer) and has a relatively low-cost firm transportation rate compared to the other two pipelines. ANR Patterson LA will have the narrowest negative basis (and thus highest price) among the three gas hubs and has a relatively high firm transportation tariff (see prior tariff discussion). Therefore, for the purposes of modeling new CCGTs and CTs, an average of the projected gas basis at the two lowest hubs, Texas Gas Zone 1 and Trunkline Zone 1A, was used.

6.3 Natural Gas Forecast Methodology

The Gas Pipeline Competition Model (GPCM) was used to develop long-term price forecasts by incorporating the fundamental drivers of supply, demand, and infrastructure described in the prior section. In the short-term, natural gas forwards (dated 7/9/19, 7/16/19, and 7/23/19) were averaged and used explicitly for the first 18 months of the forecast, after historical prices. In the subsequent 18 months, the forecast is blended away from forwards toward the fundamental GPCM forecast, after which the forecast is purely fundamentals-based. This provides a view of natural gas prices and basis to Henry Hub delivered to liquid market trading points throughout the United States. The price forecast does not include delivery from the market trading hub to each plant gate, as not all these transportation costs align with the published tariffs nor can it be certain which hub is indexed in each plant's supply contract.

6.4 Other Fuel Price Forecasts

Siemens also developed a crude oil and petroleum products price outlook and a coal price outlook for this analysis. For comparison, coal price forecasts at the mine are presented for the Powder River Basin (PRB), Illinois Basin (ILB) and both Northern (NAPP) and Central (CAPP) Appalachian regions. These forecasts are provided below for reference.

Exhibit 74: WTI, Diesel, and Heavy Fuel Oil Price Outlook

	WTI (Gulf Coast)		Diesel (Gulf Coast)		HFO (Gulf Coast)	
Year	2018 $/bbl	Nom$/bbl	2018 $/gal	Nom$/gal	2018 $/bbl	Nom$/bbl
2020	30.67	32.14	0.98	1.03	20.04	20.98
2021	32.65	35.13	1.04	1.12	22.87	24.61
2022	41.60	45.89	1.31	1.45	34.17	37.71
2023	51.02	57.62	1.61	1.81	46.02	51.99
2024	53.69	62.05	1.69	1.95	49.64	57.37
2025	56.06	66.26	1.76	2.08	52.88	62.50
2026	58.28	70.44	1.83	2.21	55.91	67.58
2027	60.08	74.29	1.88	2.33	58.44	72.26
2028	61.62	77.97	1.93	2.44	60.65	76.75
2029	63.14	81.75	1.98	2.56	62.83	81.34
2030	64.10	84.90	2.01	2.66	64.31	85.17
2031	64.16	86.96	2.01	2.72	64.70	87.68
2032	64.18	89.00	2.01	2.78	65.02	90.17
2033	64.37	91.35	2.01	2.86	65.55	93.03
2034	64.51	93.71	2.02	2.93	66.02	95.90
2035	64.57	95.99	2.02	3.00	66.38	98.68
2036	64.55	98.21	2.02	3.07	66.63	101.38
2037	64.39	100.28	2.01	3.13	66.71	103.89
2038	64.12	102.24	2.00	3.19	66.66	106.28
2039	63.64	103.89	1.99	3.24	66.33	108.29

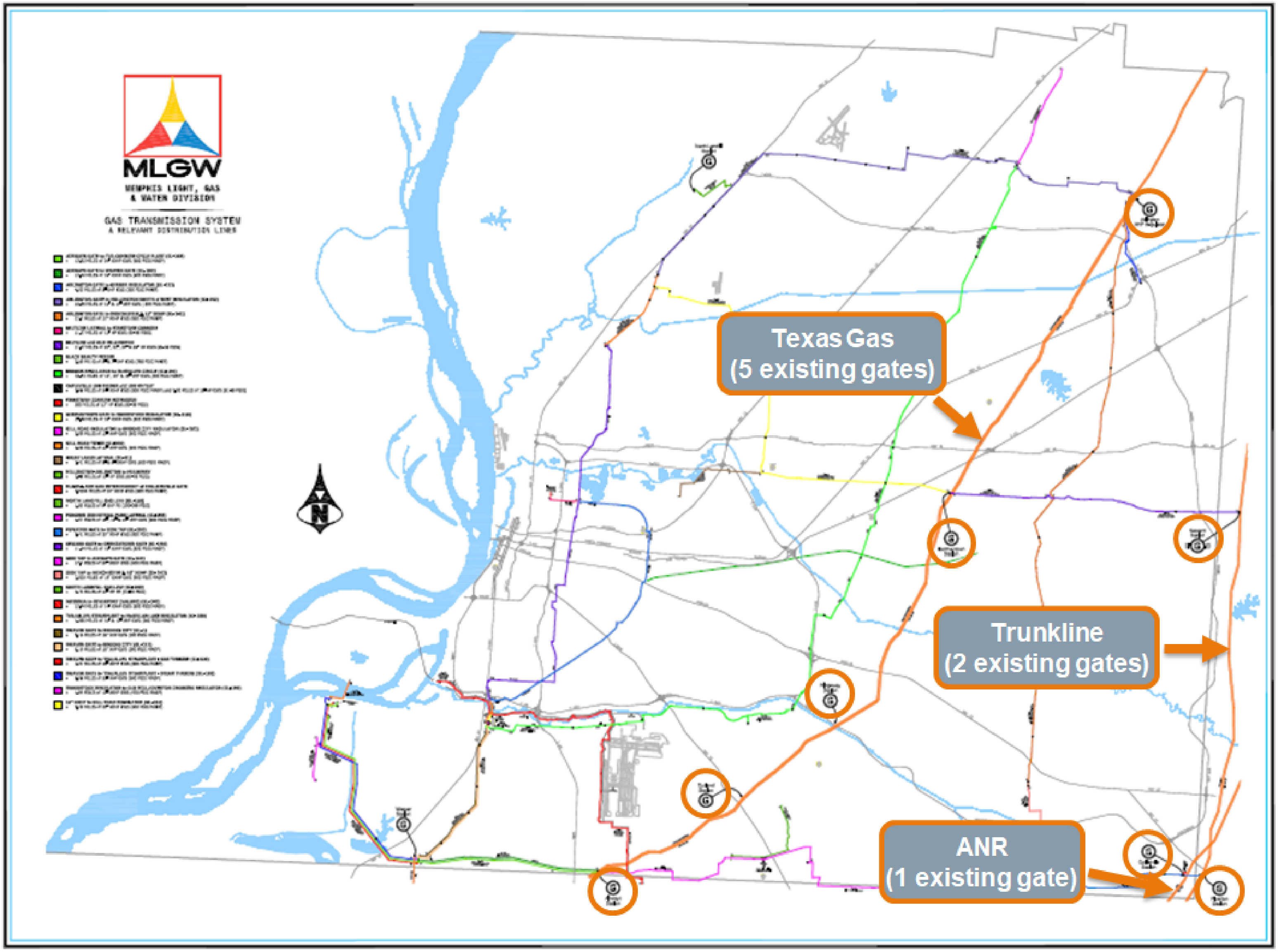
Source: Siemens

Exhibit 75: Coal Price Outlook by Basin in $/MMBTu

	ILB	CAPP	NAPP	PRB
Year	Reference	Reference	Reference	Reference
2020	1.60	2.61	1.93	0.68
2021	1.58	2.53	1.90	0.69
2022	1.50	2.47	1.84	0.69
2023	1.42	2.40	1.77	0.70
2024	1.35	2.34	1.71	0.70
2025	1.28	2.28	1.64	0.70
2026	1.22	2.22	1.59	0.70
2027	1.15	2.16	1.53	0.71
2028	1.15	2.16	1.54	0.71
2029	1.14	2.16	1.54	0.71
2030	1.13	2.16	1.55	0.72
2031	1.13	2.16	1.55	0.72
2032	1.12	2.16	1.56	0.72
2033	1.11	2.16	1.57	0.72
2034	1.11	2.16	1.57	0.73
2035	1.10	2.16	1.58	0.73
2036	1.09	2.16	1.58	0.73
2037	1.09	2.16	1.59	0.74
2038	1.08	2.16	1.60	0.74
2039	1.07	2.16	1.60	0.74

Source: Siemens

Exhibit 76: Map of Natural Gas Transmission Pipelines and Delivery Points (Gates) Crossing MLGW Service Territory



AIRWAYS GATE to TVA COMBINE CYCLE PLANT (GL-265)
- 12.63 MILES of 24" XXHP CWS (900 PSIG MAOP)

AIRWAYS GATE to WEAVER GATE (GL-193)
- 13.39 MILES of 16" XXHP CWS (900 PSIG MAOP)

ARLINGTON GATE to GERBER REGULATOR (GL-222)
- 4.02 MILES of 8" XHP CWS (300 PSIG MAOP)

ARLINGTON GATE to MILLINGTON SOUTH of RUST REGULATOR (GL-152)
- 19.56 MILES of 12" & 14" XHP CWS (300 PSIG MAOP)

ARLINGTON GATE to WINCHESTER & 12" XXHP (GL-241)
- 21.2 MILES of 12" XXHP CWS (820 PSIG MAOP)

BELTLINE LATERAL to FIRESTONE CORRINE
- 11.27 MILES of 12" HP CWS (61-99 PSIG)

BELTLINE and OLD MILLINGTON
- 11.27 MILES of 20", 22", 24" & 26" HP CWS (61-99 PSIG)

BLACK BEAUTY FEEDER
- 0.56 MILES of 6" & 2" XHP CWS (260 PSIG MAOP)

BROOKS REGULATOR to McMULLEN CIRCLE (GL-194)
- 32.54 MILES of 12", 10" & 16" XHP CWS (300 PSIG MAOP)

CAPLEVILLE LNG FEEDER and **LNG OUTLET**
- 0.65 MILES of 24" XXHP CWS (900 PSIG MAOP) and 0.00 MILES of 12" HP CWS (61-99 PSIG)

FIRESTONE CORRINE EXTENSION
- 000 MILES of 12" HP CWS (61-99 PSIG)

GERMANTOWN GATE to WOODSTOCK REGULATOR (GL-219)
- 15.88 MILES of 18" XXHP CWS (820 PSIG MAOP)

GILL ROAD REGULATOR to BROOKS CITY REGULATOR (GL-262)
- 0.06 MILES of 12" XHP CWS (900 PSIG MAOP)

GILL ROAD TIE-IN (GL-000)
- 0.06 MILES of 12" XHP CWS (900 PSIG MAOP)

GREAT LAKES LATERAL (GL-61)
- 3.41 MILES of 8" & 6" XXHP CWS (820 PSIG MAOP)

MILLINGTON-ARLINGTON to MULBERRY
- 3.55 MILES of 10" HP CWS (61-99 PSIG)

MLGW & ANR GAS INTERCONNECT at COLLIERVILLE GATE
- 0.0294 MILES of 24" XXHP CWS (900 PSIG MAOP)

Source: MLGW

NORTH LANDFILL GAS LINE (GL-150)
- 1.63 MILES of 6" XHP PE (100-399 PSIG)

PIDGEON INDUSTRIAL PARK LATERAL (GL-256)
- 1.57 MILES of 16", 12" & 10" XHP CWS (900 PSIG MAOP)

PIPERTON GATE to SIDE TAP (GL-253)
- 5.41 MILES of 30" XXHP CWS (900 PSIG MAOP)

SEWARD GATE to GERMANTOWN GATE (GL-246)
- 11.54 MILES of 18" XXHP CWS (820 PSIG MAOP)

SIDE TAP to AIRWAYS GATE (GL-244)
- 17.3 MILES of 24" XXHP CWS (900 PSIG MAOP)

SIDE TAP to WINCHESTER & 16" XXHP (GL-242)
- 3.835 MILES of 16" XXHP CWS (900 PSIG MAOP)

SOUTH LANDFILL GAS LINE (GL-000)
- 3.73 MILES of 12" MP PE (31-60 PSIG)

SWINNEA to RIVERPORT (VALERO) (GL-240)
- 12.44 MILES of 14" XXHP CWS (900 PSIG MAOP)

TVA/ALLEN STEAMPLANT to McKELLAR LAKE REGULATOR (GL-250)
- 1.065 MILES of 10" & 12" XHP CWS (260 PSIG MAOP)

WEAVER GATE to BROOKS CITY (GL-1)
- 5.16 MILES of 18" XHP CWS (260 PSIG MAOP)

WEAVER GATE to BROOKS CITY (GL-212)
- 5.16 MILES of 18" XHP CWS (260 PSIG MAOP)

WEAVER GATE to TVA/ALLEN STEAMPLANT - GAS TURBINE (GL-228)
- 7.27 MILES of 16" XXHP CWS (900 PSIG MAOP)

WEAVER GATE to TVA/ALLEN STEAMPLANT - STEAM TURBINE (GL-192)
- 6.95 MILES of 22" XHP CWS (260 PSIG MAOP)

WOODSTOCK REGULATOR to OLD MILL/OVERTON CROSSING REGULATOR (GL-199)
- 1.94 MILES of 12" XXHP CWS (470 PSIG MAOP)

12" XXHP to GILL ROAD REGULATOR (GL-261)
- 0.28 MILES of 00" XXHP CWS (900 PSIG MAOP)

7. Resource Adequacy

7.1 Introduction

If MLGW were to join MISO, it would be subject to MISO's resource adequacy requirements. These requirements have implications on the minimum levels required of local generation and the total generation capacity owned or contracted by MLGW to provide the necessary reserves to cover its load with adequate reliability. These requirements also affect the capacity of the transmission interconnections to MISO, and whether MLGW would join MISO as a separate Local Resource Zone (LRZ) or part of an existing zone (LRZ – f8). In this section we cover these aspects in detail and make recommendations with respect to these issues.

MISO, as the rest of the ISOs and utilities in the US, defines its resource adequacy (i.e. the minimum amounts of generation capacity to cover its load) in terms of the necessary generation capacity for making sure that the Loss of Load Expectation (LOLE) is at maximum 1 in 10 years; that is, only once every 10 years there would be insufficient resources to meet load, due to a combination generation or transmission outages.

Power systems in the U.S. have been planned to use this resource adequacy criterion for decades, which has provided adequate reliability for the grid. The criterion is mandate by the North American Reliability Council (NERC)

MISO assesses the adequacy of the resources of its members in terms of a MISO-wide Planning Reserve Margin (MISO PRM) requirement and a Local Clearing Requirement (LCR).

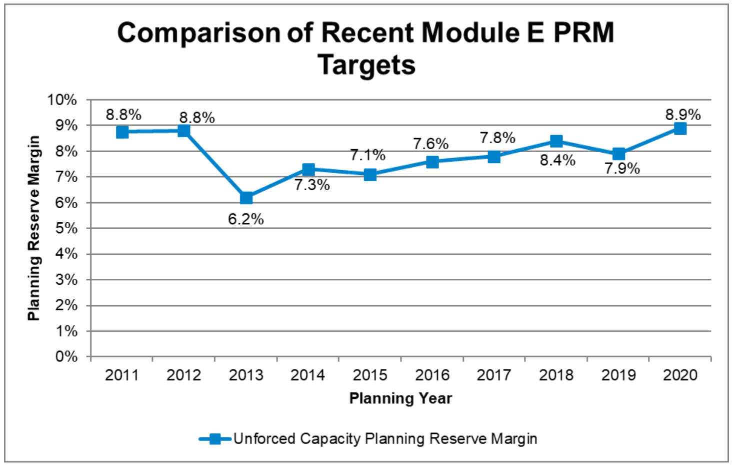
MISO's PRM is expressed both in terms of installed generation capacity (ICAP) and more commonly, the unforced generation capacity (UCAP), which is the installed capacity affected by the forced unavailability of the conventional units. Renewable generation is modeled both for ICAP and UCAP reserve calculations in terms of its load carrying capability as expressed as a percentage of the nameplate capacity. Load carrying capability is the effective capacity of the renewable resource that can be depended upon to be there to supply the peak load.

According to the latest MISO Resource Adequacy Study[37] MISO's PRM is 8.9%. Exhibit 77 shows MISO's calculations leading to this PRM, the historical PRM, and the projections to 2029. We note that at 8.9% the PRM is at the highest value since 2011. This means that the installed generation once de-rated by its unavailability needs to exceed the peak load by 8.9%.

[37] Planning Year 2019-2020 Loss of Load Expectation Study Report Loss of Load Expectation Working Group (MISO)

Exhibit 77: MISO PRM Calculation

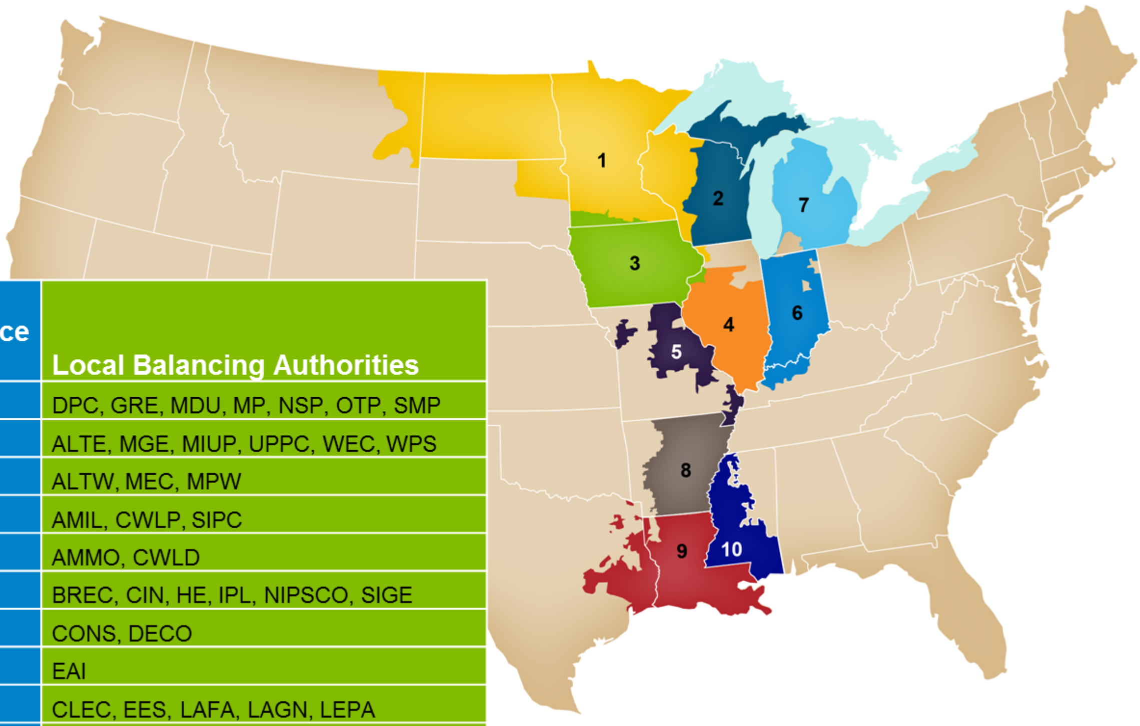
MISO Planning Reserve Margin (PRM)	2020/2021 PY (June 2020 - May 2021)	2023/2024 PY (June 2023 - May 2024)	2025/2026 PY (June 2025 - May 2026)	Formula Key
MISO System Peak Demand (MW)	124,625	125,308	125,600	[A]
Installed Capacity (ICAP) (MW)	156,426	160,125	161,228	[B]
Unforced Capacity (UCAP) (MW)	144,456	148,152	148,922	[C]
Firm External Support (ICAP) (MW)	1,626	1,626	1,626	[D]
Firm External Support (UCAP) (MW)	1,572	1,572	1,572	[E]
Adjustment to ICAP {1d in 10yr} (MW)	-7,950	-11,000	-11,360	[F]
Adjustment to UCAP {1d in 10yr} (MW)	-7,950	-11,000	-11,360	[G]
Non-Firm External Support (ICAP) (MW)	2,987	2,987	2,987	[H]
Non-Firm External Support (UCAP) (MW)	2,331	2,331	2,331	[I]
ICAP PRM Requirement (PRMR) (MW)	147,115	147,764	148,507	[J]=[B]+[D]+[F]-[H]
UCAP PRM Requirement (PRMR) (MW)	135,747	136,393	136,804	[K]=[C]+[E]+[G]-[I]
MISO PRM ICAP	**18.00%**	17.90%	18.20%	[L]=([J]-[A])/[A]
MISO PRM UCAP	**8.90%**	**8.80%**	**8.90%**	[M]=([K]-[A])/[A]



Metric	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
ICAP (GW)	158.1	161.4	161.6	161.8	161.8	162.9	162.9	162.9	162.9	162.9
Demand (GW)	124.6	124.8	125.1	125.3	125.3	125.6	125.8	126	126.2	126.5
PRM $_{ICAP}$	**18.00%**	**18.00%**	**17.90%**	**17.90%**	**18.20%**	**18.20%**	**18.10%**	**18.20%**	**18.20%**	**18.30%**
PRM $_{UCAP}$	**8.90%**	**8.90%**	**8.80%**	**8.80%**	**8.80%**	**8.90%**	**8.90%**	**8.90%**	**8.90%**	**8.90%**

*The non-pseudo tied exports were not available at this time and were omitted. However, these values would only reduce the LCR.
Source: MISO

Exhibit 78: MISO Local Resource Zones (LRZs)



Local Resource Zone	Local Balancing Authorities
1	DPC, GRE, MDU, MP, NSP, OTP, SMP
2	ALTE, MGE, MIUP, UPPC, WEC, WPS
3	ALTW, MEC, MPW
4	AMIL, CWLP, SIPC
5	AMMO, CWLD
6	BREC, CIN, HE, IPL, NIPSCO, SIGE
7	CONS, DECO
8	EAI
9	CLEC, EES, LAFA, LAGN, LEPA
10	EMBA, SME

Source: MISO

To account for its size, MISO is subdivided into ten Local Resource Zones (LRZ), which are geographically large areas with substantial internal load and adequate internal transmission (see Exhibit 78) to be a coherent zone. Resource adequacy for each LRZ is assessed in a two phase process; first the LRZ Local Reliability Requirement is determined, which is the internal generation that would be necessary for the LRZ to meet the 1/10 year requirement, if it were isolated (electric island) without any interconnections, and second this value is corrected to account for the interconnections with the rest of MISO (i.e. ZIL, the adjusted Capacity Import Limit CIL[38]) and direct tied exports, producing the LCR of the zone. This last value is fundamental as it represents the minimum amount of capacity internal to each LRZ to ensure that the LOLE of 1/10 is met at the local level.

The above means that each zone must have enough capacity (designated or purchased via the Planning Resource Auction) to comply with the larger of the MISO PRM (8.9%) or its own LCR.

In general, for all LRZs the MISO-wide planning reserve margin is more stringent than the LCR, i.e. the UCAP required to meet the MISO PRM is the highest. However, for MLGW, the situation can be different and therefore the LCR must be assessed. This is discussed in the next section.

[38] The ZIL is equivalent to the Capacity Import Limit (CIL) except that the former makes adjustments for exports to non-MISO load.

7.2 MLGW Resource Adequacy

7.2.1 Overview

If MLGW were to join MISO, given its geographical location and the planned interconnections, it could become part of the Local Resource Zone 8 (LRZ- 8) that covers the state of Arkansas. Another option would be LRZ-10 (Mississippi), but the interconnection to that zone is weaker and LRZ-10 has about 50% of the resources currently in service in LRZ-8

If MLGW were to become part of LRZ- 8, it is expected that it would only need to meet the MISO-wide PRM with the combination of local resources within MLGW territory and acquired external resources (MISO Capacity). The reason for this is that LRZ-8's internal capacity (UCAP) is larger than the zone's LCR, and MLGW joining LRZ-8 is expected to improve this situation as presented below.

7.2.2 MLGW Resource Adequacy as an Independent LRZ

To assess the resource adequacy of the generation portfolios developed in this IRP, Siemens worked with MISO to ensure reasonableness of the assumptions and procedures; the results below are a direct result of this collaboration with MISO.[39]

The first step in the process to assess the resource adequacy is to estimate MLGW's Local Reliability Requirement (LRR) and the changes, if any, that the addition of MLGW to MISO would introduce in the MISO-wide PRM.

Following MISO's procedures, the MLGW hourly load profile was added to the MISO system and it was observed that there is important diversity across the hours of the day both during summer peak and across the months of the year. MLGW's summer load peaks much earlier than MISO's summer load and LRZ-8's summer load (3:00 pm vs. 5:30 pm), and MLGW's winter peak load is much lower than the summer peak load as compared with LRZ-8 and MISO's load.

To assess the impact of MLGW on MISO, Portfolio 2 (see Section 11) was modeled under its 2026 conditions, i.e. when the initial phase of development is complete and there are 3 combined cycle units (CCGTs), 1 combustion turbine, and 1000 MW of solar capacity directly connected to MLGW's system. The main parameters for this generation are shown in Exhibit 79.

Exhibit 79: MLGW Generation Modeled

	Convl. Frame 7FA CT			1x1 Combined Cycle (450 MW)			Utility Solar	Total
	# Units	Per unit	Total	# Units	Per unit	Total		
Installed	1	237	237	3	450	1350	1000	2587
Summer ICAP	1	216	216	3	414	1242	300	1758
Summer UCAP	1	206	206	3	390	1171	300	1677
EFOR		4.65%	4.65%		5.70%	5.70%	--	

Source: Siemens

[39] The central resource adequacy calculations were carried out by Astrape Consulting at the direction of MISO.

Note that the selection of a portfolio with 3 CCGTs is conservative and it would lead to a slightly higher Local Reliability Requirement (LRR) than Portfolios with less generation. This can be verified considering that the procedure for the estimation of the LRR adds (or subtracts if the actual reliability is better) 100% dependable generation *until the 1/10 Loss of Load Equivalent (LOLE) is met*. Thus, the higher the amount of actual generation in the system the less the need for corrections (with "perfect" units). This was confirmed on a sensitivity where 3 combined cycle units were reduced to 2 with a net reduction on the UCAP of 390 MW and the required increase in the number of perfect units was slightly less 377 MW, resulting in a slightly lower LRR. Thus, maintaining the same LRR for lower amounts of installed generation is conservative.

The exhibit below shows the effects of integrating MLGW into the MISO market. It can be observed the net effect is a slight reduction of the MISO's PRM from 8.9% to 8.8%. Note that while there was a reduction in the required adjustment to meet the 1/10 LOLE (line [F]) this is less than the increase on the peak demand (line [A]) which is in the denominator of the calculation (line [L]).

Exhibit 80: Assessment of the Effect on MISO's PRM Due to Integration of MLGW

MISO Planning Reserve Margin (PRM)	MISO (Pre- MLGW) (June 2025 - May 2026)	MLGW (June 2025 - May 2026)	MISO (Post- MLGW) (June 2025 - May 2026)	Formula Key
System Peak Demand (MW)	125,600	3,197	128,505	[A]
Installed Capacity (ICAP) (MW)	161,228	1,758	162,986	[B]
Unforced Capacity (UCAP) (MW)	148,922	1,677	150,599	[C]
Firm External Support (ICAP) (MW)	1,626		1,626	[D]
Firm External Support (UCAP) (MW)	1,572		1,572	[E]
Adjustment to ICAP {1d in 10yr} (MW)	-11,360		-10,085	[F]
Adjustment to UCAP {1d in 10yr} (MW)	-11,360		-10,085	[G]
Non-Firm External Support (ICAP) (MW)	2,987		2,987	[H]
Non-Firm External Support (UCAP) (MW)	2,331		2,331	[I]
ICAP PRM Requirement (PRMR) (MW)	148,507		151,540	[J]=[B]+[D]+[F]-[H]
UCAP PRM Requirement (PRMR) (MW)	136,803		139,755	[K]=[C]+[E]+[G]-[I]
MISO PRM ICAP	18.24%		17.93%	[L]=([J]-[A])/[A]
MISO PRM UCAP	**8.90%**		**8.8%**	[M]=([K]-[A])/[A]

Source: MISO and Siemens

For the determination of MLGW's LRR as a separate zone (say LRZ-11), starting from the fact that the modeled internal generation has a UCAP of 1,677 MW which is lower than the peak load (3,197 MW), perfect units of 160 MW each were added to the zone until the using a dedicated software it was found that the LOLE of 1/10 years is met. This required the addition of 2,351 MW, resulting in an LRR of 126%.

$$(1{,}677 + 2{,}351) \,/\, 3{,}197 = 126\%$$

This is a fundamental number for MLGW resource adequacy as it can be used to confirm that even if it were to remain as its own LRZ, the Local Clearing Requirement (LCR) would be smaller than its local UCAP, and by joining LRZ-8, both MLGW and the LRZ-8 would benefit.

To make this determination, we considered that for the case of 3 CCGTs and 1 CT (Portfolio 2) the associated transmission system has capacity import limit (CIL) of 2,579 MW (same as the ZIA). For the Portfolios with 2 CCGTs and 1 CT (Portfolio 1 or 6) the transmission system has a CIL of 2,783 MW; and finally, for the case with only 1 CCGT the CIL is 3,445 MW. All these Portfolios have the same 1000 MW of PV.

The exhibit below shows the amounts of UCAP required for MLGW to meet the LCR and the MISO-wide PRM under each of the three Portfolios. As can be observed, under all cases the LCR in MW is lower than the value required to meet the MISO-wide PRM (8.8%) and the zone PRM (LRZ PRM) is given by the MISO-wide PRM. We also note in the exhibit that as the internal generation within the MLGW footprint drops, the greater the amount of capacity that MLGW needs to acquire in LRZ-8 (through UCAP Purchases).

Exhibit 81: MLGW Resource Adequacy Alone (LRZ-11).

Local Resource Zone (LRZ)	MLGW LRZ 11 (3 CCGT)	MLGW LRZ 11 (2 CCGT)	MLGW LRZ 11 (1 CCGT)	Formula Key
	TN	TN	TN	
2025-2026 Planning Reserve Margin (PRM) Study				
Installed Capacity (ICAP) (MW)	1,758	1,344	714	[A]
Unforced Capacity (UCAP) (MW)	1,677	1,287	690	[B]
Adjustment to UCAP {1d in 10yr} (MW)	2,351	2,741	3,338	[C]
Local Reliability Requirement (LRR) (UCAP) (MW)	4,028	4,028	4,028	[D]=[B]+[C]
LRZ Peak Demand (MW)	3,197	3,197	3,197	[E]
LRR UCAP per-unit of LRZ Peak Demand	**126.0%**	**126.0%**	**126.0%**	[F]=[D]/[E]
Zonal Import Ability (ZIA)	2,579	2,783	3,445	[G]
Zonal Export Ability (ZEA)	1,500	1,500	1,500	[H]
Forecasted LRZ Peak Demand	3,197	3,197	3,197	[I]
Forecasted LRZ Coincident Peak Demand	3,197	3,197	3,197	[J]
Non-Pseudo Tied Exports UCAP (ignored as not availa	0	0	0	[K]
Local Reliability Requirement (LRR) UCAP	4,028	4,028	4,028	[L]=[F]x[I]
Local Clearing Requirement (LCR)	**1,449**	**1,245**	**583**	[M]=[L]-[G]-[K]
Zone's System Wide PRM	3,478	3,478	3,478	[N]=[1.089]X[J]
LRZ PRM (MW)	**3,478**	**3,478**	**3,478**	[O] = Higher of [M] or [N]
LRZ PRM %	8.8%	8.8%	8.8%	[P] = [O]/[J]-1
LCR % of Peak Demand	45%	39%	18%	[Q] = [M]/[I]
MISO PRM	8.8%	8.8%	8.8%	[R]
UCAP > LCR	TRUE	TRUE	TRUE	[S] TRUE IF [B] > [M]
UCAP Purchases (if negative available for sale)	**1,801**	**2,192**	**2,788**	[T] = [O] - [B]

Source: Siemens

Other Portfolios considered in this IRP also have lower LCRs than the PRM, so the reserve requirement is driven by the MISO PRM. For example, Portfolio 9 is the same as Portfolio 5, but with 4 CTs installed in 2025. For Portfolio 9, the UCAP is 1,524 MW, which falls between the case with 2 and 3 CCGTs discussed above. Portfolio 10, with a larger CCGT (950 MW), has a UCAP of 1,124 MW; this falls between the case with 1 CCGT and with 2 CCGTs discussed above.

7.2.3 MLGW Resource Adequacy as a Member of LRZ-8

If MLGW becomes a member of LRZ-8, the LOLE analysis shows that the LRR of the zone drops from 132% to 120.6%.[40] Based on this, we assessed the overall situation of LRZ-8 before and after MLGW joins. We assessed the effect on current members, considering the capacity that they would have available for sale before MLGW joins and their situation after MLGW joins and acquires capacity in MISO to meets its capacity obligations, i.e. 8.8% of the peak load.

The results of this analysis are shown in Exhibit 82 below where we observe that before MLGW joins LRZ-8 the UCAP in the zone (11,026 MW in line [B]) exceeded the LRZ PRM (8,279 MW, line [O]) by 2,747 MW (line [U])that is available for sale to other MISO members. After MLGW joins with a Portfolio of 3 CCGT, this surplus is reduced to 1,283 MW (line [T]) as while the UCAP increased to 12,703 MW the LRZ PRM also increased to 11,420 MW (Line [O]). However, under this condition as shown in Exhibit 81, MLGW would need to acquire 1,801 MW (line [T]) to meet its capacity obligations and this would likely be procured from LRZ-8. Thus, adding the surplus plus the sales to MLGW we observe that the LRZ-8 members now can enter in sales up to 3,084 MW, a 12% increase.

[40] This analysis as indicated earlier was carried out by Astrape consulting at the direction of MISO.

Exhibit 82: MLGW Resource Adequacy as a Member of LRZ-8.

Local Resource Zone (LRZ)	LRZ-8 + MLGW (3 CCGT) AR+TN	LRZ-8 + MLGW (2 CCGT) AR+TN	LRZ-8 + MLGW (1 CCGT) AR+TN	Formula Key
2025-2026 Planning Reserve Margin (PRM) Study				
Installed Capacity (ICAP) (MW)	13,524	13,110	12,480	[A]
Unforced Capacity (UCAP) (MW)	12,703	12,313	11,716	[B]
Adjustment to UCAP {1d in 10yr} (MW)	423	813	1,410	[C]
Local Reliability Requirement (LRR) (UCAP) (MW)	13,126	13,126	13,126	[D]=[B]+[C]
LRZ Peak Demand (MW)	10,884	10,884	10,884	[E]
LRR UCAP per-unit of LRZ Peak Demand	**120.6%**	**120.6%**	**120.6%**	[F]=[D]/[E]
Zonal Import Ability (ZIA)	4,185	4,185	4,185	[G]
Zonal Export Ability (ZEA)	5,328	5,328	5,328	[H]
Forecasted LRZ Peak Demand	10,884	10,884	10,884	[I]
Forecasted LRZ Coincident Peak Demand	10,496	10,496	10,496	[J]
Non-Pseudo Tied Exports UCAP (ignored as not available)	0	0	0	[K]
Local Reliability Requirement (LRR) UCAP	13,126	13,126	13,126	[L]=[F]x[I]
Local Clearing Requirement (LCR)	**8,941**	**8,941**	**8,941**	[M]=[L]-[G]-[K]
Zone's System Wide PRM	11,420	11,420	11,420	[N]=[1.089]X[J]
LRZ PRM (MW)	**11,420**	**11,420**	**11,420**	[O] = Higher of [M] or [N]
LRZ PRM %	8.8%	8.8%	8.8%	[P] = [O]/[J]-1
LCR % of Peak Demand	82%	82%	82%	[Q] = [M]/[I]
MISO PRM	8.8%	8.8%	8.8%	[R]
UCAP > LCR	TRUE	TRUE	TRUE	[S] TRUE IF [B] > [M]
UCAP Purchases (if negative available for sale)	(1,283)	(893)	(296)	[T] = [O] - [B]
Available for Sale + Sold to MLGW	**3,084**	**3,084**	**3,084**	[U] = [T] + [MLGW Purchases]
UCAP > LRZ PRM	TRUE	TRUE	TRUE	

Source: MISO and Siemens

This situation is the same with the other two (2 CTs and 1 CT) Portfolios; the surplus reduces, but when adding the purchases, we arrive at the same value of 3,084 MW.[41]

7.2.4 Conclusions

Base on the above, we derive the following conclusions:

- All Portfolios should be designed with enough transmission so that the CIL plus the UCAP of the generation resources achieves at least 126% of the peak load. This will ensure that MLGW maintains adequate reliability, whether it becomes part of LRZ-8 or not.
- If MLGW decides to join MISO, it should pursue the option to join LRZ-8.

[41] The case with 2 CCGTs and 1 CCGT was assessed assuming the same LRR for LRZ-8 of 126.6%, however Astrape conducted a sensitivity with 2 CCGTs instead of 3 and as expected the LRR reduced to 126.5%. We conservatively maintained the former.

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 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 was 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 $607 million (2018 $) including a 10% contingency, before any generation interconnection costs and approximately $695 million (2018 $) considering local generation interconnection costs. The total transmission investments 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.

- Local generation interconnection transmission costs of $88 million; this amount is a function of the local units in the portfolio.
- Reimbursements to TVA (to reconnect the Allen combined cycle plant and for reliability upgrades near Southaven 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.

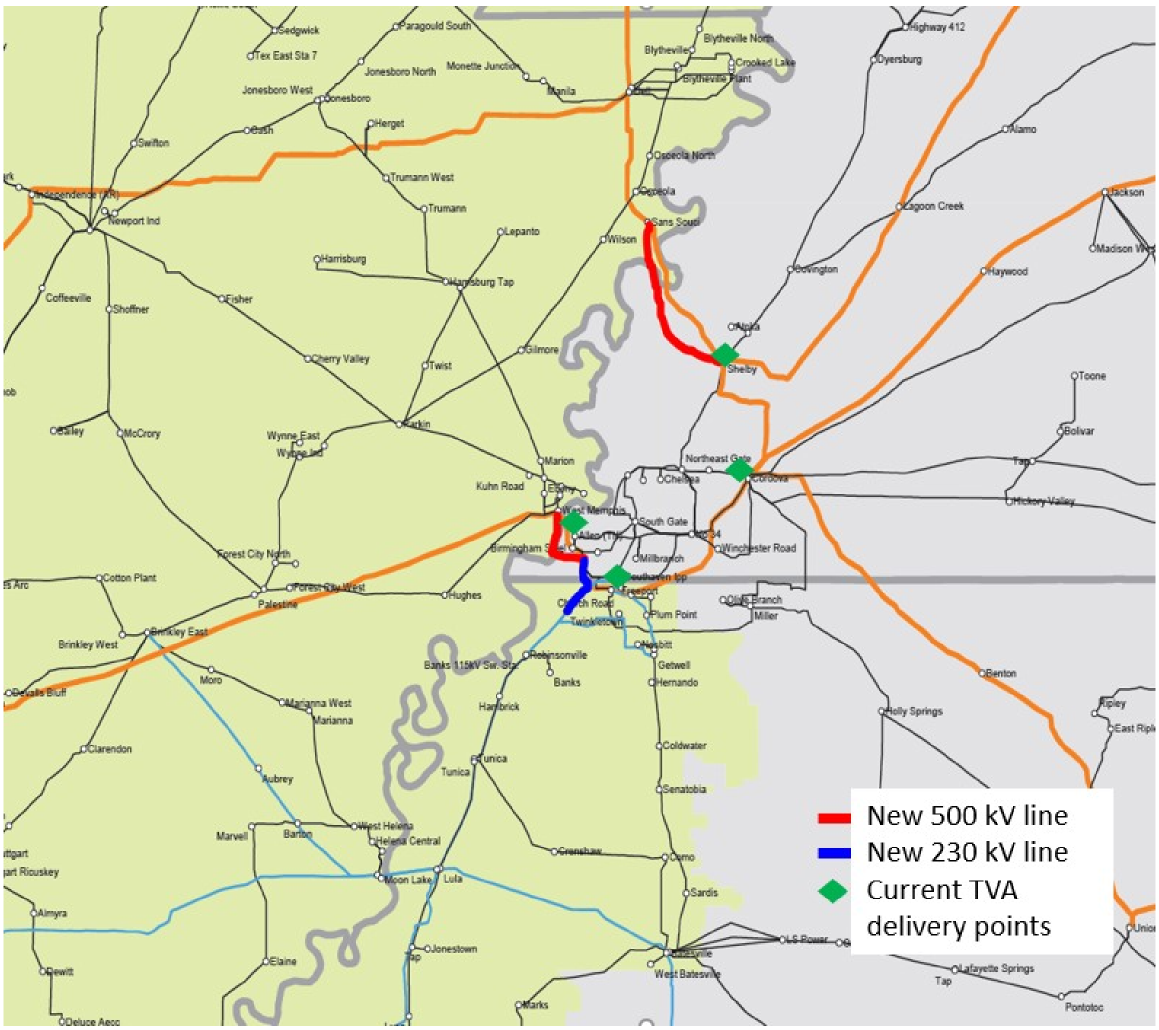
8.2 Transmission Expansions

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 83: Transmission Expansions Geographic Map



Source: MISO and Siemens

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[42] 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.

[42] Replacing the conductor of a line with one with higher capacity is known as “reconductoring” in the industry.

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 84, 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 84: 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 2,200 MW import limit and a 1,500 MW export limit are used for all scenarios for Strategy 3 (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 2,200 MW import limit and 1,500 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 rarer 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 Southaven 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 new local generation being built.

This strategy was assessed to determine the estimated transmission costs necessary to supply the entirety of MLGW's load without the benefit of local generation. While local generation is expected to be the lowest cost generation available to MLGW, which indicates that Strategy 4 is not least cost, the analysis of the All MISO solution provides additional visibility on the options open to MLGW.

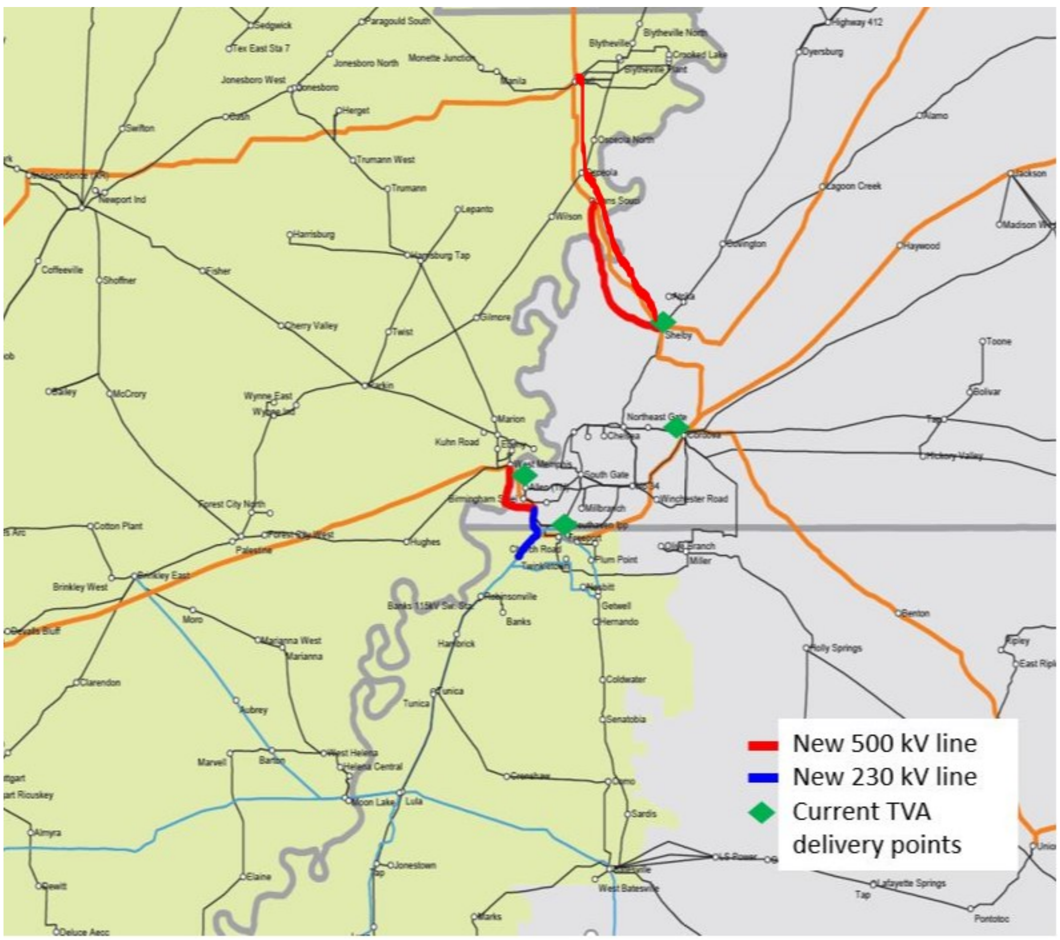
For this strategy to be feasible from the transmission perspective, additional interconnections to MISO are required in addition to the three interconnections in the baseline transmission plan; this is due to the risks associated with losing two or more interconnections. Because there is no local MLGW dispatchable generation under pre-existing contingency, at a minimum, N-2 events should be assessed to determine the applicable import capability and overall reliability of the system. MLGW also needs to have a minimum firm import of 3,500 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: 2,598/2,598 MVA summer rating (approximately 44 miles), and
b. Two new 500/161 kV transformers, 1,300 MVA each at the new Shelby 500 kV substation.

Exhibit 85: Transmission Expansions for All MISO Strategy



Source: MISO and Siemens

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

In addition, a total of about 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 3,500 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 incremental 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 these additional costs for the All MISO strategy are added to the $607 million (2018 $) needed as discussed in Section 8.1, the total capital investment on transmission system is approximately $1.014 billion, before any applicable generation interconnection costs[43] and well over $1.2 billion including the estimated interconnection costs for all new generations. The $1.014 billion investments, when expressed as a function of the present value of the load served, represent about $3.09/MWh of 2025-2039 NPV assuming 30-year repayment.

The full steady state contingency analysis performed for N-1 and N-1-1 contingencies confirmed that no local overloads are expected inside MLGW under this topology with the reinforcements above. However, some thermal violations were identified in MISO footprint outside of MLGW for the 2025 Summer Day-Peak condition and without any local generation within MLGW. These thermal violations likely will require additional transmission upgrades and further increase the total transmission cost of this Portfolio. Additional analyses would be required in coordination with MISO and impacted transmission owner for facility upgrades determination, if this Portfolio (no local generation) were selected.

There were also some voltage violations (low voltage) identified only under N-1-1 conditions for loss of two 500 kV lines interconnected to MISO, and it has been determined that additional reactive compensation devices are required to resolve low voltage issues to meet reliability standards. Devices such as switchable shunt capacitors can be effective to meet the need for increased reactive support. A preliminary cost estimated determined that to cost is about $14 million (2018 $) based on the reactive support needed. Note this cost for reactive support is only applicable for the All MISO Strategy, which further increased the total transmission capital cost.

The All MISO Portfolio, with only the minimum transmission investment at $1.014 billion, was not competitive in the NPVRR ranking among all selected Portfolios as presented in Section 13, even before the costs of additional transmission investments outside MLGW footprint, and thus was determined to be not a preferred Portfolio.

[43] Generator interconnection costs, unless otherwise noted, are not included in the transmission capital expenditure estimation. Most of the generator interconnection costs were already included in the capital costs of new generation resources and will be recovered via PPA payments from MLGW to 3rd party developers, even if they are not included, the uncovered portion would be applicable to new resources developed both in MLGW and MISO footprint.

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 Chambers 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 at 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 is supplied by the two photovoltaic facilities operating at 30% of capacity and the remaining 170 MW is supplied from Chambers 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 2,850 MW (3,200 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 and the Chambers 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 Chambers Chapel combined cycle (three-phase fault at the point of interconnection)

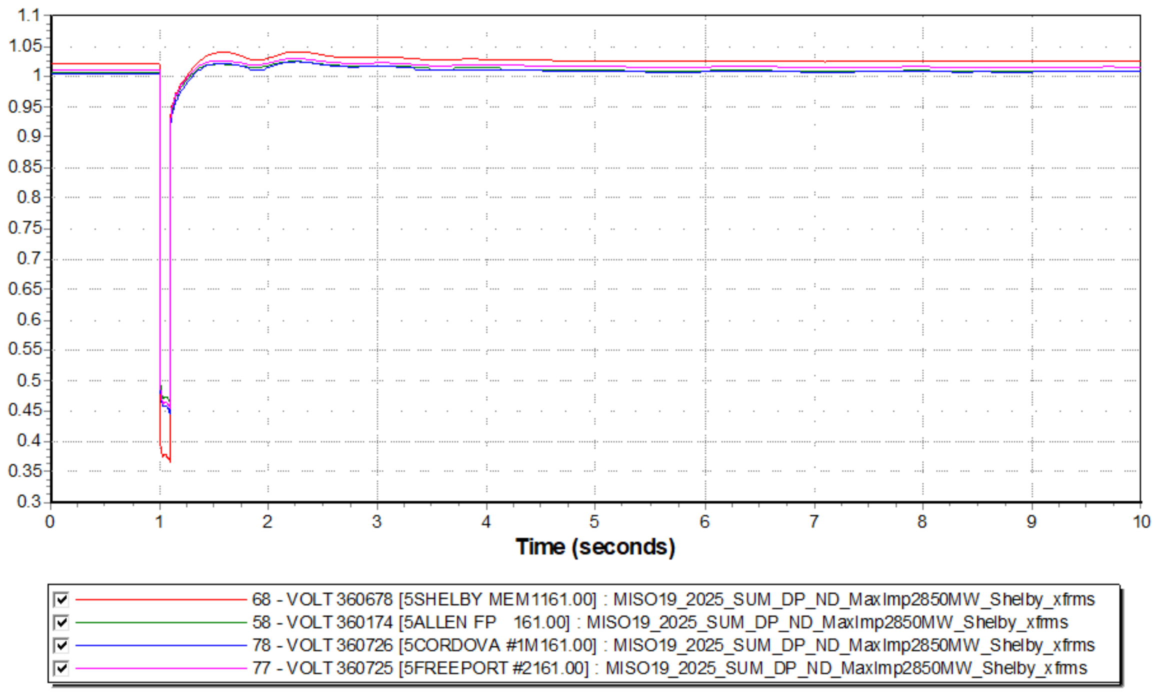
The three-phase faults were assumed to be cleared after 6 cycles by removing the faulted elements.

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

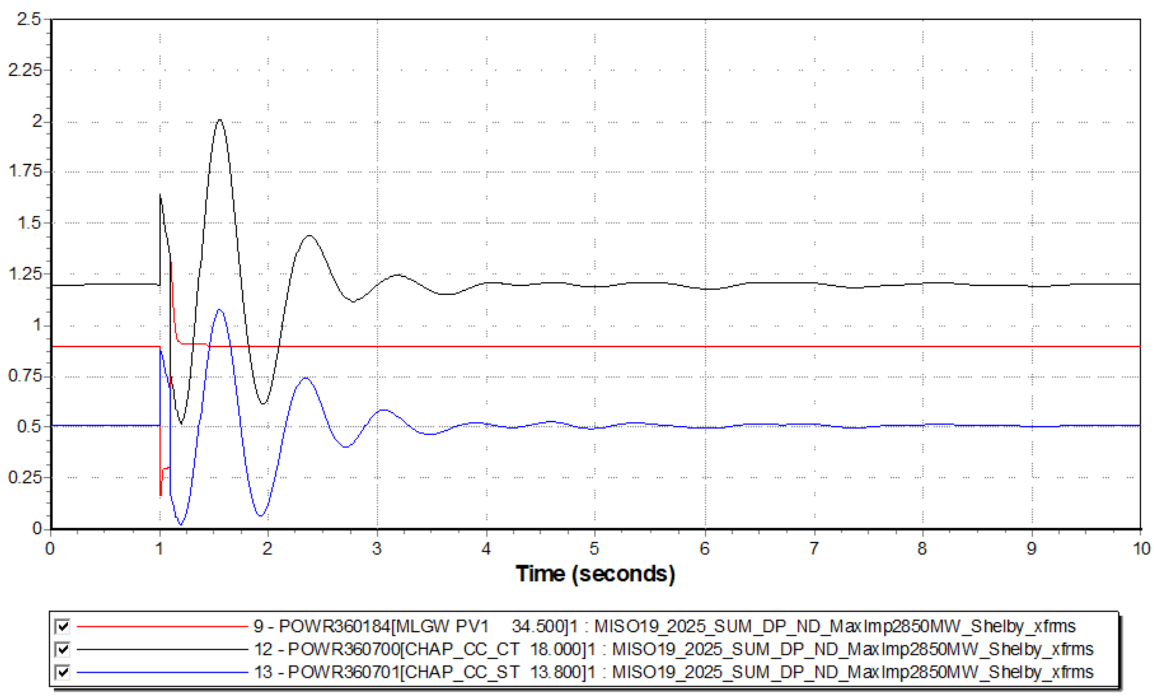
In the following Exhibits, the simulation results are provided, showing fast voltage recovery for the MLGW power system and no instabilities. The generation showed adequate damped response. Reactive power compensation devices such as Static Synchronous Compensator (STATCOM) or Static VAR Compensator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

Exhibit 86: Fault at Shelby 500/161 kV Transformers (2025 summer peak) – Bus Voltage [p.u.]



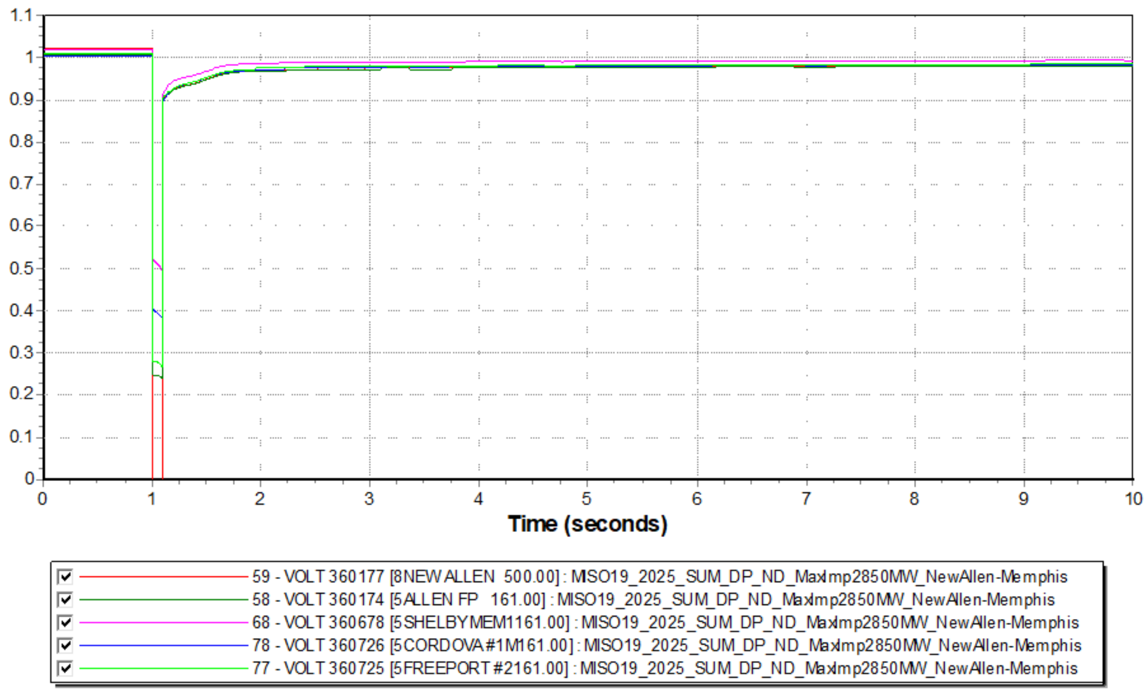
Source: Siemens

Exhibit 87: Fault at Shelby 500/161 kV Transformers (2025 summer peak) – PV and C. Chapel CC Active Power [p.u.]



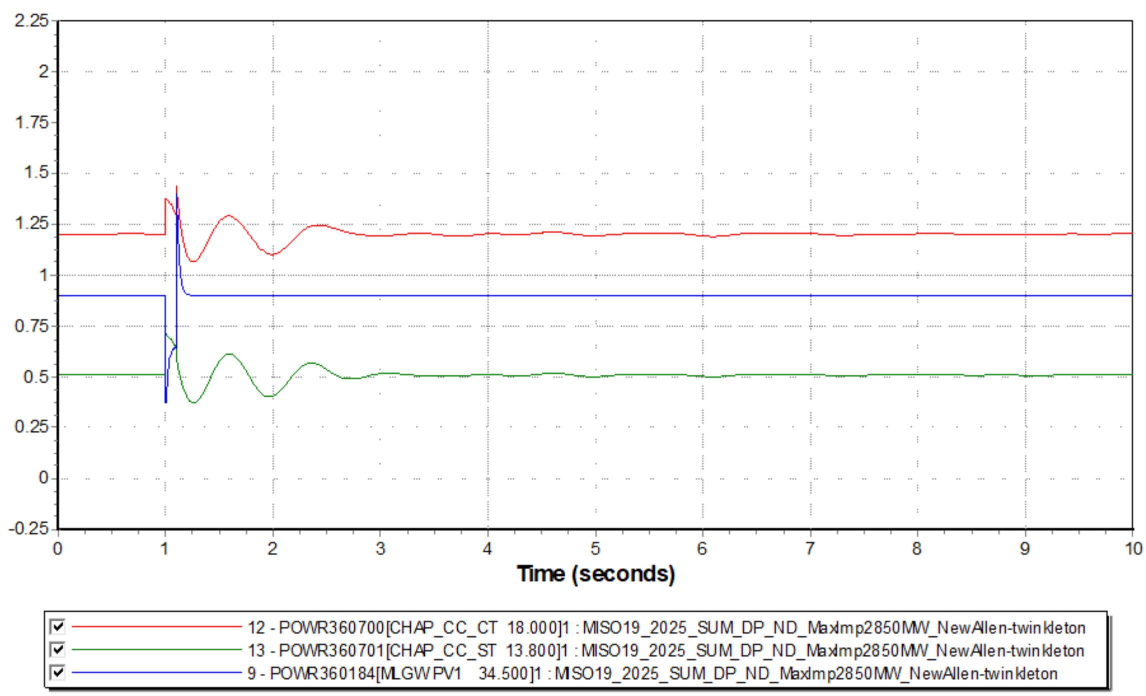
Source: Siemens

Exhibit 88: Fault at New Allen 500 kV (2025 summer peak) – Bus Voltage [p.u.]



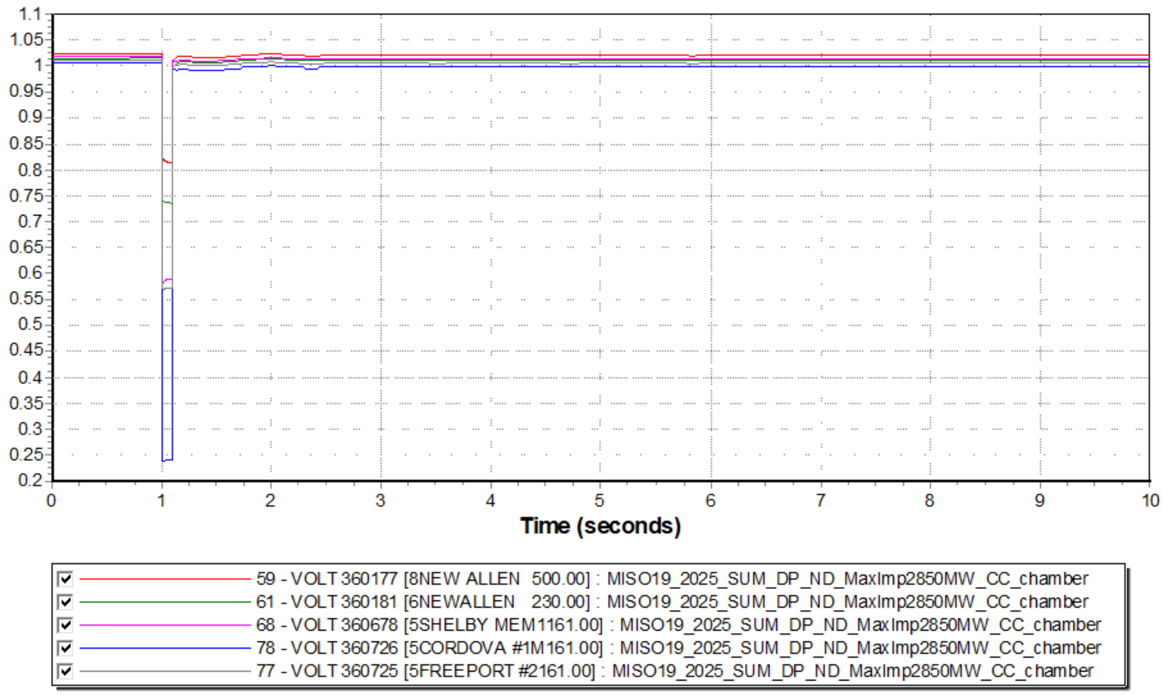
Source: Siemens

Exhibit 89: Fault at New Allen 230 kV (2025 summer peak) – PV and C. Chapel CC Active Power [p.u.]



Source: Siemens

Exhibit 90: Fault at C. Chapel CC (2025 summer peak) – Bus Voltage [p.u.].



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 Portfolio with more local generation 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 conducted a supplementary nodal production cost analysis using PROMOD® IV to fully evaluate the system congestion and generation economics focusing on renewable resources of a selected LTCE plan. The latest MISO MTEP20 PROMOD® Powerbase Databases were used as the starting base cases. All four MTEP20 Futures representing different MISO generation fleet forecasts were ran for completeness, i.e. Accelerated Fleet Change (AFC), Continued Fleet Change (CFC), Distributed and Emerging Technology (DET), and Limited Fleet Change (LFC).

TVA BAU strategy was represented as the base case where all the transmission system remains connected with TVA while the only change was made that the MLGW's system was formed as an individual area under TVA for the purpose of reporting. MLGW's peak demand and energy demand were updated according to the forecast. Henry Hub gas price was updated based on Siemens' forecast. Generation retirements both in TVA and MISO were verified.

Self-Supply + MISO strategy was modeled by separating the MLGW's system from TVA and incorporating into MISO LRZ-8. MLGW became disconnected from TVA while new transmission interconnection lines and upgrades were modeled for MLGW to be interconnected with MISO system. Same as base case, both demand and gas price were updated in the model. Under this strategy, Portfolio 7 (S3S1_2CT) was selected for modeling and analysis and refer to Appendix D: Portfolio Details for detailed portfolio buildout. Generation modeling was carried out by staging the various resources including 2x450 MW CC, 2x237 MW CT, 1000 MW local Solar,1800 MW MISO Solar, and 400 MW MISO Wind from the LTCE plan over the years into the nodal models.

8760 hourly nodal simulations were conducted in year 2025, 2030, and 2035 for both the TVA BAU Portfolio and Portfolio 8. Various metrics including flowgate and interface flows, flowgate congestion, LMP prices, renewable generation production and curtailment, etc. were evaluated to attest to the efficacy of the analysis and verify the feasibility and economics of the LTCE plan.

The performance of production cost analyses is expected to be similar among all Portfolios with two combined cycle units, i.e. Portfolios 1, 6, 7, and 8. Portfolio 2 which consisted of three combined cycle units and one CT unit was also modeled and analyzed. However, Portfolios with three combined cycle units are the least preferred plans among all Portfolios thus were not included in the report. Due to the timing of the production cost analysis, Portfolios 9 and 10 and All MISO were not included in the nodal production cost analysis.

In sum, the production cost analysis showed satisfactory results for the studied Portfolio 7. No congestion observed on MLGW system with projected reductions on the overall system congestions. This was confirmed by flowage and interface flow results and LMP prices comparisons. Finally, almost no curtailment on renewable generations was observed in the analysis.

8.9.1 Flowgate and Interface Flows

For flowgate and MISO-MLGW interface flows we mainly look at the annual maximum flows on the key flowgate monitored elements (individual transmission line) and interface (a group of transmission lines). The results are shown in Exhibit 91 below where we can see:

- Some of the key monitored elements around Freeport area in the south in between MISO and TVA did show increased flows as compared with TVA BAU Portfolio, however, with the line upgrades included in the transmission plan, no flows exceeded the line capacity.
- The three new interconnection lines showed similar flows across simulated years and MTEP Futures and are evenly balanced among them.

- The MISO-MLGW interface which is the group of the three new interconnections has an interface limit of 2579 MW resulted from the CIL analysis from resource adequacy assessment and showed a maximum of 2330 MW of flows under contingency.

As a result, none of the above flowgates and interface caused any system congestion validating the adequacy of the proposed transmission expansion plan.

Exhibit 91: Annual Maximum Flowgate and Interface Flows (MW)

		TVA BAU				Portfolio 7			
Monitored Element	**Year**	**AFC**	**CFC**	**DET**	**LFC**	**AFC**	**CFC**	**DET**	**LFC**
Freeport to Twinkletown 230 kV (EES-EMI) [462 MVA in TVA BAU and 1405 MVA in P7]	2025	420	450	453	450	1391	1352	1330	1336
	2030	266	254	248	245	772	759	718	729
	2035	277	259	237	226	803	767	739	724
Freeport to South Haven CC 230 kV (TVA) [1069 MVA in TVA BAU and 1991 MVA in P7]	2025	680	688	700	691	855	851	849	856
	2030	661	692	680	683	850	854	830	823
	2035	655	710	682	672	843	840	818	840
Twinkletown to New Allen 230 kV (MLGW) [1991 MVA in P7]	2025					1220	1194	1177	1189
	2030					1081	1120	1086	1051
	2035					1188	1038	1091	1026
West Memphis to New Allen 500 kV (MLGW) [2598 MVA in P7]	2025					1628	1588	1693	1632
	2030					1558	1490	1360	1363
	2035					1573	1357	1371	1338
San Souci to Shelby MLGW 500 kV (MLGW) [2598 MVA in P7]	2025					1190	1282	1249	1247
	2030					1284	1060	1042	1023
	2035					1142	942	1009	1038
MISO–MLGW Interface [2579 MW of CIL based on Resource Adequacy]	2025					2305	2208	2326	2236
	2030					2276	2180	1995	2005
	2035					2330	1911	1993	1939

Source: Siemens

8.9.2 Flowgate Congestion

It is essential to get a view of transmission congestion pattern changes between the TVA BAU Portfolio and the Strategy 3 Portfolio as congestion has a direct impact on the market prices where MLGW needs to procure energy in the MISO market. Higher system congestion around MLGW area means higher locational marginal price (LMP) that MLGW would have to transact at for the energy purchase from market, and it also means market volatility. Congestion results were also used to identify if additional transmission is needed and justified as part of the overall transmission plan. We mainly look at near-term 2025 to mid-term 2030 system congestions and break into both projected increased and decreased congestions. Congestion results are shown in the following exhibits.

Exhibit 92: 2025 Decreased System Congestion ($)

	TVA BAU				Portfolio 7			
Monitored Element	AFC	CFC	DET	LFC	AFC	CFC	DET	LFC
B:3371815HORN LAKE% 3600245FREEPORT TN1	3,810,893	3,090,400	3,359,331	3,705,496	-	-	-	-
B:3379493LYNCH-W! 3384893NLR GALLOWY1	4,674,508	343,768	1,294,470	556,699	184,051	-	15,476	-
B:3379578KEO% 3381628W.MEMPHIS% 1	2,884,308	1,292,632	1,881,772	1,320,472	-	-	-	1,351
B:3381515NEWPORT! 3387335NEWPORT-E# 1	629,521	729,153	1,053,630	712,264	-	-	-	-
B:3381655MARKEDTREE!3381675HARRISBURG+1	157,279	720,350	1,170,101	656,295	-	-	-	-
B:3381888SANS SOUCI%3381988DRIVER% 1	770,583	878,600	961,580	692,584	-	-	-	-
B:3600515MAURY TN 3603105MONSANTO TN1	4,584,830	-	-	-	3,039,799	-	-	-
B:3605215RIDGELY TN 3612615TIPTONVL TN1	302,680	345,563	1,044,680	332,282	-	-	-	-
B:3607255FREEPORT #23657885MENDENHAL891	272,759	456,223	507,169	522,772	-	-	-	-
MISO TVA MLGW	Total Decreased Congestion Cost				14,863,510	7,856,690	11,257,259	8,497,513

Source: Siemens

Exhibit above shows the projected congestion cost decreased on selected flowgates for about $10 million on average in across the futures in 2025 from TVA BAU Portfolio to Portfolio 7, mainly due to the new transmission expansions almost parallel to the existing transmission between MISO and TVA which resulted in congestion reduction in the MISO footprint. The exhibit below shows the projected congestion cost increased on selected flowgates for about $2.5 million on average across the futures in 2025, mainly due to the flow pattern changes after MLGW joins MISO which shifted congestion around in the system. The net system congestion is projected to be decreased for about $7.5 million on average in 2025 going from TVA Portfolio to Portfolio 7.

Although we note TVA is not a market based on LMPs, the reduction in overall system congestion in the near-term analysis indicates that the market prices in MISO South after the incorporation of MLGW under the studied LTCE Plan are not expected to be higher than MLGW staying with TVA.

Exhibit 93: 2025 Increased System Congestion ($)

	TVA BAU				Portfolio 7			
Monitored Element	AFC	CFC	DET	LFC	AFC	CFC	DET	LFC
B:3361296BOGALUSA 3361308BOGALUS 1	1,115,923	141,559	352,744	1,766	1,415,292	633,566	641,961	54,492
B:3371373COLDWATER! 3371383HERNANDO! 1	393,305	720,026	597,388	1,040,203	1,974,208	1,345,535	1,395,401	1,655,236
B:3376743AMITY% 3388493MURFBORO.E#1	-	762,609	284,564	632,286	28,086	1,078,989	537,770	1,079,646
B:3600725WILSON TN 3610205GLADEVL TP 1	1,009,730	754,921	363,897	345,878	1,582,006	1,632,848	711,993	870,821
B:3602145BATESVILLE 3616235E BATESVILE1	857,979	557,266	732,682	663,640	2,381,161	716,034	1,068,352	457,584
MISO TVA MLGW	Total Increased Congestion Cost				4,003,814	2,470,590	2,024,202	1,434,004

Source: Siemens

Exhibit 94: 2030 Decreased System Congestion ($)

	TVA BAU				Portfolio 7			
Monitored Element	AFC	CFC	DET	LFC	AFC	CFC	DET	LFC
B:3032236FR_BRANCH 3884256LOGTWN W6 1	7,307,657	-	-	-	4,113,668	-	-	-
B:3182043SLVR CRKN% 3182143SILVCRK S 2	-	1,329,618	-	7,117,651	-	937,938	-	1,322,560
B:3182143SILVCRK S 3365753NEW HEBRON 1	-	975,728	-	3,696,578	-	849,335	-	805,852
B:3370603WINONA! 3370613SAWYER+ 1	327,976	441,046	830,412	3,214,005	82,388	204,291	332,029	101,145
B:3371006CROSSROADS!5001643CLARKMUN 1	2,011,140	60,647	427,099	3,665,693	935,260	34,018	191,974	186,312
B:3371815HORN LAKE% 3600245FREEPORT TN1	2,007,193	6,020,443	3,629,630	10,451,953	-	-	-	-
B:3379215MORILTON.E!3379275GLEASON 1	67,837,312	29,741,797	43,140,684	33,461,188	51,339,511	19,133,993	30,014,575	14,664,050
B:3380063CABOT 3380163HOLND BTM! 1	1,719,434	768,257	525,544	2,270,964	440,901	-	522,175	11,744
B:3388135MIDWY JRDN#505460BULL SH5 1	19,663,617	12,214,252	11,099,810	20,084,626	14,938,573	8,571,656	6,983,641	10,680,646
B:3600308LOWNDES MS 3606058VALLEYVIEW 1	-	-	-	13,043,628	-	-	-	1,287,672
B:3601005J SEVIER #13604835PERSIA TN 1	-	-	2,253,170	5,703,075	90,315	-	1,626,518	448,822
B:3601135HIWASSEE #23604255CHARLESTON 1	37,990,792	42,011,309	46,224	78,637,288	34,466,995	38,397,384	65,855	9,592,481
B:3601305MAYFIELD KY3601385PARIS TN 1	195,944	318,590	490,474	27,975,698	130,092	111,173	259,240	471,440
B:3601685COUNCE TN 3601695PICKWICK HP1	1,136,415	3,022,315	-	-	41,069	-	-	-
B:3602835ALBERTVILLE3843325ATTALLA5 1	710,658	2,148,696	-	29,816,507	816,725	2,071,838	80,457	7,257,881
B:3603255HOPKINSV KY3604375LEWISBRG KY1	31,514,412	8,742,333	30,729,788	17,762,940	15,706,345	3,005,921	12,412,724	126,363
B:3603875WARTRACE TN3604035N TULLA T#11	1,159,855	224,164	746,095	23,982,396	503,588	215,784	-	5,147,855
B:3604205E CLEVELAND3611775SUGARGROV T1	10,643,191	6,555,229	10,471,686	29,915,523	10,361,929	7,461,138	11,750,074	5,173,286
B:3606795SHELBY MEM23655915NE GATE 33 1	17,266,585	-	-	-	-	-	-	-
B:3606895CLAY 3611075EGYPT MS TP1	7,005,505	159,219	2,989,758	2,489,127	1,511,519	-	388,117	25,289
B:3606895CLAY 3611215ABERD MS TP1	9,716	-	184,082	1,082,801	9,718	-	7,833	-
B:3607255FREEPORT #23657885MENDENHAL891	-	3,380,545	-	-	-	-	-	-
B:3610065FONTANA HP 3612645HWY 411 TN 1	9,550,614	11,397,376	14,962,760	56,628,157	9,089,062	10,921,634	13,528,488	23,350,249
MISO / TVA / MLGW	Total Decreased Congestion Cost				73,480,359	37,595,459	44,363,514	290,346,151

Source: Siemens

Exhibit above shows the 2030 projected congestion cost that are expected to decrease on selected flowgates for about $111 million on average across the Futures from TVA BAU Portfolio to Portfolio 7, mainly due to the new transmission expansions and local MLGW upgrades. The Exhibit below shows the projected congestion cost increased on selected flowgates for about $7 million on average in 2030, mainly due to the flow pattern changes after MLGW joins MISO which shifted congestion around in the system.

The net system congestion is projected to be decreased for more than $100 million on average in 2030 from TVA Portfolio to Portfolio 7. Note that the congestion results from further year analysis are only indictive and may not be accurate due to various uncertainties in generation additions and retirements, and future transmission plans , nevertheless the reduction in overall system congestion in the 10-year out analysis indicates that the market prices in MISO South after the incorporation of MLGW under the studied LTCE Plan are not expected to be higher than with MLGW staying with TVA due to congestion effects.

Exhibit 95: 2030 Increased System Congestion ($)

Monitored Element	TVA BAU AFC	TVA BAU CFC	TVA BAU DET	TVA BAU LFC	Portfolio 7 AFC	Portfolio 7 CFC	Portfolio 7 DET	Portfolio 7 LFC
B:3371373COLDWATER! 3371383HERNANDO! 1	199,642	73,565	-	60,312	571,672	1,730,372	589,384	1,761,861
B:3373733BERNICE 3375493JNCTN CITY!1	5,149,907	1,738,740	2,086,018	-	7,024,726	2,717,796	4,637,038	275,171
B:3376003REED% 3376023DUMAS% 1	456,673	360,954	90,436	46,708	1,450,048	1,280,574	208,347	242,155
B:3376743AMITY% 3388493MURFBORO.E#1	1,057,949	-	-	2,140,094	1,326,032	-	205,379	10,871,136
B:3388145SOUTHLAND# 505448NORFORK5 1	-	-	-	-	1,040,920	-	2,051	-
B:3600385JVILLE FP#13611045CAMDEN TAP 1	135,581	-	-	-	1,923,064	-	-	-
B:3601365MARTIN TN 3605975SUMMERS RD 1	2,448,204	-	-	-	6,443,495	-	33,596	-
B:3607275CORDOVA #1T3610885ROSSVILL TP1	-	-	-	-	-	-	1,081,988	-
Total Increased Congestion Cost					10,332,003	3,555,482	4,581,328	10,903,209

MISO TVA MLGW

Source: Siemens

Congestion results for long-term (2035) analysis also displayed similar pattern as the near-term and mid-term analyses however due to the even greater uncertainties on the generation and transmission assumptions, results are less meaningful compared to near-term analysis.

8.9.3 LMP Prices

The overall congestion reductions as discussed above were also observed from the average LMP prices between the TVA BAU Portfolio and Portfolio 7 as the cost of congestion is a component in the LMP definition, which also includes the cost of energy and losses. The table below shows the average annual LMP prices for MISO Arkansas hub and MISO Mississippi hub for the portfolio comparison for all years and MTEP Futures. As can be seen, the LMP prices are projected to be consistently lower in Portfolio 7 than in TVA Portfolio. For example, the LMP for MISO Arkansas hub is projected to be decreased by about $2/MWh over the 10-year horizon which is partially due to the overall reduced system congestion. The lower market prices in MISO Arkansas zone which MLGW is likely to purchase from could mean savings for MLGW on the market purchases. Although the amount of purchases varies from Portfolio to Portfolio, the MISO hub prices stay largely the same under the same Strategy. Assuming MLGW purchases 10% of energy from the market, $2/MWh could mean roughly $2.5 million savings for MLGW on an annual basis.

Exhibit 96: LMP Price Comparison ($/MWh)

		TVA BAU				Portfolio 7			
LMP Node	Year	AFC	CFC	DET	LFC	AFC	CFC	DET	LFC
Entergy ARK Hub	2025	33.60	32.09	32.49	31.92	33.03	31.95	32.35	31.72
	2030	41.42	38.85	39.99	43.04	39.85	37.97	38.72	38.05
	2035	48.53	48.33	61.52	53.35	47.08	45.92	55.01	47.46
Entergy MS Hub	2025	33.98	32.78	33.27	32.40	33.90	32.85	33.29	32.60
	2030	40.58	39.08	39.79	41.37	39.80	38.84	39.12	38.29
	2035	45.87	45.73	56.15	48.68	45.48	45.11	52.95	46.08

Source: Siemens

8.9.4 Renewable Generation Production and Curtailment

As every Portfolio under Strategy 3 was trying to install as much renewable generation as possible to take advantage of the lower cost of renewable resources, there is the risk of renewables being curtailed which need to be assessed from the production cost simulations. Large solar installations from Strategy 3 Portfolios could mean there would be excess energy produced during the day that needs to be sold into MISO market. Renewables could be curtailed due to either reliability reasons, for example the MLGW-MISO interface is congested, or for economic reasons, for example the LMP prices at certain times are too low for the generator to be profitable. The assessment on curtailment for MLGW owned or contracted renewables would be able to help minimize the risks associated with curtailment which could further imply reduced savings after leaving TVA.

In the table shown below, we summarize the production and curtailment of all the renewable generation in the Portfolio 7 for different MTEP Futures and years. As can be seen there is only very small amount (0.02%) of renewable energy projected to be curtailed in 2035 when most of the renewable installations were commissioned, and there was no curtailment projected in 2025 and 2030. Based on the results, we estimate the curtailment risk is very low and MLGW can sell excess energy in the MISO market as needed.

Exhibit 97: Renewable Production and Curtailment

		Portfolio 7			
		AFC	CFC	DET	LFC
2025	Energy From Renewable (MWh)	3,639,729	3,639,729	3,639,729	3,639,729
	Curtailment (MWh)	0	0	0	0
	Curtailment %	0%	0%	0%	0%
2030	Energy From Renewable (MWh)	6,938,098	6,938,098	6,938,098	6,938,098
	Curtailment (MWh)	0	0	0	0
	Curtailment %	0%	0%	0%	0%
2035	Energy From Renewable (MWh)	6,967,800	6,969,092	6,968,538	6,969,877
	Curtailment (MWh)	2,077	785	1,339	0
	Curtailment %	0.03%	0.01%	0.02%	0.00%

Source: Siemens

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 in Strategy 3 is approximately $552 million without contingency, based on the proposed baseline transmission expansion and local reliability upgrades.

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, and such was added to the base estimation. Also, a 5% cost saving was assumed to reflect synergies on economic scale in developing multiple large transmission projects simultaneously and sharing on common services and equipment. 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 $607 million, or $1.85/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[44], 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. If assuming a 2.5% factor, this cost is approximately $11 million on an annual basis 2025-2039, or $0.84/MWh of 15-year NPV for the baseline transmission plan. Finally, for the All MISO Strategy, this cost increased to $18 million, or approximately $1.33/MWh of 15-year NPV.

[44] The All MISO strategy, due to the lack of local generation, may require additional investments in the MISO footprint that would increase its cost further. These costs were not assessed as the MISO only is not a preferred Portfolio.

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 and transmission 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 paying local governments by means of payment in lieu of taxes (PILOT). In the event of MLGW's departure from TVA as its wholesale provider of power, MLGW or the new wholesale generation provider would be required to make PILOT payments to the State of Tennessee for which are currently TVA's responsibility.

TVA makes annual PILOT payments to the states in the Valley based on 5% of TVA's annual gross revenues. In Tennessee, a portion of these TVA payments are allocated to cities and counties annually. TVA has reported PILOT payments of approximately $18.2 million in fiscal year 2018 to local governments within Shelby County that could be at risk.[45].

If MLGW were to terminate the contract with TVA, MLGW or the new wholesale generation provider would have to assume 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 or the new wholesale generation provider would incur a PILOT imposed by the state and local taxing jurisdictions within Shelby County, where the state PILOT is based on wholesale power cost and the local PILOT is based on transmission and/or generation physical assets within each local taxing jurisdiction 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.

[45] 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, and purchases power from another entity, that entity would be required to pay the state PILOT. It is assumed that the cost of PILOT would be incorporated into the wholesale rate to MLGW.

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 wholesale power 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 local taxing jurisdictions 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 local taxing jurisdictions will start to collect PILOT starting the first year when MLGW leaves TVA (2025).

We assume the same local PILOT factor for all local taxing jurisdictions; 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 the local taxing jurisdictions, 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 locally, then MLGW would be required to pay the local PILOT. In such case there would be offsetting economies since 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, and PILOT as well as indirect benefits such as economic growth, job creation, and business attraction.

TVA has provided Siemens with a high-level summary of benefits[46] for the Memphis communities. If MLGW were to leave TVA, these benefits are expected to be discontinued by TVA. For continuity 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 collectively 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 as 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.

[46] Memphis Summary of Benefits v3.pptx

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.

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 implement new energy efficiency programs, 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 for business customers 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 fund similar technical expertise for business energy audits.

9.4 MISO Membership Cost

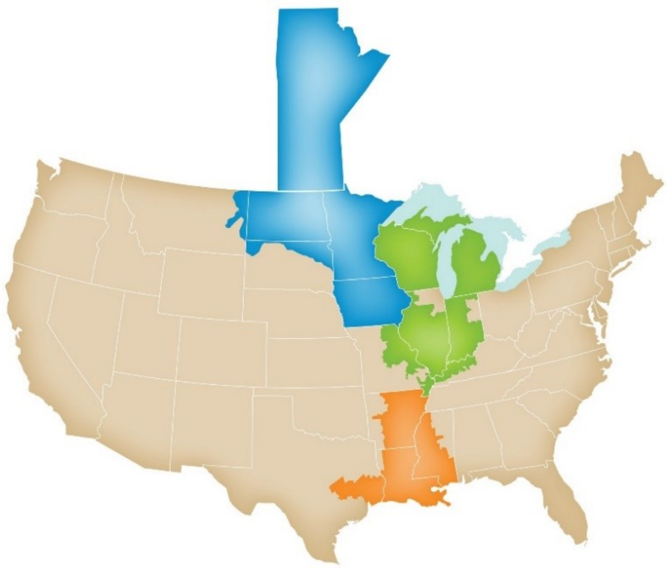
9.4.1 About MISO

The Midcontinent Independent System Operator (MISO)[47] 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 in 1998 and as the nation's first

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

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.

Exhibit 98: 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 acted 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, which MLGW shared 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. Details on this and other operating costs and capital for infrastructure upgrades are provided 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 $800,000 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, substations and greater than 1,500 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 99.

Exhibit 99: 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 MWh 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.

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 100.

Exhibit 100: 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 101: 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	$0.3
Total Cost ($Million)	**$1.3**	**$2.4**	**$2.6**	**$2.6**	**$2.6**	**$2.6**	**$2.6**	**$2.1**	**$1.8**	**$1.6**	**$1.6**

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 needed that do not exist at MLGW today 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.

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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, and other factors, 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.

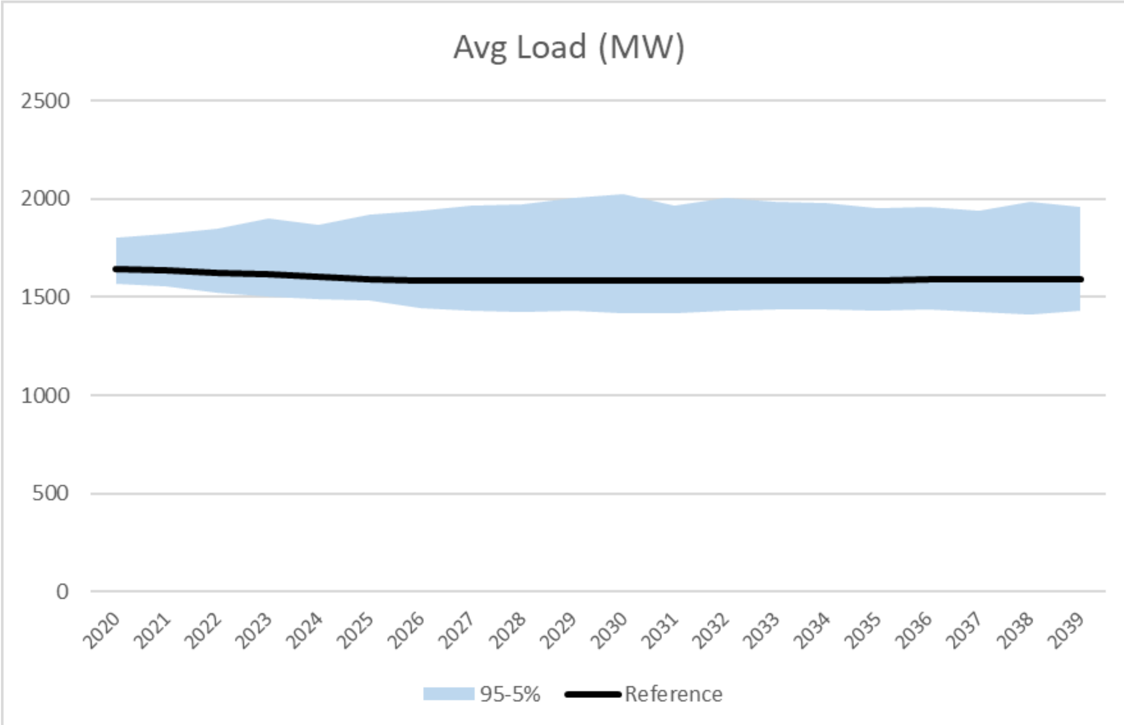
11.3 Stochastic Distributions

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.

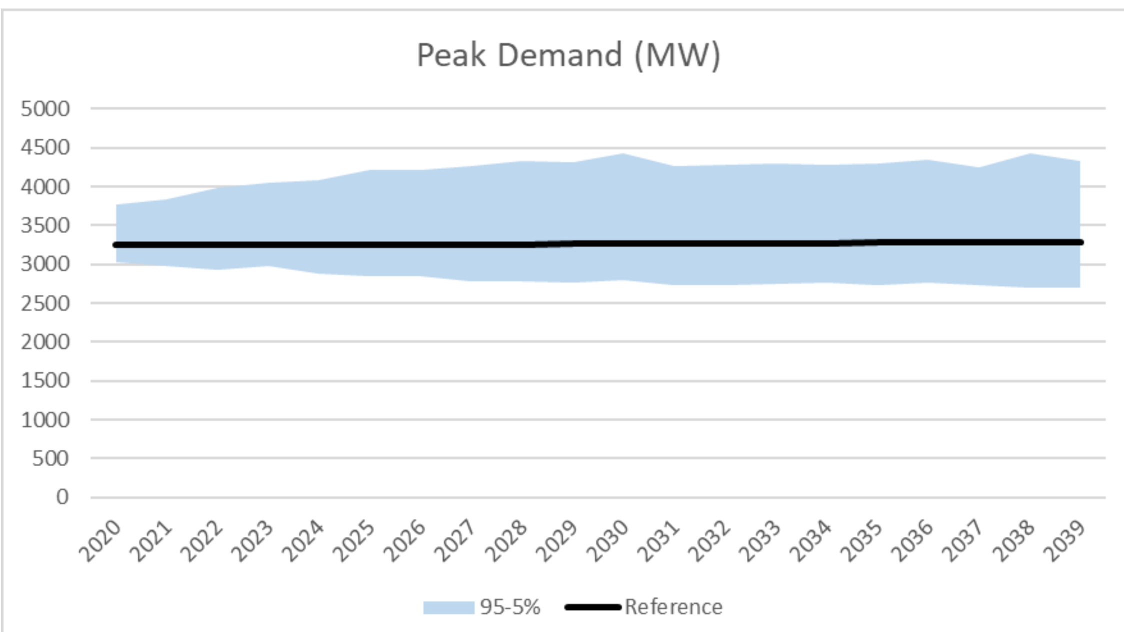
11.3.1 Load Stochastics

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 102: MLGW Load (MW) Distribution



Source: Siemens

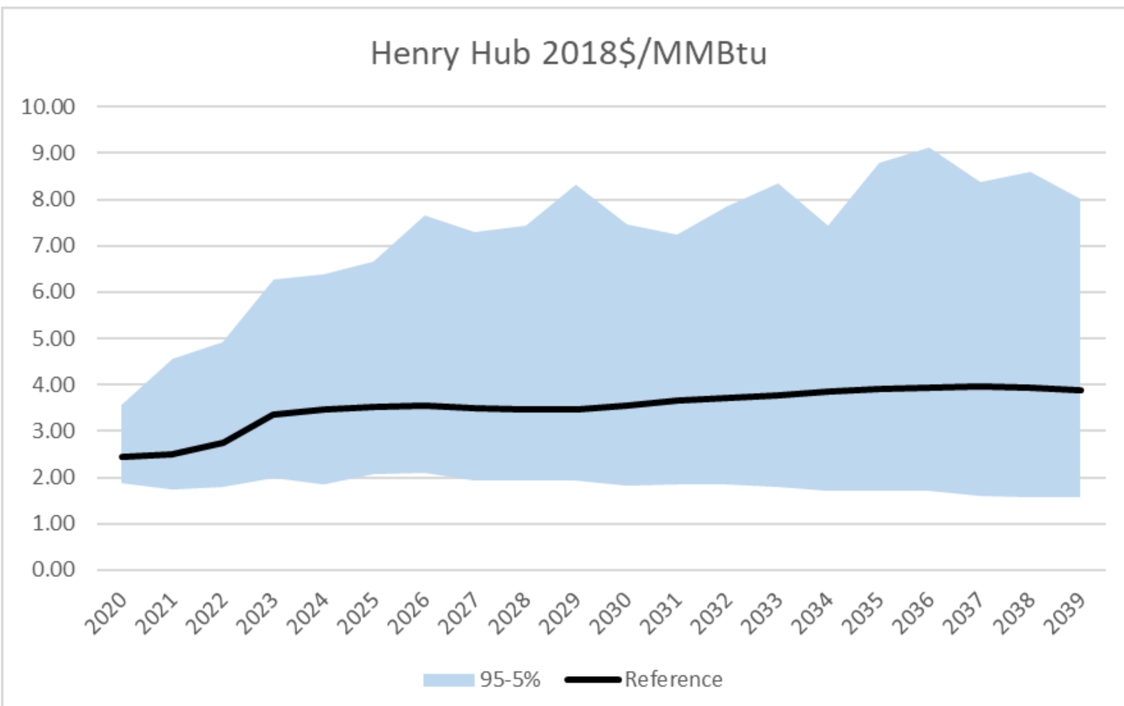


Source: Siemens

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

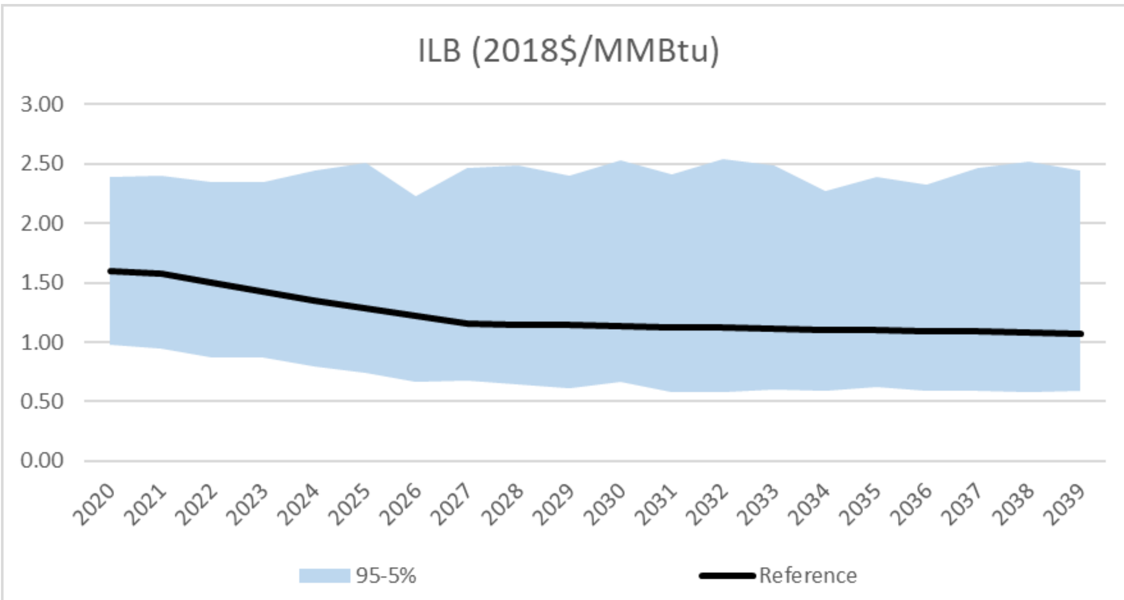


Source: Siemens

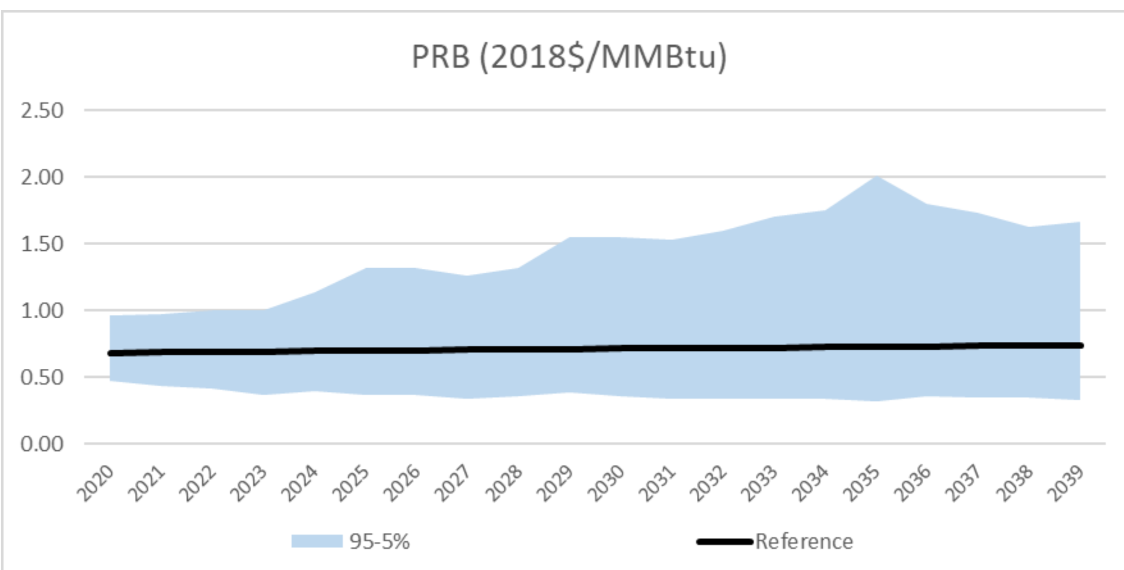
11.3.3 Coal Stochastics

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 104: Coal Price Distribution (2018 $/MMBtu)



Source: Siemens

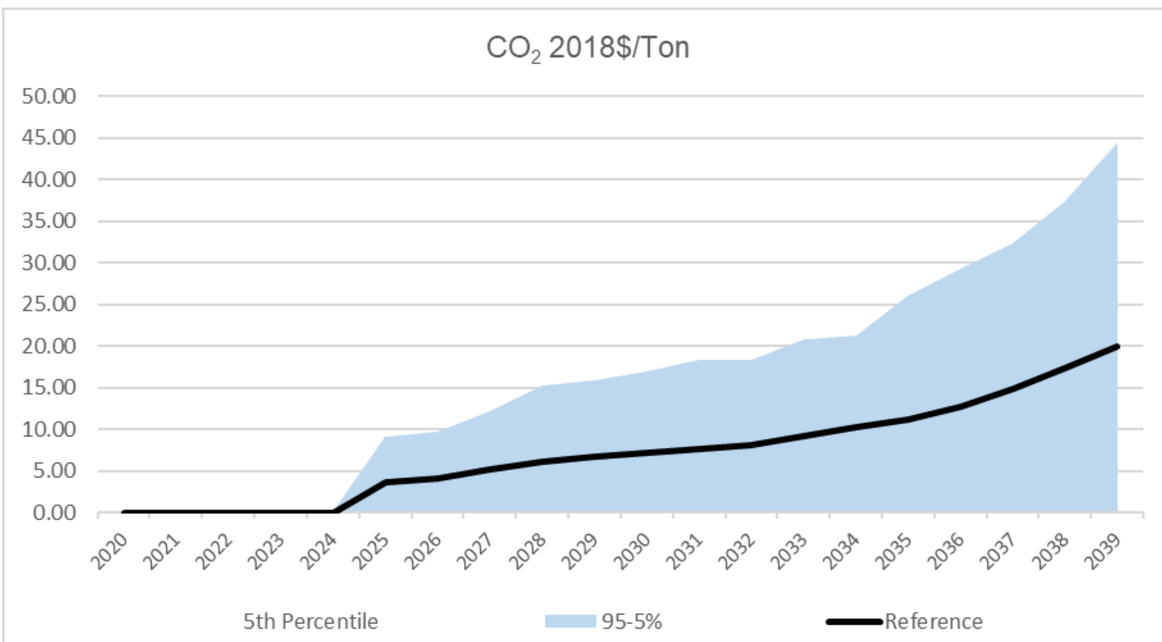


Source: Siemens

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 105: CO_2 Price Distribution (2018 $/ton)

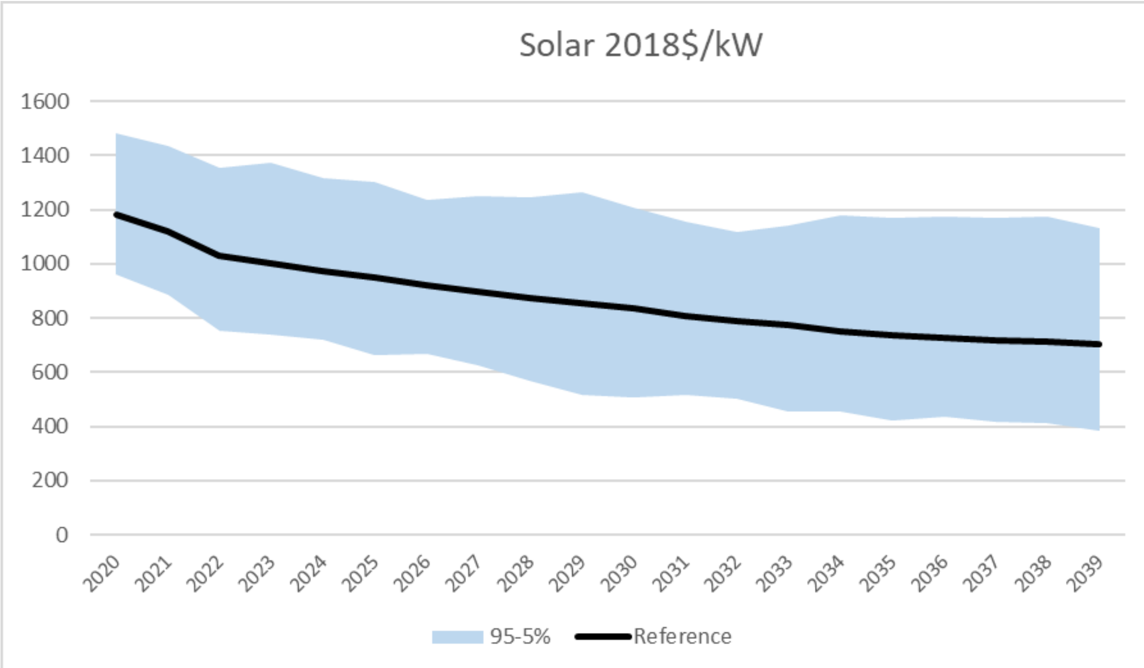


Source: Siemens

11.3.5 Capital Cost Stochastics

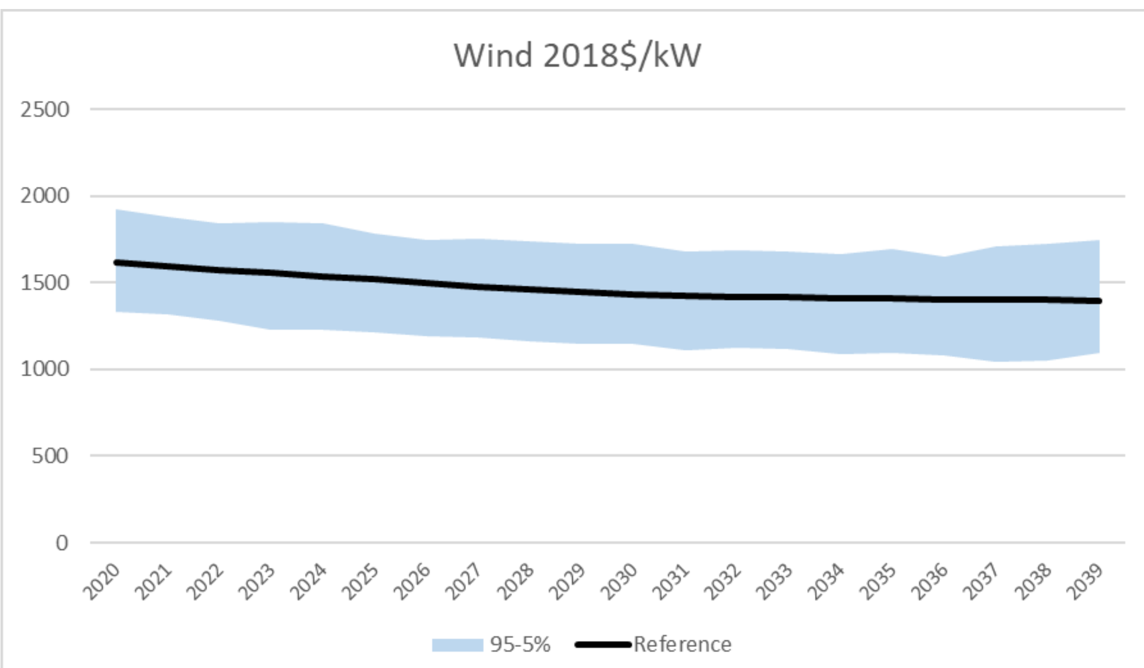
Siemens PTI developed the uncertainty distributions for the cost of new entry units by technology type, which was used in AURORA for determining the economic new builds based on market signals. These technologies included gas peaking units, gas combined cycles units, solar, wind, and battery storage 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 106: Solar Capital Costs Distribution (2018 $/kW)



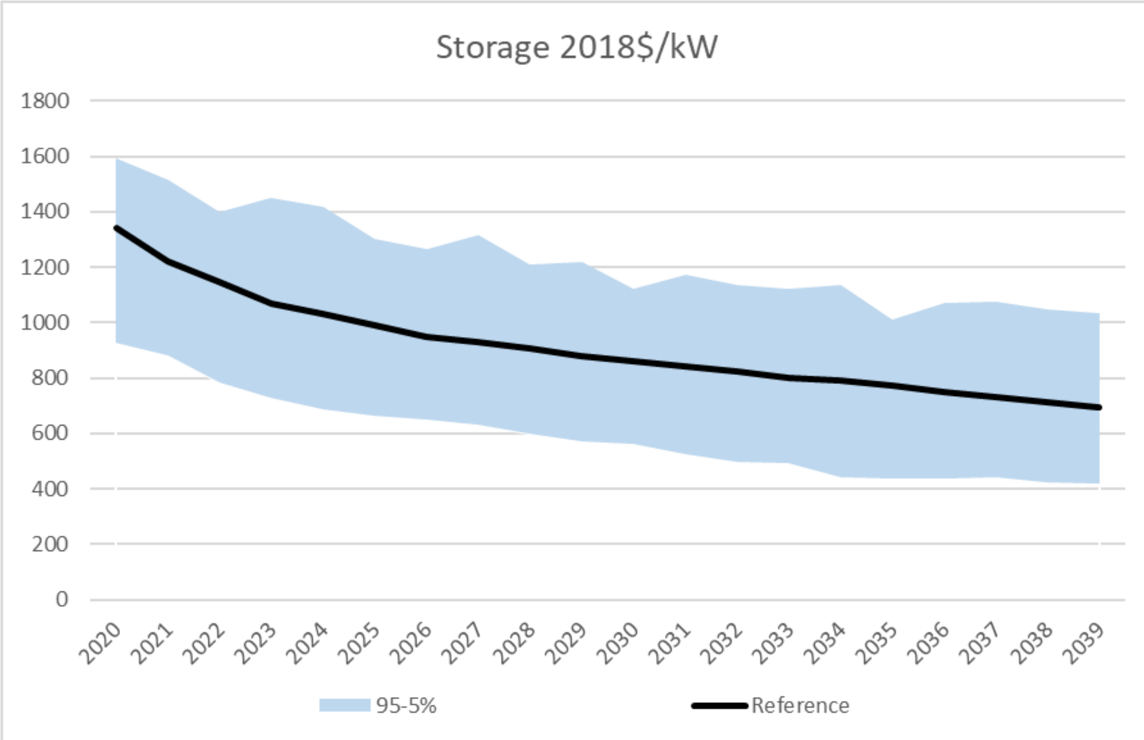
Source: Siemens

Exhibit 107: Wind Capital Costs Distribution (2018 $/kW)



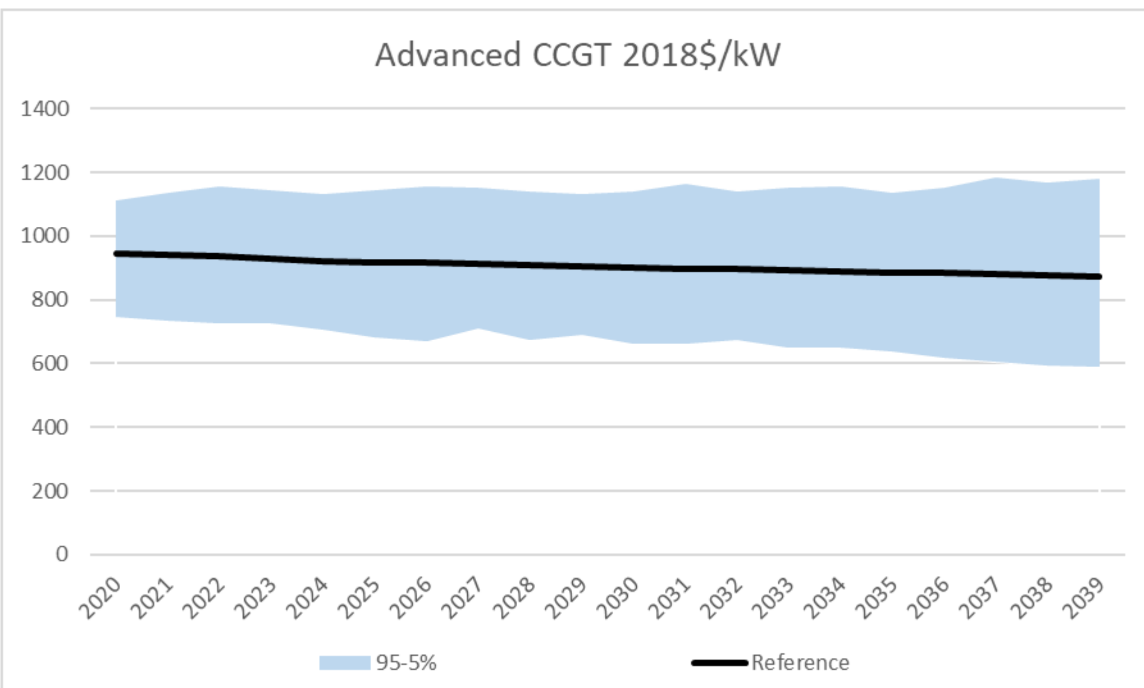
Source: Siemens

Exhibit 108: Lithium-Ion 4-hour Battery Storage Capital Costs Distribution (2018 $/kW)



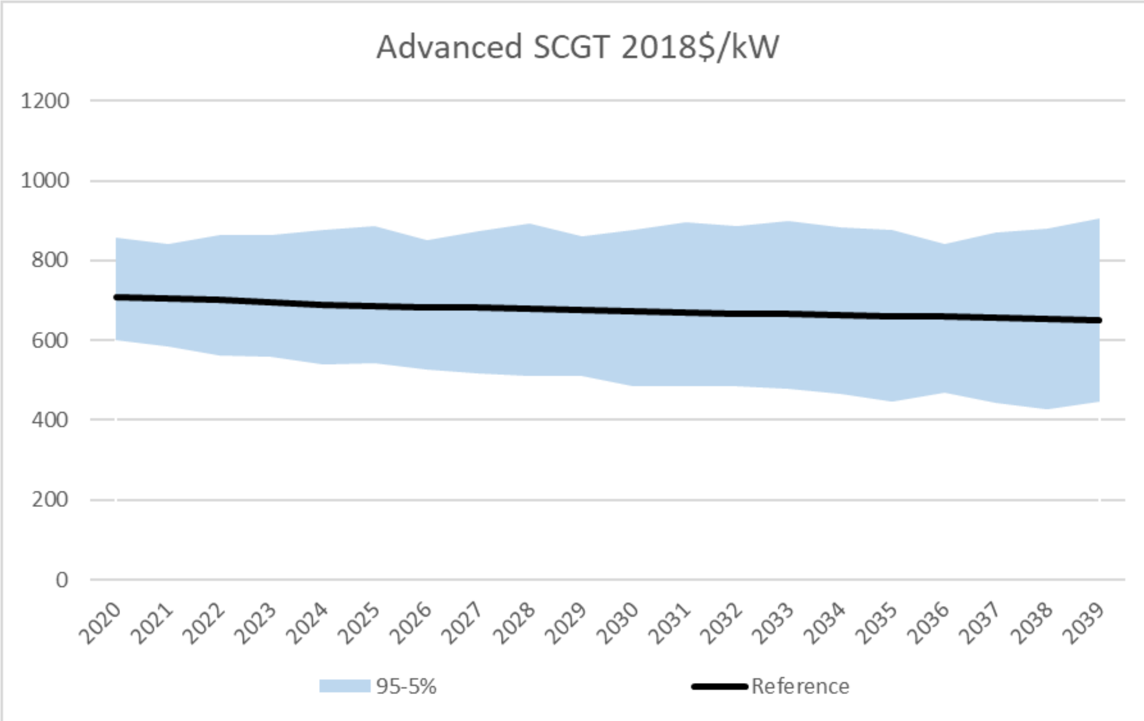
Source: Siemens

Exhibit 109: Advanced 2x1 Combined Cycle Capital Costs Distribution (2018 $/kW)



Source: Siemens

Exhibit 110: Advanced Simple Cycle Frame CT Capital Costs Distribution (2018 $/kW)



Source: Siemens

11.3.6 Cross-Commodity Stochastics

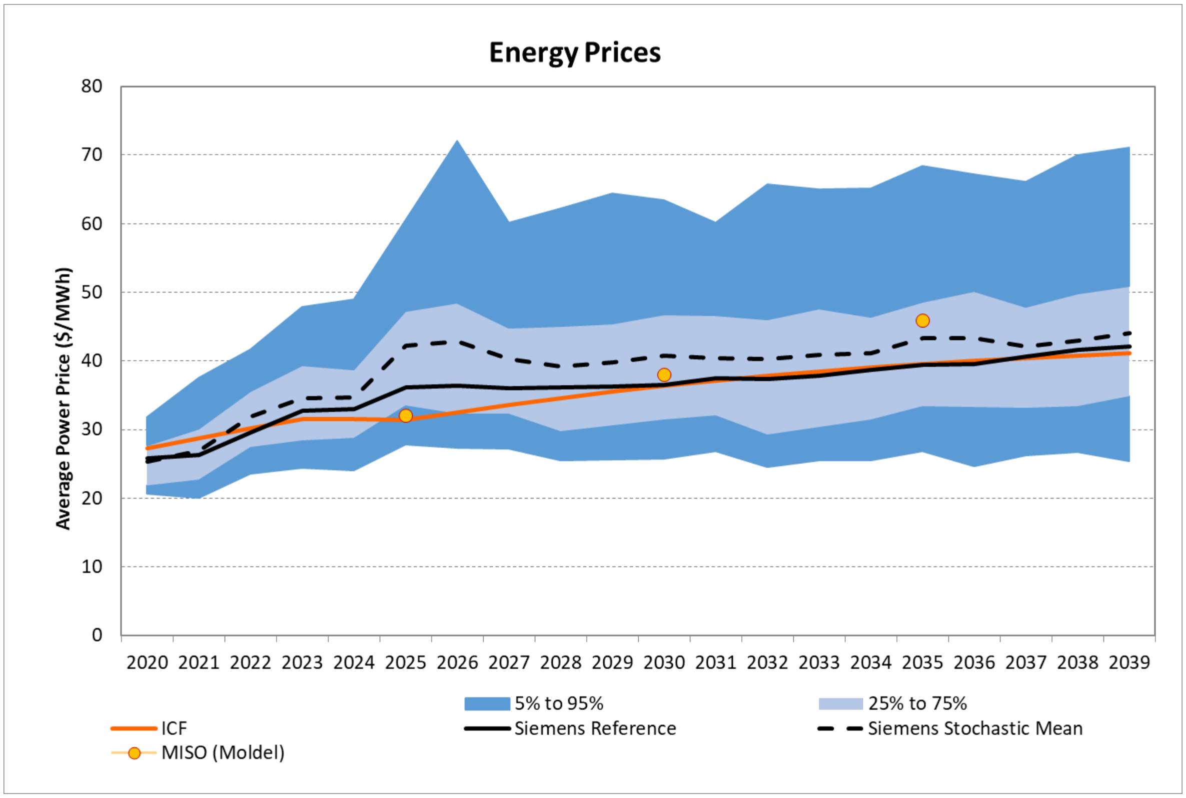
Siemens PTI captured the cross-commodity correlations in the stochastic process, which is a separate stochastic process from those for gas, coal and CO_2 prices. The feedback effects are based on statistical relationships between coal and gas switching and the variable cost of coal and gas generators. 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 Siemens has superimposed the ICF and MISO forecasts on the same graph as Siemens' distribution. They are well within the range of prices Siemens include in the 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 111: Stochastic Inputs – Energy Price 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 judgment 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 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, -the PILOT, or other requirements, etc.).

Exhibit 112: 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	Portfolio NPV Cost ($000)	Demand Weighted NPV ($/MWh)
S3S1	No	Base	Base	1137	1000	0	2137	2200	1761	0	2	1	0	9,054,690	50.00
S3S1_P	Portfolio 1	Base	Base	1137	1000	0	2137	2200	1761	0	2	1	0	9,089,087	50.19
S3S1_F	Portfolio 2	Base	Base	1587	1000	0	2587	1550	1487	0	3	1	0	9,300,273	51.36
S3S1_2CT	Portfolio 7	Base	Base	1374	1000	0	2374	2200	1550	0	2	2	0	9,125,223	50.39
S3S1_M	No	Base	Base	1930	650	0	2580	1050	1342	0	3	1	1	9,410,590	51.97
S3S1_MP	No	Base	Base	1587	750	0	2337	1800	1487	0	3	1	0	9,342,020	51.59
S3S1_A	No	Base	Base	1587	1000	0	2587	1150	1554	0	3	1	0	9,373,917	51.76
S3S2	No	High	Base	1824	1000	0	2824	1350	1746	0	3	2	0	10,770,685	51.24
S3S2_BB	Portfolio 3	Base	Base	1824	1000	0	2824	1350	1308	0	3	2	0	9,341,806	51.59
S3S3	No	Low	Base	1350	1000	0	2350	1550	1655	0	3	0	0	8,793,587	50.96
S3S3_BB	Portfolio 4	Base	Base	1350	1000	0	2350	1550	1697	0	3	0	0	9,126,137	50.40
S3S4	No	High	Low	1824	1000	25	2849	700	1849	0	3	2	0	9,140,036	43.48
S3S5	Portfolio 5	Base	Base	1398	1000	100	2498	3450	1183	0	1	4	0	8,980,510	49.59
S3S5_YD	Portfolio 9	Base	Base	1398	1000	100	2498	3450	1186	0	1	4	0	9,073,691	50.11
S3S6_N	No	Base	Base	900	1000	475	2375	2200	1505	0	2	0	0	9,414,739	51.99
S3S6	No	Base	Base	900	1000	475	2375	2200	1505	0	2	0	0	9,201,548	50.81
S3S7	No	Low	High	1137	1000	0	2137	2200	1718	0	2	1	0	9,965,303	57.75
S3S7_BB	Portfolio 6	Base	Base	1137	1000	0	2137	2200	1761	0	2	1	0	9,214,886	50.89
S3S7_2CT	Portfolio 8	Base	Base	1374	1000	0	2374	2200	1550	0	2	2	0	9,251,110	51.09
S3S10	Portfolio 10	Base	Base	950	1000	0	1950	2250	1901	1	0	0	0	8,532,493	47.12
S4S1	Portfolio All MISO	Base	Base	950	0	0	0	3200	1909	1	0	0	0	8,778,702	48.48

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 Portfolio 3. (As mentioned above, changing load, gas assumption, and other factors in the Scenarios 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 2,000 MW limit from MLGW to MISO. The import limit is about 300 MW more than the MLGW's peak forecasted load and 1,300 MW more than the import limit assumption in the reference base at 2,200 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 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 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[48]. 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 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 and Portfolio 9). In this Scenario, we did not offer the option to build any CT units to see if any BESS will be selected.

[48] The high gas prices in this scenario could be directly due to an increase in the price of the commodity or more likely due to combination of increases in commodity plus CO_2 emissions costs $/Ton. In the gas price increase by 210% in this scenario by 2039 as compared with 59% in the base scenario.

When CTs were not offered as options, 475 MW of BESS were selected, which is equal to the capacity of 2 CTs (S3S6_N). However, due to the relatively high capital cost of BESS compared to CT, the NPV of the S3S6_N case is the highest among all reference cases[49].

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 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 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.

[49] BESS have multiple value streams, and this includes the energy shifting, i.e. moving renewable energy from daytime to nighttime. However, in the case of MLGW this service can also be provided by selling energy to MISO during the daytime and purchasing it back at night. The optimization program found this later to be the preferred option. In addition to the above BESS also provides local reserves and peaking service that the optimization program found that it was more effective provided using CTs.

Exhibit 113: 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) and, MISO Admin costs, as well as costs of replacing TVA's energy efficiency, demand response and renewable generation programs. 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 percentage 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 3,197 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 and highlight differences.

Economic Growth is calculated based on the total generation and transmission investment capital expenditure in the region expressed in millions of dollars in 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 plus state and local tax revenue for the region.

Exhibit 114 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 114: Strategy 3 Portfolios Balanced Scorecard (Reference Case Conditions)

	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%

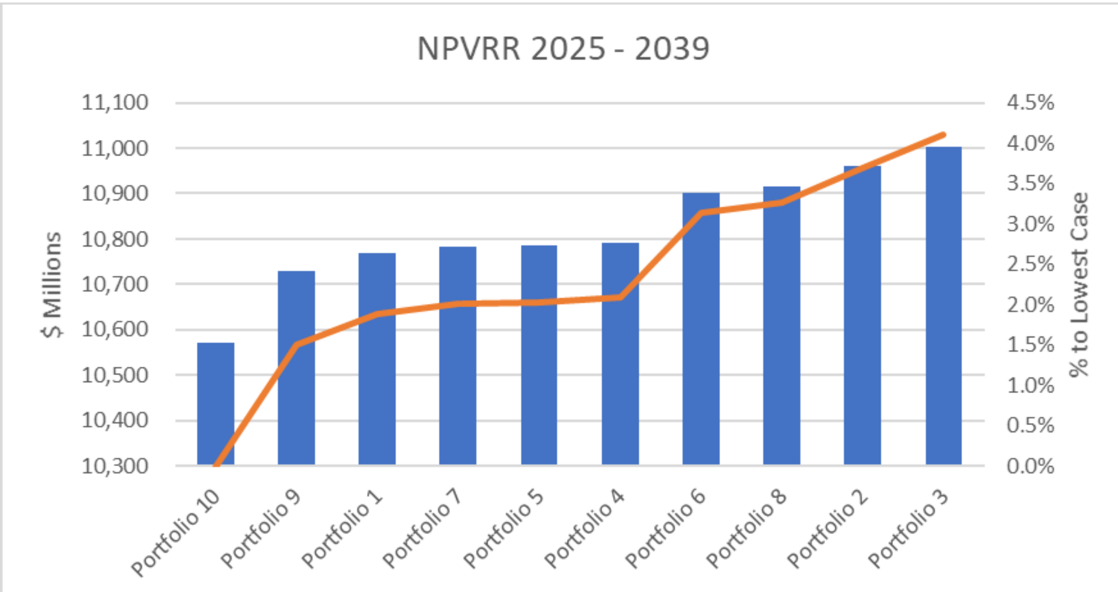
All $ in 2018 | Local = Shelby County, TN

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 115: Least Cost NPVRR



Source: Siemens

In the exhibit above and throughout this document the bars represent the metric in reference (e.g. the NPVRR in this case) and are measured against the left axis and the lines are the percentages and measured against the right axis.

Note that the total NPV differences are very small for the Portfolios where 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

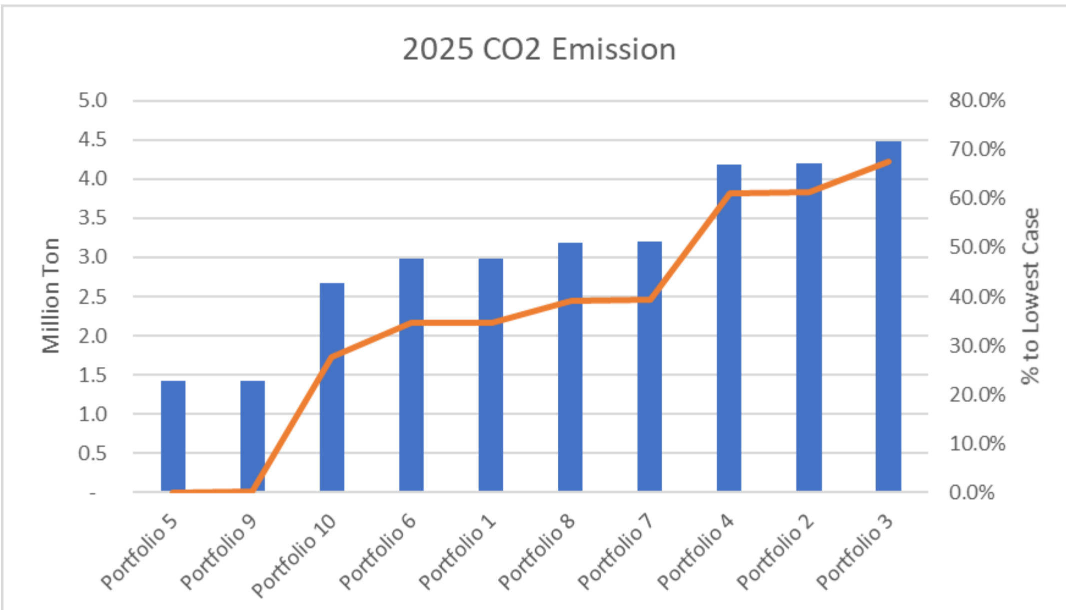
Portfolios 5 and 9 with one CC unit and heavy renewable buildout have the lowest CO_2 emission, water consumptions, and the highest RPS, all by a significant margin.

The 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 assumed local solar PV constraint of 1000 MW.

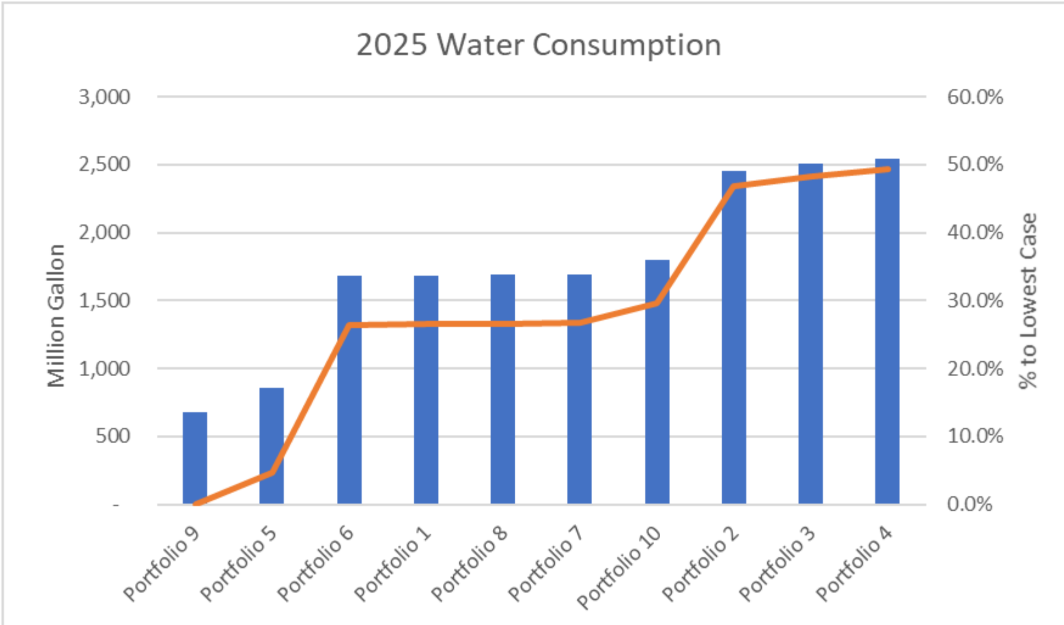
The exhibits below provide a visual comparison of the ten Portfolios. Note that for CO_2 we show the emissions of the portfolio generation fleet as the purpose here is to highlight differences. In the stochastic section we add the effect of the CO2 production from MISO net purchases as this is the metric that will be used for comparison with the TVA.

Exhibit 116: 2025 MLGW Generation CO_2 Emission



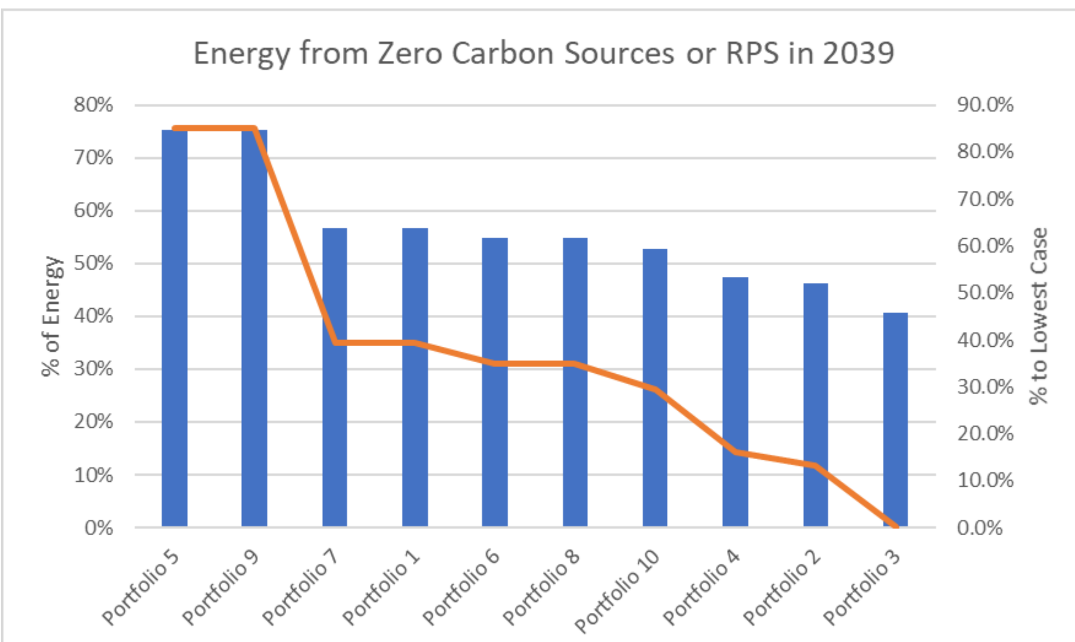
Source: Siemens

Exhibit 117: 2025 Water Consumption



Source: Siemens

Exhibit 118: Energy from Zero Carbon Sources or RPS in 2039

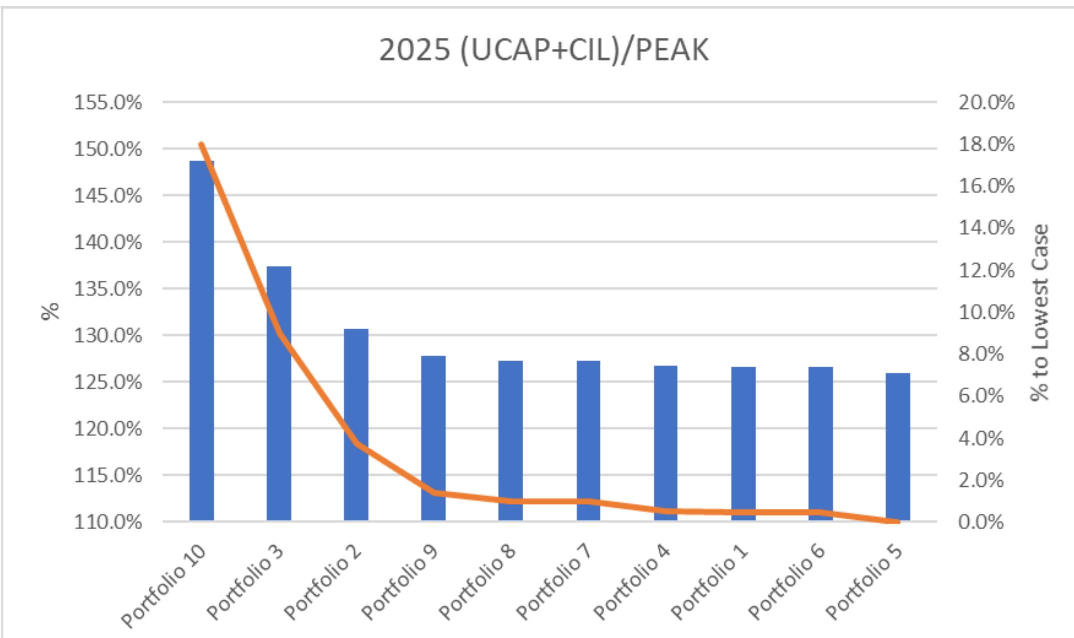


Source: Siemens

12.4.4 Reliability

Portfolio 10 ranked the highest score (148%) in the Reliability metric due to the preservation of high transmission integration with MISO for the All MISO Strategy (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 119: Reliability Metric



Source: Siemens

12.4.5 Resiliency

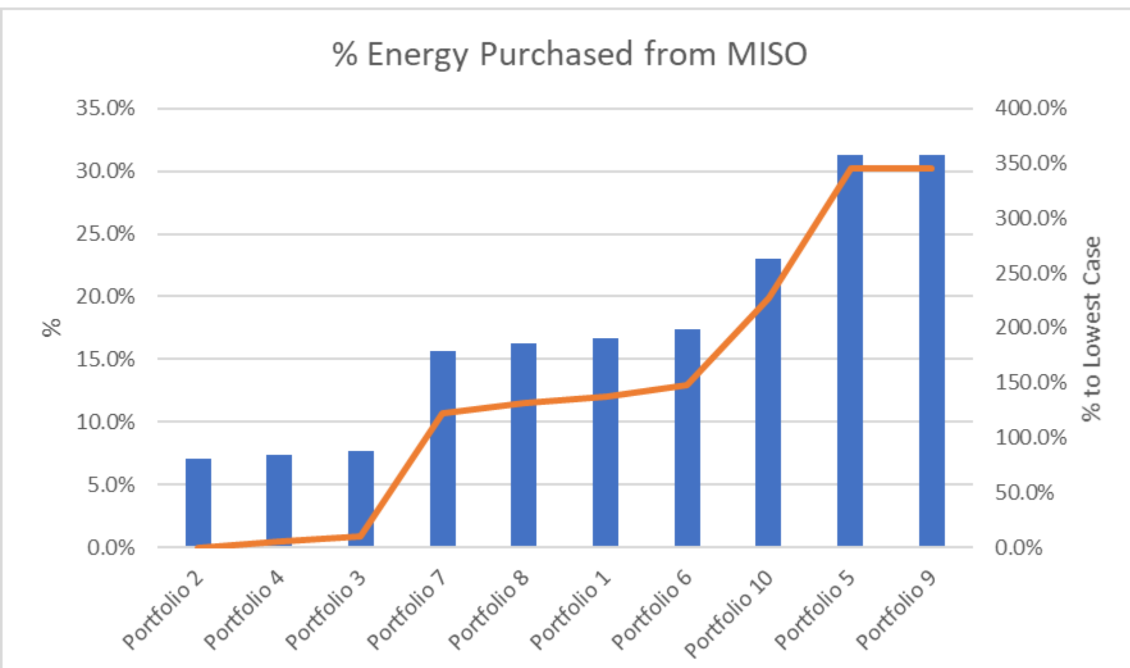
The Resiliency is assessed on the potential load shed amount by MLGW under N-2 conditions. These are the extreme but very rare events and which, if these occur, could mean extended power outages. All final Portfolios perform well except Portfolio 5 which shows a possibility of more than 600 MW of load 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 uncertainties 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.

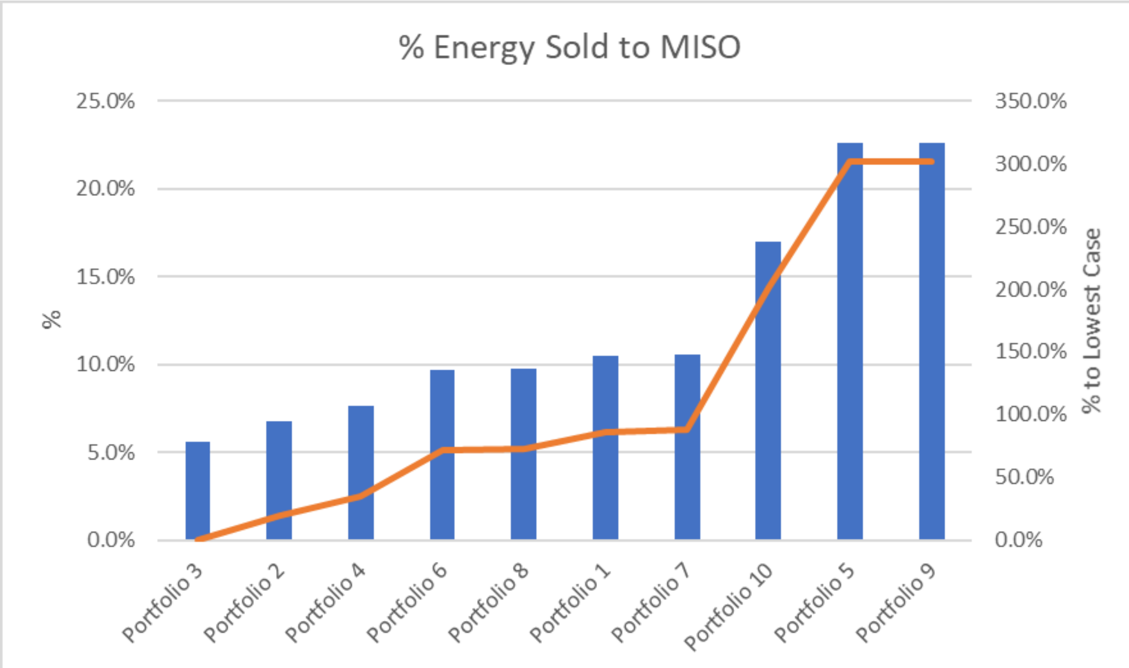
The Market Risk of energy sales is not as significant as the risk from energy purchases, given that the nature of the energy surplus coming from MLGW is mostly energy from renewable generation. Market purchases mostly at night, when renewable energy is not available, represent a higher risk due to price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

Exhibit 120: Market Risk-Energy Purchases



Source: Siemens

Exhibit 121: Market Risk-Energy Sales



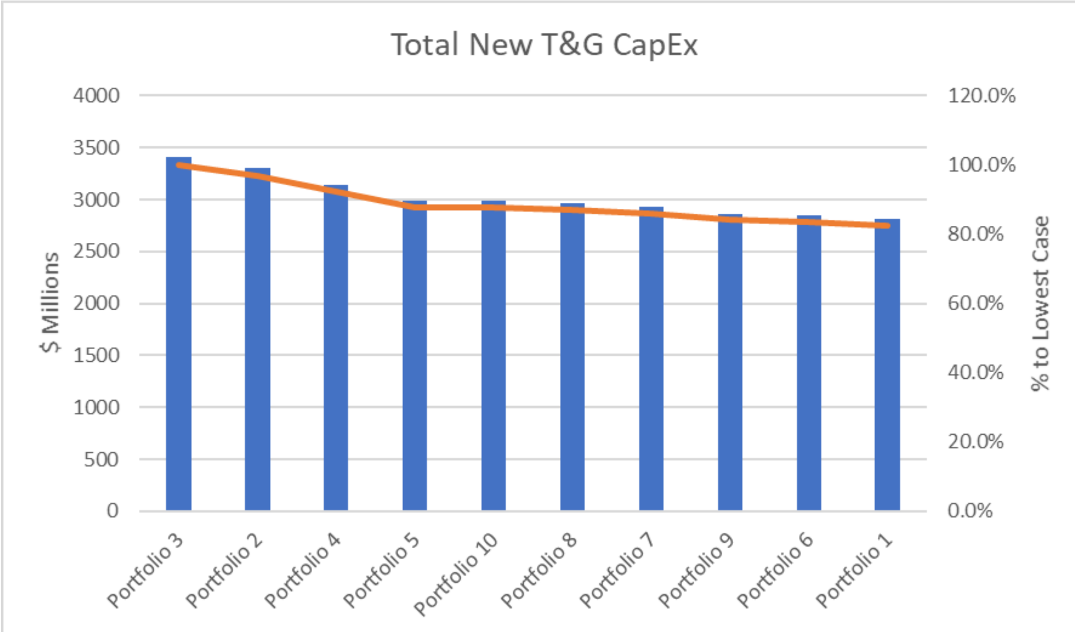
Source: Siemens

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 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 122: Local Economic Growth T&G CapEx



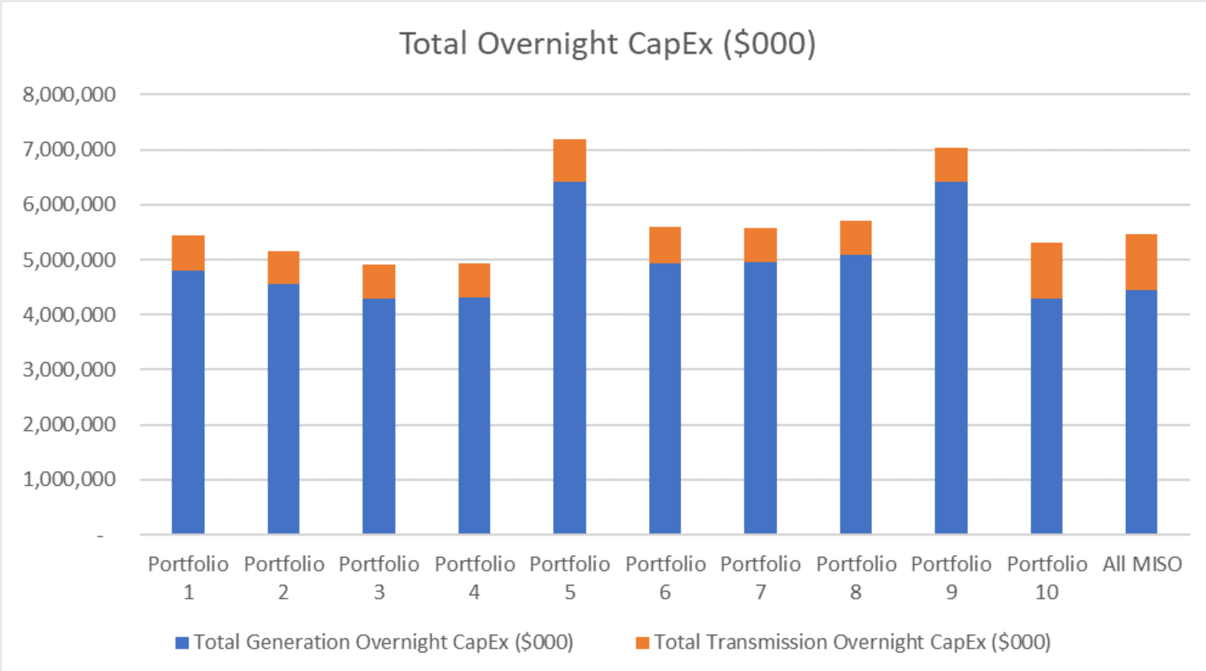
Source: Siemens

12.4.8 Capital Expenditure

The figure below shows the total capital expenditure by portfolio. Note that only the transmission CapEx is expected to be covered by MLGW as the generation capex is assumed to be expensed by third parties and recovered via PPA payments from MLGW. The CapEx includes all costs to the commissioning of the project including interests during construction. This CapEx will be spent at different times over the development of the various portfolios as shown in Appendix D: Portfolio Details where the overnight CapEx at the year that the project comes in service is shown.

It can be observed below that the highest overnight CapEx ($7.18 billion) occurs in Portfolio 5 followed by Portfolio 9 ($ 7.0 billion).

Exhibit 123: Total Overnight 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 124, 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 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 124: 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	2,940,414	3,589,347	3,953,393	3,865,043	1,656,530	2,552,458	2,940,662	2,552,706	1,657,373	3,091,664
		% to Lowest Case	78%	117%	139%	133%	0%	54%	78%	54%	0%	87%
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 2025-2039	MW	1931	1655	1509	1943	1885	1808	1720	1598	1270	2082
		% to Lowest Case	52.0%	30.2%	18.8%	52.9%	48.4%	42.3%	35.4%	25.7%	0.0%	63.9%

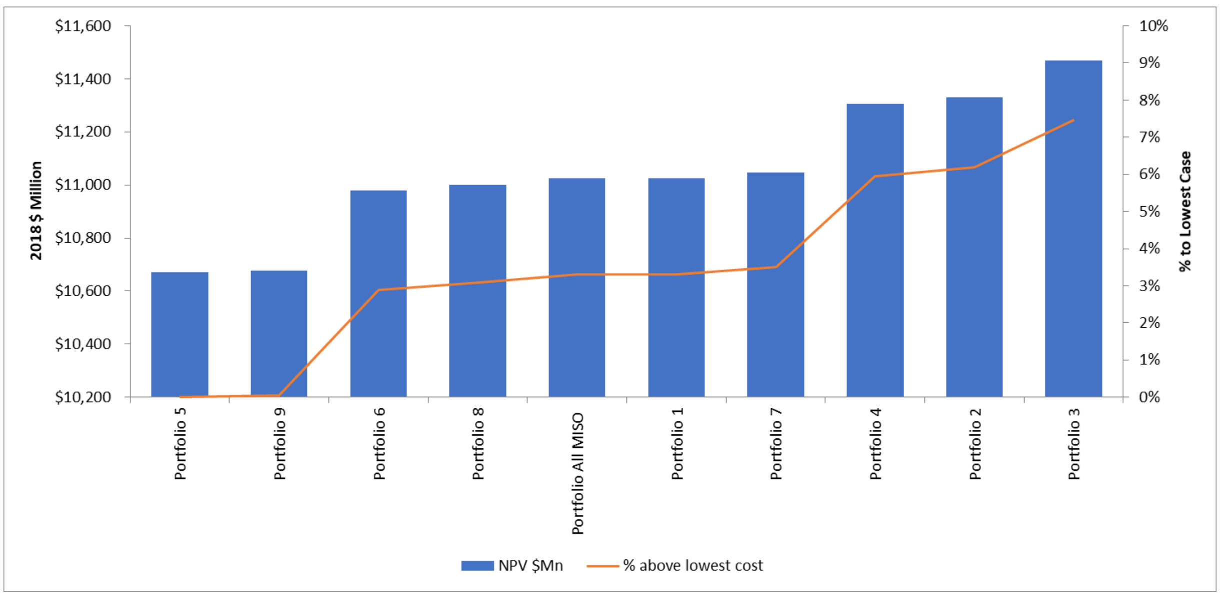
Source: Siemens

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 125: Mean of NPVRR



Source: Siemens

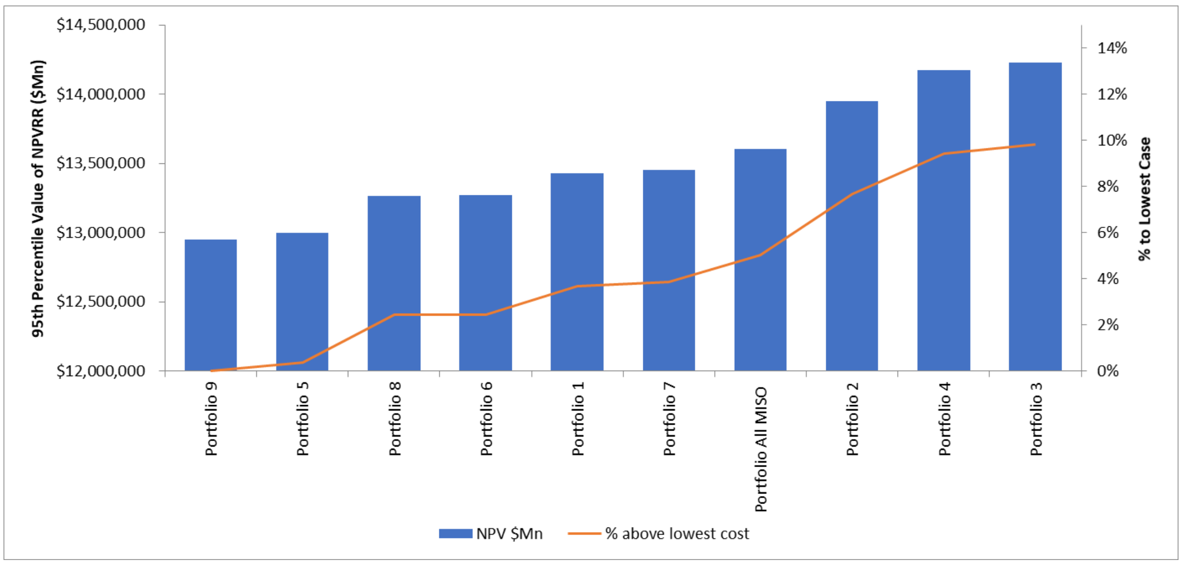
As indicated earlier, in the exhibit above and throughout this document the bars represent the metric in reference (e.g. the NPVRR in this case) and are measured against the left axis and the lines are the percentages and measured against the right axis.

12.6.2 Price Risk Minimization

In addition to the expected NPVRR of portfolio cost, 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 126 shows the 95th percentile of NPVRR for each portfolio. The 95th percentile costs of Portfolios 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.

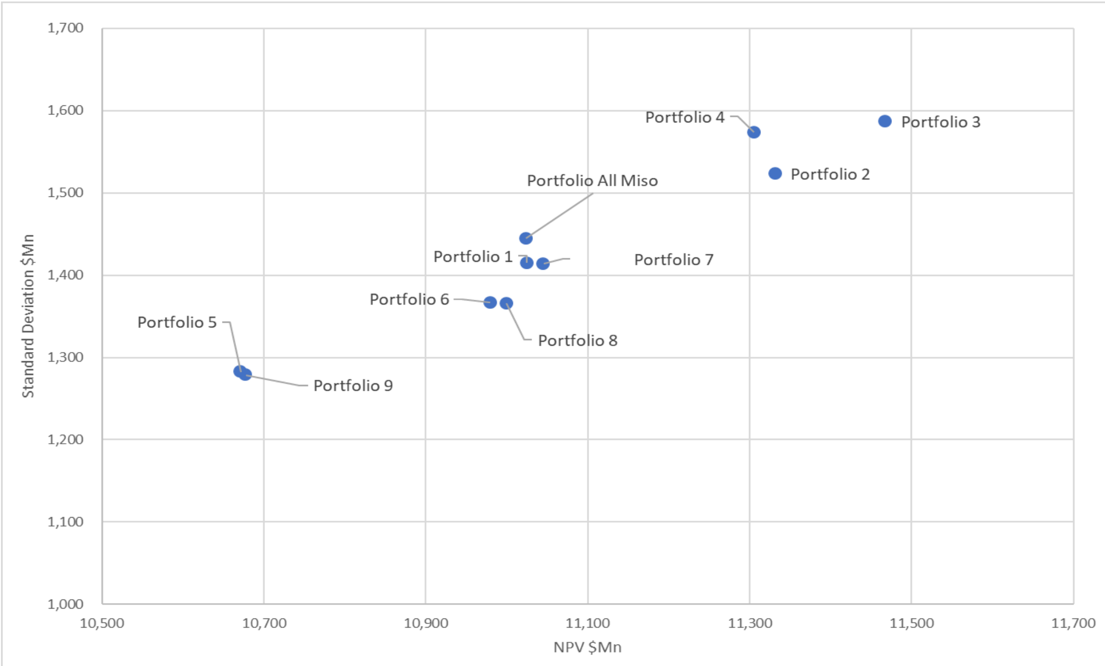
Exhibit 127 shows the trade-off of NPVRR and variability (Standard Deviation) of NPVRR. Portfolio 5 shows the best cost-risk trade-off, while Portfolio 3 (3 CCGTs + 2 CTs) has the poorest expected cost-risk tradeoff compared with other portfolios. We also note clusters around 1 CCGT (Portfolio 5, 9), 2 CCGTs (Portfolios 1, 6, and 7) and 3 CCGTs (Portfolios 2, 3, and 4).

Exhibit 126: 95th Percentile of NPVRR



Source: Siemens

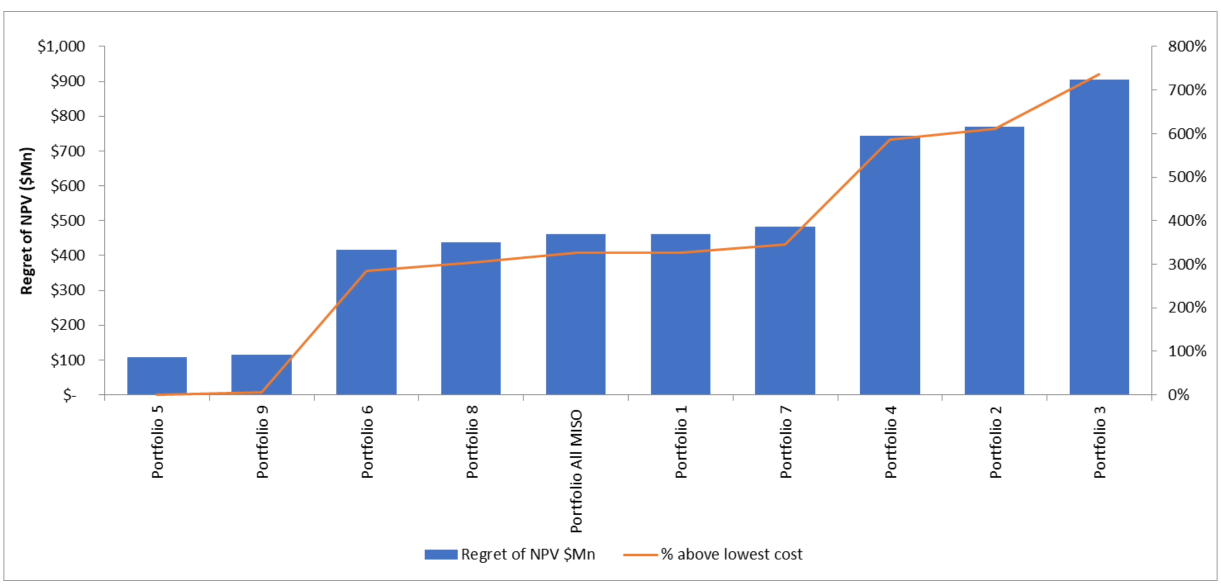
Exhibit 127: Cost-Risk Trade-off



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 128 shows the regret by Portfolio.

Exhibit 128: NPVRR Regret



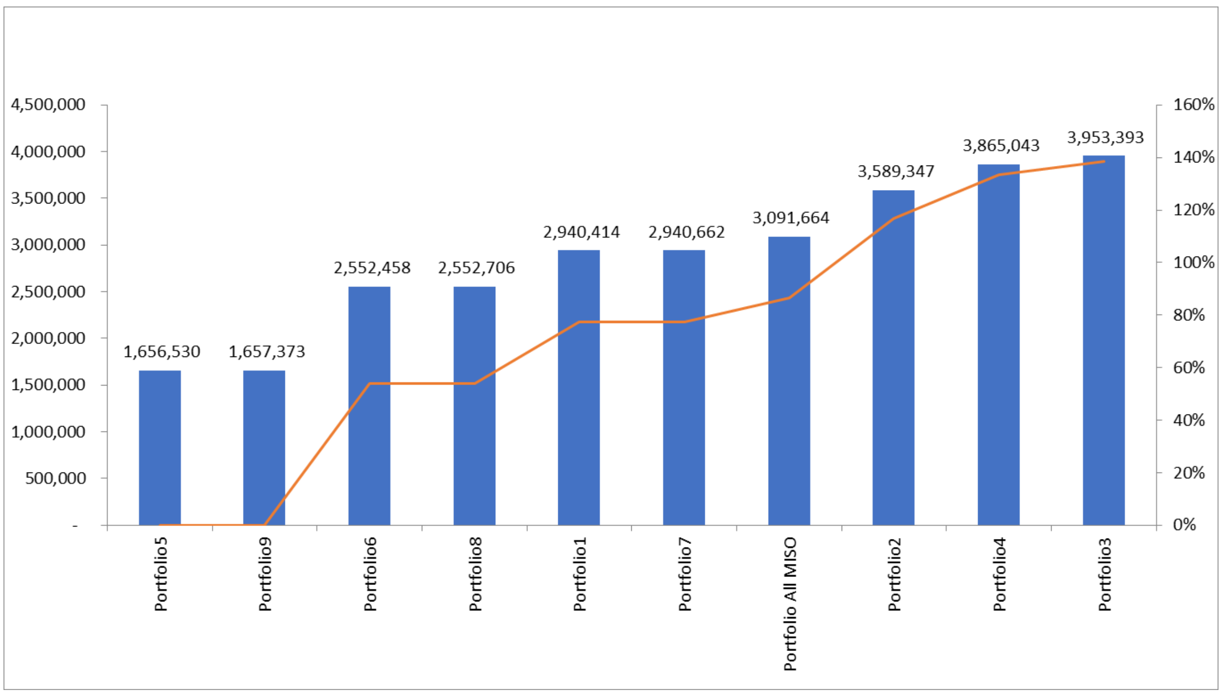
Source: Siemens

12.6.3 Environmental Risk Minimization

Environmental risk is measured as average annual portfolio carbon emissions including the emissions associated with the net energy purchases from MISO determined considering MISO's CO_2 emissions in Tons/MWh. 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 1.5 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 4 million tons (see Exhibit 129).

Most portfolios, except for the portfolios that have 3 combined cycle units, would result in lower emissions relative to the expected levels from TVA Portfolio, as will be shown in Section 13.

Exhibit 129: Average MLGW CO_2 Emissions from 2025 to 2039 (tons)



Source: Siemens

12.6.4 Market Risk Minimization

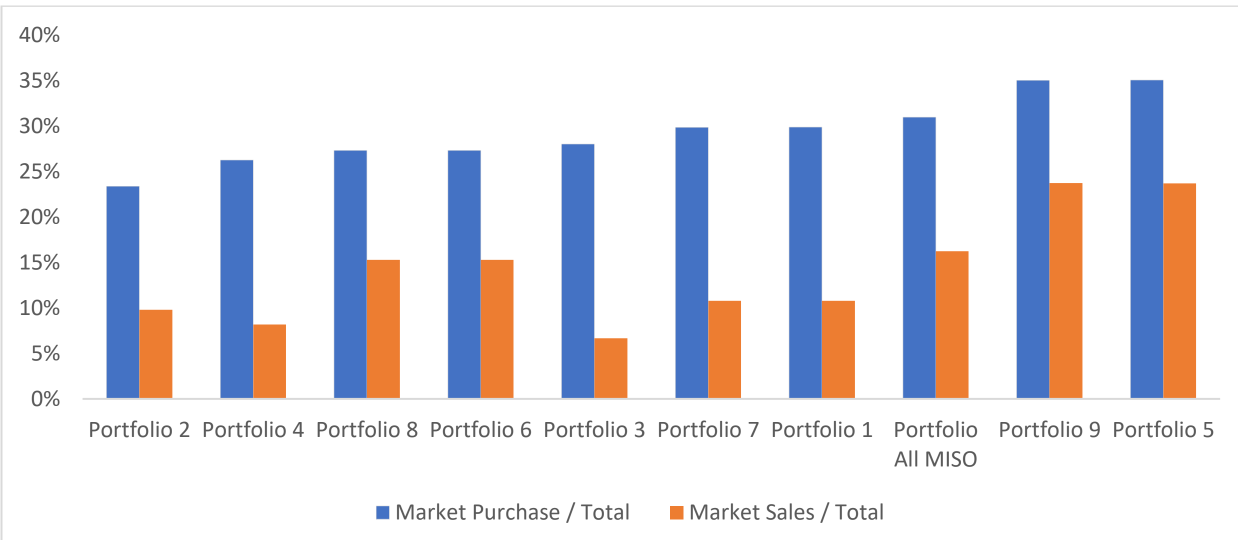
If MLGW were to join MISO, a significant portion of MLGW's energy and capacity need may come from the MISO energy market and capacity market. The amount of spot energy purchases depends on MLGW's total energy need, as well as the least cost dispatch of MISO resources, and the amount of capacity needs 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 130 shows the average percentage of energy exposed to market purchases and market sales, respectively. The higher the percentage is, the higher the market risk is, and the more 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 the daily shape of solar generation, 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 130: Market Purchase and Sales as Percentage of Load

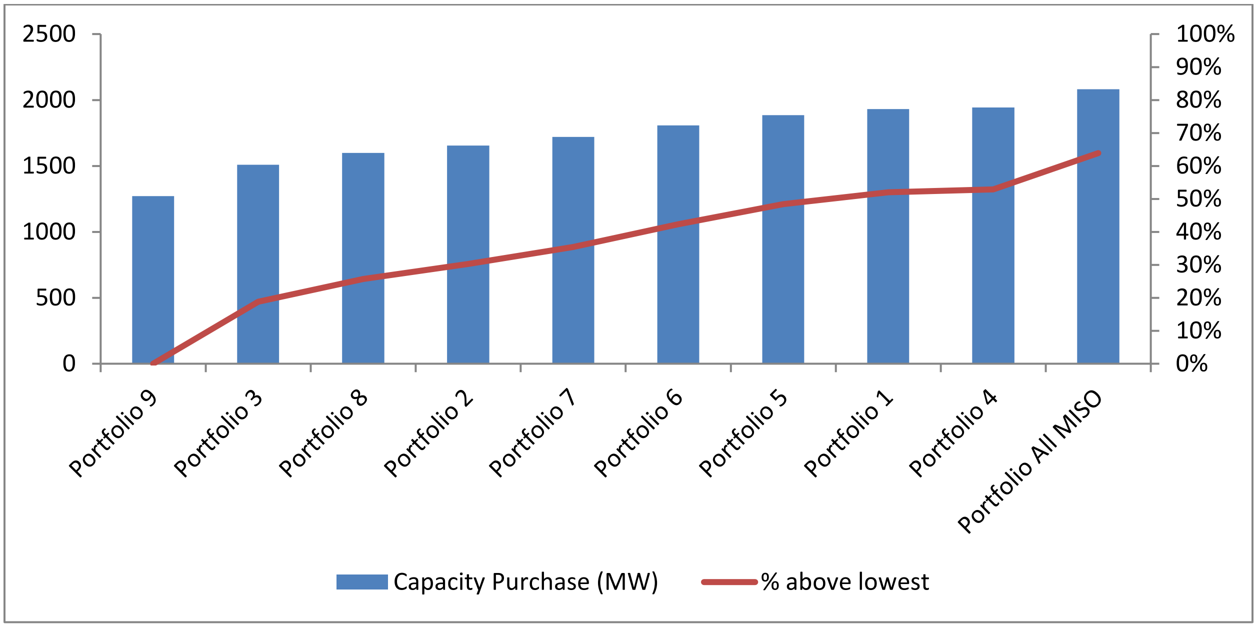


Source: Siemens

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 131: MISO Capacity Purchase



Source: Siemens

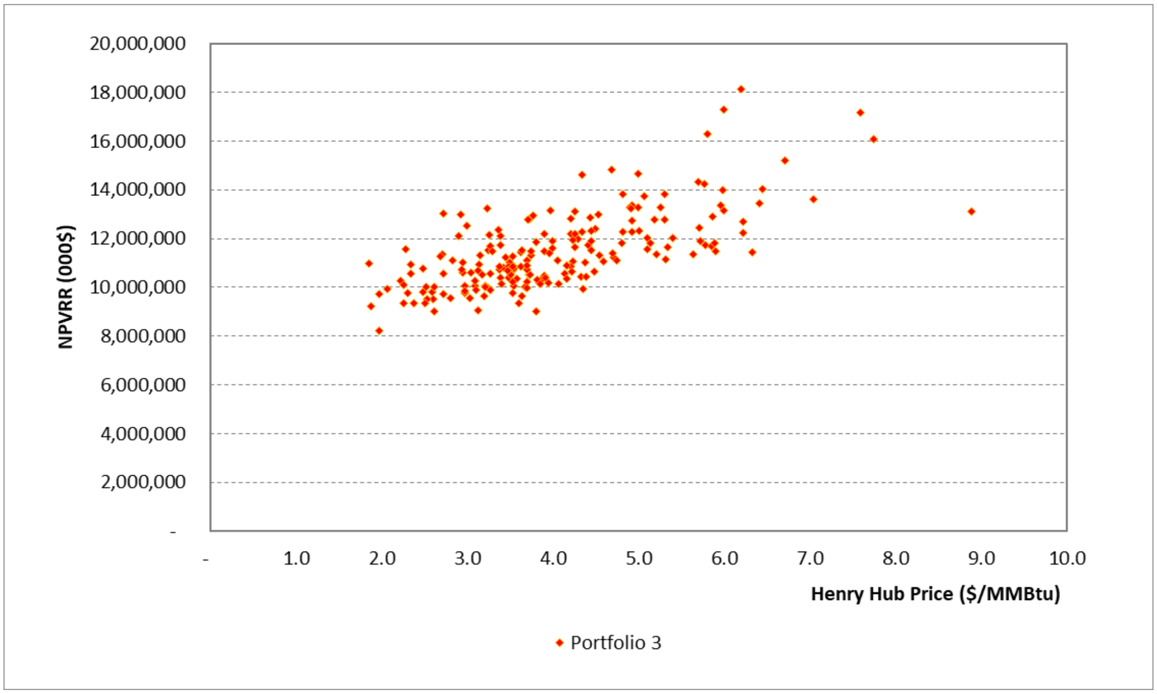
12.6.5 NPV Correlation with Inputs

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 clarifies the impact of several important inputs.

NPV Correlation with Gas Prices

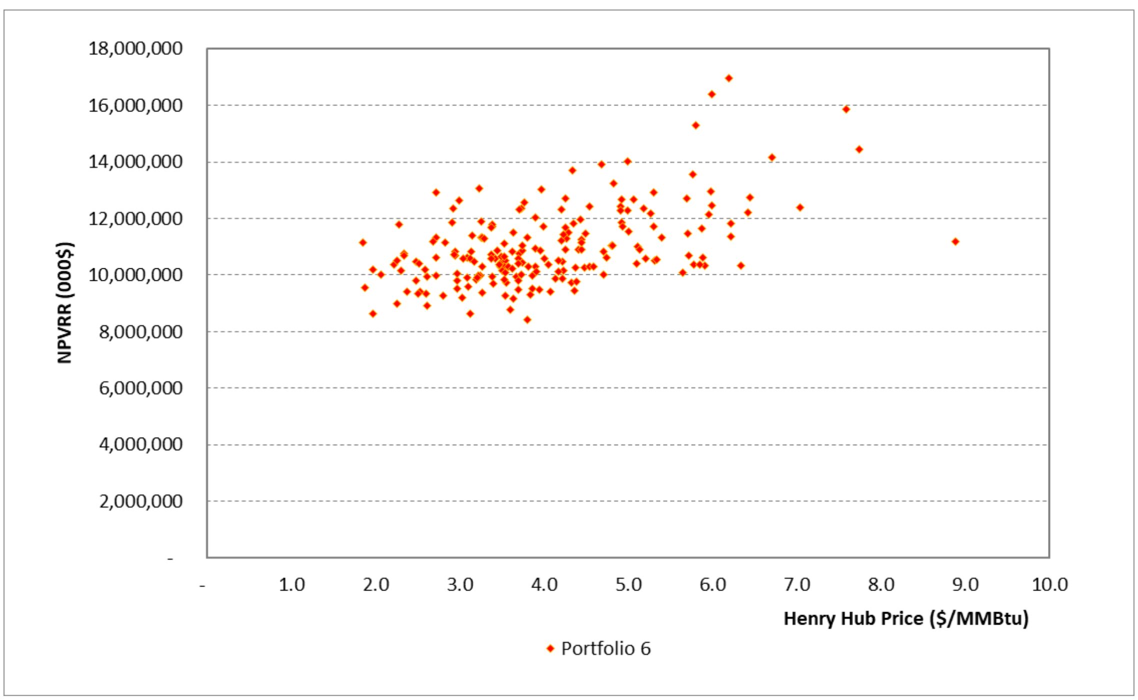
As illustrated in Section 11, gas prices are quite volatile, with a wide range of outcomes in the medium to long term, which could be driven by increased gas demand, fracking regulation, environmental regulation, and other factors. In Siemens forecast, the standard deviation expressed as a function of the mean of annual gas prices is about 40% which means 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 numbers of CC units are presented in the following exhibit to illustrate this correlation.

Exhibit 132: NPVRR with Henry Hub Gas Price Correlation (Portfolio 3)



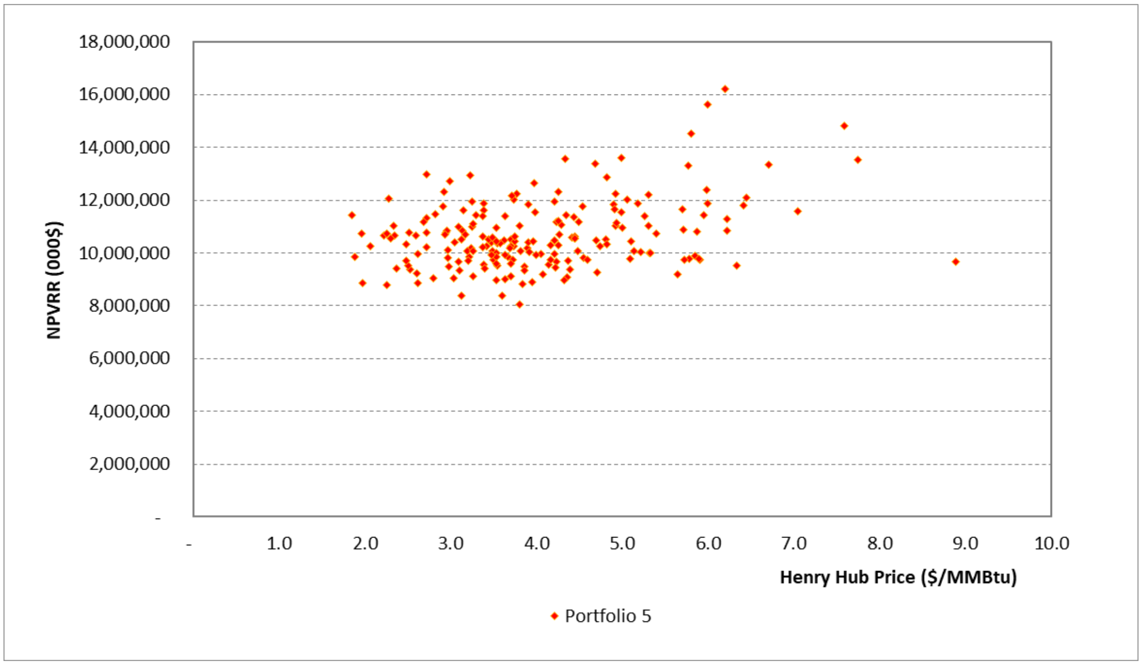
Source: Siemens

Exhibit 133: NPVRR with Henry Hub Gas Price Correlation (Portfolio 6)



Source: Siemens

Exhibit 134: NPVRR with Henry Hub Gas Price Correlation (Portfolio 5)



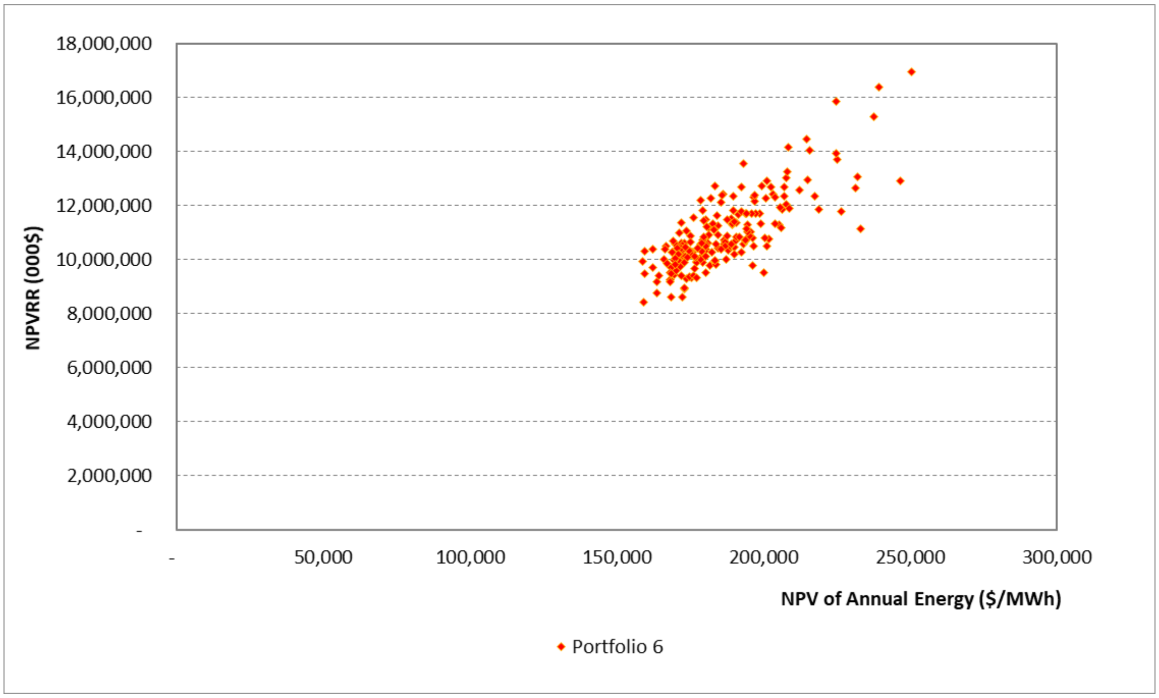
Source: Siemens

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

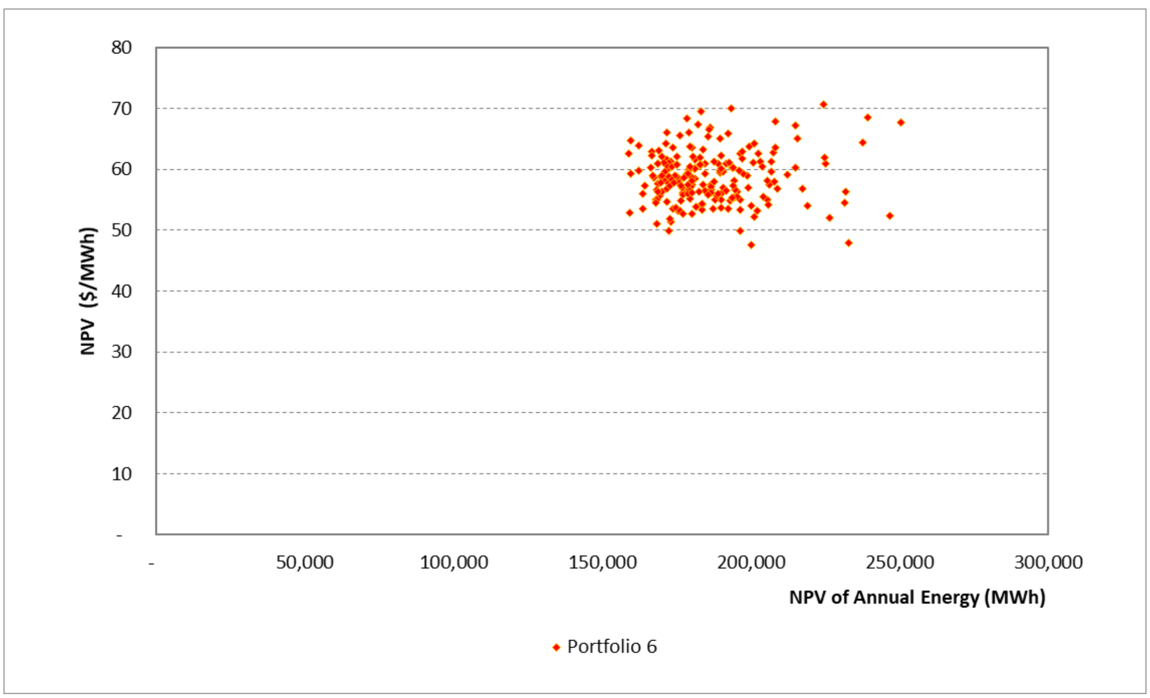
Load is a large driver of the NPVRR. Using Portfolio 6 as an example, Exhibit 135 shows a strong and tight positive correlation between the NPV of annual energy and NPVRR However, if we take out the impact of the absolute value of the load from the NPV and only show the $/MWh cost for the NPV, there is no correlation.

Exhibit 135: NPVRR with Load (Portfolio 6)



Source: Siemens

Exhibit 136: NPVRR per MWh with Load (Portfolio 6)

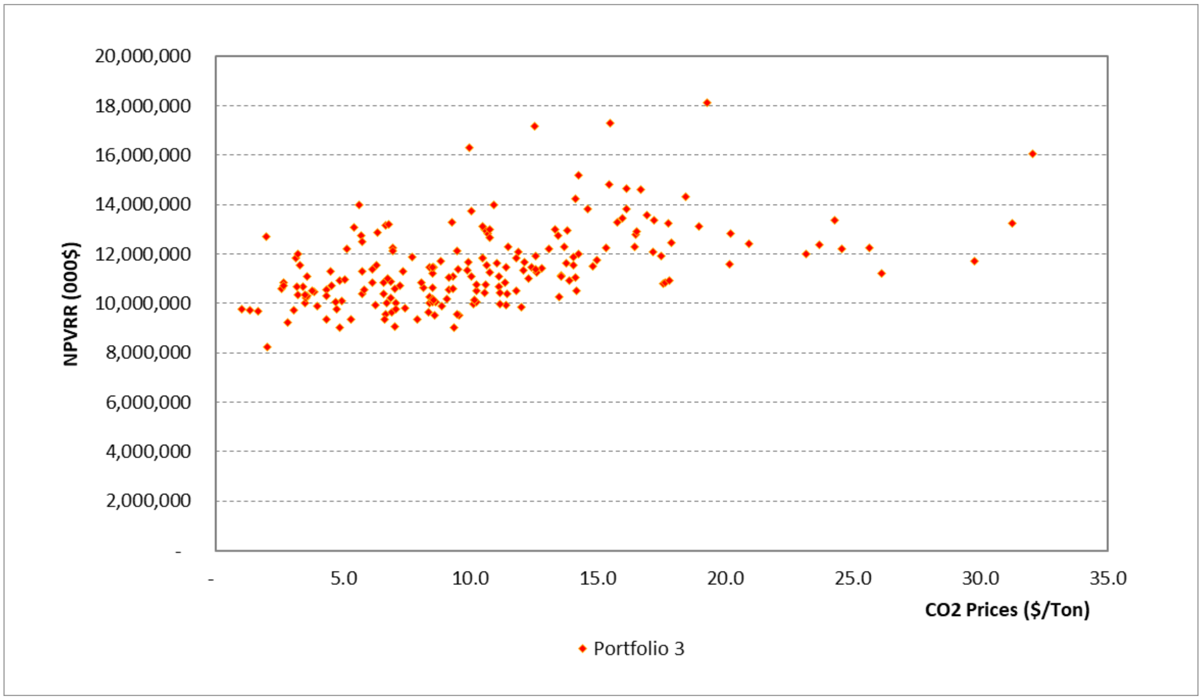


Source: Siemens

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 137 shows weak correlation between the average CO_2 price and NPVRR.

Exhibit 137: NPVRR with CO2 Prices (Portfolio 3)



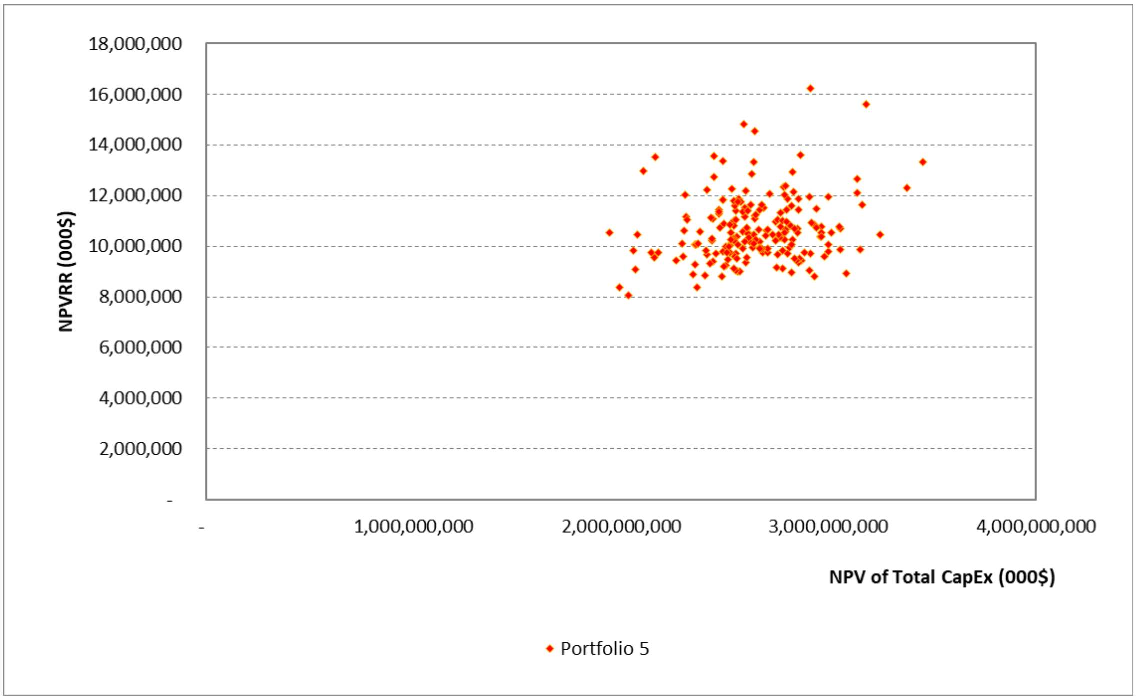
Source: Siemens

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 Siemens 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 are a large portion of total portfolio cost, the low volatility of the aggregated capital costs, means it is not, a good explanatory variable for the NPV, compared to other factors such as gas prices.

The weak correlation can be observed in Exhibit 138 below for Portfolio 5. which has the largest capital cost. The trend is clearly in the positive direction, but the variability is not heavily correlated.

Exhibit 138: 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, lowest risk as measured in 95th percentile and lowest regret. It also has the best environmental performance. However, from a reliability point of view Portfolio 5 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 is similar to Portfolio 5; it is less than 1% more expensive and slightly higher emissions than Portfolio 5. With all four CTs installed by 2025, there would be no load shedding with Portfolio 9 under the extreme event considered. Portfolios 6 and 8, which 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 139: 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%
Min Envr. Risk	CO_2 Emissions Mean 15-Year	Tons CO_2	2,940,414	3,589,347	3,953,393	3,865,043	1,656,530	2,552,458	2,940,662	2,552,706	1,657,373	3,091,664
		% to Lowest Case	78%	117%	139%	133%	0%	54%	78%	54%	0%	87%
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 2025-2039	MW	1931	1655	1509	1943	1885	1808	1720	1598	1270	2082
		% to Lowest Case	52.0%	30.2%	18.8%	52.9%	48.4%	42.3%	35.4%	25.7%	0.0%	63.9%

Source: Siemens

Currently, the Portfolios with three CCGTs all appear to be the least desirable, while the Portfolios with only one CCGT appear to be more desirable.

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13. All MISO Strategy

13.1 Introduction

Strategy 4: 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, Strategy 4 requires construction of an additional high voltage interconnection line, and the total transmission expenditure is more than $1 billion, which is $400 million more than the baseline plan's 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 Exhibit 140 below.

Exhibit 140: 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.

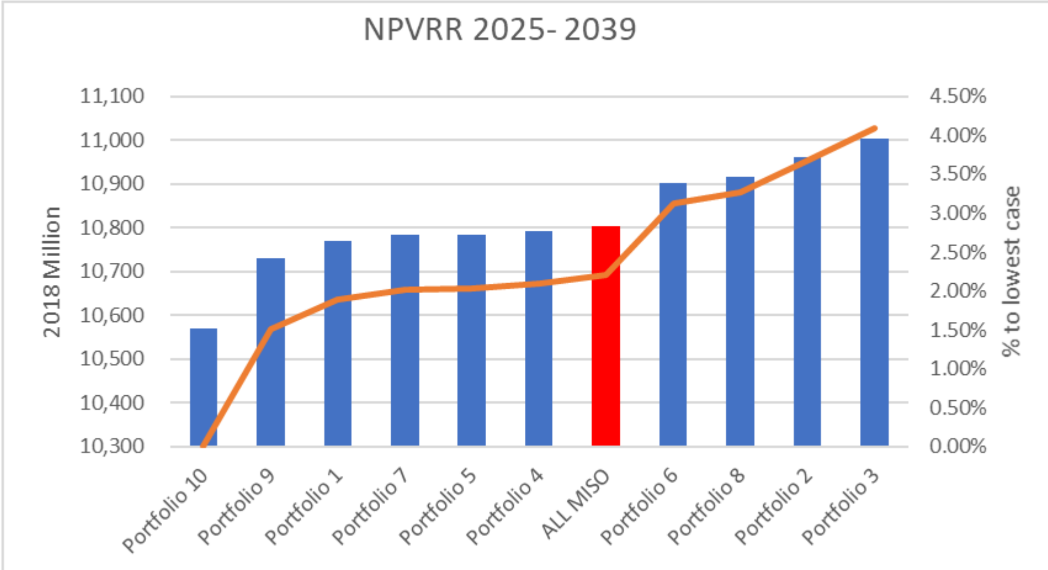
13.3 Portfolio Deterministic Results

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 near 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 Exhibit 141 below.

Exhibit 141: NPV of Revenue Requirements



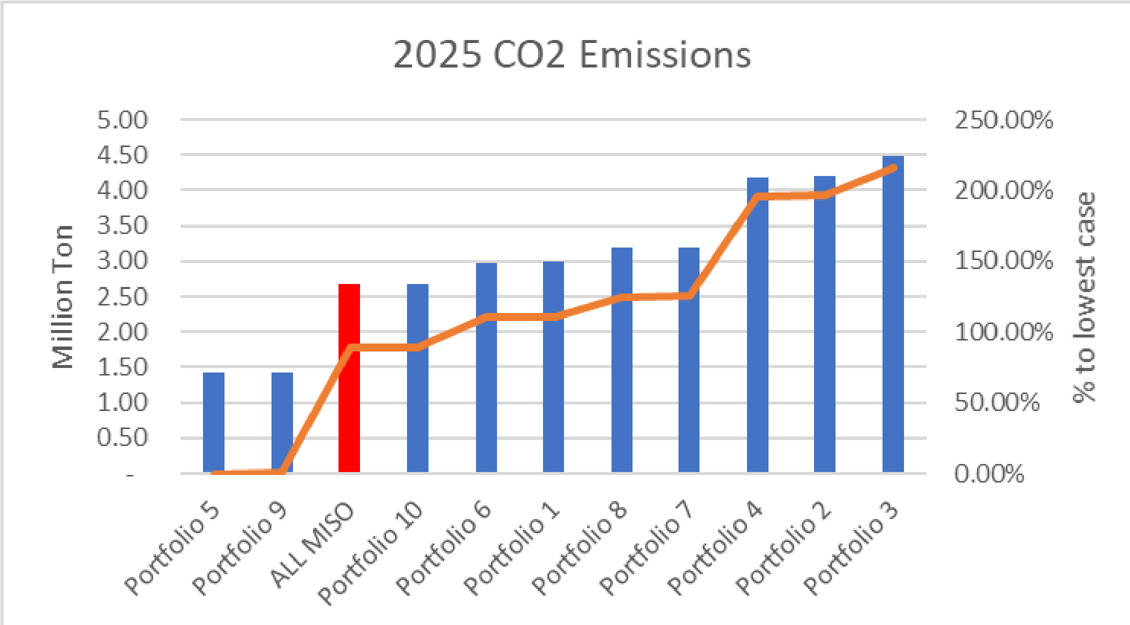
Source: Siemens

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, while also requiring about 1,800 million gallons of water to cool the combined cycle unit in 2025

The All MISO portfolio has fewer emissions than most portfolios with the exception Portfolio 5 and 10, as shown in Exhibit 142 below.

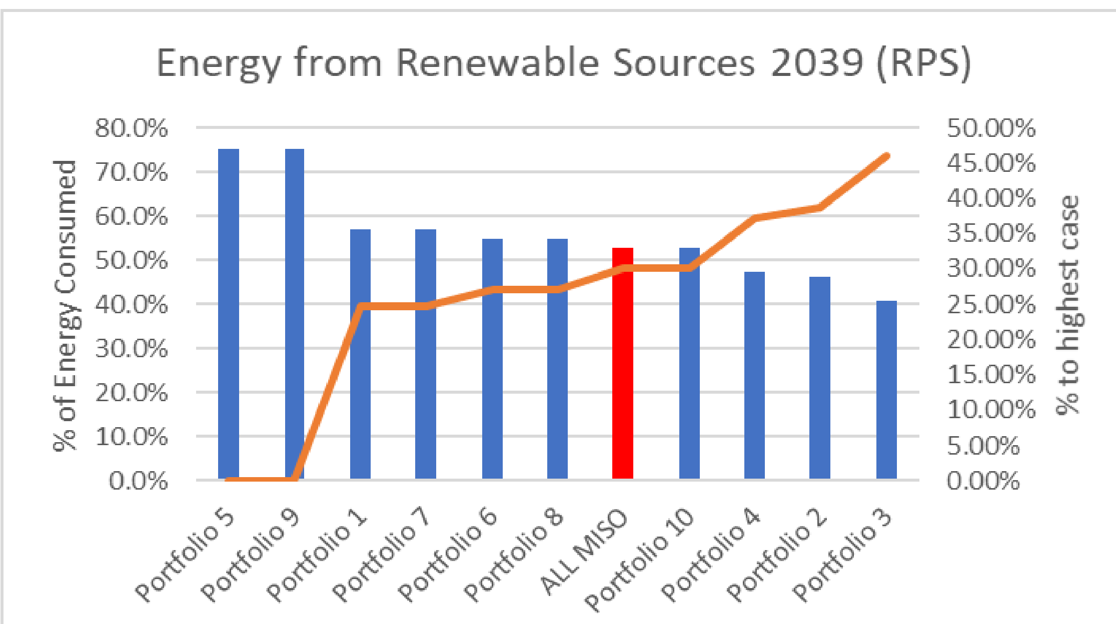
Exhibit 142: MLGW Generation CO_2 Emissions



Source: Siemens

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

Exhibit 143: Energy from Zero Carbon Sources or RPS in 2039

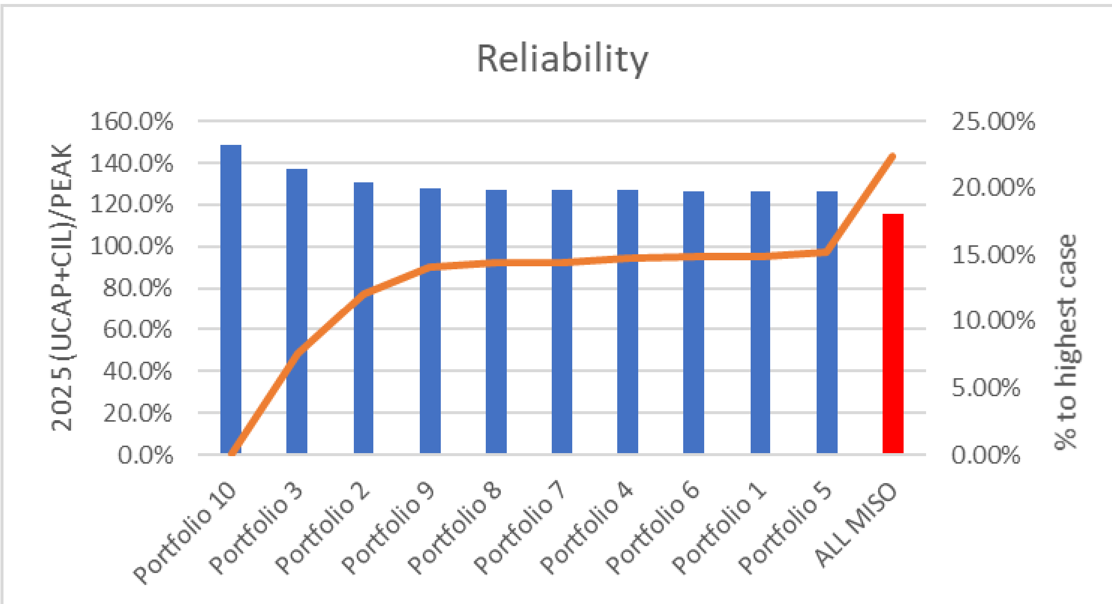


Source: Siemens

13.3.3 Reliability

This Portfolio does include over $1 billion on transmission investments. With no local generation providing UCAP, the reliability scores solely relied on the CIL, which in this case was assessed based on N-2 transfer analysis. The CIL was calculated to be 3,690 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 at least 126%.

Exhibit 144: Reliability Metric



Source: Siemens

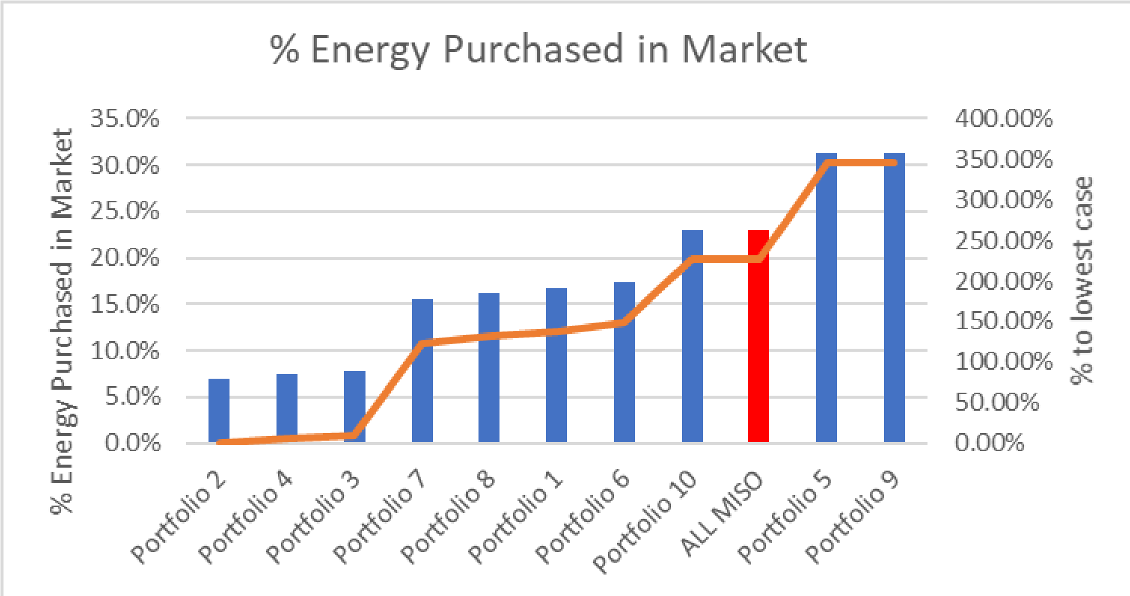
13.3.4 Resiliency

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

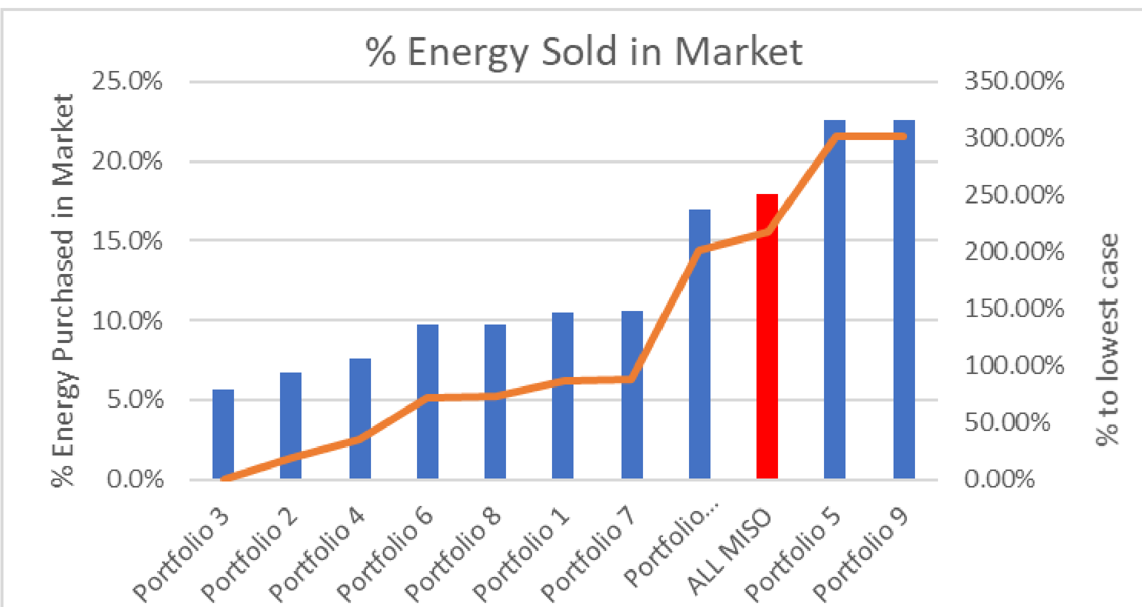
In this portfolio the MISO market purchases are about 23% and sales are about 17% of load by 2039, which is in between the other Portfolios with 1 CCGT and 2 CCGTs, and higher than the ones with 3 CCGTs. This is consistent with the Portfolio makeup of one large CCGT.

Exhibit 145: Market Purchases



Source: Siemens

Exhibit 146: Market Sales



Source: Siemens

13.3.6 Economic Growth

Because all new generation will be developed within the MISO footprint, the only component that fits the economic growth criteria is 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

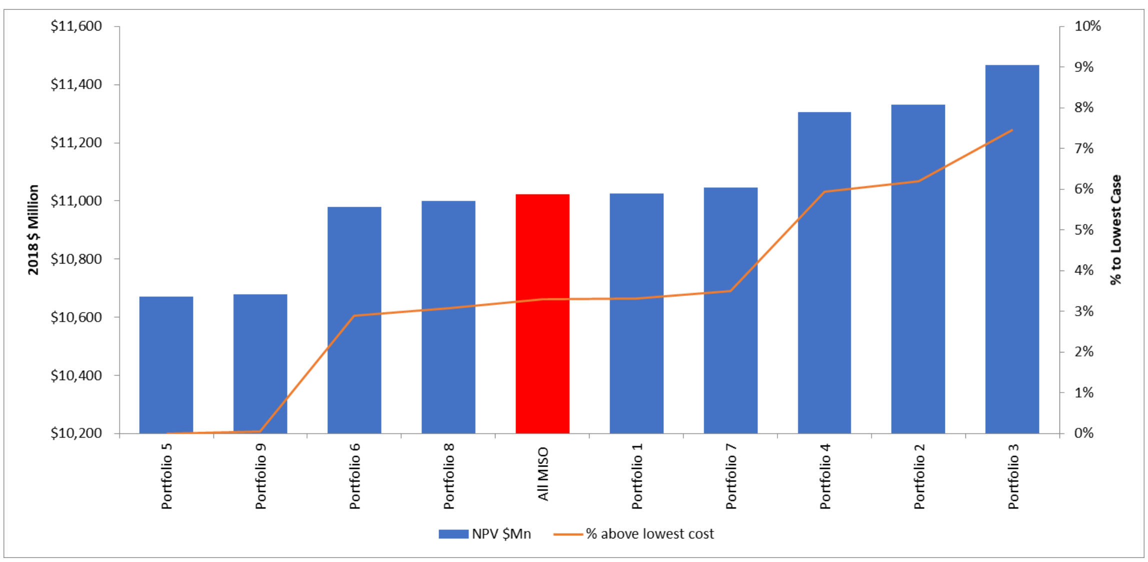
Appendix D: Portfolio Details contains the generation buildout by year and by technology type for this All MISO Portfolio, as well as various key performance metrics.

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 147: Mean of NPVRR

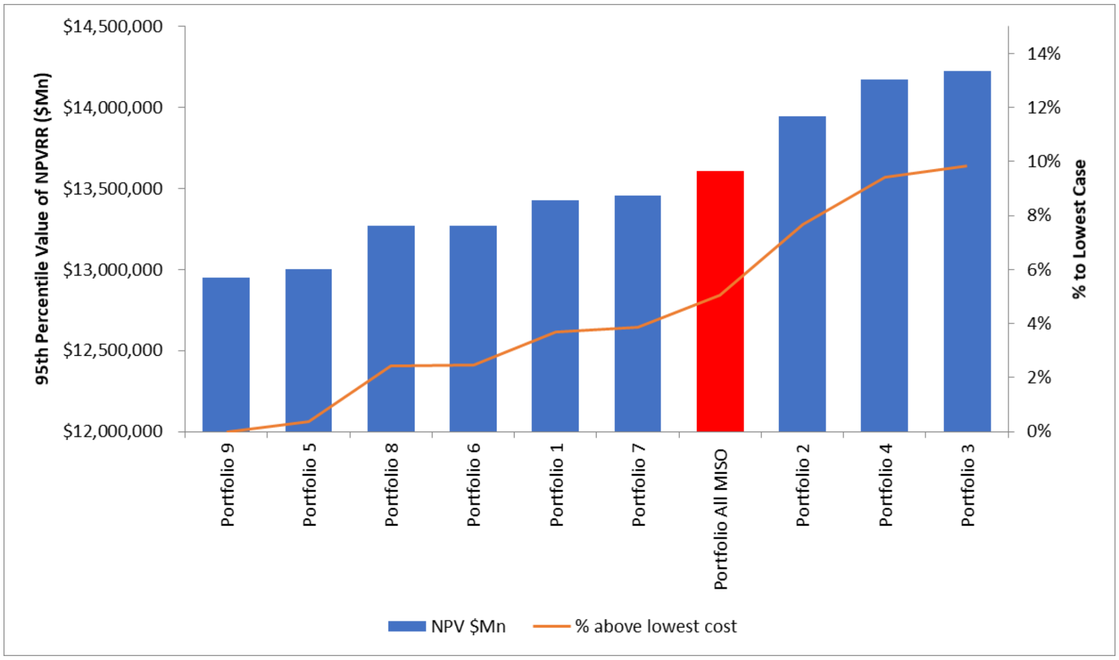


Source: Siemens

13.4.2 Price Risk Minimization

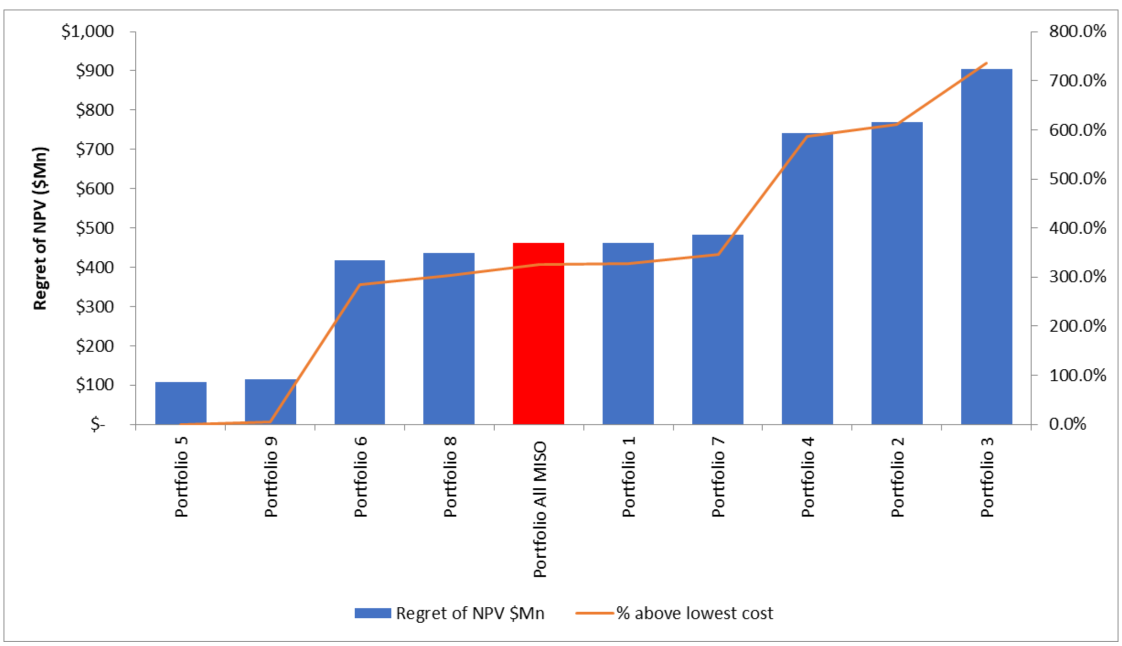
Cost stability plays an important role in determining the preferred portfolio, especially when considering the worst-case outcome of a portfolio. The All MISO Portfolio has higher risk than most portfolios except for those portfolios with three CCGTs and has greater regret than portfolios with one CCGT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

Exhibit 148: 95th Percentile of NPVRR



Source: Siemens

Exhibit 149: NPVRR Regret

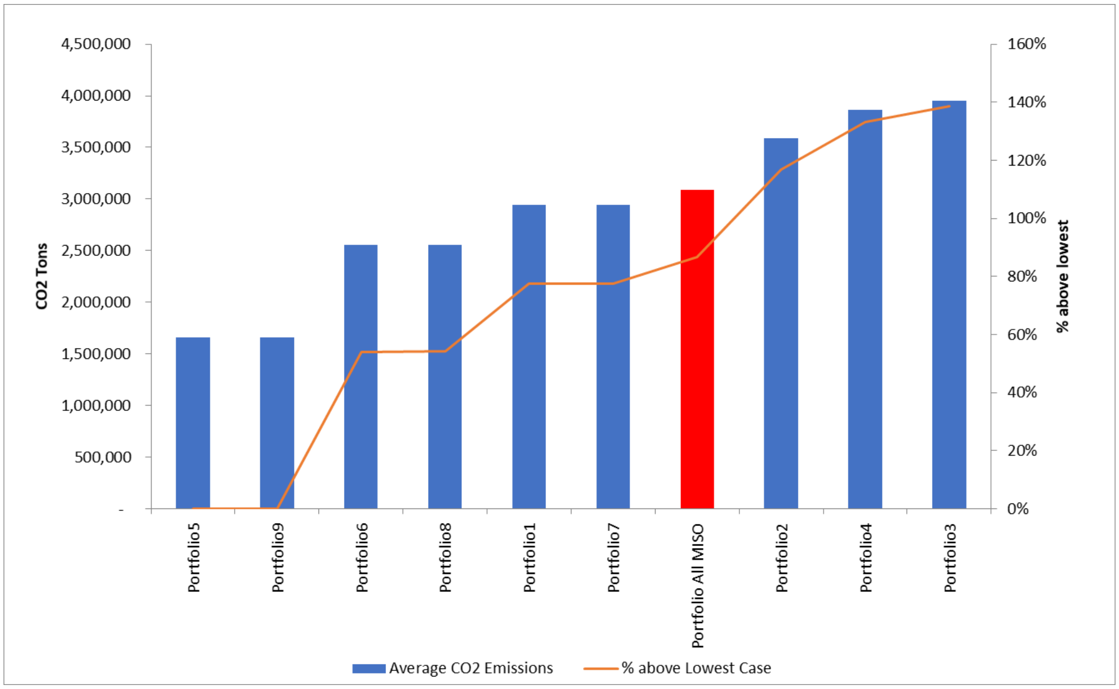


Source: Siemens

13.4.3 Environmental Risk

Environmental risk is measured as average annual portfolio carbon emissions, including the emissions associated with the net energy purchased from MISO. 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 150: Average MLGW CO_2 Emissions from 2025 to 2039 (tons)

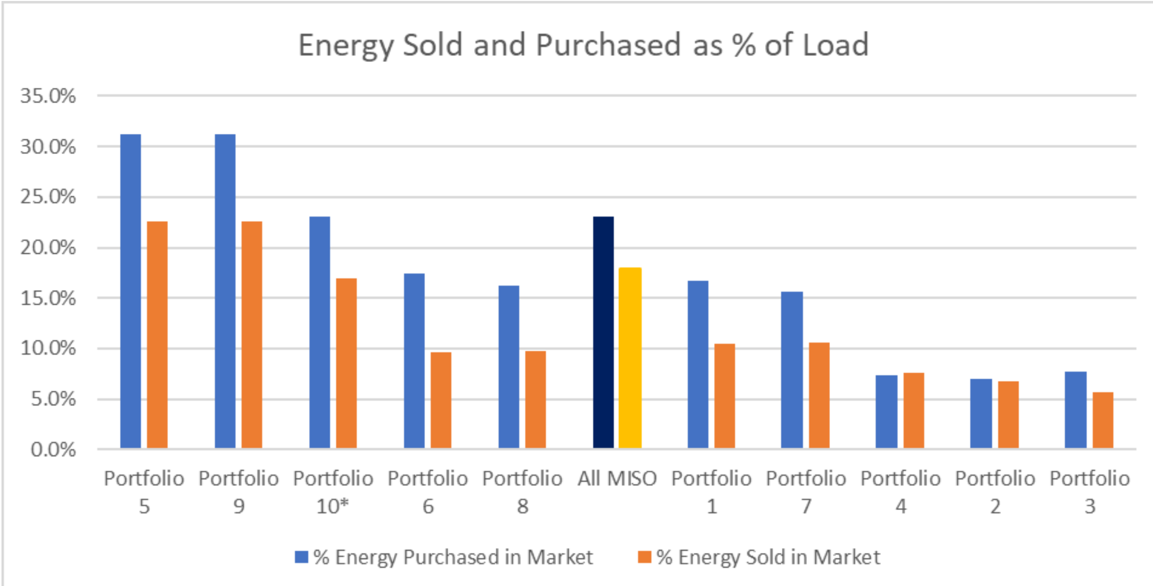


Source: Siemens

13.4.4 Market Risk Minimization

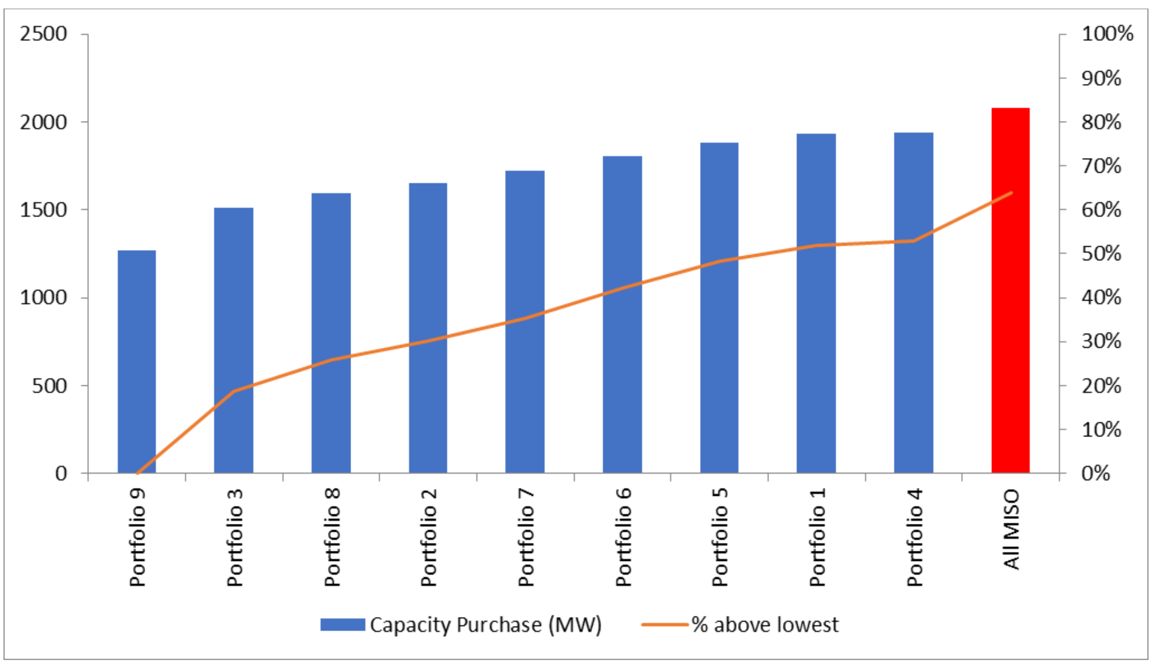
If MLGW were to join MISO, a significant portion of MLGW's energy and capacity needs may come from the MISO energy market and capacity market. Portfolio All MISO has higher risk, as measured in terms of energy purchases and sales, than most portfolios, except for Portfolio 5 and 9. It also has the greatest dependence on capacity purchases in the market, as shown in Exhibit 151 below.

Exhibit 151: Market Purchase and Sales as Percentage of Load



Source: Siemens

Exhibit 152: 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 the option to give 5-year notice, 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 a 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 wholesale power contract, or 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 153 below provides correlation between the revenue requirement cost components and the data sources.

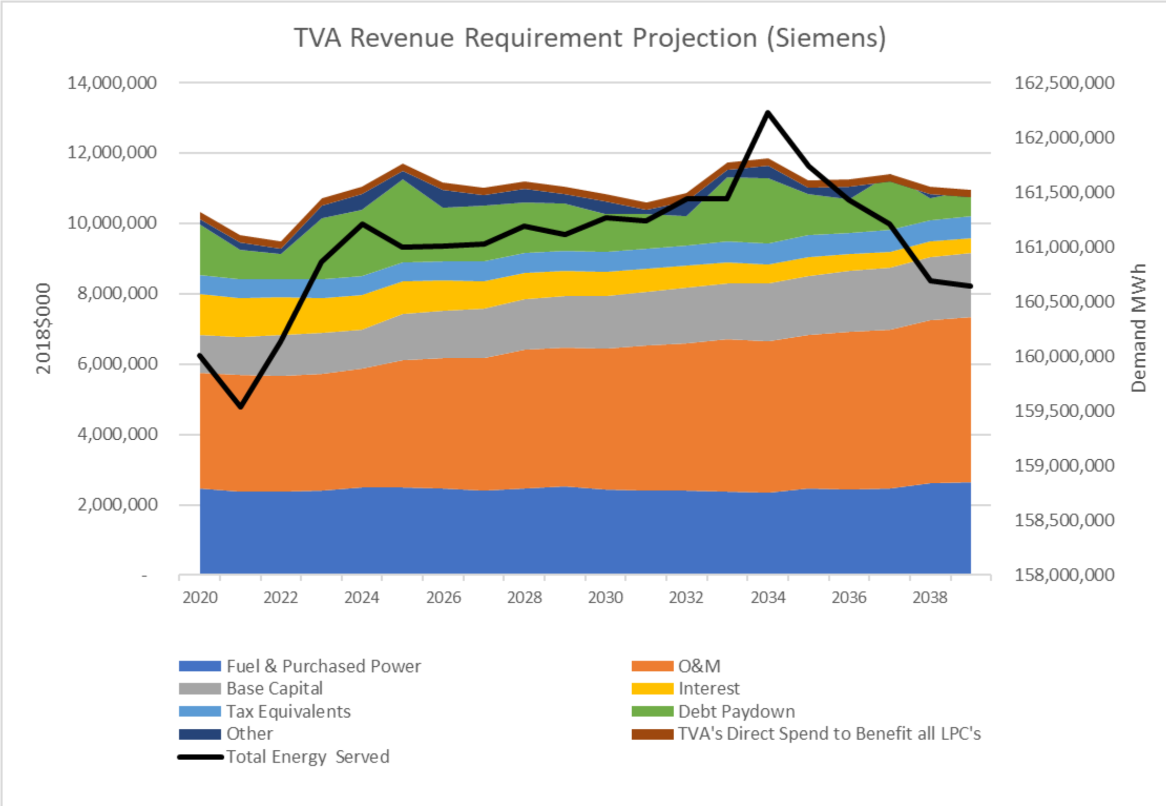
Exhibit 153: Revenue Requirement Cost Components and Data Sources

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 154: 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 155: TVA's Net Present Value of Revenue Requirements (NPVRR) and Levelized Cost of Energy (LCOE) – 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, which 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 156: 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 forms the basis for computing the revenue requirement that MLGW will need to collect, should it choose to continue being served by TVA. Siemens used two different methods to estimate MLGW's levelized cost of energy should it stay with TVA, as described below.

14.4 Allocation Based on Variable and Fixed Components

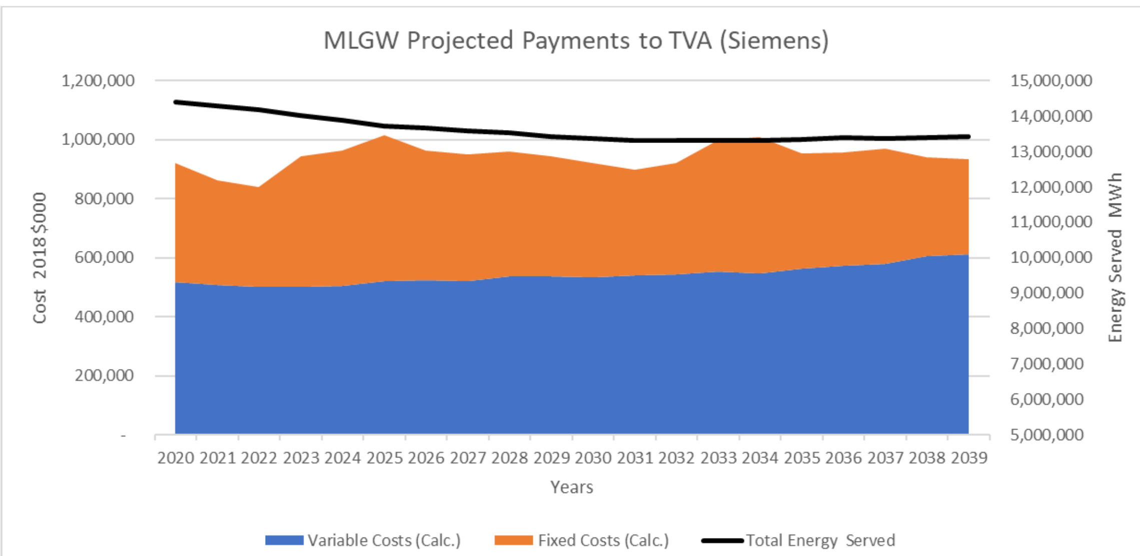
TVA's cost components making up its revenue requirements can be broken down into variable and fixed costs. Fuel and purchased power as well as O&M vary proportionately with the amount of energy served and can be allocated based on the energy that MLGW is forecasted to consume. All the other components 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. Under this method, a ratio of 8.9% was determined, meaning 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 157: 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 Exhibit 158 below.

Exhibit 158: 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 and allocating it to MLGW (using the Top 200 Hours methodology described above), we computed the NPV and levelized cost of energy, as shown in Exhibit 159 below.

Exhibit 159: 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, which 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 Exhibit 160 below.

Exhibit 160: MLGW Rate-Based on the TVA Rate 2019

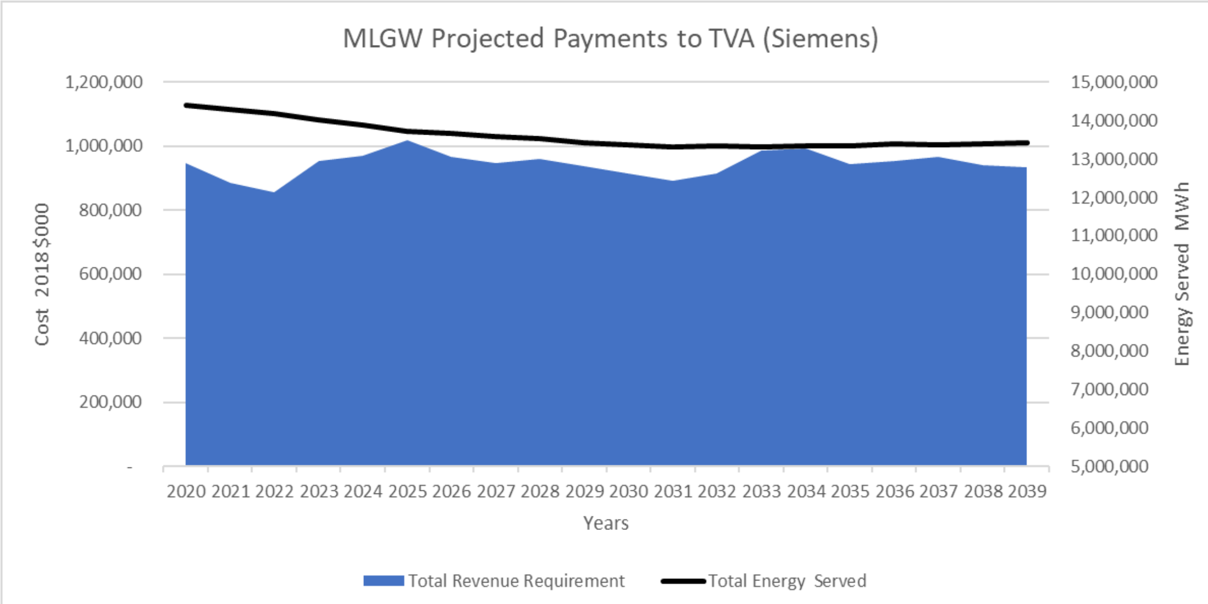
	Revenue (millions)	GWh	cents/KWh
Local Power Companies	10,351	138,928	7.45
Direct Serve Companies	686	17,363	3.95
Federal Agencies	122	2,152	5.67
Total TVA	**11,159**	**158,443**	**7.04**
MLGW	1,036	13,920	7.45
Less Transmission Credit	-36	13,920	-0.26
Net Power Cost	**1,000**		**7.19**
MLGW Ratio to 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 161 shows the projected revenue requirement (2018 $) that MLGW would need to collect, calculated using this allocation method (which does not distinguish between fixed and variable costs).

Exhibit 161: 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 Exhibit 162 below.

Exhibit 162: 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, results in the NPV and levelized costs of energy shown in Exhibit 163.

Exhibit 163: 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 calculations 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 and others) 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 in savings, with a present value of $391 million using a real discount rate of 1.37% for the period 2020 to 2039. 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 164: 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 165 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). For reference we provide a comparison with the eleven Portfolios selected for analysis. We discuss next these results. The corresponding values for the Strategy 3 portfolios are also included, 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 165: 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

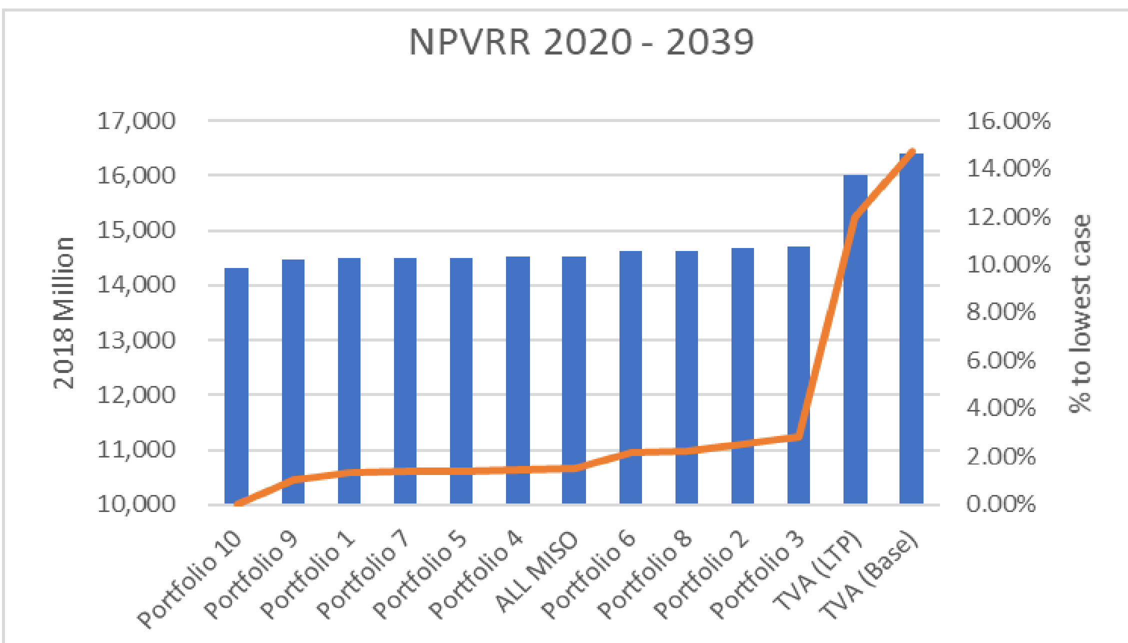
Least Costs

We observe in Exhibit 166 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.

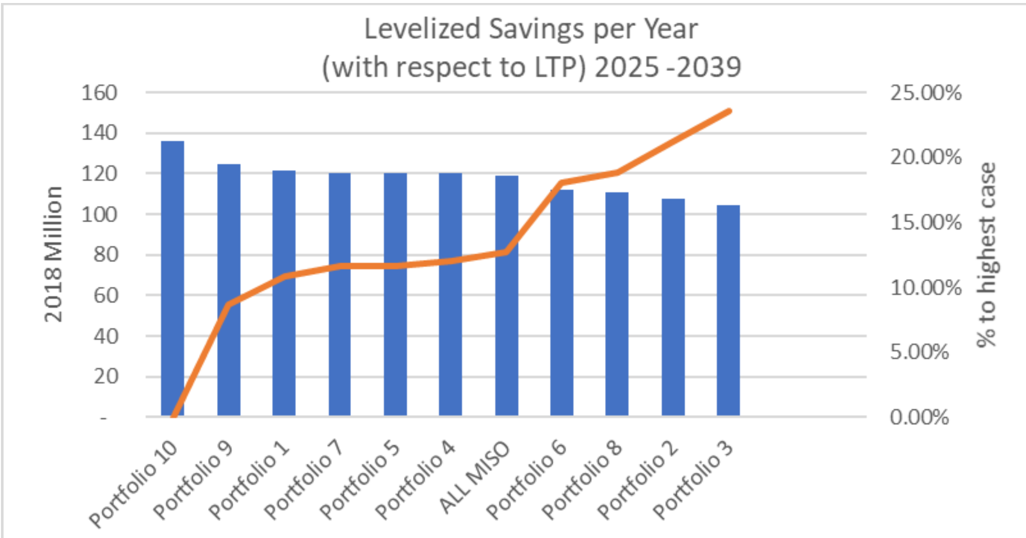
The exhibit below shows graphically the NPVRR for both TVA options and all Portfolios. This is followed by the levelized savings by portfolio.

Exhibit 166: NPVRR of 2020 – 2039



Source: Siemens

Exhibit 167: Levelized Savings 2025 – 2039



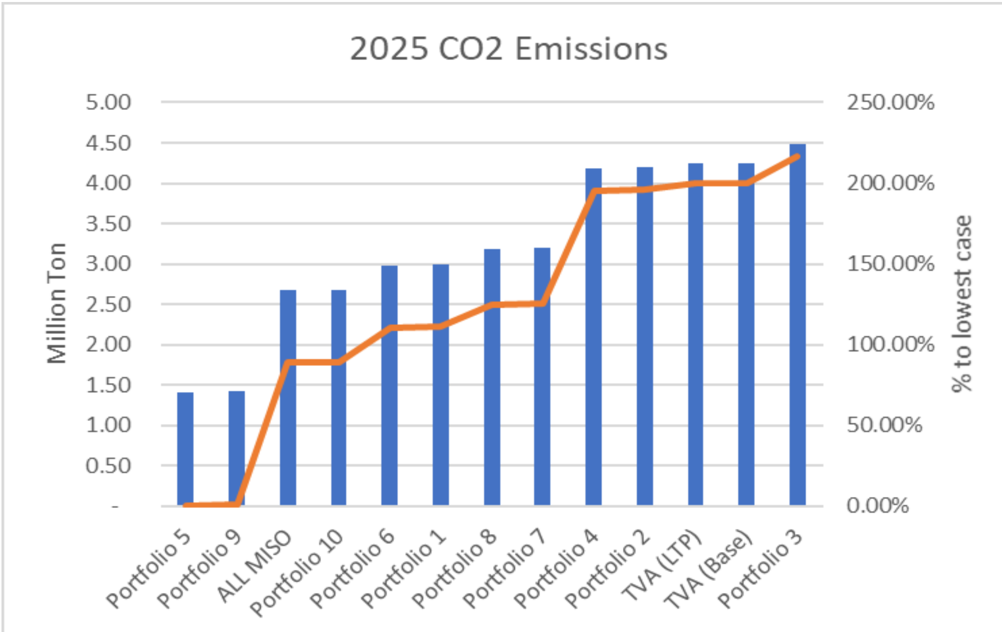
Source: Siemens

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 entire TVA fleet, using the percentage of TVA energy delivered to MLGW (8.5% approximately). Additionally, a metric that assesses the water consumed inside Shelby County; in the case of TVA this is Siemens' estimation of the consumption of the Allen power plant.

As can be observed in Exhibit 165 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 in Exhibit 168. We also assessed the CO_2 emissions within Shelby County, as shown in Exhibit 165, but this is less relevant as CO_2 is a global problem. Note that in Exhibit 168, the effect of the CO_2 production associated with the MISO purchases is not yet included and this correction was made for the stochastic assessment.

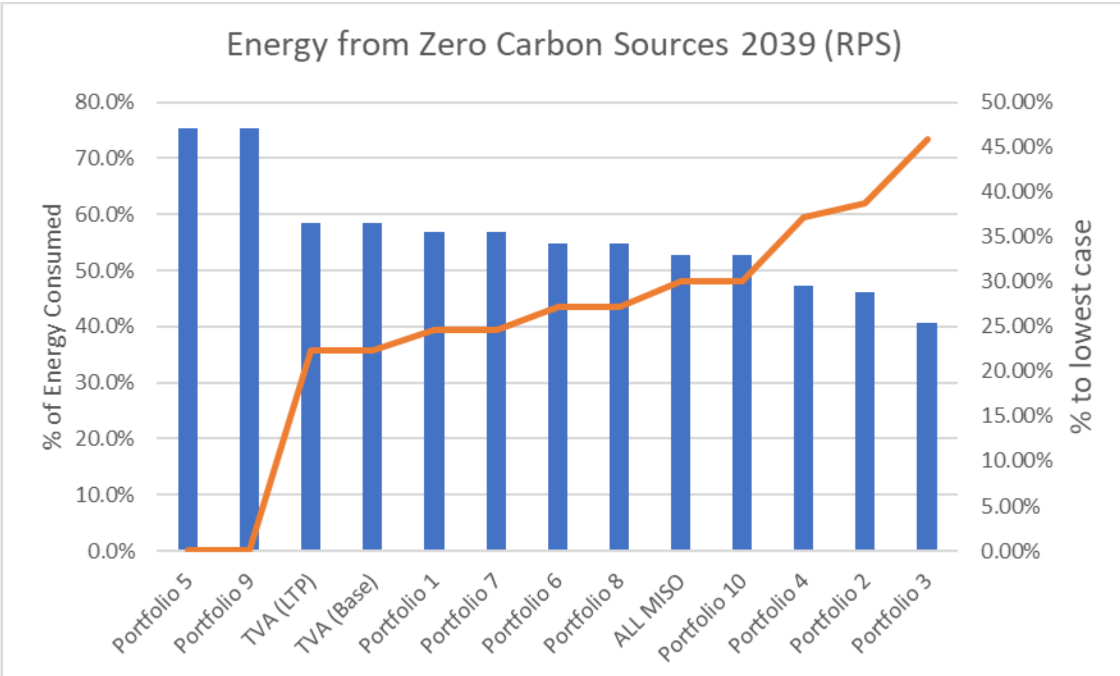
Exhibit 168: 2025 MLGW CO_2 Emissions



Source: Siemens

For TVA we measured the generation from zero carbon sources which, 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 169 below.

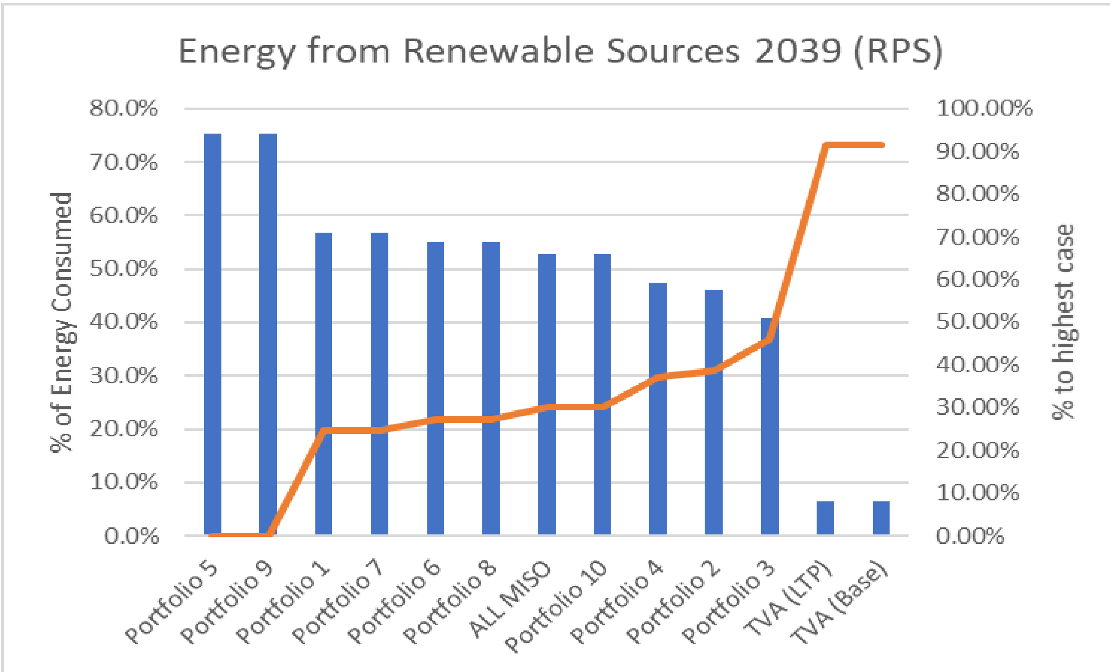
Exhibit 169: 2039 Generation from Zero Carbon Sources



Source: Siemens

Considering a renewable portfolio standard (RPS) centered on only PV and wind (and not including nuclear nor large hydro) the TVA options would rank last and fairly low as illustrated in Exhibit 169 below. Even if large hydro is included, the RPS value would increase to only 16%.

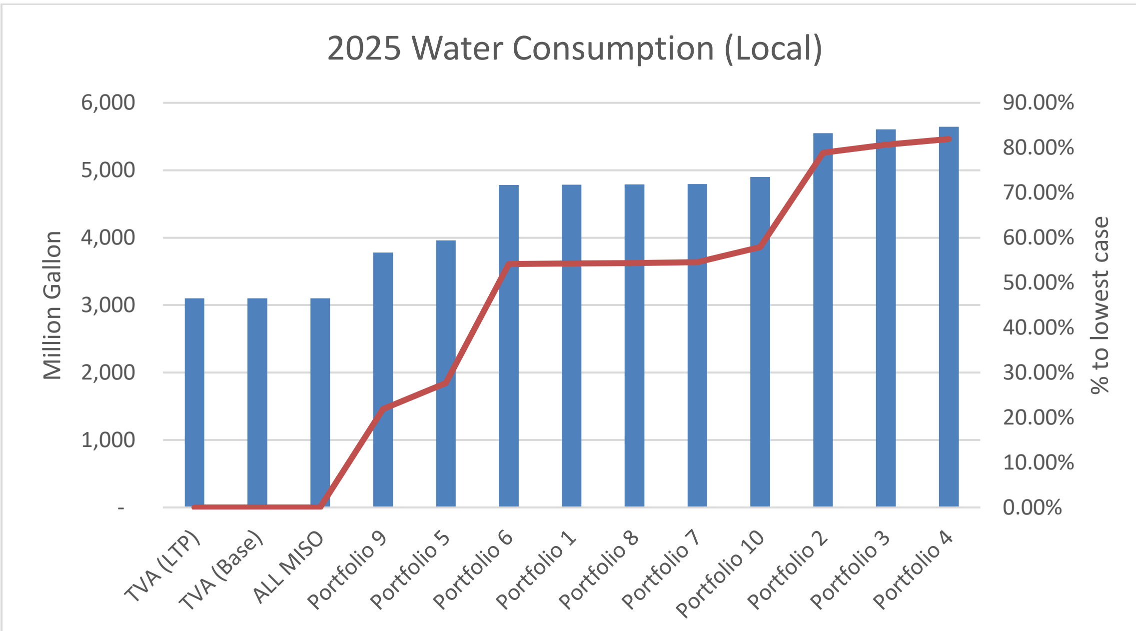
Exhibit 170: 2039 Renewable Generation Percentage



Source: Siemens

With respect to local water consumed, estimated using the same approach presented earlier for the Portfolios, Exhibit 171 shows that the TVA options have the lowest impact in Shelby County water consumed , as all other options would increase the need for local water, with the exception of the All MISO Portfolio, which has thermal resources outside Shelby County.

Exhibit 171: 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 below 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 being heavily dependent on transmission to avoid load shed under N-1-1 conditions.

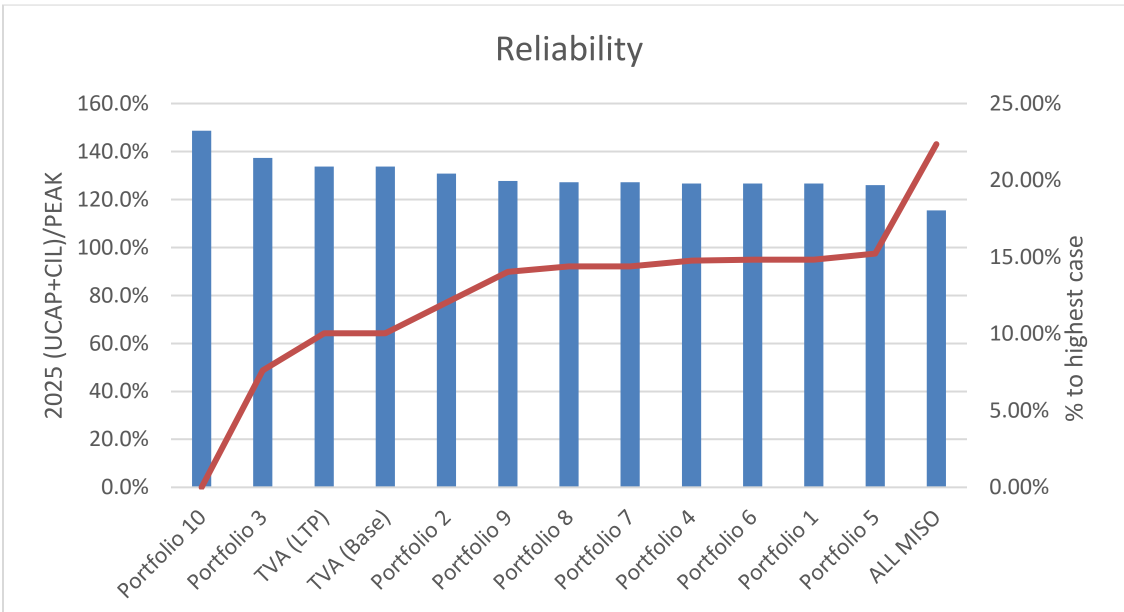
This metric for the TVA case was assessed considering the existing system and no local generation with the CIL estimated at 4,275 MW.

It should be noted that nearly all Portfolios, met 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 172: Reliability



Source: Siemens

Resiliency

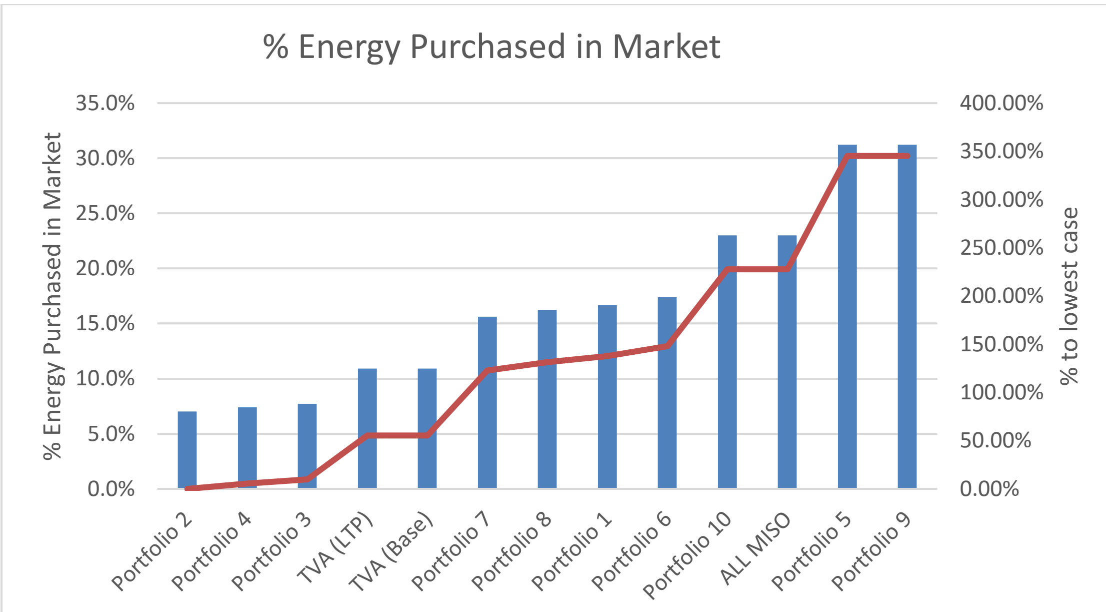
Resiliency in this case is measured as the amount of load that would need to be shed to prevent overloads in the case that the two 500 kV lines that interconnect MLGW to MISO were to both experience outages either by a storm, or by one being in forced maintenance when the other failed. This event is unlikely but possible. However, for load shed to be required in this situation, MLGW also 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, this risk is material only in Portfolio 5.

Market Risk

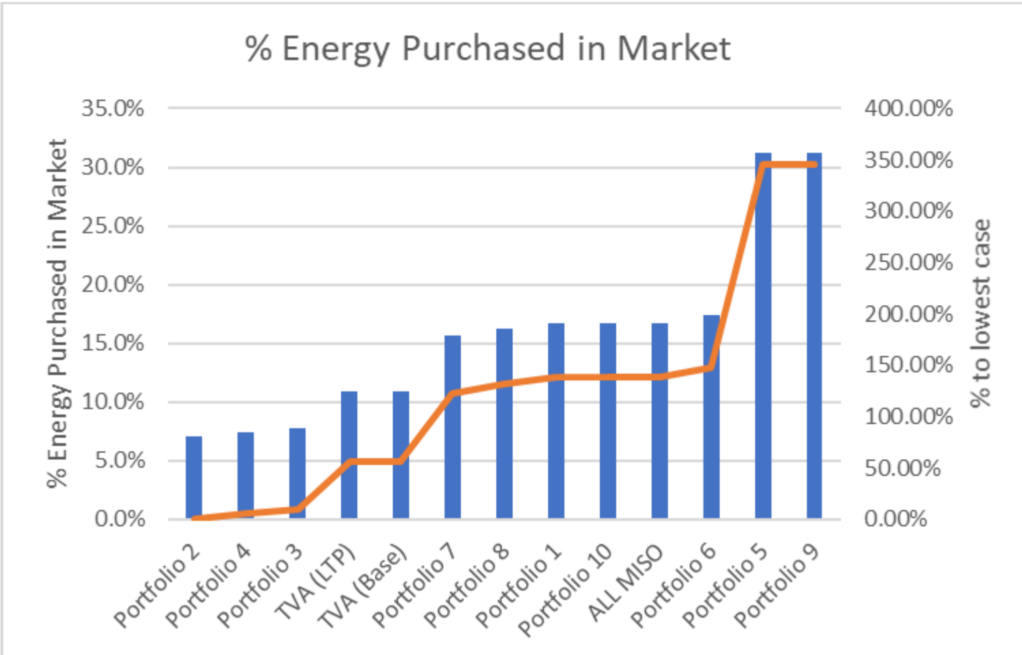
Market risk with the TVA options is very small as TVA is not expected to purchase or sell a significant percentage of its energy (expressed as a function of the load) in the surrounding markets (e.g. MISO) and this risk is comparable with that of the portfolios with 3 CCGTs, as shown in exhibit below.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

Exhibit 173: Percentage of Energy Purchased in Market



Source: Siemens

Exhibit 174: Percentage of Energy Sold in Market



Source: Siemens

Economic Growth

With the TVA options, very limited new generation development is expected within Shelby County (up to 5% of MLGW load under the LTP) 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 175 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 Portfolio. 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 175. 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 $).

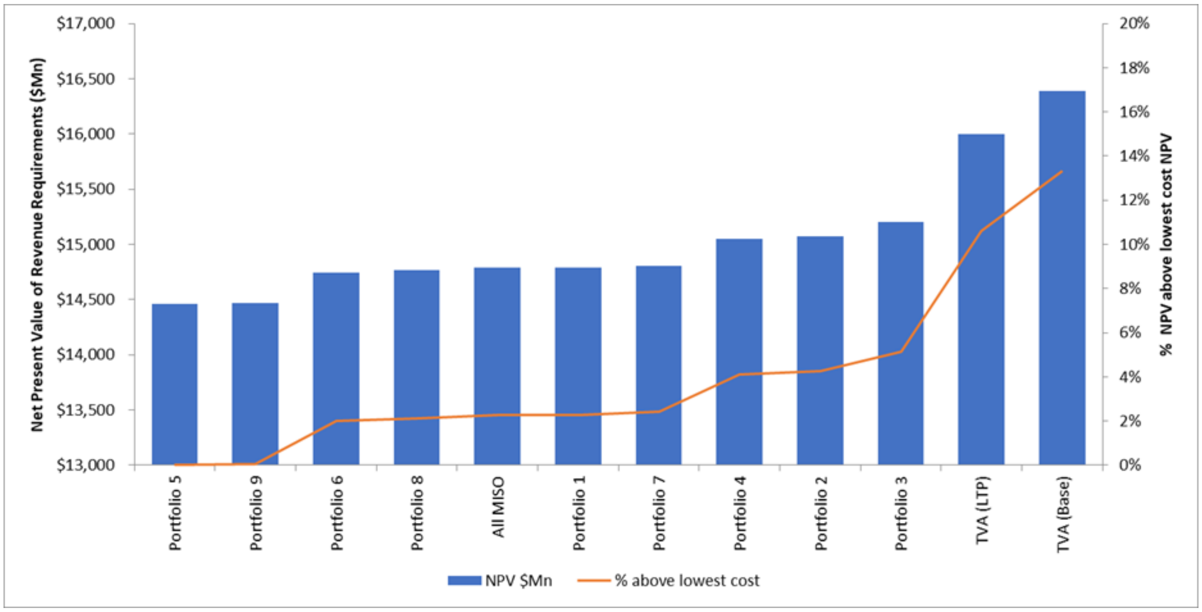
Exhibit 176 shows the NPVRR for both TVA options and the selected portfolios.

Exhibit 175: 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%
Min 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%
Min Envr. Risk	CO_2 Emissions Mean 20-Year	Tons CO_2	3,805,017	3,805,017	3,328,674	3,815,374	4,088,408	4,022,145	2,365,760	3,037,707	3,328,860	3,037,892	2,366,393	3,442,111
		% to Lowest Case	61%	61%	41%	61%	73%	70%	0%	28%	41%	28%	0%	45%

Source: Siemens

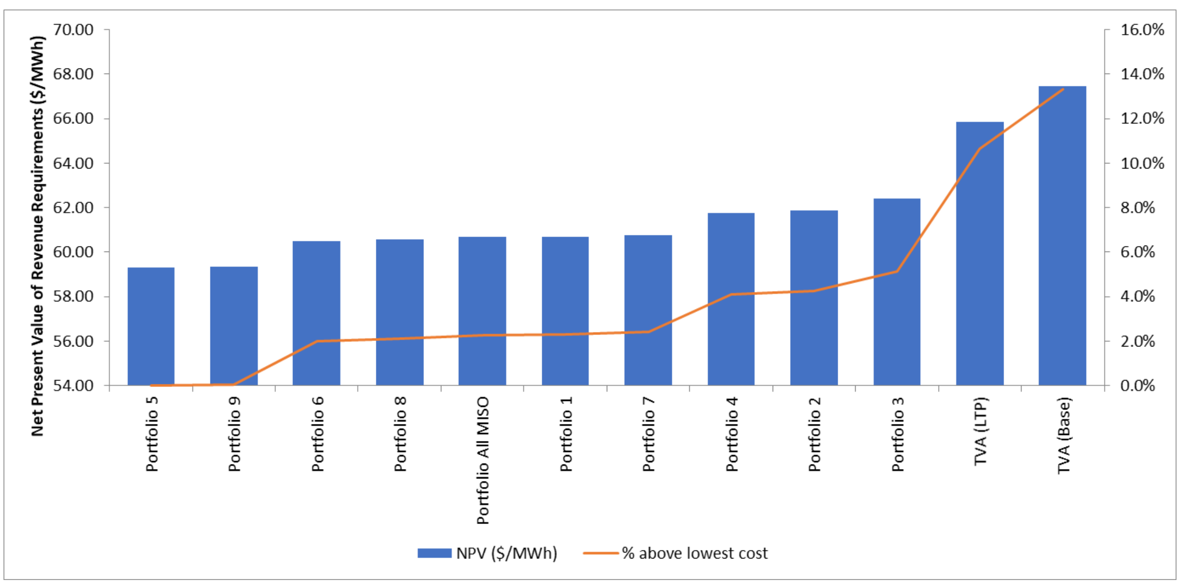
Exhibit 176: NPVRR 2020-2039



Source: Siemens

Similarly, as shown in Exhibit 177, 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 177: NPVRR 2020-2039 ($/MWh)

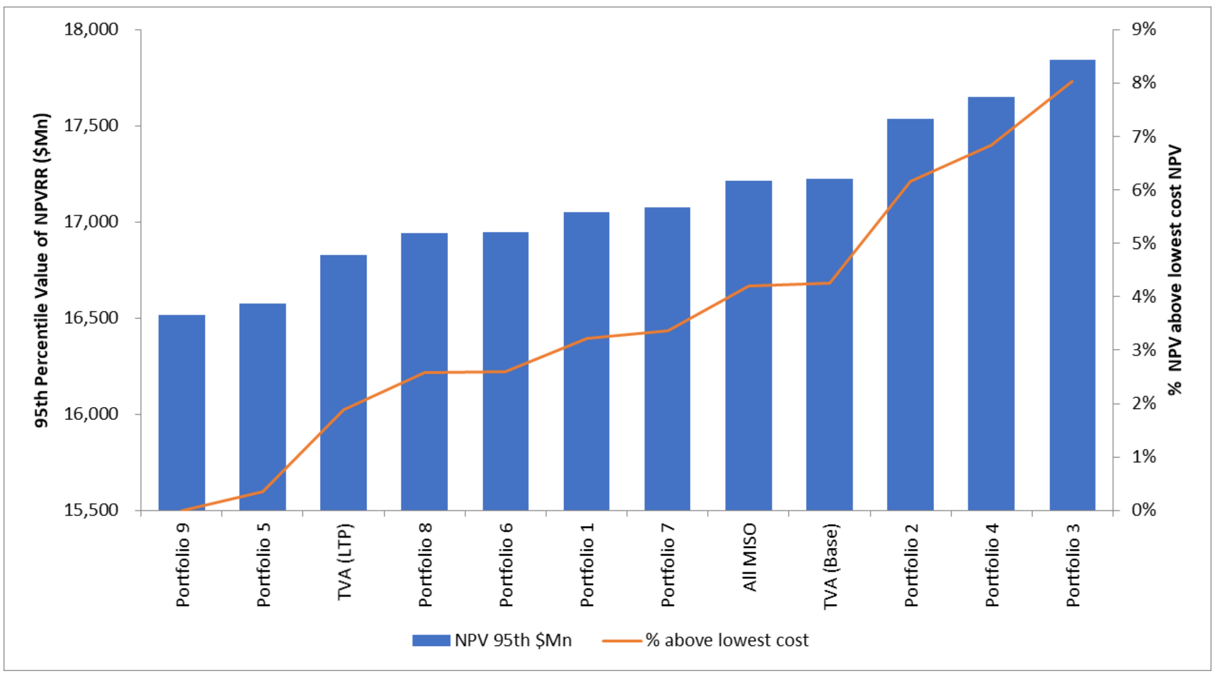


Source: Siemens

Risk Minimization

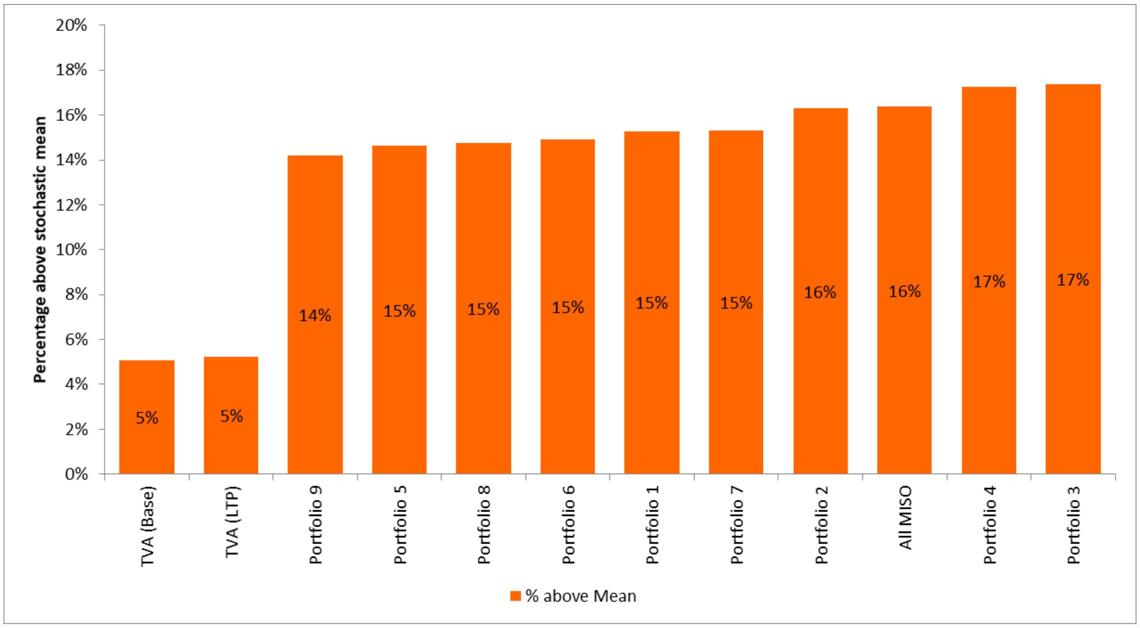
TVA's Base portfolio cost shows a moderate price variability as expressed in terms of the 95th percentile costs as shown in the figure below, and it is less variable than any of the alternative portfolios considered. The TVA 95th percentile is only 5% above the mean, while in Portfolio 3 it is 17% higher 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 180, 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, which 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 178: 95th Percentile of NPVRR



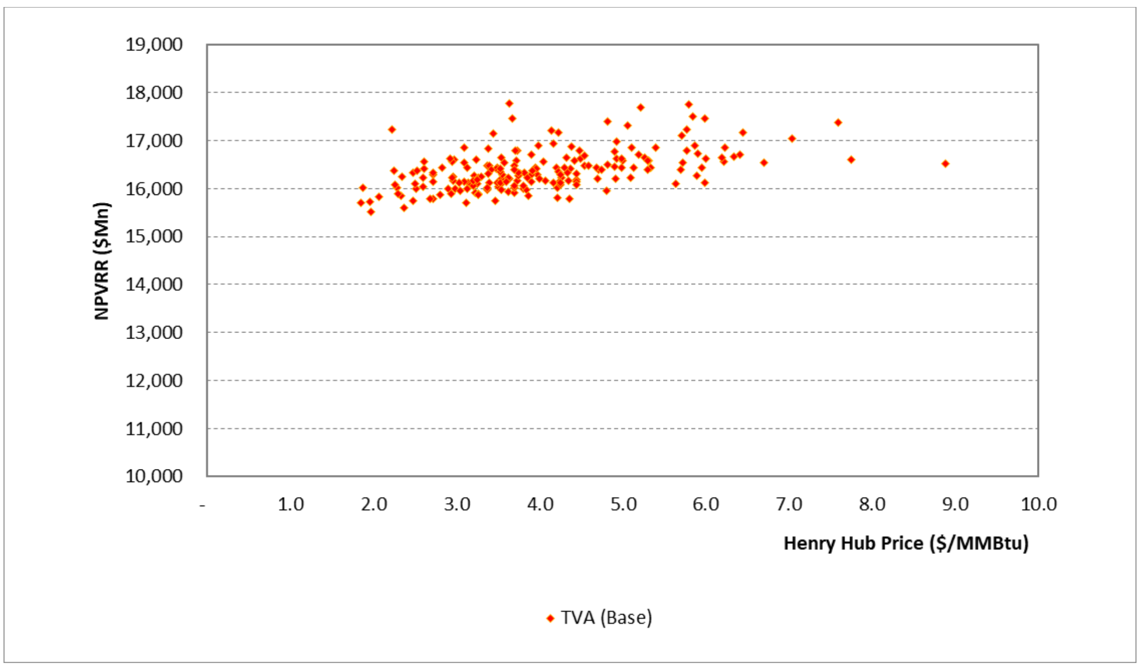
Source: Siemens

Exhibit 179: Increase of the 95th Percentile of NPVRR with Respect of the Mean NPVRR



Source: Siemens

Exhibit 180: 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 portfolios, which is susceptible to 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

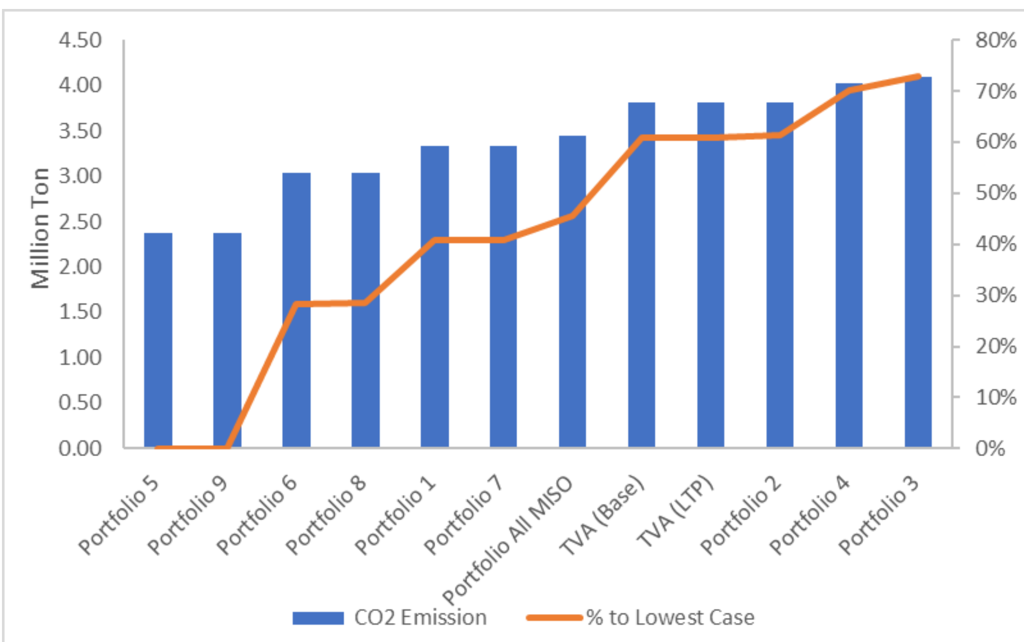
In TVA's generation fleet, coal plants account for about 25% of the generation, including several aged coal plants that stay on throughout the study horizon, and gas plants account for about 15% of the generation. TVA has plans to retire some coal units in coming years but, at this time, is expected 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, b have environmental risk associated with them. Strategy 3 and Strategy 4 Portfolios are comprised of new, more efficient CCGTs, and renewables. Therefore, there will be more environmental impact associated with Strategy 1.

Exhibit 181 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 most of the portfolios considered, except for those that have three CCGTs. Portfolios 5 and 9 have the lowest emissions. The emissions below account for the emissions associated with the net MISO purchases.

Exhibit 181: 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, plus 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 comply with NERC reliability requirements.

The analysis used over 200 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 183), 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; —having 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 and align the reliability of Portfolio 5 with 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 183), 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 moved 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 1,000 MW of local PV and the large combined cycle unit also locally developed (see Exhibit 183). Due to all the above the All MISO Portfolio is not included in the top four Portfolios used for comparison with TVA.

Exhibit 183 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. Exhibit 182 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. Portfolio 10 and the All MISO Portfolio have slightly higher risk than the other portfolios, possibly due to the dependence on one large CCGT[50].

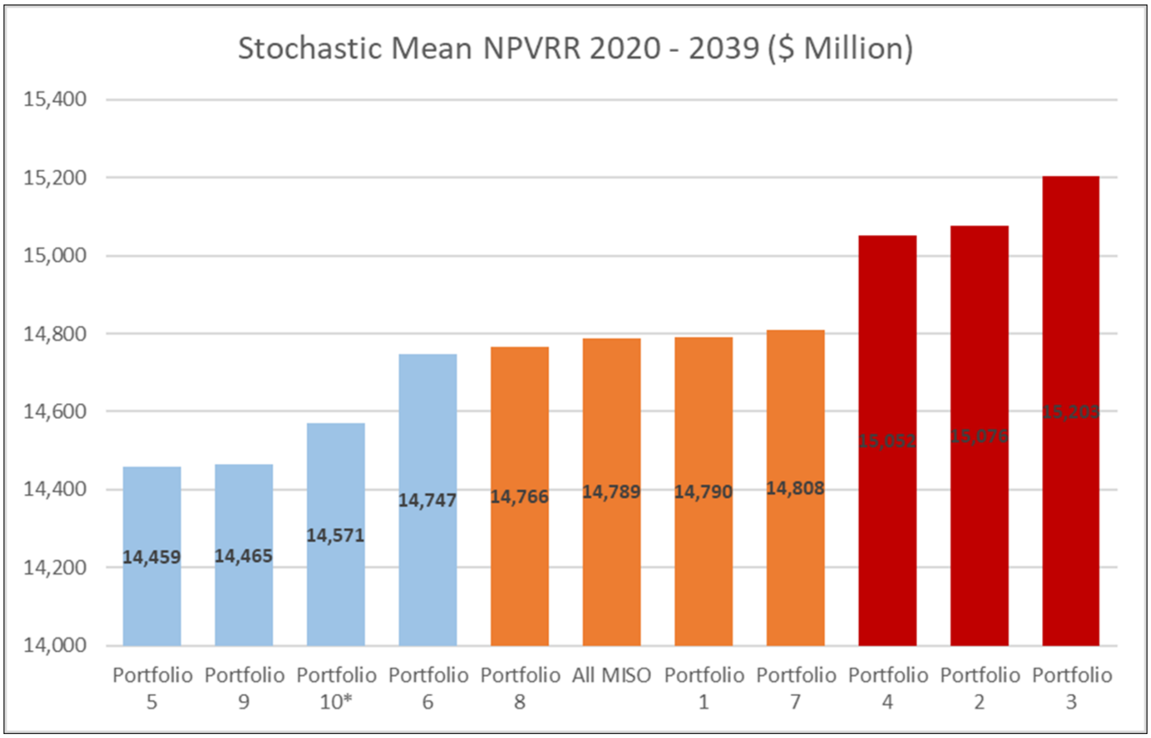
As a reference Exhibit 185 shows the total capital expenditure by portfolio. Note that only the transmission CapEx is expected to be covered by MLGW as the generation capex is expected to be expensed by third parties and recovered via PPA payments from MLGW. The CapEx includes all costs to the commissioning of the project including interests during construction. This CapEx will be spent at different times over the development of the various portfolios as shown in Appendix D: Portfolio Details where the overnight CapEx at the year that the project comes in service is shown. It can be observed that the highest overnight CapEx ($7.18 billion) occurs in

[50] 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).

Portfolio 5, followed by Portfolio 9 ($ 7.0 billion) which is expected given the higher amounts of capital-intensive renewable resources.

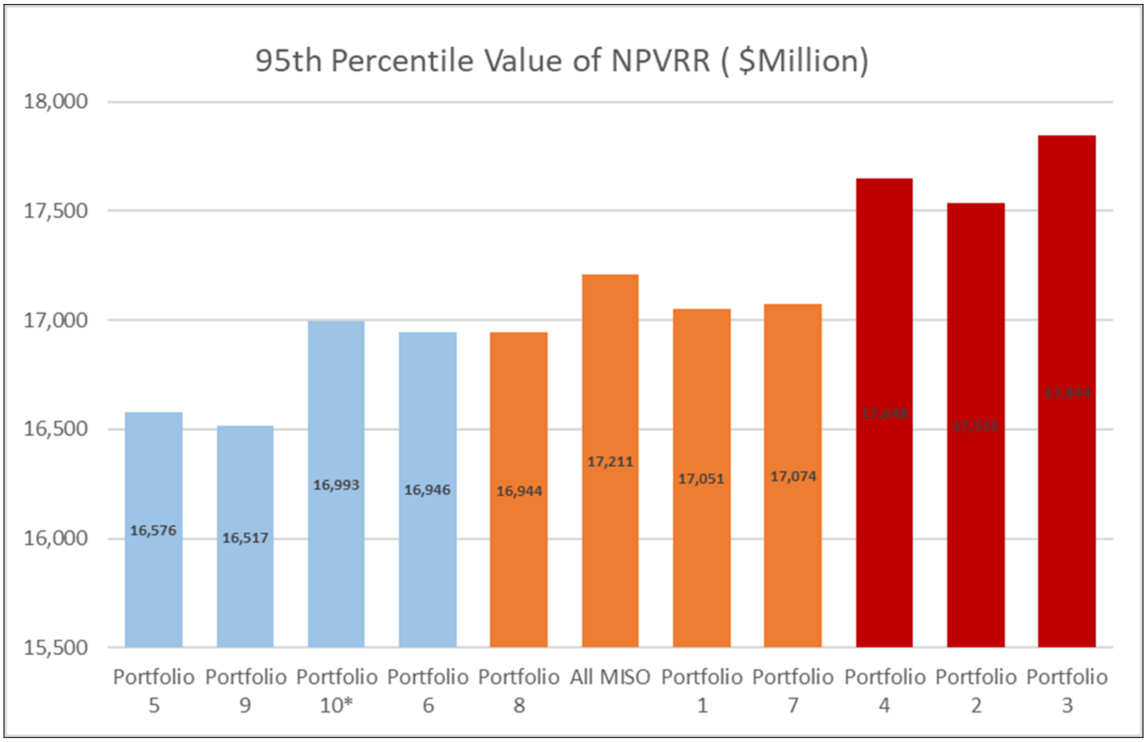
Exhibit 186 shows a balanced scorecard for the total supply options analyzed, where the overall results for all portfolios are presented. Portfolio 5, Portfolio 9, Portfolio 10 and Portfolio 6 are selected for contrasting the results with respect to the TVA option.

Exhibit 183: Ranking of Portfolios According to NPVRR



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

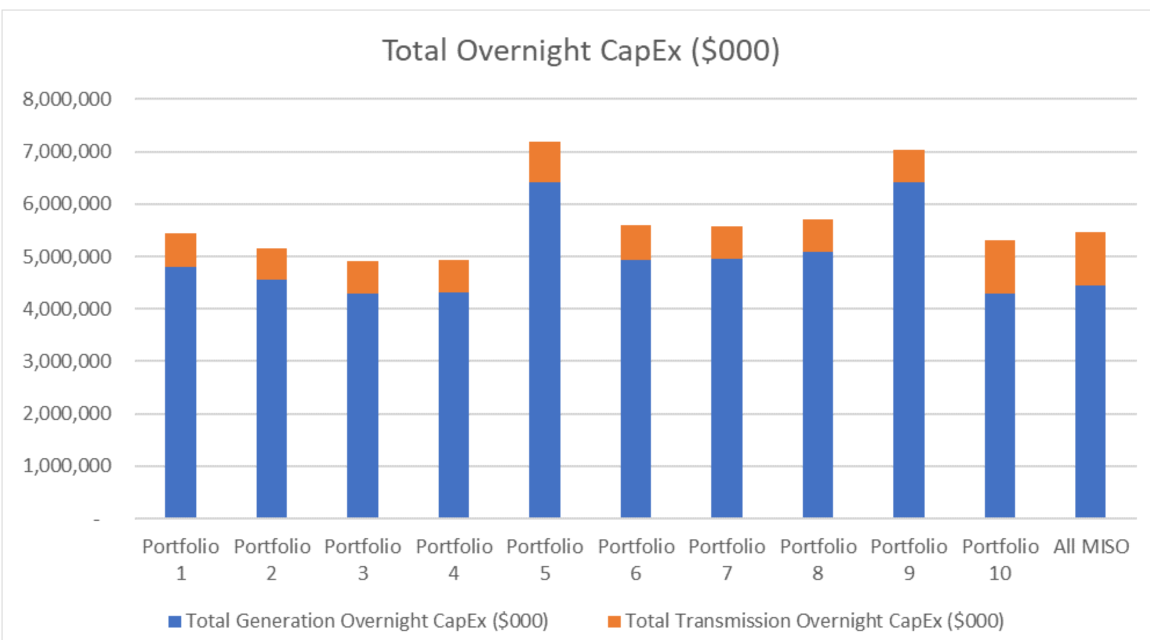
Exhibit 184: Portfolio Risk



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

Source: Siemens

Exhibit 185: Total Overnight T&G CapEx



Source: Siemens

15.1 Comparisons with TVA

Exhibit 186 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.

Afterward, each metric is looked at separately.

Exhibit 186: Summary of Results by Portfolio and TVA

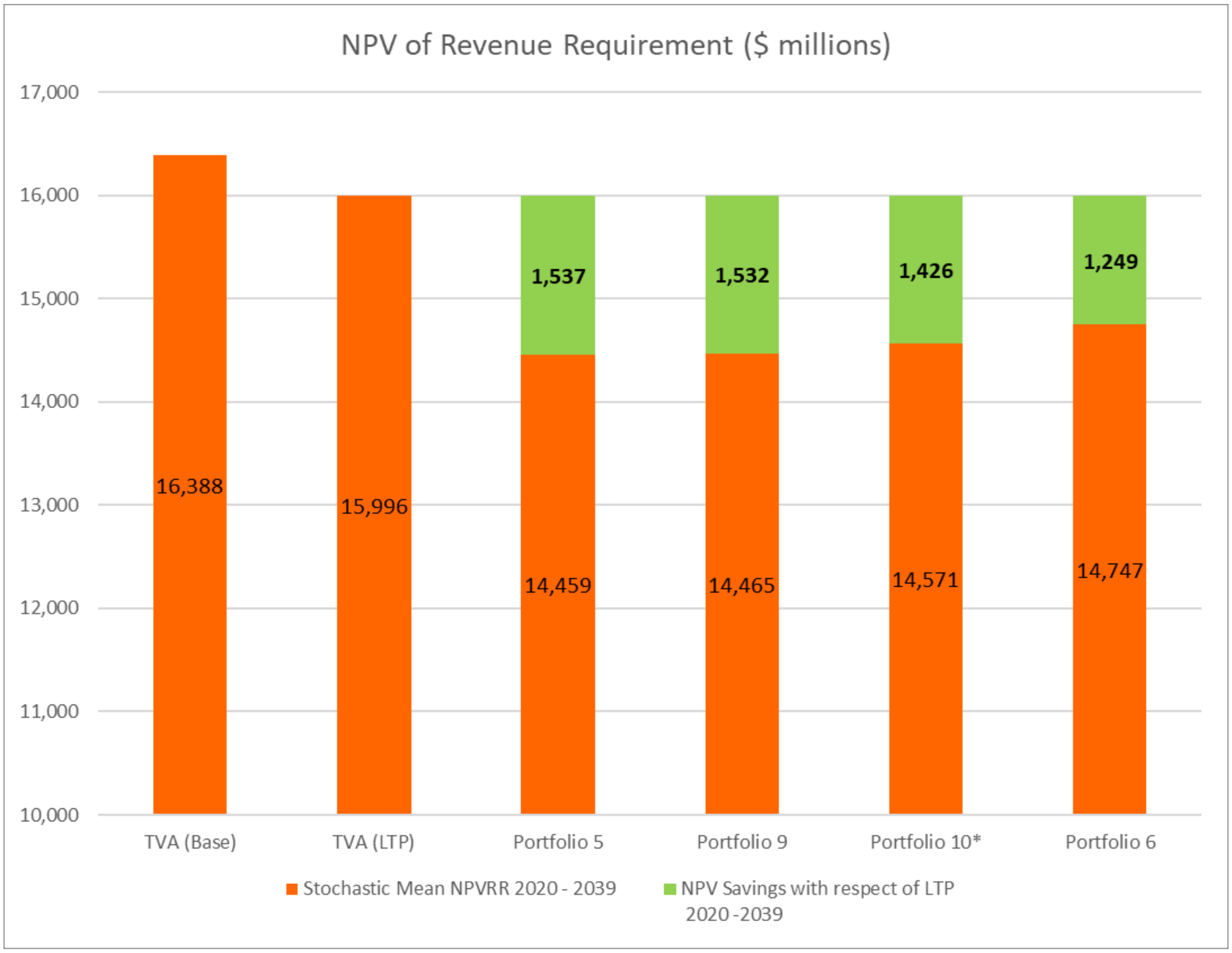
Objective	Measure	Unit	TVA (Base)	TVA (LTP)	Portfolio 5	Portfolio 9	Portfolio 10*	Portfolio 6	Portfolio 8	All MISO	Portfolio 1	Portfolio 7	Portfolio 4	Portfolio 2	Portfolio 3
					1 CC + 4 CT	1 CC + 4 CT	1 CC + 0 CT	2 CC + 1 CT	2 CC+2 CT	1 CC + 0 CT	2 CC + 1 CT	2 CC+2 CT	3 CC + 1 CT	3 CC + 2 CT	3 CC + 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
Least Cost	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
Least Cost	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
Least Cost	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**
Least Cost	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**
Least Cost	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	2.37	2.37	3.44	3.04	3.04	3.44	3.33	3.33	4.02	3.82	4.09
Min Envr. Risk	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%
Min Envr. Risk	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%
Reliable	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
Resilient	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%
Resilient	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%	23.0%	16.7%	15.6%	7.4%	7.0%	7.7%
Min Market Risk	% Energy Sold in Market	%	8.7%	8.7%	22.6%	22.6%	17.0%	9.7%	9.7%	17.9%	10.5%	10.6%	7.6%	6.7%	5.6%
Econ. Growth	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.

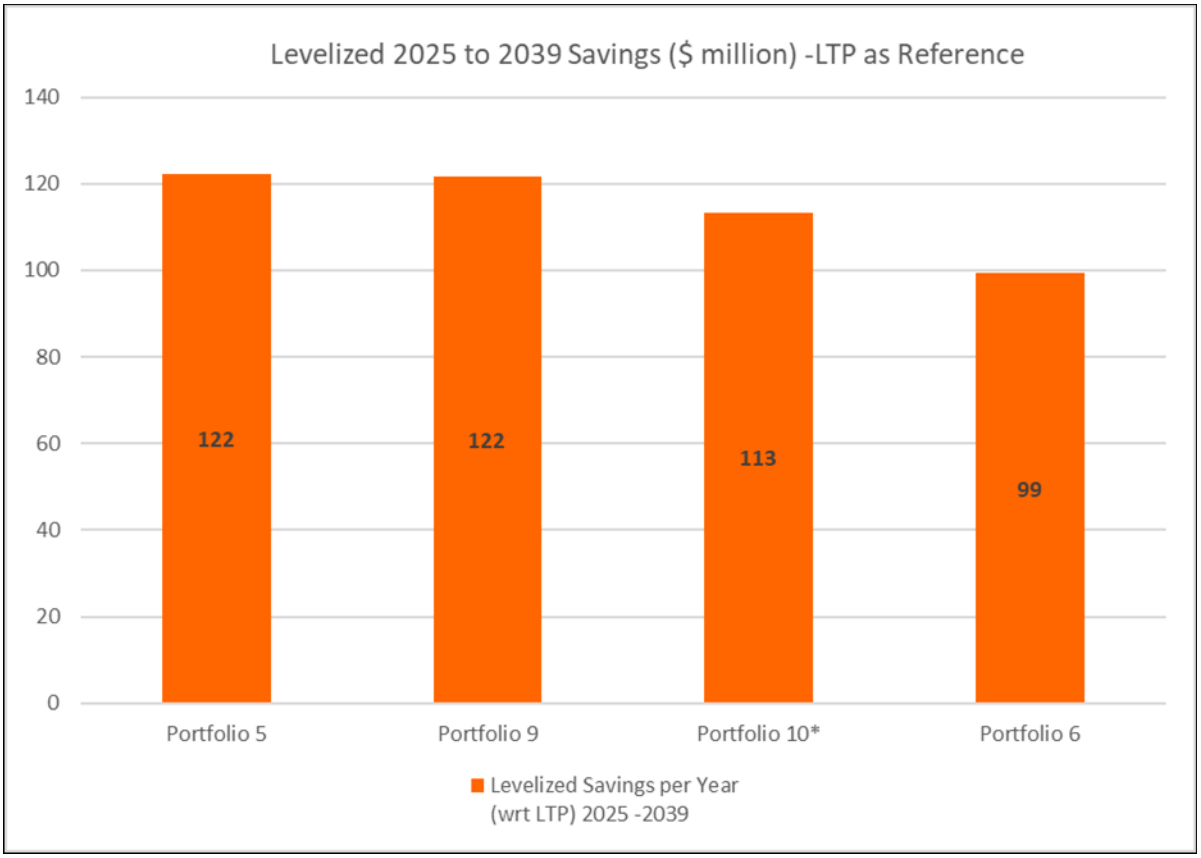
Exhibit 187: Affordability



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.

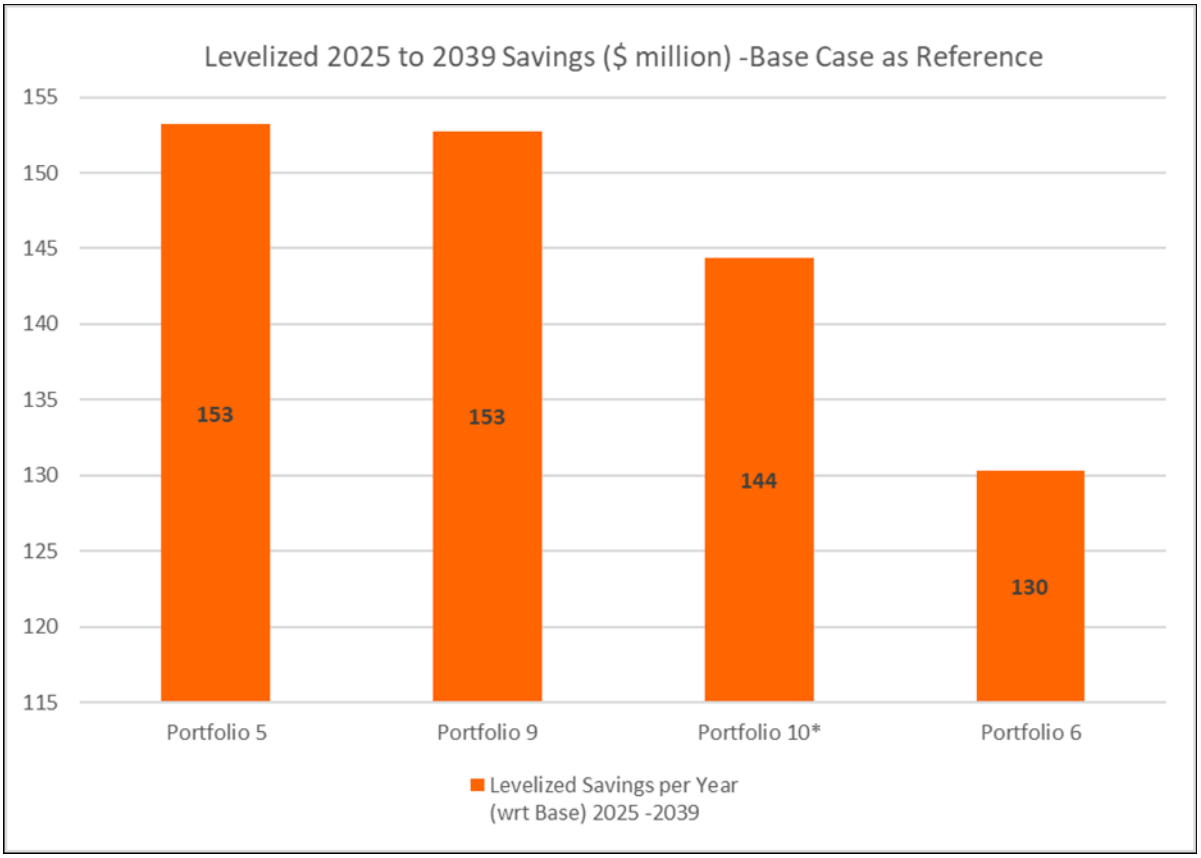
Exhibit 188: Levelized Savings per Year with Respect to the LTP



Source: Siemens

If the LTP is not considered, then the savings increase to $130 to $153 million per year as shown in Exhibit 189 below.

Exhibit 189: Levelized Savings per Year with Respect to the Base TVA Contract

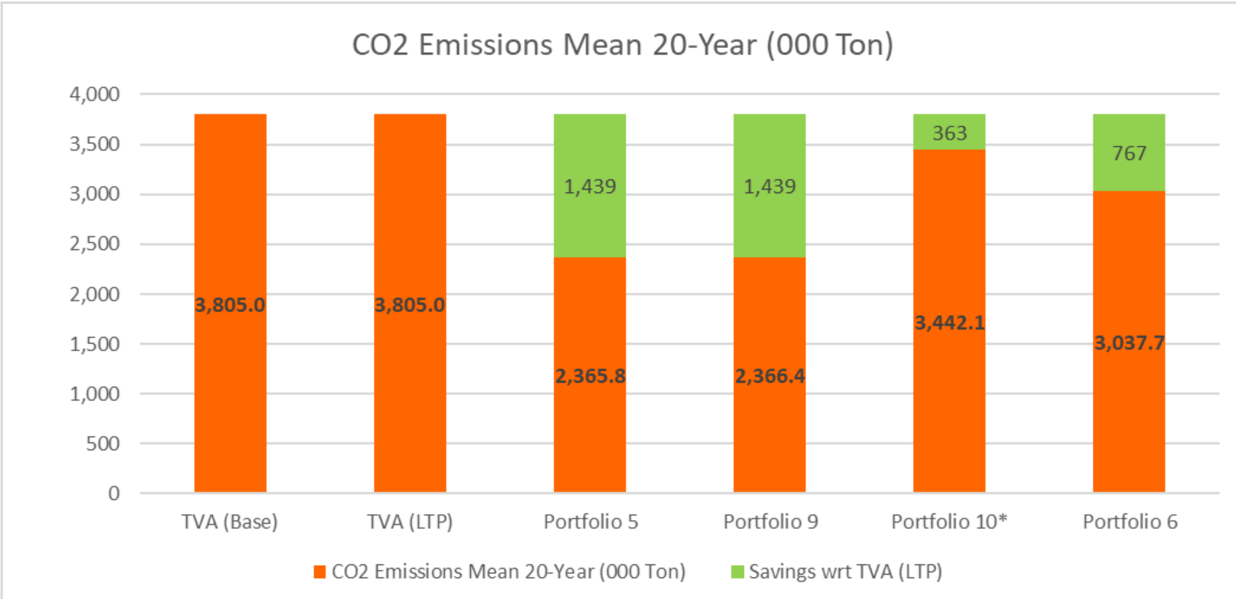


Source: Siemens

15.1.2 Sustainability Metric

Exhibit 190 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. For the MLGW portfolios the emission include the CO_2 associated with the net purchased from MISO.

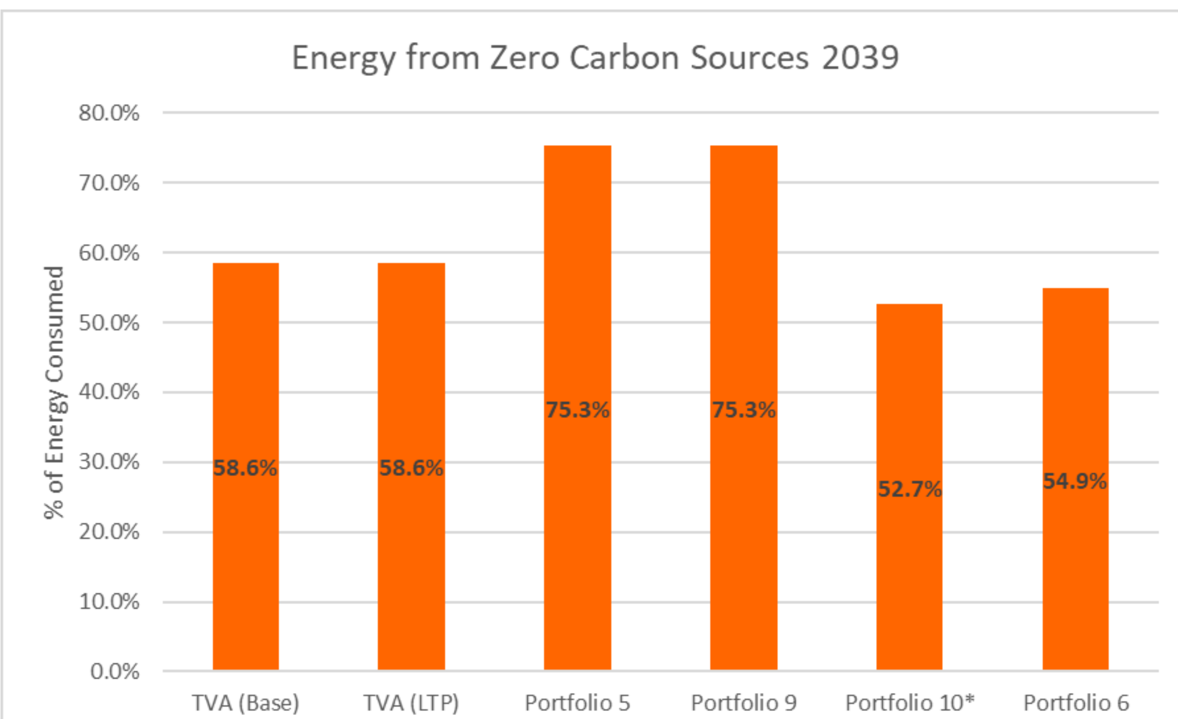
Exhibit 190: Sustainability Metric (CO_2 Emissions)



Source: Siemens

Portfolio 5 and 9 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 191).

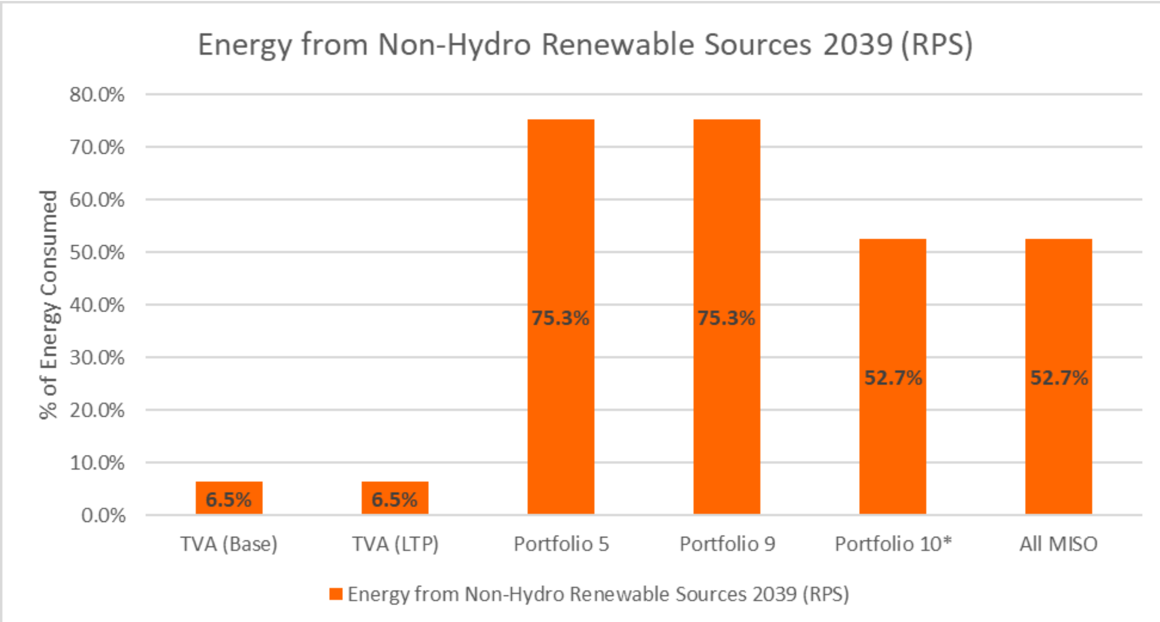
Exhibit 191: Zero Carbon Sources



Source: Siemens

Considering only photovoltaic and wind generation, TVA fares poorly on an RPS measure. Even if large hydro were considered, this value would only increase to 16%. Exhibit 192 displays a comparison of renewable energy as a percentage of total energy.

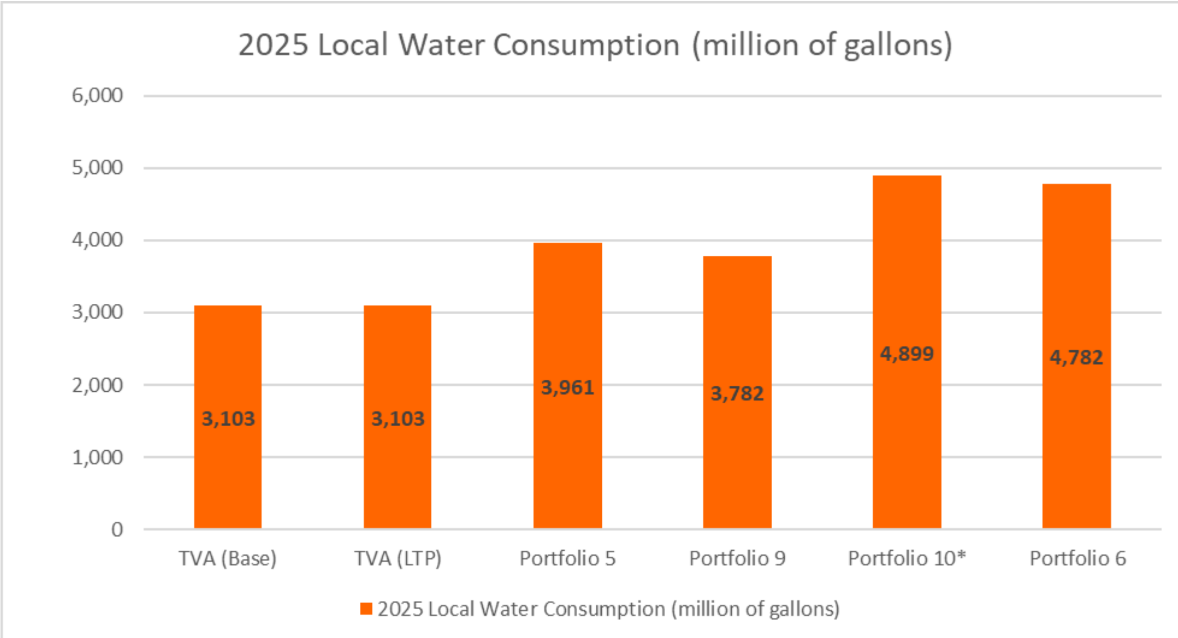
Exhibit 192 RPS



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 193.

Exhibit 193: Water Consumption



Source: Siemens

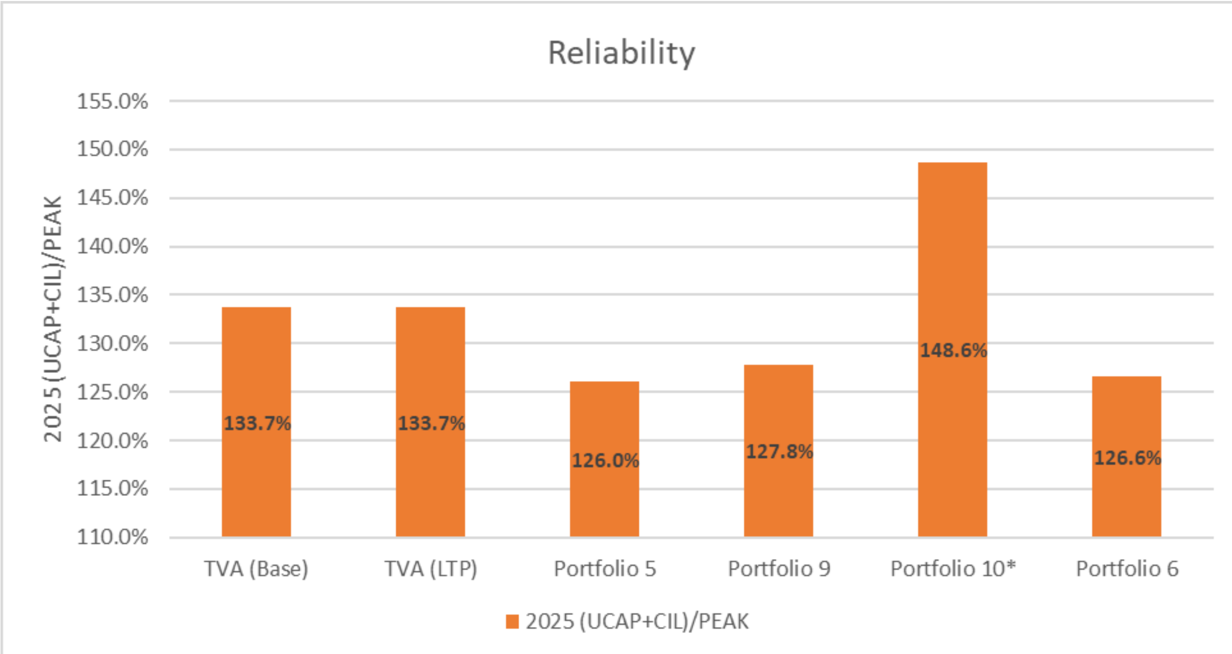
15.1.3 Reliability

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 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.

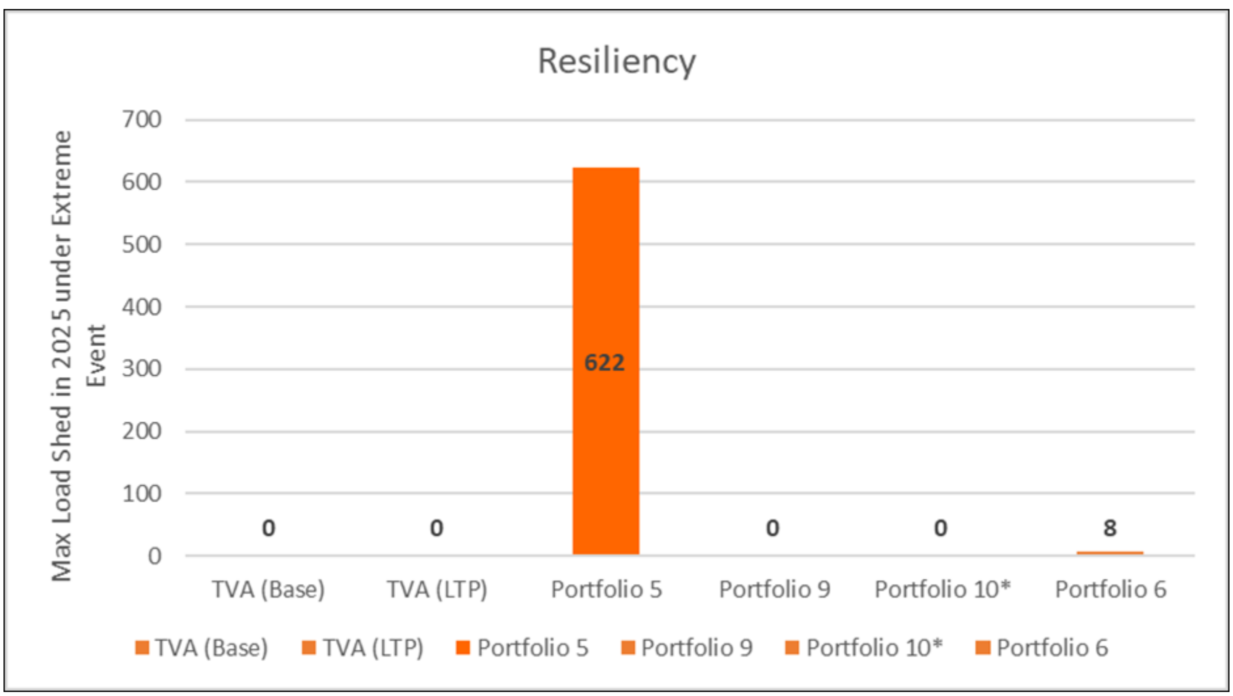
We also note that Portfolio 10 has the highest value according to this metric, but it can be misleading as this portfolio has only one large CCGT and its extended outage could lead to dependence exclusively on transmission(similar to Portfolio 5), but, in this case it was reinforced allowing the incorporation 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. Portfolio 8, which has on more CT, eliminates this issue.

Exhibit 194: Reliability



Source: Siemens

Exhibit 195: Resiliency



Source: Siemens

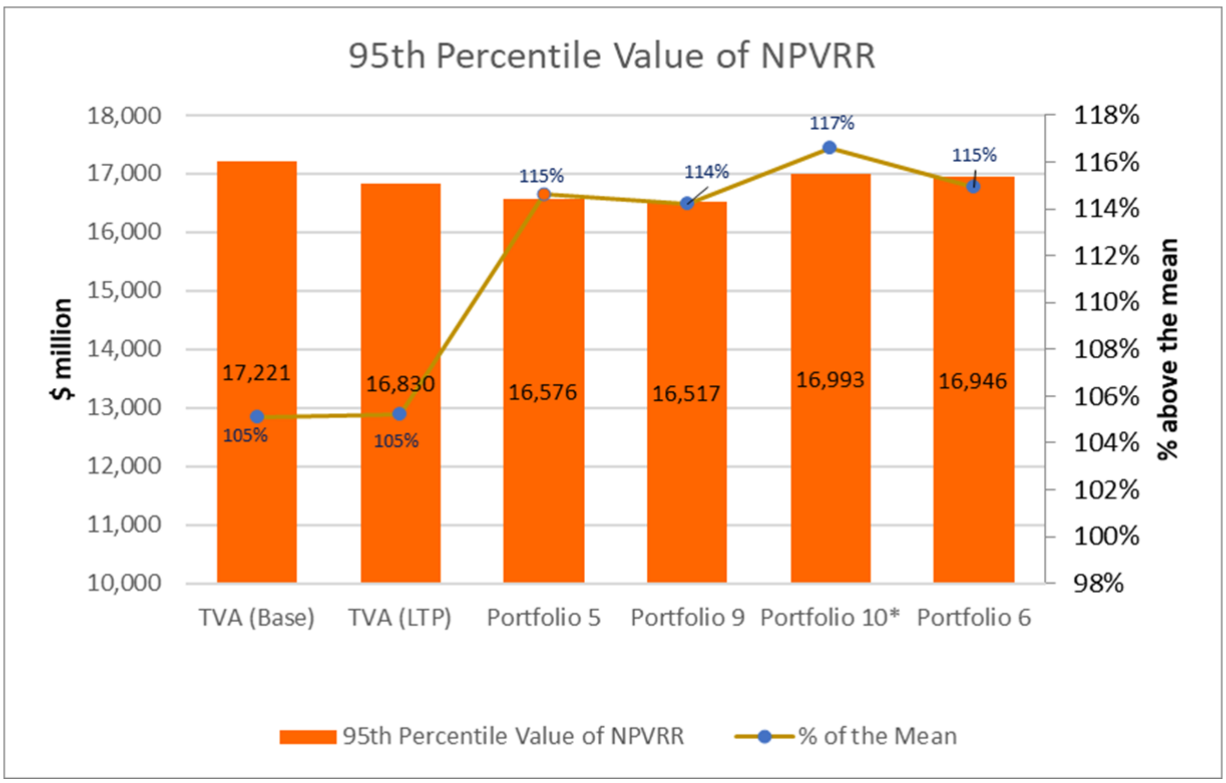
15.1.4 Price Risk

TVA's portfolio 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, i.e. the NPVRR that is exceeded only in 5% of the runs, is 105% times the stochastic mean (the average value). This means that 95% of the time the results are within 105% of the average, showing lower risk.

On the other hand, Portfolio 5, 9 and 6 the 95th percentile is within 114% to 115% times the mean and in Portfolio 10 it is 117%. This shows higher volatility of the outcomes and it is 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 assess options to achieve fuel price volatility mitigation as part of its assessment to leave TVA.

Exhibit 196: 95th Percentile of Revenue Requiriments and Changes with Respect of the Mean



Source: Siemens

15.1.5 Market Risk

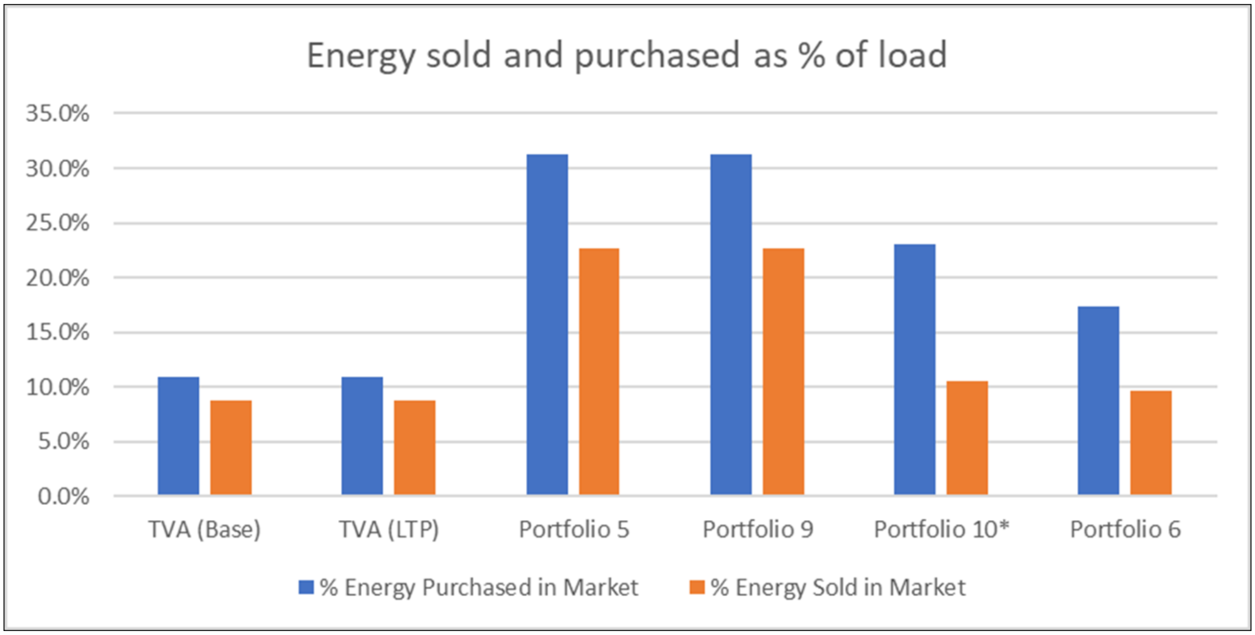
Market risk is measured as a function of the percentage of the energy that is sold and purchased in the MISO market as a percentage of the total load. As portfolios have different development timelines and

there tend to be higher purchases from MISO in the earlier years (e.g. 2025), in order to highlight the actual long term difference between portfolios, the value shown below and

Exhibit 186 corresponds to the purchases and sales by 2039. In Appendix D: Portfolio Details the actual MISO Purchases and Sales per Portfolio and year can be observed.

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 (with its large CCGT) and Portfolio 6 (with its two CCGTs) have a reduced risk particularly on energy purchases.

Exhibit 197: Market Risk



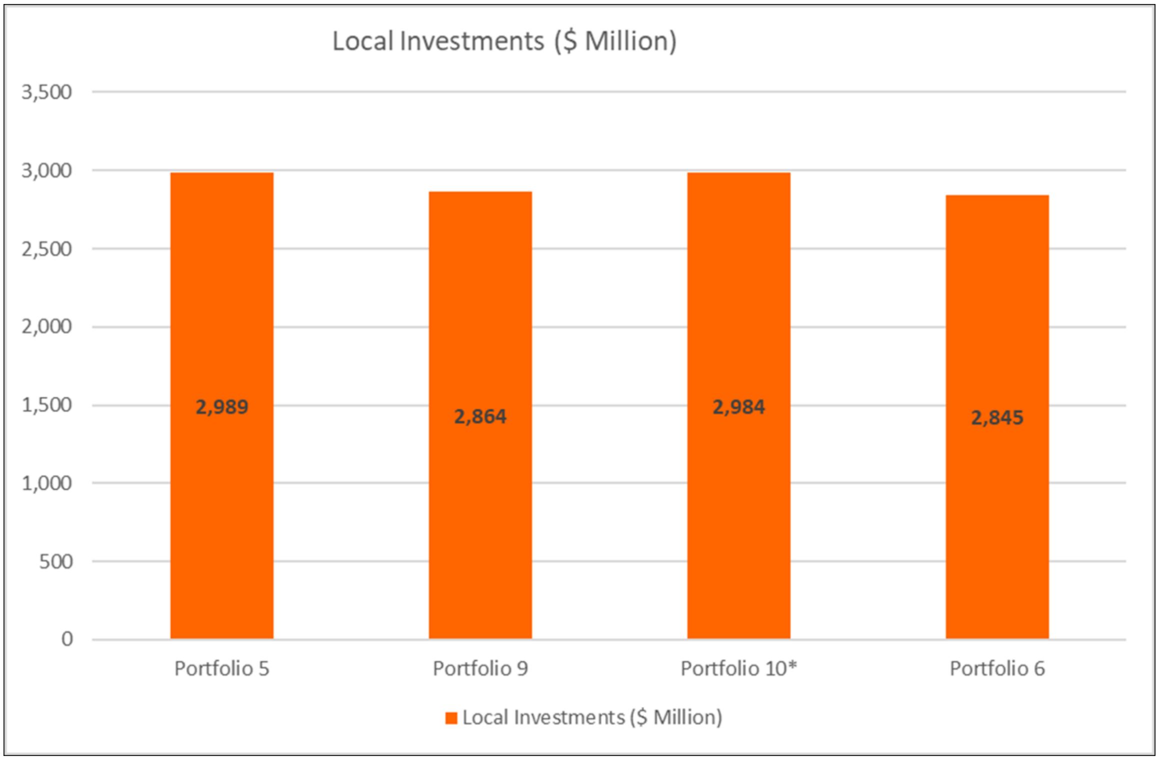
Source: Siemens

15.1.6 Local Economic Development

Local economic development is measured using the total local capital expenditures per Portfolio as a proxy (i.e. investments in local renewable, thermal power plants and transmission). This is presented just for portfolio ranking purposes.

As shown in Exhibit 198, all portfolios are very similar, with Portfolios 5 and 10 slightly ahead largely due to the transmission investments (it has the same amounts of local renewable generation as in other portfolios).

Exhibit 198: Economic Development



Source: Siemens

15.1.7 Municipality Departure Impact on Portfolio Cost

The studies conducted assume that all the Municipalities that are associated with MLGW will stay with MLGW in their transition to one of the selected portfolios. The question arises what happens to the Portfolio costs if some of them do not stay with MLGW. To assess this impact on Portfolio costs Siemens evaluated one of the preferred portfolios (Portfolio 9) under the assumption that some of the Municipalities would choose to provide power to their citizens and leave MLGW.

The analysis conducted assumes that approximately12% of the total load that MLGW currently serves would separate from MLGW. This level of departure represents a higher bound of potential load loss from Municipalities that would choose to leave MLGW and provide power to their own citizens.

Adjustments were made to the following:

- MLGW Demand was reduced according to the load assumptions for the Municipalities that potentially will choose to separate from MLGW.
  - The demand was determined from an 8760-hour 2019 Municipal load profile.
  - This load profile was assumed to be relatively constant for the analysis period (2025-2039), i.e. any growth is compensated by energy efficiency and distributed solar.

- To adapt the reduction in load, the Portfolio was modified by: a) reducing the market purchases and increasing the market sales to MISO (net market purchases reduction) and b) reducing the MISO capacity purchases in response to the reduced peak demand and the requirement to maintain the 8.9% reserve margin.

The analysis concentrates specifically on a set number of metrics in order to show the impact of the Municipalities' potential departure on the Portfolio cost. The impact on the reduction in demand for MLGW is evaluated in terms of the final NPV costs per MWh, including all the cost of supply as derived from Portfolio 9, as representative of other portfolios.

The analysis shows (see Exhibit 198) that, before MISO Capacity cost, the load weighted NPV of the total fixed costs would increase by $4.92 /MWh. This was expected since these costs do not change, but the present value of the load is reduced. The MISO Capacity Fixed Costs decreased by $1.44 /MWh due to less MISO Capacity needed resulting from the load reduction. The total variable costs (fuel and variable O&M) remains the same (energy is sold to MISO) but, the cost when expressed in $/MWh, increased by $0.96/MWh. The cost of MISO net purchases is expected to be reduced with the Municipalities departure. The net MISO purchases decreased by $4.89/MWh. Totaling these, it is showing a slight reduction of the load weighted present value of the adjusted production costs from $50.11/MWh to $49.66/MWh, or 0.9%. However, when adding other costs associated with transmission, PILOT, TVA benefits, Gap, etc., which make up the total revenue requirements of the portfolio, the municipalities' departure results in an increase of the load weighted present value of the Portfolio revenue requirements by $ 0.48/MWh or 0.8%.

It is important to note that beyond the increase in Portfolio costs, there would be other impacts to MLGW that could be significant such as impacts in operations and the loss of margin.

Exhibit 199: Portfolio 9 Less Municipalities versus Portfolio 9 Comparison

	Portfolio 9 Less MUNI		Portfolio 9		DELTA	%
	NPV	NPV/MWh	NPV	NPV/MWh	NPV/MWh	
Demand (MWh)	**158,706,173**	N/A	**181,088,154**	N/A	(22,381,981.54)	-12.4%
Total Fixed Cost before MISO Capacity ($000)	6,320,248	39.82	6,320,248	34.90	4.92	14.1%
MISO Capacity ($000)	284,434	1.79	585,422	3.23	(1.44)	-44.6%
Total Variable Costs	1,233,548	7.77	1,233,548	6.81	0.96	14.1%
Total Production Cost ($000)	**7,838,230**	**49.39**	**8,139,218**	**44.95**	**4.44**	**9.9%**
Net MISO Purchases	43,540	0.27	934,474	5.16	(4.89)	-94.7%
Adjusted Production Cost ($000)	**7,881,771**	**49.66**	**9,073,692**	**50.11**	**(0.44)**	**-0.9%**
Transmission CapEx Recovery ($000)	341,868	2.15	341,868	1.89	0.27	14.1%
Transmission O&M ($000)	150,961	0.95	150,961	0.83	0.12	14.1%
State PILOT ($000)	394,089	2.48	453,685	2.51	(0.02)	-0.9%
Local PILOT ($000)	247,677	1.56	247,677	1.37	0.19	14.1%
TVA Benefits ($000)	181,739	1.15	181,739	1.00	0.14	14.1%
Gap-LBA ($000)	58,251	0.37	58,251	0.32	0.05	14.1%
Gap-Other ($000)	33,103	0.21	33,103	0.18	0.03	14.1%
MISO Admin ($000)	81,388	0.51	81,388	0.45	0.06	14.1%
Energy Efficiency ($000)	115,027	0.72	115,027	0.64	0.09	14.1%
Total NPVRR 2025-2039 ($000)	**9,485,873**	**59.77**	**10,737,390**	**59.29**	**0.48**	0.8%

Source: Siemens

15.1.8 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 trade-offs 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 the study are:

- There are levelized cost savings of about $99 to $122 million in real 2018 $ per year on an expected basis (probability weighted) associated with exiting the TVA contract assuming under the LTP and joining MISO for the 2020 to 2039 period. These savings increase to $130 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 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, which 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 assess options to 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.

▪ If MLGW chooses 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). This generation should not be limited to distribution level solutions but must include the possibility of MLGW deploying utility scale renewable generation which is more economical.
- 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 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 in the future and only needs to be performed if MLGW chooses to stay with TVA.
- Seek written contractual guarantees from TVA that provide long-term wholesale rate stability. This could take the form of a ceiling rate not-to-be exceeded for a clearly defined term to be followed by a cap on future rate increases.

▪ 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.

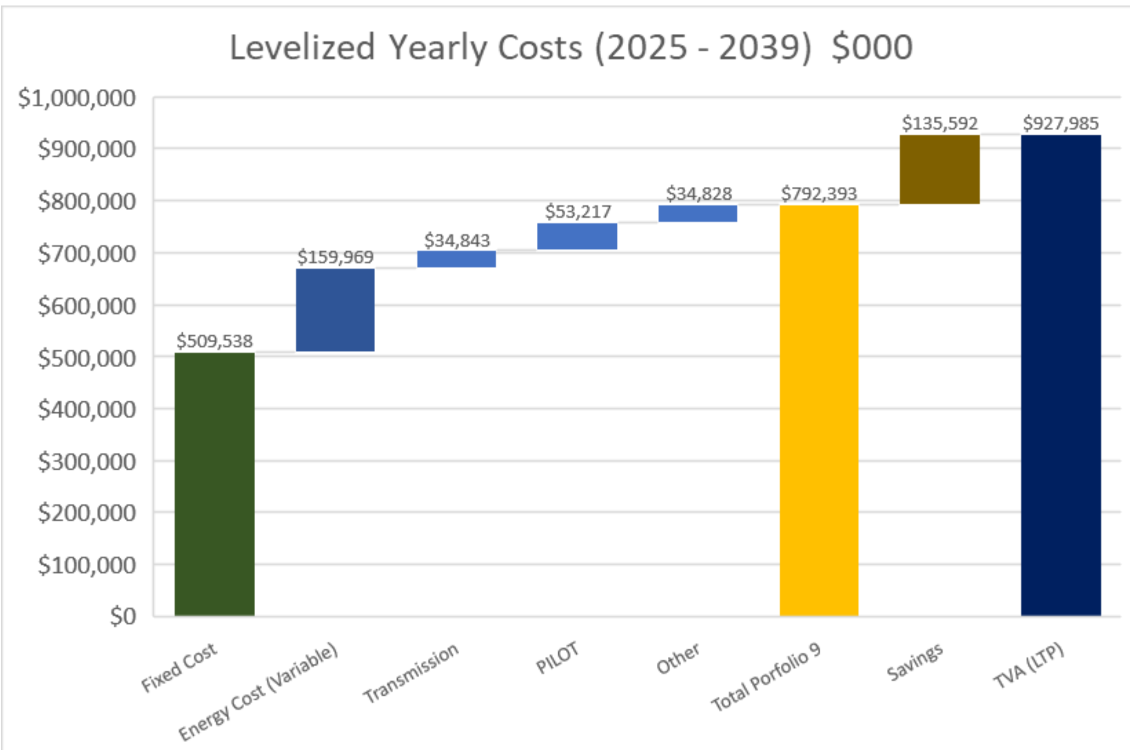
▪ An RFP should be undertaken by MLGW to confirm all estimated savings before making a final decision. The IRP can be utilized to determine the general mix of assets and locations of interest in the RFP and the orders of magnitude of transmission required. Differences between Portfolios 5, 9, 6, and 10 can be reassessed with bids provided by potential suppliers.

15.1.9 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 media.

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.

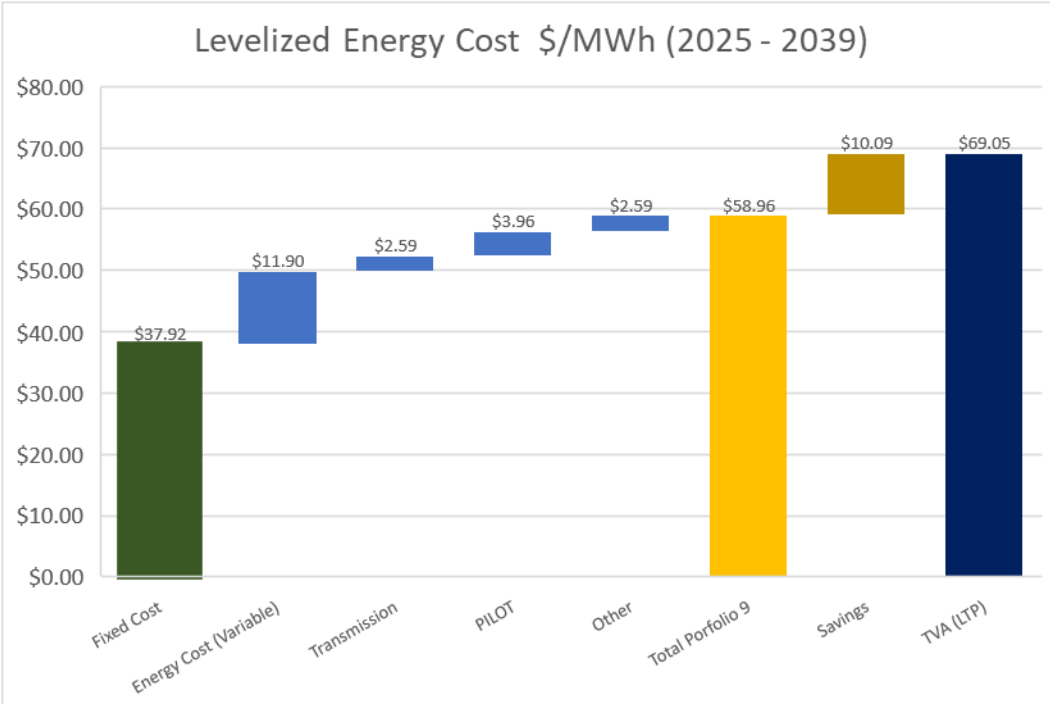
Exhibit 200: Portfolio 9 Levelized Yearly Costs for 2025 to 2039 with Respect to TVA LTP (2018 $)



Source: Siemens

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

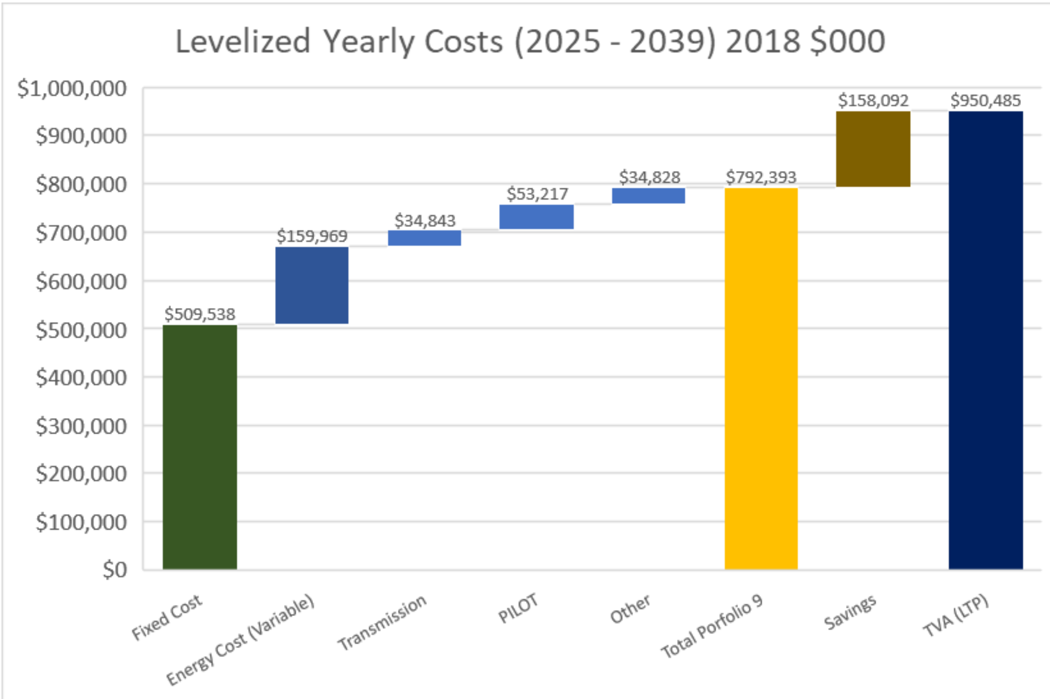
Exhibit 201: Portfolio 9 Levelized Energy Costs for 2025 to 2039 with Respect to TVA LTP (2018 $)



Source: Siemens

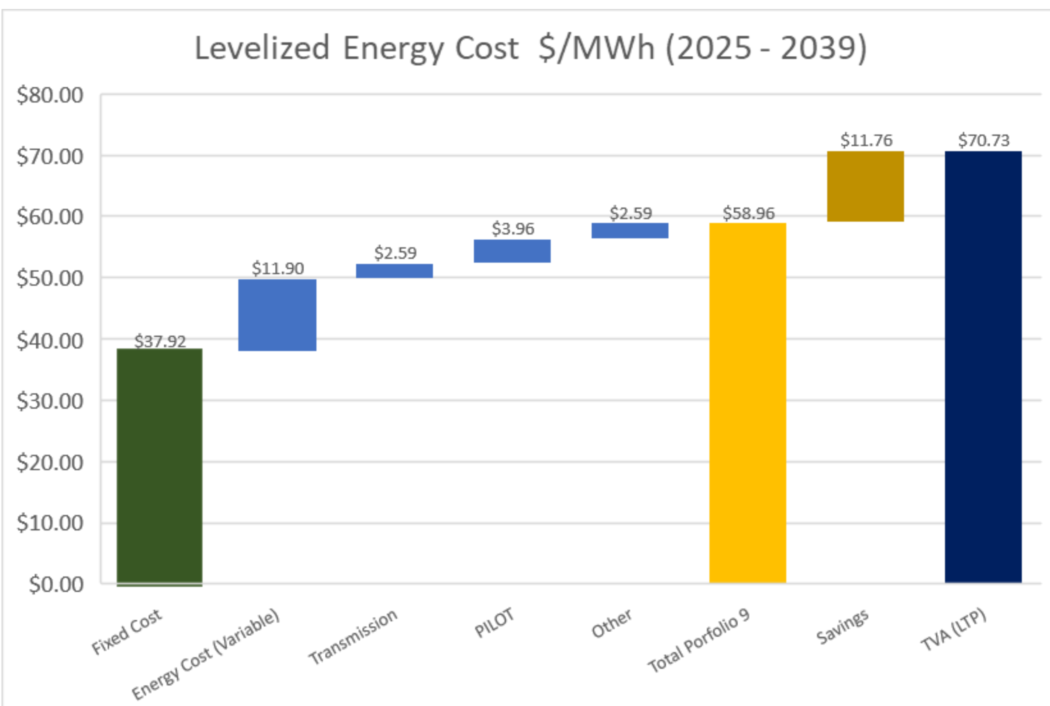
A similar comparison with respect to the current contract shows savings in the order of $160 million per year.

Exhibit 202: Portfolio 9 Levelized Costs for 2025 to 2039 with Respect to TVA Current Contract (2018 $)



Source: Siemens

Exhibit 203: Portfolio 9 Levelized Energy Costs for 2025 to 2039 with Respect to TVA (2018 $)



Source: Siemens

In this last case, the payments for transmission, PILOT and Others (Gap analysis costs, MISO membership, matching TVA community benefits and energy efficiency, demand response and renewable generation programs) are an important cost for direct comparison to TVA because they account for approximately $123 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 . 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 that TVA pays today might be borne by developers as actual taxes included in the prices that 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 TVA could be larger.

Appendix A: TVA Materials

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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

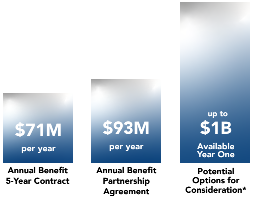
RATE TRAJECTORY

- 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



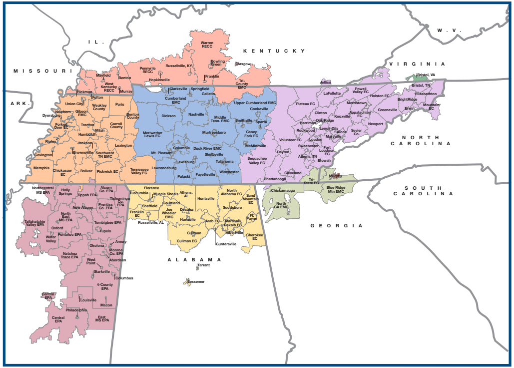
- As a part of the partnership agreement, TVA has offered a 3.1% credit on wholesale power rates to all Local Power Companies (LPCs); for MLGW, this credit is approximately $22.5 million per year, or $400 million over 20 years.
- LPCs that commit to the partnership agreement also gain additional access 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:	<u>TVA Defaults</u> 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. <u>Distributor Defaults</u> 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:	<u>TVA Default</u> 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. <u>Distributor Default</u> 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.

ANY ACTIONS TAKEN BY A PARTY IN RELIANCE ON THE TERMS SET FORTH IN THIS TERM SHEET OR ON STATEMENTS MADE DURING NEGOTIATIONS PURSUANT TO THIS TERM SHEET SHALL BE AT SUCH PARTY'S OWN RISK. UNTIL DEFINITIVE AGREEMENT(S) HAVE BEEN EXECUTED BETWEEN OR AMONG THE PARTIES, NO PARTY SHALL HAVE ANY LEGAL OBLIGATIONS, EXPRESS OR IMPLIED, OR ARISING IN ANY OTHER MANNER UNDER THIS TERM SHEET OR IN THE COURSE OF NEGOTIATIONS. SUCH DEFINITIVE AGREEMENT(S) ARE THE ONLY DOCUMENT(S) THAT WOULD CREATE A BINDING LEGAL OBLIGATION BETWEEN OR AMONG THE PARTIES WITH RESPECT TO THE SUBJECT MATTER OF THIS TERM SHEET.

Memphis Summary of Benefits

December 2019

Benefits of Memphis Contract with TVA

Annual Value (FY18)	Description
$10M - $15M	Economic Development benefits, incl. investment credits, performance grants, etc.
$18.3M	Payments in Lieu of Taxes (PILOT)
$2.2M	Community benefits, including Home Uplift (weatherization) and other energy efficiency programs
$330k	Community investments in schools, local organizations, and non-profits
$37M	Revenue from 161kV transmission lease (varies slightly year to year)
$140k	Comprehensive Services Program (CSP) matching funds (split 50/50 with MLGW)
$50M* - $120M*	Capital investment by businesses in the Memphis area induced by TVA's economic development efforts

**Note that capital investment by other businesses does not represent direct spend by TVA but does represent increased MLGW revenue and increased City of Memphis tax base*

Memphis-Area Investment & Job Creation

Since 2012, TVA has helped attract 24 new location projects and 63 expansion projects in the Memphis area

Recent Announcements:

Jobs :

	indigo	JNJ Express Memphis, TN	St. Jude Children's Research Hospital Finding cures. Saving children.
Jobs	**700**	**610**	**500+**
	North American Operations Headquarters	Headquarters Expansion	Advanced Research Center
Investment	**$6.6** million	**$83.6** million	**$412** million

Investment:

Since 2012:

28,000 jobs

24 New Projects
63 Expansions

$3.6 billion

PARTNERSHIP BENEFITS AND TVA PUBLIC POWER

Benefits of TVA Public Power

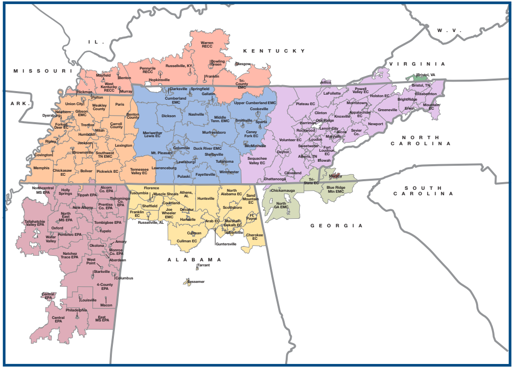
- As a part of the partnership agreement, TVA has offered a 3.1% credit on wholesale power rates to all Local Power Companies (LPCs); for MLGW, this credit is approximately $22.5 million per year, or $400 million over 20 years.
- LPCs that commit to the partnership agreement also gain additional access 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.

Tennessee Valley Authority, 400 West Summit Hill Drive, Knoxville, Tennessee 37902-1401

September 27, 2019

Nelson Bacalao
Yan Du
Siemens Industry Inc.
10900 Wayzata Blvd.
Minnetonka, Minnesota

Re: *MLGW IRP Study — Transmission Analysis*

Dear Mr. Bacalao and Mr. Du:

During the Power Supply Advisory Team (PSAT) meeting on September 16, 2019, a question arose regarding whether TVA's transmission system could be used to supply electricity to Memphis Light, Gas and Water (MLGW) from MISO South. To ensure that the PSAT members have accurate information regarding TVA's transmission system and, ultimately, the best information to formulate a recommendation to MLGW, we felt it important to clarify TVA's position on this question.

In 1959, Congress amended the TVA Act to enable TVA to self-finance electric system projects without Congressional appropriations and also restricted TVA's power sales authority to TVA's existing service area as of July 1, 1957, with certain limited exceptions (the TVA Fence). In 1992 Congress gave the Federal Energy Regulatory Commission (FERC) authority to order certain utilities to provide "open access" wholesale transmission service. Congress recognized, however, that requiring TVA to wheel power from other utilities to supply any of TVA's customers would be inequitable because other power suppliers would be able to "cherry-pick" TVA's most attractive customers, unfairly leaving the remaining (less attractive from a competitive standpoint) TVA customers to bear the costs of paying for TVA's generation and transmission facilities as the Fence precluded TVA from making any new sales to offset those losses. For this reason, Congress enacted the Anti-Cherrypicking Amendment to the Federal Power Act (Section 212) to protect TVA ratepayers and the Tennessee Valley public power model. In short, the Anti-Cherrypicking Amendment prohibits FERC from ordering TVA to wheel power that would be consumed within the TVA Fence.

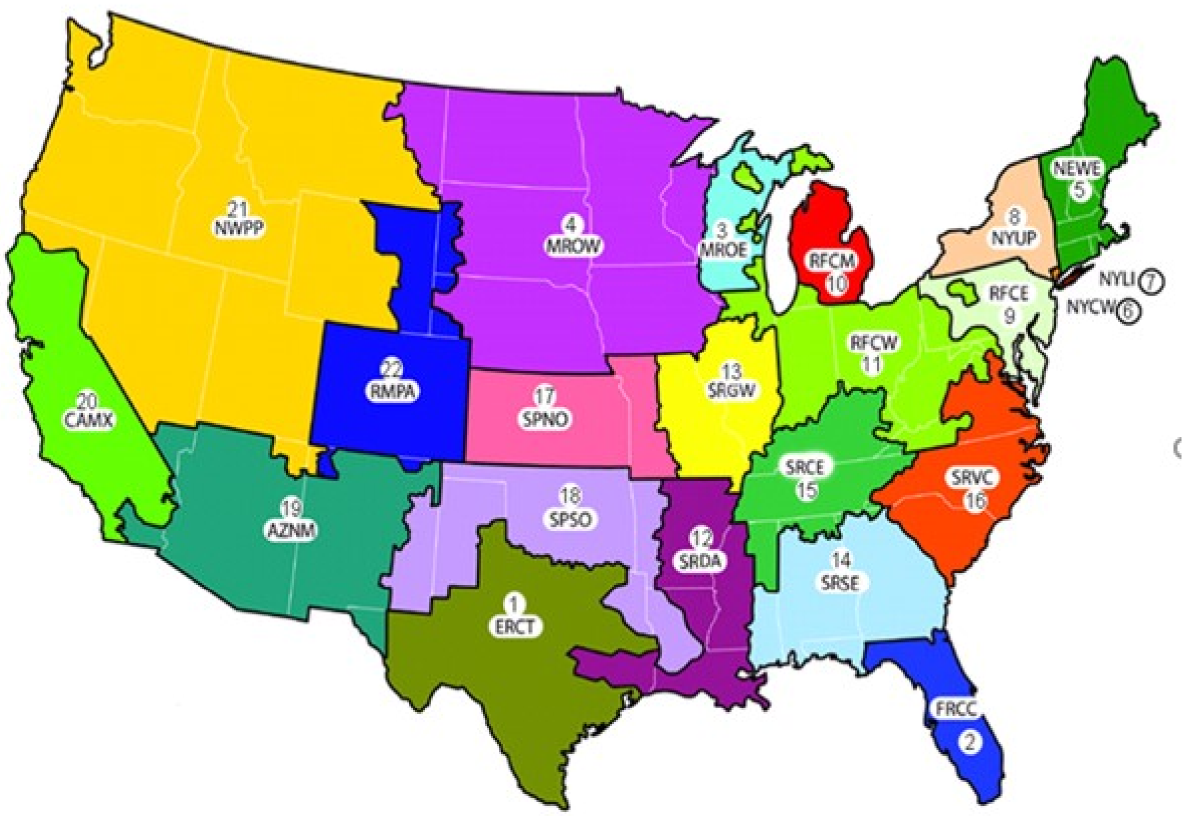
In furtherance of the Tennessee Valley public power model created by Congress, TVA has built an extensive transmission system designed to provide safe, clean, reliable, and affordable power to its customers. Our responsibility is to ensure that all TVA ratepayers are protected utilizing any legal, contractual, or physical means available. Therefore, TVA will not consider wheeling for MLGW or agree to any other power supply options that utilize any part of the TVA transmission system to deliver power to MLGW as those actions would erode the protections established by Congress for TVA's remaining customers and its ratepayers.

Please let me know if you have any questions or if you would like to discuss further.

Sincerely,

Aaron P. Melda
Vice President
Tennessee Valley Authority
Telephone 423.751.4129
Email apmelda@tva.gov

Appendix B: Regional Capital Cost Multiplier



Source: Siemens

Technology	Advanced 2x1 Combined Cycle	Advanced Simple Cycle Frame CT	Small Aero Simple Cycle CT	Onshore Wind	Offshore Wind	Utility Solar PV Tracking	Batteries Li-ion
Average	1	1	1	1	1	1	1
ERCT	0.88	0.91	0.88	0.78	1.00	0.88	1.00
FRCC	0.90	0.94	0.91	N/A	1.00	0.94	1.00
MROE	0.87	0.90	0.87	1.07	N/A	0.98	1.00
MROW	0.91	0.93	0.91	0.88	N/A	1.01	1.00
NEWE	1.02	0.98	0.98	1.19	1.00	1.06	1.00
NYCW	1.39	1.33	1.40	N/A	1.00	N/A	1.00
NYLI	1.39	1.33	1.40	1.08	1.00	1.43	1.00
NYUP	1.03	0.97	0.97	1.08	N/A	1.00	1.00
RFCE	1.07	1.04	1.05	1.08	1.00	1.06	1.00
RFCM	0.91	0.93	0.91	1.07	N/A	1.01	1.00
RFCW	0.95	0.96	0.93	1.07	N/A	1.01	1.00
SRDA	0.88	0.92	0.89	0.98	1.00	0.91	1.00
SRGW	0.96	0.97	0.95	1.07	N/A	1.03	1.00
SRSE	0.90	0.94	0.93	1.16	1.00	0.90	1.00
SRCE	0.96	1.00	0.97	0.97	N/A	0.94	1.00
SRVC	0.86	0.89	0.87	1.16	1.00	0.86	1.00
SPNO	0.93	0.95	0.93	0.73	N/A	0.98	1.00
SPSO	0.91	0.93	0.91	0.67	N/A	0.94	1.00
AZNM	1.08	1.09	1.07	0.96	N/A	0.99	1.00
CAMX	1.17	1.08	1.09	0.96	N/A	1.14	1.00
NWPP	1.00	0.99	0.97	0.96	1.00	1.01	1.00
RMPA	1.12	1.13	1.30	0.73	N/A	0.96	1.00

Source: Siemens

Appendix C: Model Description

In order to perform the stochastic analysis, a set of probability distributions are required for key market driver variables. These include probabilistic distributions for demand growth (load), fuel costs (natural gas and coal), environmental compliance costs (carbon), and capital costs.

Load Stochastics

To account for variations in electricity demand stemming from economic growth, weather, and energy efficiency and demand side management measures, Siemens developed stochastics around the load growth expectations for the MLGW control area and the neighboring ISO zones. While values in the 95th percentile are driven by strong economic growth, values in the 5th percentile are driven by economic stagnation or other load modifiers such as energy efficiency and demand-side management implementation.

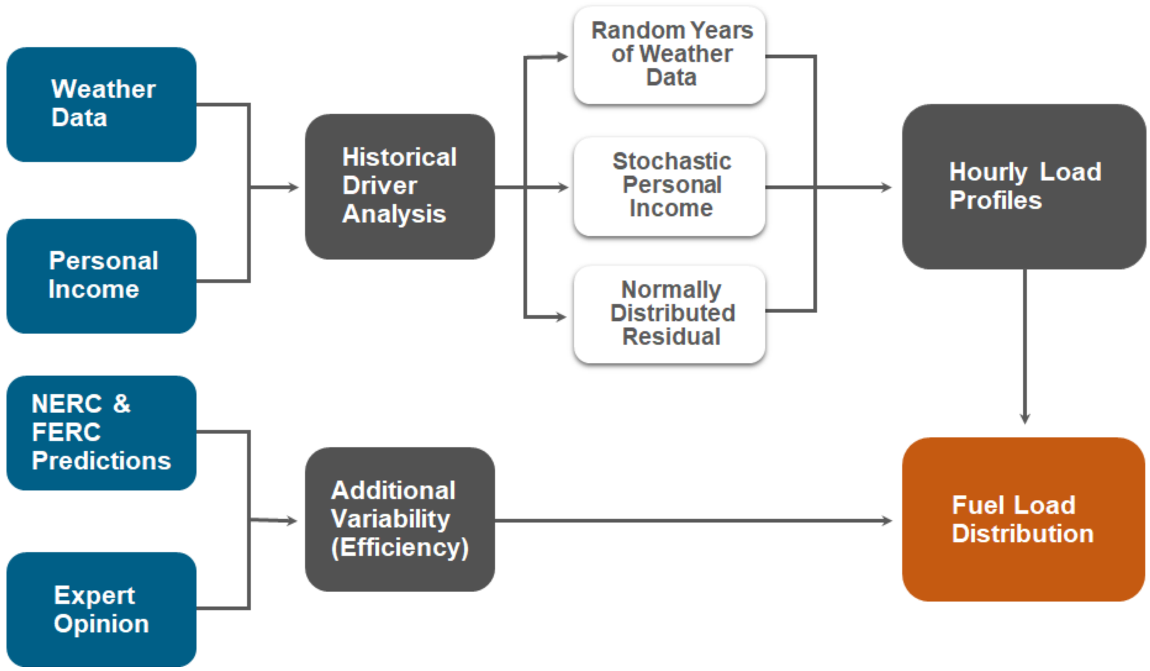
Siemens 's long-term load forecasting process captures both the impact of historical load drivers such as economic growth and variability of weather and the possible disruptive impacts of energy efficiency penetration in constructing the average and peak demand outlook.

Finally, Siemens benchmarked the projections against MISO-sponsored load forecasting studies that are conducted by independent consultants and institutions and then released into the public domain. The process to benchmark the load to MISO's forecasts is undertaken during the quantum step, which is described below.

Load Forecast Process

The process for developing stochastic distributions for MLGW and surrounding MISO zone loads begins with a deterministic estimation of load uncertainties, followed by parametric forecasts for the MISO zones.

Exhibit 204: Flow Chart to Address Load Uncertainty



Source: Siemens

With respect to the historical driver analysis, we find that historical monthly weather data and personal income have explained changes in monthly average and peak load well. This relationship forms the basis for Siemens 's load uncertainty analysis. The basic premise of the model is that load can be expressed as a function of heating degree days, cooling degree days, humidity, and personal income.

$$Load_t=\alpha+ \beta_1*HDD_t+ \beta_2*CDD_t+ \beta_3*HUM_t+ \beta_4*PI_t+ \xi_t$$

Where the independent variables are:

- HDD (Heating Degree Days): 65 - Average daily temperature in degrees Fahrenheit or zero (HDD is never negative)
- CDD (Cooling Degree Days): Average daily temperature -65 in degrees Fahrenheit or zero. (CDD is never negative)
- HUM (Humidity): Average daily percent humidity
- PI: Personal Income
- ξ: A normally distributed variable with mean 0 and constant variance
- α: A constant derived from the regression analysis
- β_n: Coefficients derived from the regression analysis
- t: Month of the year

A stepwise regression then calibrates this model for the historic net peak and average MLGW load data. The stochastic distributions of the load were then computed by running 200 iterations on the independent variables as the randomly generated input parameters and applied to the equation and the calibrated model coefficients above.

MISO Forecast Load Uncertainty

The subsequent load stochastics propagation for the surrounding MISO zones is a parametric estimation process that separately employs the same econometric specification for each MISO Local Resource Zone (LRZ) based on the historical relationships between average and peak load, and key driver variables, including temperature data (HDD, CDD, and humidity) and an economic factor variable (personal income for the geographical area). Siemens uses the historical personal income drift rates and volatility and a sampling from 17 years of historical data for each region to assess the distribution of overall load growth conditions for each year of the forecast. The base average and peak demand forecasts are based on the average of the peak and average demand forecasts.

To produce load stochastics, Siemens propagates three independent random paths: weather data, personal income, and a residual. Weather data includes heating and cooling degree days and humidity. To produce reasonable weather data projections, Siemens samples actual yearly paths from history. On average, we use about 17 years of historical data to perform the weather projections for the forward study period. Personal income is assumed to follow Geometric Brownian Motion. This means that there exists a normal distribution with constant mean and variance that describes how the return on personal income will behave at any time. Historical personal income data produces a best estimate for the relevant monthly mean and variance of this process going forward. Finally, to account for unexplained variation in the observed data, Siemens adds a normally distributed residual with mean zero and standard deviation equal to the root mean squared error of the previously mentioned stepwise regression.

Finally, to benchmark and formulate a reference, Siemens used the most recent historical average and peak load for each of the MISO LRZs and the forecasted compounded annual growth rate (CAGR) of peak and average demand from MISO-sponsored 10-year independent load forecasts.

Gas Stochastics

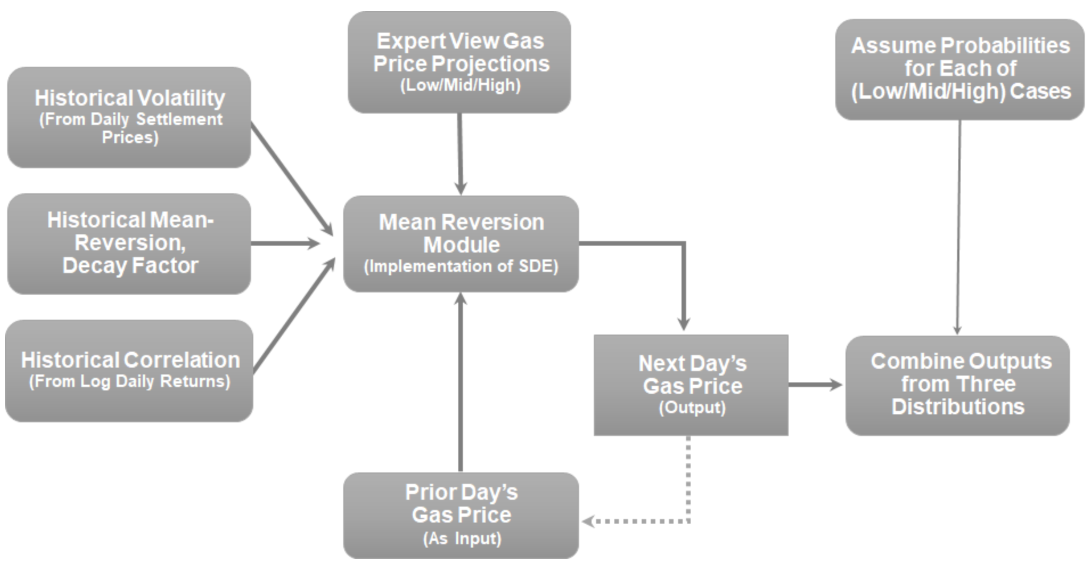
Siemens develops natural gas stochastic distributions for Henry Hub and other basis points. These stochastic distributions are based on a reference case view of natural gas prices with probability bands developed based on a combination of historical volatility and mean reversion parameters as well as a forward view of expected volatility.

Siemens has developed stochastics around the price at the Henry Hub (and other gas basis point as needed) based on historical volatility, current market forwards, and a long-term term fundamental view that considers the expected supply-demand balance. The 95th percentile probability bands are driven by increased gas demand (most likely due to 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 down as well as little to no environmental legislation around power plant emissions.

The steps involved in the development of gas stochastics are as follows:

- As the first step, Siemens develops the long-term fundamental forecast of Henry hub and several other gas basis points prices (using the GPCM model). The probability distributions are developed around this fundamental forecast.
- From historical data sets, the volatility parameter is calculated using the daily settled prices. Volatilities for different historical time periods are calculated (such as past 10-years, past 5 years, recent 2.5 years etc.)
- The daily gas prices are modeled as a single-factor continuous mean-reverting process. The mean reversion parameter is also calculated from the historical daily settled prices.
- For more than one gas basis point prices, the appropriate correlations are also calculated from the historical data.
- The entire process to develop the gas stochastics is described in Exhibit 205.

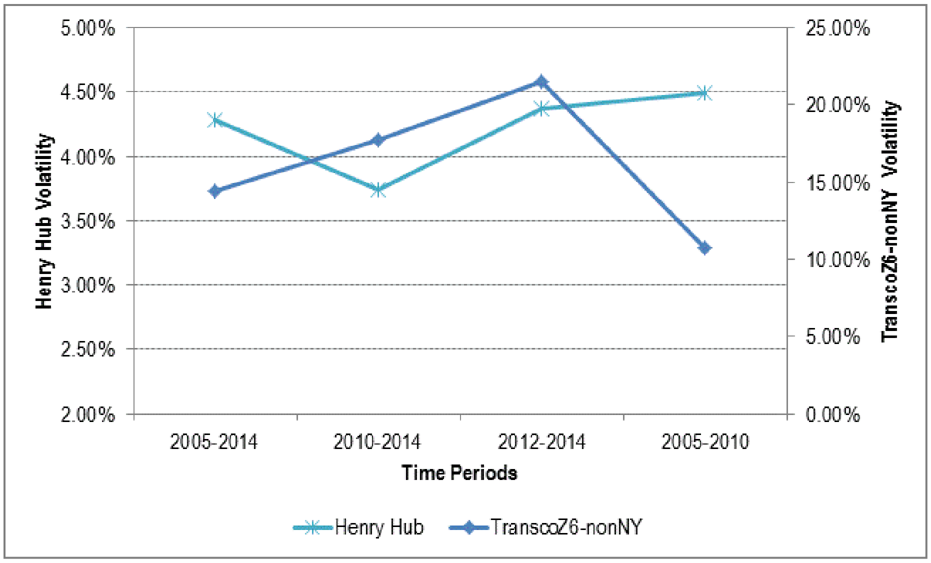
Exhibit 205: Gas Stochastics Development Process



Source: Siemens

- The volatilities tend to vary for different time periods. In order to capture this for the forecast time period, different volatility values from different historical time periods are considered. For example, for the first 3 forecast years, volatility calculated from the past 30 months price data will be used. For years 4-8, volatility calculated from the past 5 years will be used. Beyond that time period, the past 10-year historical volatility will be used.
- For example, the exhibit below shows the volatilities for Henry hub and a gas point in the Northeast (for illustration), for different historical time periods.

Exhibit 206: Illustrative – Northeast Henry Hub Volatilities



Source: Siemens

- The long-term fundamental forecast for each month in the forecast time period will be treated as the mean-reverting level in this process.

Coal Stochastics

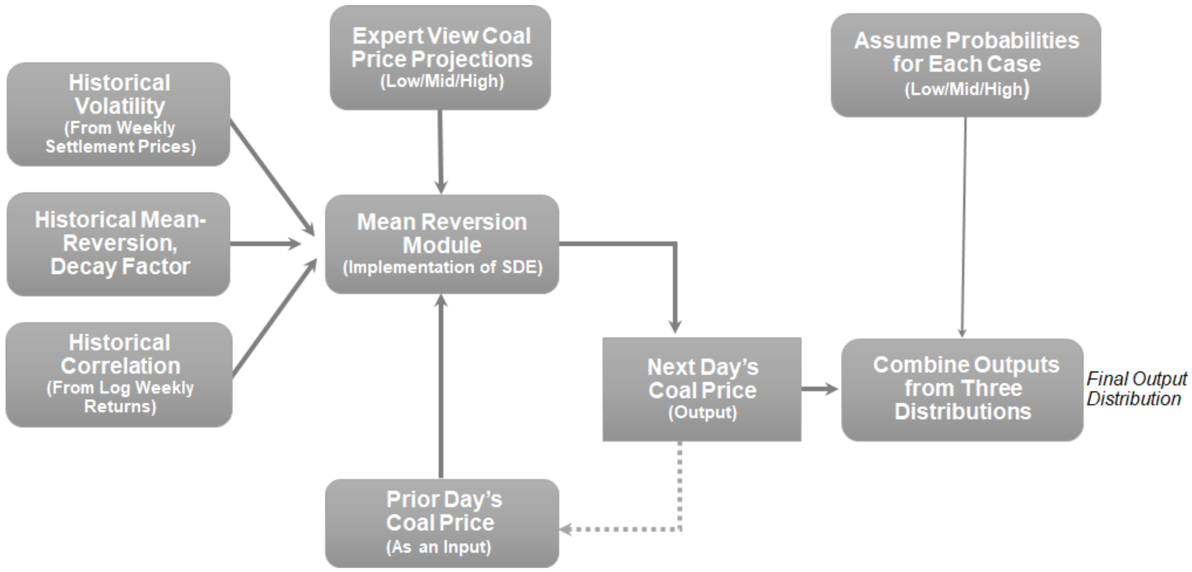
Siemens develops coal price stochastic distributions for CAPP, NAPP, ILB and PRB basins.

These stochastic distributions are based on a reference case view of coal prices with probability bands developed based on a combination of historical volatility and mean reversion parameters.

It is to be noted that majority of coal contracts in the U.S. are bilateral and only about 20% are traded in NYMEX. The historical data set which is used to calculate the parameters comprise of the traded data reported in NYMEX, which is weekly.

The methodology involved in the distribution of stochastic coal prices is exactly similar to natural gas stochastics.

Exhibit 207: Process for Coal Price Stochastic



Source: Siemens

The steps involved in the development of coal basin price stochastics are as follows:

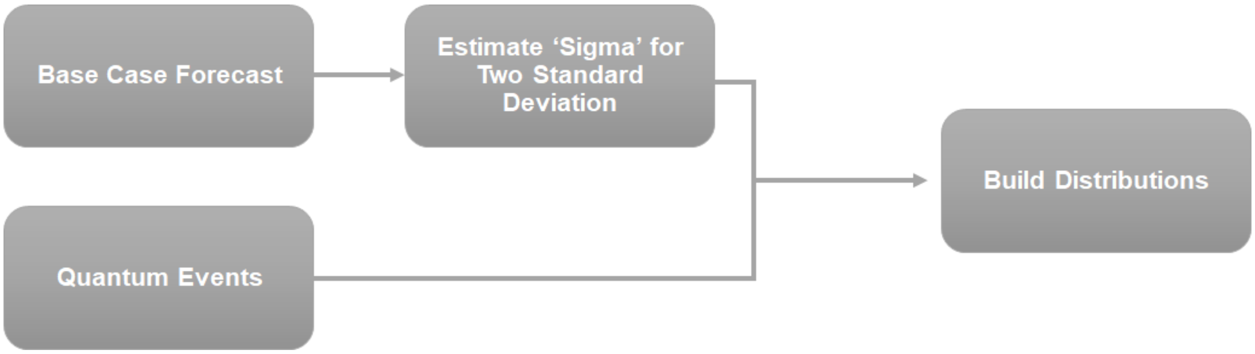
- As the first step, Siemens develops the long-term fundamental forecast of each of the coal basins. The probability distributions are developed around these fundamental forecasts.
- From historical data sets, the volatility parameter is calculated using the weekly prices. Volatilities for different historical time periods are calculated (such as past 10-years, past 5 years, recent 2.5 years etc.)
- The coal prices are modeled as a single-factor continuous mean-reverting process. The mean reversion parameter is also calculated from the historical prices.
- For the four coal basin prices, the appropriate correlations are calculated from the historical data.

CO_2 Stochastics

Siemens develops uncertainty distributions around carbon compliance costs, which will be used in the power dispatch modeling to capture the inherent risk associated with regulatory compliance requirements.

The technique to develop carbon costs distributions, unlike the previous variables, is based on the "expert-opinion" based projections. There are no historical data sets to estimate the parameters for developing carbon costs distributions. The views of the internal subject matter experts (Siemens's) are taken into consideration. The exhibit below shows the high-level methodology for developing stochastic distributions, when the historical data is not available.

Exhibit 208: Technique to Develop Carbon Costs Distributions



Source: Siemens

Given below are the steps involved in this process:

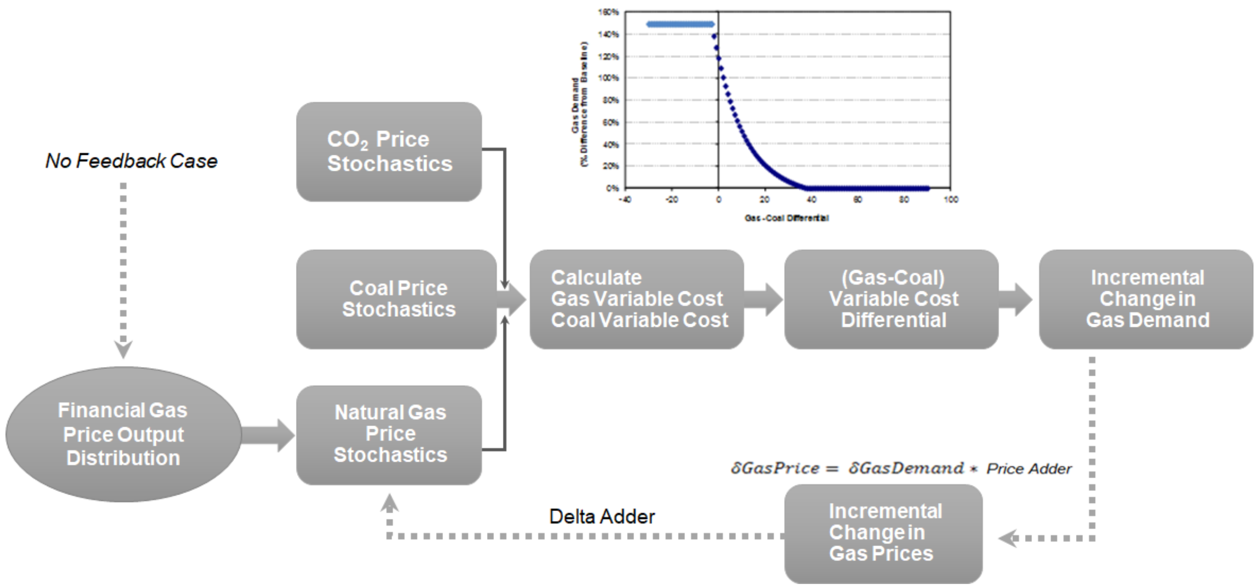
- Siemens PTI's environmental team develops a reference case (base case) forecast, and an associated high and low case. In addition to the high and low cases, the probability values for the high and low cases are also developed.
- These three cases are treated as 16th, 50th and 84th percentiles. Using these percentiles and statistical techniques (tools), the standard deviation values are calculated.
- The reference case is treated as the mid-case (median).
- Using the standard deviation values and a sampling from an underlying standard normal distribution (which has a mean zero and variance one), the probability bands are constructed around the reference projections. This underlying distribution captures the "quantum" events that can happen in the market.
- The distributions are then adjusted to incorporate probabilities such as "the probability of a CO_2 program not taking effect", "greater chance of a nation-wide CO2 regime starting in, say 2022" etc.
- Separate distributions are developed for national carbon costs, California carbon costs and RGGI prices, which are then applied to the respective states.

Gas-Coal-CO_2 prices feedback (Cross-Commodity Correlations)

Siemens has implemented a distinct process to capture the cross-commodity correlations into the stochastic processes. This is a separate process which is implemented after modeling the gas, coal and CO_2 processes discussed above.

The exhibit below describes the coal and CO_2 feedback to gas prices. At a high level, the feedback effects are based on statistical relationships between coal and gas switching and the variable cost of coal and gas generators.

Exhibit 209: Cross Commodity Correlations



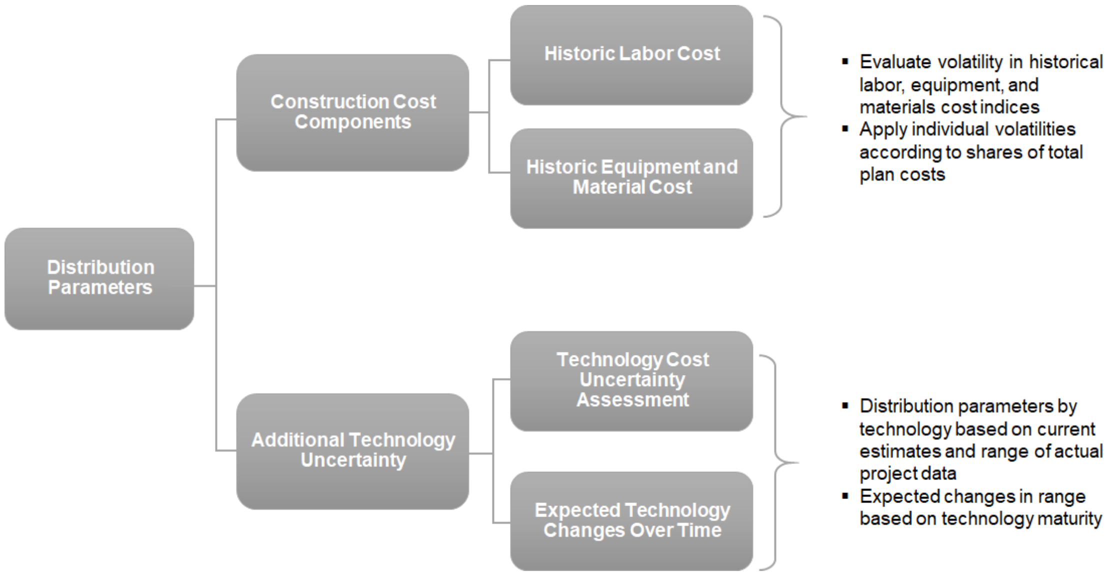
Source: Siemens

- Siemens PTI has performed some fundamental analyses to define the relationship between gas-coal dispatch cost and demand; incremental gas demand curve as a function of the gas-coal differential was calibrated.
- For each iteration, the dispatch cost of gas and coal is calculated from the fuel stochastics and CO_2 stochastics, along with generic assumptions for VOM.
- If the gas-coal dispatch differential changes significantly enough to affect demand, gas demand from previous year is adjusted to reflect the corresponding change in demand.
  - Adjustment can happen in both directions
- A gas price delta is then calculated based on the defined gas demand – price relationship developed.
- This gas price delta is added to the gas stochastic path developed from historic volatility to calculate an integrated CO_2 and natural gas stochastic price.

Capital Cost Stochastics

Siemens develops the uncertainty distributions for the cost of new entry units by technology types, which will be used in the AURORA dispatch model for determining the economic new builds based on market signals. The exhibit below describes the methodology at a high level:

Exhibit 210: Capital Costs Stochastics Methodology



Source: Siemens

The methodology of develop the capital cost distributions is a two-step process:

Step 1: Parametric Distribution:

Siemens 's subject matter experts provide a reference case forecast of $/KW all-in capital costs for different technology types. Along with it, high and low case forecasts are also developed.

The plant costs are broken down by Equipment, Materials, Labor & Others. Historical data (from Handy-Whitman Index) is used to estimate mean price changes and volatilities in these cost categories.

Suitable weights are allocated to each of these 4 categories. The weighted average of the historical mean and volatilities are then estimated.

Using the mean and volatility values, and sampling from an underlying standard normal distribution (which has a mean zero and variance one), the probability bands are constructed around the reference forecast.

Step 2: Quantum Distribution:

This step captures the additional uncertainty associated with each technology. It also factors-in the learning curve effects, improvements in technology over time and other "uncertain" events. The expert-opinion based high and low cases are treated as 1 standard deviation from the mean. With this assumption, the variance values are calculated.

To come with probability distributions, a log-normal distribution is assumed. This distribution is combined with the parametric distribution obtained in the previous step, to come up with the final set of distributions.

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Appendix D: Portfolio Details

This appendix covers the detailed generation buildout by year and by technology type for the planning horizon 2025-2039 for each of the ten selected final Portfolios and the All MISO Portfolio, as well as the key performance metrics and cost details[51].

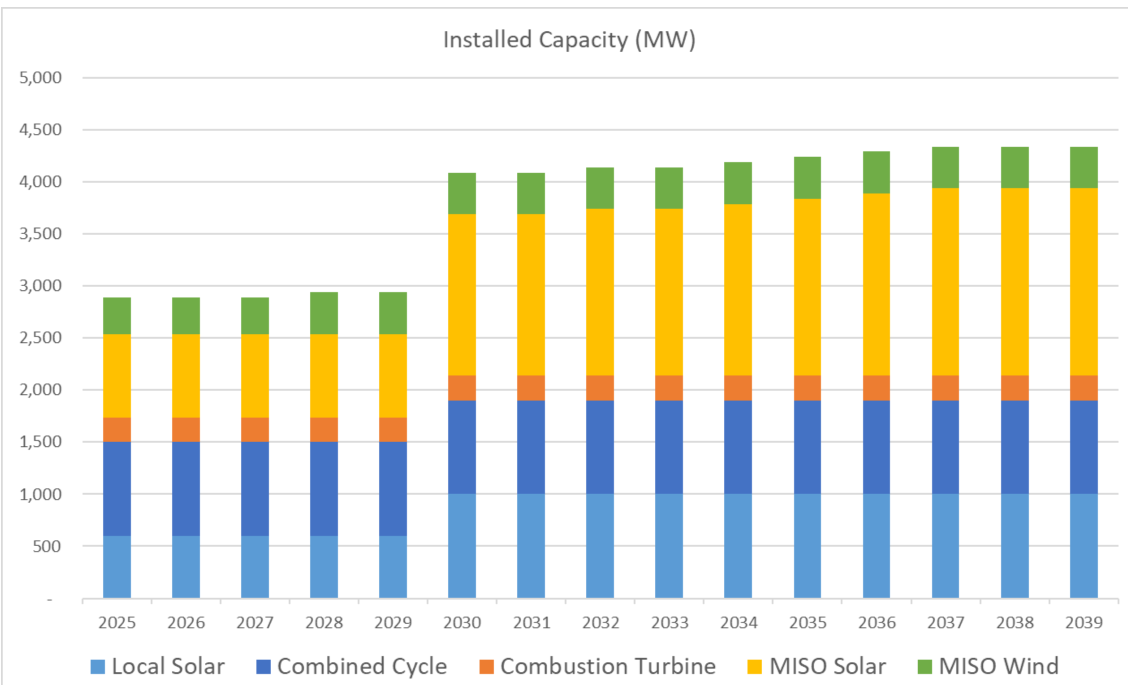
Portfolio 1 (S3S1_P)

This is the base portfolio derived from the capacity expansion plan, with the CT advanced to 2025 from 2039 as in S3S1.

Capacity Expansion (Buildout)

The exhibits below show the capacity expansion by year. 600 MW local Solar is installed in first year, and another 400 MW installed in 2030. Thermal generation (3CCGTs+1 CT) are all installed in first year 2025.

Exhibit 211: Portfolio 1 Installed Capacity by Year



Source: Siemens

[51] All graphs in this section were the result of analysis performed by Siemens.

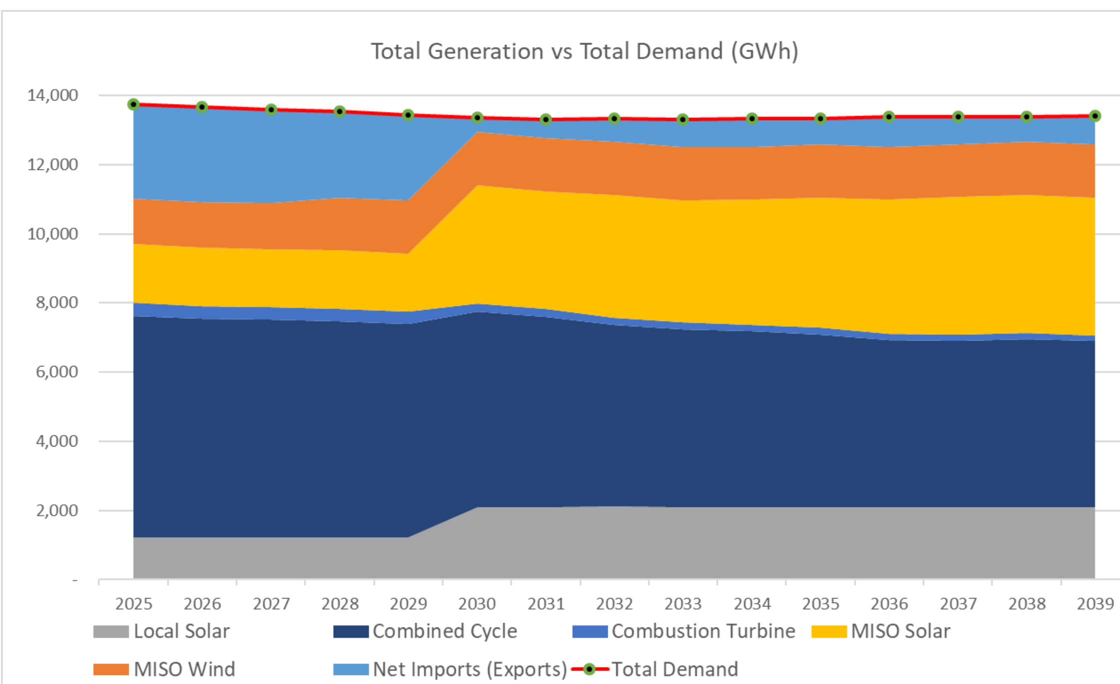
Exhibit 212: Portfolio 1 Installed Capacity by Year (Table)

	Advanced Frame CT	Convl. Frame 7FA CT	1x1 Combined Cycle	Utility Solar	Battery	Arkansas Solar	Arkansas Wind	MISO_Cap	Demand
2025	0	237	900	600	0	800	350	1989	3197
2026	0	0	0	0	0	0	0	1983	3182
2027	0	0	0	0	0	0	0	1977	3168
2028	0	0	0	0	0	0	50	1963	3153
2029	0	0	0	0	0	0	0	1958	3139
2030	0	0	0	400	0	750	0	1648	3124
2031	0	0	0	0	0	0	0	1654	3113
2032	0	0	0	0	0	50	0	1654	3108
2033	0	0	0	0	0	0	0	1675	3110
2034	0	0	0	0	0	50	0	1684	3112
2035	0	0	0	0	0	50	0	1694	3114
2036	0	0	0	0	0	50	0	1704	3116
2037	0	0	0	0	0	50	0	1715	3118
2038	0	0	0	0	0	0	0	1738	3121
2039	0	0	0	0	0	0	0	1761	3123

Source: Siemens

Energy generated from thermal decreases over the years while energy coming from renewables increases, especially starting in 2030 when the cost of renewables is projected to be much more competitive. Imported energy goes down after 2030 as well.

Exhibit 213: Portfolio 1 Energy by Resource Type by Year

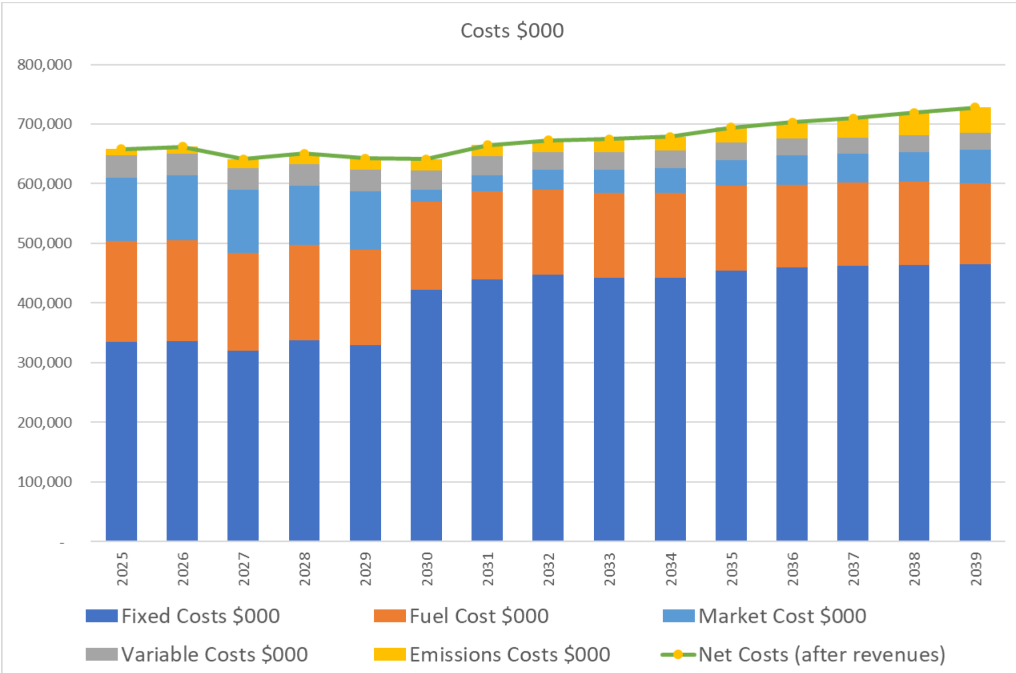


Source: Siemens

Portfolio Costs

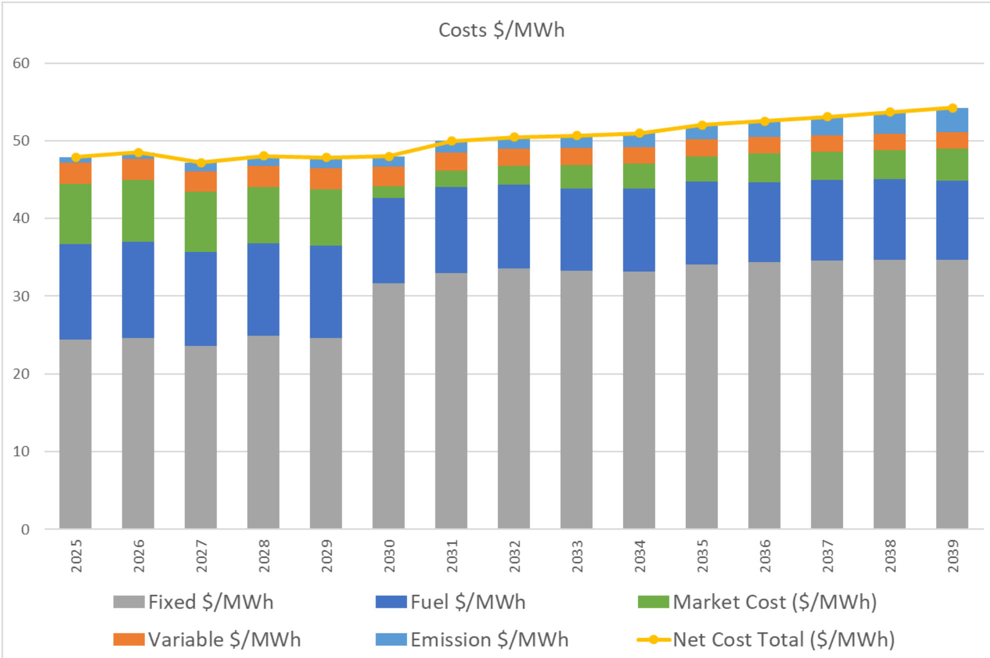
Exhibit below shows the supply side NPV cost by year as can be seen the cost is about $670 million per year (2018 $) or $50/MWh, where fixed cost is the largest component due to the investments in generation, followed by cost of fuels and market purchases.

Exhibit 214: Portfolio 1 Cost Components 2018 $



Source: Siemens

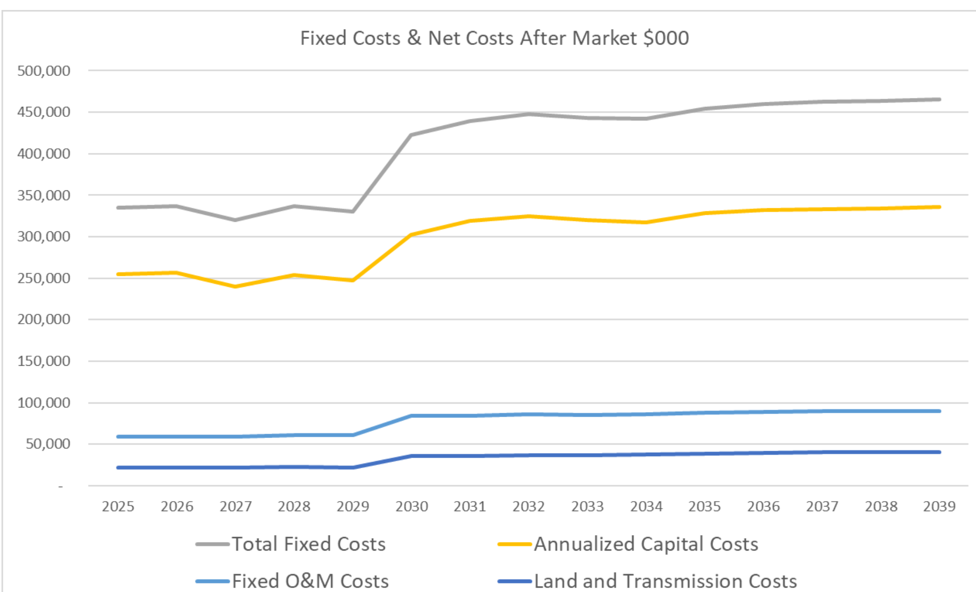
Exhibit 215: Portfolio 1 Cost Components 2018 $/MWh



Source: Siemens

Graph below shows the breakdown of total fixed costs by components, where the majority comes from the base capital costs on generation.

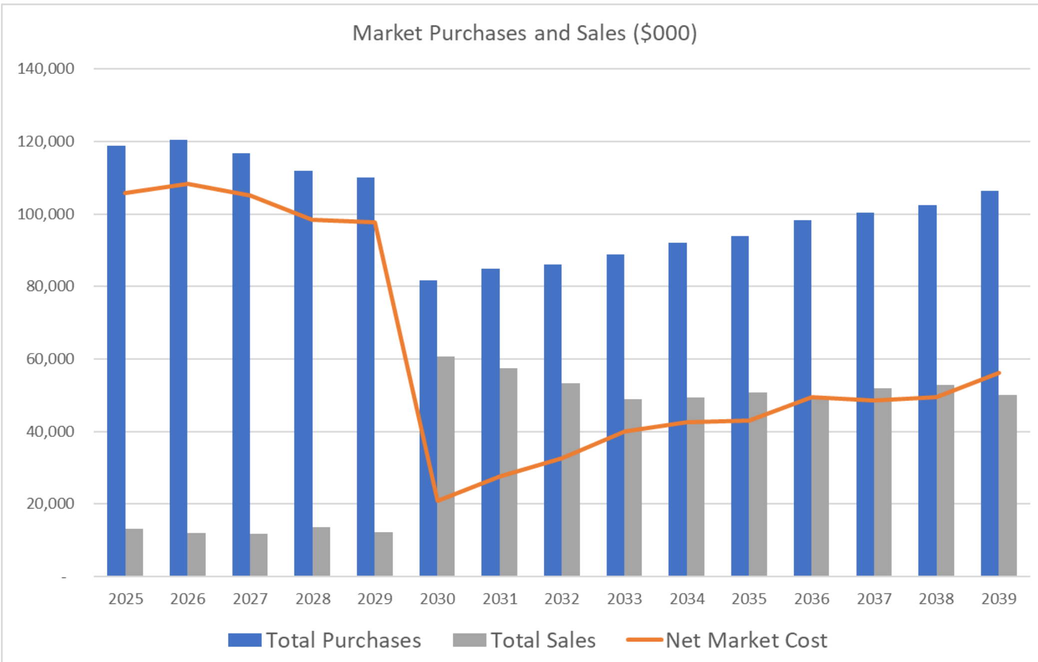
Exhibit 216: Portfolio 1 Fixed Cost Components 2018 $



Source: Siemens

Market purchases and sales as also important components. The market purchases by MLGW system are projected to be decreasing while the sales are increasing although the sales are maintained at a low level. As mentioned above, the cost of renewables is projected to be much more competitive after 2030, which resulted in reduced market purchases.

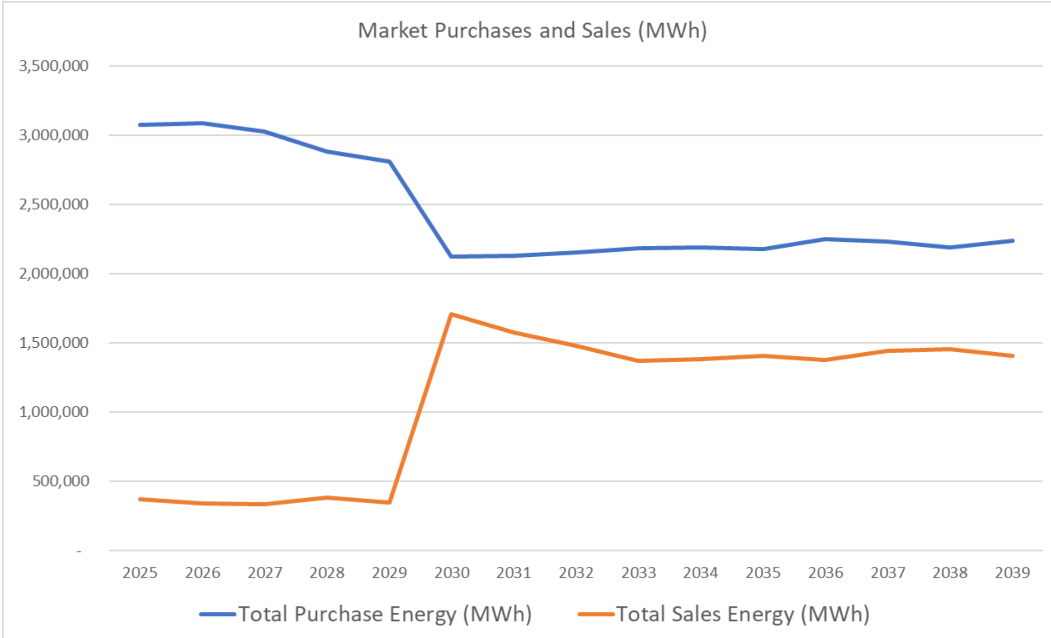
Exhibit 217: Portfolio 1 Market Purchases and Sales 2018 $



Source: Siemens

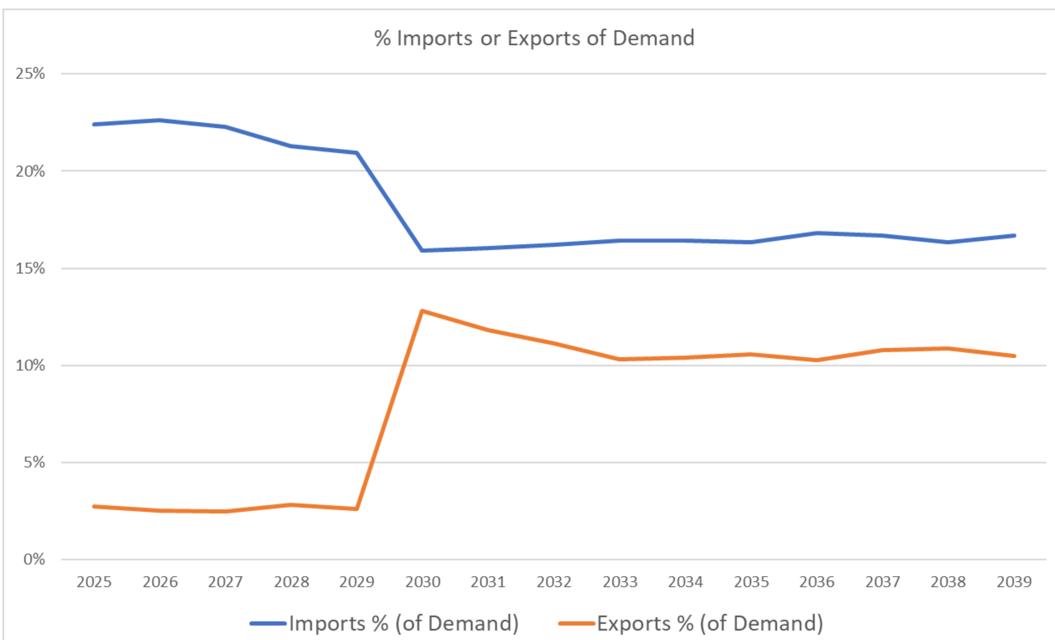
These graphs show the purchases and sales amount in energy and as % of demand. It shows the high market risk in the beginning of the planning years of this portfolio.

Exhibit 218: Portfolio 1 Market Purchases and Sales in Energy



Source: Siemens

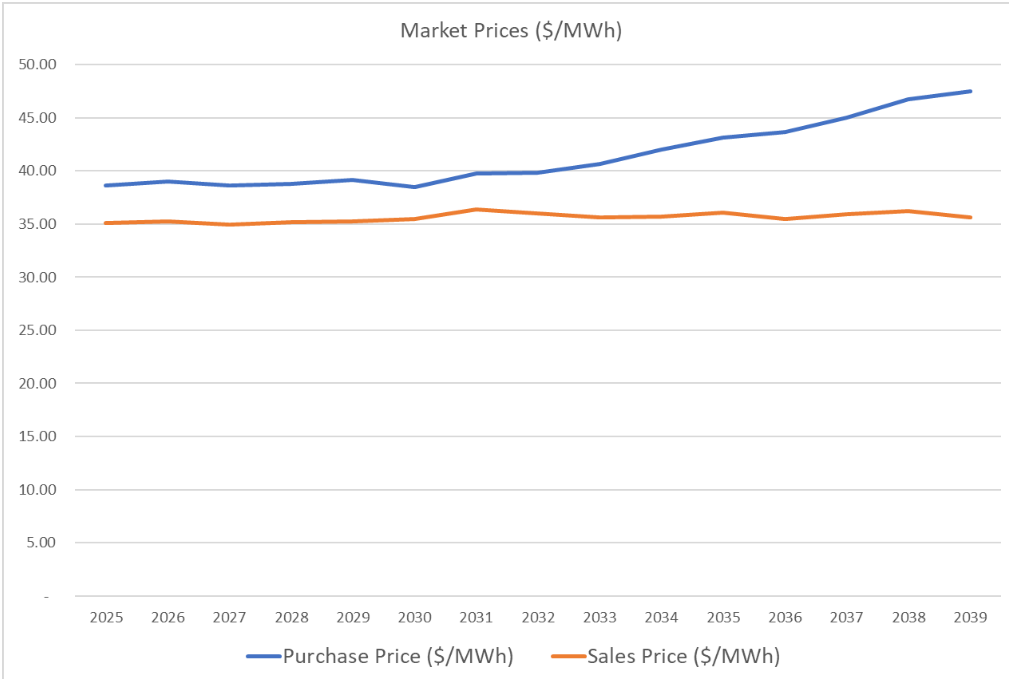
Exhibit 219: Portfolio 1 Market Purchases and Sales as % of Demand



Source: Siemens

The risk can also be appreciated looking at the difference between purchase price (high) and sale price (low). The more purchase this portfolio needs, the higher risk.

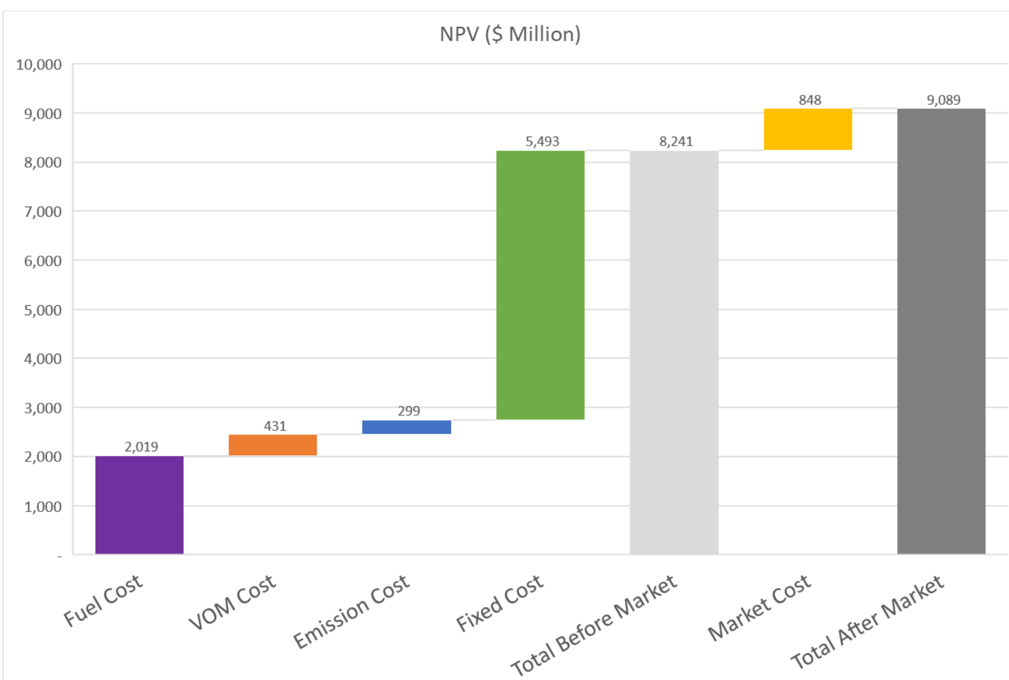
Exhibit 220: Portfolio 1 Market Purchases and Sales Prices $/MWh



Source: Siemens

Exhibit 221 shows the supply side total NPV for 2025-2039, which is about $9.09 billion in 2018 $. Fixed cost is the largest component, followed by fuel and market costs.

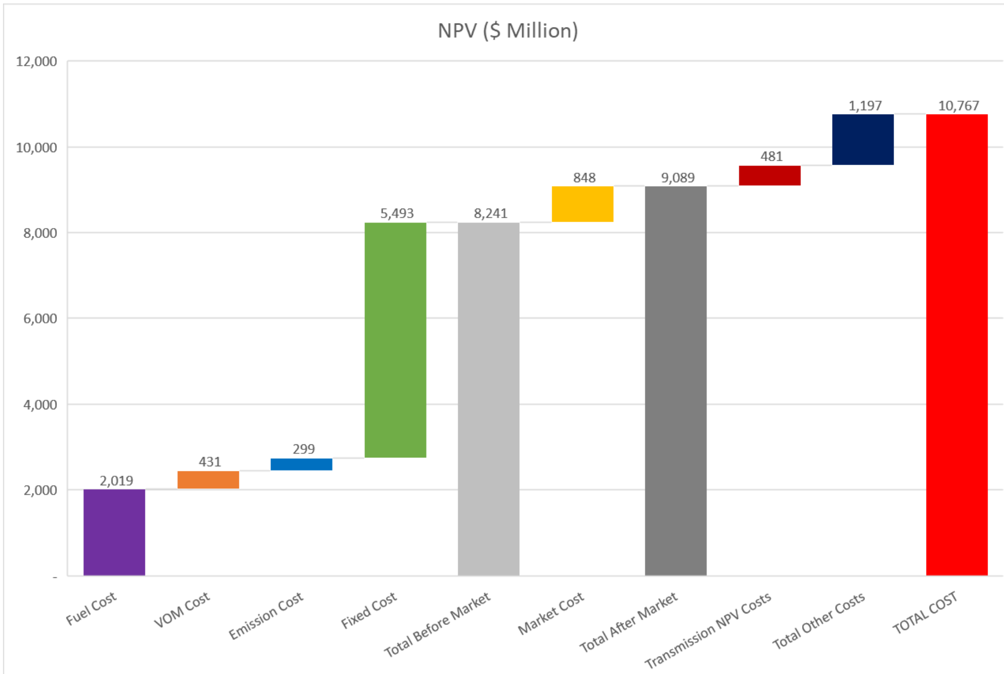
Exhibit 221: Portfolio 1 Generation Resource NPV 2018 $



Source: Siemens

The total NPVRR is in Exhibit 222 below which includes the other cost components, i.e. transmission and other costs, including PILOT, TVA Benefits, energy efficiency, gap costs, MISO Admin fees. The total NPVRR of this portfolio is approximately $10.77 billion for 2025-2039 in 2018 $.

Exhibit 222: Portfolio 1 All NPVRR with Other Components 2018 $

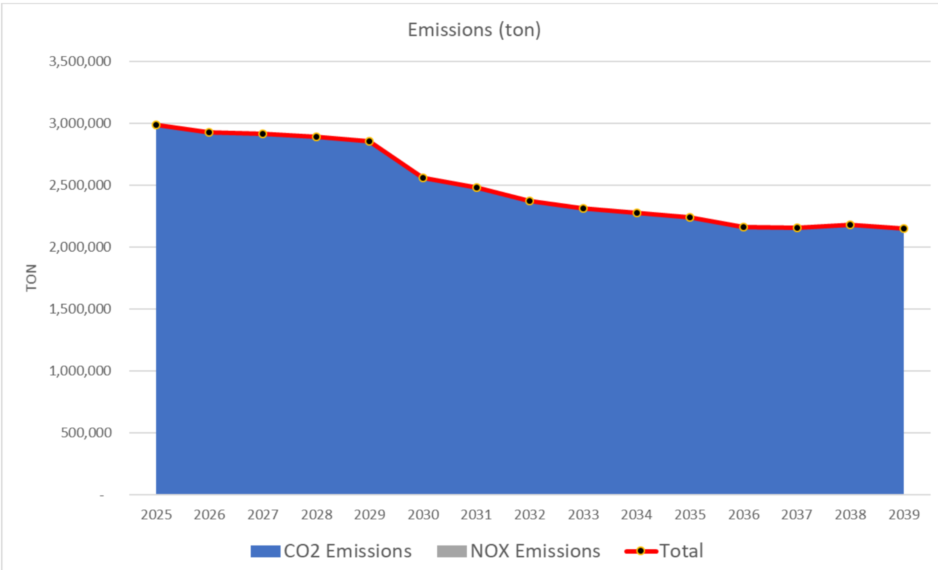


Source: Siemens

Environmental

The emission from this portfolio is shown in Exhibit 223 below. As energy from thermal generation is coming down, the capacity factor of the units decreases which resulted in decreased CO_2 emission over the years.

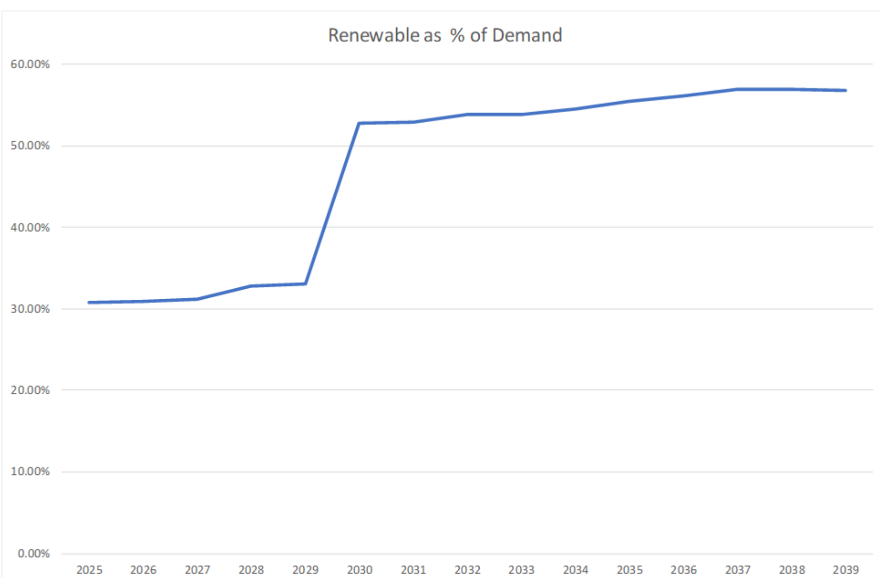
Exhibit 223: Portfolio 1 MLGW Emission by Year



Source: Siemens

The RPS as of demand in energy of this portfolio starts at about 30% and reaches more than 55% in 2039 as there are new renewables built in 2030 and onwards.

Exhibit 224: Portfolio 1 RPS by Year

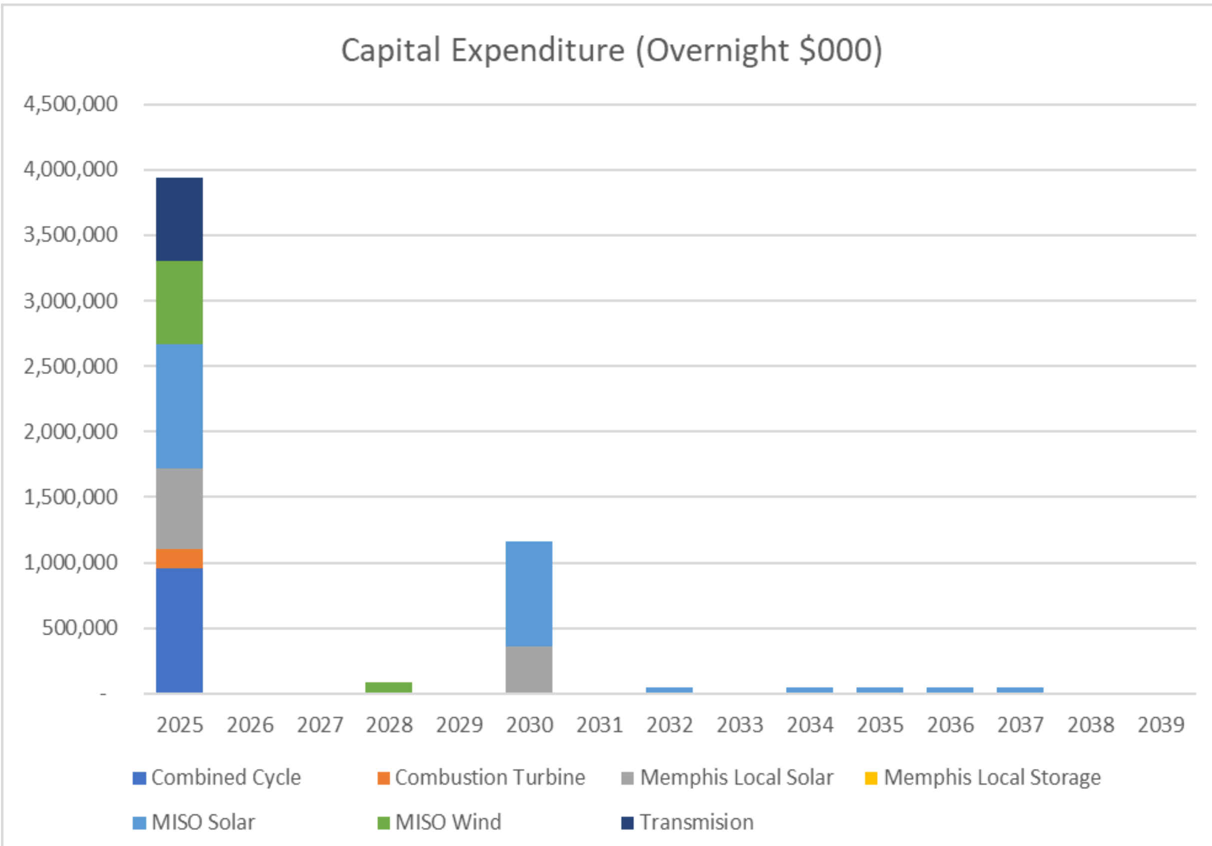


Source: Siemens

Capital Expenditure

Total capital expenditures on generation and transmission are shown in Exhibit 225 below. We present these capital expenditures in overnight from 2025 to 2039 while the actual drawdown may vary. Most of the CapEx are on the generation side and occur prior to 2025. Note that only the transmission CapEx is expected to be covered by MLGW as the generation CapEx is assumed to be expensed by third parties and recovered via PPA payments from MLGW.

Exhibit 225: Portfolio 1 Overnight Capital Expenditure by Year



Source: Siemens

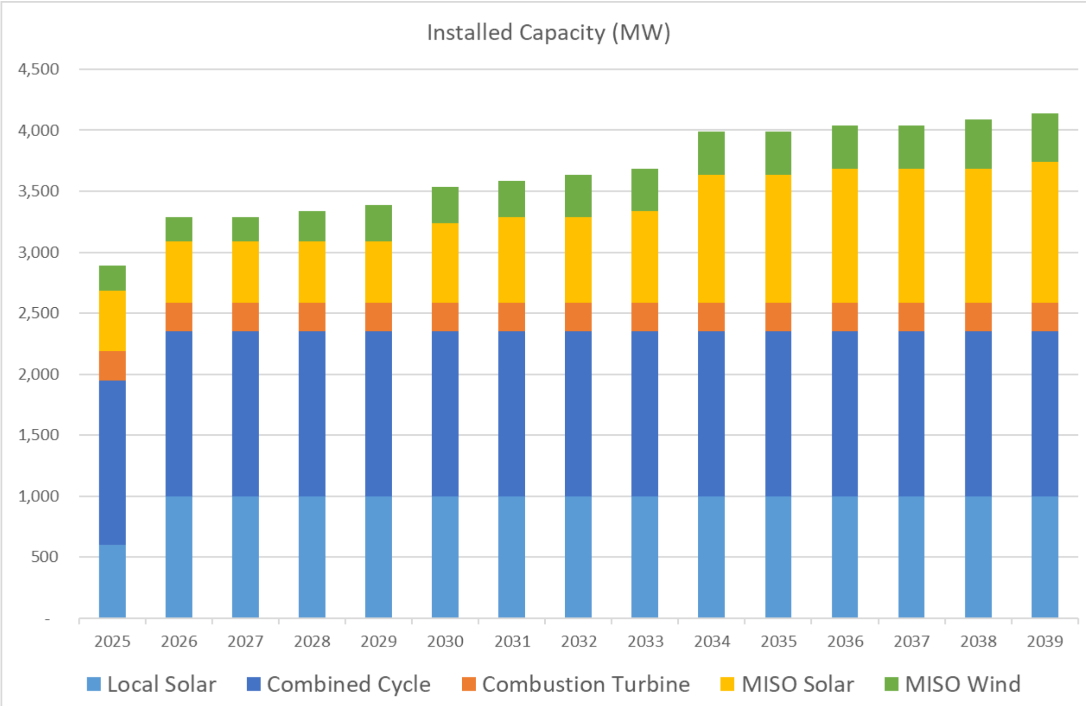
Portfolio 2 (S3S1_F)

This is the modified portfolio derived from the capacity expansion plan, with one more CCGT added to the case, also with accelerated local renewables.

Capacity Expansion (Buildout)

Exhibit 226 below show the capacity expansion by year. 3 CCGTs and 2 CT are installed in the first year 2025. Local solar is installed as much and quickly as it can in this portfolio.

Exhibit 226: Portfolio 2 Installed Capacity by Year



Source: Siemens

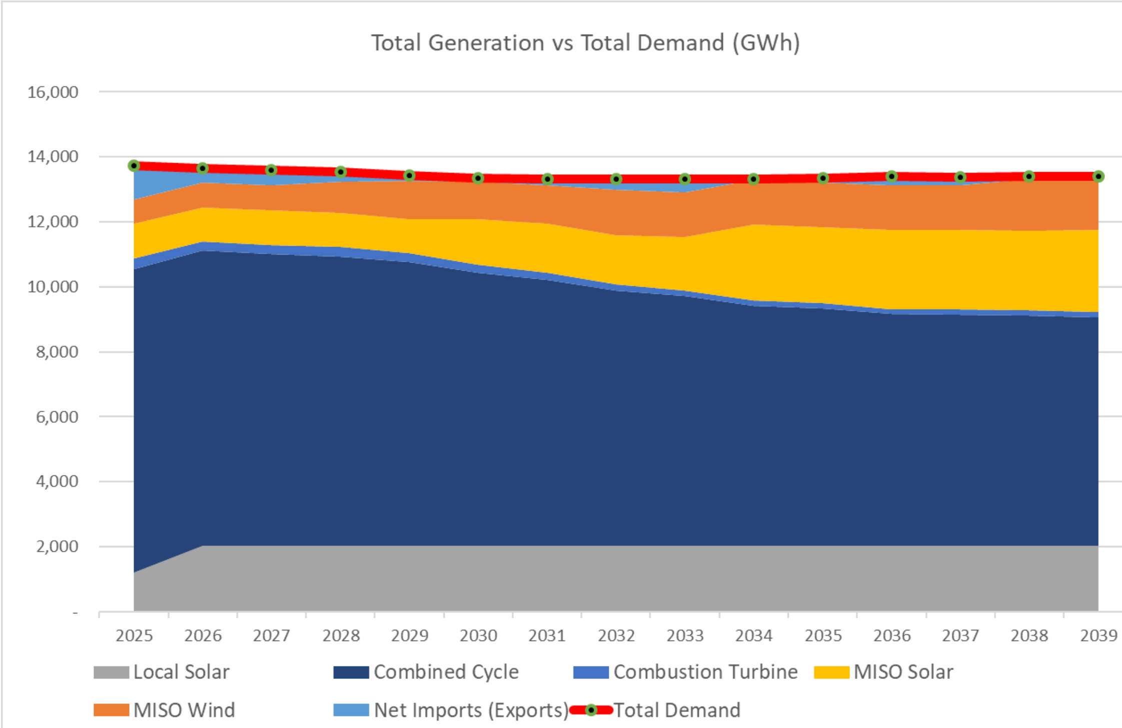
Exhibit 227: Portfolio 2 Installed Capacity by Year (Table)

	Advanced Frame CT	Convl. Frame 7FA CT	1x1 Combined Cycle	Utility Solar	Battery	Arkansas Solar	Arkansas Wind	MISO_Cap	Demand
2025	0	237	1350	600	0	500	200	1699	3197
2026	0	0	0	400	0	0	0	1573	3182
2027	0	0	0	0	0	0	0	1569	3168
2028	0	0	0	0	0	0	50	1555	3153
2029	0	0	0	0	0	0	50	1543	3139
2030	0	0	0	0	0	150	0	1498	3124
2031	0	0	0	0	0	50	0	1485	3113
2032	0	0	0	0	0	0	50	1483	3108
2033	0	0	0	0	0	50	0	1486	3110
2034	0	0	0	0	0	300	0	1430	3112
2035	0	0	0	0	0	0	0	1446	3114
2036	0	0	0	0	0	50	0	1452	3116
2037	0	0	0	0	0	0	0	1469	3118
2038	0	0	0	0	0	0	50	1480	3121
2039	0	0	0	0	0	50	0	1487	3123

Source: Siemens

Energy generated from thermal generation decreases slightly over the years while energy coming from renewables increases.

Exhibit 228: Portfolio 2 Energy by Resource Type by Year

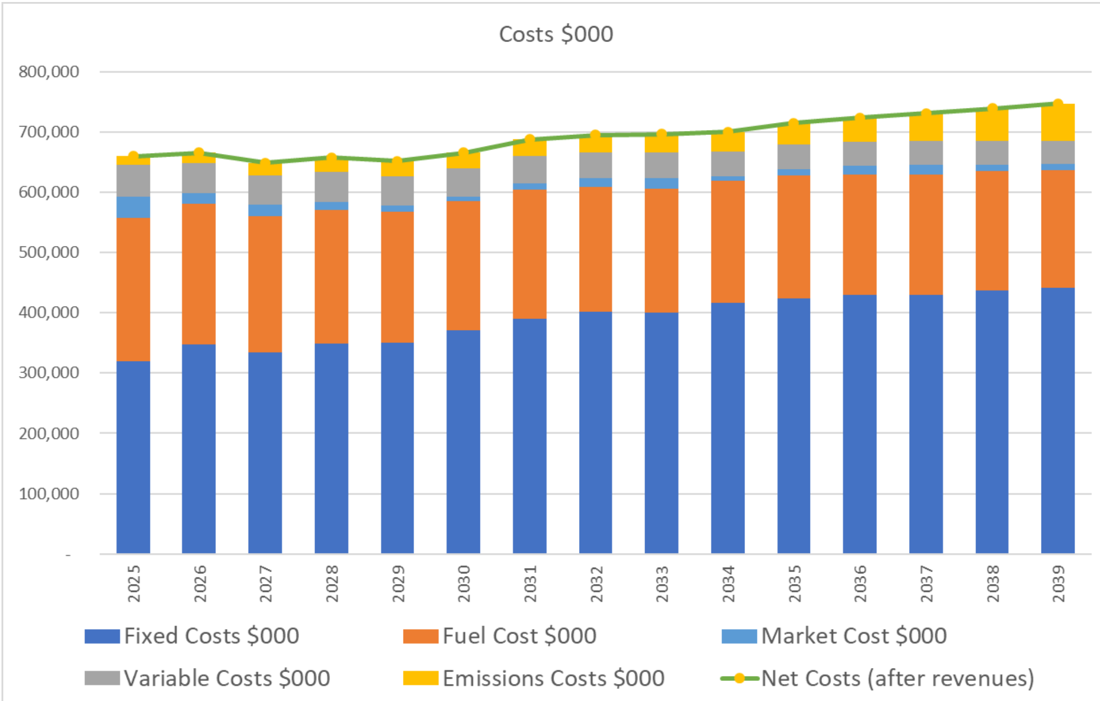


Source: Siemens

Portfolio Costs

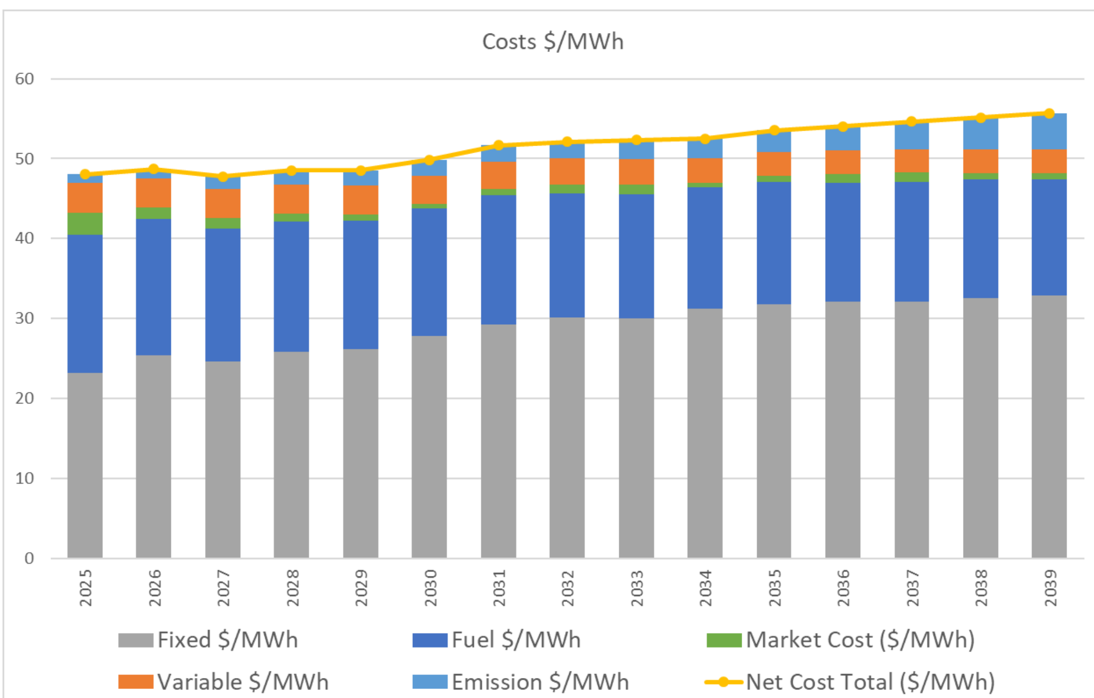
Exhibit 229 shows the supply side NPV cost by year as can be seen the cost is about $700 million per year (2018 $) or $52/MWh, where fixed cost is the largest component due to the investments in generation, followed by cost of fuels. The net market cost is very low in this portfolio due to more local thermal generation.

Exhibit 229: Portfolio 2 Cost Components 2018 $



Source: Siemens

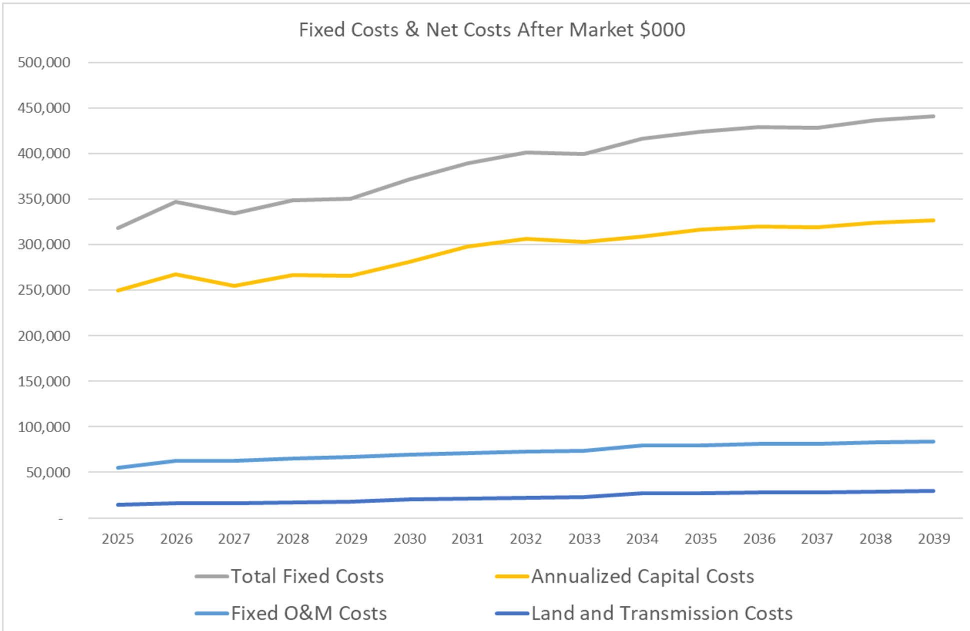
Exhibit 230: Portfolio 2 Cost Components 2018 $/MWh



Source: Siemens

Exhibit 231 shows the breakdown of total fixed costs by components, where the majority comes from the base capital costs on generation.

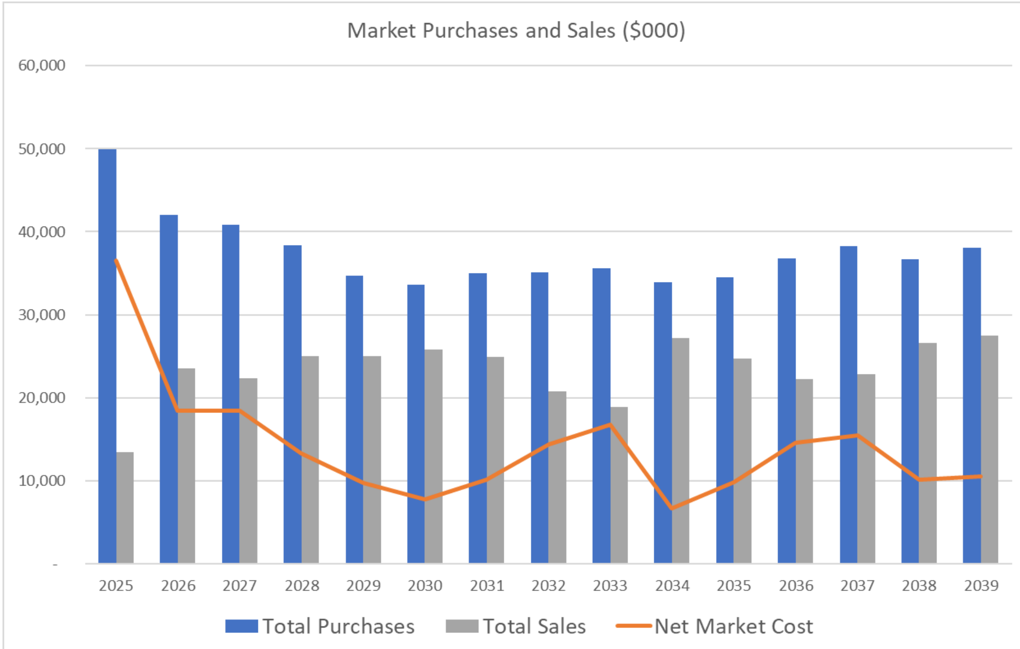
Exhibit 231: Portfolio 2 Fixed Cost Components 2018 $



Source: Siemens

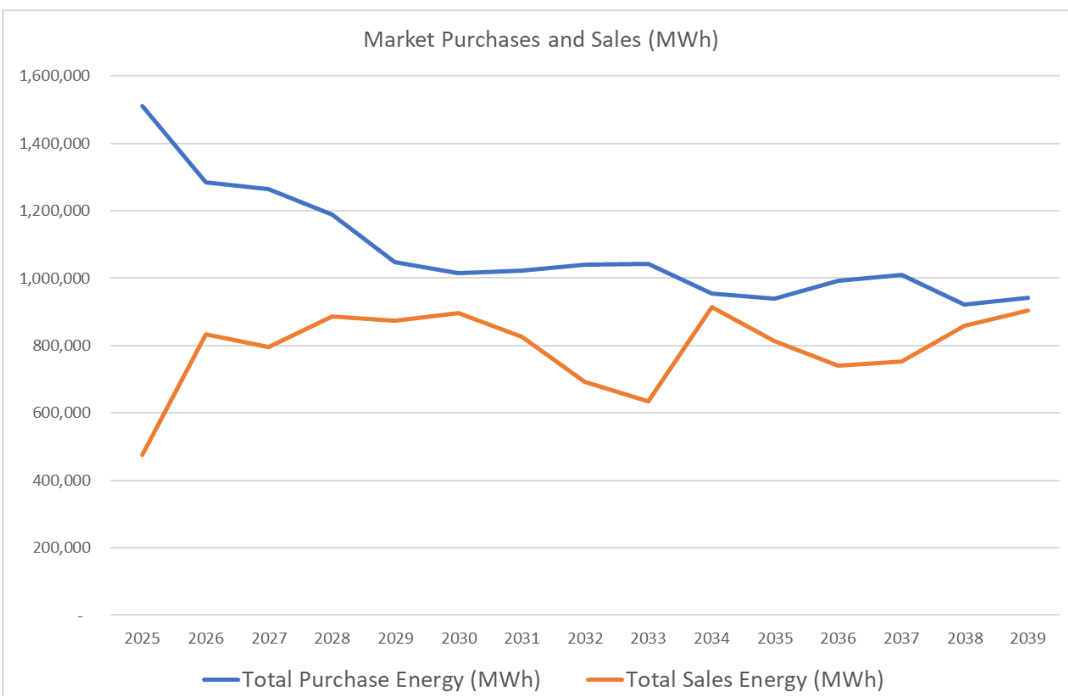
Market purchases and sales as also important components. The market purchases by MLGW system are projected to be decreasing while the sales are increasing although the sales are maintained at the same level throughout. The net market cost stays flat except for the first couple years due to ramping up of generation development.

Exhibit 232: Portfolio 2 Market Purchases and Sales 2018 $



Source: Siemens

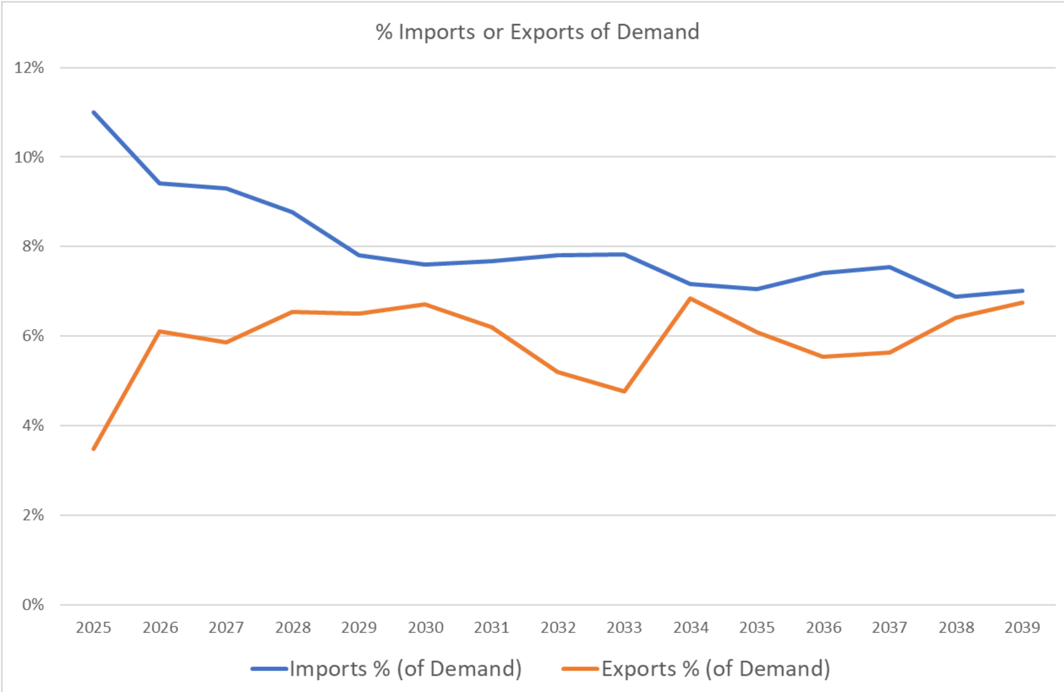
Exhibit 233: Portfolio 2 Market Purchases and Sales in Energy



Source: Siemens

These graphs show the purchases sales amount in energy and as % of demand.

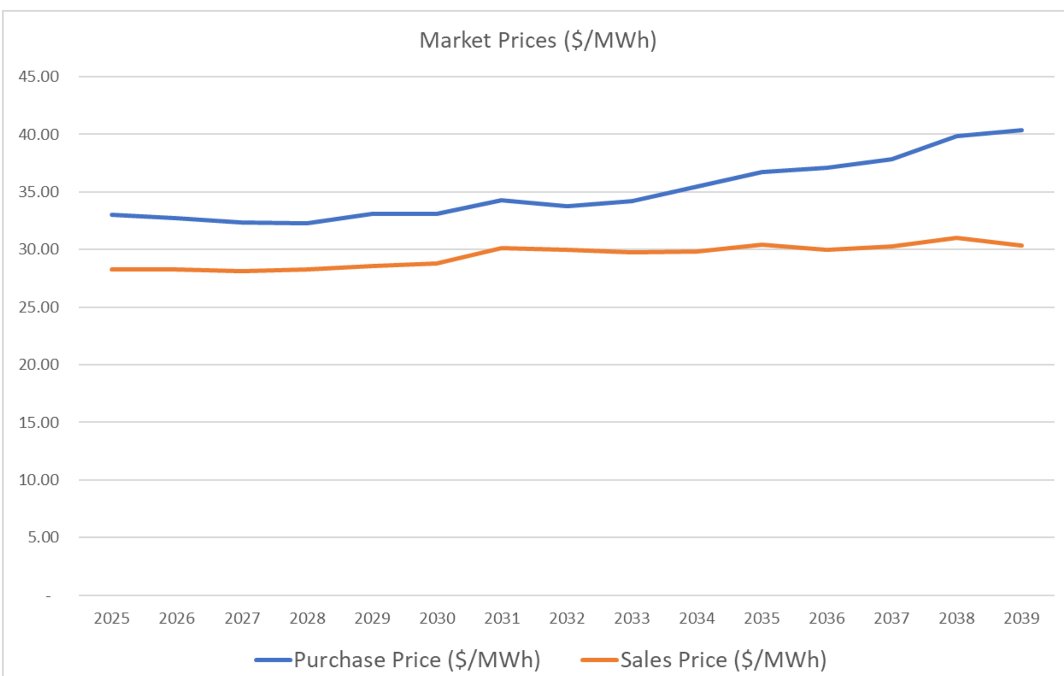
Exhibit 234: Portfolio 2 Market Purchases and Sales as % of Demand



Source: Siemens

The market risk of this portfolio is estimated to be low as a result of more local generation.

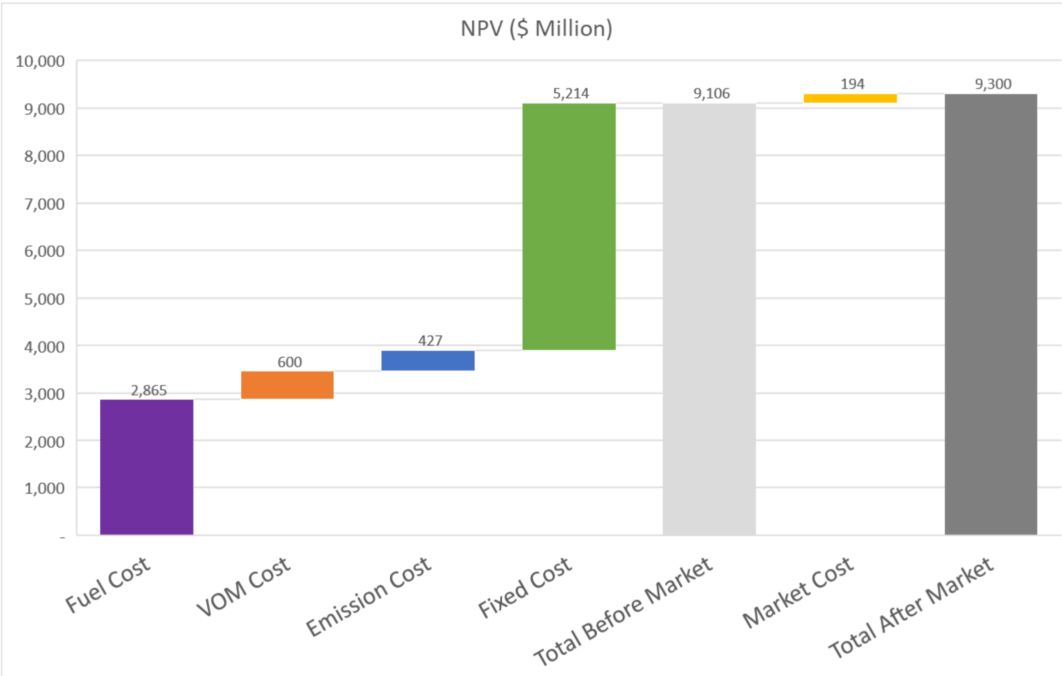
Exhibit 235: Portfolio 2 Market Purchases and Sales Prices $/MWh



Source: Siemens

Exhibit 236 shows the supply side total NPV for 2025-2039, which is about $9.3 billion in 2018 $. Fixed cost is the largest component, followed by fuel.

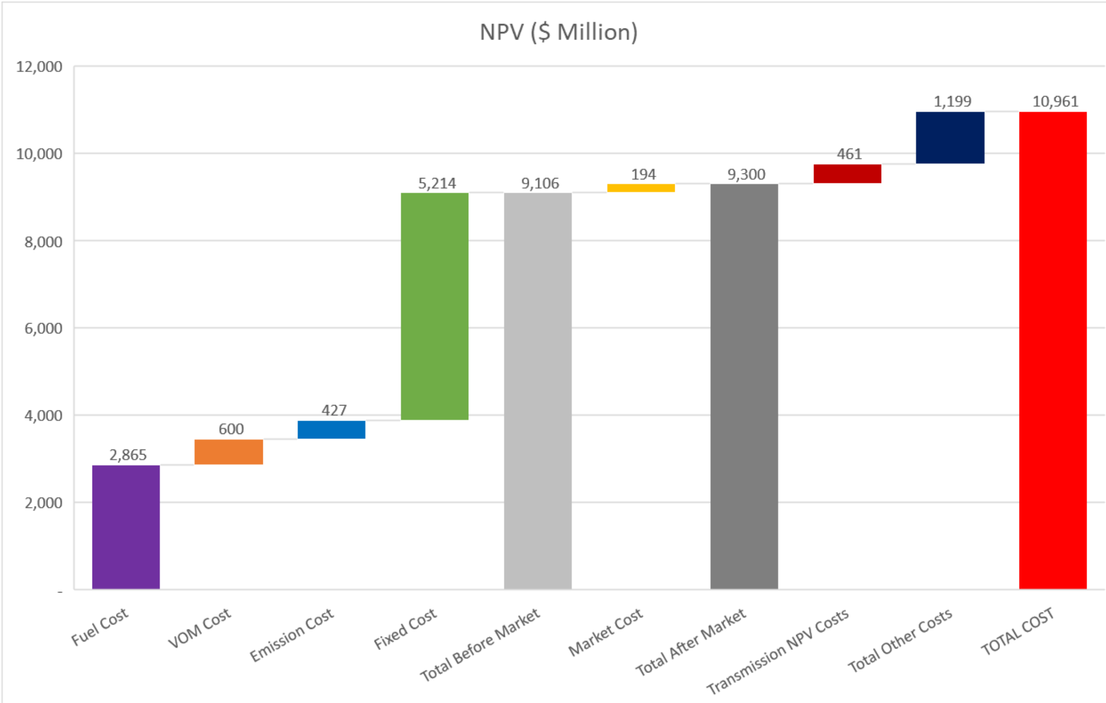
Exhibit 236: Portfolio 2 Generation Resource NPV 2018 $



Source: Siemens

The total NPVRR of this portfolio is approximately $10.96 billion for 2025-2039 in 2018 $.

Exhibit 237: Portfolio 2 All NPVRR with Other Components 2018 $

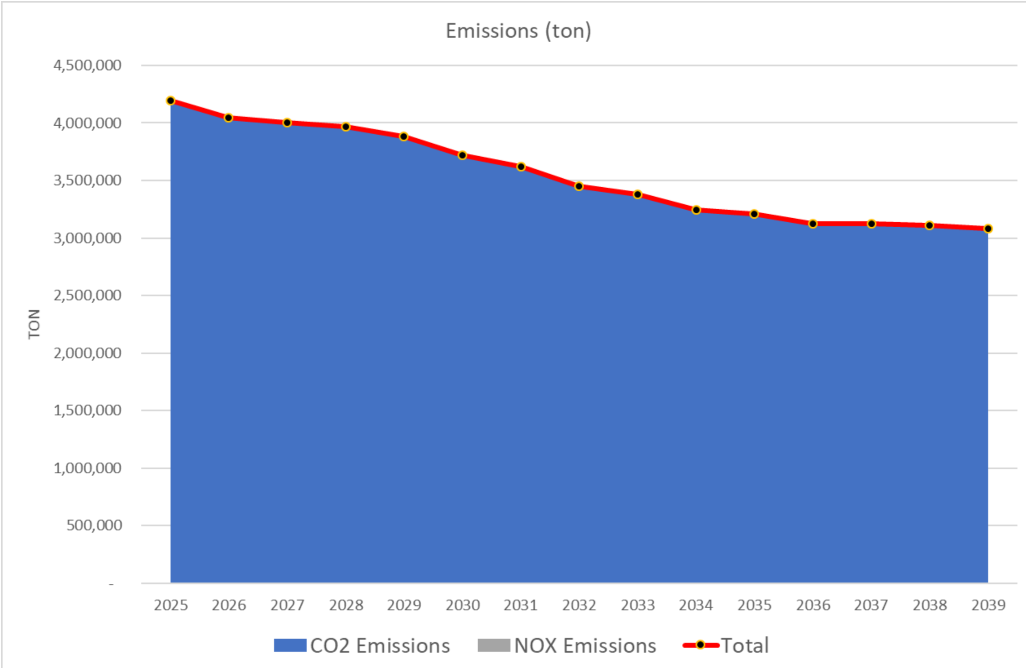


Source: Siemens

Environmental

The emission from this portfolio is shown in the graph below. As energy from thermal generation is coming down, the capacity factor of the units decreases which resulted in decreased CO_2 emission over the years.

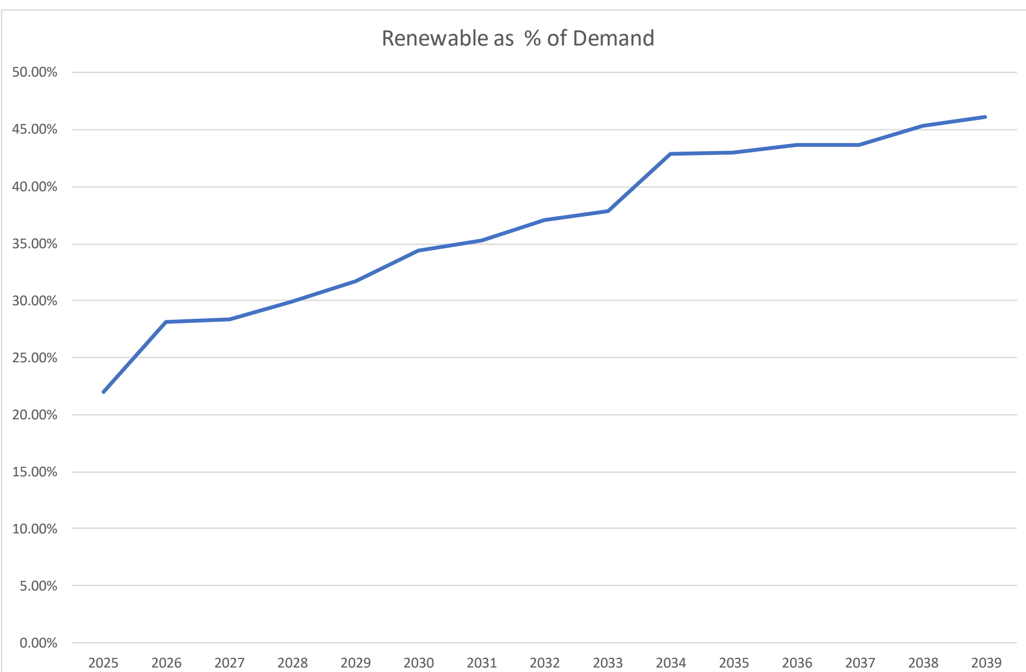
Exhibit 238: Portfolio 2 MLGW Emission by Year



Source: Siemens

And the RPS as of demand in energy of this portfolio starts at about 22% and reaches just over 45% in 2039 as more renewable generation are built.

Exhibit 239: Portfolio 2 RPS Year

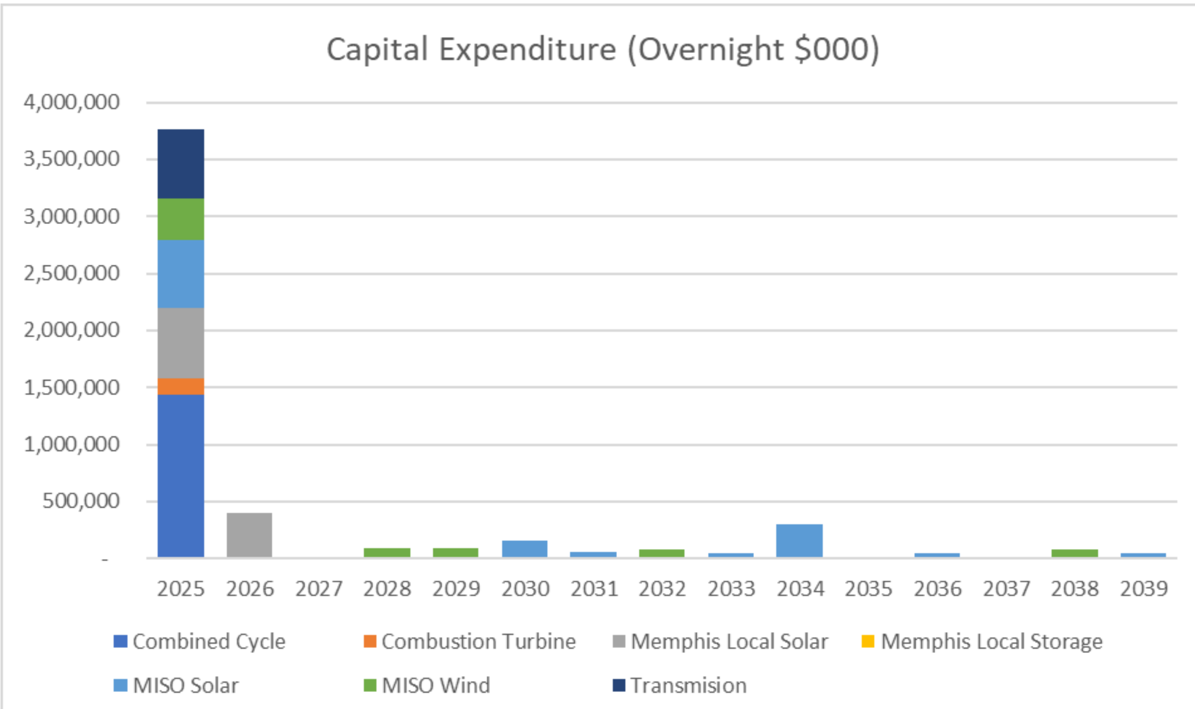


Source: Siemens

Capital Expenditure

Total capital expenditures on generation and transmission are shown in Exhibit 240. Siemens present these capital expenditures in overnight from 2025 to 2039 while the actual drawdown may vary. Most of the CapEx are on the generation side and occur prior to 2025. Note that only the transmission CapEx is expected to be covered by MLGW as the generation CapEx is assumed to be expensed by third parties and recovered via PPA payments from MLGW.

Exhibit 240: Portfolio 2 Overnight Capital Expenditure by Year



Source: Siemens

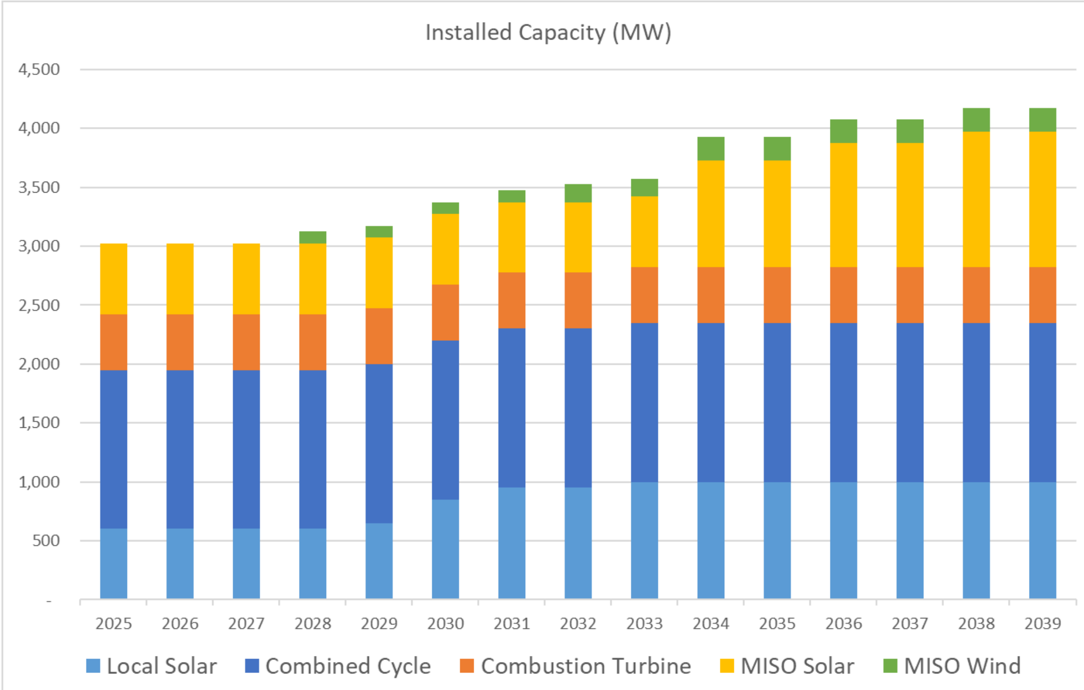
Portfolio 3 (S3S2_BB)

This is the portfolio derived from the high load base gas price scenario.

Capacity Expansion (Buildout)

The exhibits below show the capacity expansion by year. 600 MW local Solar is installed in first year, and additional installed in 2029 and beyond. Thermal generation (3 CCGTs + 2 CT) are all installed in first year 2025.

Exhibit 241: Portfolio 3 Installed Capacity by Year



Source: Siemens

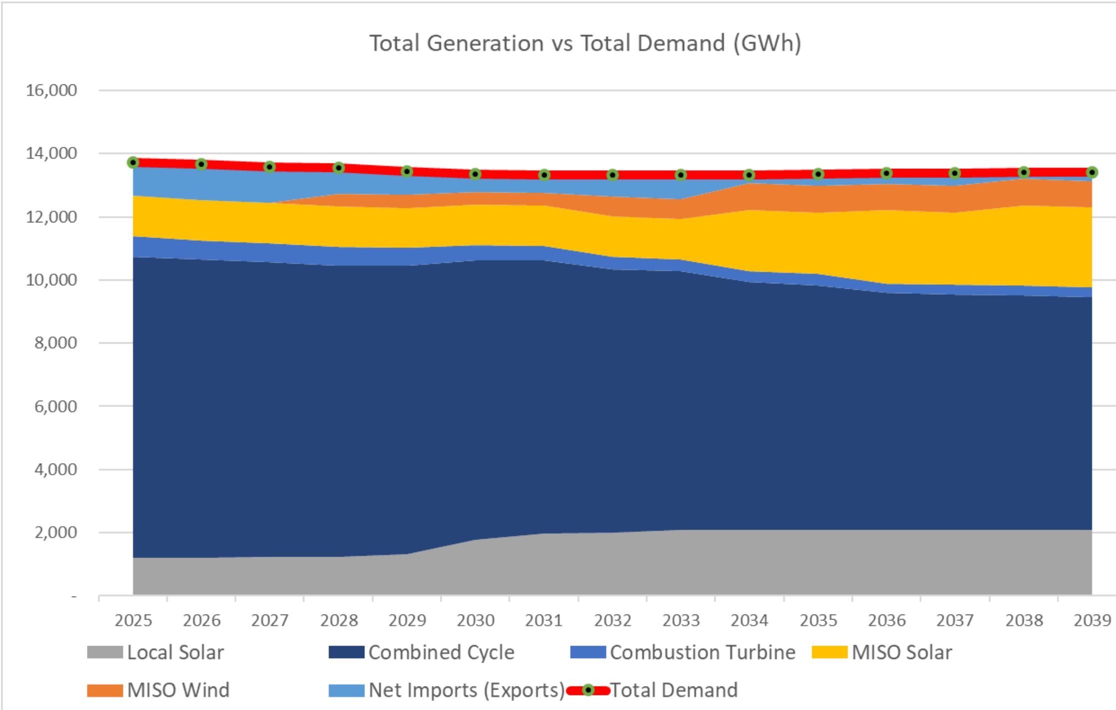
Exhibit 242: Portfolio 3 Installed Capacity by Year (Table)

	Advanced Frame CT	Convl. Frame 7FA CT	1x1 Combined Cycle	Utility Solar	Battery	Arkansas Solar	Arkansas Wind	MISO_Cap	Demand
2025	0	474	1350	600	0	600	0	1490	3197
2026	0	0	0	0	0	0	0	1482	3182
2027	0	0	0	0	0	0	0	1476	3168
2028	0	0	0	0	0	0	100	1452	3153
2029	0	0	0	50	0	0	0	1432	3139
2030	0	0	0	200	0	0	0	1372	3124
2031	0	0	0	100	0	0	0	1344	3113
2032	0	0	0	0	0	0	50	1342	3108
2033	0	0	0	50	0	0	0	1343	3110
2034	0	0	0	0	0	300	50	1278	3112
2035	0	0	0	0	0	0	0	1294	3114
2036	0	0	0	0	0	150	0	1276	3116
2037	0	0	0	0	0	0	0	1293	3118
2038	0	0	0	0	0	100	0	1291	3121
2039	0	0	0	0	0	0	0	1308	3123

Source: Siemens

Energy generated from thermal decreases slightly over the years while energy coming from renewables increases. Imported energy goes down over the years as well.

Exhibit 243: Portfolio 3 Energy by Resource Type by Year

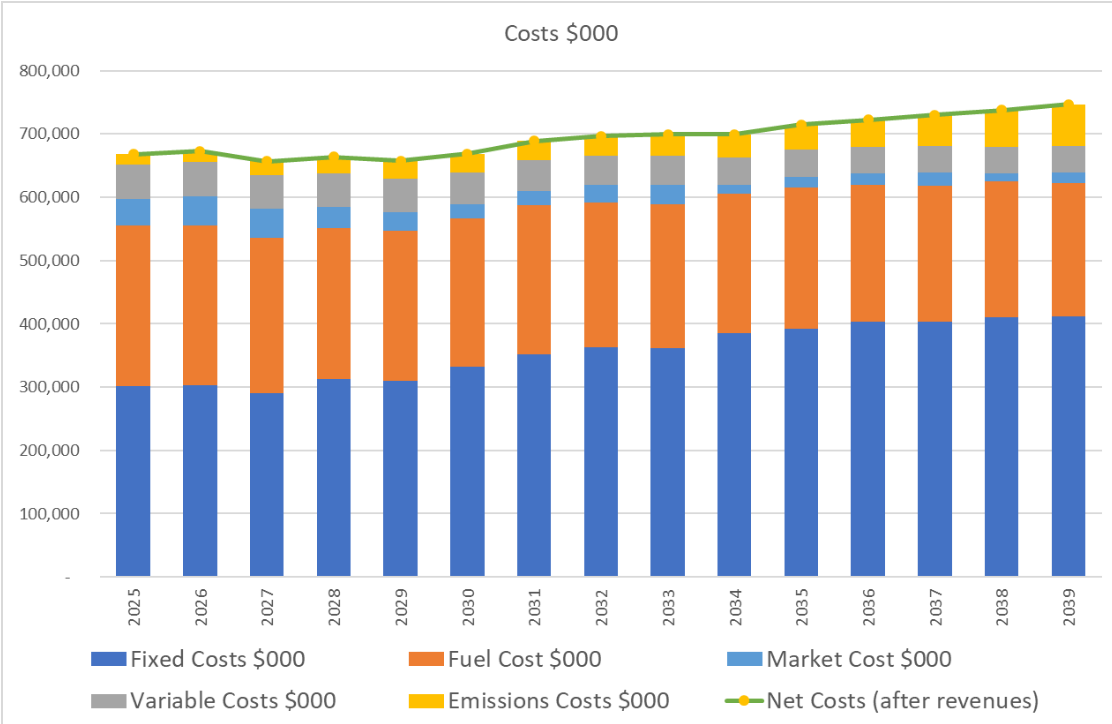


Source: Siemens

Portfolio Costs

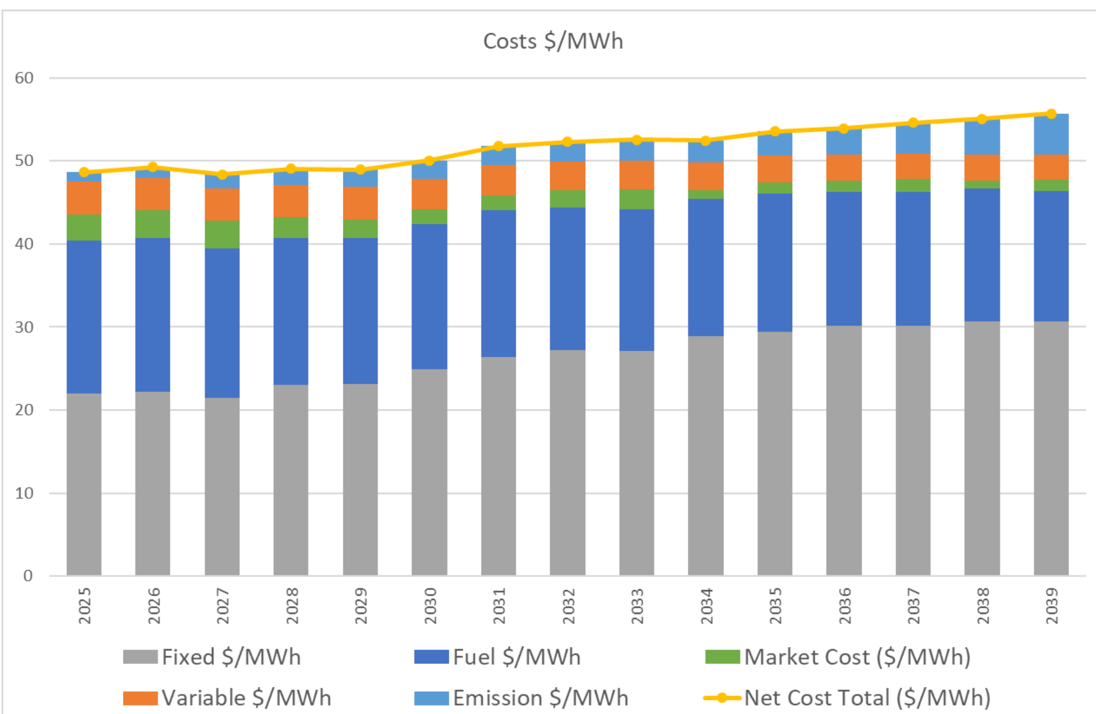
Exhibit 244 and Exhibit 245 below shows the supply side NPV cost by year as can be seen the cost is about $700 million per year (2018 $) or $52/MWh, where fixed cost is the largest component due to the investments in generation, followed by fuel costs.

Exhibit 244: Portfolio 3 Cost Components 2018 $



Source: Siemens

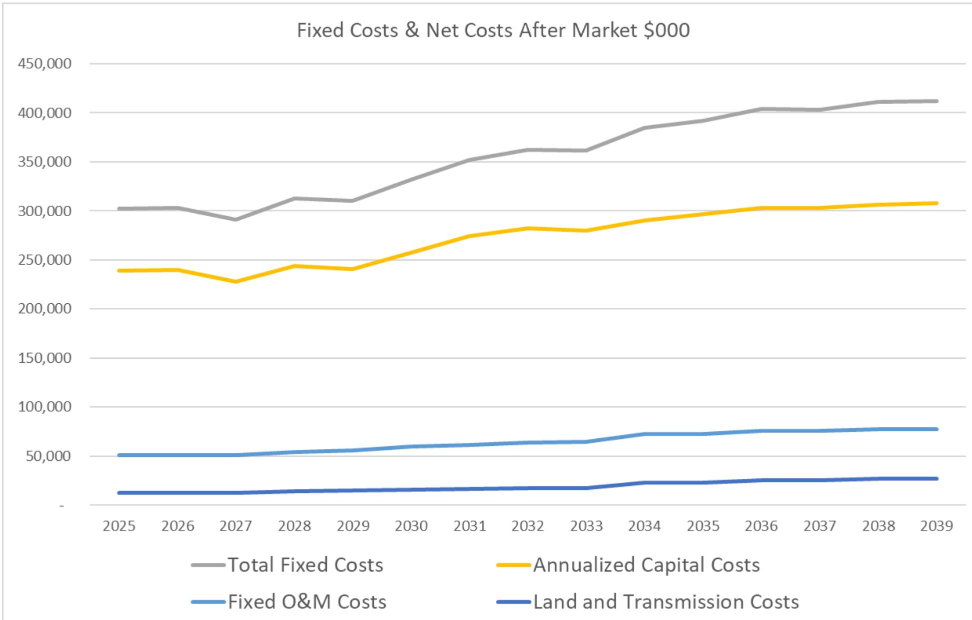
Exhibit 245: Portfolio 3 Cost Components 2018 $/MWh



Source: Siemens

Exhibit 246 shows the breakdown of total fixed costs by component, where the majority comes from the base capital costs on generation.

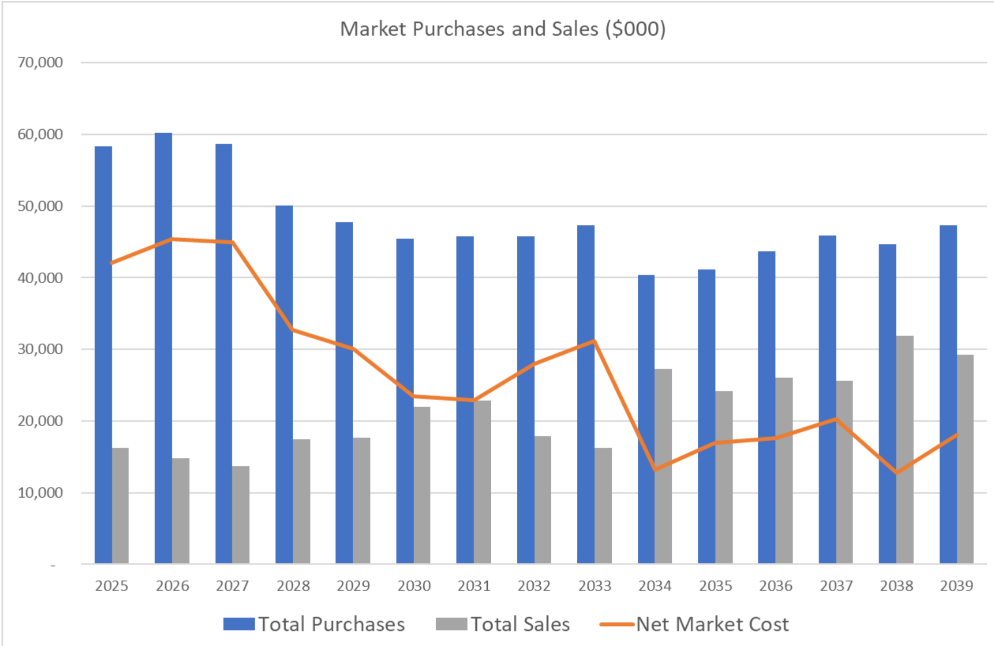
Exhibit 246: Portfolio 3 Fixed Cost Components 2018 $



Source: Siemens

Market purchases and sales as also important components. The market purchases by MLGW system are projected to be decreasing while the sales are increasing although the sales are maintained at a low level. As mentioned above, the cost of renewables is projected to be much more competitive after 2030, which resulted in reduced market purchases.

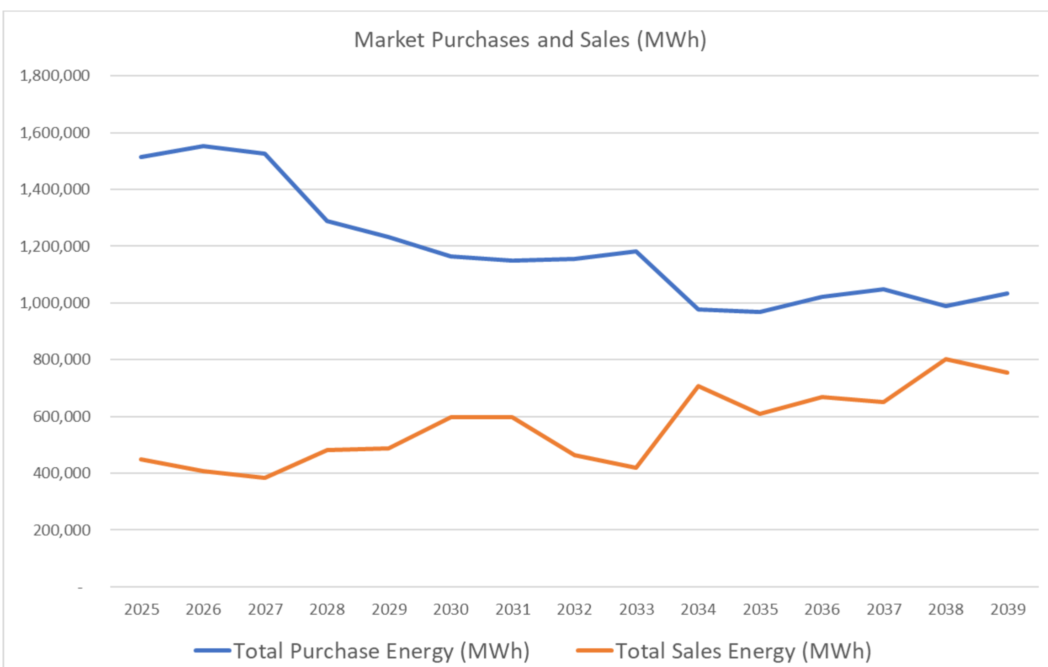
Exhibit 247: Portfolio 3 Market Purchases and Sales 2018 $



Source: Siemens

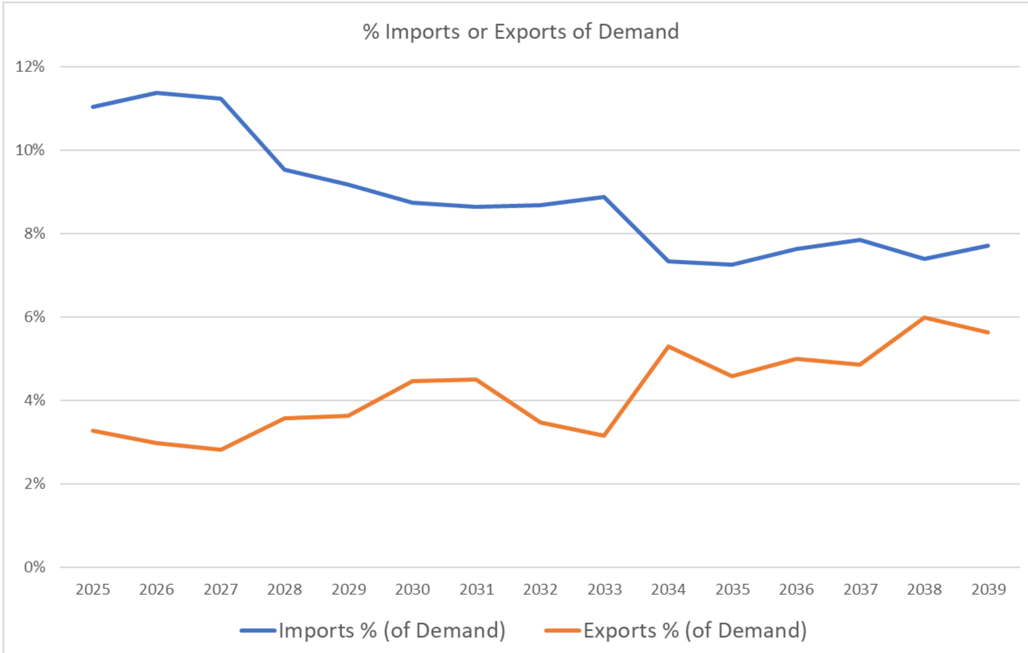
Exhibit 248 and Exhibit 249 show the purchases sales amount in energy and as % of demand, respectively. The purchase cost stays low throughout the planning years of this portfolio.

Exhibit 248: Portfolio 3 Market Purchases and Sales in Energy



Source: Siemens

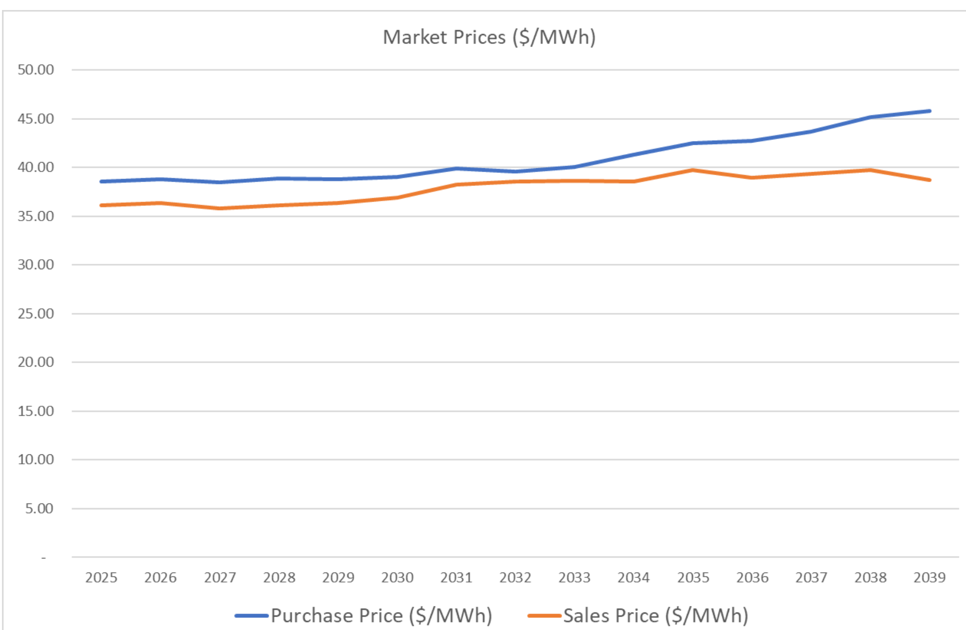
Exhibit 249: Portfolio 3 Market Purchases and Sales as % of Demand



Source: Siemens

The risk can also be appreciated looking at the difference between purchase price (high) and sale price (low).

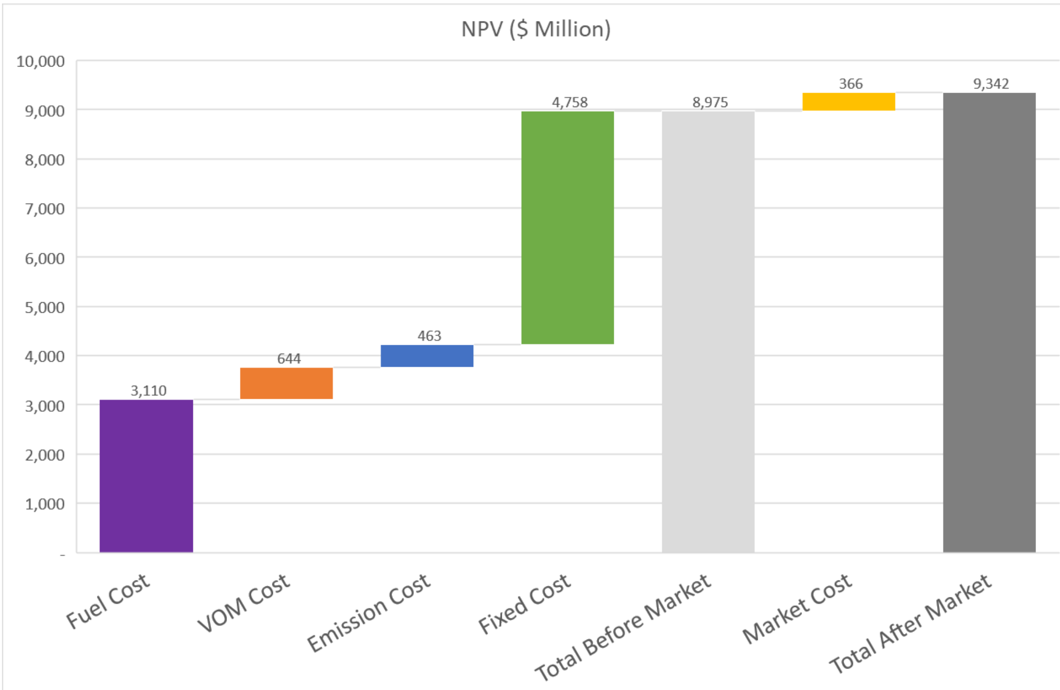
Exhibit 250: Portfolio 3 Market Purchases and Sales Prices $/MWh



Source: Siemens

Exhibit 251 shows the supply side total NPV for 2025-2039, which is about $9.34 billion in 2018 $. Fixed cost is the largest component, followed by fuel.

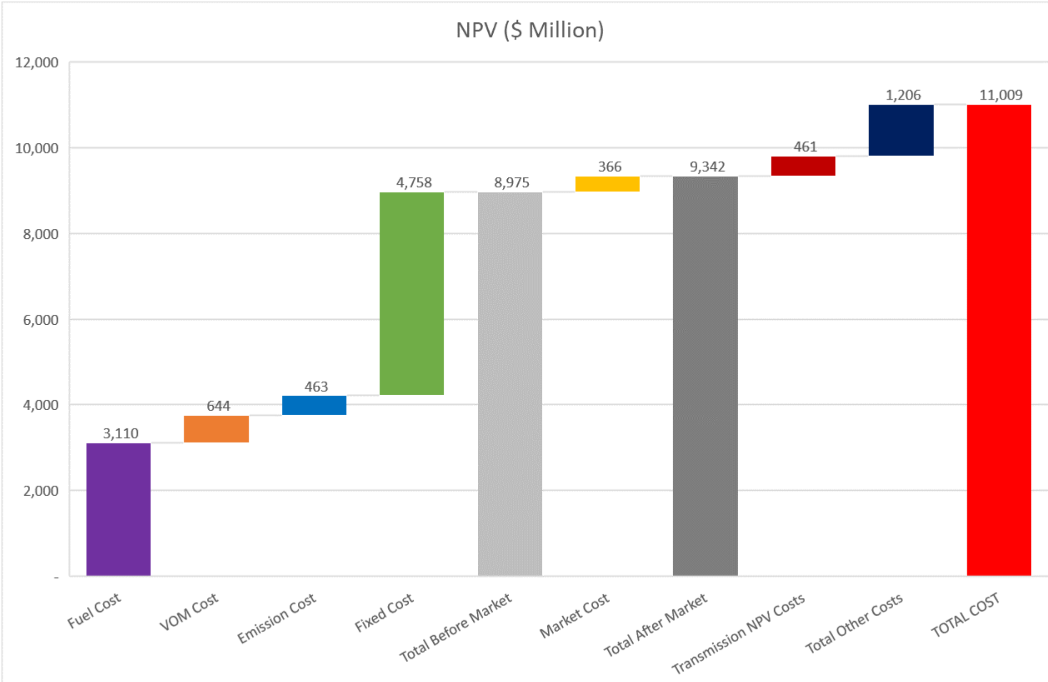
Exhibit 251: Portfolio 3 Generation Resource NPV 2018 $



Source: Siemens

The total NPVRR of this portfolio is approximately $11 billion for 2025-2039 in 2018 $.

Exhibit 252: Portfolio 3 All NPVRR with Other Components 2018 $

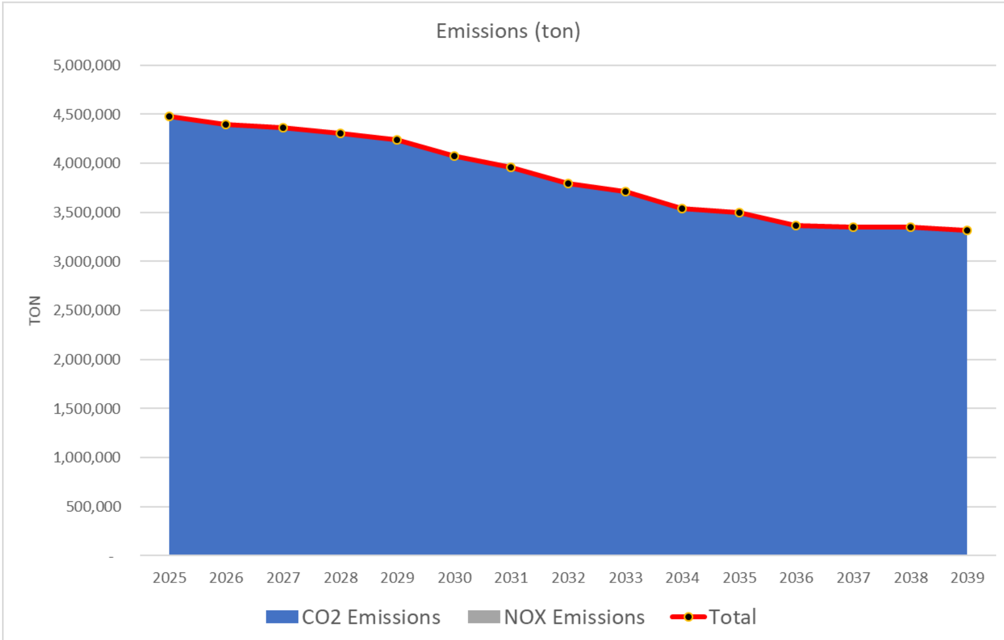


Source: Siemens

Environmental

The emission from this portfolio is shown in the graph below. As energy from thermal generation is coming down, the capacity factor of the units decreases which resulted in decreased CO_2 emission over the years.

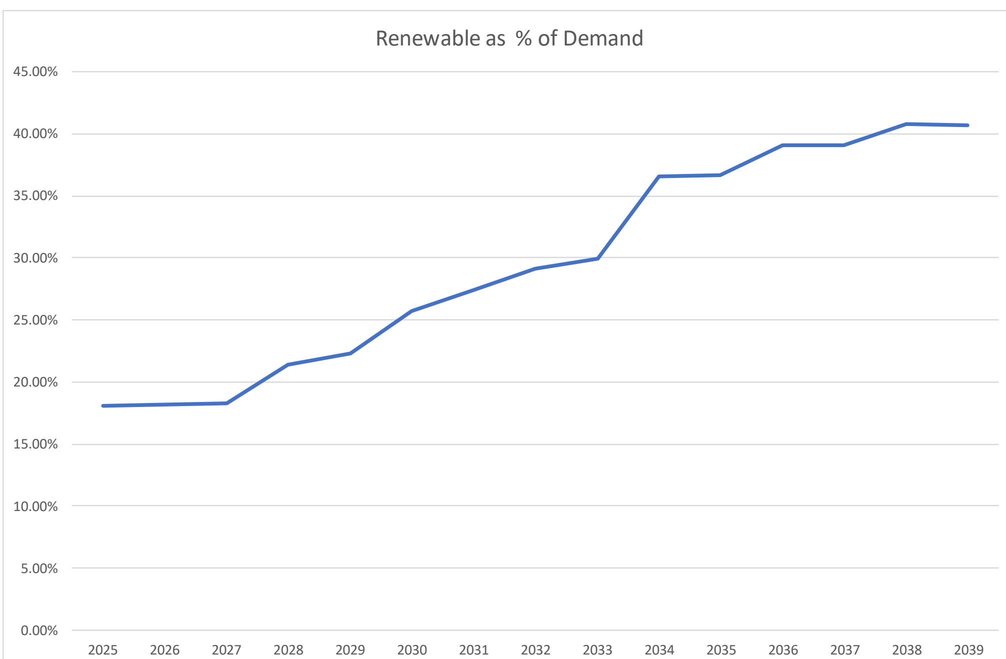
Exhibit 253: Portfolio 3 MLGW Emission by Year



Source: Siemens

The RPS as of the demand in energy of this portfolio starts at about 17% and reaches just over 40% in 2039 as more renewable generation is built.

Exhibit 254: Portfolio 3 RPS by Year

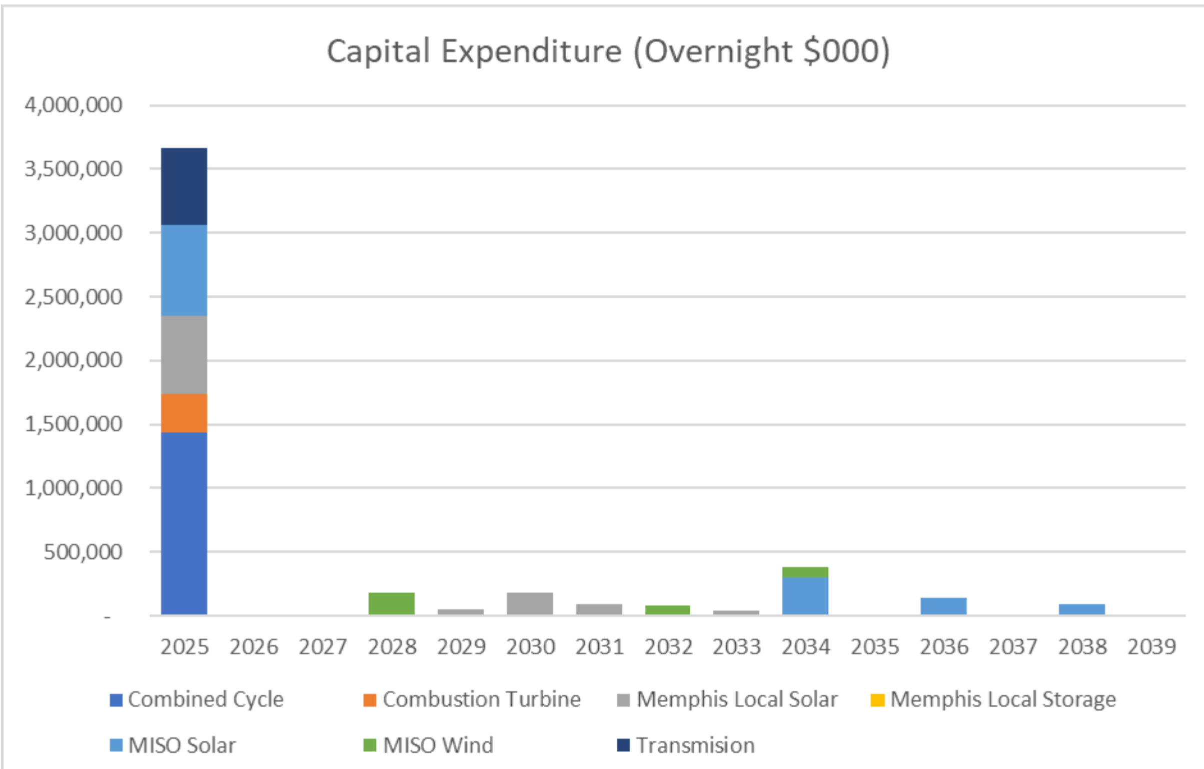


Source: Siemens

Capital Expenditure

Total capital expenditures on generation and transmission are shown in Exhibit 255 below. We present these capital expenditures in overnight from 2025 to 2039 while the actual drawdown may vary. Most of the CapEx are on the generation side and occur prior to 2025. Note that only the transmission CapEx is expected to be covered by MLGW as the generation CapEx is assumed to be expensed by third parties and recovered via PPA payments from MLGW.

Exhibit 255: Portfolio 3 Overnight Capital Expenditure by Year



Source: Siemens

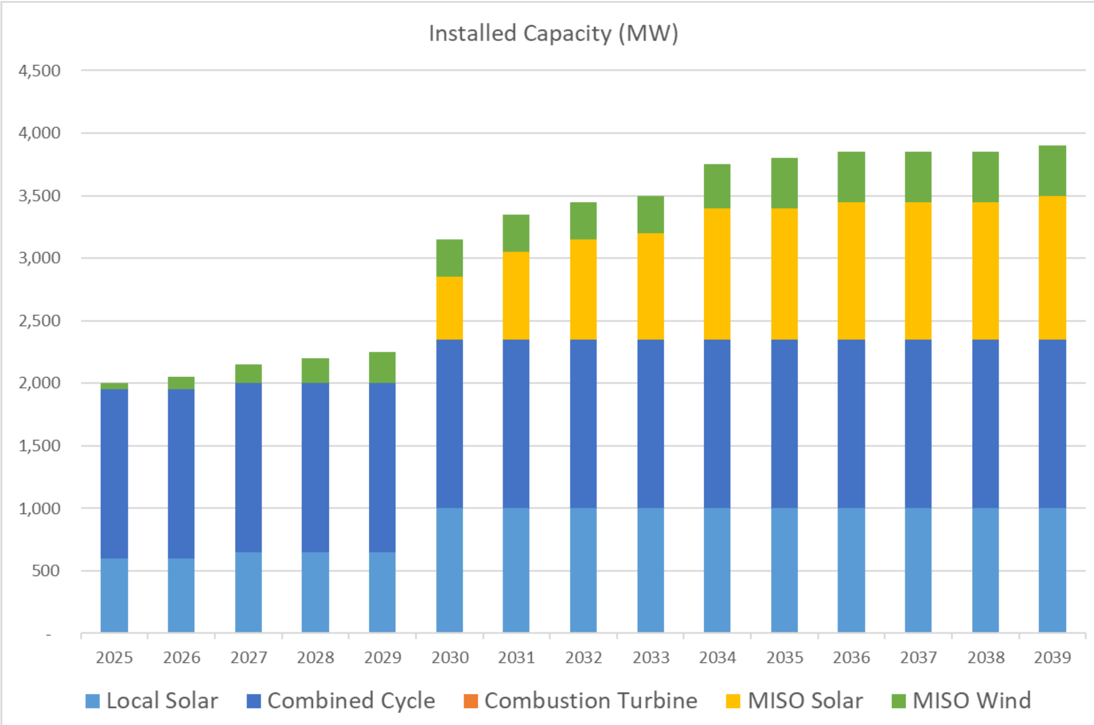
Portfolio 4 (S3S3_BB)

This is the portfolio derived from low load base gas price scenario.

Capacity Expansion (Buildout)

Exhibit 256 and Exhibit 257 show the capacity expansion by year. Thermal generation is installed all in first year 2025, with a total of three CCGTs.

Exhibit 256: Portfolio 4 Installed Capacity by Year



Source: Siemens

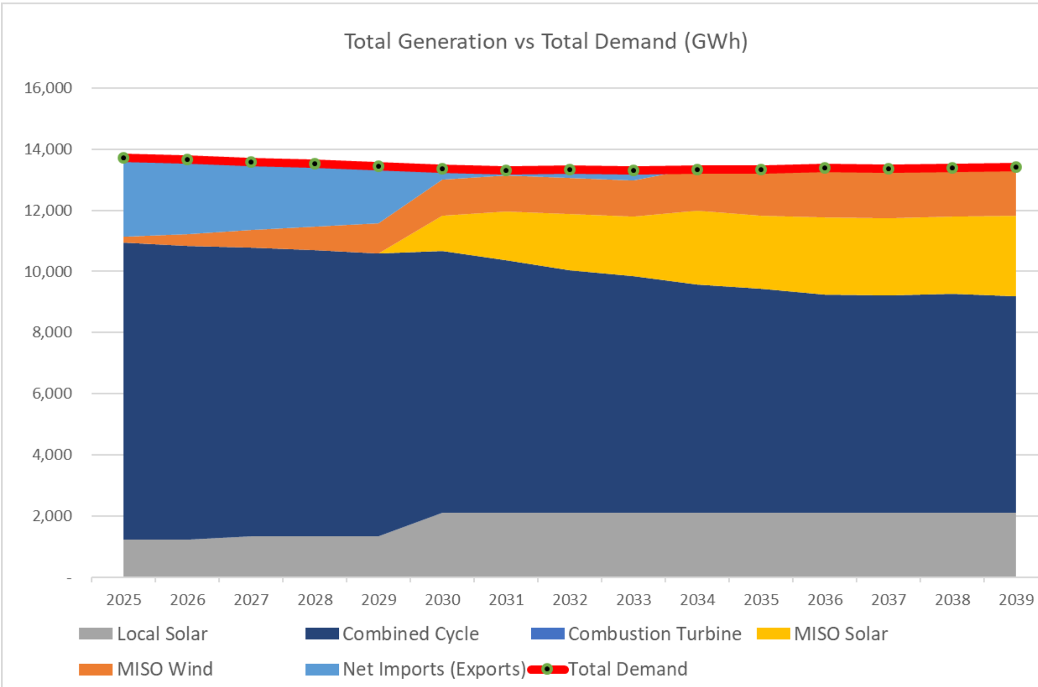
Exhibit 257: Portfolio 4 Installed Capacity by Year (Table)

	Advanced Frame CT	Convl. Frame 7FA CT	1x1 Combined Cycle	Utility Solar	Battery	Arkansas Solar	Arkansas Wind	MISO_Cap	Demand
2025	0	0	1350	600	0	0	50	2083	3197
2026	0	0	0	0	0	0	50	2063	3182
2027	0	0	0	50	0	0	50	2030	3168
2028	0	0	0	0	0	0	50	2010	3153
2029	0	0	0	0	0	0	50	1992	3139
2030	0	0	0	350	0	500	50	1748	3124
2031	0	0	0	0	0	200	0	1695	3113
2032	0	0	0	0	0	100	0	1677	3108
2033	0	0	0	0	0	50	0	1679	3110
2034	0	0	0	0	0	200	50	1640	3112
2035	0	0	0	0	0	0	50	1649	3114
2036	0	0	0	0	0	50	0	1655	3116
2037	0	0	0	0	0	0	0	1672	3118
2038	0	0	0	0	0	0	0	1690	3121
2039	0	0	0	0	0	50	0	1697	3123

Source: Siemens

Energy generated from thermal generation decreases over the years while energy coming from renewables increases, especially starting 2030 when the cost of renewables is projected to be much more competitive. Imported energy goes down after 2030.

Exhibit 258: Portfolio 4 Energy by Resource Type by Year

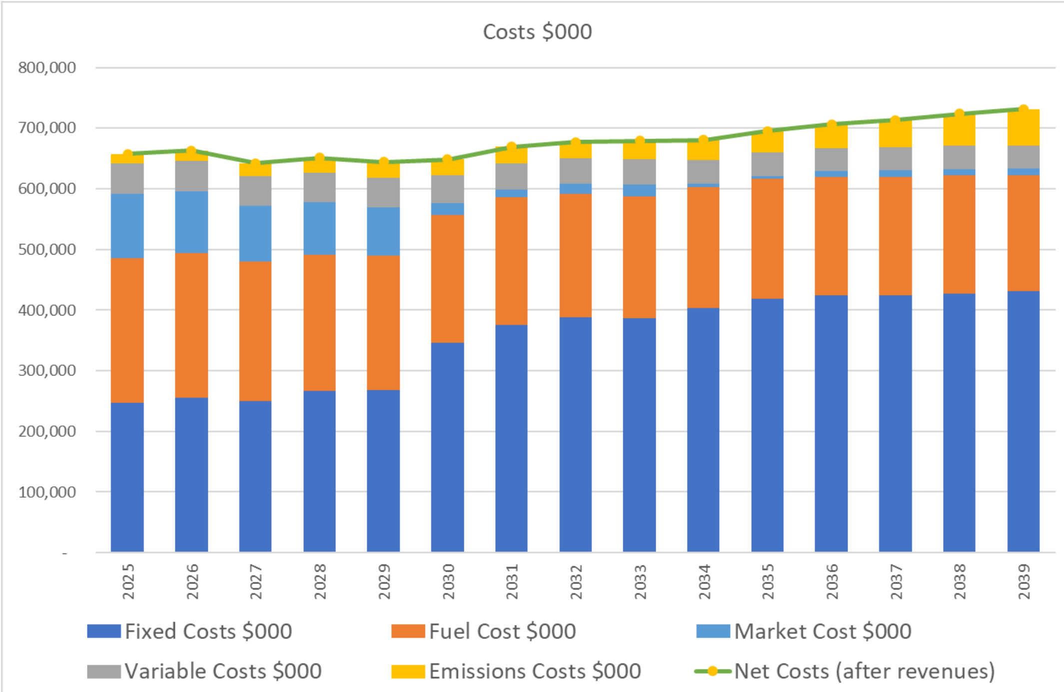


Source: Siemens

Portfolio Costs

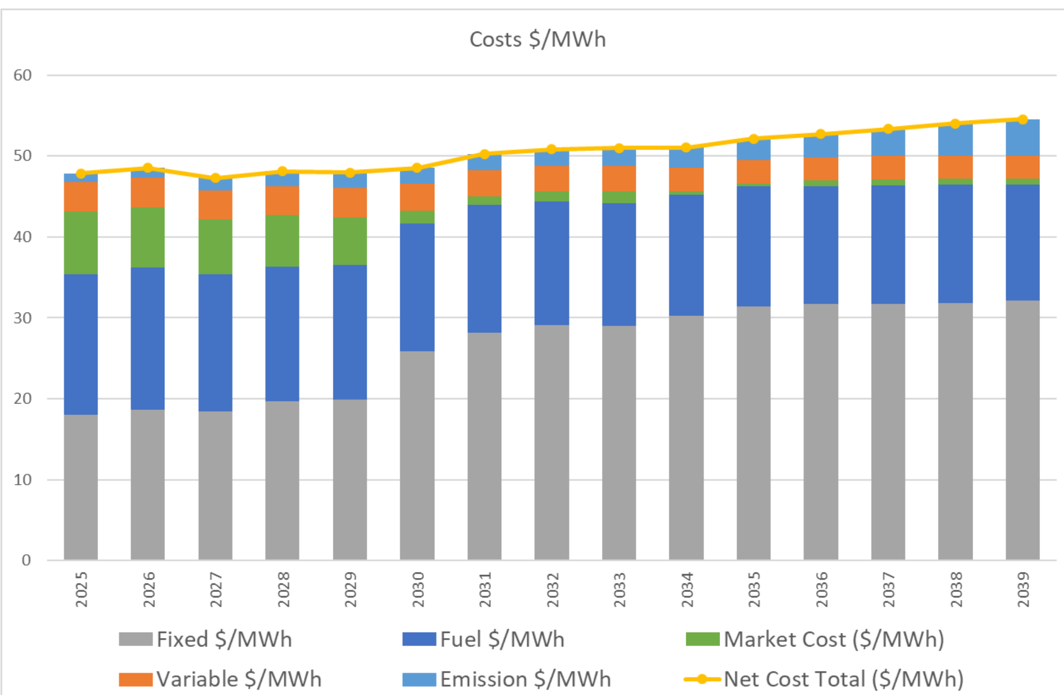
Exhibit 259 shows the supply side NPV cost by year, as can be seen the cost is about $680 million per year (2018 $) or $50/MWh, where fixed cost is the largest component due to the investments in generation, followed by cost of fuels.

Exhibit 259: Portfolio 4 Cost Components 2018 $



Source: Siemens

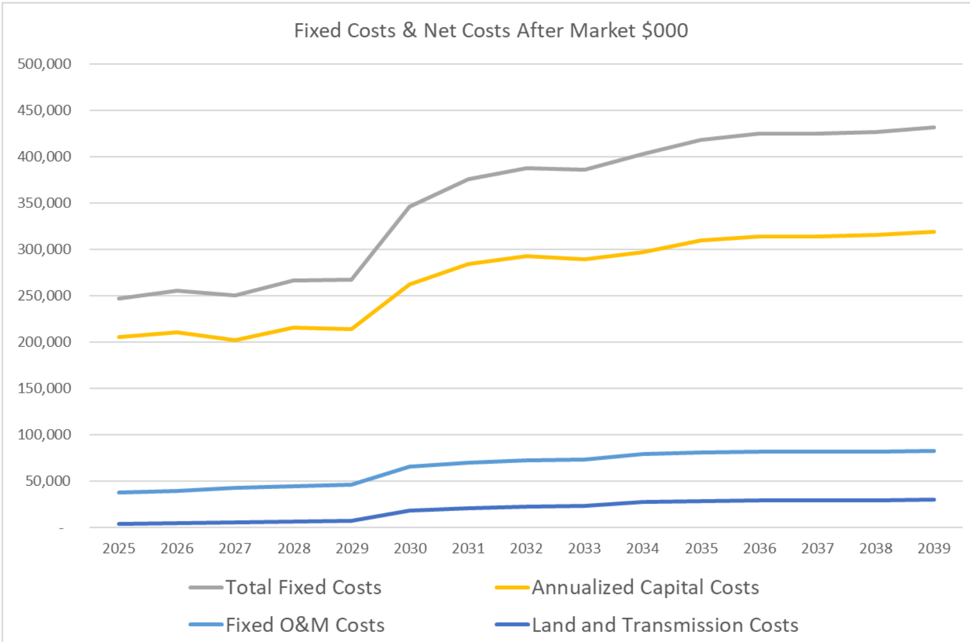
Exhibit 260: Portfolio 4 Cost Components 2018 $/MWh



Source: Siemens

Exhibit 261 shows the breakdown of total fixed costs by components, where the majority comes from the base capital costs on generation.

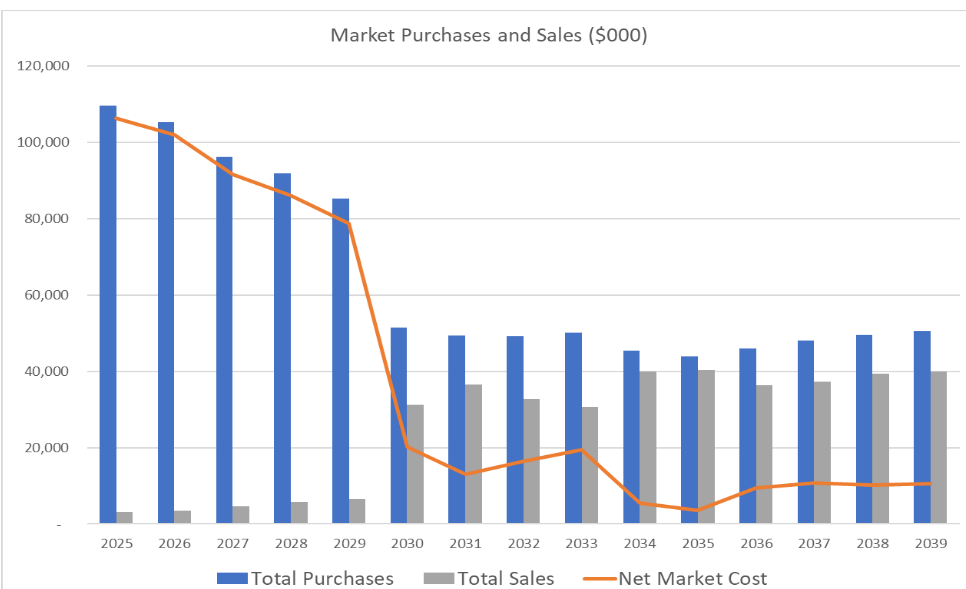
Exhibit 261: Portfolio 4 Fixed Cost Components 2018 $



Source: Siemens

Market purchases and sales as also important components. The market purchases by MLGW system are projected to be decreasing while the sales are increasing although the sales are maintained at a low level.

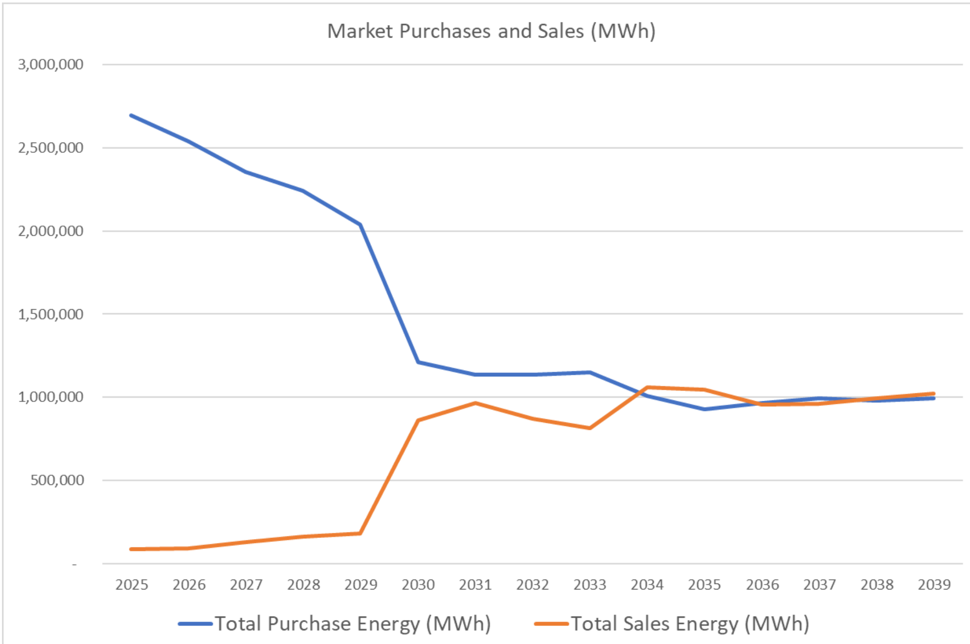
Exhibit 262: Portfolio 4 Market Purchases and Sales 2018 $



Source: Siemens

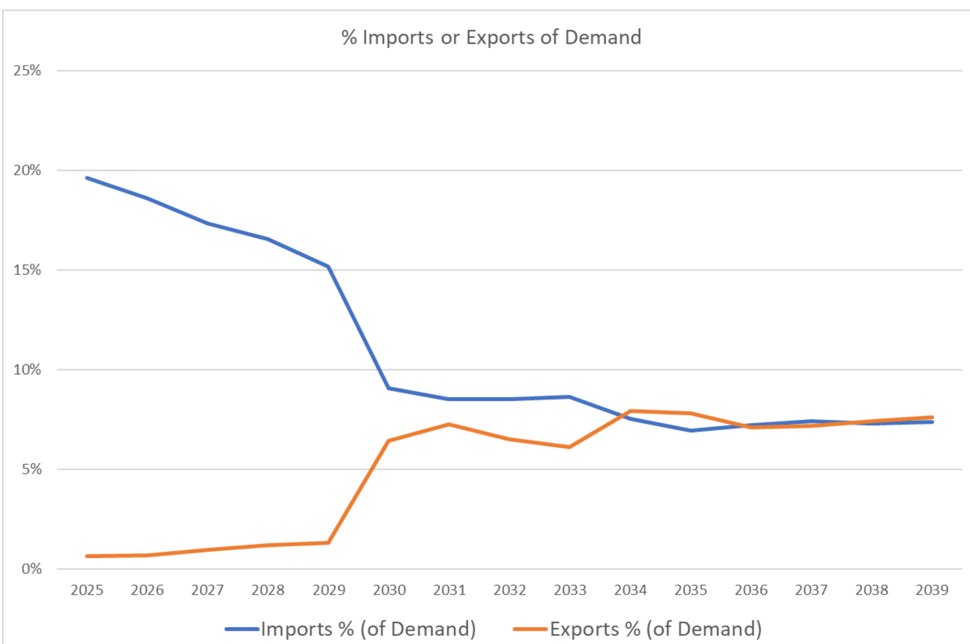
Exhibit 263 and Exhibit 264 show the purchases sales amount in energy as a % of demand. It shows the high market risk in the beginning of the planning years of this portfolio.

Exhibit 263: Portfolio 4 Market Purchases and Sales in Energy



Source: Siemens

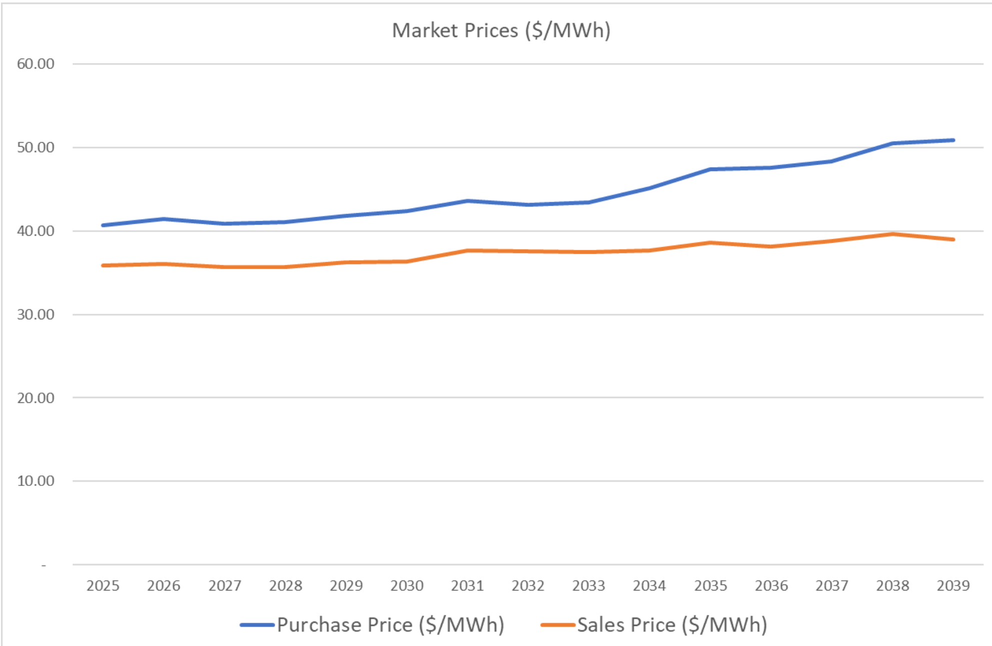
Exhibit 264: Portfolio 4 Market Purchases and Sales as % of Demand



Source: Siemens

The risk can also be appreciated looking at the difference between purchase price (high) and sale price (low). The more purchase this portfolio needs, the higher risk.

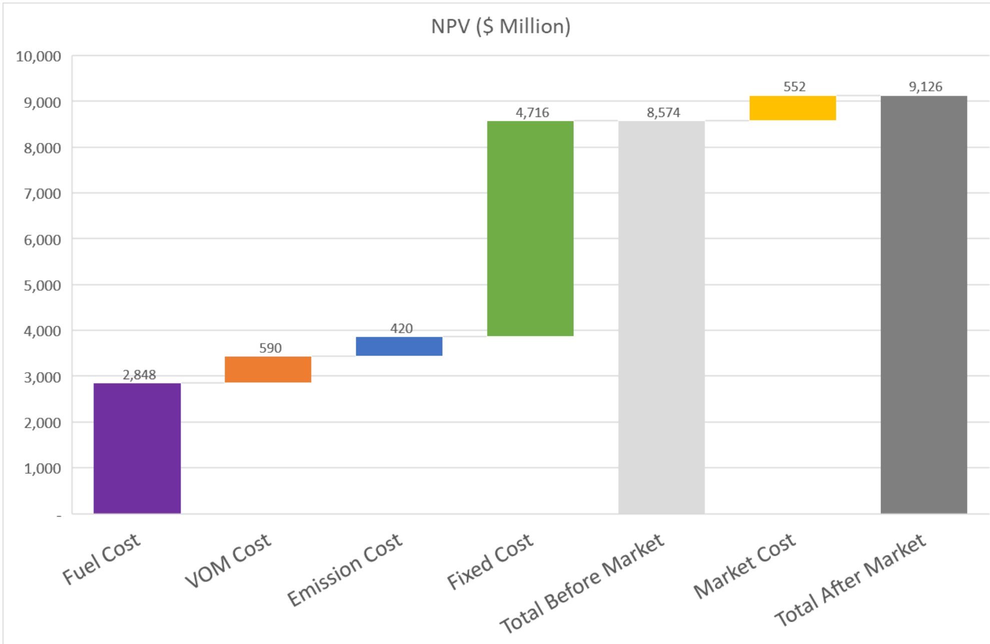
Exhibit 265: Portfolio 4 Market Purchases and Sales Prices $/MWh



Source: Siemens

Exhibit 266 shows the supply side total NPV for 2025-2039, which is about $9.13 billion in 2018 $. Fixed cost is the largest component, followed by fuel cost.

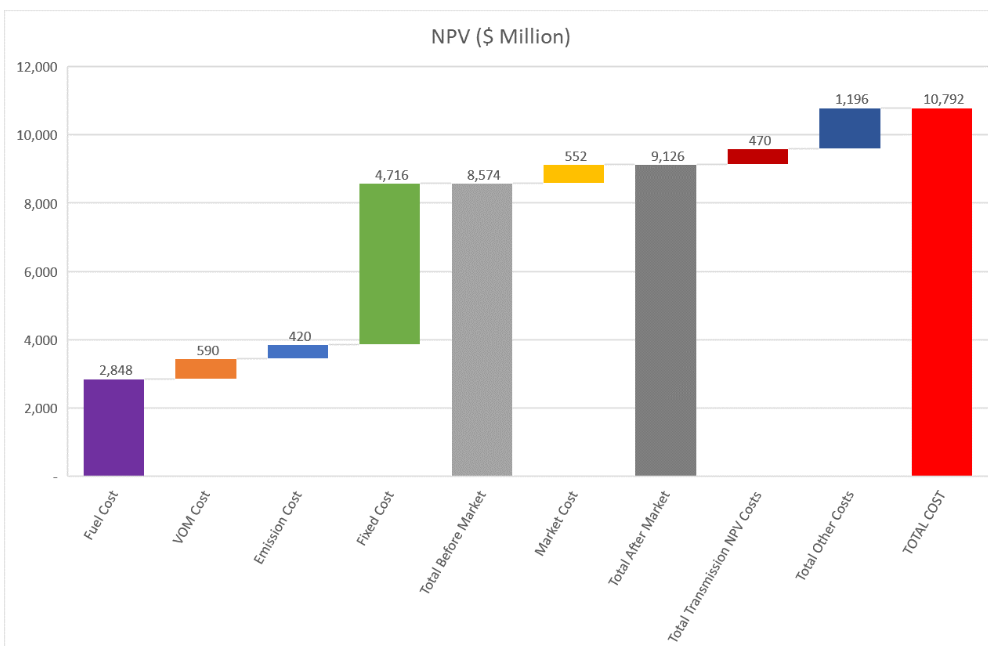
Exhibit 266: Portfolio 4 Generation Resource NPV 2018 $



Source: Siemens

The total NPVRR is shown in Exhibit 267, including the other cost components, i.e. transmission and other costs, including PILOT, TVA Benefits, energy efficiency, gap costs, MISO Admin fees. The total NPVRR of this portfolio is approximately $10.79 billion for 2025-2039 in 2018 $.

Exhibit 267: Portfolio 4 All NPVRR with Other Components 2018 $

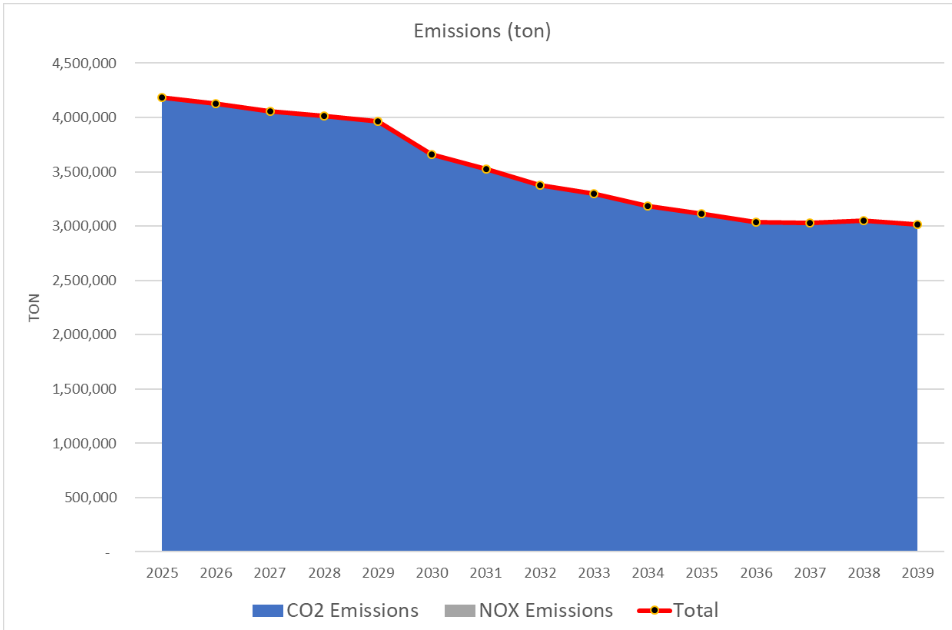


Source: Siemens

Environmental

The emission from this portfolio is shown in Exhibit 268. As energy from thermal generation is coming down, the capacity factor of the units decreases which resulted in decreased CO_2 emission over the years.

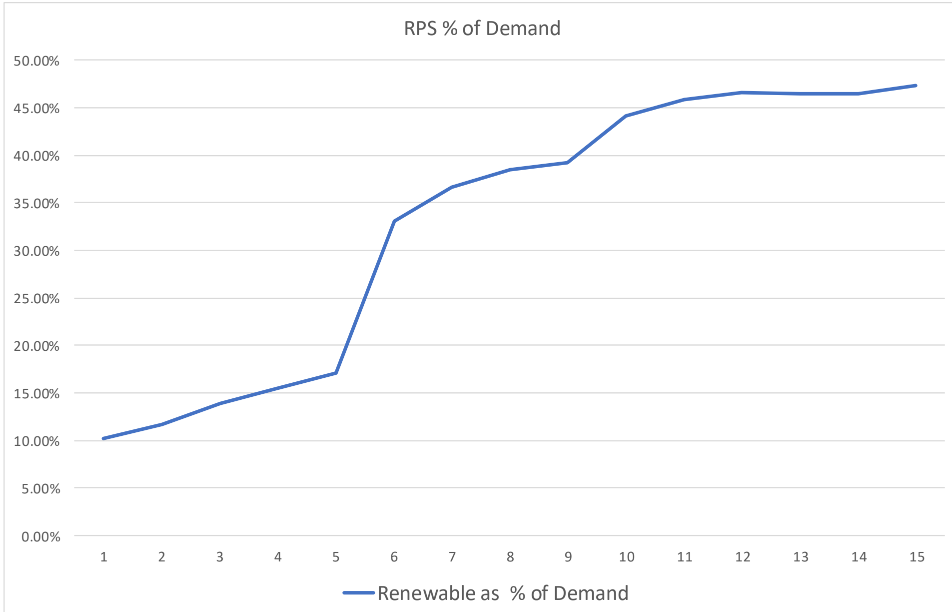
Exhibit 268: Portfolio 4 MLGW Emission by Year



Source: Siemens

The RPS as of the demand in energy of this portfolio starts at about 10% and reaches more than 45% in 2039 as more renewable generation are built.

Exhibit 269: Portfolio 4 RPS by Year

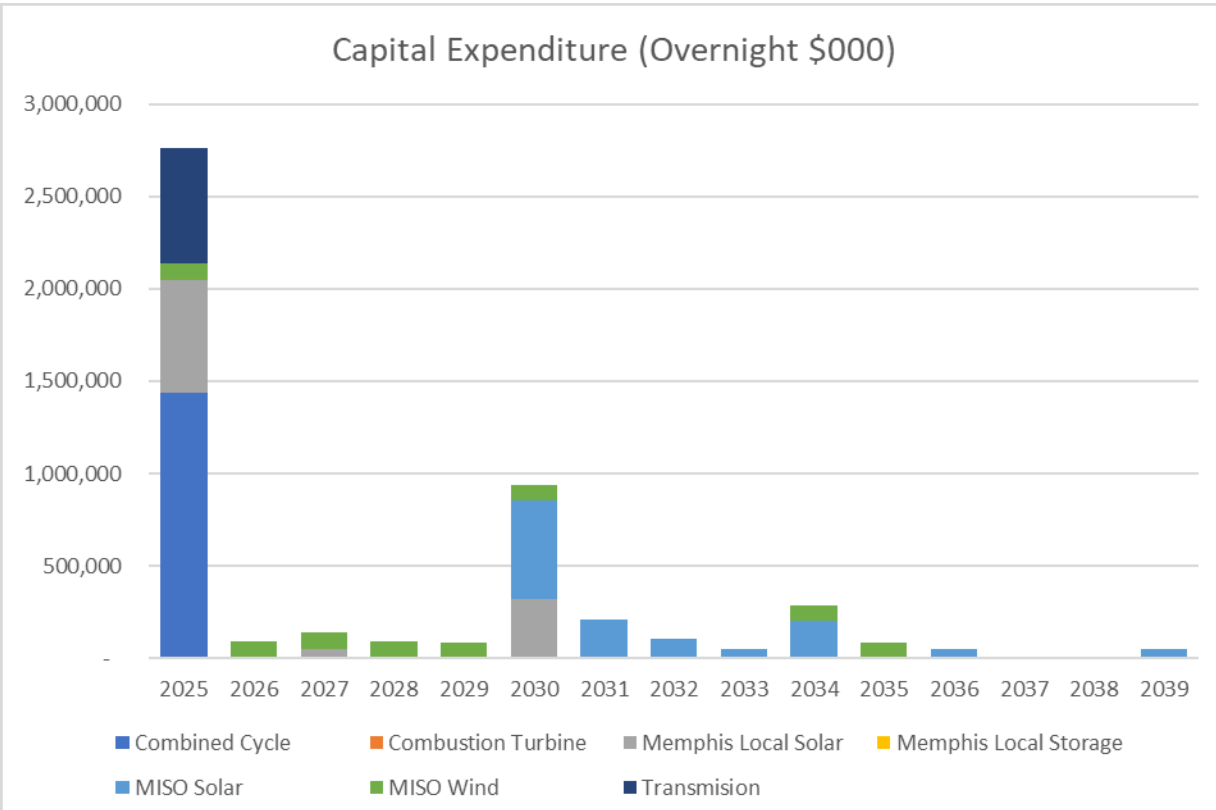


Source: Siemens

Capital Expenditure

Total capital expenditures on generation and transmission are shown in Exhibit 270. Siemens present these capital expenditures in overnight from 2025 to 2039 while the actual drawdown may vary. Most of the CapEx are on the generation side and occur prior to 2025. Note that only the transmission CapEx is expected to be covered by MLGW as the generation CapEx is assumed to be expensed by third parties and recovered via PPA payments from MLGW.

Exhibit 270: Portfolio 4 Overnight Capital Expenditure by Year



Source: Siemens

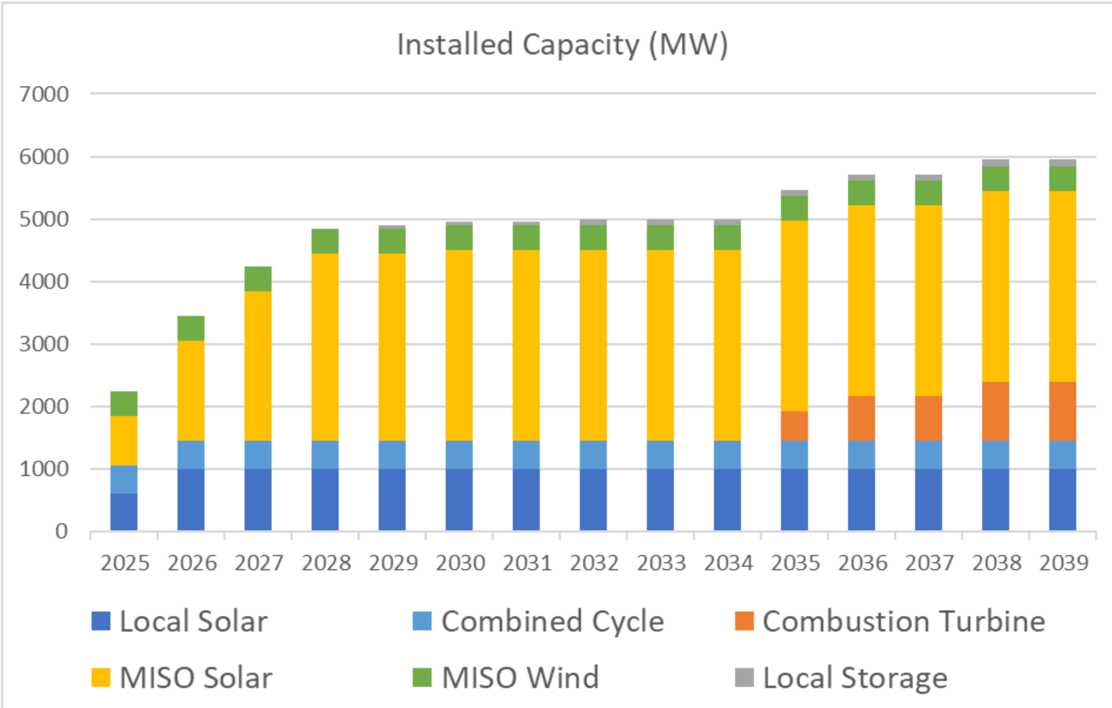
Portfolio 5 (S3S5)

This is the base portfolio derived from high transmission scenario, with the CTs built in the last few years from the expansion plan.

Capacity Expansion (Buildout)

Exhibit 271 and Exhibit 272 show the capacity expansion by year, where local solar is installed as much and quickly as possible. Only the CCGT of all thermal generation is installed in first year 2025, and the rest of CTs are installed in the last few years of the planning horizon. This portfolio also has installed 100MW of battery energy storage systems (BESS).

Exhibit 271: Portfolio 5 Installed Capacity by Year



Source: Siemens

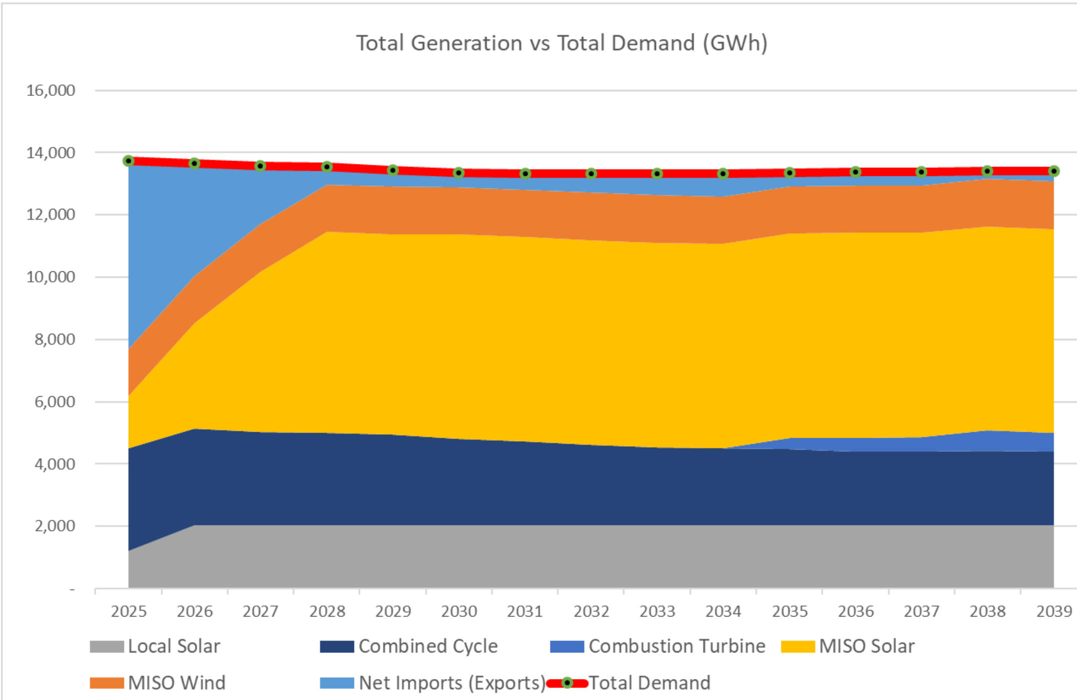
Exhibit 272: Portfolio 5 Installed Capacity by Year (Table)

	Advanced Frame CT	Convl. Frame 7FA CT	1x1 Combined Cycle	Utility Solar	Battery	Arkansas Solar	Arkansas Wind	MISO_Cap	Demand
2025	0	0	450	600	0	800	400	2595	3197
2026	0	0	0	400	0	800	0	2237	3182
2027	0	0	0	0	0	800	0	2012	3168
2028	0	0	0	0	0	600	0	1853	3153
2029	0	0	0	0	50	0	0	1816	3139
2030	0	0	0	0	0	50	0	1815	3124
2031	0	0	0	0	0	0	0	1832	3113
2032	0	0	0	0	50	0	0	1806	3108
2033	0	0	0	0	0	0	0	1837	3110
2034	0	0	0	0	0	0	0	1868	3112
2035	0	474	0	0	0	0	0	1478	3114
2036	0	237	0	0	0	0	0	1299	3116
2037	0	0	0	0	0	0	0	1330	3118
2038	0	237	0	0	0	0	0	1152	3121
2039	0	0	0	0	0	0	0	1183	3123

Source: Siemens

Energy generated from thermal generation decreases over the years while energy coming from renewables increases, especially starting 2030 when the cost of renewables is projected to be much more competitive. Imported energy goes down after 2030 as well.

Exhibit 273: Portfolio 5 Energy by Resource Type by Year

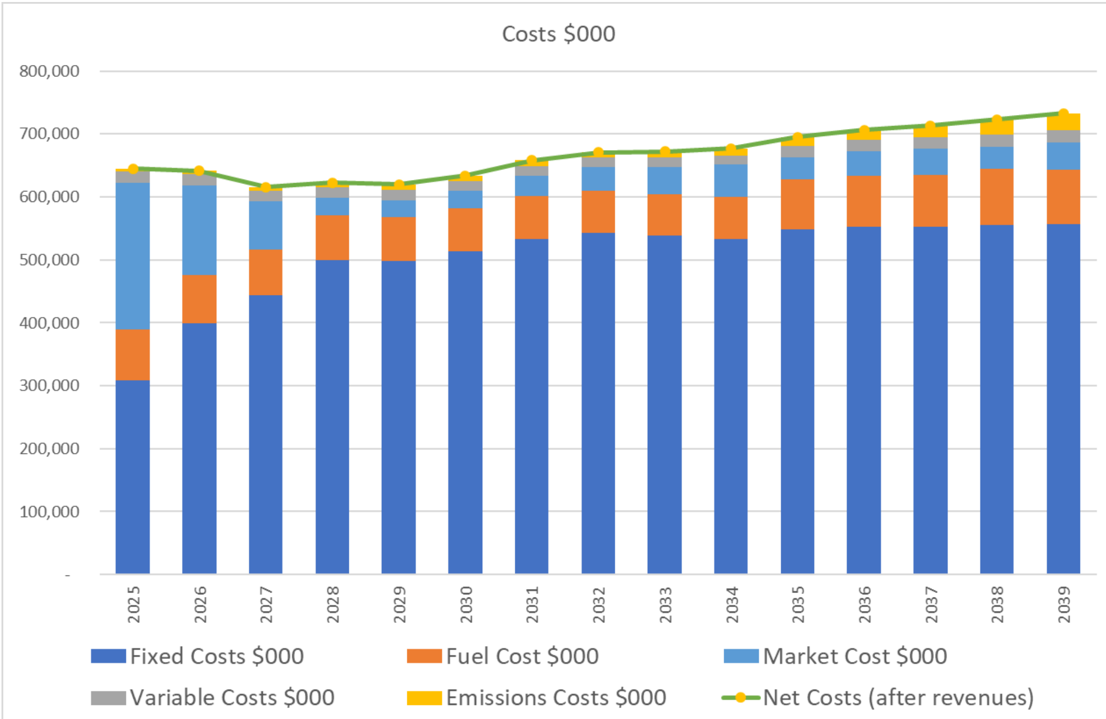


Source: Siemens

Portfolio Costs

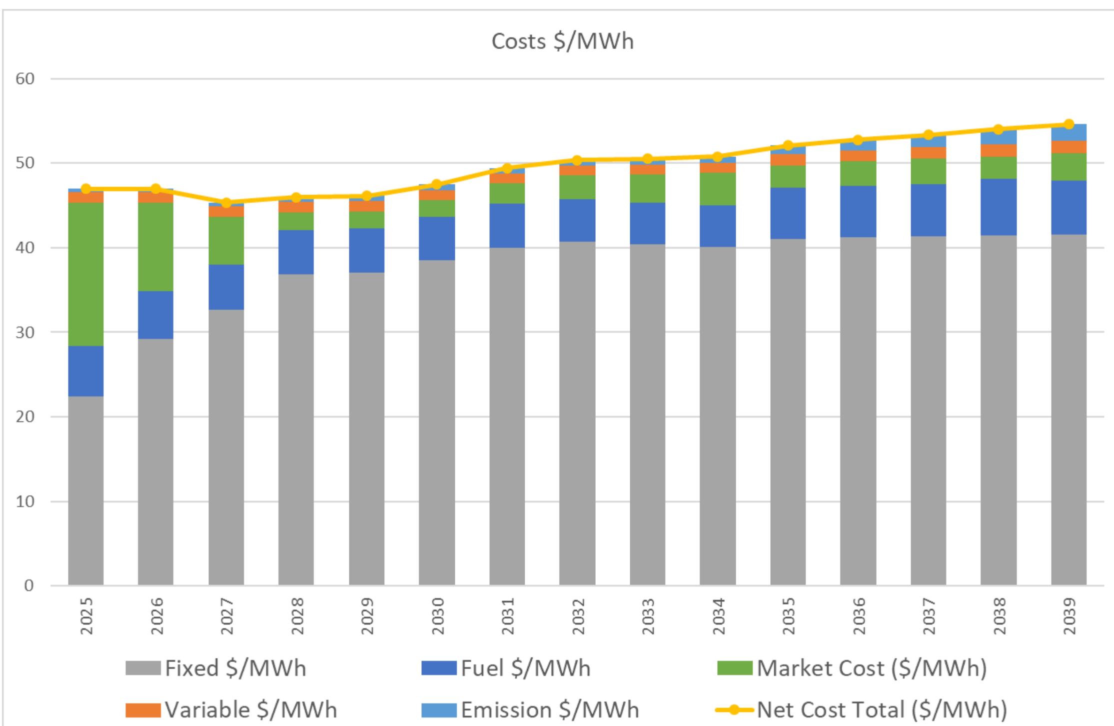
Exhibit 274 shows the supply side NPV cost by year. As can be seen, the cost is about $670 million per year (2018 $) or $50/MWh, where fixed cost is the largest components due to the investments in generation, followed by cost of fuels and market purchases.

Exhibit 274: Portfolio 5 Cost Components 2018 $



Source: Siemens

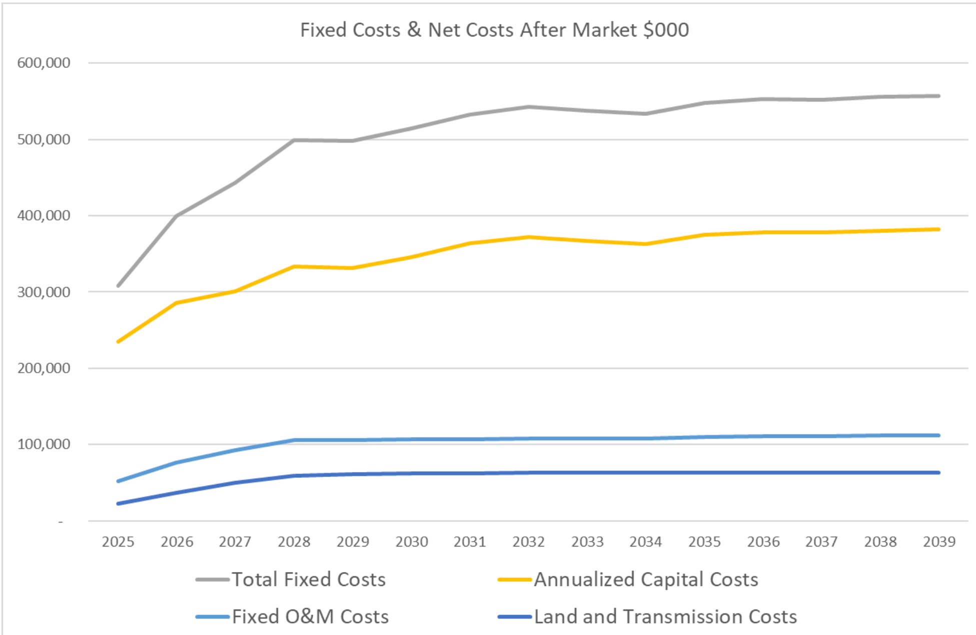
Exhibit 275: Portfolio 5 Cost Components 2018 $/MWh



Source: Siemens

Exhibit 276 shows the breakdown of total fixed costs by component, where the majority comes from the base capital costs on generation.

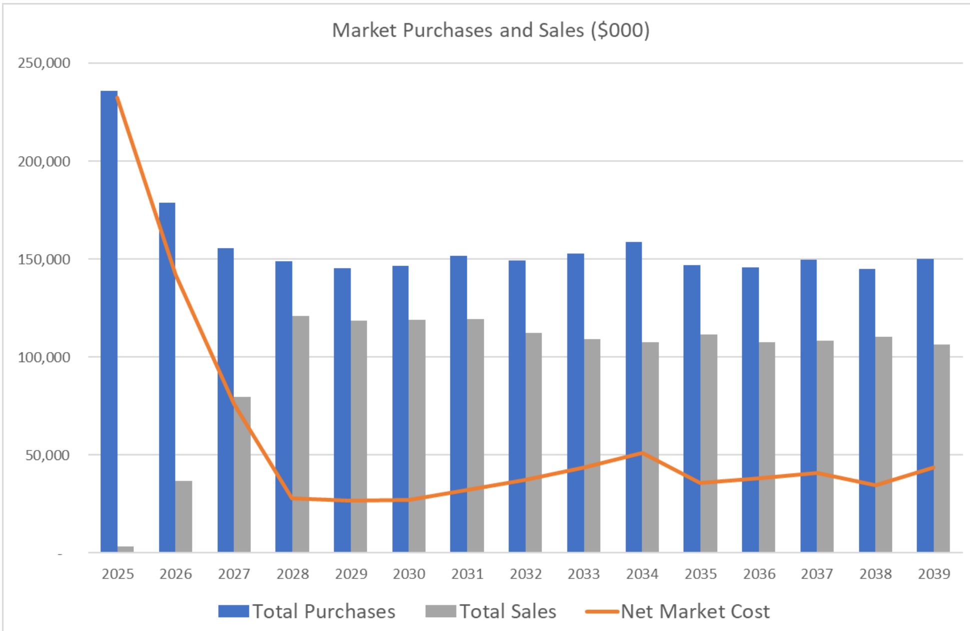
Exhibit 276: Portfolio 5 Fixed Cost Components 2018 $



Source: Siemens

Market purchases and sales are also important components. The market purchases by MLGW system are projected to be decreasing while the sales are increasing although the sales are maintained at a low level.

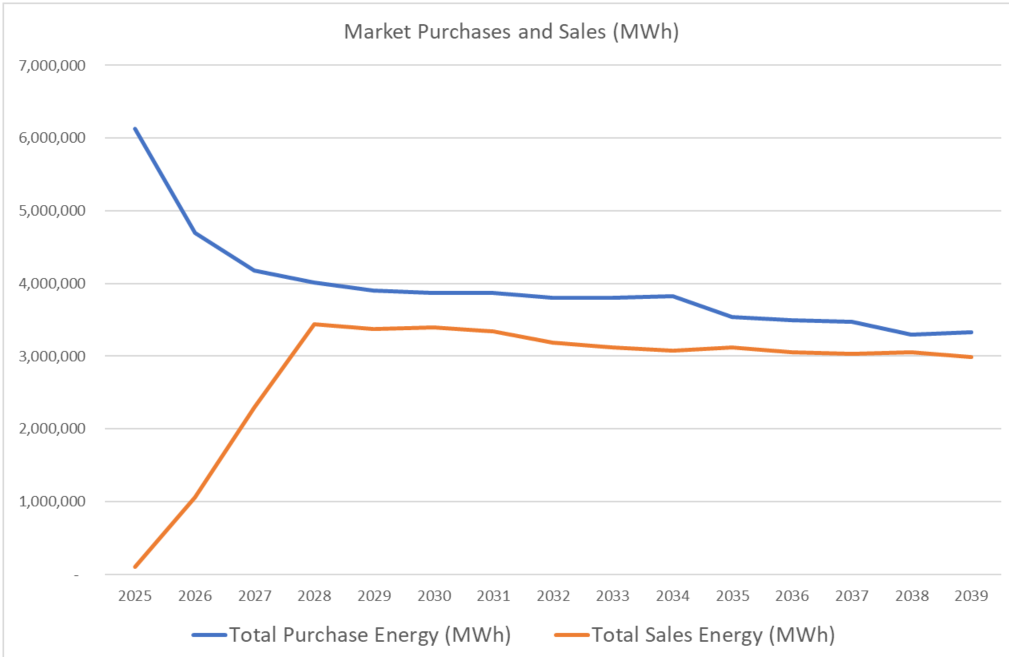
Exhibit 277: Portfolio 5 Market Purchases and Sales 2018 $



Source: Siemens

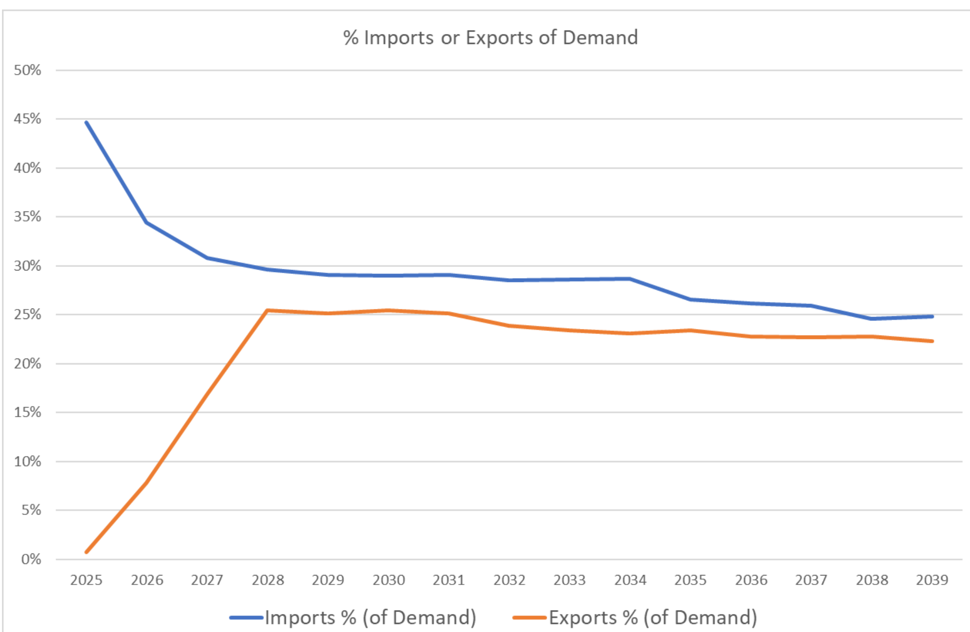
Exhibit 278 and Exhibit 279 show the purchases sales amount in energy and as % of demand, respectively. Market risk is highest in the beginning of the planning years of this portfolio.

Exhibit 278: Portfolio 5 Market Purchases and Sales in Energy



Source: Siemens

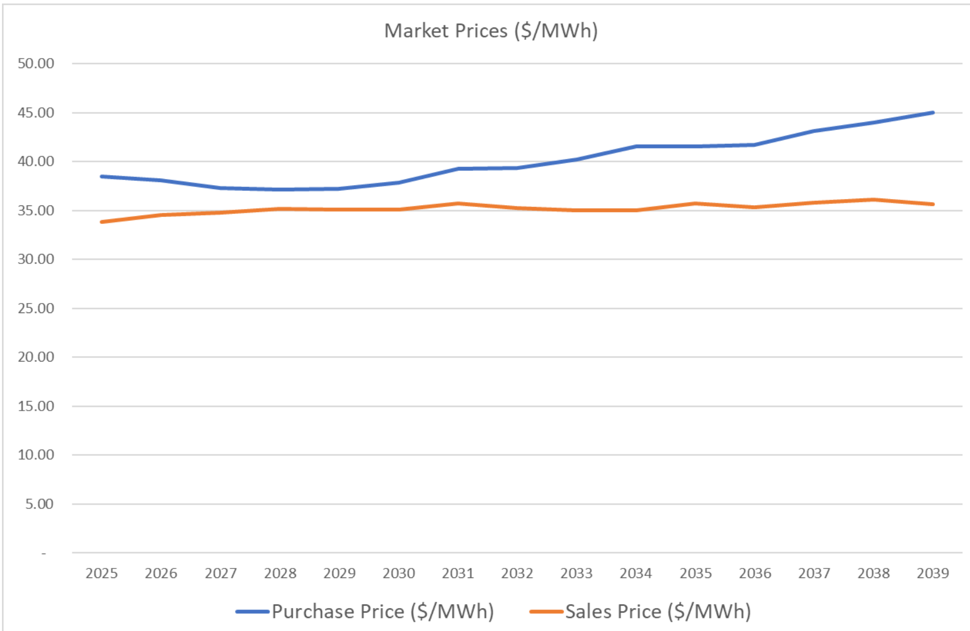
Exhibit 279: Portfolio 5 Market Purchases and Sales as % of Demand



Source: Siemens

The market risk associated with this portfolio is more related to the availability of resources in the market than the market price itself, because this is a portfolio that requires relatively higher percentages of purchase from the market due to less local generation. The more purchases this portfolio needs, the higher risk.

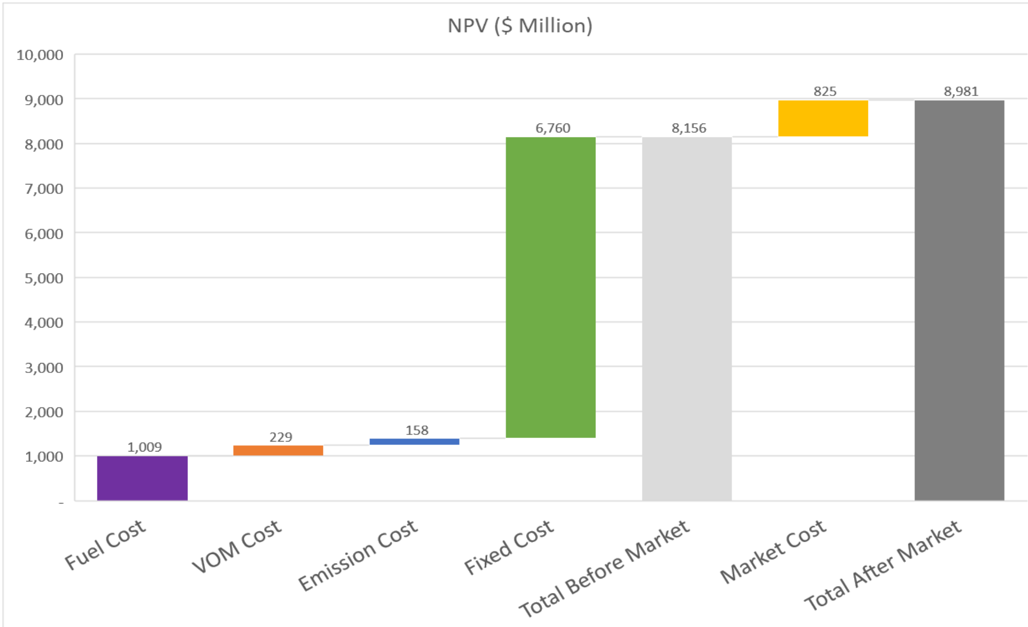
Exhibit 280: Portfolio 5 Market Purchases and Sales Prices $/MWh



Source: Siemens

Exhibit 281 shows the supply side total NPV for 2025-2039, which is about $8.98 billion in 2018 $. Fixed cost is the largest component, followed by fuel and market costs.

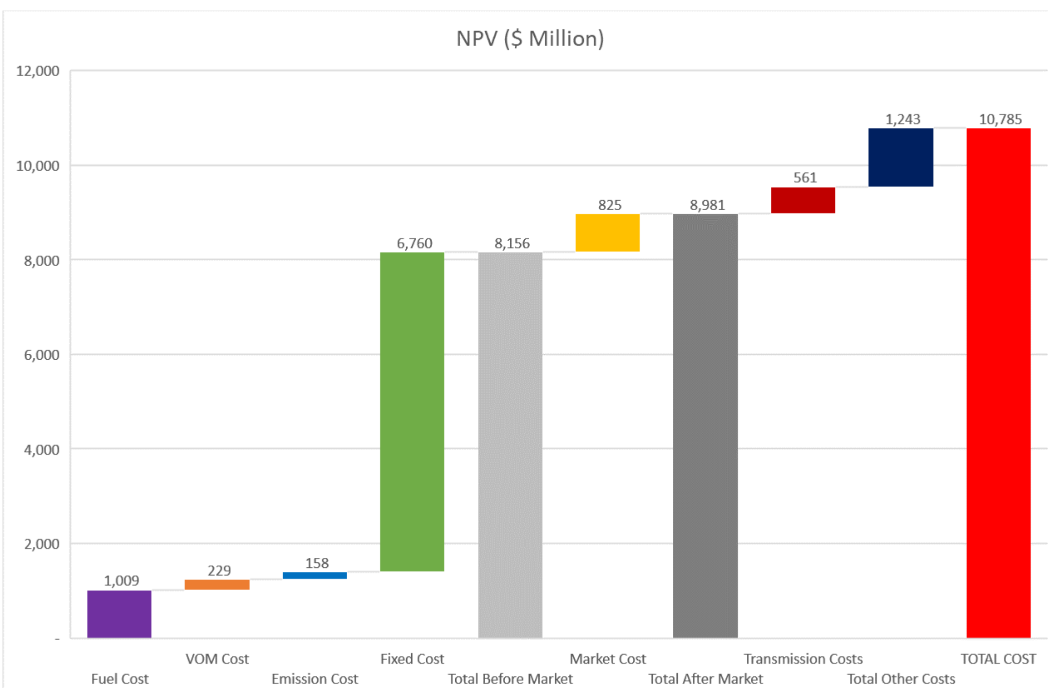
Exhibit 281: Portfolio 5 Generation Resource NPV 2018 $



Source: Siemens

The total NPVRR of this portfolio is approximately $10.79 billion for 2025-2039 in 2018 $.

Exhibit 282: Portfolio 5 All NPVRR with Other Components 2018 $

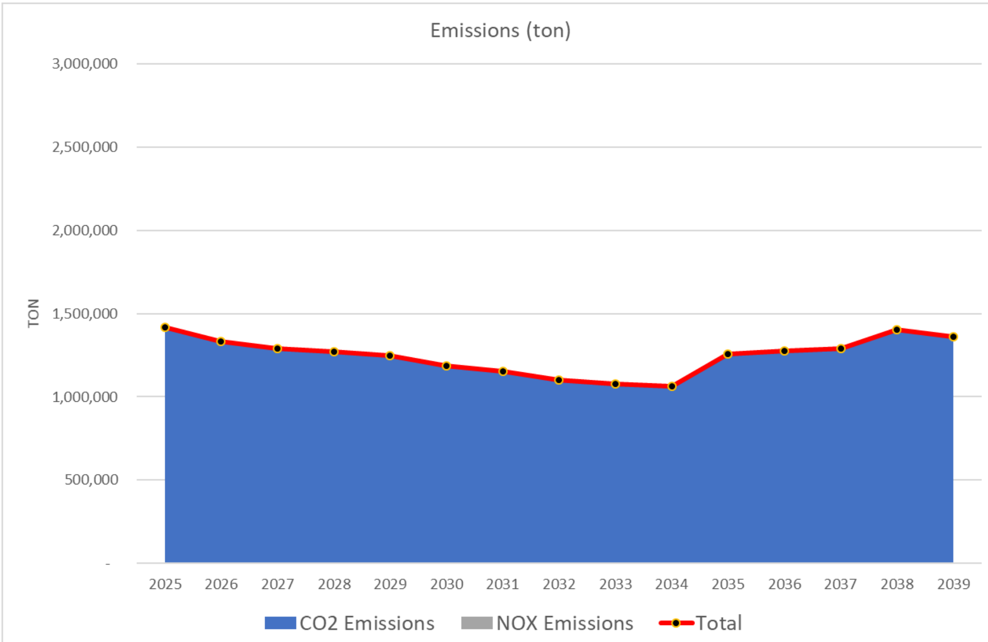


Source: Siemens

Environmental

The emission from this portfolio is shown in Exhibit 283 below. The emission is low compared with other portfolios due to high renewable and low thermal nature in this portfolio.

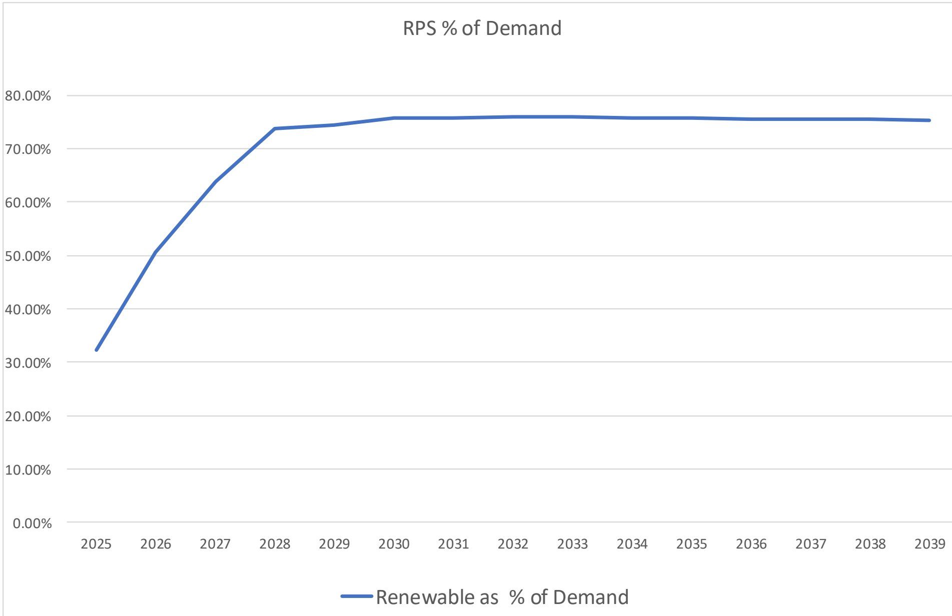
Exhibit 283: Portfolio 5 MLGW Emission by Year



Source: Siemens

This is the high renewable case and the RPS as of % of demand in this portfolio starts at about 32% and reaches very quickly to 75% in 2039 as much renewable generation is built in this portfolio.

Exhibit 284: Portfolio 5 RPS by Year

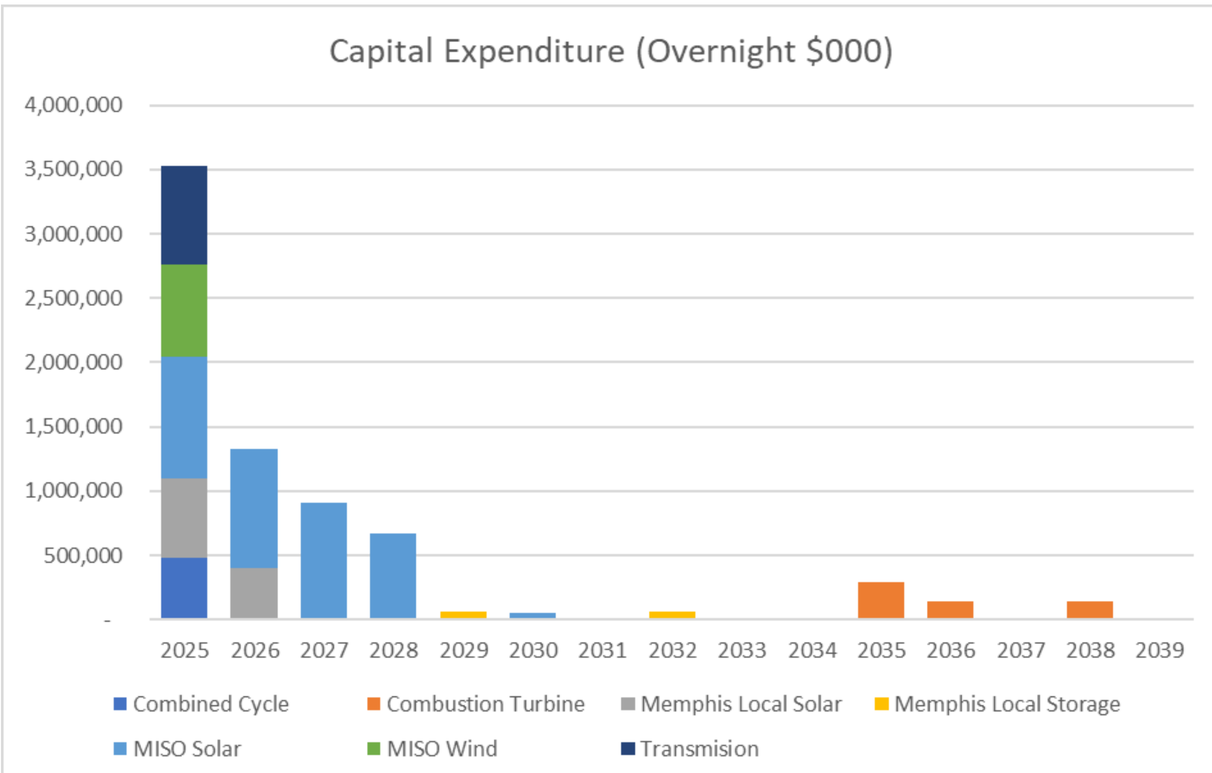


Source: Siemens

Capital Expenditure

Total capital expenditures on generation and transmission are shown in the graph below. Siemens present these capital expenditures in overnight from 2025 to 2039 while the actual drawdown may vary. Most of the CapEx are on the generation side and occur prior to 2025. Note that only the transmission CapEx is expected to be covered by MLGW as the generation CapEx is assumed to be expensed by third parties and recovered via PPA payments from MLGW.

Exhibit 285: Portfolio 5 Overnight Capital Expenditure by Year



Source: Siemens

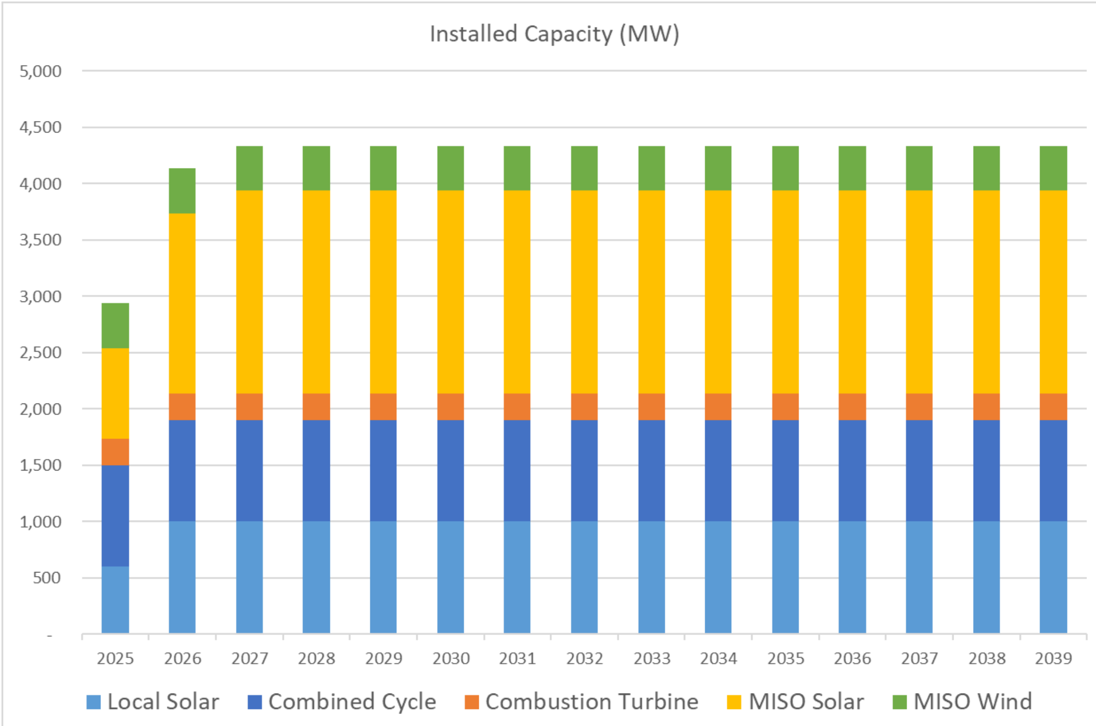
Portfolio 6 (S3S7_BB)

This is the S3S7 low load high gas price portfolio derived from the capacity expansion plan, with the CCGT, CT and solar all accelerated, ran on the base load base gas price conditions.

Capacity Expansion (Buildout)

Exhibit 286 and Exhibit 287 below show the capacity expansion by year. Both local solar and MISO renewables are installed as much and fast as possible. Thermal generations are 2 CCGTs and 1 CT, which were all installed in 2025.

Exhibit 286: Portfolio 6 Installed Capacity by Year



Source: Siemens

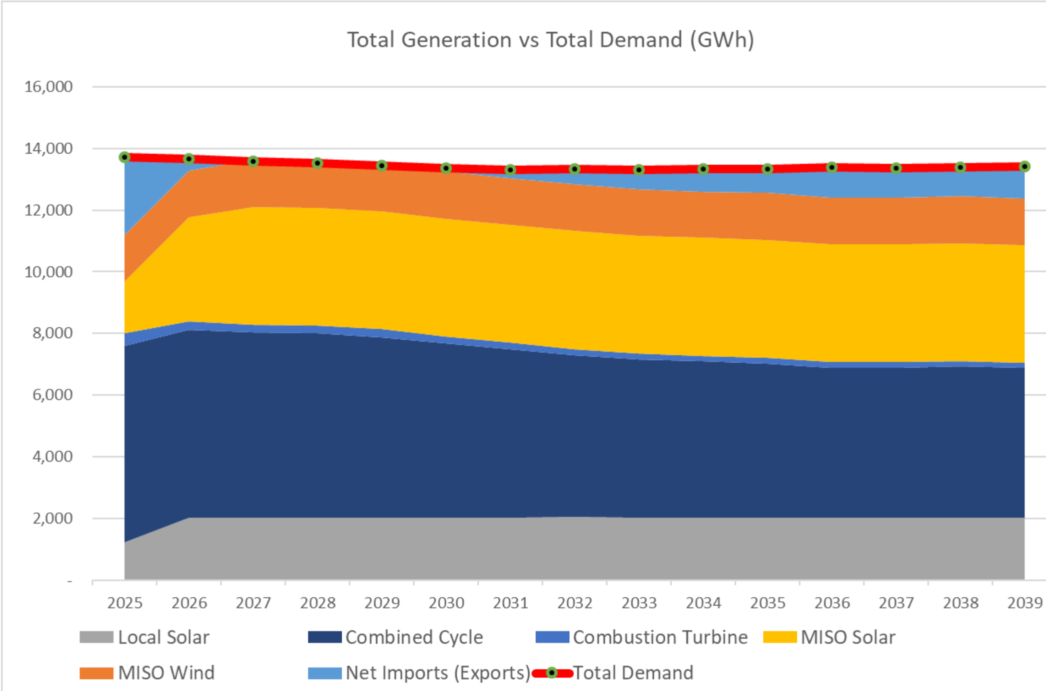
Exhibit 287: Portfolio 6 Installed Capacity by Year (Table)

	Advanced Frame CT	Convl. Frame 7FA CT	1x1 Combined Cycle	Utility Solar	Battery	Arkansas Solar	Arkansas Wind	MISO_Cap	Demand
2025	0	237	900	600	0	800	400	1981	3197
2026	0	0	0	400	0	800	0	1623	3182
2027	0	0	0	0	0	200	0	1570	3168
2028	0	0	0	0	0	0	0	1573	3153
2029	0	0	0	0	0	0	0	1578	3139
2030	0	0	0	0	0	0	0	1582	3124
2031	0	0	0	0	0	0	0	1590	3113
2032	0	0	0	0	0	0	0	1604	3108
2033	0	0	0	0	0	0	0	1626	3110
2034	0	0	0	0	0	0	0	1649	3112
2035	0	0	0	0	0	0	0	1671	3114
2036	0	0	0	0	0	0	0	1693	3116
2037	0	0	0	0	0	0	0	1715	3118
2038	0	0	0	0	0	0	0	1738	3121
2039	0	0	0	0	0	0	0	1761	3123

Source: Siemens

Energy generated from all resources stay relatively flat over the years.

Exhibit 288: Portfolio 6 Energy by Resource Type by Year

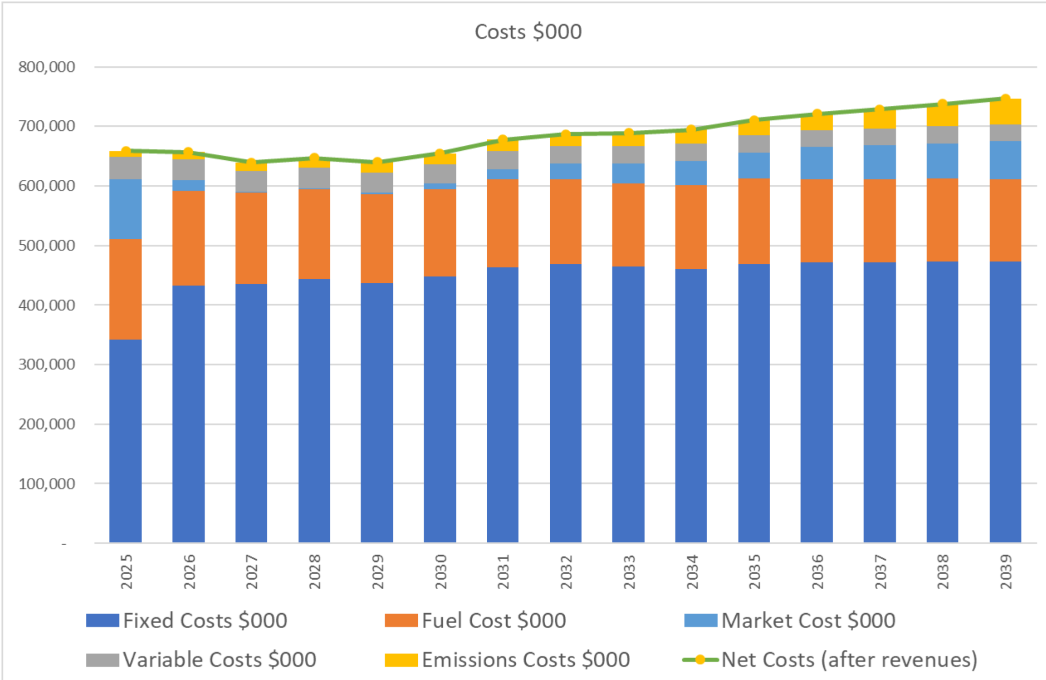


Source: Siemens

Portfolio Costs

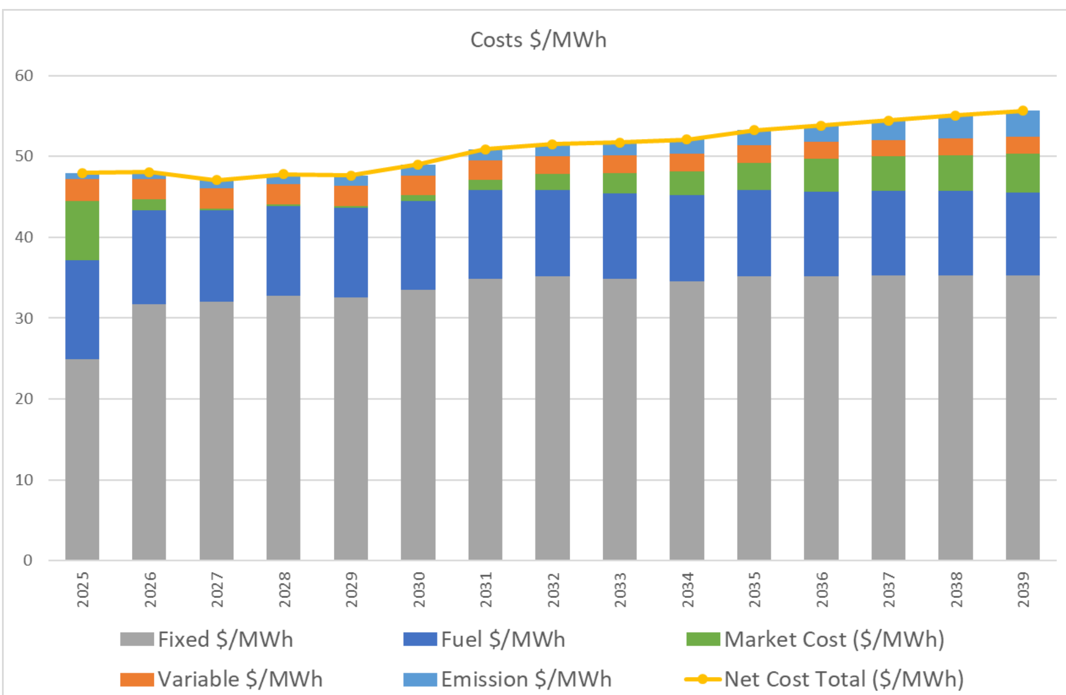
Exhibit 289 shows the supply side NPV cost by year. As can be seen the cost is about $690 million per year (2018 $) or $51/MWh, where fixed cost is the largest components due to the investments in generation, followed by cost of fuels.

Exhibit 289: Portfolio 6 Cost Components 2018 $



Source: Siemens

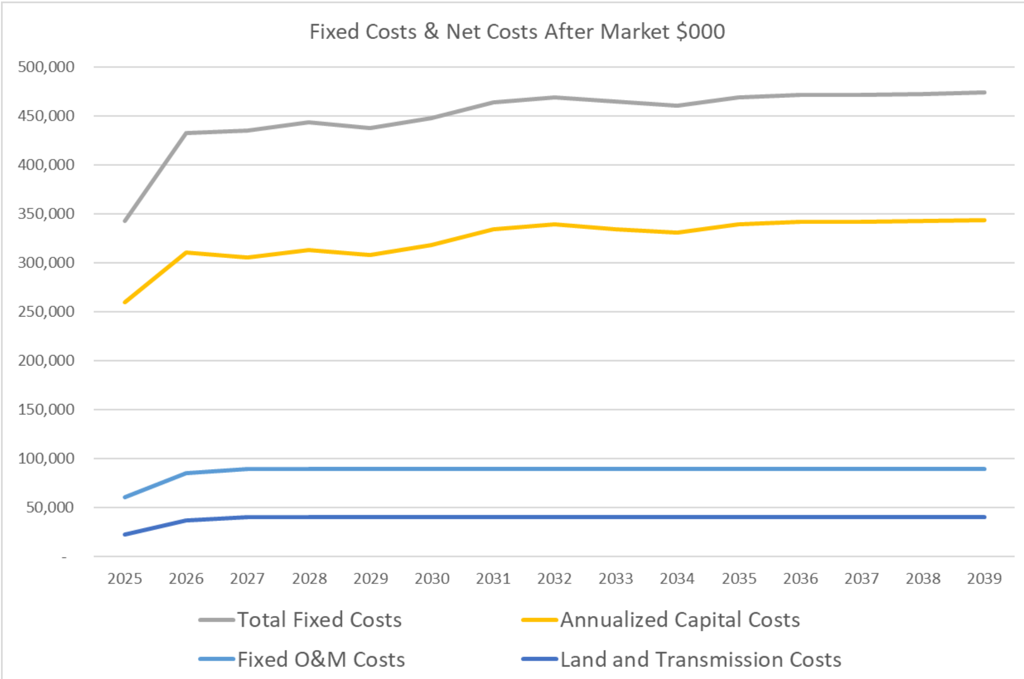
Exhibit 290: Portfolio 6 Cost Components 2018 $/MWh



Source: Siemens

Exhibit 291 shows the breakdown of total fixed costs by component, where the majority comes from the base capital costs on generation.

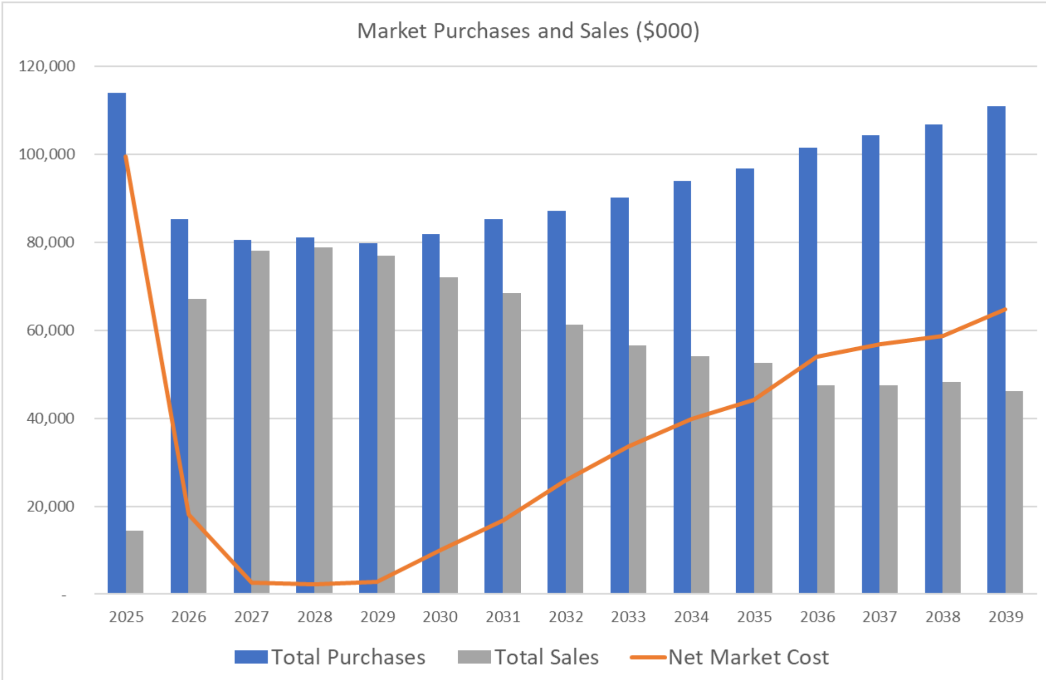
Exhibit 291: Portfolio 6 Fixed Cost Components 2018 $



Source: Siemens

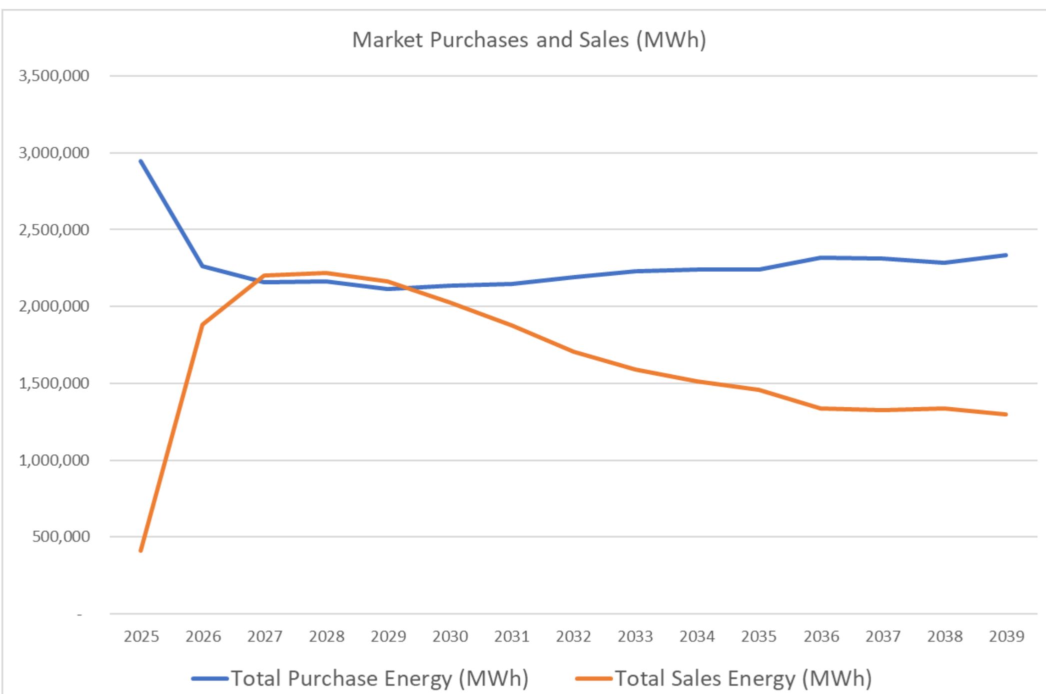
Market purchases and sales as also important components. The market purchases by MLGW system are projected to be increasing slightly while the sales are decreasing.

Exhibit 292: Portfolio 6 Market Purchases and Sales 2018 $



Source: Siemens

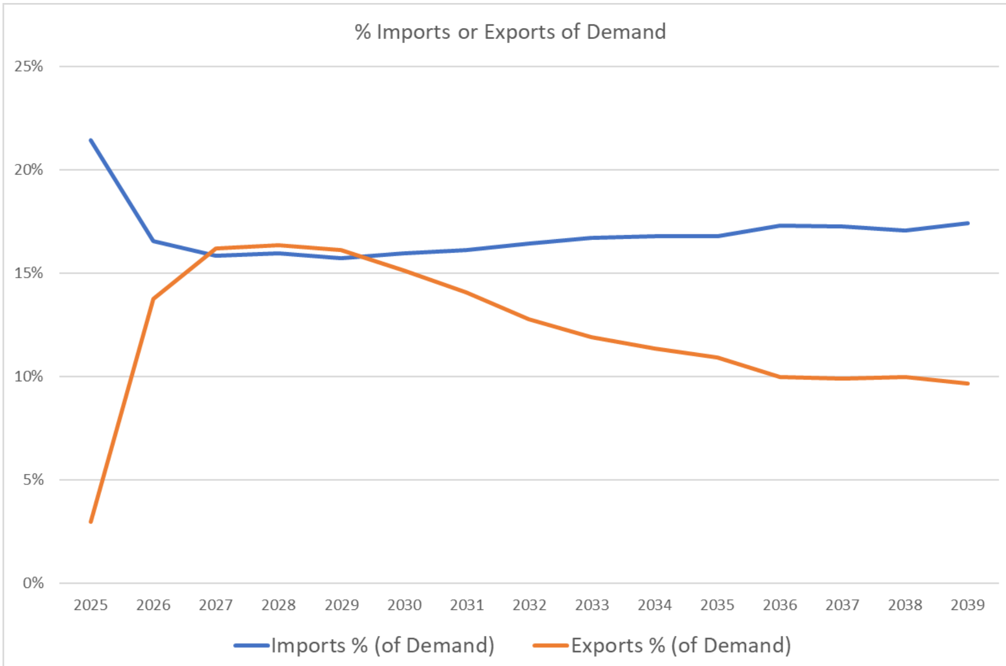
Exhibit 293: Portfolio 6 Market Purchases and Sales in Energy



Source: Siemens

Exhibit 294 and Exhibit 295 the purchases sales amount in energy and as % of demand, respectively. It shows the high market risk towards the end of the planning years of this portfolio.

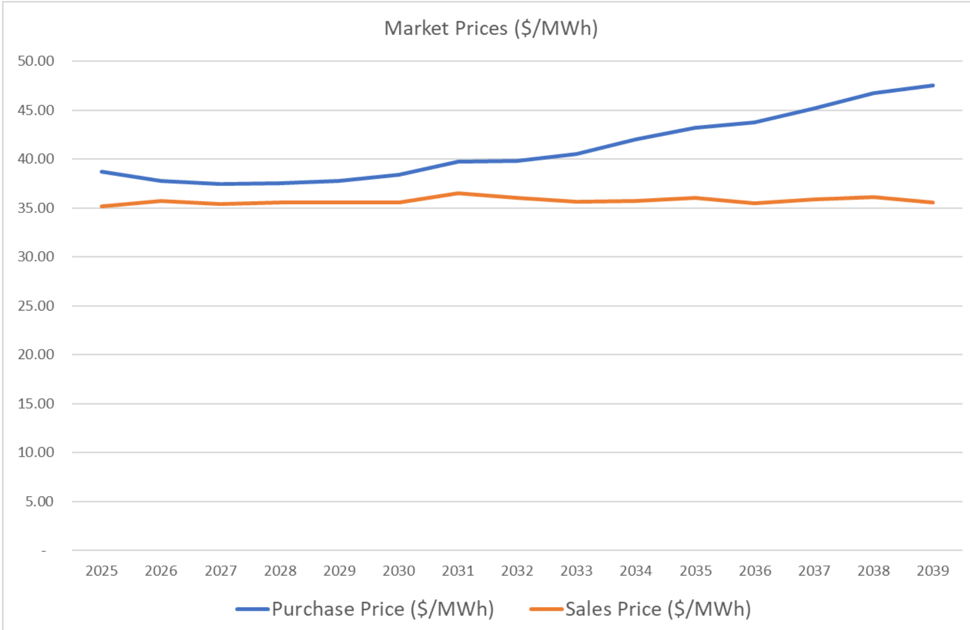
Exhibit 294: Portfolio 6 Market Purchases and Sales as % of Demand



Source: Siemens

The risk can also be appreciated looking at the difference between purchase price (high) and sale price (low). The more purchases this portfolio needs, the higher risk it has, especially the price is estimated to be high in the far future.

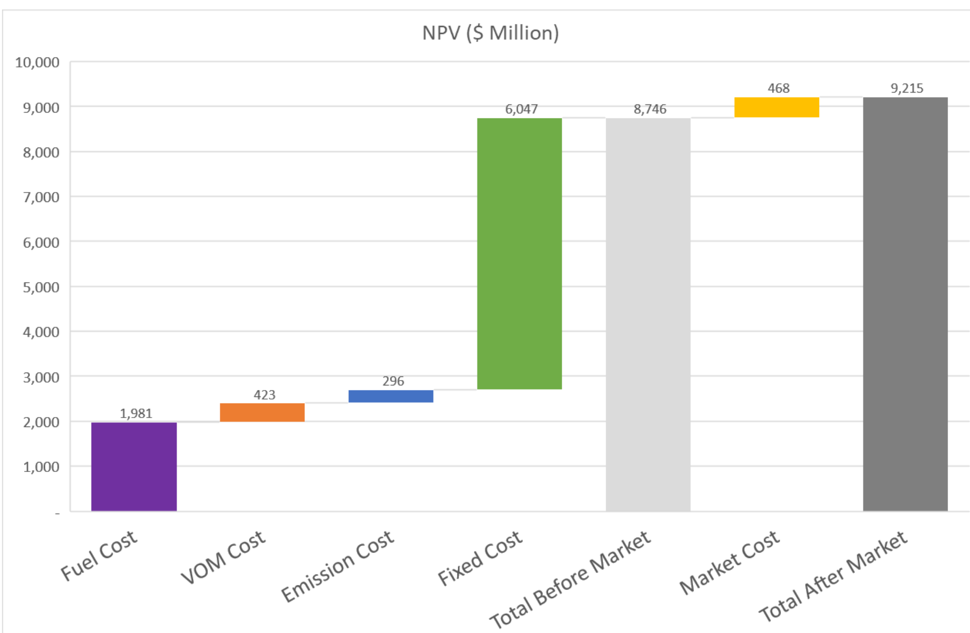
Exhibit 295: Portfolio 6 Market Purchases and Sales Prices $/MWh



Source: Siemens

Exhibit 296 shows the supply side total NPV for 2025-2039, which is about $9.22 billion in 2018 $. Fixed cost is the largest component, followed by fuel and market costs.

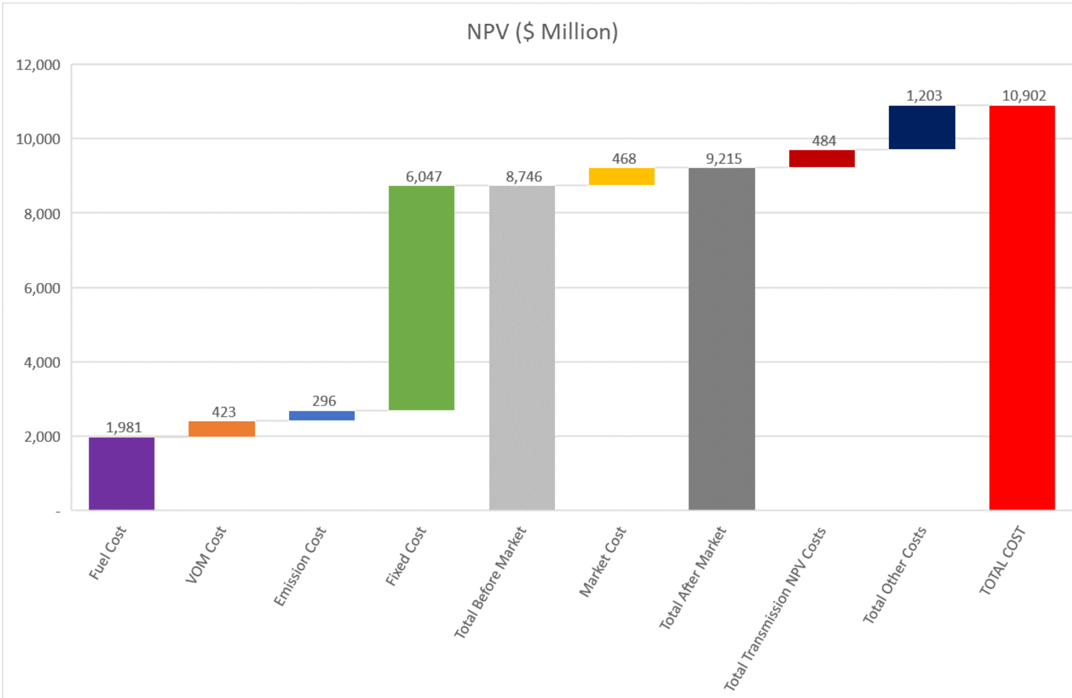
Exhibit 296: Portfolio 6 Generation Resource NPV 2018 $



Source: Siemens

The total NPVRR of this portfolio is approximately $10.9 billion for 2025-2039 in 2018 $.

Exhibit 297: Portfolio 6 All NPVRR with Other Components 2018 $

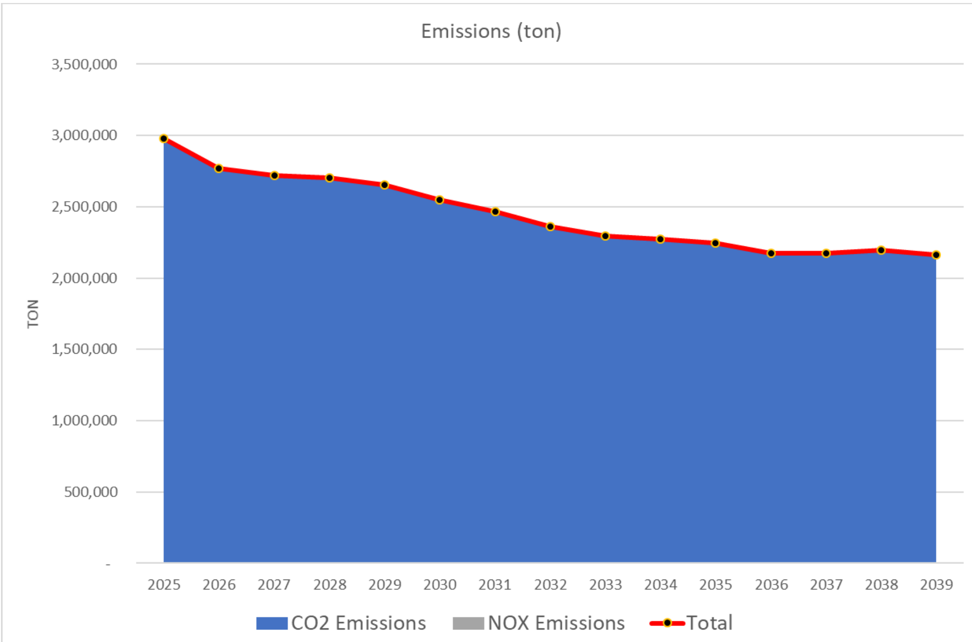


Source: Siemens

Environmental

The emission from this portfolio is shown in the graph below. As energy from thermal generation is coming down, the capacity factor of the units decreases which resulted in decreased CO_2 emission over the years.

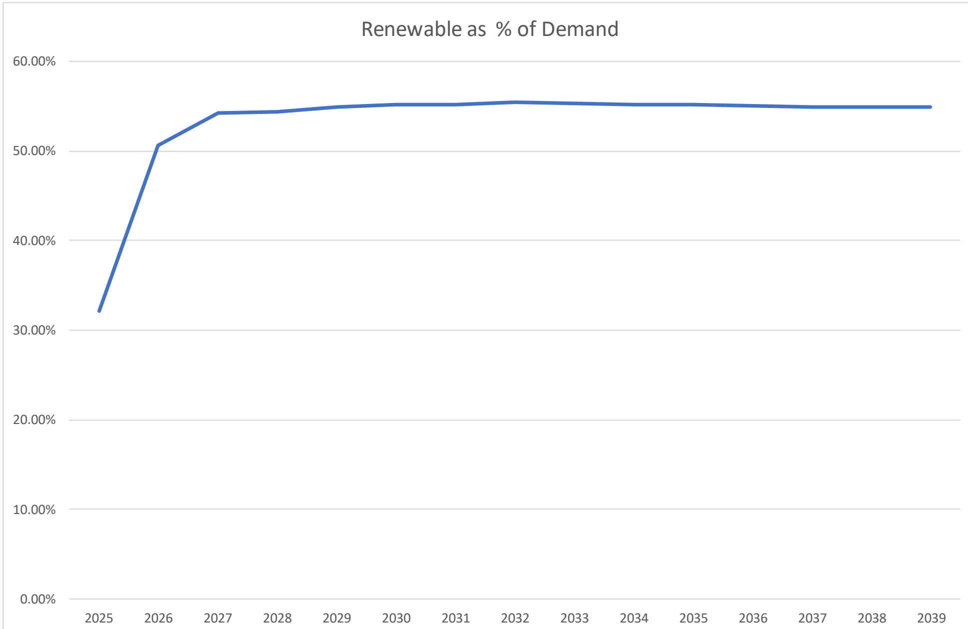
Exhibit 298: Portfolio 6 MLGW Emission by Year



Source: Siemens

The RPS as of the demand in energy of this portfolio starts at about 32% and quickly reaches to about 55% and stays flat until 2039.

Exhibit 299: Portfolio 6 RPS by Year

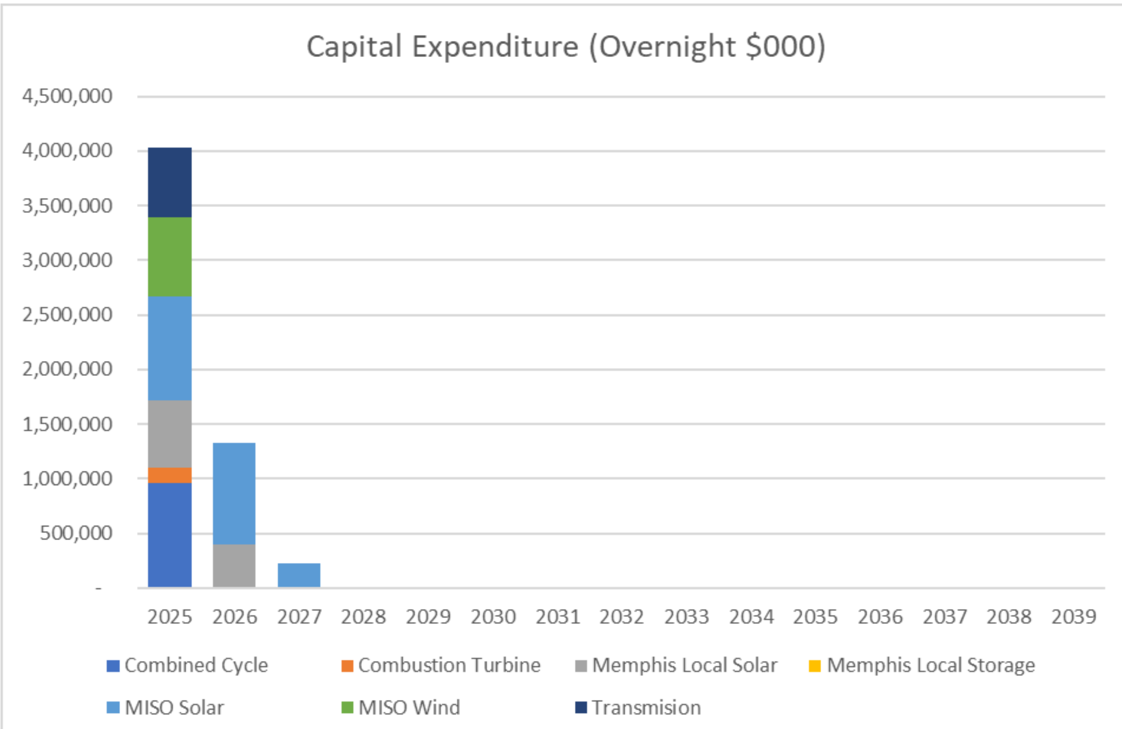


Source: Siemens

Capital Expenditure

Total capital expenditures on generation and transmission are shown in the graph below. Siemens present these capital expenditures in overnight from 2025 to 2039 while the actual drawdown may vary. Most of the CapEx are on the generation side and occur prior to 2025. Note that only the transmission CapEx is expected to be covered by MLGW as the generation CapEx is assumed to be expensed by third parties and recovered via PPA payments from MLGW.

Exhibit 300: Portfolio 6 Overnight Capital Expenditure by Year



Source: Siemens

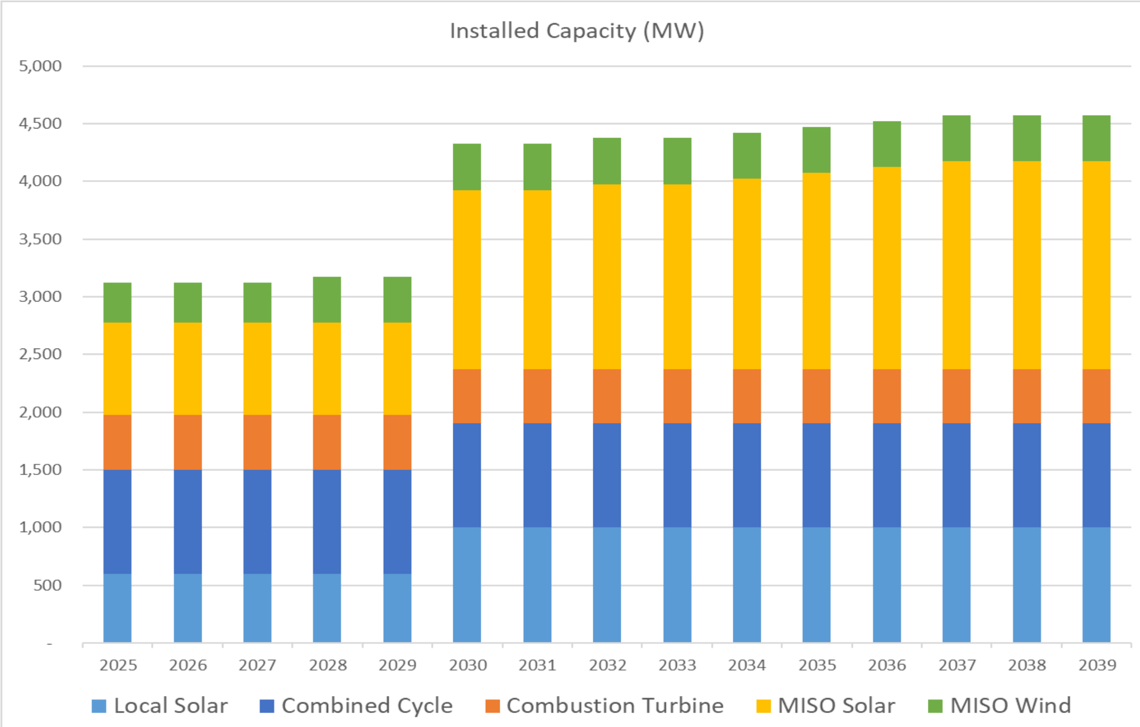
Portfolio 7 (S3S1_2CT)

This is the modified portfolio derived from the S3S1, with one additional CT built in 2025 due to resource adequacy concern.

Capacity Expansion (Buildout)

Exhibit 301 show the capacity expansion by year. It is the same buildout except the additional CT in 2025 as compared to the S3S1 case.

Exhibit 301: Portfolio 7 Installed Capacity by Year



Source: Siemens

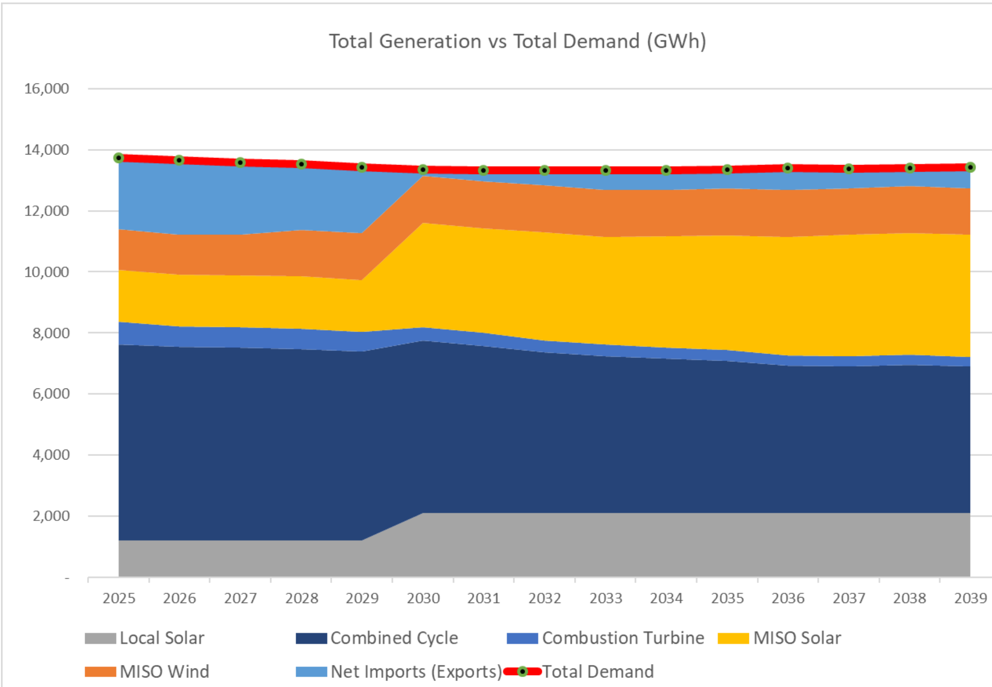
Exhibit 302: Portfolio 7 Installed Capacity by Year (Table)

	Advanced Frame CT	Convl. Frame 7FA CT	1x1 Combined Cycle	Utility Solar	Battery	Arkansas Solar	Arkansas Wind	MISO_Cap	Demand
2025	0	474	900	600	0	800	350	1779	3197
2026	0	0	0	0	0	0	0	1772	3182
2027	0	0	0	0	0	0	0	1767	3168
2028	0	0	0	0	0	0	50	1753	3153
2029	0	0	0	0	0	0	0	1748	3139
2030	0	0	0	400	0	750	0	1437	3124
2031	0	0	0	0	0	0	0	1444	3113
2032	0	0	0	0	0	50	0	1444	3108
2033	0	0	0	0	0	0	0	1465	3110
2034	0	0	0	0	0	50	0	1474	3112
2035	0	0	0	0	0	50	0	1483	3114
2036	0	0	0	0	0	50	0	1494	3116
2037	0	0	0	0	0	50	0	1505	3118
2038	0	0	0	0	0	0	0	1528	3121
2039	0	0	0	0	0	0	0	1550	3123

Source: Siemens

Energy generated from thermal generation decreases over the years while energy coming from renewables increases, especially starting 2030 when the cost of renewables is projected to be much more competitive. Imported energy goes down after 2030 as well.

Exhibit 303: Portfolio 7 Energy by Resource Type by Year

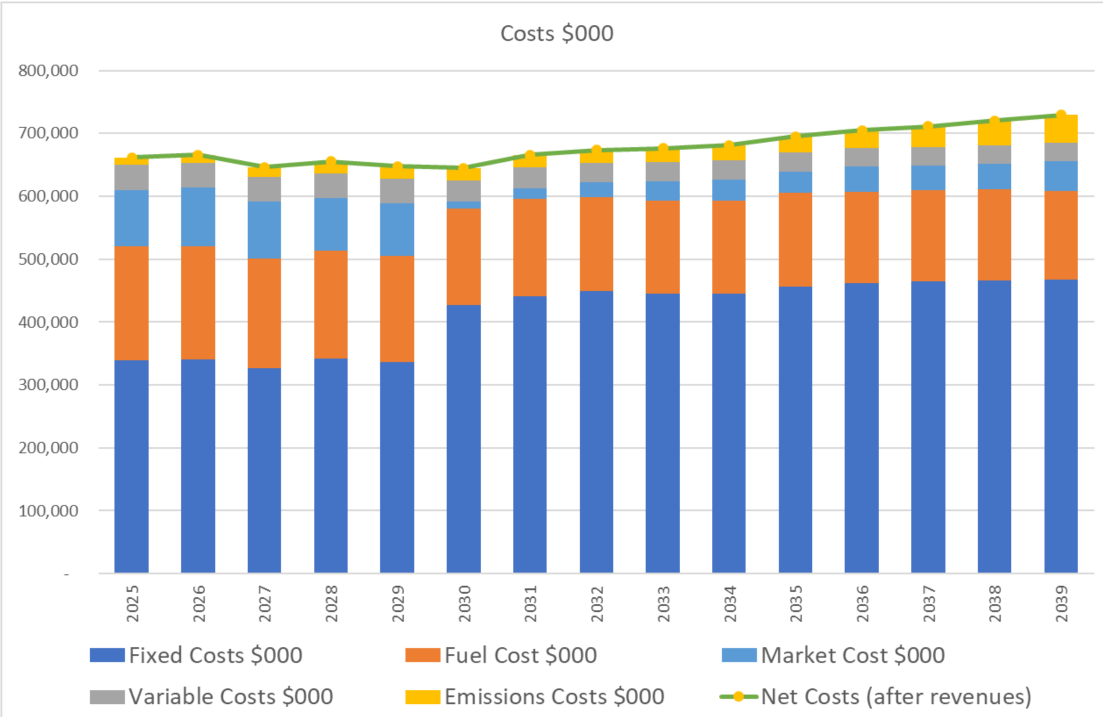


Source: Siemens

Portfolio Costs

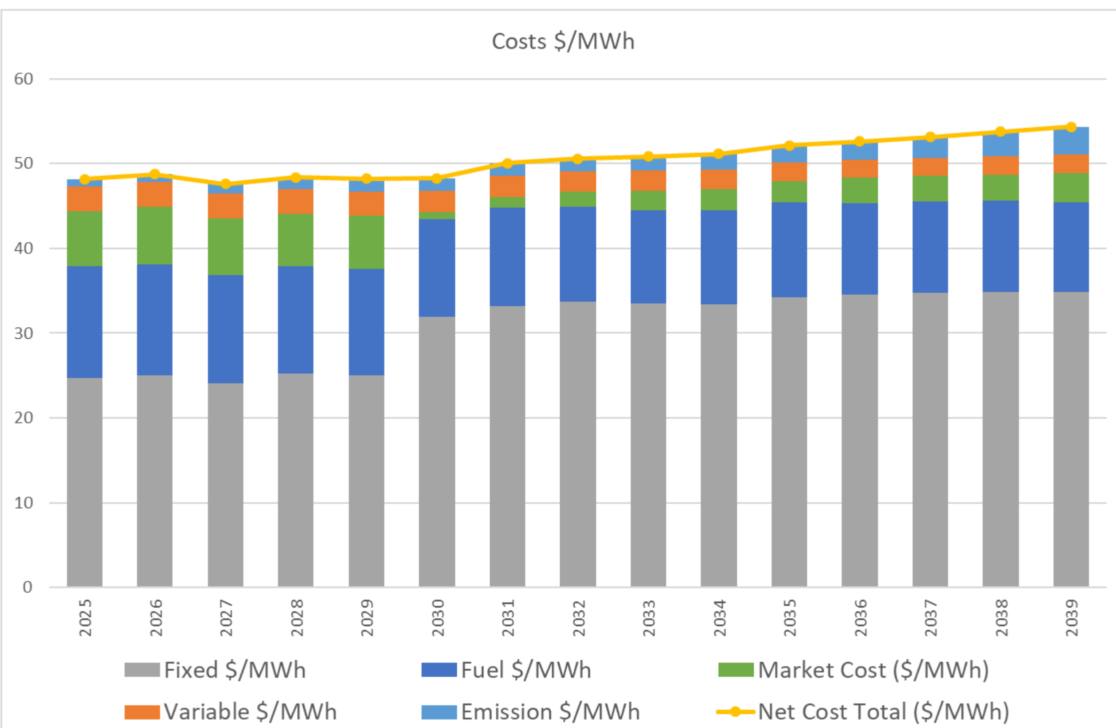
Exhibit 304 shows the supply side NPV cost by year. As can be seen the cost is about $680 million per year (2018 $) or $50/MWh, where fixed cost is the largest components due to the investments in generation, followed by cost of fuels and market purchases.

Exhibit 304: Portfolio 7 Cost Components 2018 $



Source: Siemens

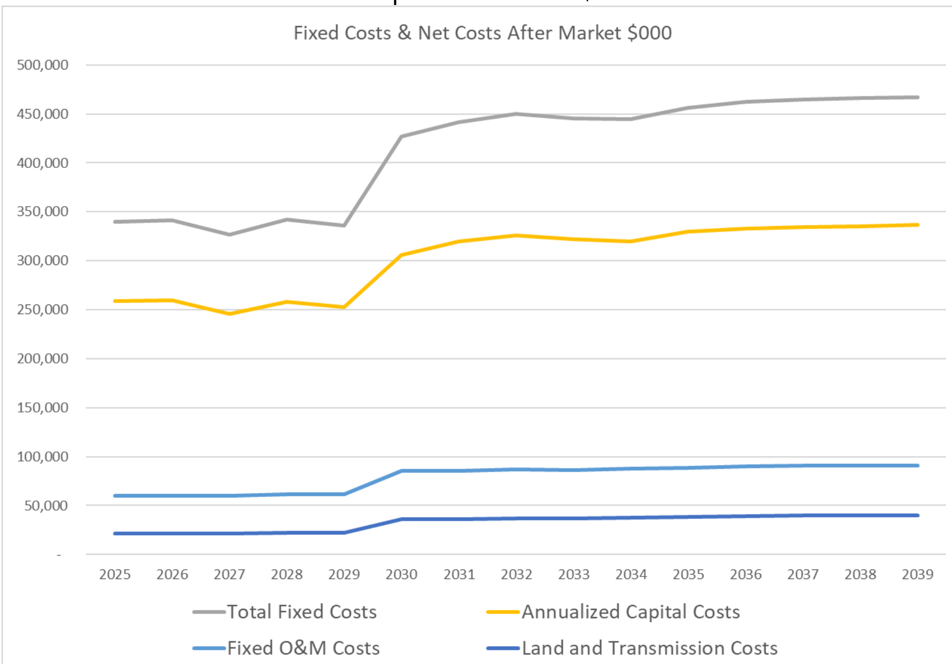
Exhibit 305: Portfolio 7 Cost Components 2018 $/MWh



Source: Siemens

Exhibit 306 shows the breakdown of total fixed costs by component, where the majority comes from the base capital costs on generation.

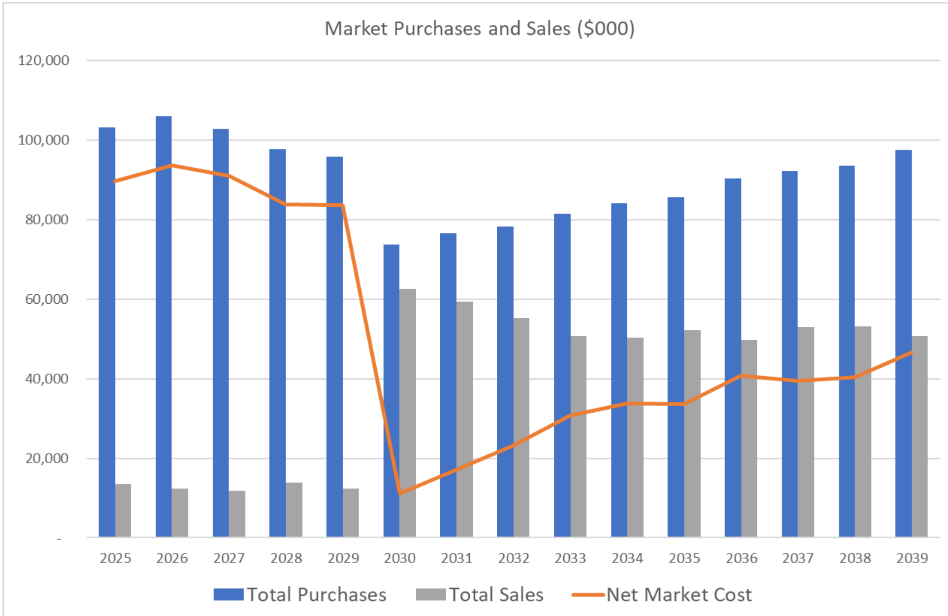
Exhibit 306: Portfolio 7 Fixed Cost Components 2018 $



Source: Siemens

Market purchases and sales are also important components. The market purchases by MLGW decreased and then increased over the years while the sales showing increased trend, especially starting 2030.

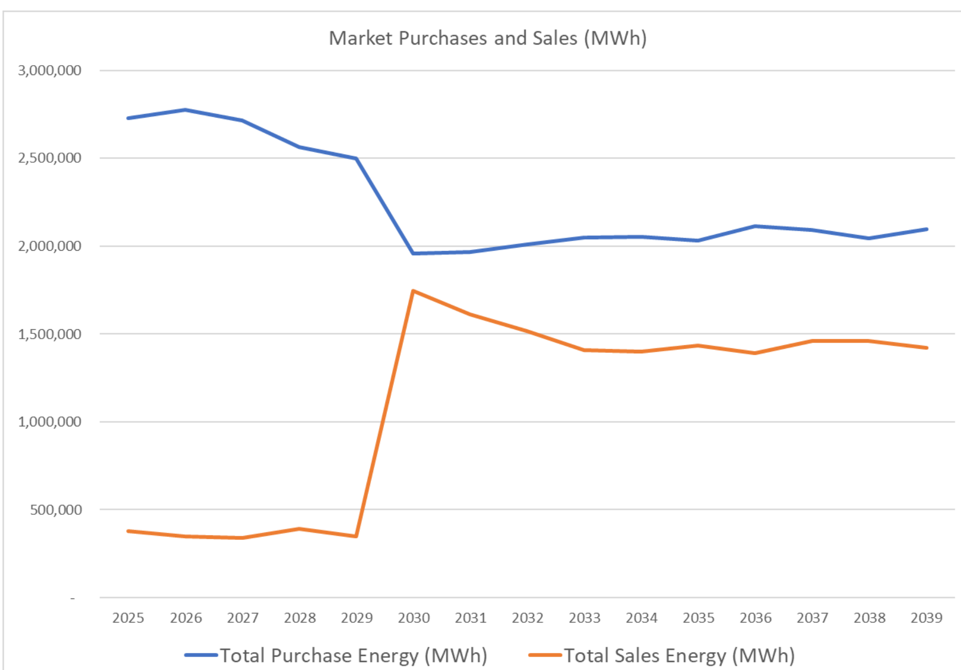
Exhibit 307: Portfolio 7 Market Purchases and Sales 2018 $



Source: Siemens

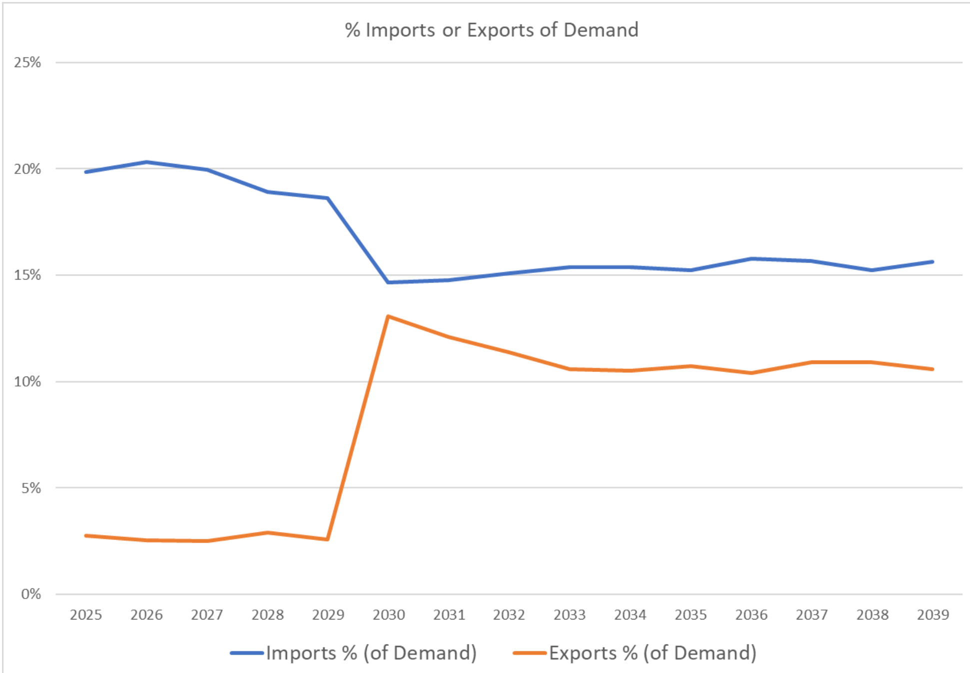
Exhibit 308 and Exhibit 309 show the purchases and sales amount in energy and as % of demand, respectively. It shows the high market risk in the beginning of the planning years of this portfolio.

Exhibit 308: Portfolio 7 Market Purchases and Sales in Energy



Source: Siemens

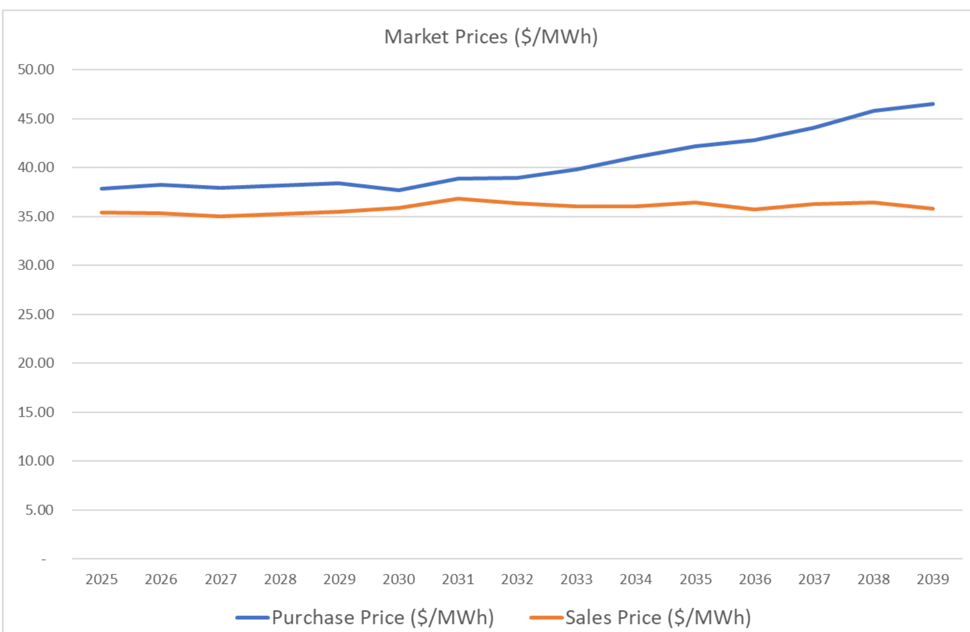
Exhibit 309: Portfolio 7 Market Purchases and Sales as % of Demand



Source: Siemens

The risk can also be appreciated by looking at the difference between purchase price (high) and sale price (low). The more purchase this portfolio needs, the higher risk.

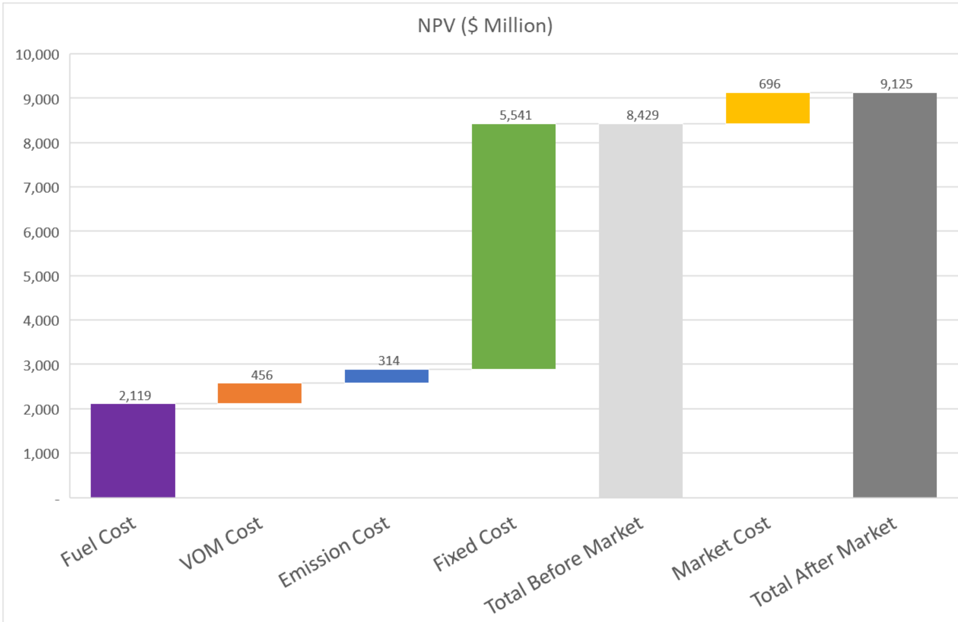
Exhibit 310: Portfolio 7 Market Purchases and Sales Prices $/MWh



Source: Siemens

Exhibit 311 shows the supply side total NPV for 2025-2039, which is about $9.13 billion in 2018 $. Fixed cost is the largest component, followed by fuel and market costs.

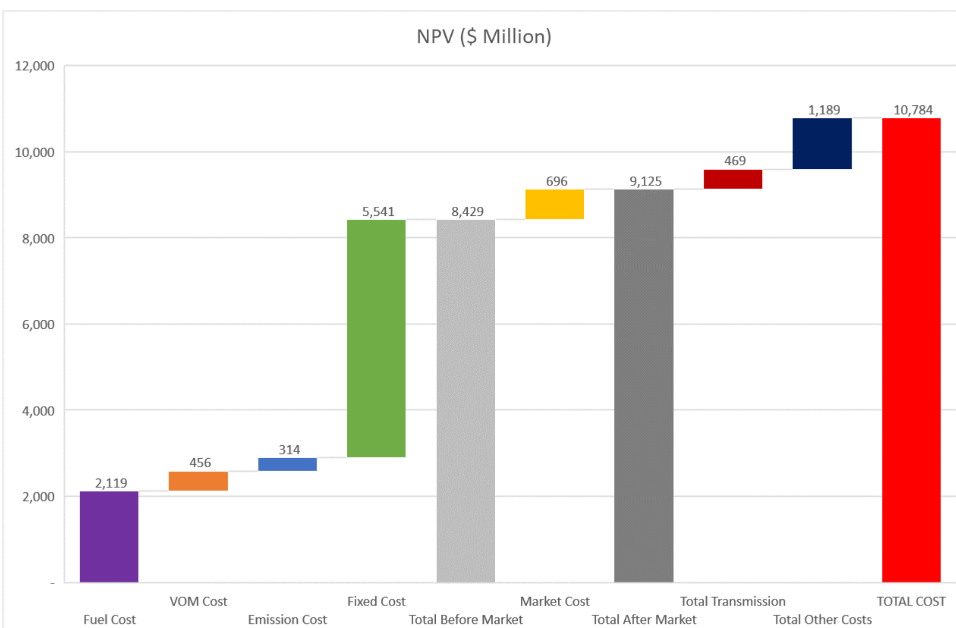
Exhibit 311: Portfolio 7 Generation Resource NPV 2018 $



Source: Siemens

The total NPVRR of this portfolio is approximately $10.78 billion for 2025-2039 in 2018 $.

Exhibit 312: Portfolio 7 All NPVRR with Other Components 2018 $

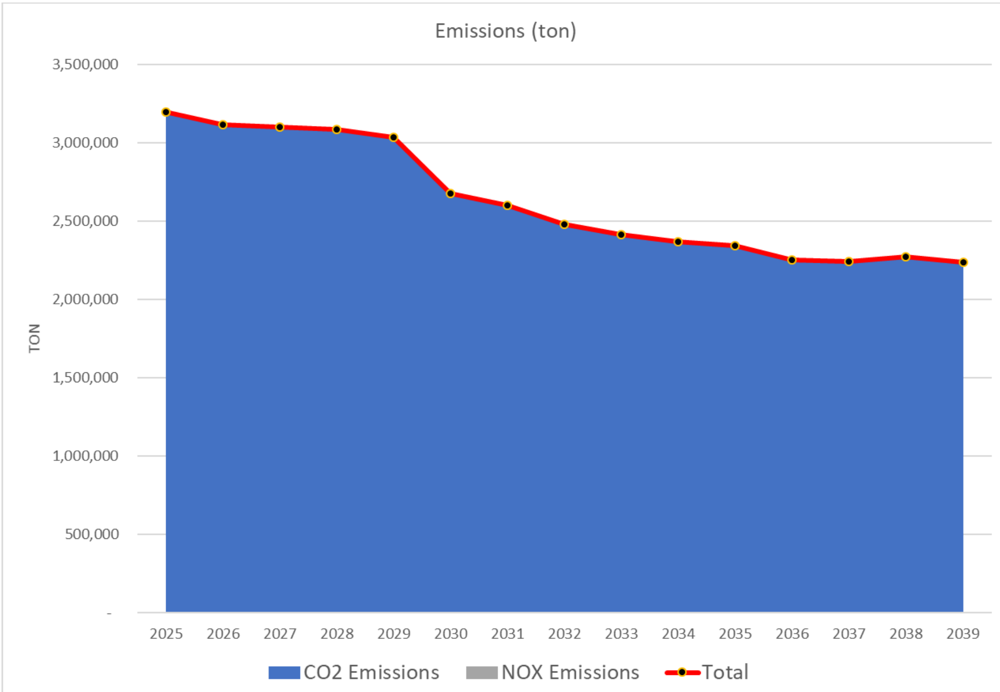


Source: Siemens

Environmental

The emission from this portfolio is shown in Exhibit 313. As energy from thermal generation is coming down, the capacity factor of the units decreases which resulted in decreased CO_2 emission over the years.

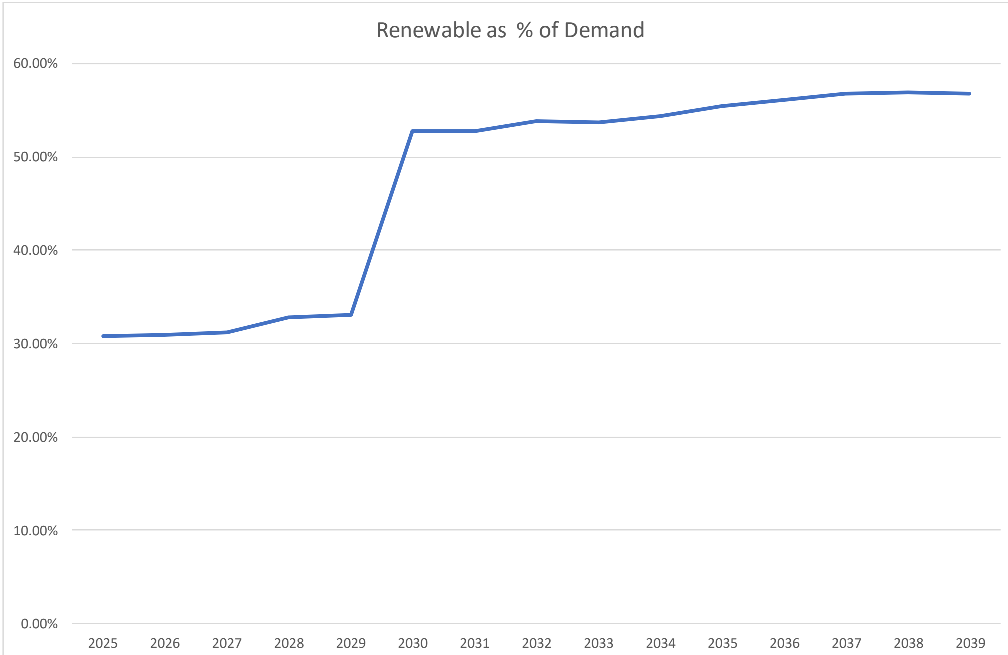
Exhibit 313: Portfolio 7 MLGW Emission by Year



Source: Siemens

And the RPS as of demand in energy of this portfolio starts at about 30% and reaches just over 55% in 2039 as more renewable generations are built.

Exhibit 314: Portfolio 7 RPS by Year

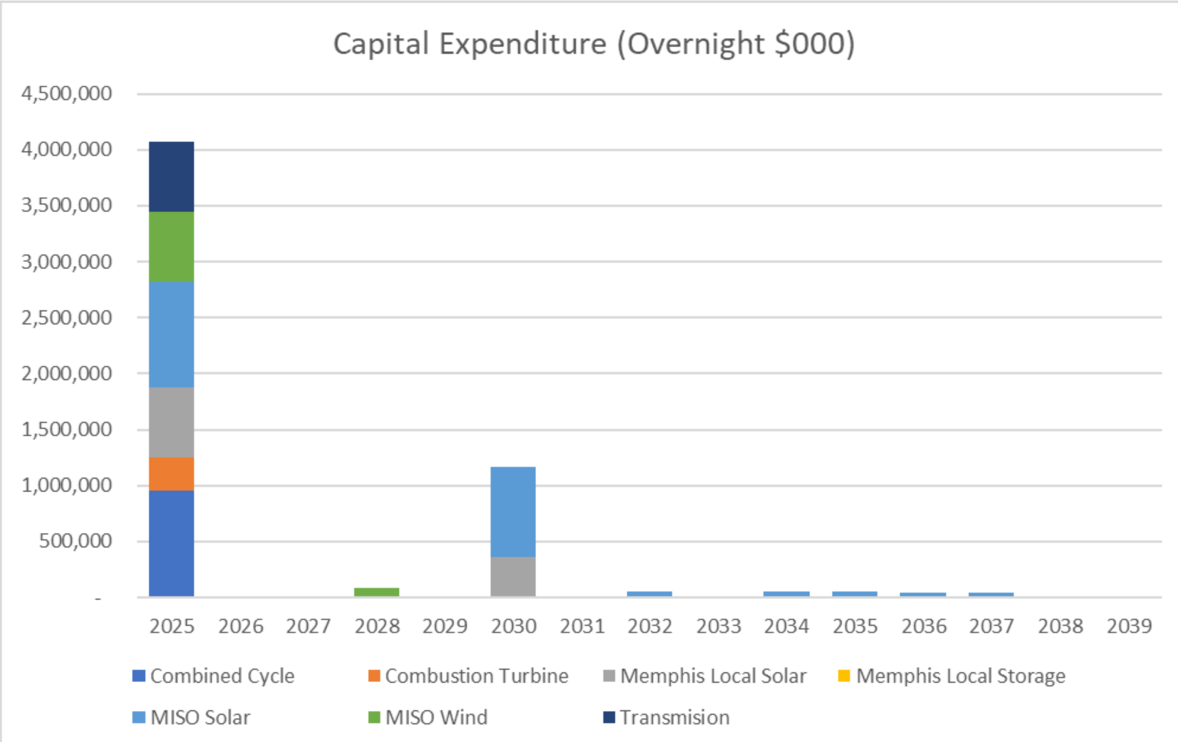


Source: Siemens

Capital Expenditure

Total capital expenditures on generation and transmission are shown in Exhibit 315. Siemens present these capital expenditures in overnight from 2025 to 2039 while the actual drawdown may vary. Most of the CapEx are on the generation side and occur prior to 2025. Note that only the transmission CapEx is expected to be covered by MLGW as the generation CapEx is assumed to be expensed by third parties and recovered via PPA payments from MLGW.

Exhibit 315: Portfolio 7 Overnight Capital Expenditure by Year



Source: Siemens

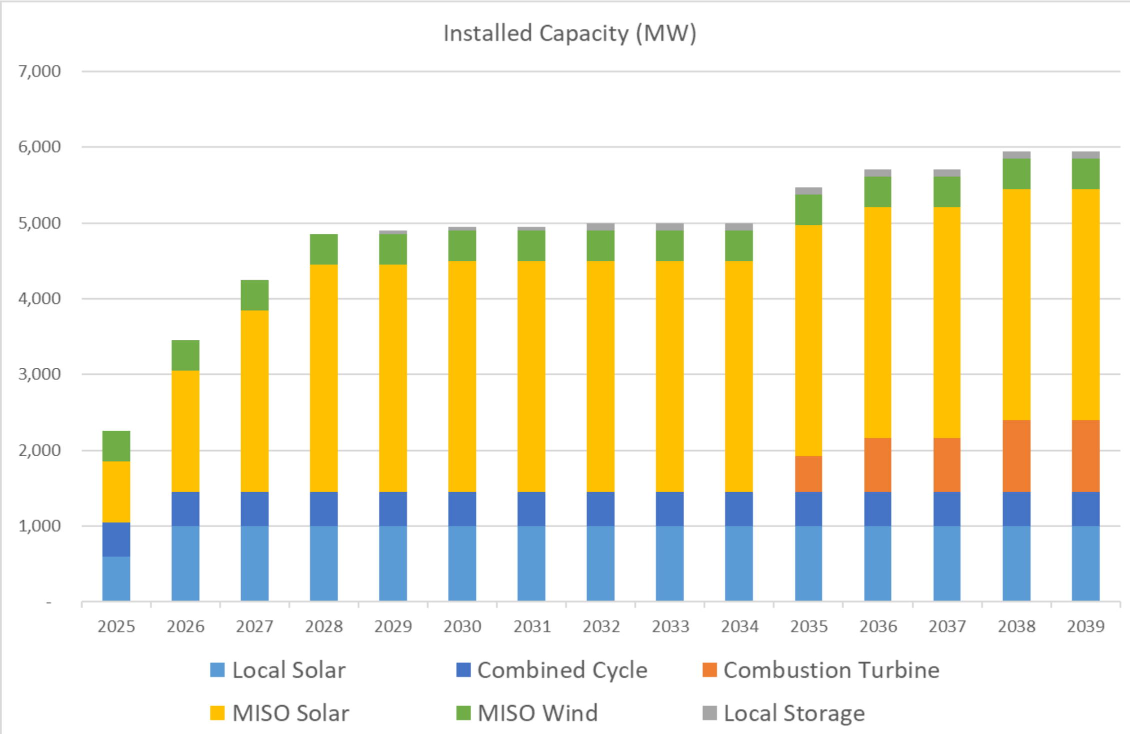
Portfolio 8 (S3S7_2CT)

This is the modified portfolio derived from the S3S7 plan, with an additional CT installed in 2025 due to resource adequacy concern.

Capacity Expansion (Buildout)

Exhibit 316 and Exhibit 317 below show the capacity expansion by year. Local solar and MISO solar were installed as much and quickly as possible. Thermal generation is installed all in first year 2025, 2 CCGTs and 2CTs.

Exhibit 316: Portfolio 8 Installed Capacity by Year



Source: Siemens

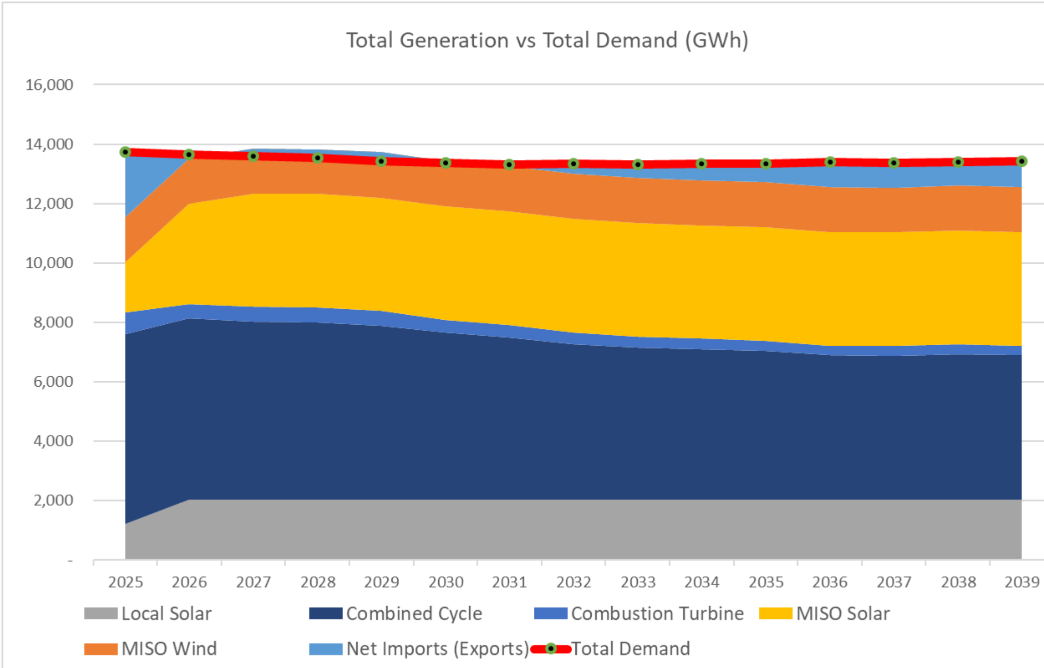
Exhibit 317: Portfolio 8 Installed Capacity by Year (Table)

	Advanced Frame CT	Convl. Frame 7FA CT	1x1 Combined Cycle	Utility Solar	Battery	Arkansas Solar	Arkansas Wind	MISO_Cap	Demand
2025	0	474	900	600	0	800	400	1771	3197
2026	0	0	0	400	0	800	0	1413	3182
2027	0	0	0	0	0	200	0	1359	3168
2028	0	0	0	0	0	0	0	1363	3153
2029	0	0	0	0	0	0	0	1368	3139
2030	0	0	0	0	0	0	0	1371	3124
2031	0	0	0	0	0	0	0	1379	3113
2032	0	0	0	0	0	0	0	1394	3108
2033	0	0	0	0	0	0	0	1416	3110
2034	0	0	0	0	0	0	0	1438	3112
2035	0	0	0	0	0	0	0	1460	3114
2036	0	0	0	0	0	0	0	1483	3116
2037	0	0	0	0	0	0	0	1505	3118
2038	0	0	0	0	0	0	0	1528	3121
2039	0	0	0	0	0	0	0	1550	3123

Source: Siemens

Energy generated from various resources stay very flat over the planning years.

Exhibit 318: Portfolio 8 Energy by Resource Type by Year

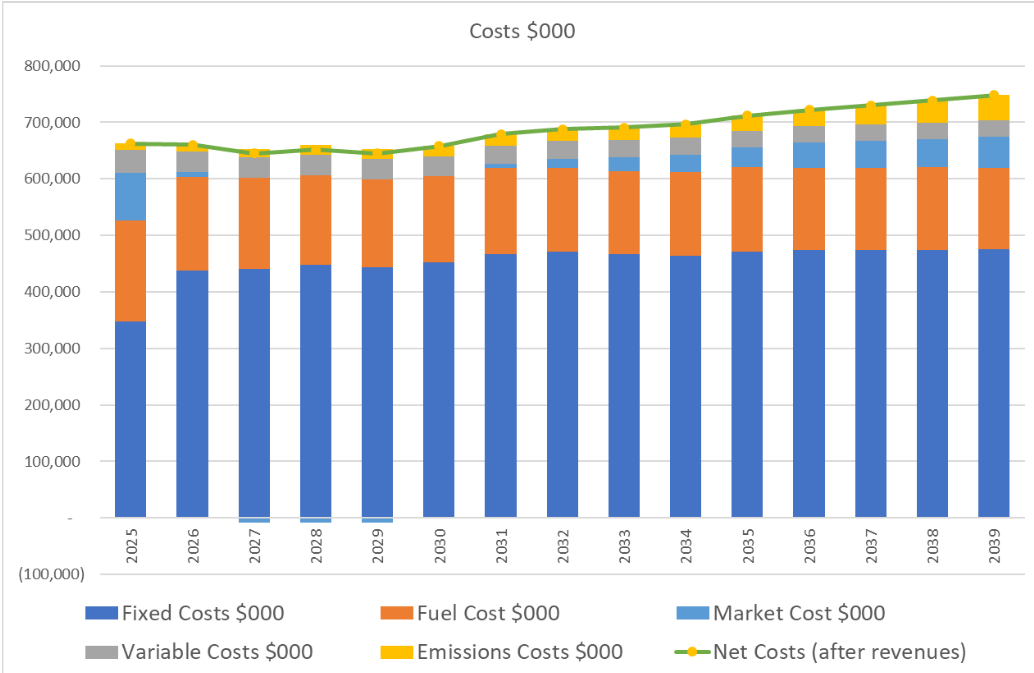


Source: Siemens

Portfolio Costs

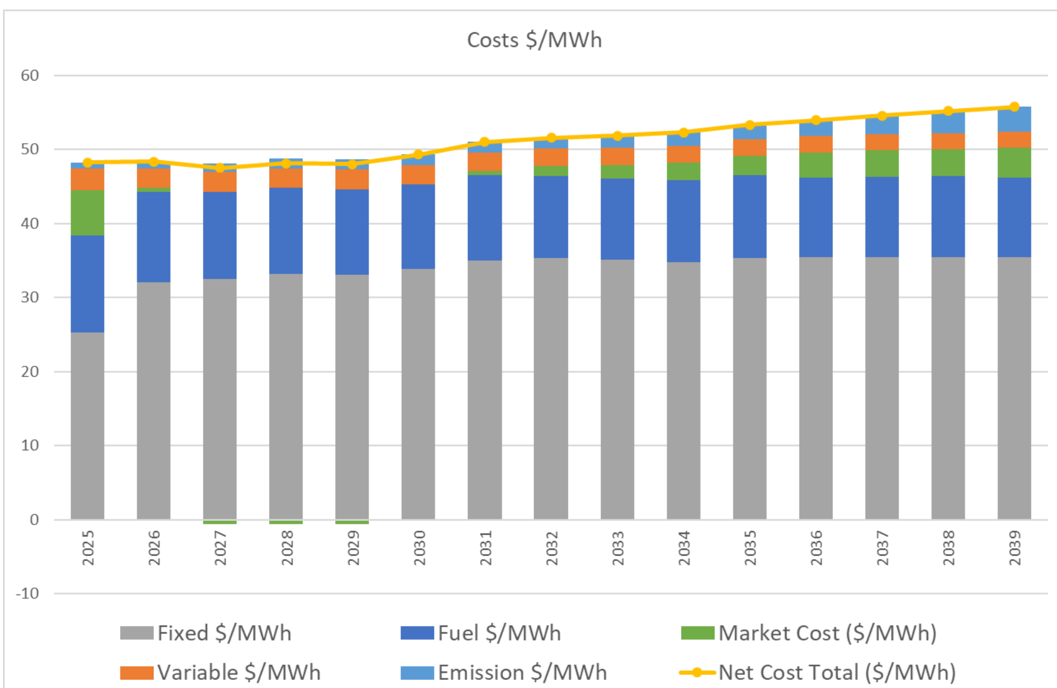
Exhibit 319 shows the supply side NPV cost by year. As can be seen the cost is about $690 million per year (2018 $) or $51/MWh, where fixed cost is the largest component due to the investments in generations, followed by cost of fuels.

Exhibit 319: Portfolio 8 Cost Components 2018 $



Source: Siemens

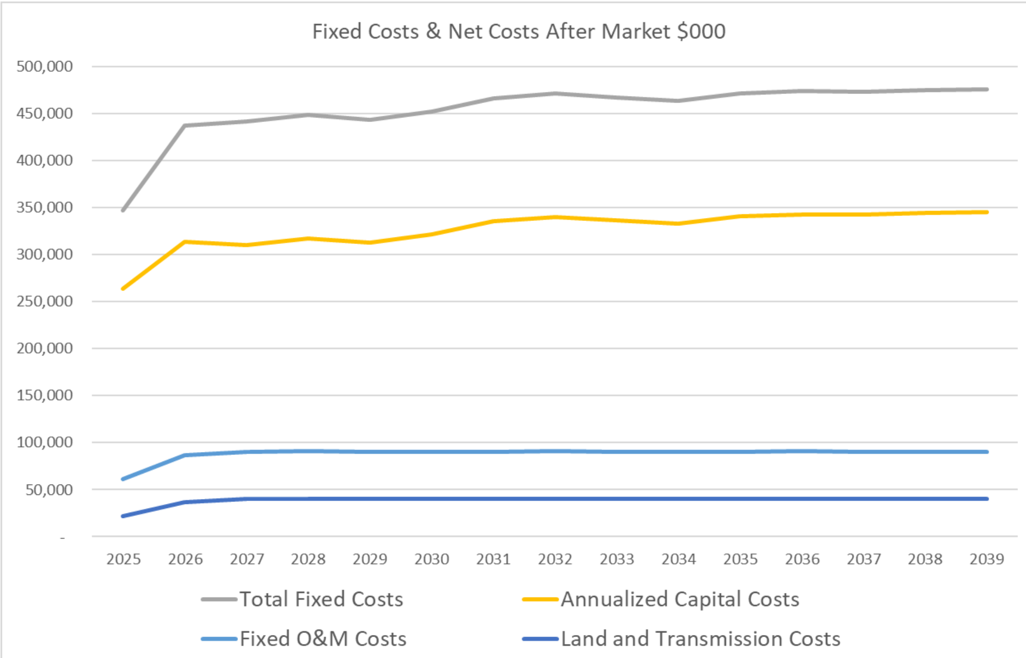
Exhibit 320: Portfolio 8 Cost Components 2018 $/MWh



Source: Siemens

Exhibit 321 shows the breakdown of total fixed costs by component, where the majority comes from the base capital costs on generation.

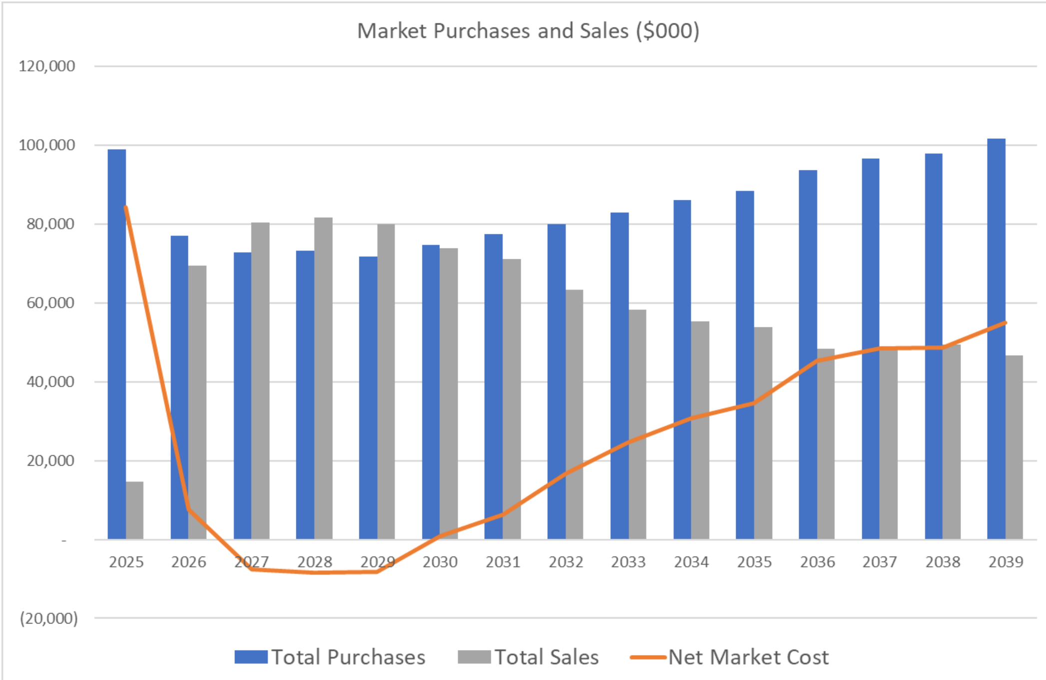
Exhibit 321: Portfolio 8 Fixed Cost Components 2018 $



Source: Siemens

Market purchases and sales as also important components. The market purchases by MLGW decreased first and then increased over the planning years. The market sales by MLGW increased from the early years due the accelerations on all the renewables, and then as the purchases increase, the sales are decreasing. The combination effect results in a net sales status for MLGW during three years of the 15-year planning horizon, although the net sales are small and MLGW is still a net purchaser for the entire planning horizon.

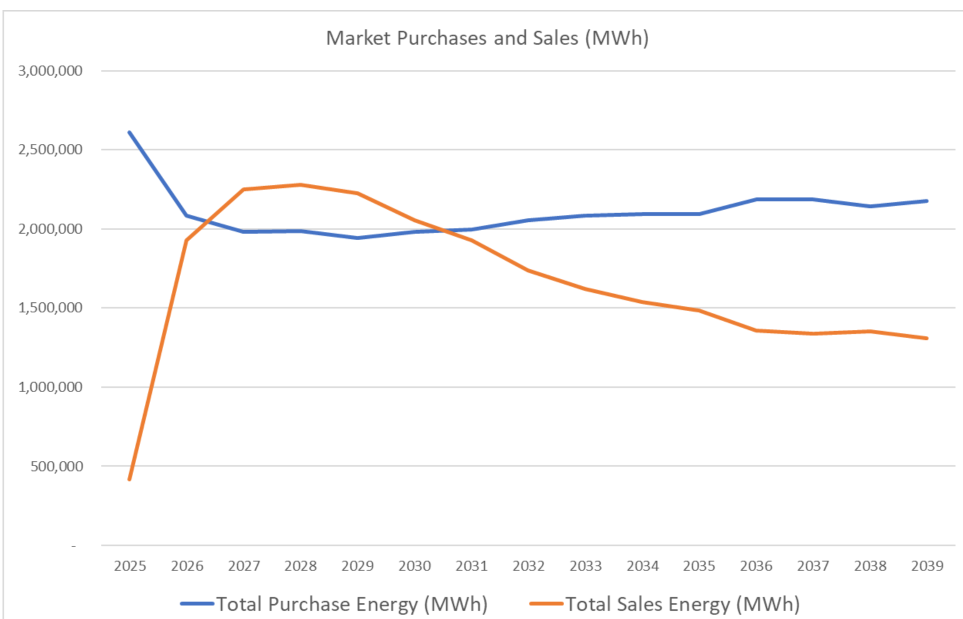
Exhibit 322: Portfolio 8 Market Purchases and Sales 2018 $



Source: Siemens

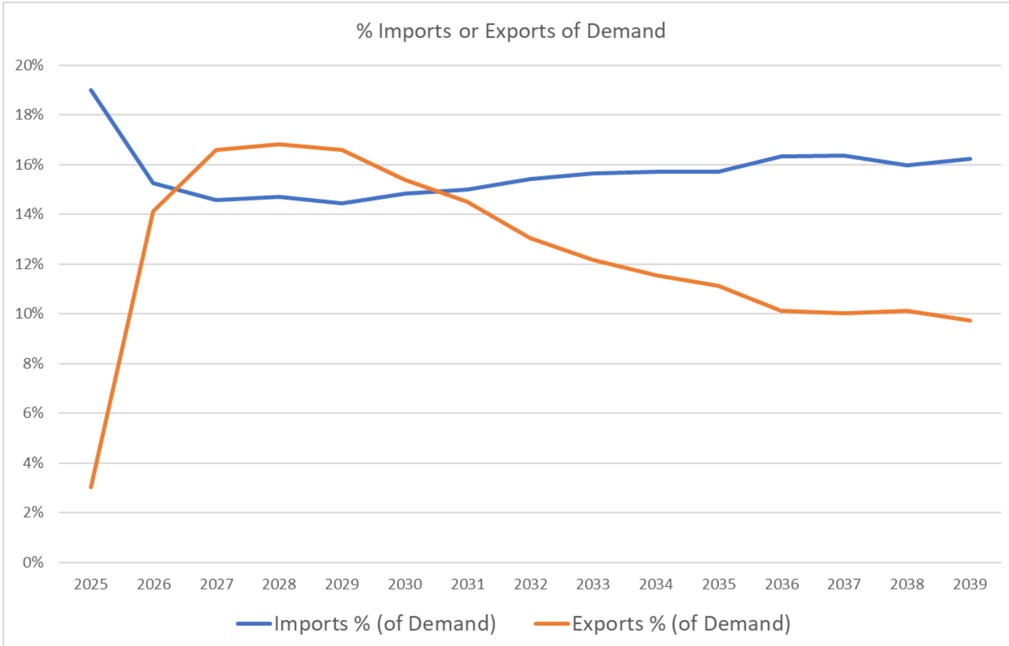
Exhibit 323 and Exhibit 324 show the purchases sales amount in energy and as % of demand, respectively. They show that the high market risk is in the beginning and towards the end of the planning years of this portfolio.

Exhibit 323: Portfolio 8 Market Purchases and Sales in Energy



Source: Siemens

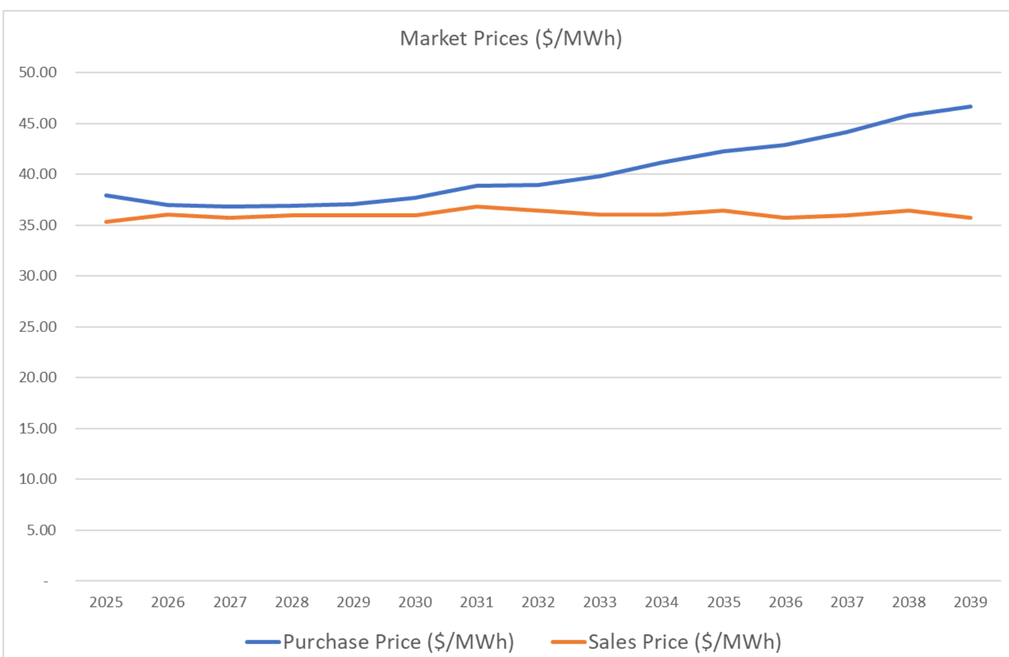
Exhibit 324: Portfolio 8 Market Purchases and Sales as % of Demand



Source: Siemens

The risk can also be appreciated by looking at the difference between purchase price (high) and sale price (low). The more purchase this portfolio needs, the higher risk.

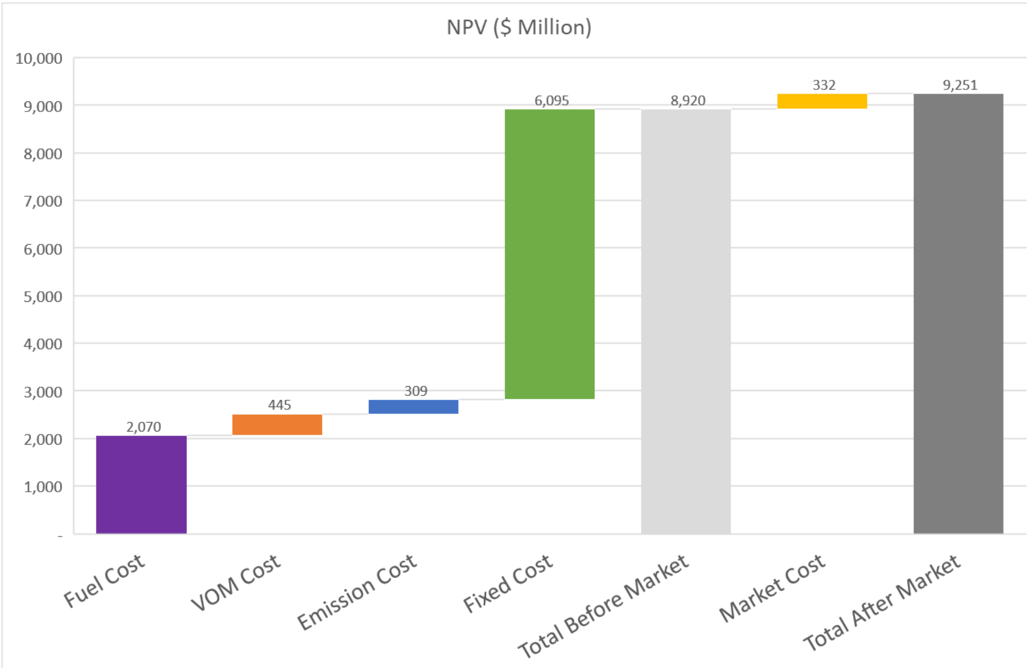
Exhibit 325: Portfolio 8 Market Purchases and Sales Prices $/MWh



Source: Siemens

Exhibit 326 shows the supply side total NPV for 2025-2039, which is about $9.25 billion in 2018 $. Fixed cost is the largest component, followed by fuel costs.

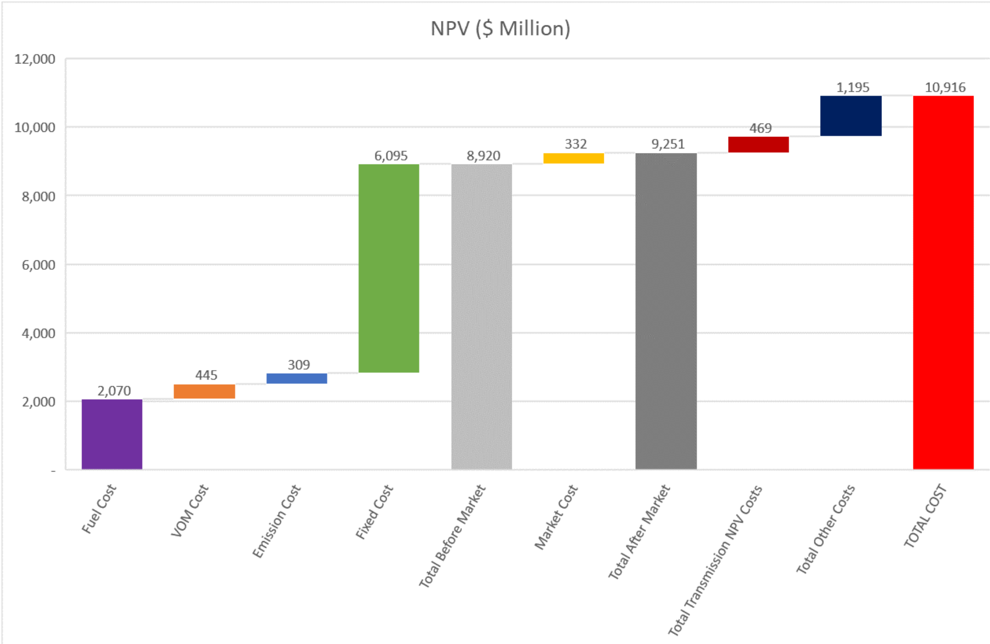
Exhibit 326: Portfolio 8 Generation Resource NPV 2018 $



Source: Siemens

The total NPVRR of this portfolio is approximately $10.92 billion for 2025-2039 in 2018 $.

Exhibit 327: Portfolio 8 All NPVRR with Other Components 2018 $

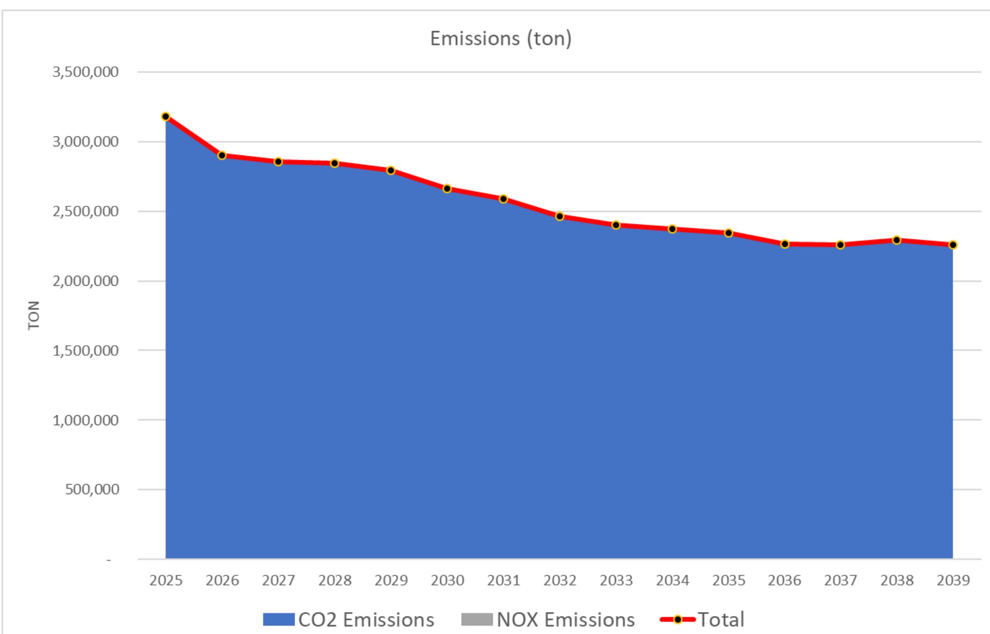


Source: Siemens

Environmental

The emission from this portfolio is shown in Exhibit 328 below. As energy from thermal generation is coming down, the capacity factor of the units decreases which resulted in decreased CO_2 emission over the years.

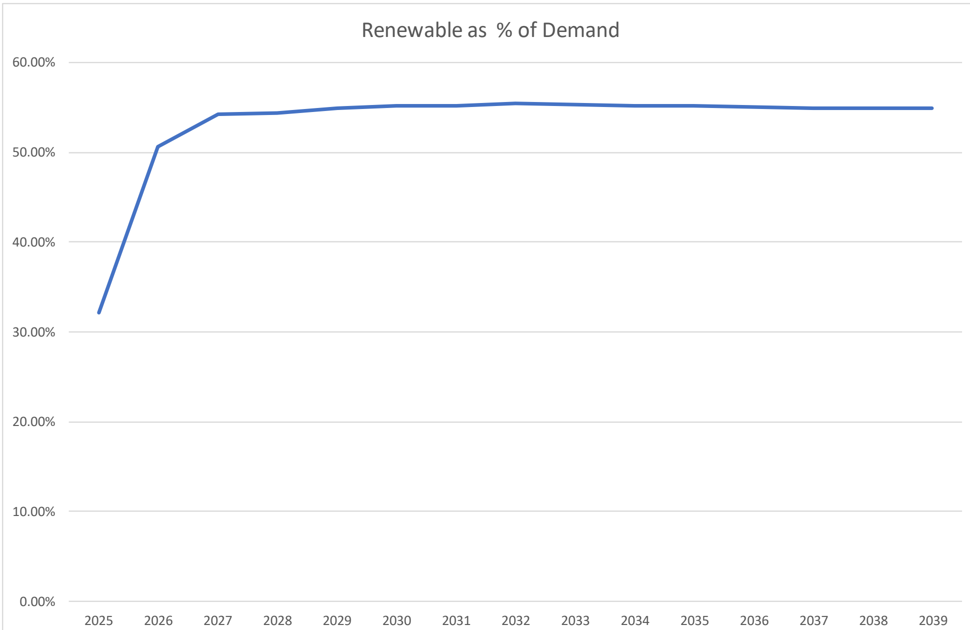
Exhibit 328: Portfolio 8 MLGW Emission by Year



Source: Siemens

The RPS as of the demand in energy of this portfolio starts at about 32% and reaches quickly to about 55% and stays flat throughout the years to 2039.

Exhibit 329: Portfolio 8 RPS by Year

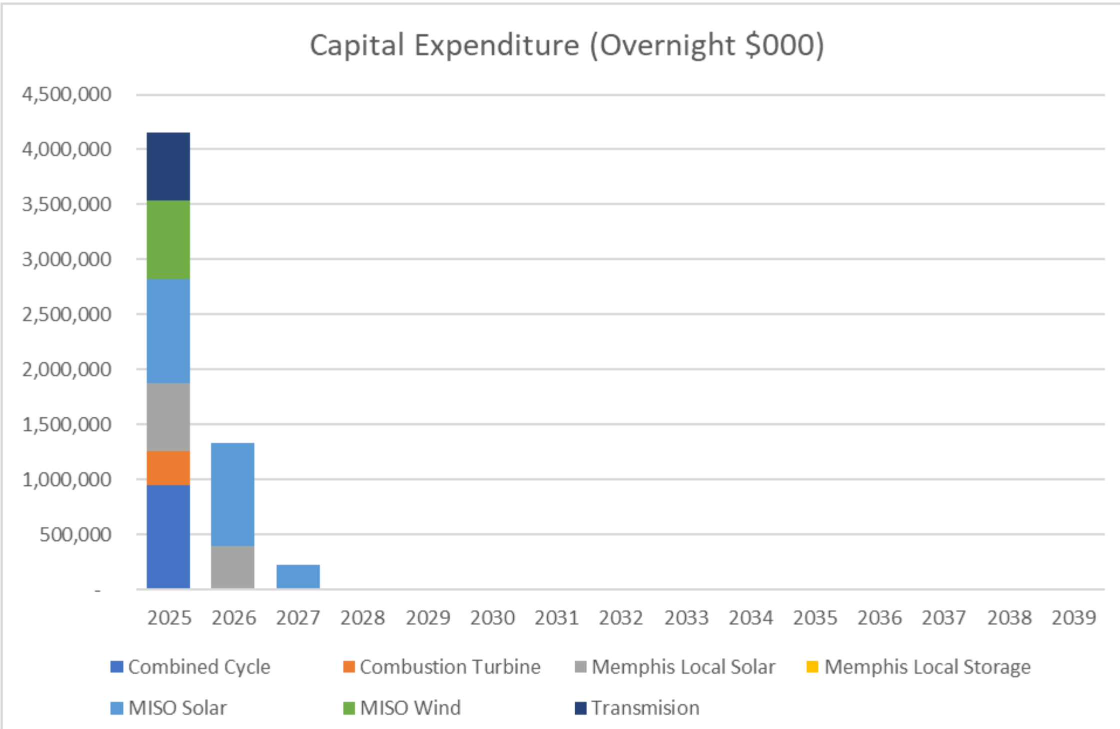


Source: Siemens

Capital Expenditure

Total capital expenditures on generation and transmission are shown in the Exhibit 330. Siemens present these capital expenditures in overnight from 2025 to 2039 while the actual drawdown may vary. Most of the CapEx are on the generation side and occur prior to 2025. Note that only the transmission CapEx is expected to be covered by MLGW as the generation CapEx is assumed to be expensed by third parties and recovered via PPA payments from MLGW.

Exhibit 330: Portfolio 8 Overnight Capital Expenditure by Year



Source: Siemens

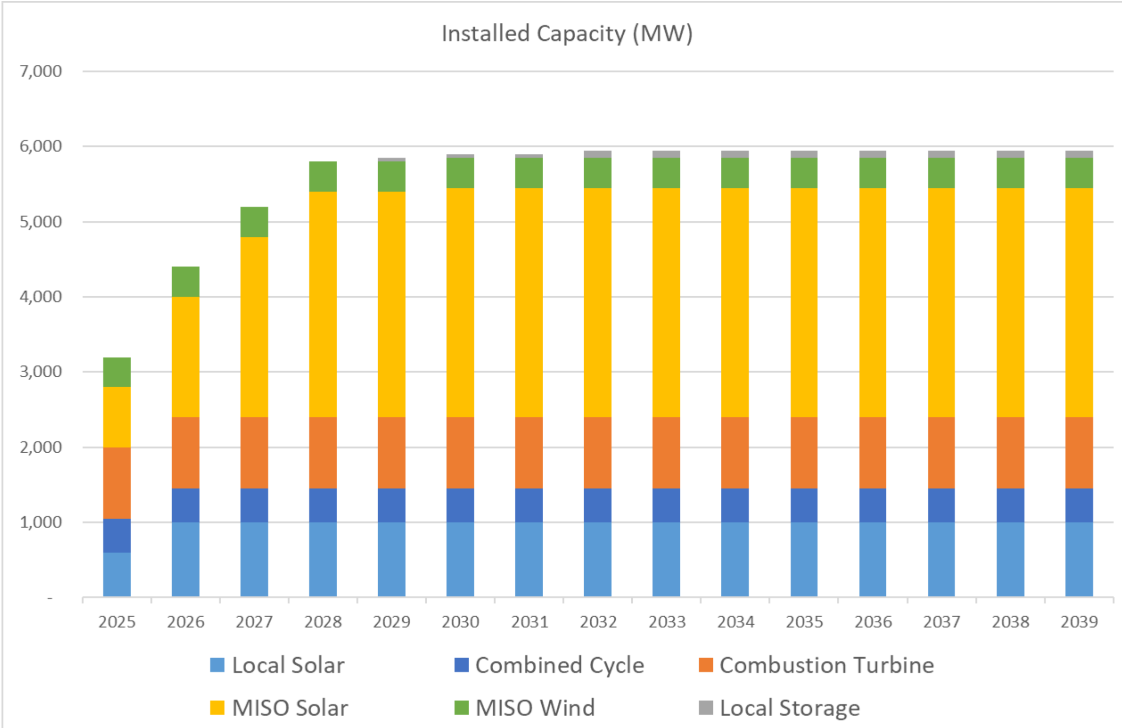
Portfolio 9 (S3S5_YD)

This is the portfolio derived from Portfolio 5 from the expansion plan, with all the CTs which were built in the last few years advanced to first year 2025 to avoid high transmission costs and resource adequacy concern.

Capacity Expansion (Buildout)

Exhibit 331 and Exhibit 332 show the capacity expansion by year, where the only difference as compared to Portfolio 5 is all CTs were installed in first year 2025.

Exhibit 331: Portfolio 9 Installed Capacity by Year



Source: Siemens

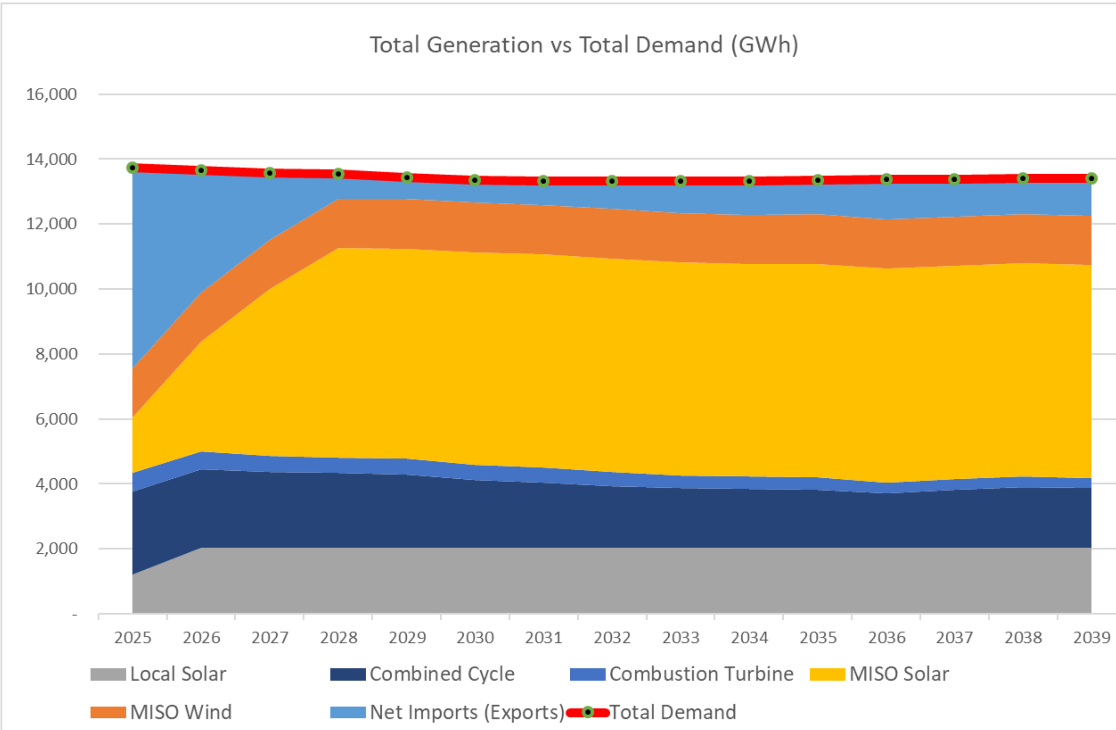
Exhibit 332: Portfolio 9 Installed Capacity by Year (Table)

	Advanced Frame CT	Convl. Frame 7FA CT	1x1 Combined Cycle	Utility Solar	Battery	Arkansas Solar	Arkansas Wind	MISO_Cap	Demand
2025	0	948	450	600	0	800	400	1754	3197
2026	0	0	0	400	0	800	0	1396	3182
2027	0	0	0	0	0	800	0	1171	3168
2028	0	0	0	0	0	600	0	1012	3153
2029	0	0	0	0	50	0	0	977	3139
2030	0	0	0	0	0	50	0	976	3124
2031	0	0	0	0	0	0	0	993	3113
2032	0	0	0	0	50	0	0	968	3108
2033	0	0	0	0	0	0	0	999	3110
2034	0	0	0	0	0	0	0	1030	3112
2035	0	0	0	0	0	0	0	1061	3114
2036	0	0	0	0	0	0	0	1092	3116
2037	0	0	0	0	0	0	0	1123	3118
2038	0	0	0	0	0	0	0	1155	3121
2039	0	0	0	0	0	0	0	1186	3123

Source: Siemens

Energy generated from thermal generation decreases over the years while energy coming from renewables increases.

Exhibit 333: Portfolio 9 Energy by Resource Type by Year

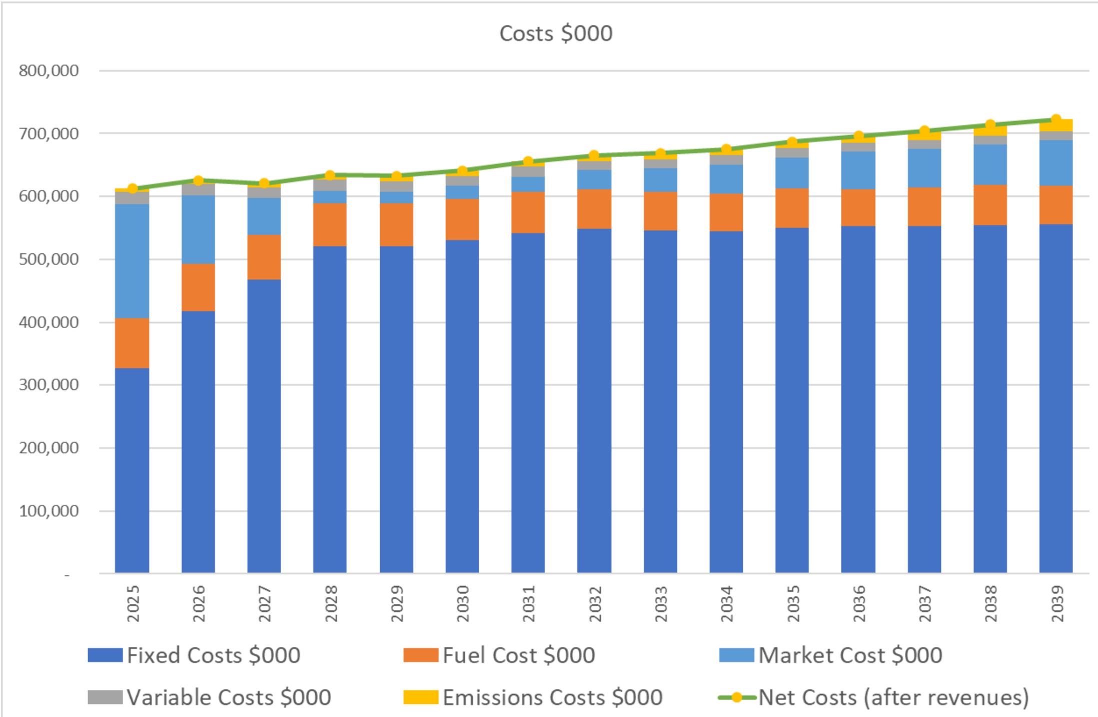


Source: Siemens

Portfolio Costs

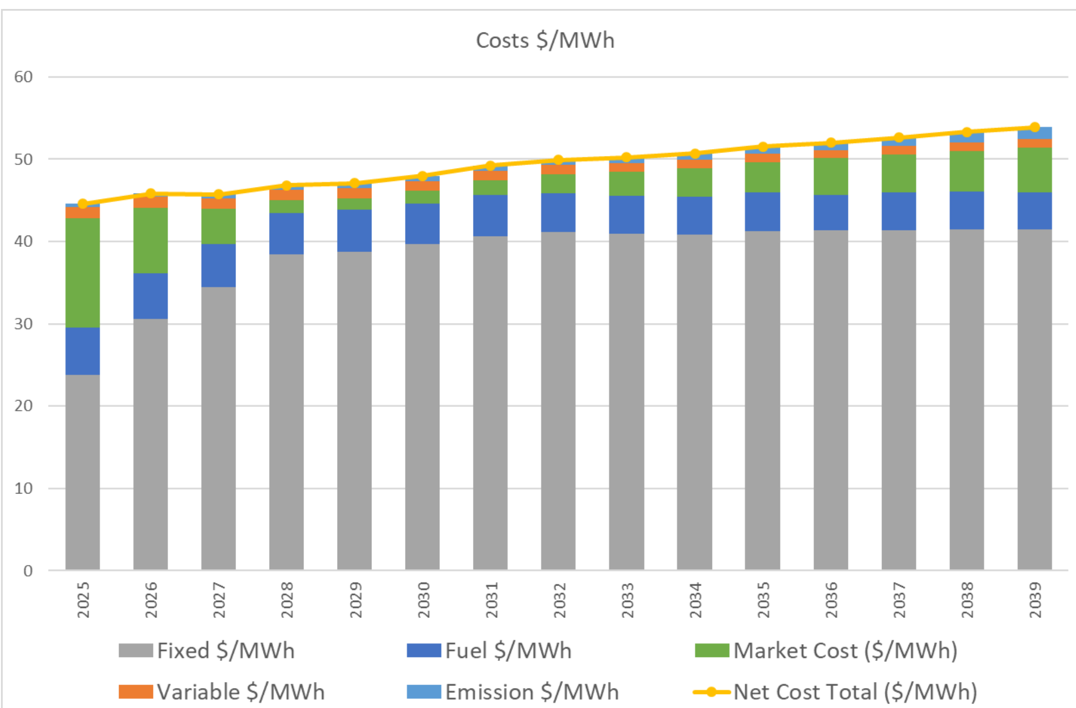
Exhibit 334 and Exhibit 335 shows the supply side NPV cost by year, as can be seen the cost is about $670 million per year (2018 $) or $50/MWh, where fixed cost is the largest components due to the investments in generation, followed by cost of fuels and market purchases.

Exhibit 334: Portfolio 9 Cost Components 2018 $



Source: Siemens

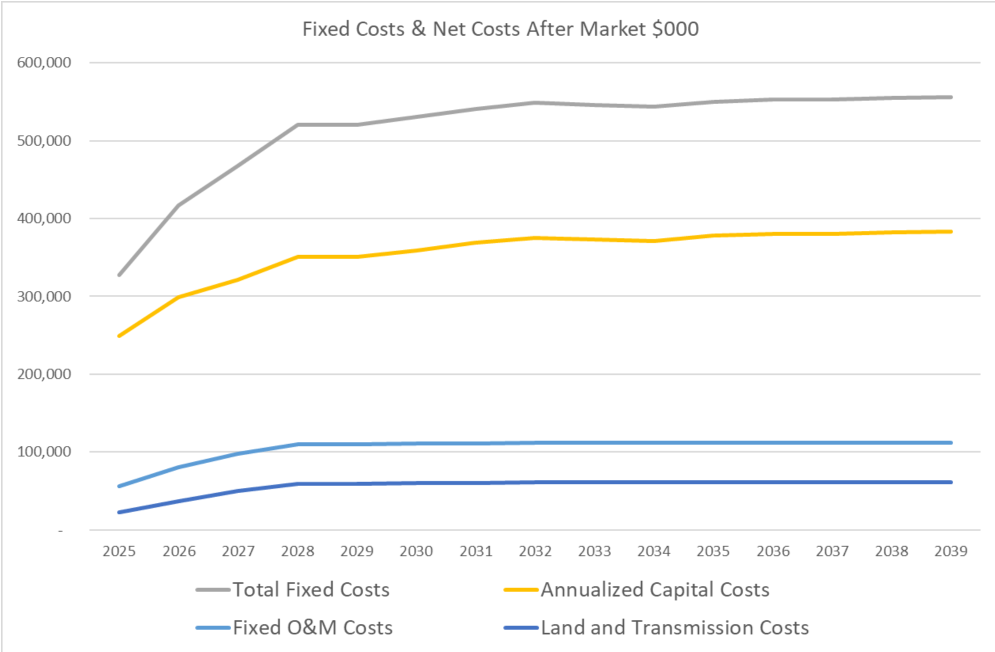
Exhibit 335: Portfolio 9 Cost Components 2018 $/MWh



Source: Siemens

Exhibit 336 shows the breakdown of total fixed costs by component, where the majority comes from the base capital costs on generation.

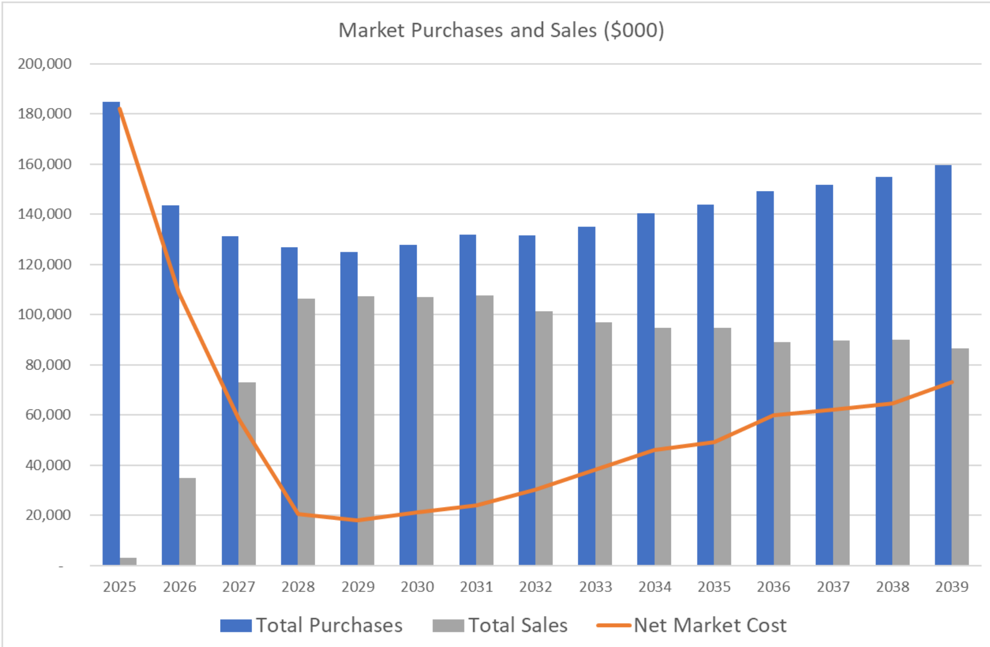
Exhibit 336: Portfolio 9 Fixed Cost Components 2018 $



Source: Siemens

Market purchases and sales are also important components. The market purchases by MLGW system are projected to be decreasing while the sales are increasing although the sales are maintained at a low level.

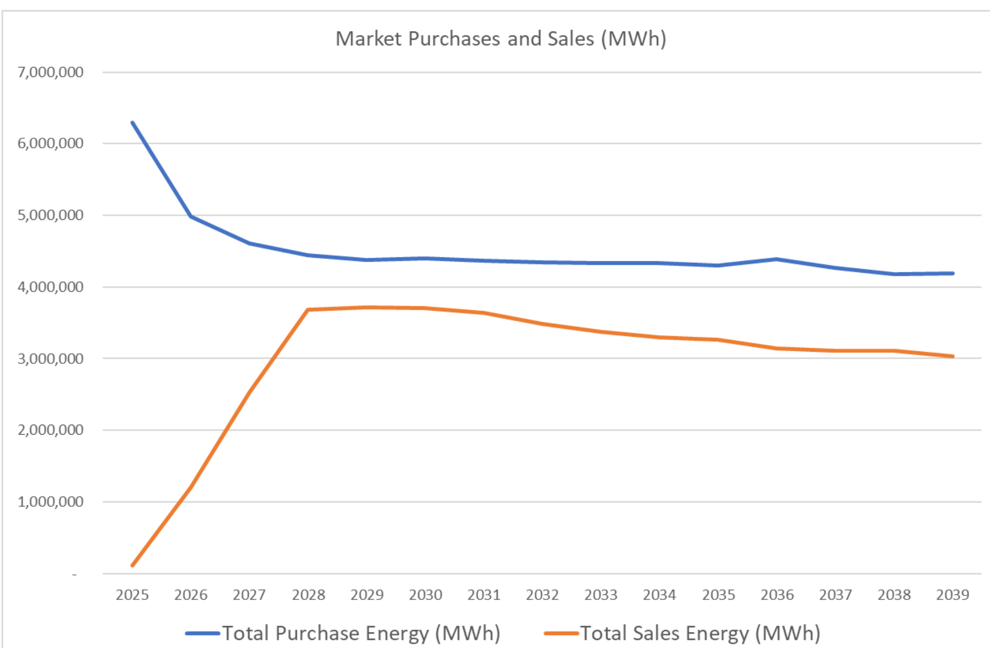
Exhibit 337: Portfolio 9 Market Purchases and Sales 2018 $



Source: Siemens

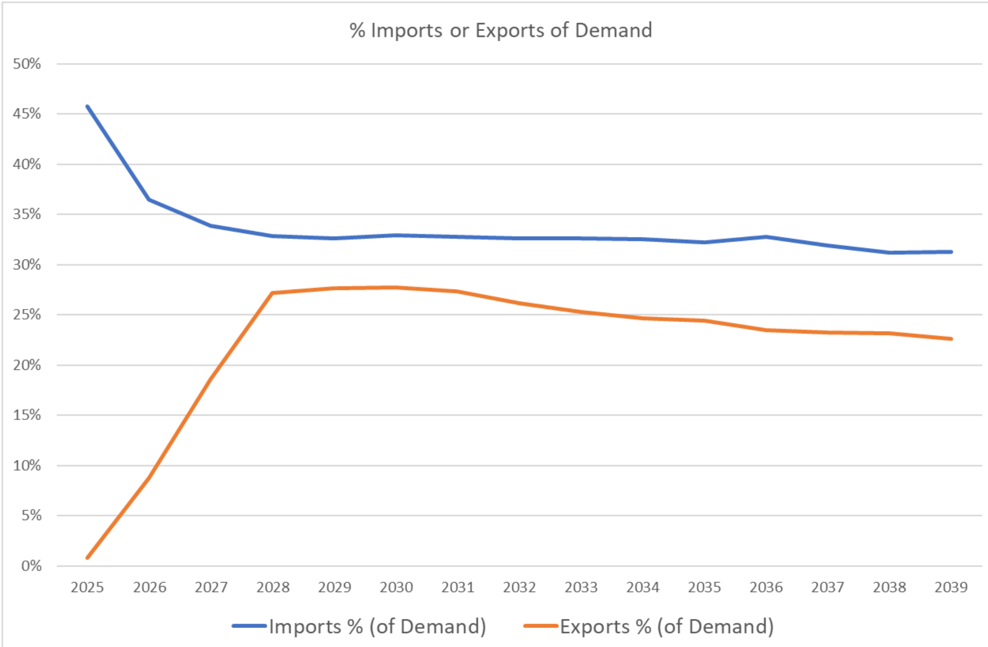
Exhibit 338 and Exhibit 339 show the purchases sales amount in energy and as % of demand. It shows the high market risk in the beginning of the planning years of this portfolio due to the amount of purchases required.

Exhibit 338: Portfolio 9 Market Purchases and Sales in Energy



Source: Siemens

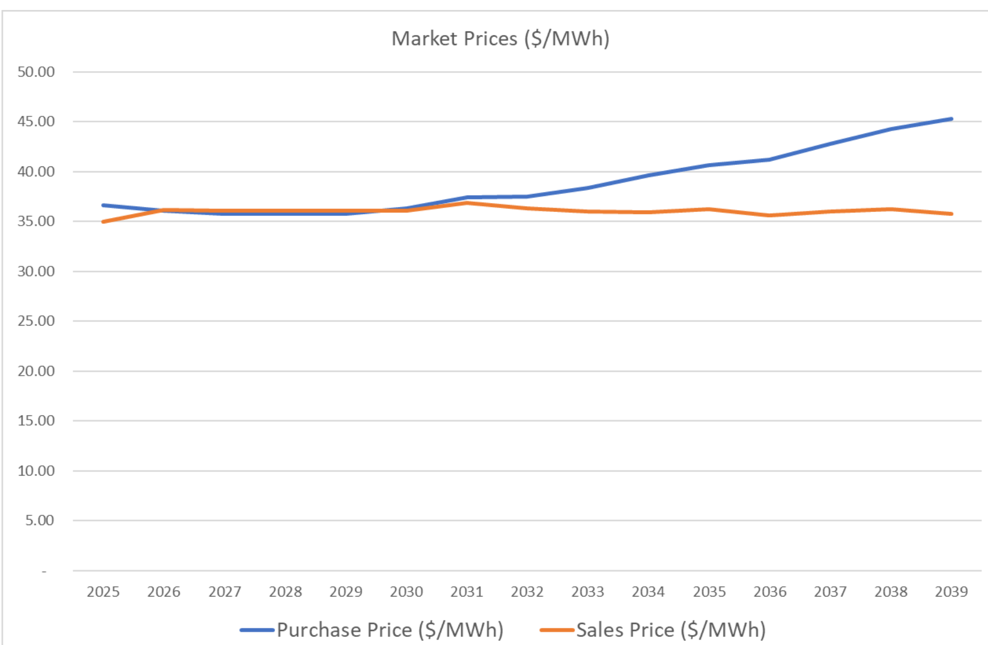
Exhibit 339: Portfolio 9 Market Purchases and Sales as % of Demand



Source: Siemens

The market risk associated with this portfolio is more related to the availability of resources in the market rather than the market price itself, because this is a portfolio that requires relatively higher percentage of purchases from the market due to less local generation. The more purchases this portfolio needs, the higher risk.

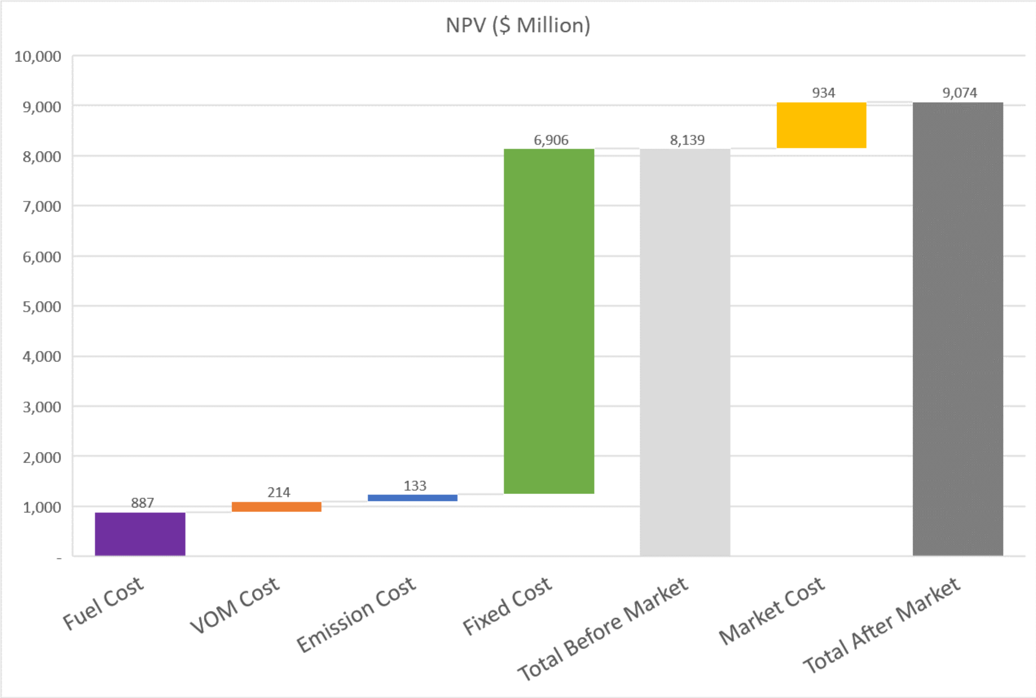
Exhibit 340: Portfolio 9 Market Purchases and Sales Prices $/MWh



Source: Siemens

Exhibit 341 shows the supply side total NPV for 2025-2039, which is about $9.07 billion in 2018 $. Fixed cost is the largest component, followed by fuel and market costs.

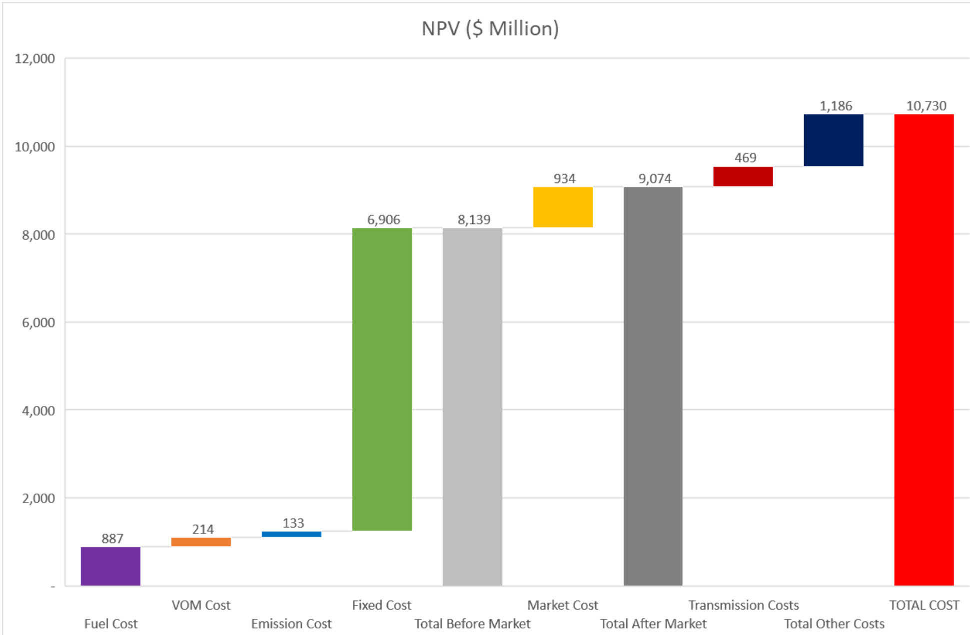
Exhibit 341: Portfolio 9 Generation Resource NPV 2018 $



Source: Siemens

The total NPVRR of this portfolio is approximately $10.73 billion for 2025-2039 in 2018 $.

Exhibit 342: Portfolio 9 All NPVRR with Other Components 2018 $

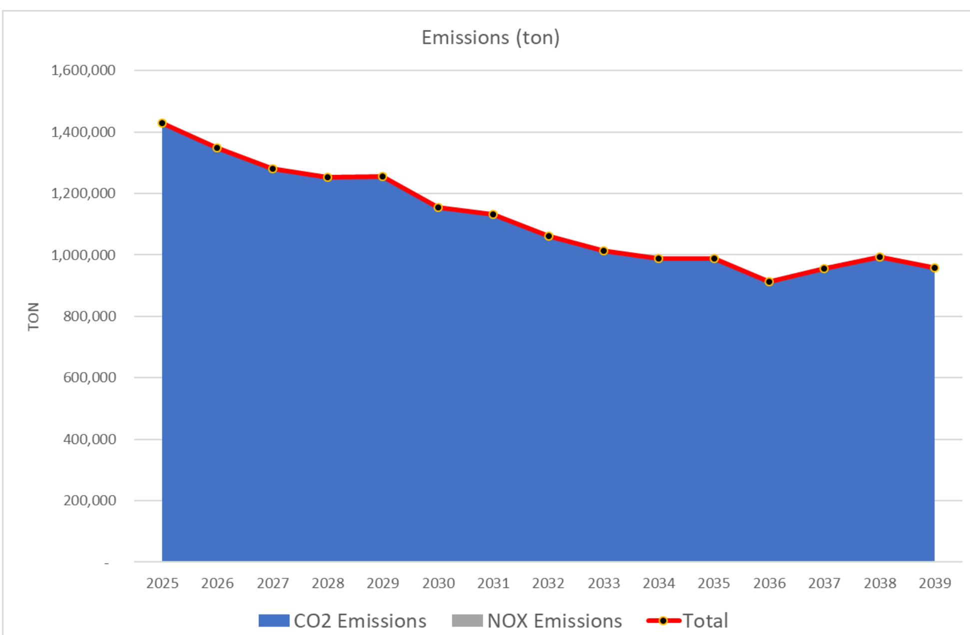


Source: Siemens

Environmental

The emission from this portfolio is shown in Exhibit 343 below. The emission is low compared with other portfolios due to high renewables and low thermal generation in this portfolio.

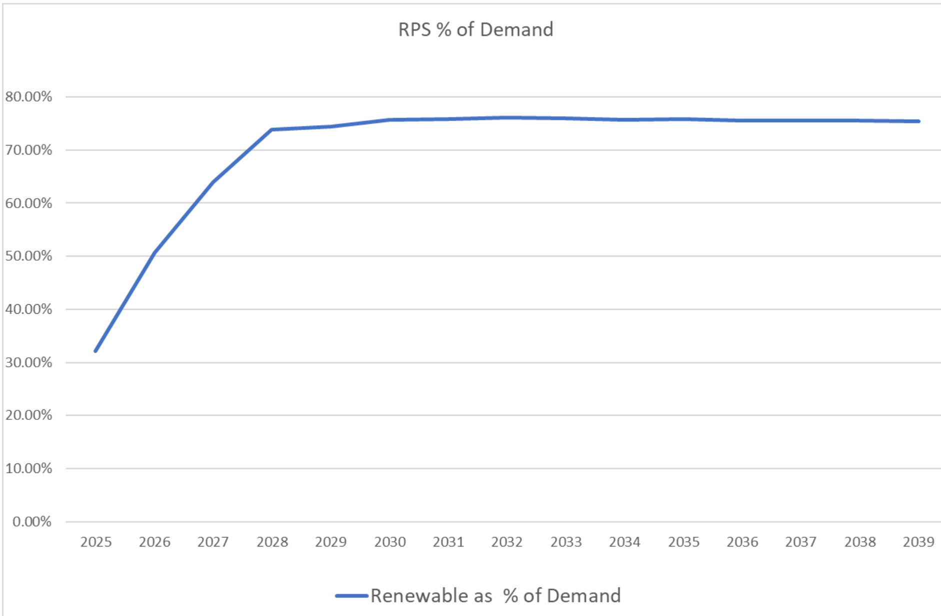
Exhibit 343: Portfolio 9 MLGW Emission by Year



Source: Siemens

This is the high renewable case and the RPS as of demand in energy of this portfolio starts at about 32% and very quickly reaches to 75% in 2039 as lots of renewable generation is built in this portfolio.

Exhibit 344: Portfolio 9 RPS by Year

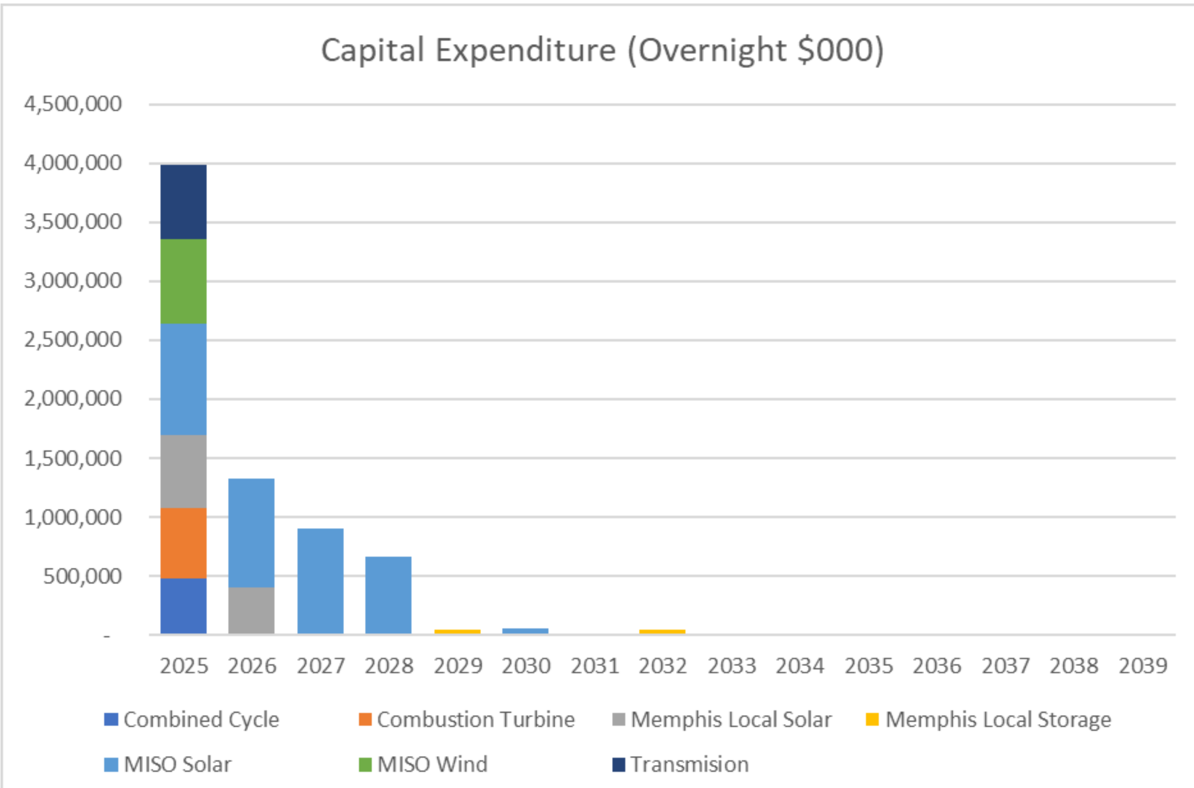


Source: Siemens

Capital Expenditure

Total capital expenditures on generation and transmission are shown in Exhibit 345. Siemens present these capital expenditures in overnight from 2025 to 2039 while the actual drawdown may vary. Most of the CapEx are on the generation side and occur prior to 2025. Note that only the transmission CapEx is expected to be covered by MLGW as the generation CapEx is assumed to be expensed by third parties and recovered via PPA payments from MLGW.

Exhibit 345: Portfolio 9 Overnight Capital Expenditure by Year



Source: Siemens

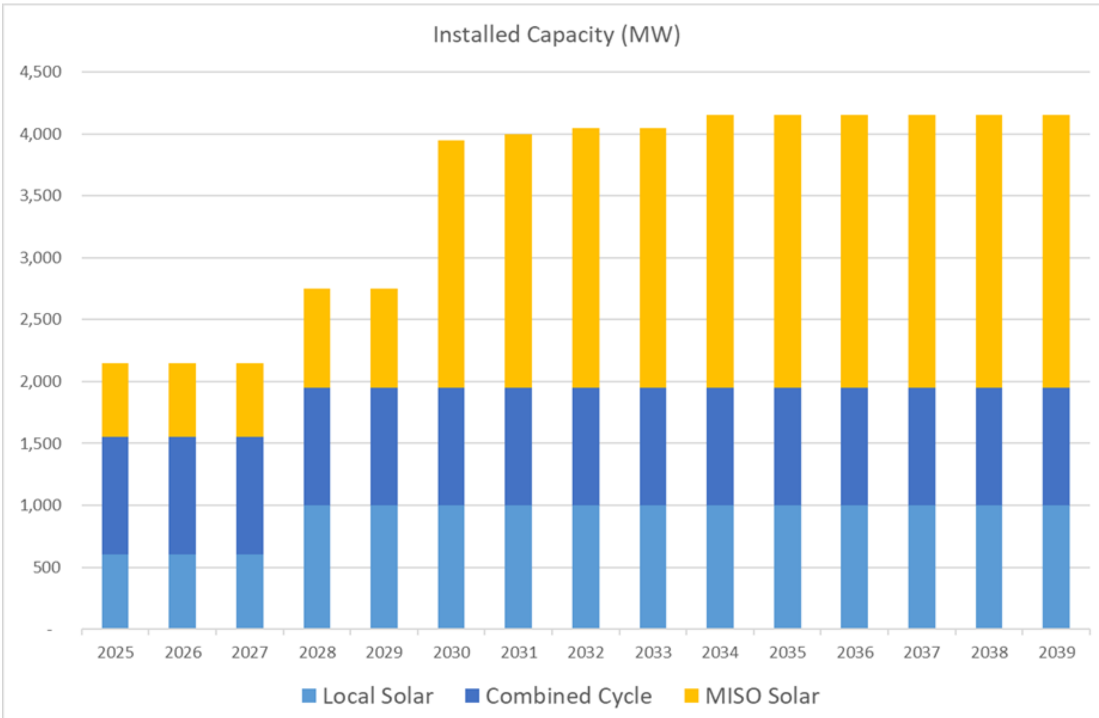
Portfolio 10 (S3S10)

This is the portfolio derived from Portfolio All MISO under Strategy 4. Based on that portfolio, we moved the CCGT and 1000 MW solar to MLGW footprint with the CCGT built in first year 2025 and local solar installed 600 MW in 2025 and 400 MW in 2028, respectively. The balance of the solar stays in MISO due to land constraint. We consider this portfolio under Strategy 3 due to the relocation of resources into MLGW as compared the Portfolio All MISO. This Portfolio is expected to produce lower NPV because as we know local resources are cheaper than remote resources.

Capacity Expansion (Buildout)

Exhibit 346 and Exhibit 347 below show the capacity expansion by year, where there is no difference in terms of total amount of each resource type compared to Portfolio All MISO, the only difference being that the CCGT and 1000 MW solar were moved to the MLGW footprint, and MISO solar was adjusted accordingly

Exhibit 346: Portfolio 10 Installed Capacity by Year



Source: Siemens

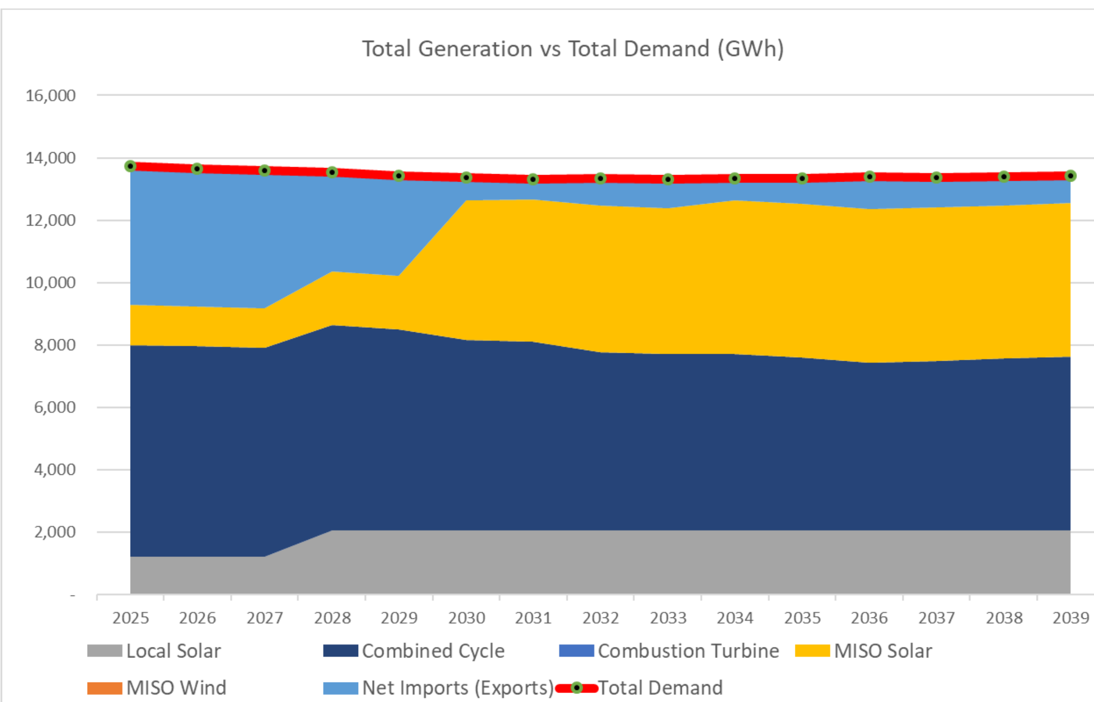
Exhibit 347: Portfolio 10 Installed Capacity by Year (Table)

	Advanced Frame CT	Convl. Frame 7FA CT	2x1 Combined Cycle	Utility Solar	Battery	Arkansas Solar	Arkansas Wind	MISO_Cap	Demand
2025	0	0	950	600	0	600	0	2269	3197
2026	0	0	0	0	0	0	0	2262	3182
2027	0	0	0	0	0	0	0	2255	3168
2028	0	0	0	400	0	200	0	2080	3153
2029	0	0	0	0	0	0	0	2078	3139
2030	0	0	0	0	0	1200	0	1757	3124
2031	0	0	0	0	0	50	0	1754	3113
2032	0	0	0	0	0	50	0	1757	3108
2033	0	0	0	0	0	0	0	1782	3110
2034	0	0	0	0	0	100	0	1783	3112
2035	0	0	0	0	0	0	0	1808	3114
2036	0	0	0	0	0	0	0	1833	3116
2037	0	0	0	0	0	0	0	1858	3118
2038	0	0	0	0	0	0	0	1883	3121
2039	0	0	0	0	0	0	0	1909	3123

Source: Siemens

Energy generated from thermal generation decreases slightly over the years while energy coming from renewables increases.

Exhibit 348: Portfolio 10 Energy by Resource Type by Year

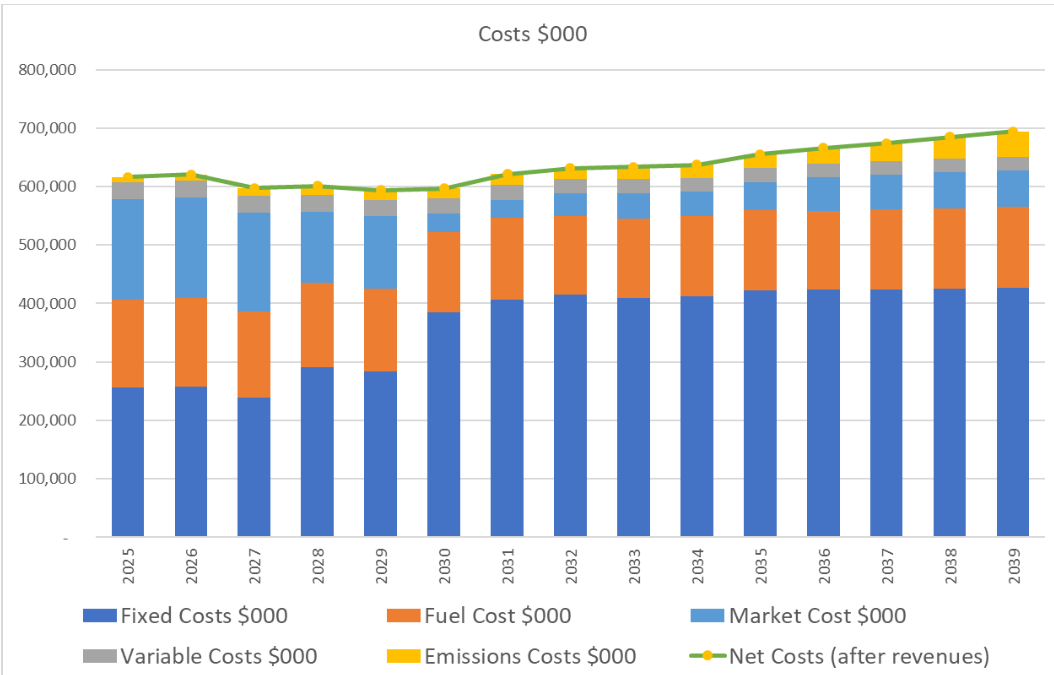


Source: Siemens

Portfolio Costs

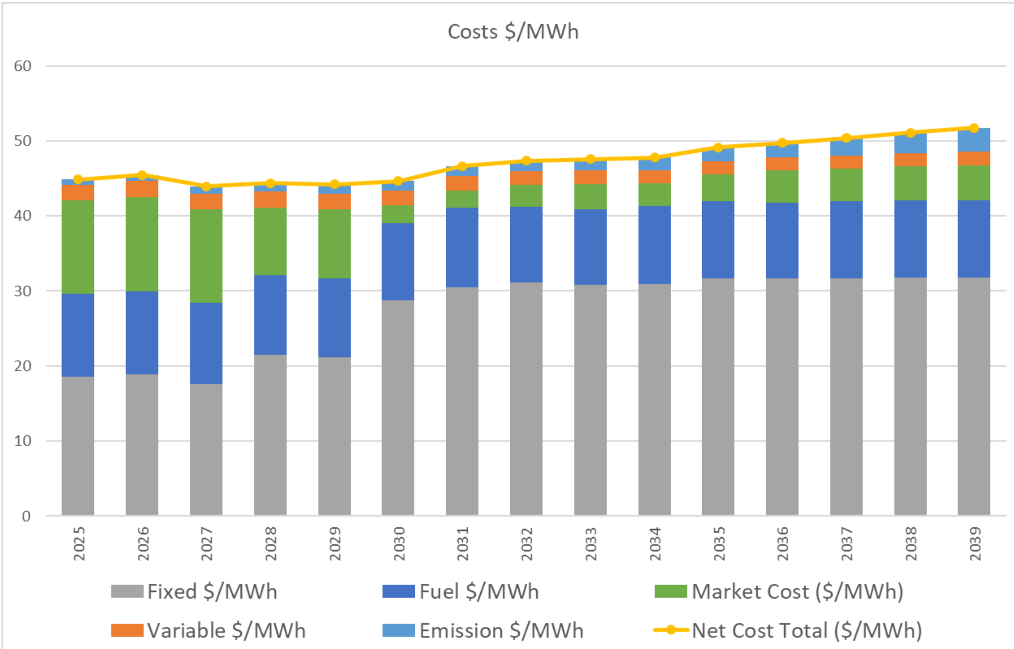
Exhibit 348 and Exhibit 349 shows the supply side NPV cost by year. As can be seen the cost is about $620 million per year (2018 $) or $47/MWh, where fixed cost is the largest components due to the investments in generation, followed by cost of fuels and market purchases.

Exhibit 349: Portfolio 10 Cost Components 2018 $



Source: Siemens

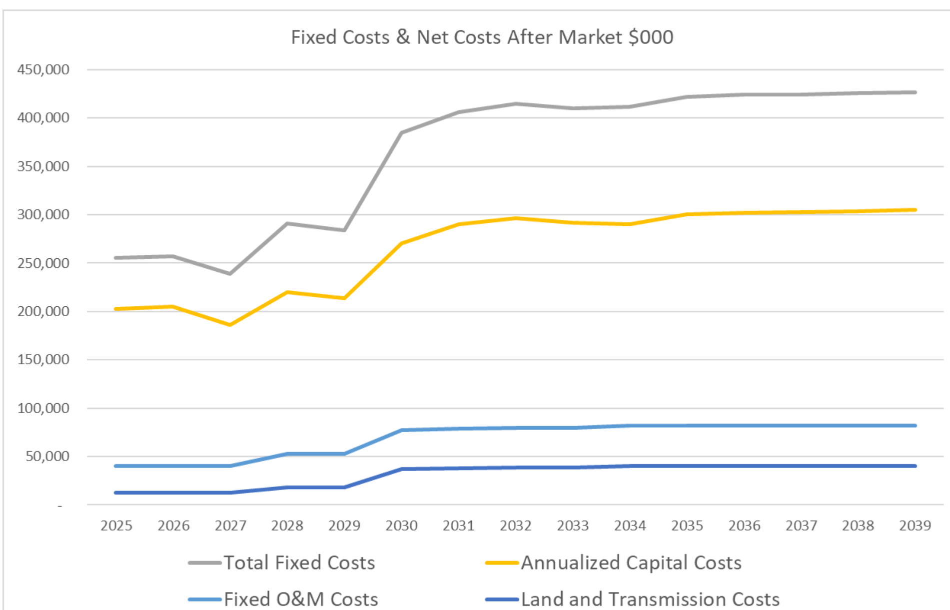
Exhibit 350: Portfolio 10 Cost Components 2018 $/MWh



Source: Siemens

Exhibit 351 shows the breakdown of total fixed costs by component, where the majority comes from the base capital costs on generation.

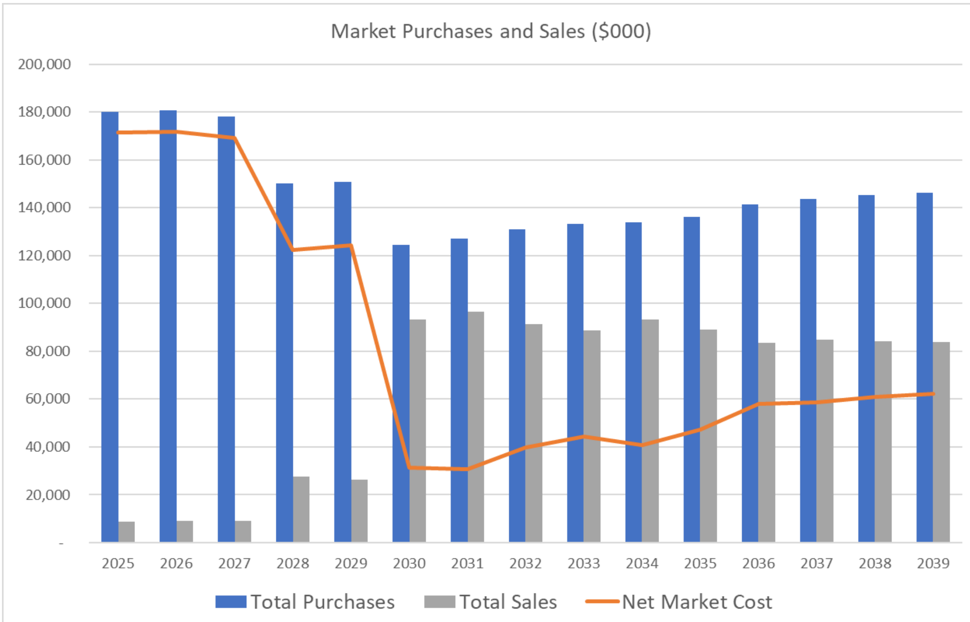
Exhibit 351: Portfolio 10 Fixed Cost Components 2018 $



Source: Siemens

Market purchases and sales are also important components. The market purchases by MLGW system are projected to be decreasing then flat while the sales are increasing especially after 2030 although the sales are maintained at a low level.

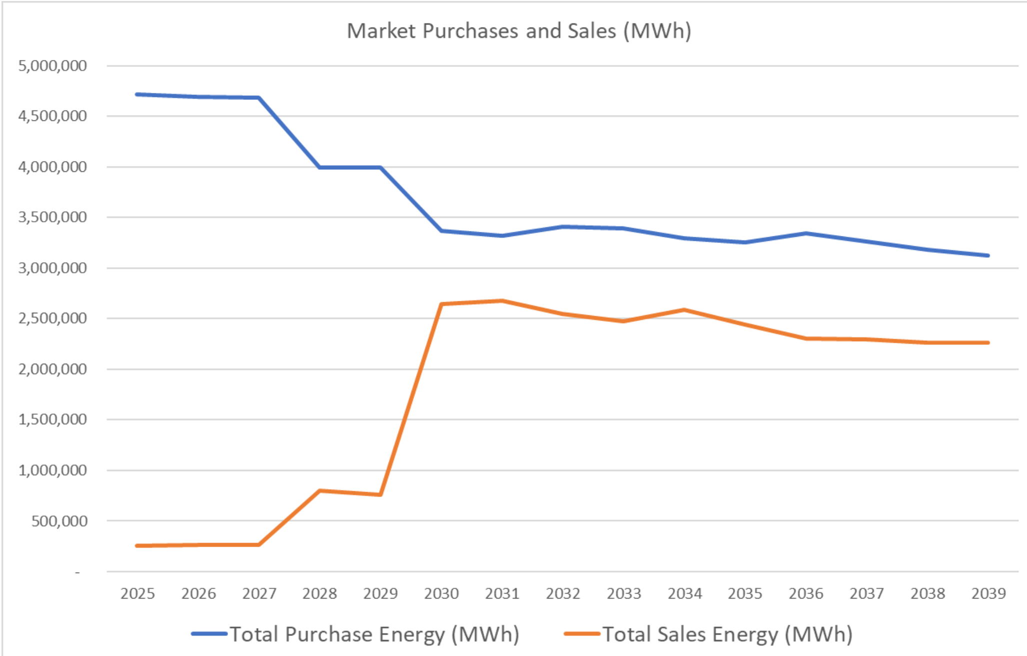
Exhibit 352: Portfolio 10 Market Purchases and Sales 2018 $



Source: Siemens

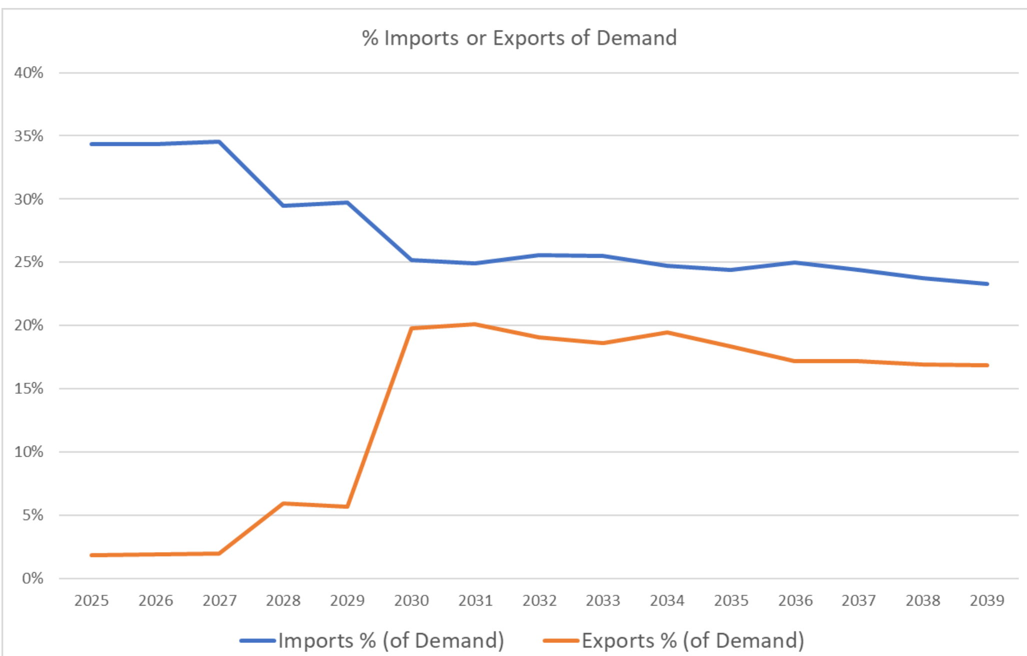
Exhibit 353 and Exhibit 354 show the purchases sales amount in energy and as % of demand, respectively. It shows the high market risk in the beginning of the planning years of this portfolio.

Exhibit 353: Portfolio 10 Market Purchases and Sales in Energy



Source: Siemens

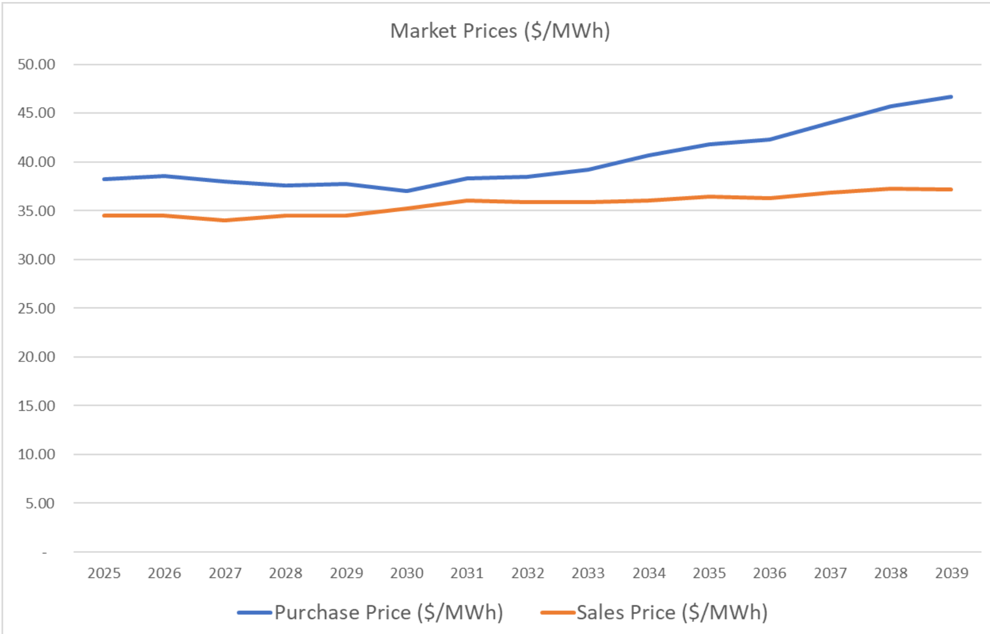
Exhibit 354: Portfolio 10 Market Purchases and Sales as % of Demand



Source: Siemens

The risk can also be appreciated looking at the difference between purchase price (high) and sale price (low). The more purchases this portfolio requires, the higher risk.

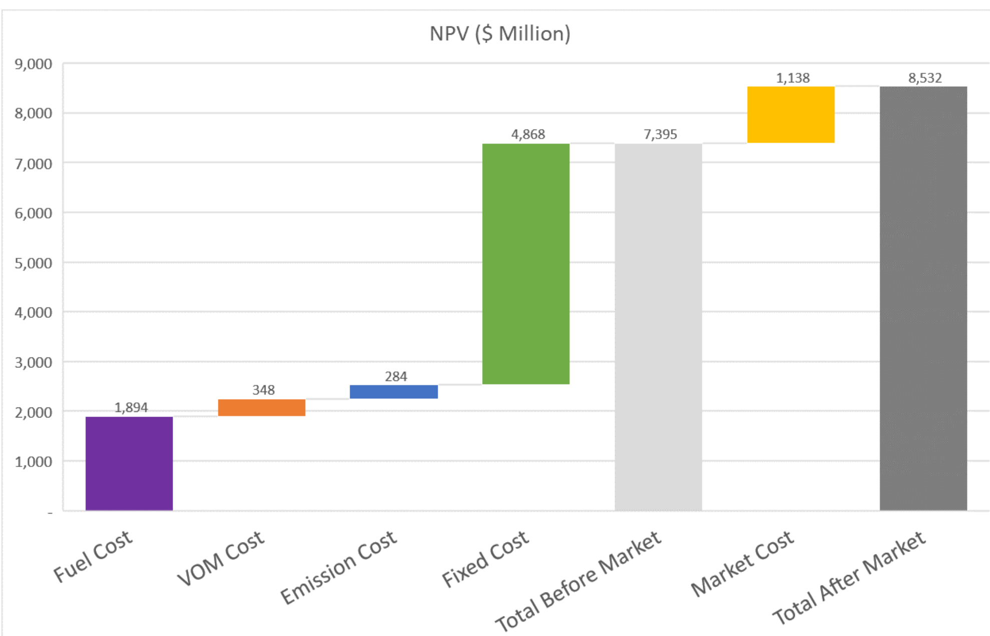
Exhibit 355: Portfolio 10 Market Purchases and Sales Prices $/MWh



Source: Siemens

Exhibit 356 shows the supply side total NPV for 2025-2039, which is about $8.53 billion in 2018 $. Fixed cost is the largest component, followed by fuel and market costs.

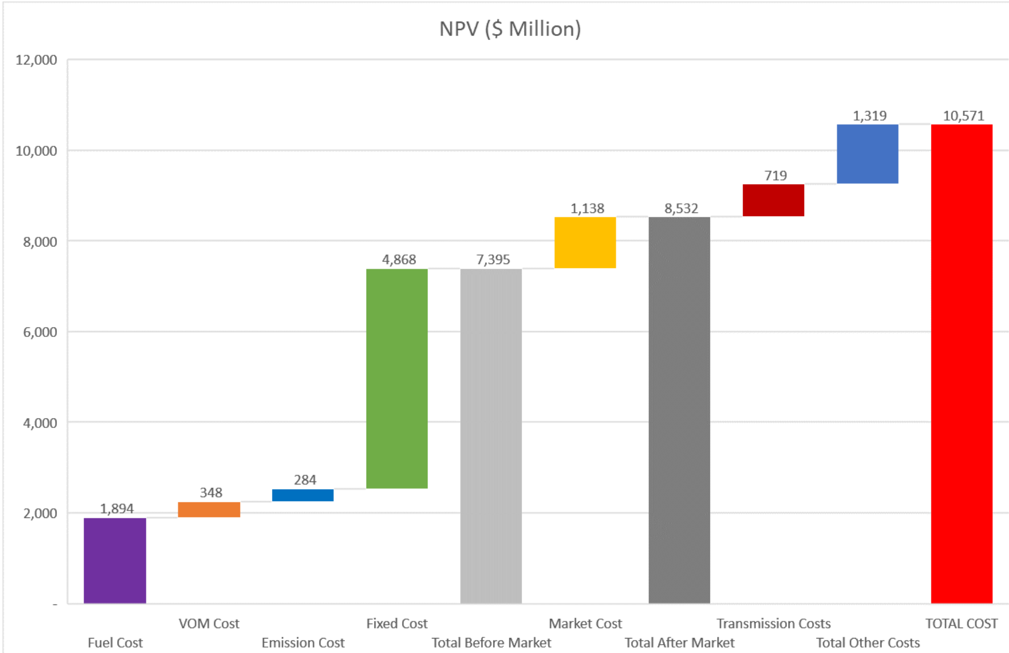
Exhibit 356: Portfolio 10 Generation Resource NPV 2018 $



Source: Siemens

The total NPVRR of this portfolio is approximately $10.57 billion for 2025-2039 in 2018 $.

Exhibit 357: Portfolio 10 All NPVRR with Other Components 2018 $

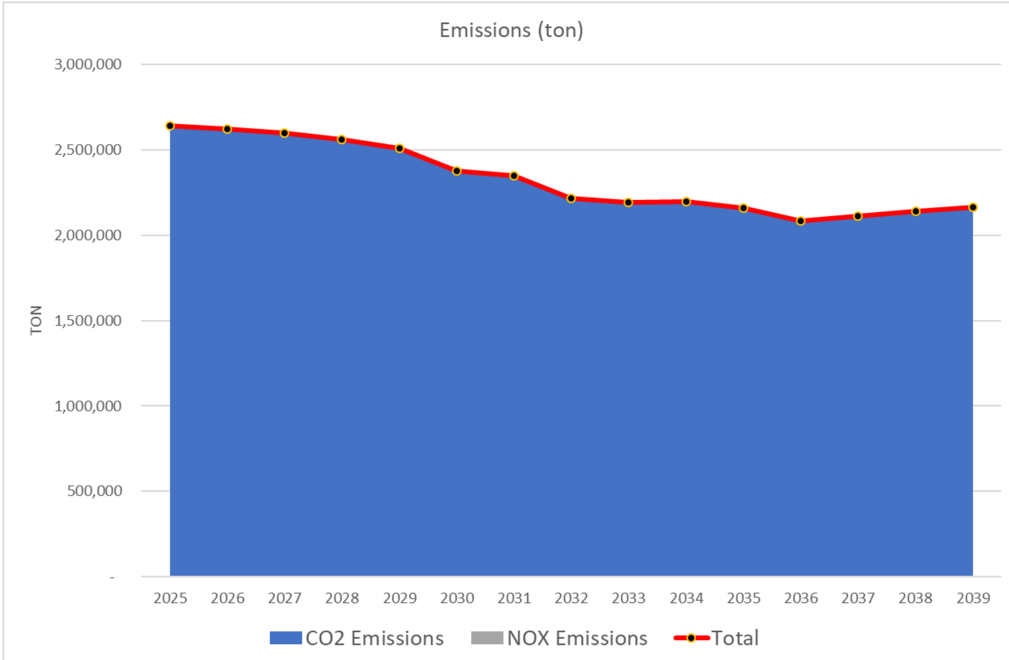


Source: Siemens

Environmental

The emission from this portfolio is shown in Exhibit 358 below. The emission is low compared with other portfolios due to high renewables and low thermal generation in this portfolio.

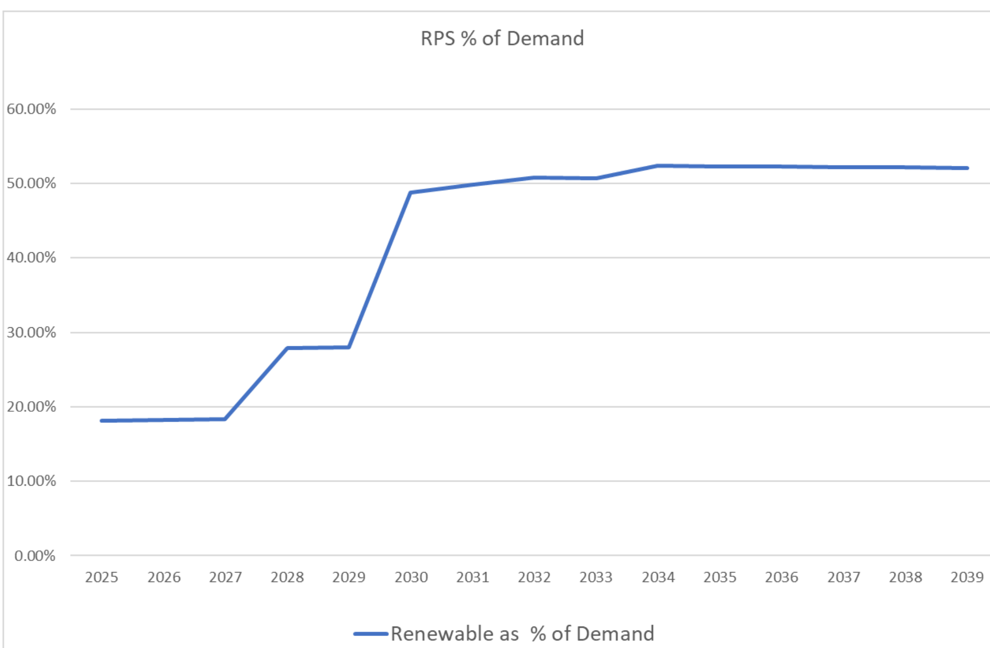
Exhibit 358: Portfolio 10 MLGW Emission by Year



Source: Siemens

This RPS as % of demand of this portfolio starts at about 20% and reaches very quickly to 53% in 2039 as lots of renewable generation are built in this portfolio.

Exhibit 359: Portfolio 10 RPS by Year

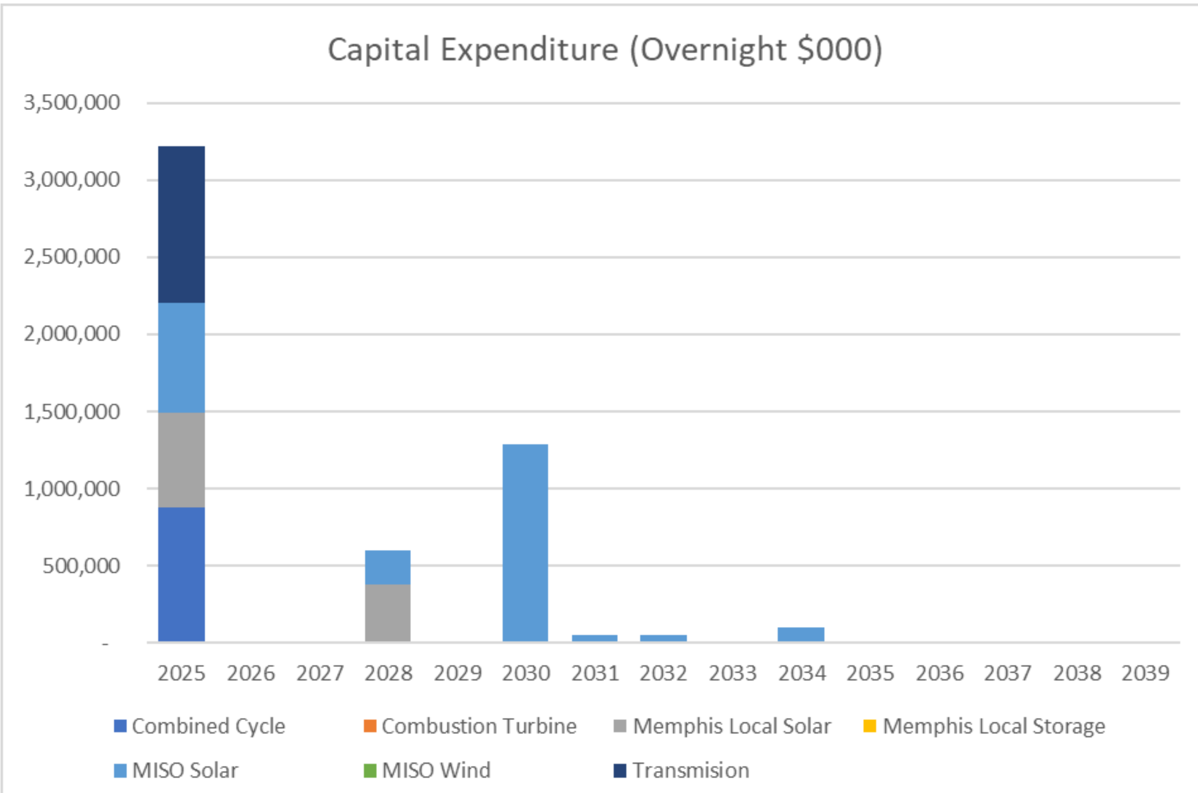


Source: Siemens

Capital Expenditure

Total capital expenditures on generation and transmission are shown Exhibit 360 below. Siemens present these capital expenditures in overnight from 2025 to 2039 while the actual drawdown may vary. Most of the CapEx are on the generation side and occur prior to 2025. Note that only the transmission CapEx is expected to be covered by MLGW as the generation CapEx is assumed to be expensed by third parties and recovered via PPA payments from MLGW.

Exhibit 360: Portfolio 10 Overnight Capital Expenditure by Year



Source: Siemens

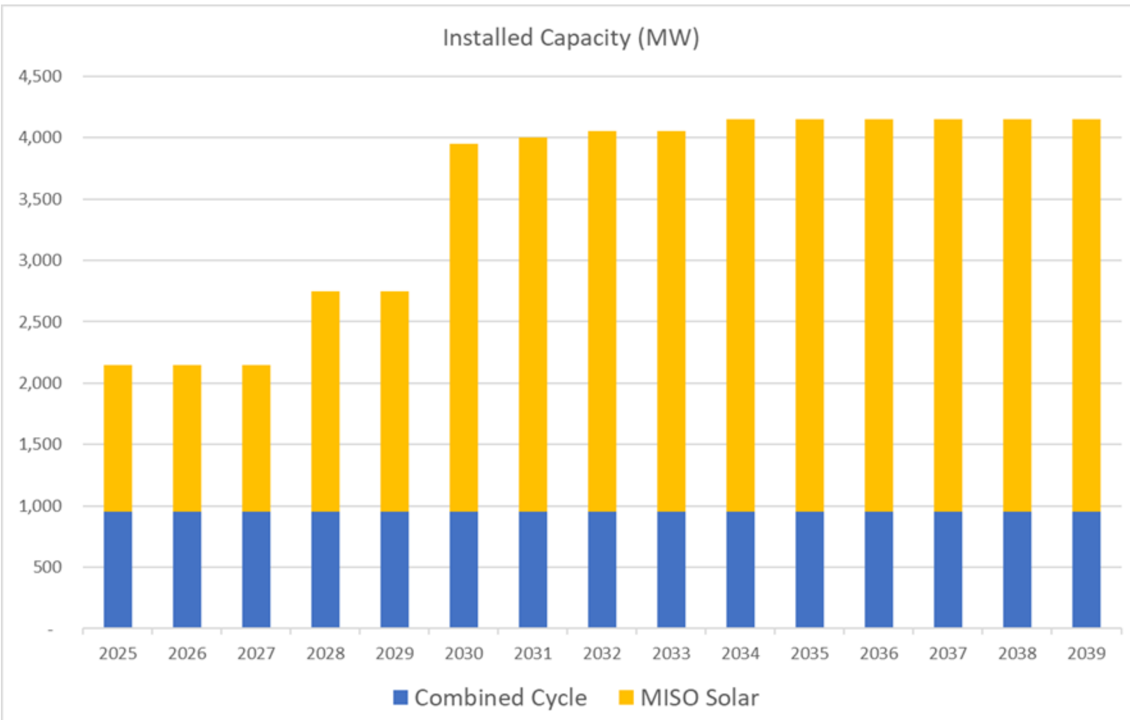
Portfolio All MISO (S4S1)

This is the Portfolio All MISO under Strategy 4.

Capacity Expansion (Buildout)

Exhibit 361 and Exhibit 362 below show the capacity expansion by year, the only resources selected in Portfolio All MISO are the large CCGT and solar.

Exhibit 361: Portfolio All MISO Installed Capacity by Year



Source: Siemens

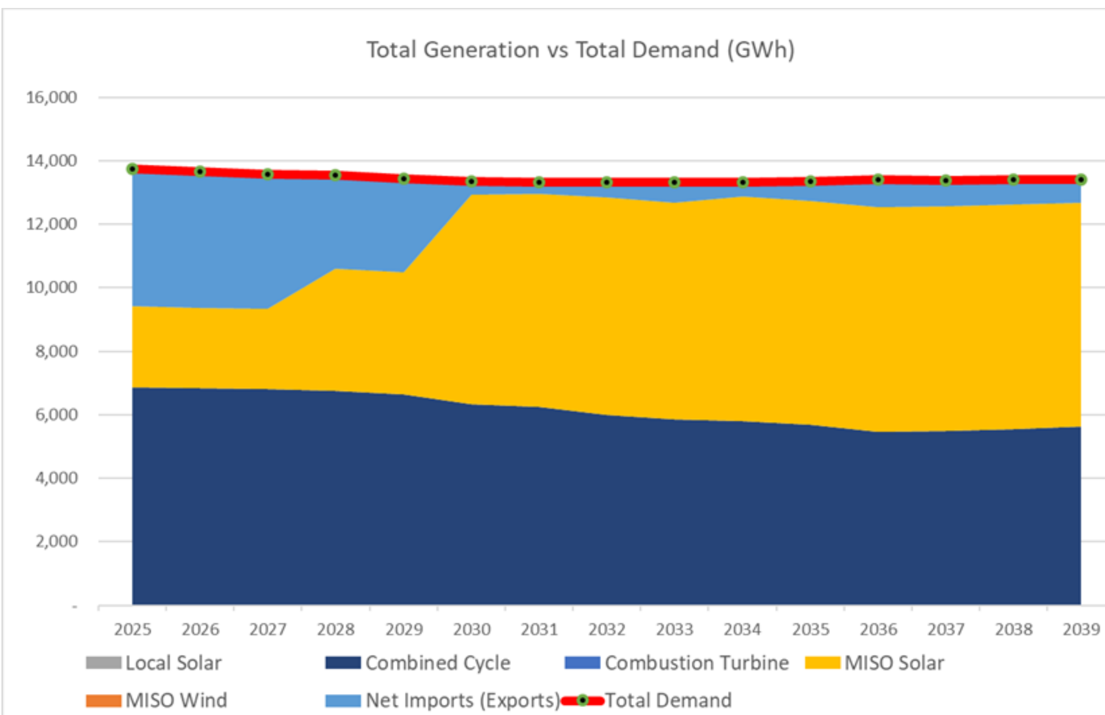
Exhibit 362: Portfolio All MISO Installed Capacity by Year (Table)

	Advanced Frame CT	Convl. Frame 7FA CT	2x1 Combined Cycle	Utility Solar	Battery	Arkansas Solar	Arkansas Wind	MISO_Cap	Demand
2025	0	0	950	0	0	1200	0	2269	3197
2026	0	0	0	0	0	0	0	2262	3182
2027	0	0	0	0	0	0	0	2255	3168
2028	0	0	0	0	0	600	0	2080	3153
2029	0	0	0	0	0	0	0	2078	3139
2030	0	0	0	0	0	1200	0	1757	3124
2031	0	0	0	0	0	50	0	1754	3113
2032	0	0	0	0	0	50	0	1757	3108
2033	0	0	0	0	0	0	0	1782	3110
2034	0	0	0	0	0	100	0	1783	3112
2035	0	0	0	0	0	0	0	1808	3114
2036	0	0	0	0	0	0	0	1833	3116
2037	0	0	0	0	0	0	0	1858	3118
2038	0	0	0	0	0	0	0	1884	3121
2039	0	0	0	0	0	0	0	1909	3123

Source: Siemens

Energy generated from thermal generation decreases slightly over the years while energy coming from renewables increases as more installed.

Exhibit 363: Portfolio All MISO Energy by Resource Type by Year

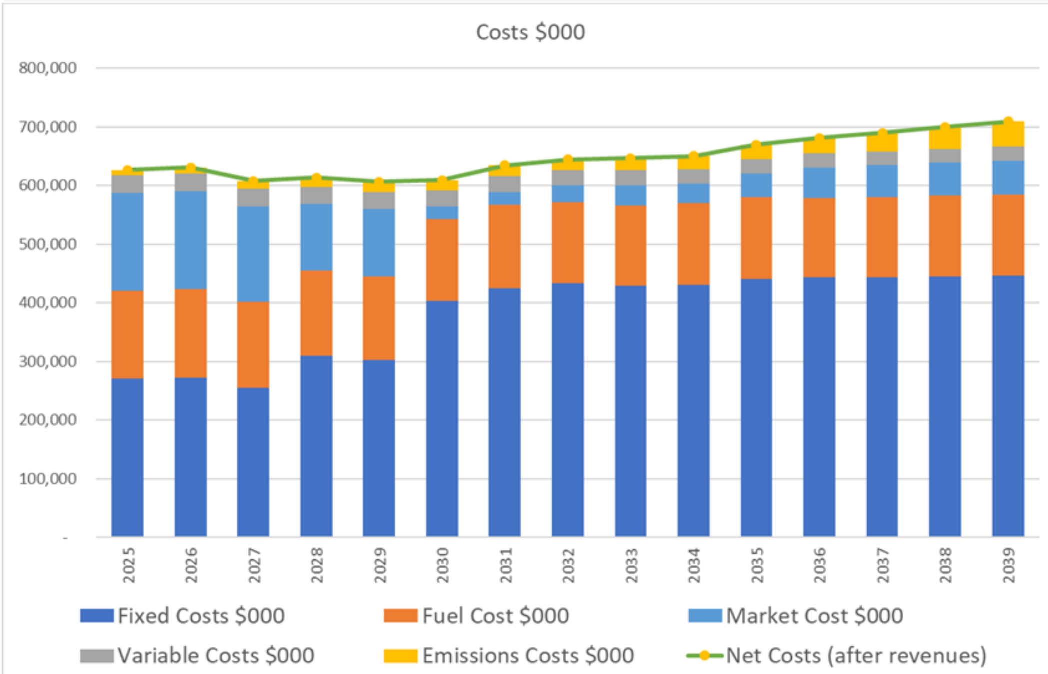


Source: Siemens

Portfolio Costs

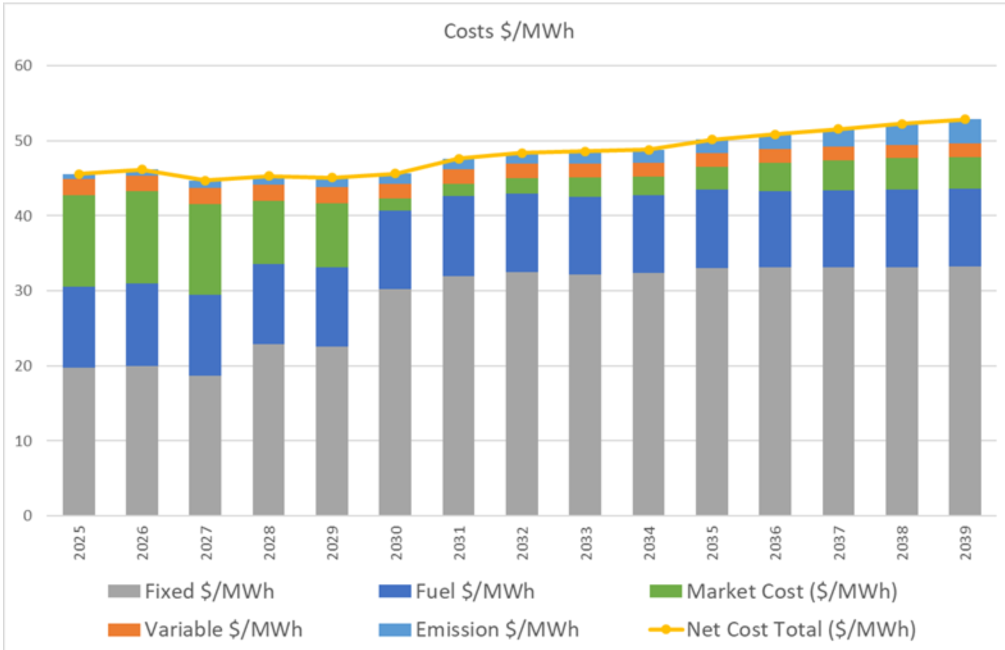
Exhibit 364 shows the supply side NPV cost by year, as can be seen the cost is about $640 million per year (2018 $) or $48.5/MWh, where fixed cost is the largest components due to the investments in generation, followed by cost of fuels and market purchases.

Exhibit 364: Portfolio All MISO Cost Components 2018 $



Source: Siemens

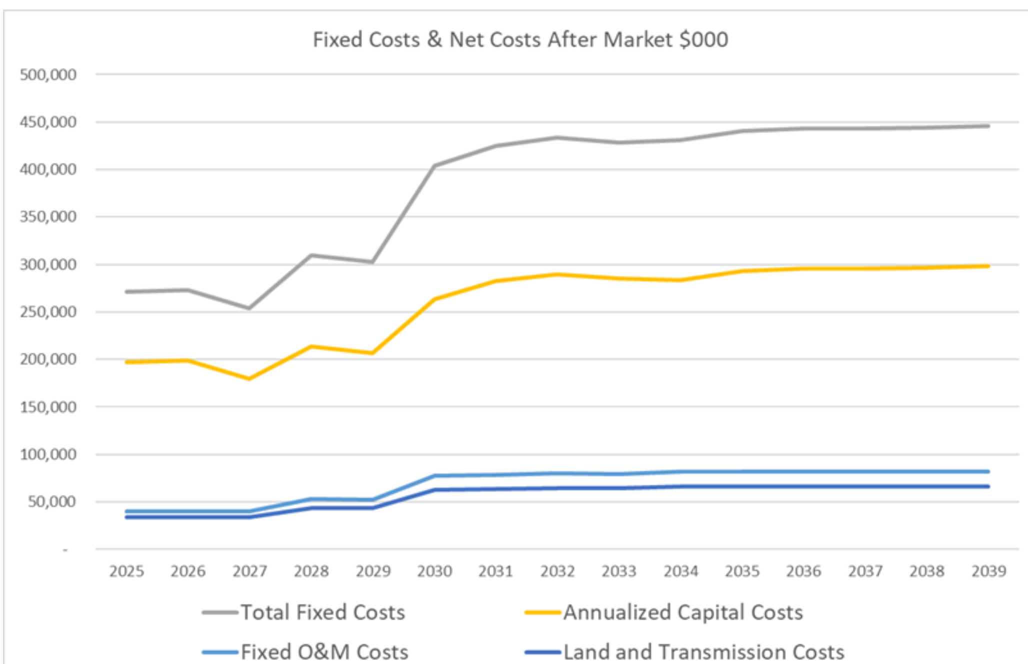
Exhibit 365: Portfolio All MISO Cost Components 2018 $/MWh



Source: Siemens

Exhibit 366 shows the breakdown of total fixed costs by component, where the majority comes from the base capital costs on generation.

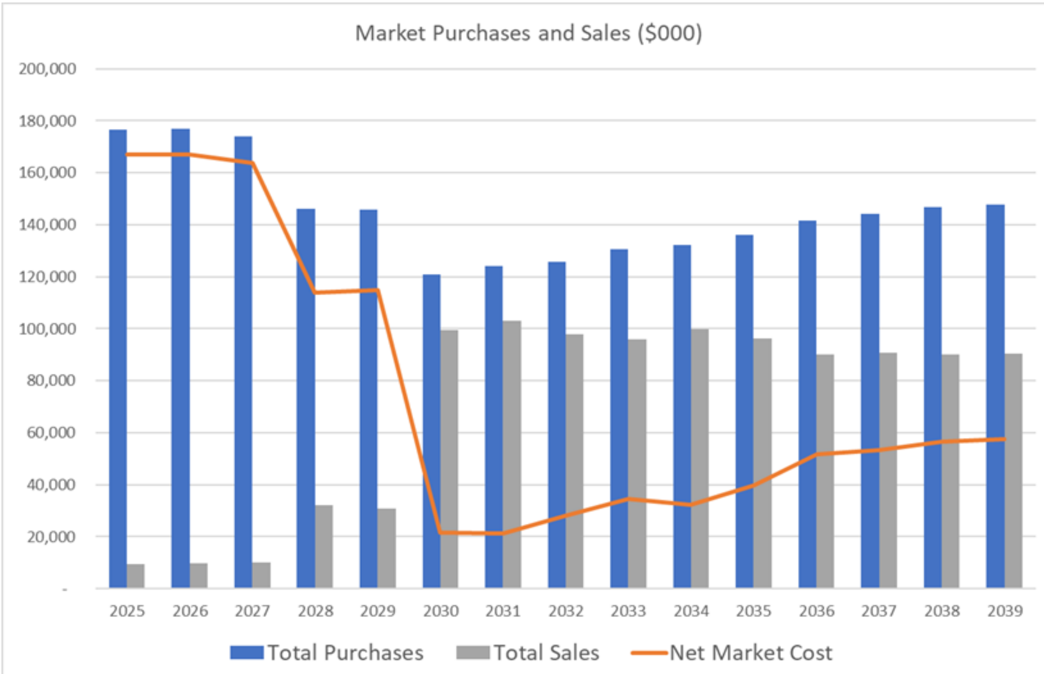
Exhibit 366: Portfolio All MISO Fixed Cost Components 2018 $



Source: Siemens

Market purchases and sales are also important components. The market purchases by MLGW system are projected to be decreasing then flat while the sales are increasing especially after 2030 although the sales are maintained at a low level.

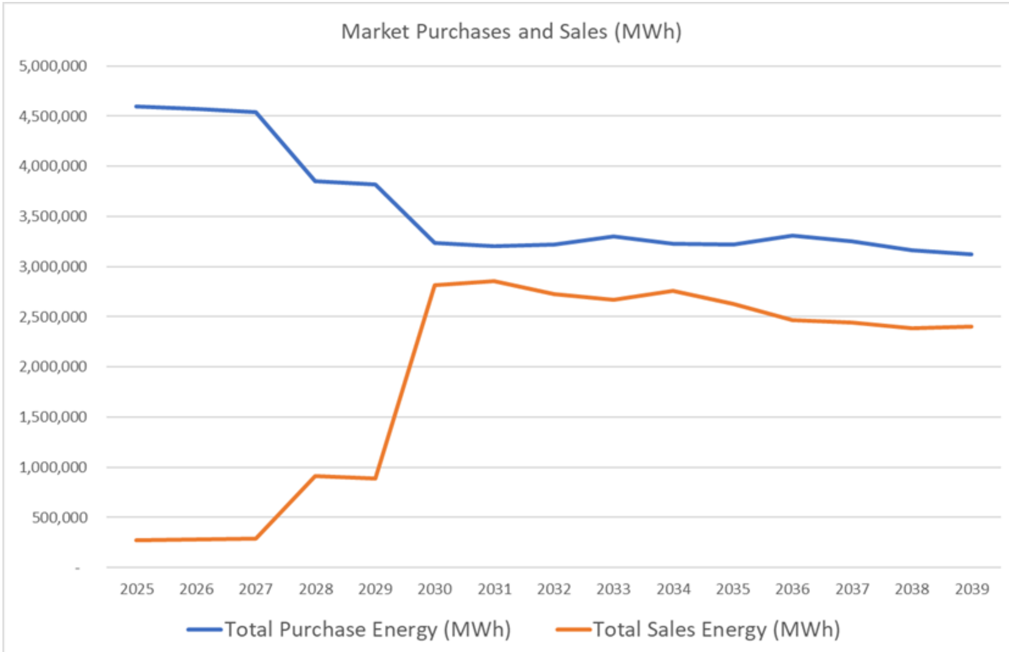
Exhibit 367: Portfolio All MISO Market Purchases and Sales 2018 $



Source: Siemens

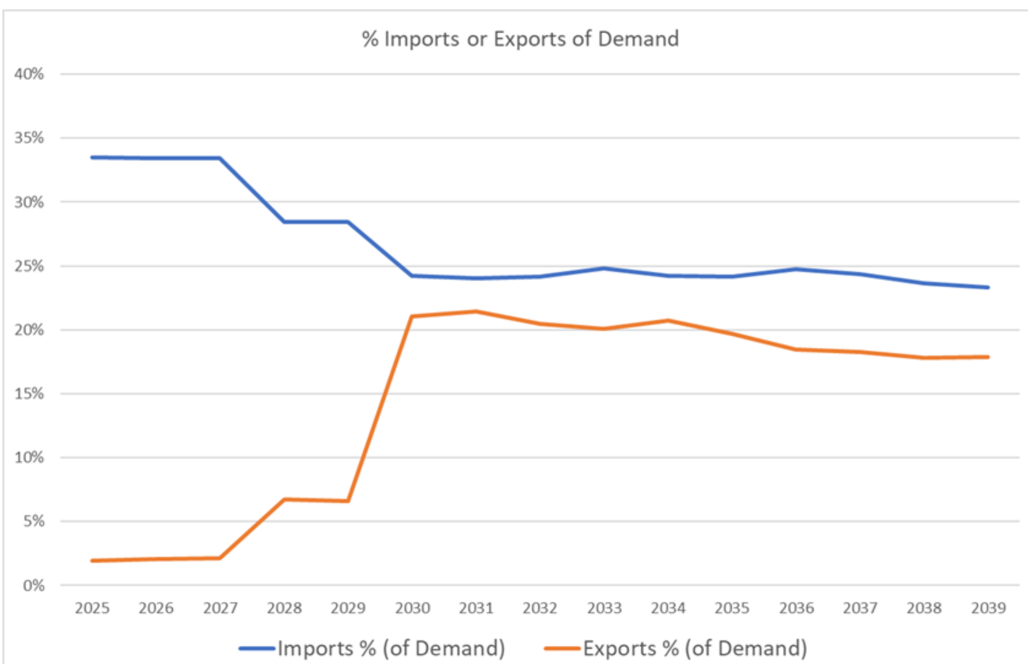
Exhibit 368 and Exhibit 369 show the purchases sales amount in energy and as % of demand, respectively. It shows the high market risk in the beginning of the planning years of this portfolio.

Exhibit 368: Portfolio All MISO Market Purchases and Sales in Energy



Source: Siemens

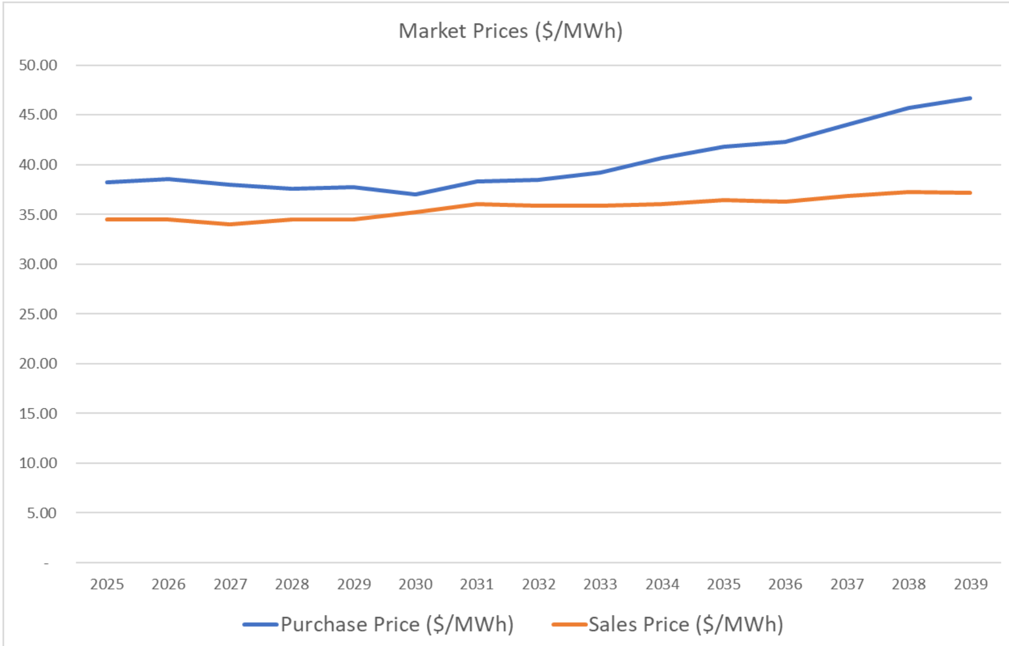
Exhibit 369: Portfolio All MISO Market Purchases and Sales as % of Demand



Source: Siemens

The risk can also be appreciated looking at the difference between purchase price (high) and sale price (low). The more purchase this portfolio needs, the higher risk.

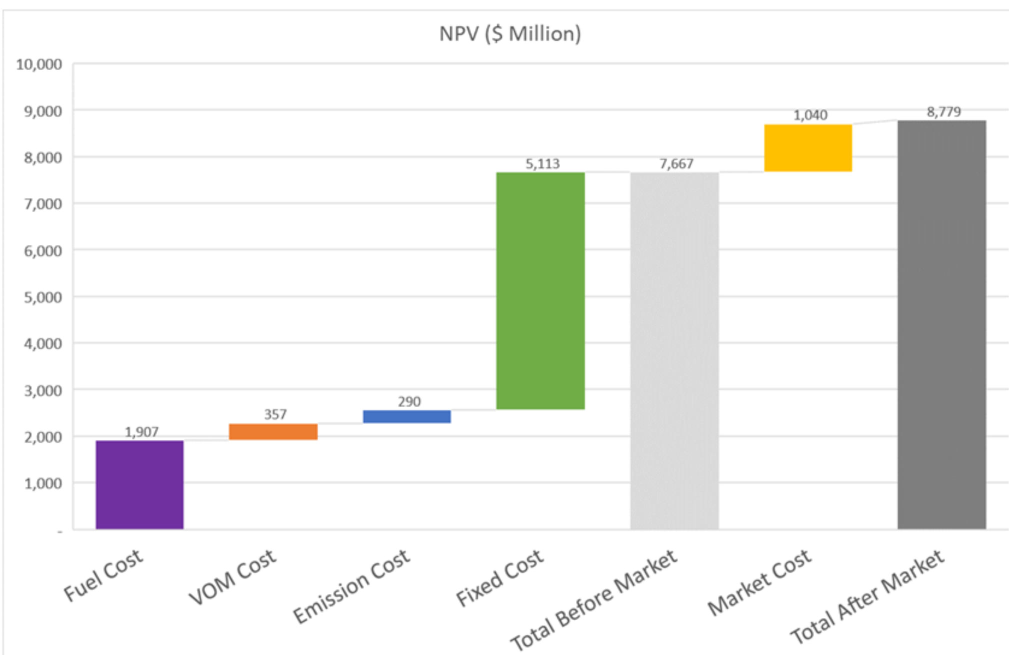
Exhibit 370: Portfolio All MISO Market Purchases and Sales Prices $/MWh



Source: Siemens

Exhibit 371 shows the supply side total NPV for 2025-2039, which is about $8.8 billion in 2018 $. Fixed cost is the largest component, followed by fuel and market costs.

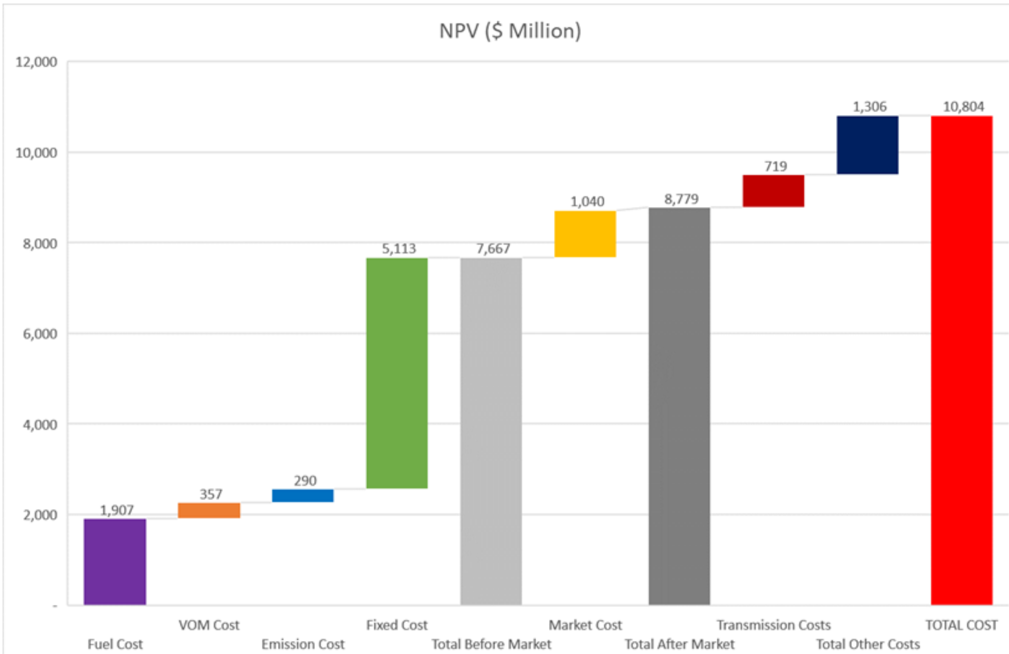
Exhibit 371: Portfolio All MISO Generation Resource NPV 2018 $



Source: Siemens

The total NPVRR of this portfolio is approximately $10.8 billion for 2025-2039 in 2018 $.

Exhibit 372: Portfolio All MISO All NPVRR with Other Components 2018 $

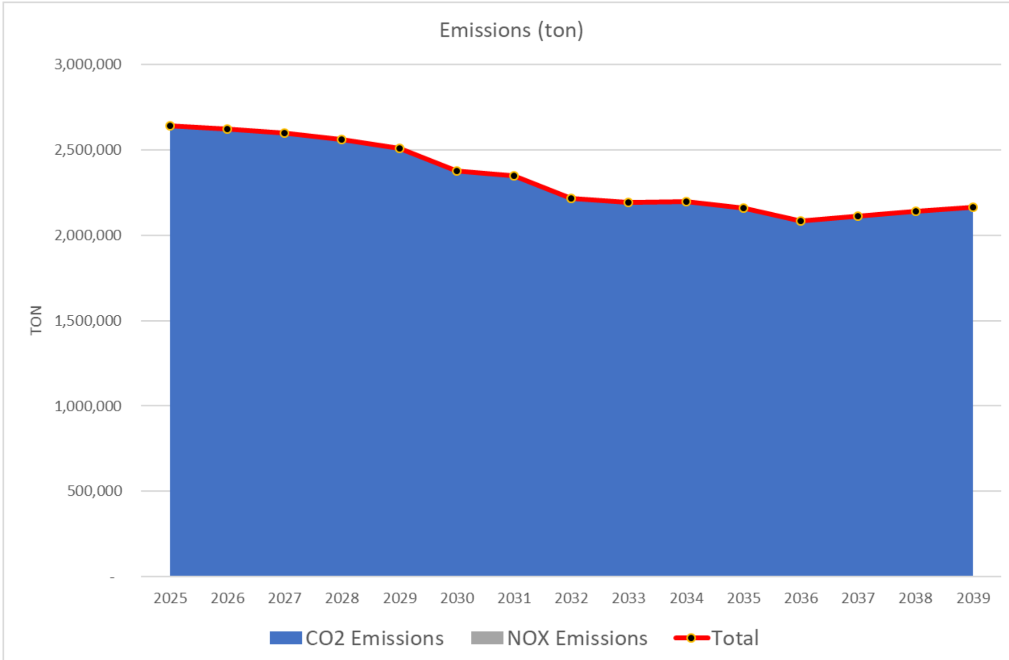


Source: Siemens

Environmental

The emission from this portfolio is shown in the graph below. The emission is low compared with other Portfolios due to high renewables and low thermal generation in this portfolio.

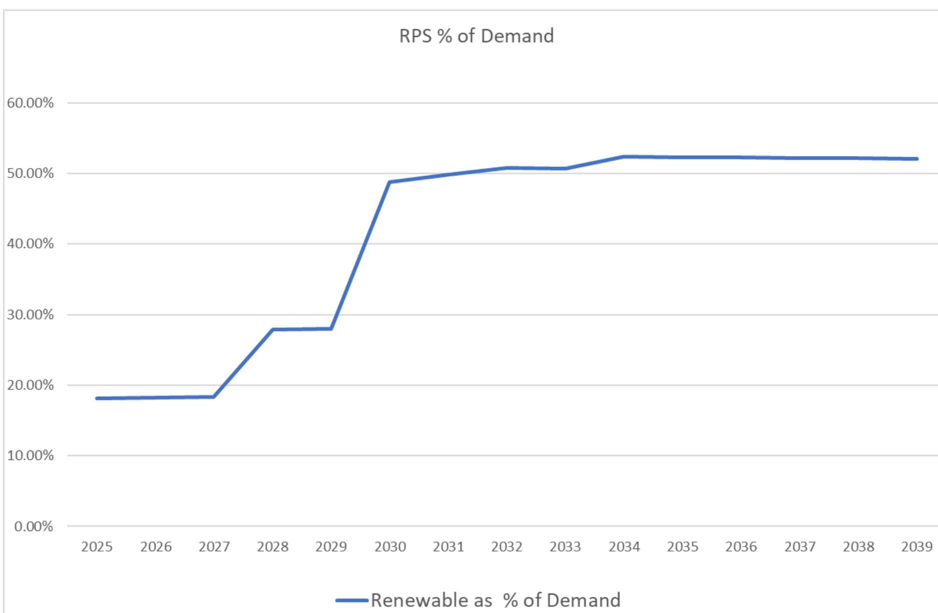
Exhibit 373: Portfolio All MISO MLGW Emission by Year



Source: Siemens

This RPS as a % of demand of this portfolio starts at about 20% and reaches 53% in 2039 as lots of renewable generation is built in this portfolio.

Exhibit 374: Portfolio All MISO RPS by Year

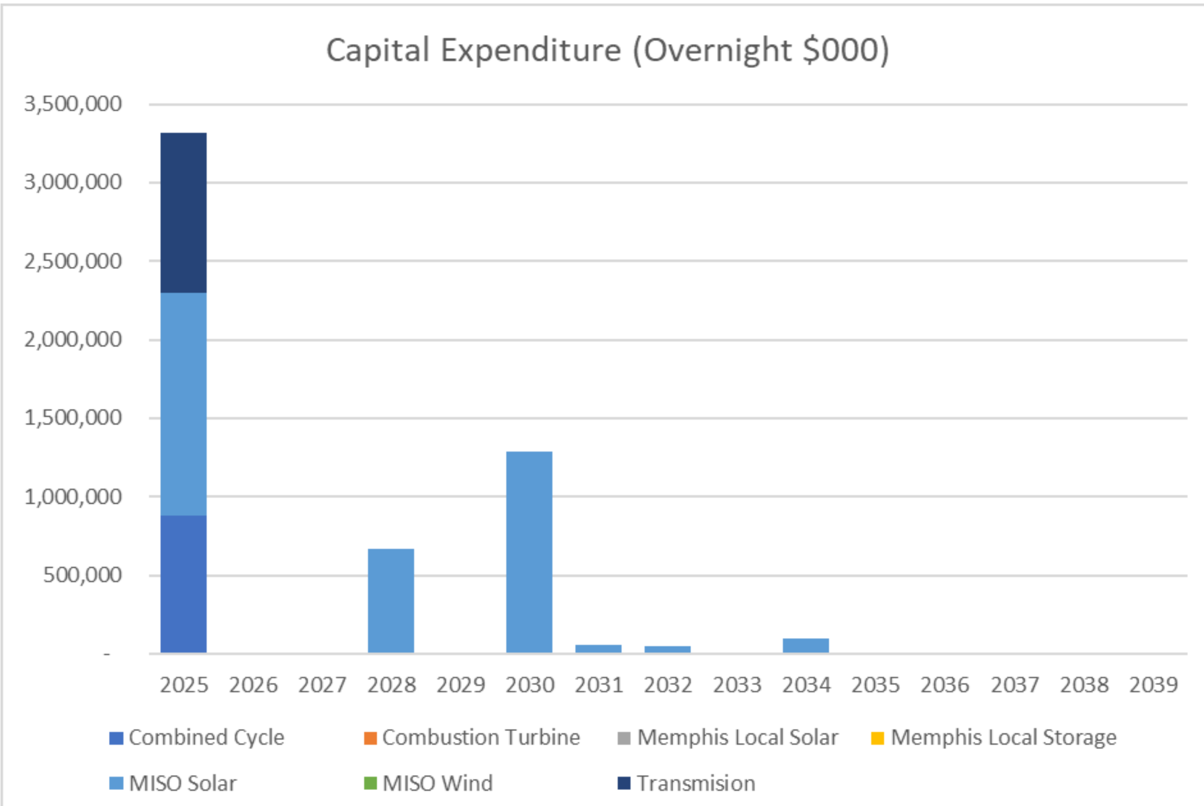


Source: Siemens

Capital Expenditure

Total capital expenditures on generation and transmission are shown in the graph below. Siemens present these capital expenditures in overnight from 2025 to 2039 while the actual drawdown may vary. Most of the CapEx are on the generation side and occur prior to 2025. Note that only the transmission CapEx is expected to be covered by MLGW as the generation CapEx is assumed to be expensed by third parties and recovered via PPA payments from MLGW.

Exhibit 375: Portfolio All MISO Overnight Capital Expenditure by Year



Source: Siemens

Appendix E: Glossary

Abbreviation	Meaning
AACE	American Association of Cost Engineers
ACA	Annual Charges Adjustment
ACE	Affordable Clean Energy
AEO	Annual Energy Outlook
AFC	Accelerated Fleet Change
AGC	Automatic Generation Control
All-in Capital Cost	The Capital Costs for Building a Facility Within the Plant Boundary, Which Includes Equipment, Installation Labor, Owners' Costs, Allowance for Funds Used During Construction, and Interest During Construction.
Appalachia Basin	Marcellus Shale Play and Utica Shale Play
ARPA	U.S. Department of Energy Advanced Research Projects Agency
ATB	Annual Technology Baseline
Average Demand	Average of the Monthly Demand in Megawatts.
Average Heat Rate	The Amount of Energy Used by an Electrical Generator to Generate One Kilowatt Hour (KWH) Of Electricity.
Baseload Heat Rate	The Amount of Energy Used by An Electrical Generator to Generate One Kilowatt Hour (KWH) Of Electricity at Baseload Production. Baseload Production is the Production of a Plant at An Agreed Level of Standard Environmental Conditions.
BAU	Business as Usual
BES	Bulk Electric System
BESS	Battery Energy Storage System
BEV	Battery Electric Vehicles
Breakeven Cost	Average Price of Gas Required to Cover Capital Spending (Ideally Adjusted to Regional Prices.
BTU	British Thermal Unit = Unit of Energy Used Typically for Fuels.
CAGR	Compound Annual Growth Rate
CAPP	Central Appalachian Region
CC or CCGT	Combined Cycle Unit

Abbreviation	Meaning
CCGT	Combined Cycle Gas Turbines
CCS	Carbon Capture and Sequestration
CDD	Cooling Degree Days
CEL	Capacity Export Limit
CF	Capacity Factor. The Output of a Power Generating Asset Divided by the Maximum Capacity of that Asset.
CFC	Continued Fleet Change
CIL	Capacity Import Limit
CIP	NERC Critical Infrastructure Protection
CME	Chicago Mercantile Exchange
CONE	Cost of New Entry
CSAPR	Cross State Air Pollution Rule
CSP	Comprehensive Services Program
CT	Combustion Turbine
DER	Distributed Energy Resources, Distributed Generation, Small Scale Decentralized Power Generation or Storage Technologies
DET	Distributed and Emerging Technology
DS	Distributed Solar
DSC	Debt-Service Coverage
Dth	Dekatherm (Equal to One Million British Thermal Units Or 1 MMBTU)
EE	Energy Efficiency
EFOR	Equivalent Forced Outage Rate
EFT	Enhanced Firm Transportation (Varies by Pipeline but Can Include Short- or No-Notice Changes to Day-Ahead Nominations of Fuel Delivery
EIA	U.S. Energy Information Administration
EPA	Environmental Protection Agency
EPC	Engineering, Procurement, and Construction
FCITC	First Contingency Incremental Transfer Capability
FCRR	FERC Charge Recovery Rate
FID	Final Investment Decision

Abbreviation	Meaning
Flowgate	A Power Flow Path on the Transmission System Consisting of a Monitored Element Paired with A Contingency
FOM	Fixed Operations and Maintenance Costs
FSS	Firm Storage Service
FT	Firm Transportation. FT Capacity on a Natural Gas Pipeline Is Available 24/7 And Is More Expensive Than Interruptible Transportation (IT) Capacity but Unused FT Capacity Can Be Sold on Secondary Market.
FTE	Full Time Equivalent
FTR	Financial Transmission Right
FTS	Firm Transportation Service
Futures	Highly Standardized Contract. Natural Gas Futures Here Are Traded on the New York Mercantile Exchange (NYMEX) Or Chicago Mercantile Exchange (CME).
GDP	Gross Domestic Product
GHG	Green House Gas
GPCM	Gas Pipeline Competition Model
GT	Gas Turbine Same As CT
HDD	Heating Degree Days
HFO	Heavy Fuel Oil
HHV	Higher Heating Value
HRSG	Heat Recovery Steam Generator
HUM	Humidity
ICAP	Installed Capacity
ICCP	Inter-Control Center Communications Protocol
ILB	Illinois Basin
IPP	Independent Power Producer
IRP	Integrated Resource Plan
ISO	Independent System Operator
ITC	Investment Tax Credit
ITS	Interruptible Transportation Service
LBA	Local Balancing Authority
LCOE	Levelized Cost of Energy

Abbreviation	Meaning
LCR	Local Clearing Requirement
LDV	Light Duty Vehicle
LFC	Limited Fleet Change
LMP	Local Marginal Price
LNG	Liquefied Natural Gas
LOLE	Loss of Load Expectation
LOLH	Loss of Load Hours
LPC	Local Power Companies
LRR	Local Reliability Requirement
LRZ	Local Resource Zone
LTCE	Long Term Capacity Expansion Plan: Optimization Process to Select Generation
LTP	Long-Term Partnership
MACRS	Modified Accelerated Cost Recovery System
MISO	Midcontinent Independent System Operator
MMBtu	Million British Thermal Units, Unit of Energy Usually Used for Fuels.
MTEP	MISO Transmission Expansion Plan
MW	Unit of Power = 1 Million Watts
MWh	Unit of Energy Usually Electric Power = 1 Million Watts X Hour
NAPP	Northern Region
NERC	North American Electric Reliability Corporation
NPV	Net Present Value
NPVRR	Net Present Value Revenue Requirement
NRC	U.S. Nuclear Regulatory Commission
NREL	National Renewable Energy Laboratory
NYMEX	New York Market Exchange
ORNL	Oak Ridge National Labs
O&M	Operation and Maintenance
Peak Demand	The Maximum Demand in Megawatts (MW) for a Year.
PEV	Plug-In Electric Vehicles
PHEV	Plug-In Hybrid Electric Vehicles
PILOT	Payment In Lieu Of Taxes

Abbreviation	Meaning
POR	Planned Outage Rate
PPA	Power Purchase Agreement: Contract to Purchase the Power from a Generating Asset
PRB	Powder River Basin
PRM	Planned Reserve Margin
PSAT	Power Supply Advisory Team
PTC	Production Tax Credit
PV	Photovoltaic Generation
QNIT	Quick Notice Interruptible Transportation
QNT	Quick Notice Transportation
REGCA, REECA, REPCA	WECC Approved Models (REGCA, REECA and REPCA
Reserve Margin	The Amount of Electric Generating Capacity Divided by The Peak Demand.
RFI	Request for Information
RFP	Request for Proposal
RGGI	Regional Greenhouse Gas Initiative
RPS	Renewable Portfolio Standard: A Regulation that Requires the Increased Production of Energy from Renewable Energy Sources
RTO	Regional Transmission Organization
SMR	Small Modular Reactor
STATCOM	Static Synchronous Compensator
SVC	Static VAR Compensator
"Sweet Spot" Core Acreage	Areas Within A Natural Gas Play That Offer the Highest Production at Least Cost.
TARA	Transmission Adequacy and Reliability Assessment
TPL	NERC Transmission Planning Reliability Standard
UCAP	Generator Unforced Capacity
Utility Scale	Large Grid-Connected Power Generation, Could Be Solar, Gas, Diesel, Wind, etc.
VAR	Value at Risk
VOM or VO&M	Variable Operations and Maintenance Costs
WACC	Weighted Average Cost of Capital
WECC	Western Electricity Coordinating Council

Abbreviation	Meaning
Wheeling	A Transaction by Which a Generator Injects Power onto a Third-Party Transmission System for Delivery to a Client (Load)
WNS	Winter No-Notice Service
WPC	Wholesale Power Contract
WTG	Wind Turbine Generator
WTI	West Texas Intermediate
ZIA	Zone Import Ability