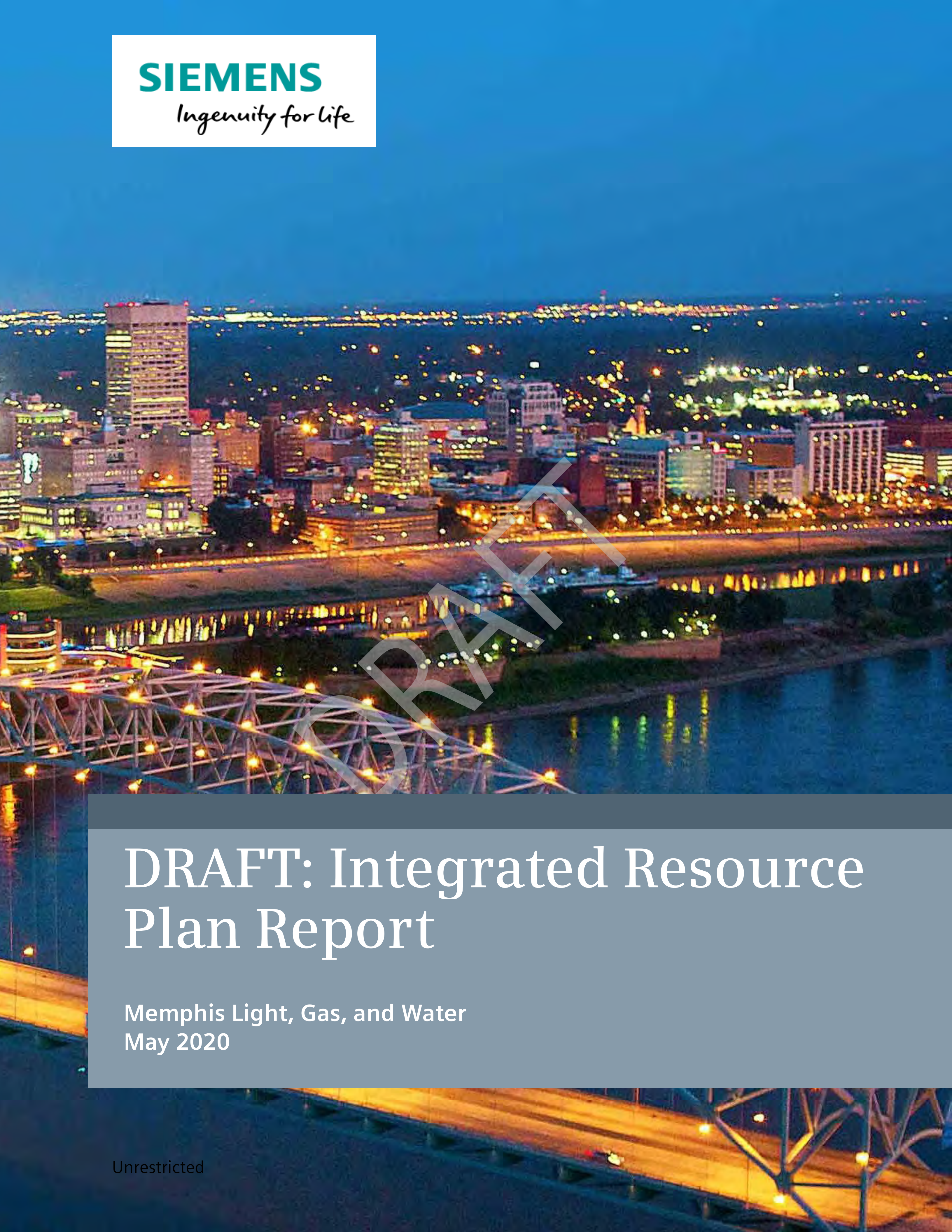

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DRAFT: Integrated Resource Plan Report

Memphis Light, Gas, and Water
May 2020

Unrestricted

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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 4,312,000 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 it's 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-supplies 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 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, we 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$). 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.

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 our 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 judgement is used to adjust the initial expansion plan and the AURORA LTCE was re-run with these adjustments in place, resulting in a unique Portfolio that is better suited to manage risks, such as reduced dependence on remote resources or 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
S3S7_BB	Portfolio 6	Base	Base	1137	1000	0	2137	2200	1761	0	2	1	0	9,214,886	50.89
S3S1_2CT	Portfolio 7	Base	Base	1374	1000	0	2374	2200	1550	0	2	2	0	9,125,223	50.39
S3S7_2CT	Portfolio 8	Base	Base	1374	1000	0	2374	2200	1550	0	2	2	0	9,251,110	51.09
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_F	Portfolio 2	Base	Base	1587	1000	0	2587	1550	1487	0	3	1	0	9,300,273	51.36
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
S3S10	Portfolio 10	Base	Base	950	1000	0	1950	2250	1909	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 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 the Portfolio 3. (As mentioned above, the different Scenarios, e.g. changing load, gas assumption, are aimed to produce different generation expansion portfolios for further analysis.)

This Portfolio was run with the reference case load 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 the 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 Portfolio

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

In this run, we assumed 3,500 MW import limit from MISO to MLGW and 2000 MW limit from MLGW to MISO. The import limit is about 300 MW more than the MLGW's peak forecasted load and 1300 MW more than the import limit assumption in the reference base. 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 the 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 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 levelized cost of BESS compared to CT, the NPV of the S3S6_N case is the highest among all reference cases.

Siemens tried to assess how low the cost of BESS had to be for BESS to become an economic option. Siemens lowered the 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), which was 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 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 the minimum levels of FERC thus the metric is designed to assess the level by NERC levels are exceeded. The ratio of Capacity Import Limits (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 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 are not counted as renewables in many states, including Tennessee).

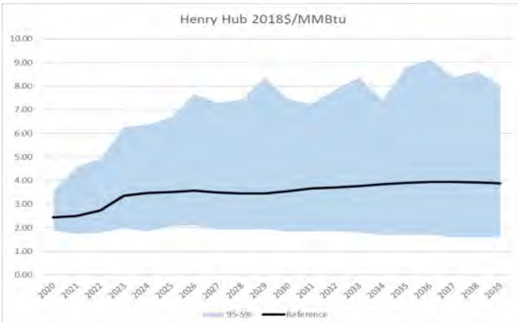
1.4 Key Inputs

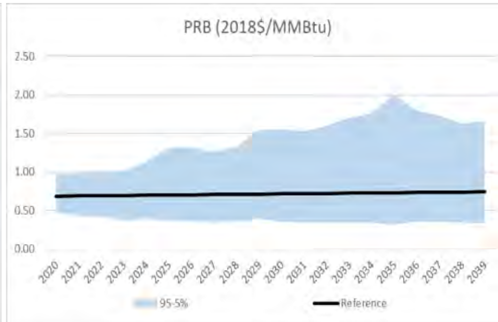
One of the critical reasons to utilize stochastics is that the analysis does not rely on a single point forecast for reaching the ultimate conclusions.

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

Exhibit 5: Stochastic Distributions

Fuels





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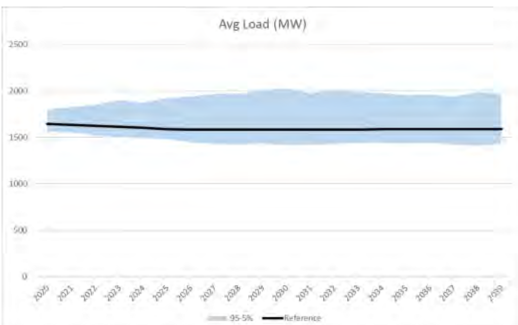
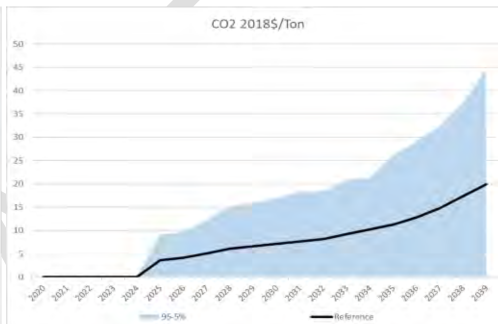
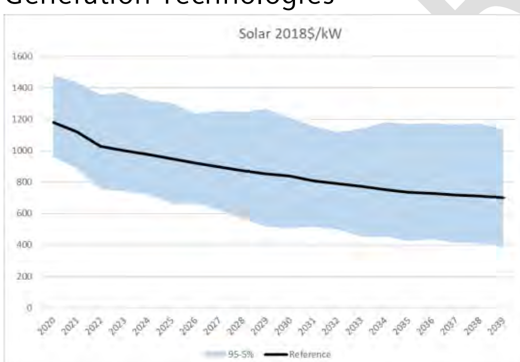
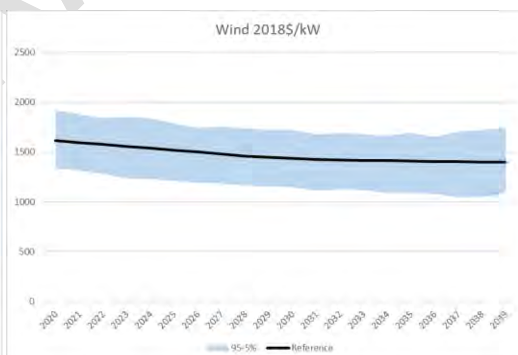
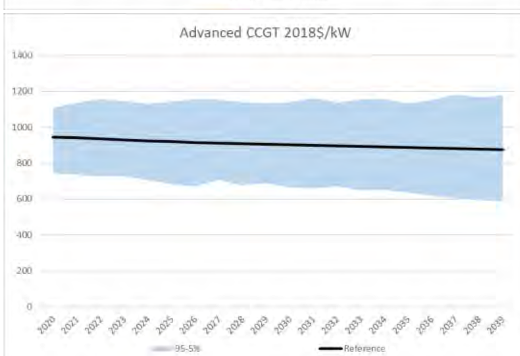


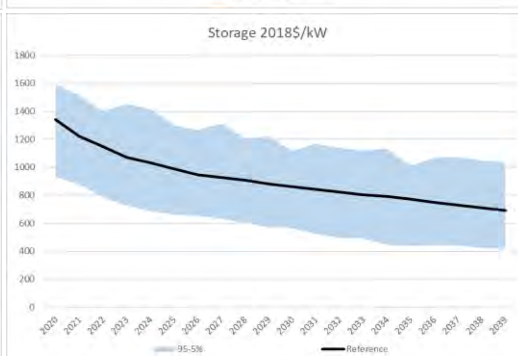


Generation Technologies





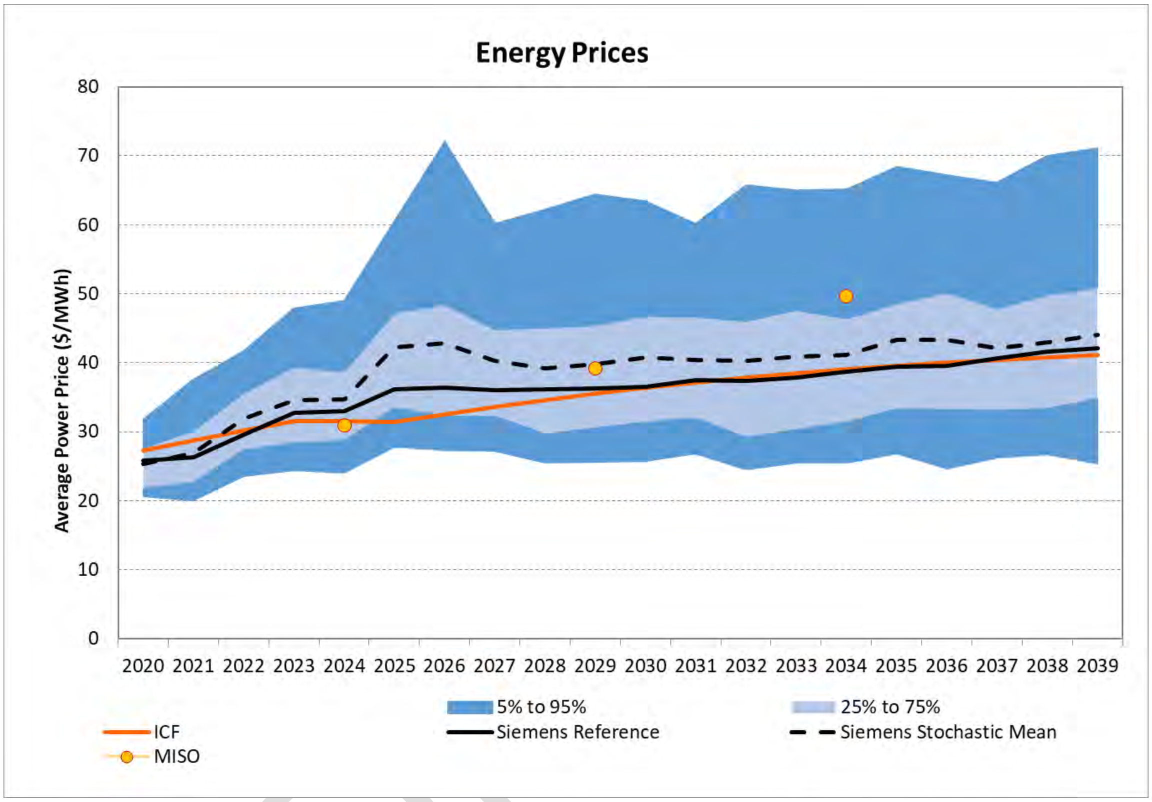




Source: Siemens

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

Exhibit 6: Energy Price Forecast for MISO Arkansas



Source: Siemens

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 above displays these prices.

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

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 are in compliance with NERC reliability requirements.

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

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

Portfolio 5 (see Exhibit 3), which is based on heavy investment in transmission to secure the maximum amount of renewable generation and only has one CCGT in MLGW footprint, exhibited the lowest expected cost; i.e. it had the lowest mean of the NPV of Revenue Requirements (NVPRR) on the stochastic runs, and it is the most environmentally sustainable portfolio of the group. While Portfolio 5 meets all reliability and resource adequacy requirements, it one of the least reliable of all the Portfolios as evidenced by significant load shedding and is also more dependent on market purchases and MISO capacity purchases than the other Portfolios.

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

Portfolio 10 (see Exhibit 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 move it to the third position according to the NPVRR on the stochastic analysis.

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

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

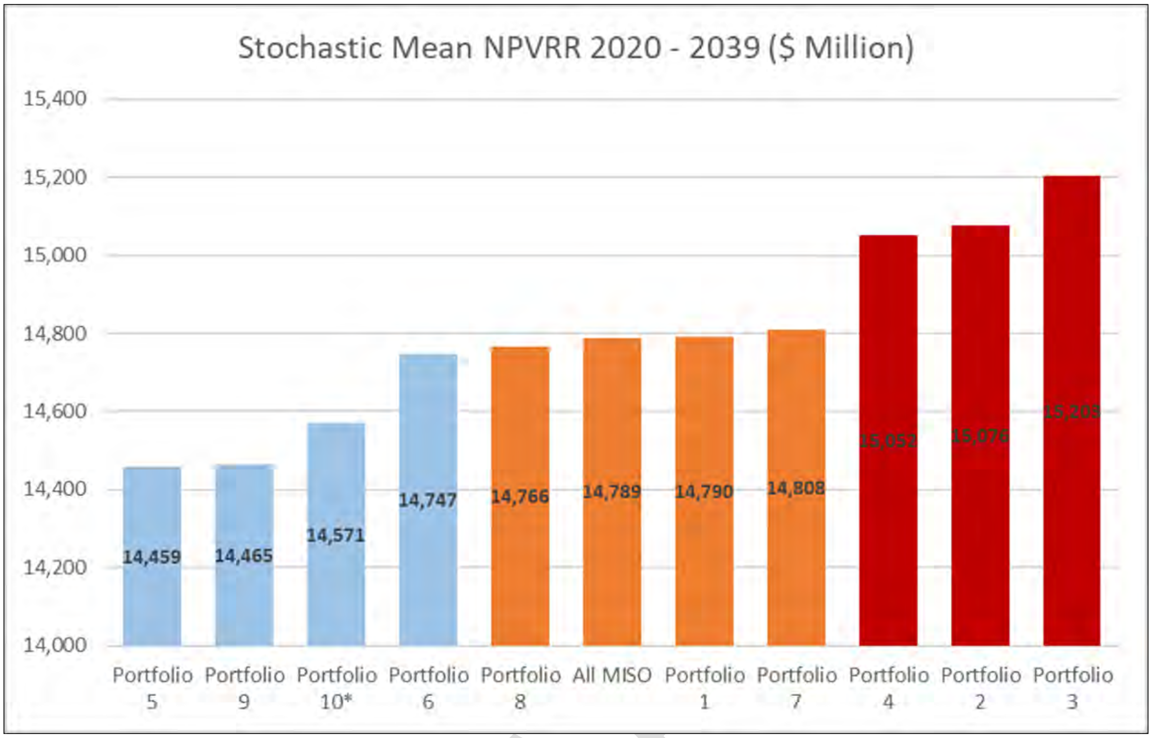
MLGW is too large to depend exclusively on the volatile day ahead energy market. The main drawbacks of this Portfolio are that: (a) all resources are outside MLGW and the entire load is dependent upon transmission that could be affected under extreme events, (b) it requires more transmission than any of the other Portfolios resulting in greater construction costs and development risks, and (c) locally developed resources are more economic as they would not incur point to point transmission costs in MISO. This was demonstrated with Portfolio 10, which is identical to the All MISO portfolio but with 1000 MW of local PV and the large combined cycle unit also locally developed (see Exhibit 3). Due to all the above the All MISO portfolio is not included in the final group for analysis.

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 service territory: best with one CCGT, next with two CCGTs (All MISO being the only exception), and last with three CCGTs. Additionally this exhibit shows the risk associated with these portfolios measured as the 95th percentile result and we note that Portfolio 9 has slightly less risk than Portfolio 5, possibly due to the flexibility added by the 4 CTs advanced, and Portfolio 10 and the All MISO portfolio have slightly higher risk than the other portfolios, possibly due to the dependence on one large CCGT[1].

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

[1] 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).

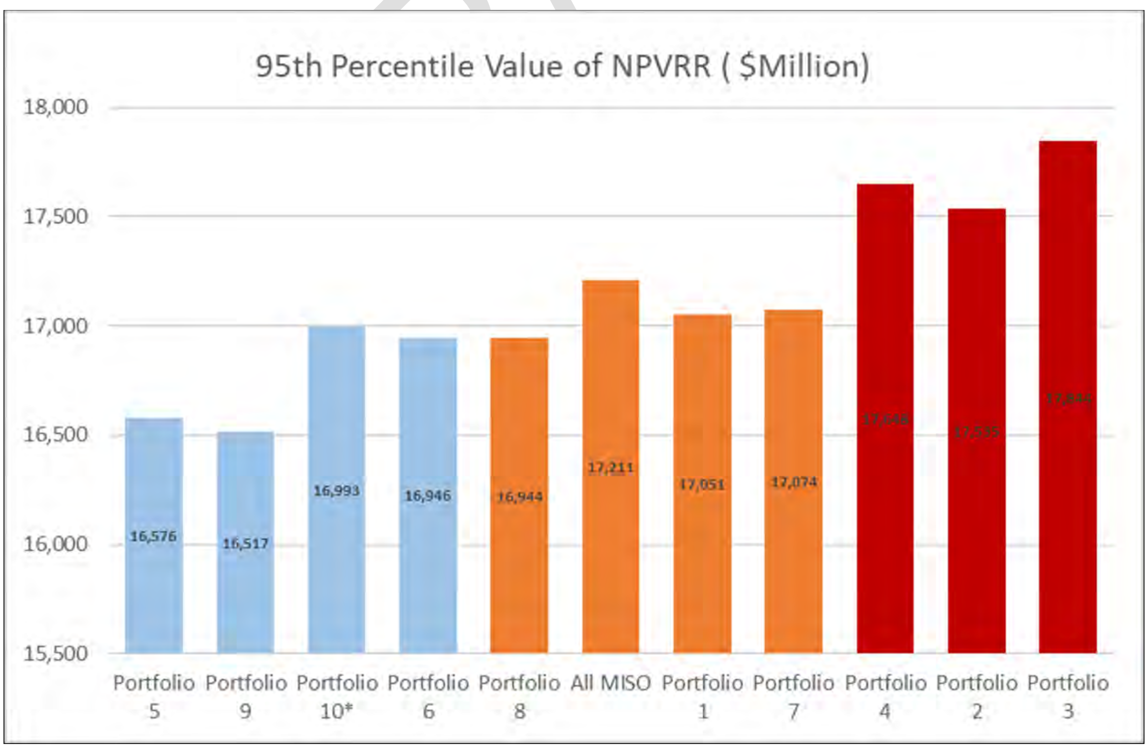
Exhibit 7: Ranking of Portfolios According to NPVRR



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

1.6 Comparisons with TVA

Exhibit 9 displays the Balanced Scorecard, which shows all the metrics for all the portfolios. It is a complicated figure, but to make it easier to digest, we have added colors for the rows to show which portfolios performed best on each measure (green is best and red is worst performing).

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

Below each metric is looked at separately.

Exhibit 9: Summary of Overall Results

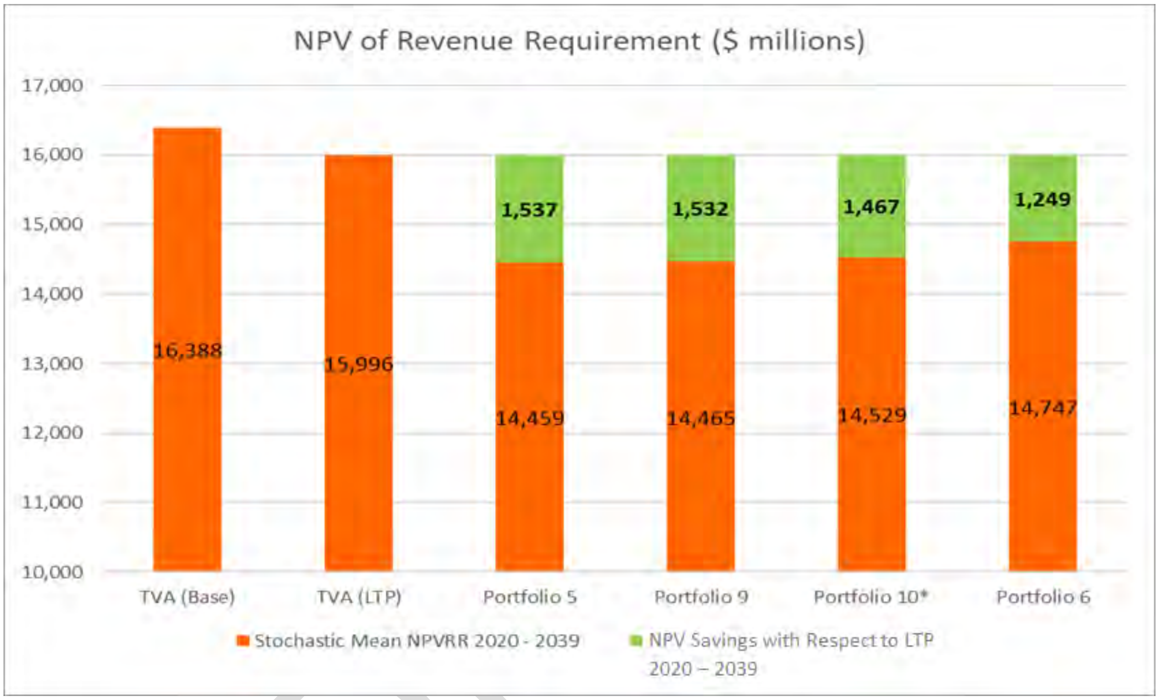
Objective	Measure	Unit	TVA (Base)	TVA (LTP)	Portfolio 5	Portfolio 9	Portfolio 10	Portfolio 6	Portfolio 8	All MISO	Portfolio 1	Portfolio 7	Portfolio 4	Portfolio 2	Portfolio 3
					1 CC + 4 CT	1 CC + 4 CT	1 CC + 0 CT	2 CC + 1 CT	2 CC + 2 CT	1 CC + 0 CT	2 CC + 1 CT	2 CC + 2 CT	3 CC + 1 CT	3 CC + 2 CT	3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

Source: Siemens

1.6.1 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.

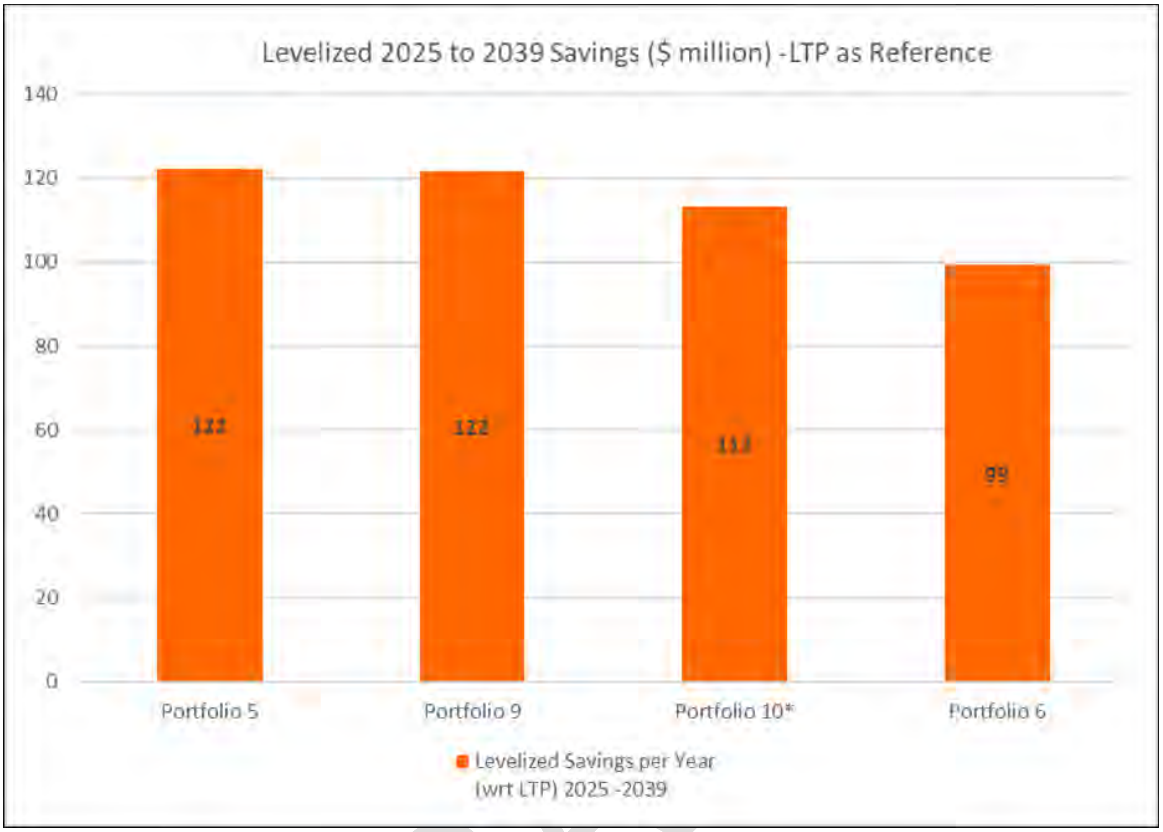
Exhibit 10: Affordability



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.

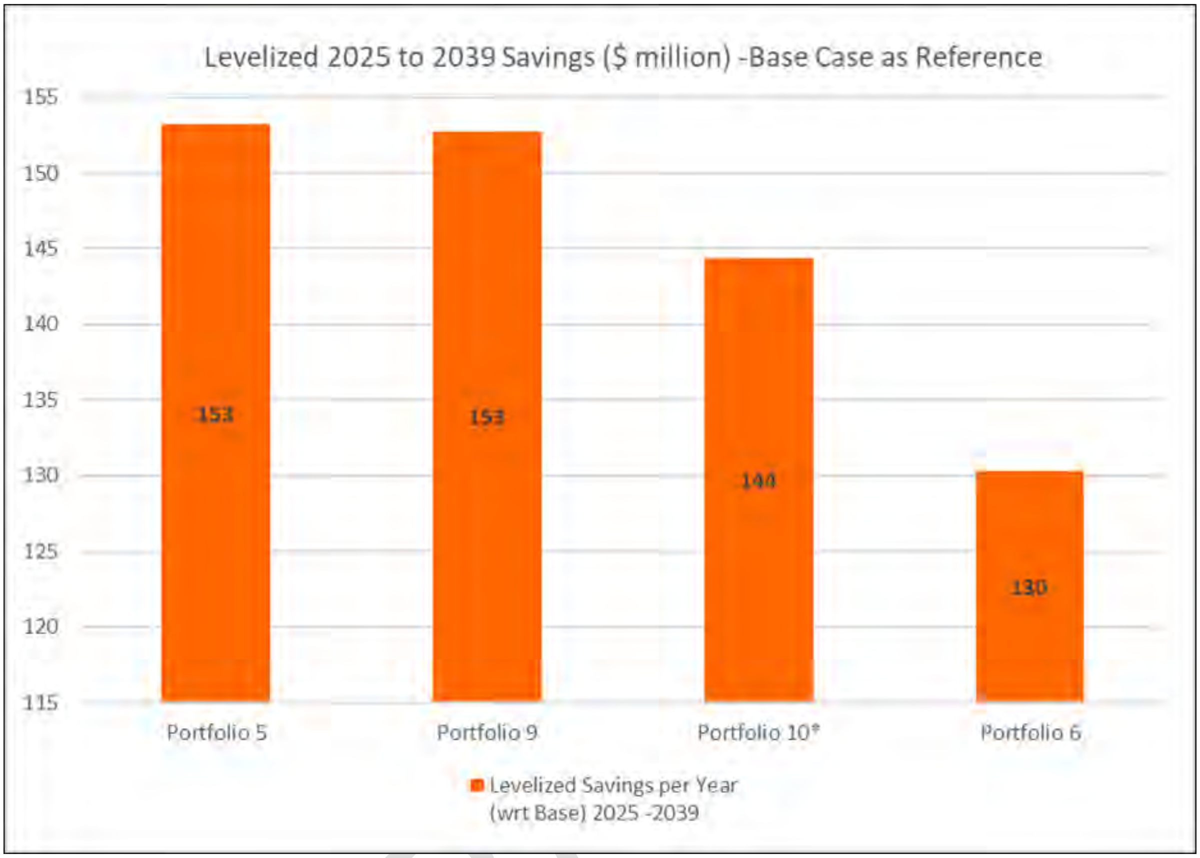
Exhibit 11: Levelized Savings per Year with Respect to the LTP



Source: Siemens

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

Exhibit 12: Levelized Savings per Year with Respect to the Base TVA Contract

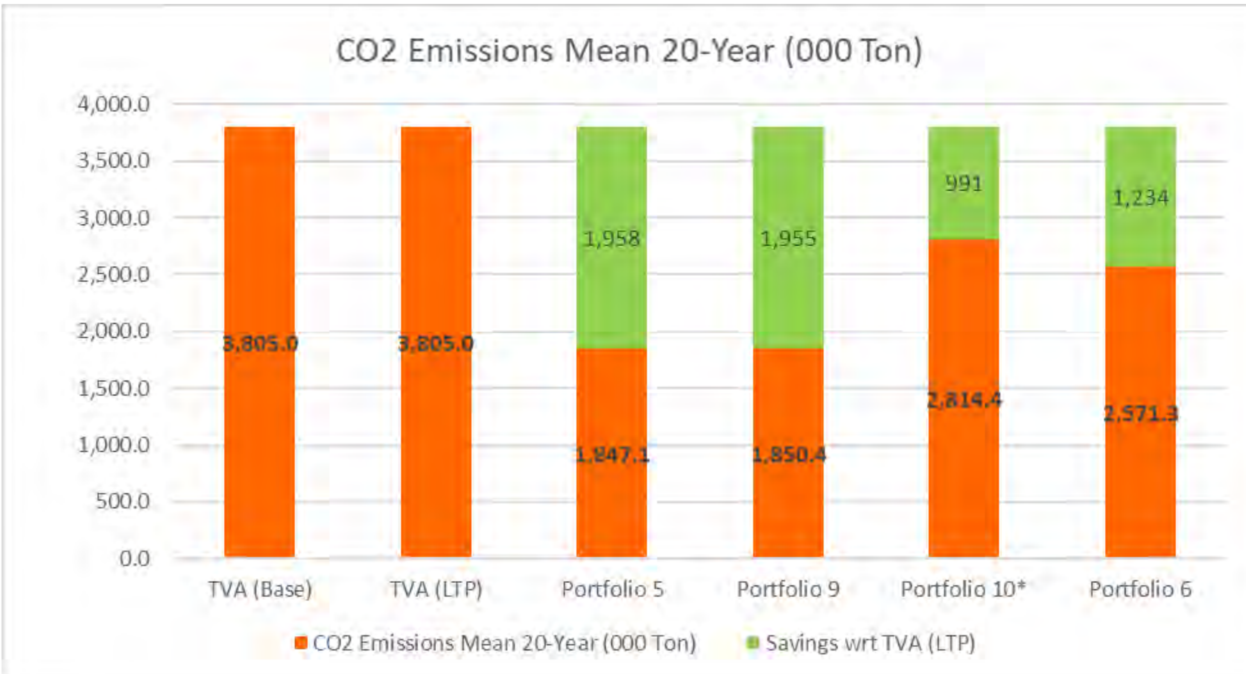


Source: Siemens

1.6.2 Sustainability Metric

Exhibit 13 shows that Portfolios 5 and 9, with their high levels of renewable generation, have significantly lower carbon emissions than the TVA options. For TVA the fleetwide CO_2 production by year was allocated to MLGW as a function of the ratio of MLGW load to total TVA load. Portfolio 10 and Portfolio 6 are also lower emissions but to a lesser degree due to the larger size of the thermal CCGT and less renewables.

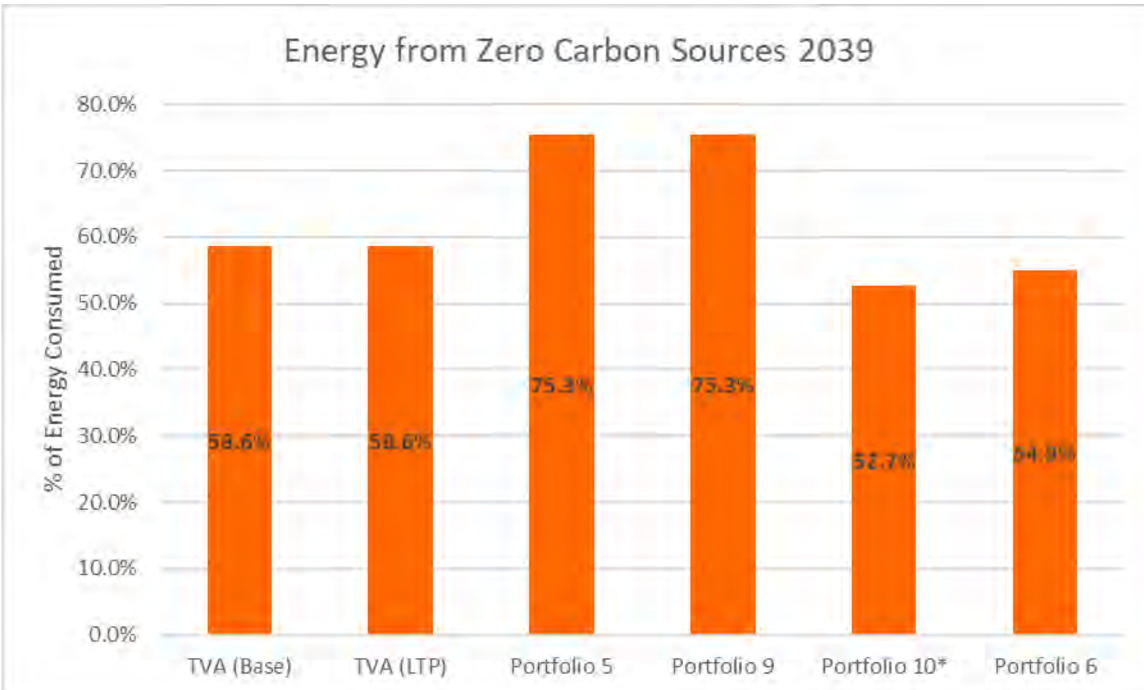
Exhibit 13: Environmental



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 14).

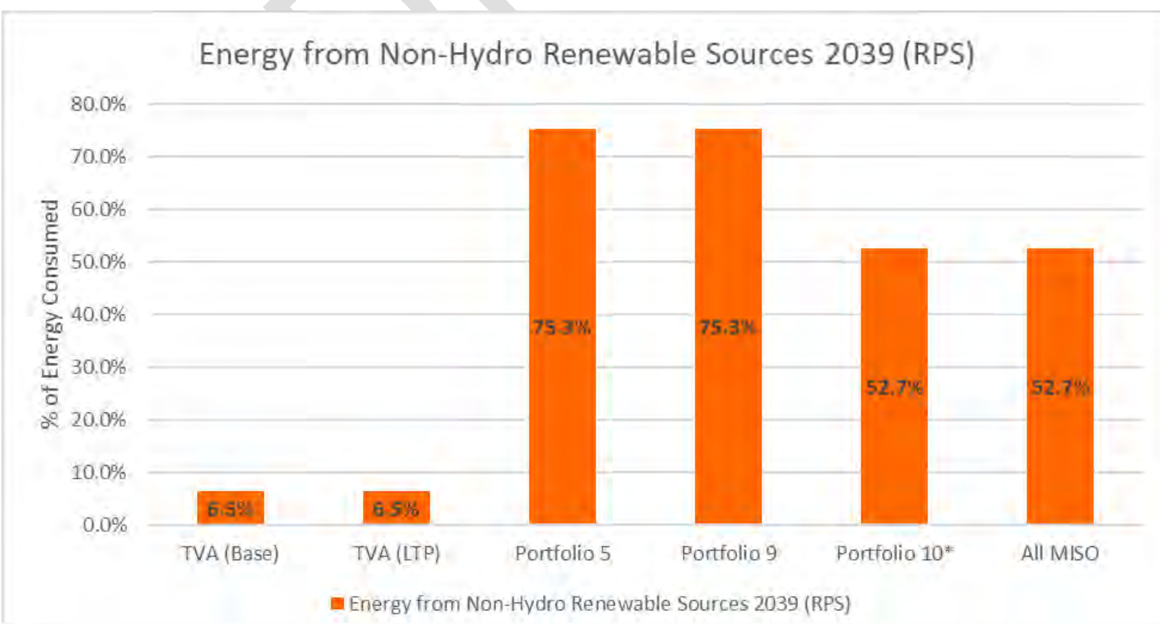
Exhibit 14: Zero Carbon Sources



Source: Siemens

Considering only photovoltaic and wind generation in the RPS, TVA fares poorly on an RPS measure. Even if large hydro were considered, this value would only increase to 16%. Exhibit: 15 displays a comparison of renewable energy as a percentage of total energy.

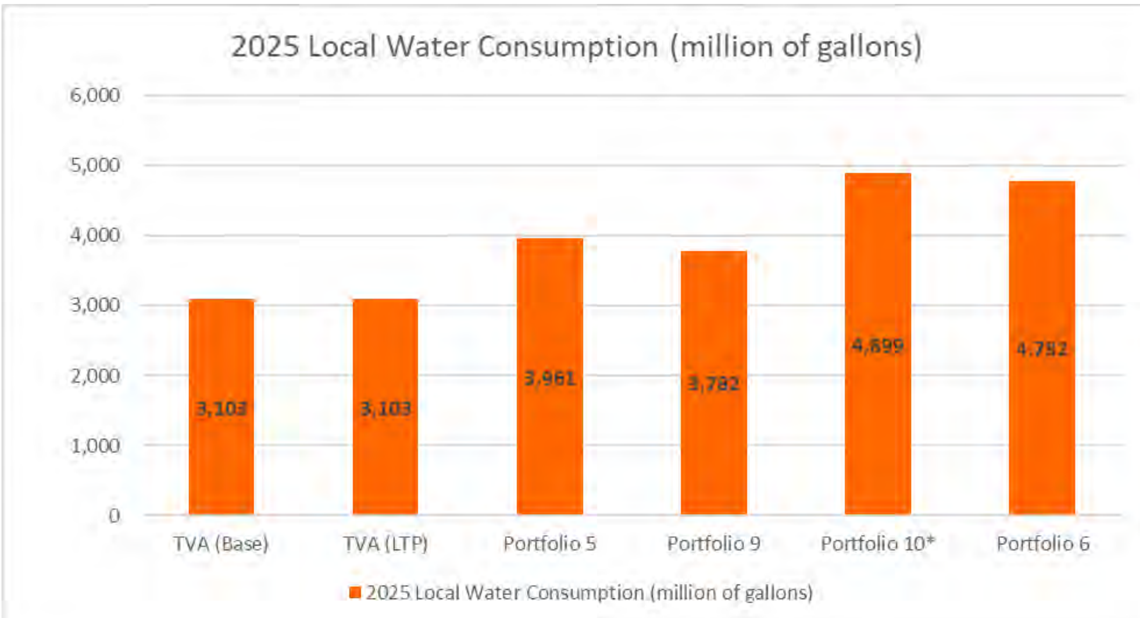
Exhibit: 15 RPS



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 16 below.

Exhibit 16: Water Consumption



Source: Siemens

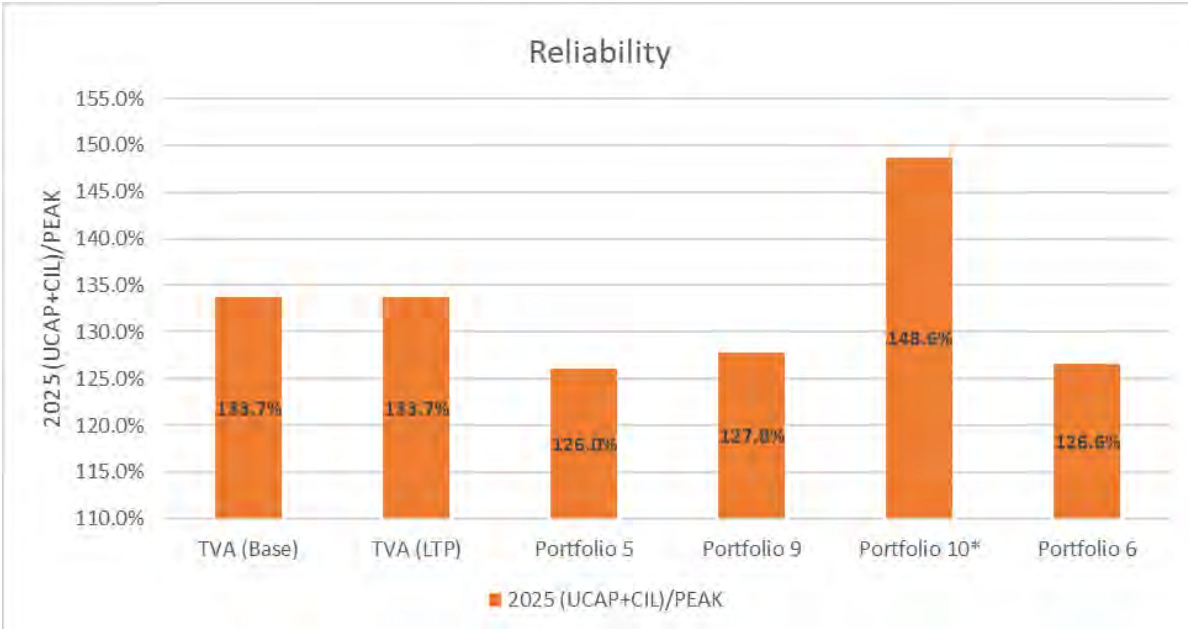
1.6.3 Reliability

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 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.

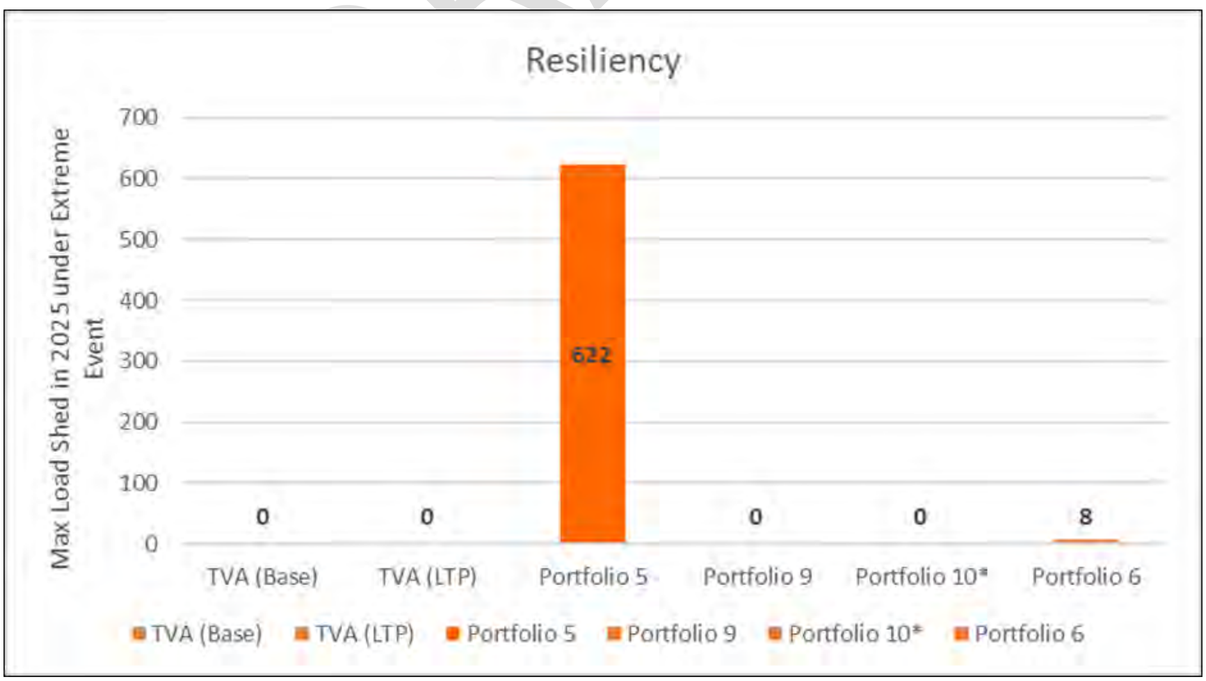
We also note that Portfolio 10 has the highest value according to this metric, but it can be misleading as this portfolio has only one large CCGT and its extended outage could lead to dependence exclusively on transmission, similar to Portfolio 5, but in this case it was reinforced allowing the incorporation 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 17: Reliability



Source: Siemens

Exhibit 18: Resiliency

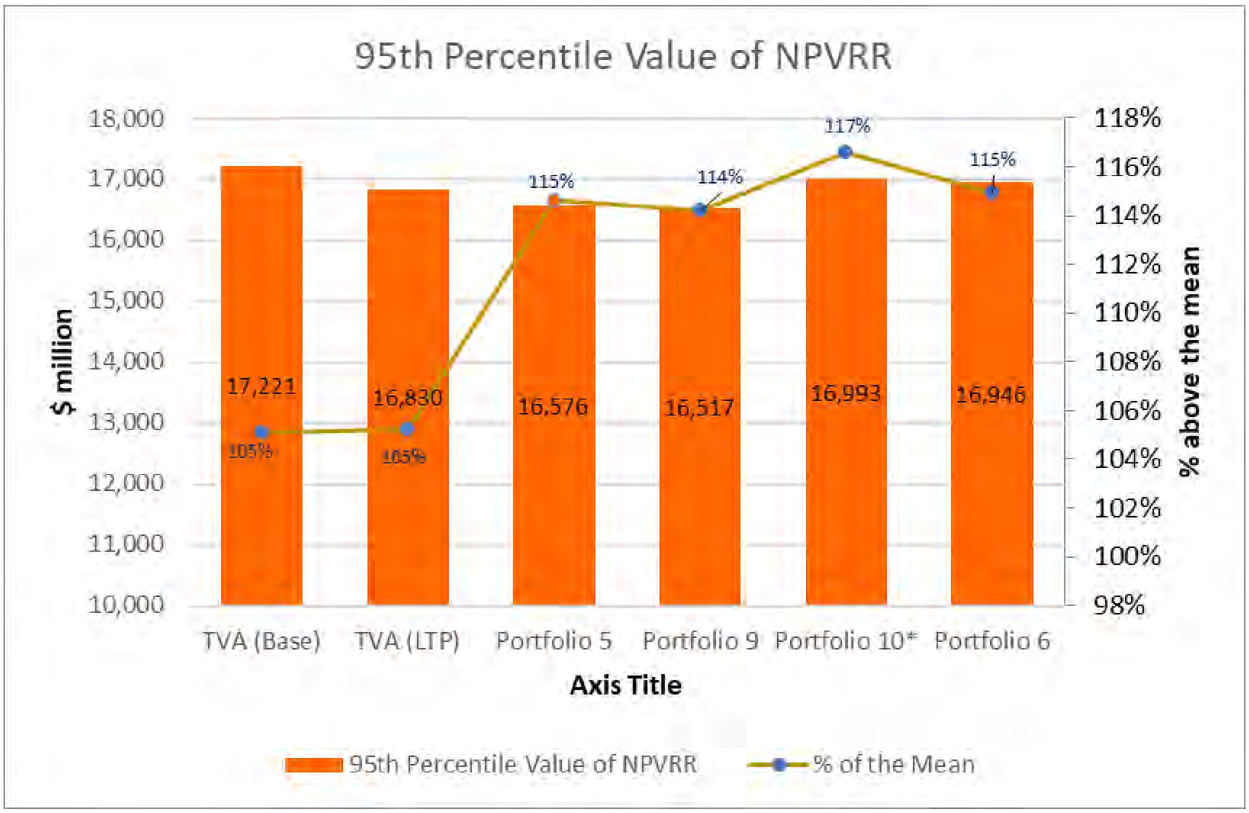


Source: Siemens

1.6.1 Price Risk

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

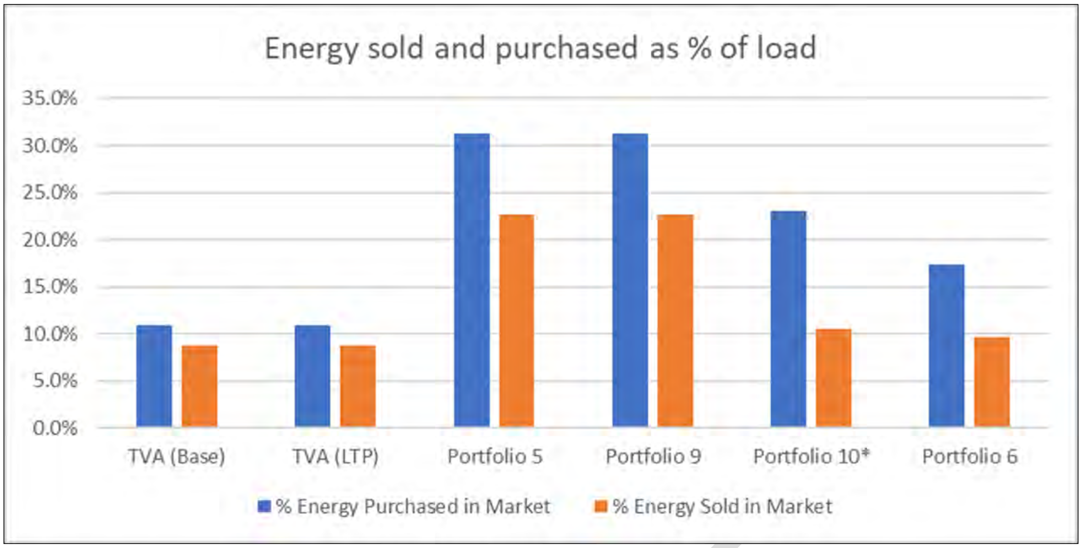
Exhibit 19: 95th percentile of revenue requiriments and changes with respect of the mean



1.6.2 Market Risk

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

Exhibit 20: Market Risk

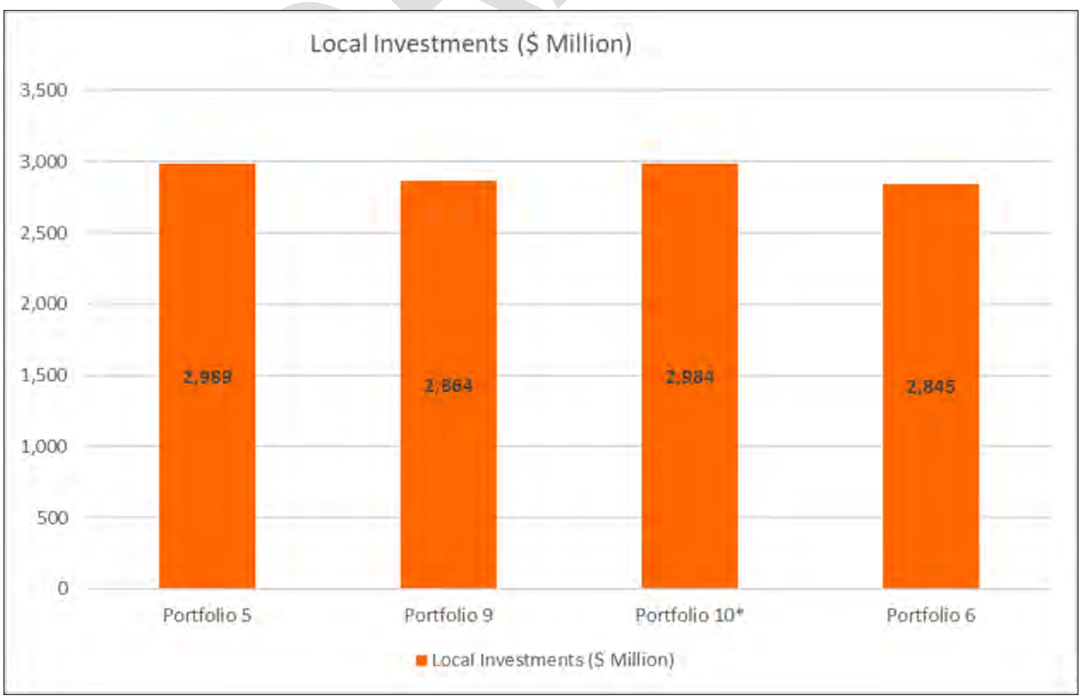


Source: Siemens

1.6.3 Local Economic Development

Local economic development is measured using the total local capital expenditures per Portfolio as a proxy. This is presented just for portfolios ranking purposes. As can be observed below all portfolios are very similar, with Portfolio 5 and 10 slightly ahead largely due to the transmission investments.

Exhibit 21: Economic Development



Source: Siemens

1.6.4 Findings and Recommendations

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

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

The key findings of our study are:

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

  – MLGW should seek to become part of MISO Local Resource Zone 8 rather than becoming an independent zone. Both MLGW and the current members stand to gain from this given the diversity between the loads and the larger size of the new zone.

- In case MLGW decides to stay with TVA, MLGW should
  – Explore options to increase the amount of local renewable generation (which would be limited to 5% even under the 20-year exit option).

  – Assess further the LTP option. On one hand there will be a reduction on the costs and the NPVRR with the LTP is approximately $400 million lower than without it. On the other hand, MLGW will be locked for 20 years and unable to control or take advantage of developments in the electric power industry such as, for example, deeper drops in the cost of renewable generation and storage that could increase the economic savings for reconsidering exiting TVA and joining MISO at a later date. This analysis can be performed at a later date and only needs to be performed if MLGW chooses to stay with TVA.

- The Payments in Lieu of Taxes (PILOT) is a payment that goes to both local and state government and directly or indirectly benefit the citizens, which are the same constituency of MLGW. Thus, the nature of who pays these costs is different than other costs. For example, payments to a generation developer, fuel costs, or investments in transmission may be treated differently and hence its impact should be considered separately. This cost is an important component of the total costs and savings. For example, in Portfolio 9 it represents approximately $720 million of the total NPVRR and it is likely larger than the payments that TVA would make in the case that MLGW decides to continue with the existing contract. MLGW should consider ways to minimize the differences between what TVA and MLGW pays for equivalent services where possible.

- An RFP should be undertaken by MLGW to confirm all estimated savings before making a final decision. The IRP can be utilized to determine the general mix of assets and locations of interest in the RFP and the orders of magnitude of transmission required. Differences between Portfolios 5, 9, 6, and 8 can be reassessed with bids provided by potential suppliers.

1.6.5 Magnitude of Savings for Exiting TVA

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

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

Exhibit 22: 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 we have the following:

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

Source: Siemens

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

Exhibit 24: Portfolio 9 Levelized Costs for 2025 to 2039 with Respect to TVA Current Contract

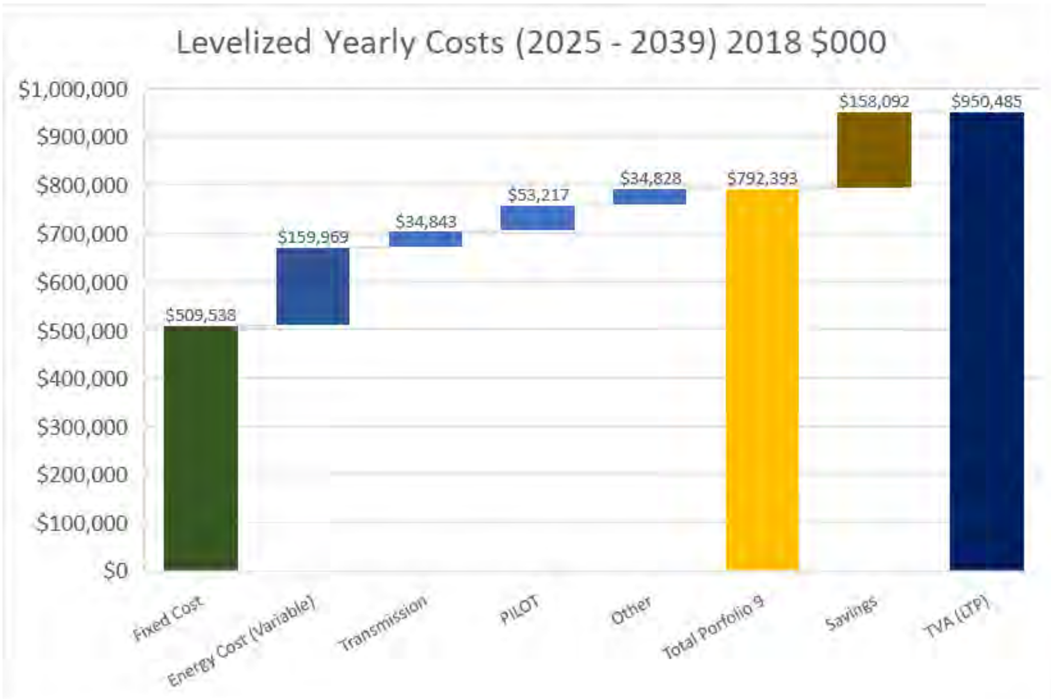


Exhibit 25: Portfolio 9 Levelized Energy Costs for 2025 to 2039 with Respect to TVA

Source: Siemens

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

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

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

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

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

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

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

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2. Introduction

Memphis Light, Gas and Water (MLGW) is the largest municipal utility in the State of Tennessee, serving approximately 4,312,000 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 in Tennessee and portions of Alabama, Mississippi, Kentucky, Georgia, 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 city and the state.

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 jurisdiction have accepted this offer.

Siemens was selected from an RFP conducted by MLGW to perform the IRP. This report presents the IRP report 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 Mid Continent ISO (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. 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 and 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. Ensure that there is 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 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 26: 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 Mid-Continent ISO or 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-Cherrypicking 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 will inevitably 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 view 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.

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)[2] 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 16% 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 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

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

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[3] 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 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)/ED. Termination of the contract will also terminate all programs in effect with the departing LPC. These payments would become a requirement of MLGW.

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

e. TVA can target any customer within the LPC territory without restriction. Hence TVA can enter negotiations to supply MLGW's members/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) the 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-supplies 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. [4]

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.

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 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.

[4] 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.

Exhibit 27: 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.[5] 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 favoring high levels of renewables and limits 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.

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

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 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. 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 build out 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 28 below provides a summary of the strategies and scenarios considered.

Exhibit 28: 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 29.

Exhibit 29: MLGW IRP Objectives and Metrics

OBJECTIVES	METRICS
Reliability	Meets or exceeds NERC reliability requirements and manages intermittency. All Portfolios meet the minimum levels of FERC; 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 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 the table 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.

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3. Load Forecast

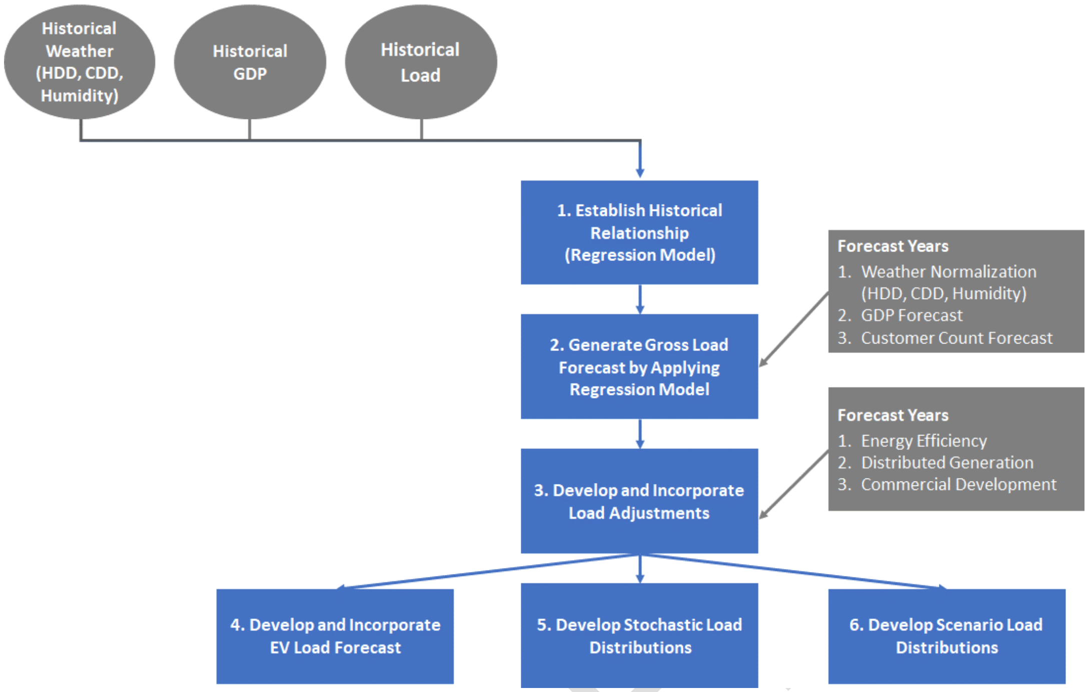
Siemens developed a reference case load forecast for the MLGW service territory. This section presents a twenty-year net load forecast which is the gross system load forecast adjusted for energy efficiency (EE), distributed solar generation (DS), electric vehicles (EV) and other known future commercial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

3.1 Load Forecasting Methodology

Siemens used a deterministic load forecasting process, described in the flow chart in Exhibit 30, 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 30: Deterministic Load Forecasting Process



Source: Siemens

3.1.1 Historical System Load Profile

Exhibit 31 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 3,507 MW in 2011 but fell to 3,097 MW in 2018—one of the lowest peak levels over the 20-year period.

Exhibit 31: 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, that 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.[6]

[6] 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.[7] 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 our 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 MLGW provided, 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

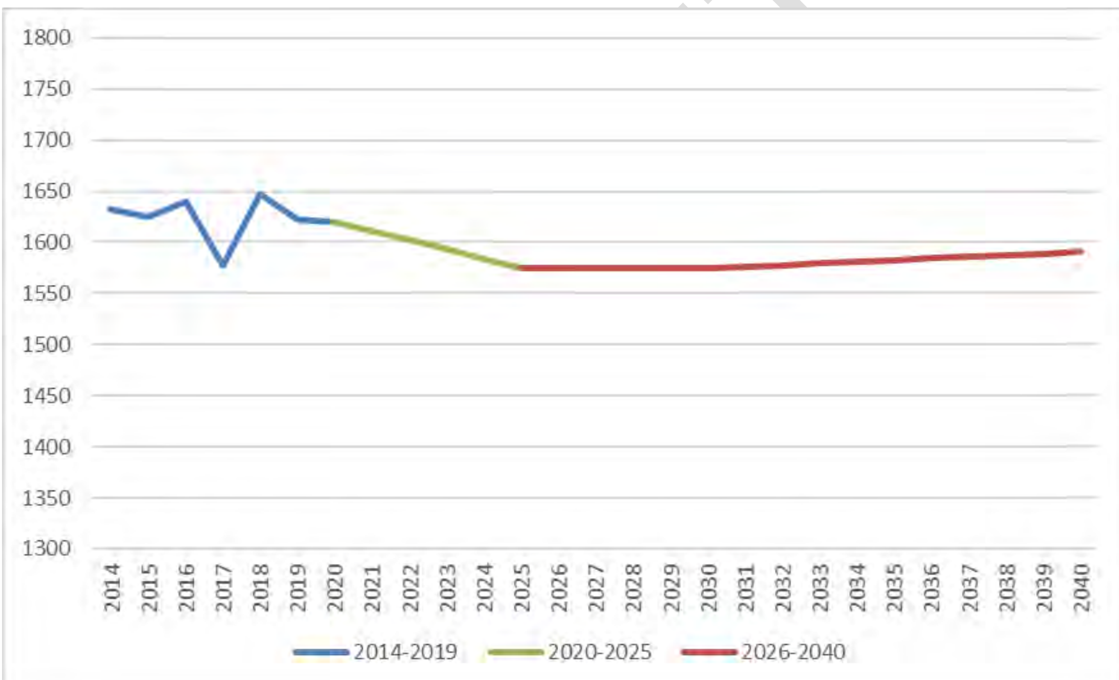
[7] https://www.eia.gov/todayinenergy/detail.php?id=14291 real estate, digitalization, and online commerce are already embedded in regional forecasts

for modest growth during this period[8], 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 32. 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 32: Historical and Forecasted Annual Gross Average Load (MW)

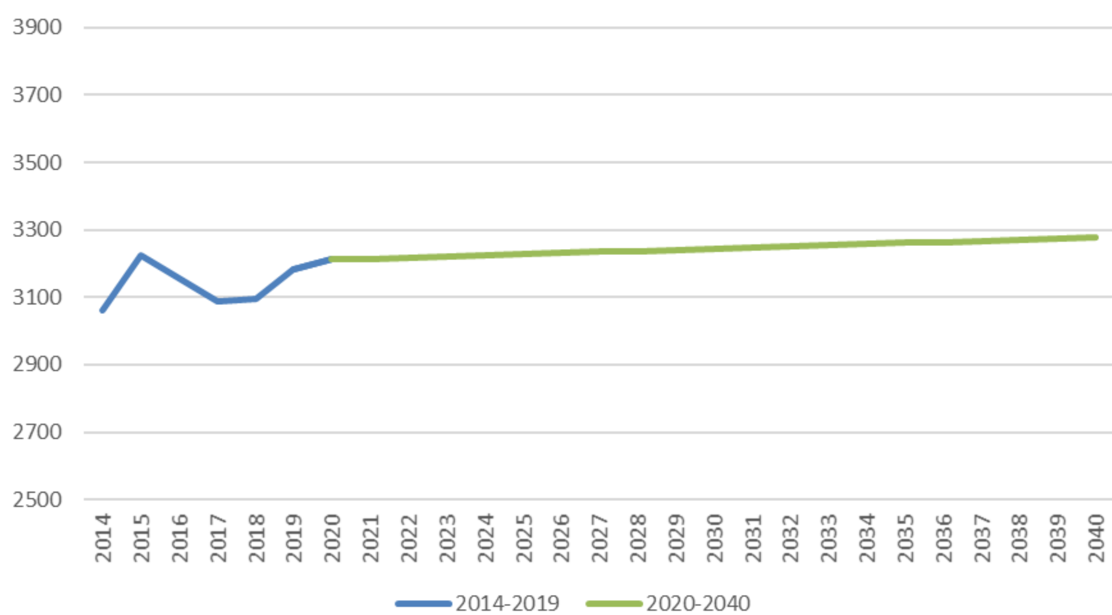


Source: Siemens

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

The gross peak load forecast is shown in Exhibit 33 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 33: Historical and Forecasted Annual Gross Peak Load (MW)



Source: Siemens

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

	Avg Load (MW)	Peak (MW)
2014	1,633	3,062
2015	1,625	3,226
2016	1,640	3,155
2017	1,577	3,086
2018	1,647	3,097
2019	1,622	3,182
2020	1,620	3,211
2021	1,611	3,215
2022	1,602	3,218
2023	1,593	3,221
2024	1,584	3,224
2025	1,575	3,228
2026	1,575	3,231
2027	1,575	3,234
2028	1,575	3,238
2029	1,575	3,241
2030	1,575	3,244
2031	1,576	3,247
2032	1,578	3,251
2033	1,580	3,254
2034	1,581	3,257
2035	1,583	3,261
2036	1,584	3,264
2037	1,586	3,267
2038	1,587	3,271
2039	1,589	3,274
	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: 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 and these are explained below.

3.2.1 Energy Efficiency (EE) Impact

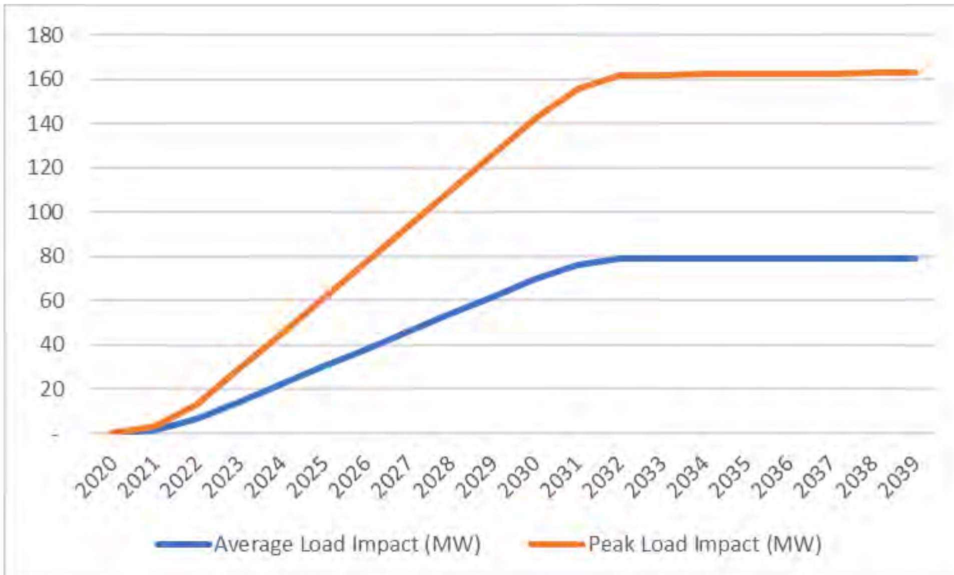
Currently, MLGW does not administer an EE portfolio. To forecast the estimated impacts of a prospective EE portfolio, Siemens used data from the U.S. Energy Information Administration (EIA) Form 861 for 2018. To develop a comparison group of utilities, Siemens considered the system size, annual energy 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.

As shown in Exhibit 35, 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.

Exhibit 35: Annual Average and Peak Load EE Reductions (MW)



Source: Siemens

The following table (Exhibit 36) 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 2039.

Exhibit 36: 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

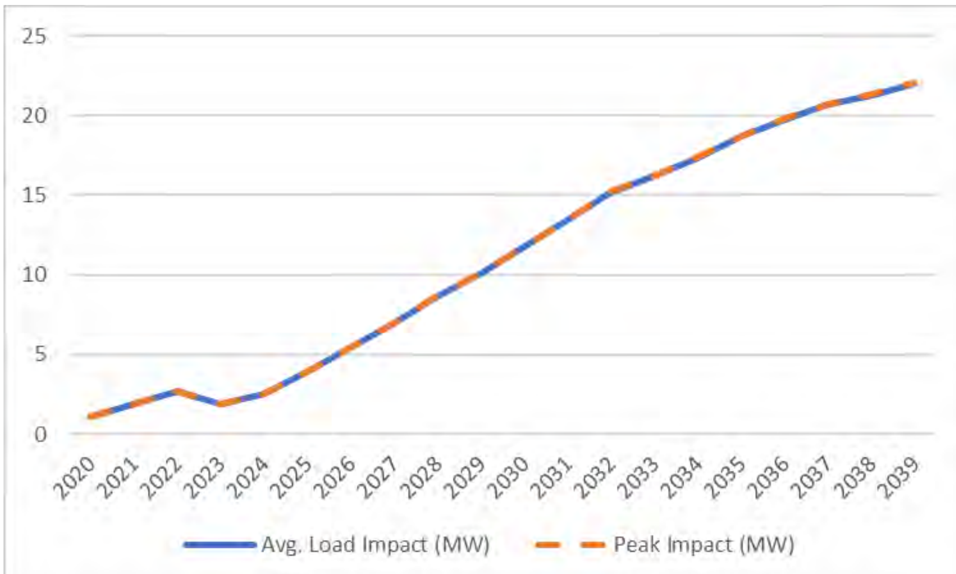
Siemens estimated the costs of administering an EE portfolio from historical data for other regional utilities. Drawing from 2018 U.S. EIA data for the same group of utilities in developing the reasonable expected portfolio savings rate, Siemens estimated the average cost of energy savings on a per KWh 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.[9]

[9] 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[10] capacity factor for the Memphis geographic location to calculate an average load and peak load DS impact for MLGW, shown in Exhibit 37.

Exhibit 37: Annual Average and Peak Load Distributed Solar Generation (MW)



Source: Siemens

The following table (Exhibit 38) 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 the exhibit below by coincidence due to rounding.

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

Exhibit 38: 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

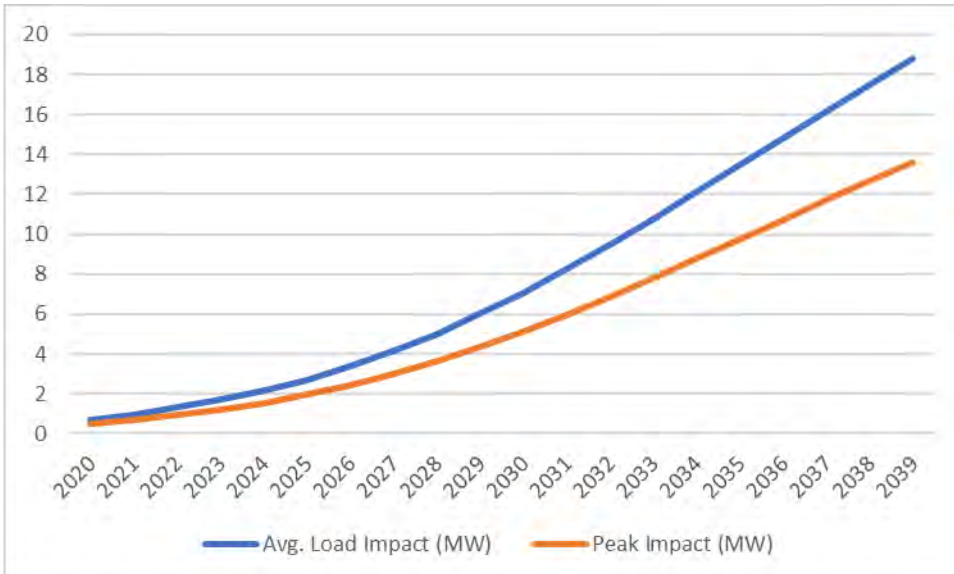
Siemens forecasted the average and peak load impacts of increased electric vehicle adoption within MLGW's service territory through the forecast period. To estimate the potential for EV adoption in MLGW's territory, Siemens applied our proprietary electric vehicle forecasting approach, which employs 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^{3}T 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 39, 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 39: Annual Average and Peak Load Electric Vehicle Contribution (MW)



Source: Siemens

The following table (Exhibit 40) 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 40: 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 41. 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 41: Forecasted Net Energy Estimates (GWh)

Year	GWh
2020	14,423
2021	14,285
2022	14,158
2023	14,017
2024	13,899
2025	13,699
2026	13,616
2027	13,534
2028	13,487
2029	13,369
2030	13,285
2031	13,229
2032	13,237
2033	13,206
2034	13,210
2035	13,212
2036	13,252
2037	13,221
2038	13,229
2039	13,236

Source: Siemens

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

Exhibit 42 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, EV 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 EV and development loads on increasing peak load.

Exhibit 42: 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 43 displays the reference case net average load forecast for the 2020-2039 period. To calculate the net average load forecast, the net load forecast is divided by the number of hours in that particular year.

Exhibit 43: Forecasted Net Average Load Estimates (MW)

Year	MW
2020	1,642
2021	1,631
2022	1,616
2023	1,600
2024	1,582
2025	1,564
2026	1,554
2027	1,545
2028	1,535
2029	1,526
2030	1,517
2031	1,510
2032	1,507
2033	1,508
2034	1,508
2035	1,508
2036	1,509
2037	1,509
2038	1,510
2039	1,511

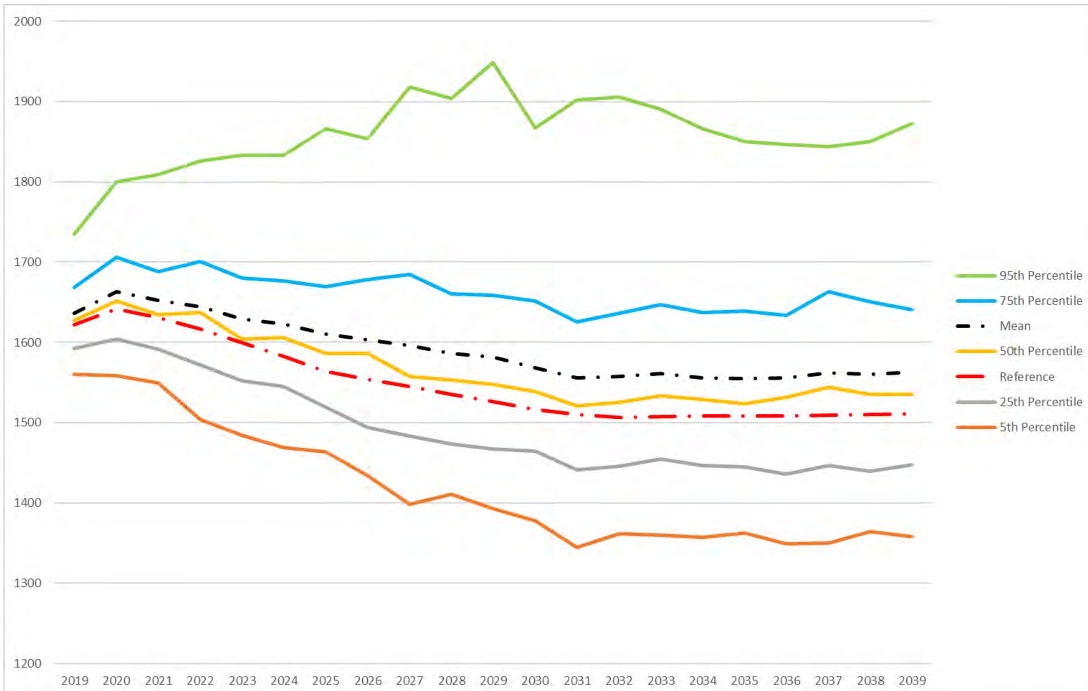
Source: Siemens

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 44, 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.

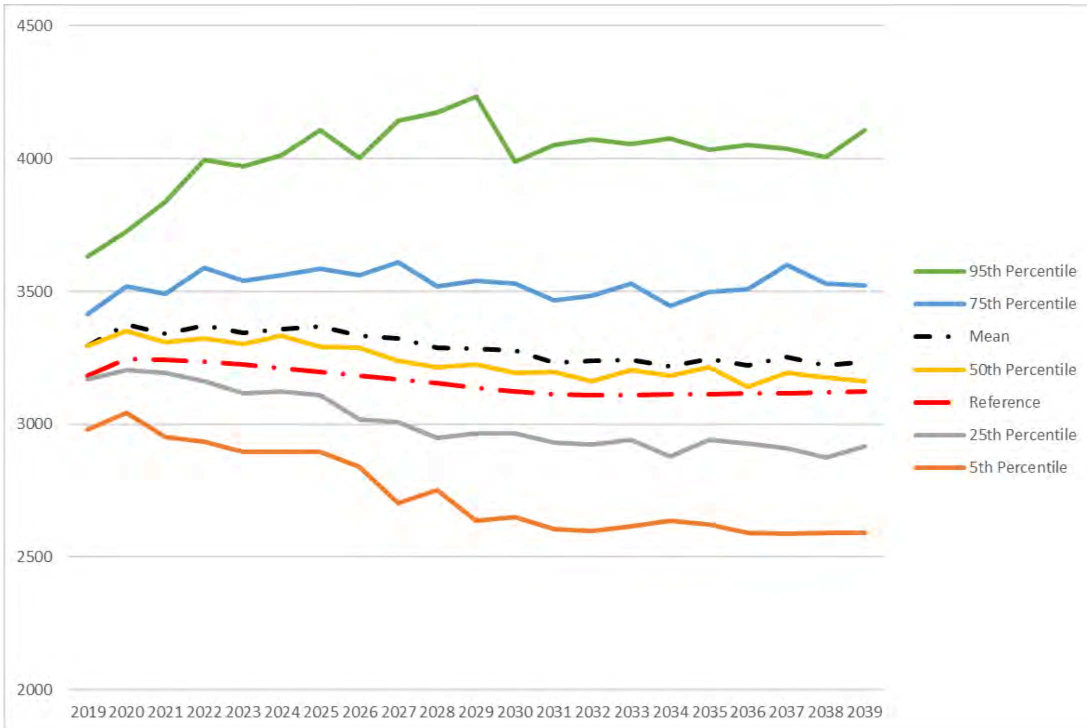
Exhibit 44: Stochastic Distribution of Average Load Forecast from 2019 to 2039 (MW)



Source: Siemens

Similarly, as shown in Exhibit 45, 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.

Exhibit 45: 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.

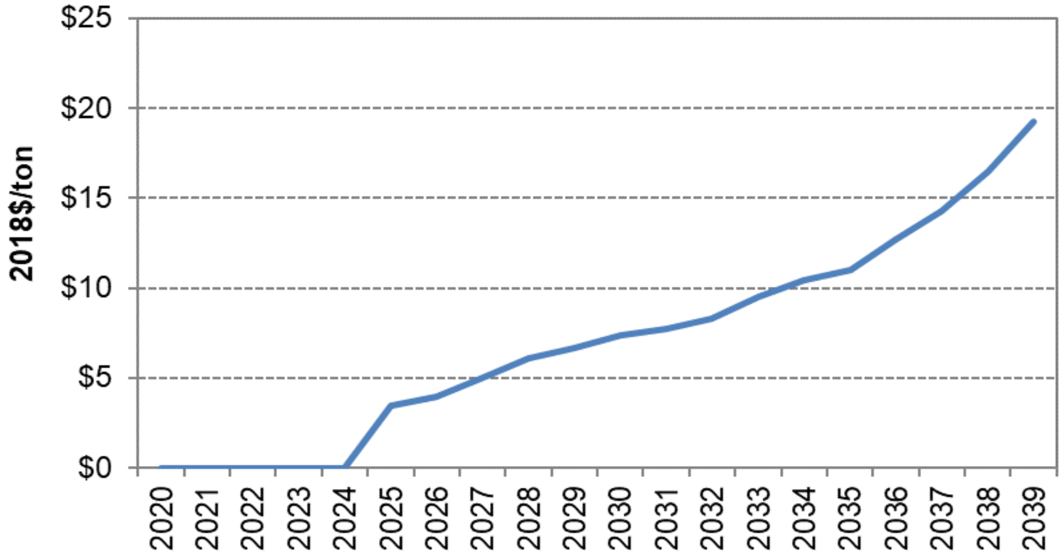
Siemens found that renewable builds including both wind and solar were economic and the base RPS target level above was always exceeded under all supply portfolios. As will be shown later in this report the level of renewable generation coverage of the load ranged from a low of 42% to a high of 77%, 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 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 46.

Exhibit 46: Carbon Price Projections (2018\$/tonCO_2)



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 47 (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 47: 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, during the implementation process leading to an RFP, MLGW will have discussion with the County on overall permitting strategy.

4.4 Water Use

Water needs for future generation units were considered in the IRP. In 2017, high arsenic levels were detected in ground 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.

Following the Allen site contamination, cooling needs for natural gas-fired units are assumed to be water from municipal supply. 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 the Allen generating station. An actual expected consumption profile would be needed to assess the design upgrades needed. 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 minor additional upgrades, water supply is feasible from the municipal system.

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 our 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 our 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.[11] 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.[12]

- 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. 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

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

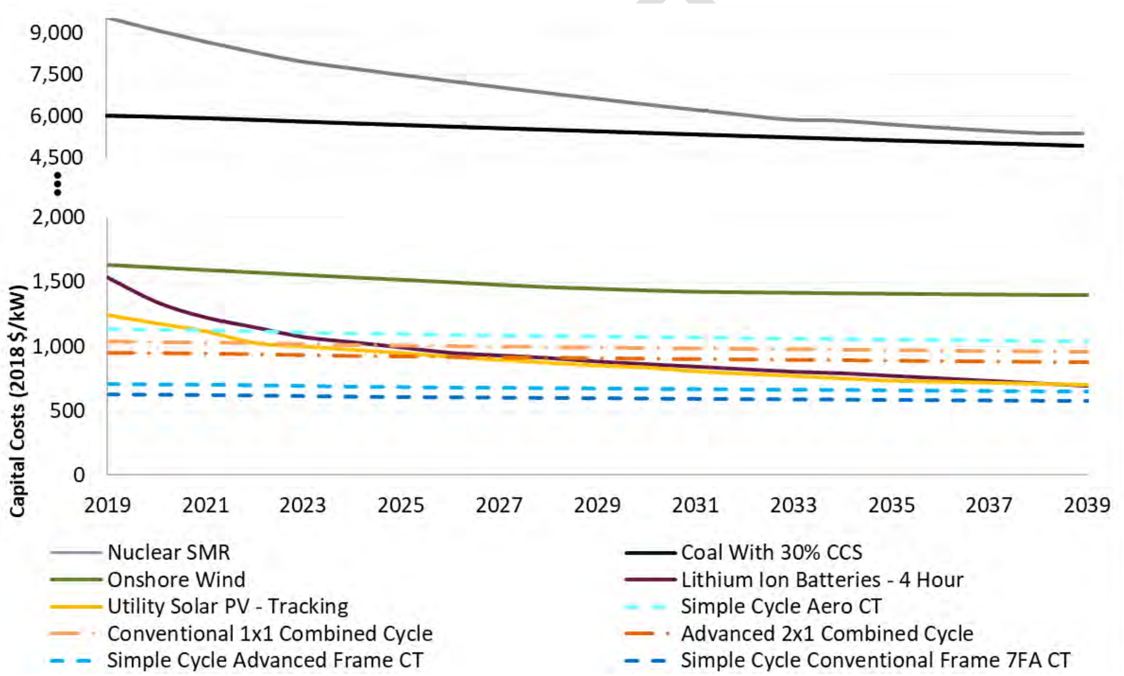
[12] Siemens "all-in" capital costs do not include additional transmission/interconnection costs past the busbar as these costs are highly variable and dependent on project specific details.

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 cost, 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 48 depicts Siemens forecasted the levelized cost for each of the utility scale technologies to be considered for new development.

Exhibit 48: 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 49. 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 plants MLGW might finance to be consistent with other utility-financed new builds in the SERC and MISO markets.

Exhibit 49: Siemens New Resource Technology Cost and Financial Assumptions

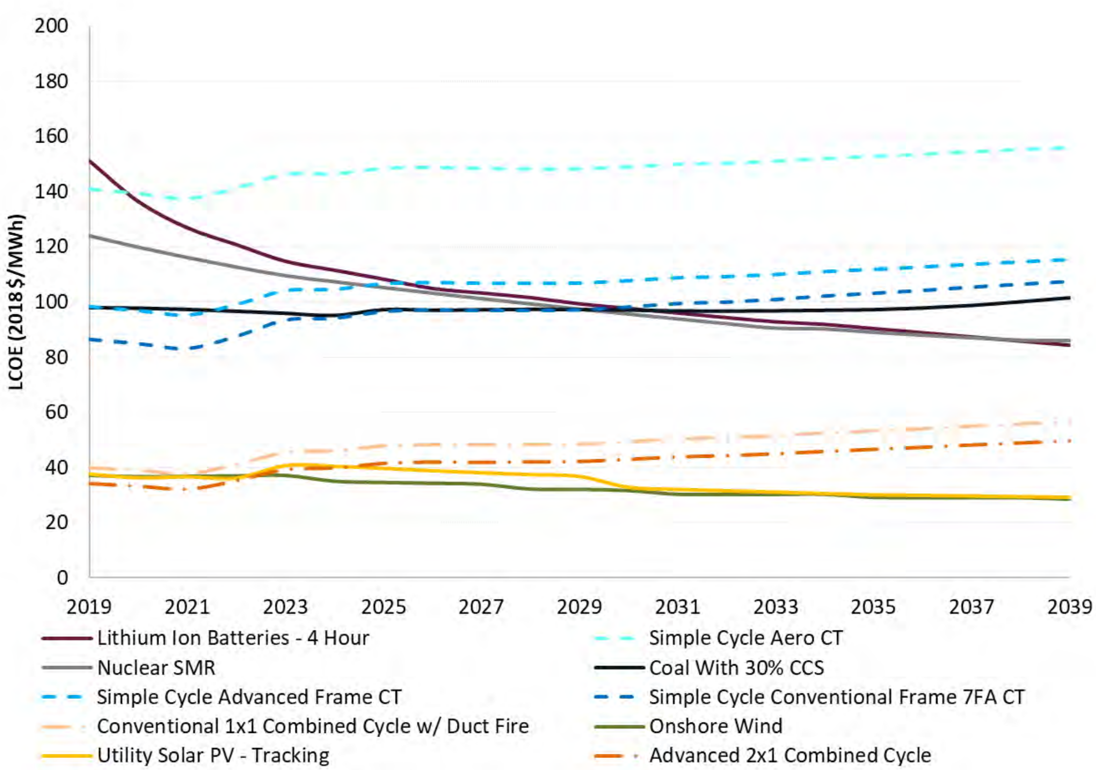
Technology	Advanced 2x1 CCGT	Conventional 1x1 CCGT, Fired	Simple Cycle Advanced Frame CT	Simple Cycle Conventional Frame 7FA CT	Simple Cycle Aero CT	Coal With 30% CCS	Utility Solar PV - Tracking	Onshore Wind	Lithium Ion Batteries (4 hrs.)	Nuclear SMR
Fuel	Nat. Gas.	Nat. Gas.	Nat. Gas.	Nat. Gas.	Nat. Gas.	Coal	Sun	Wind	Elec. Grid	Uranium
Construction Time (Yrs)	3	3	2	2	2	5	1	2	<1	7
Winter Capacity[13] (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-yr)	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[14] 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[15] (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

[13] Winter to summer capacity adjustment ratio is 0.92 for CCGT, 0.91 for SCCT, 0.99 for Coal, and 0.94 for Nuclear.
[14] Modified Accelerated Cost Recovery System (MACRS)
[15] MLGW's new builds are assumed at generic utility's WACC of 6.16%.

Exhibit 50 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. 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 50: 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 51 below provides the selected capacity factors applied to develop the LCOE presented in Exhibit 50.

Exhibit 51: Assumed Capacity Factors

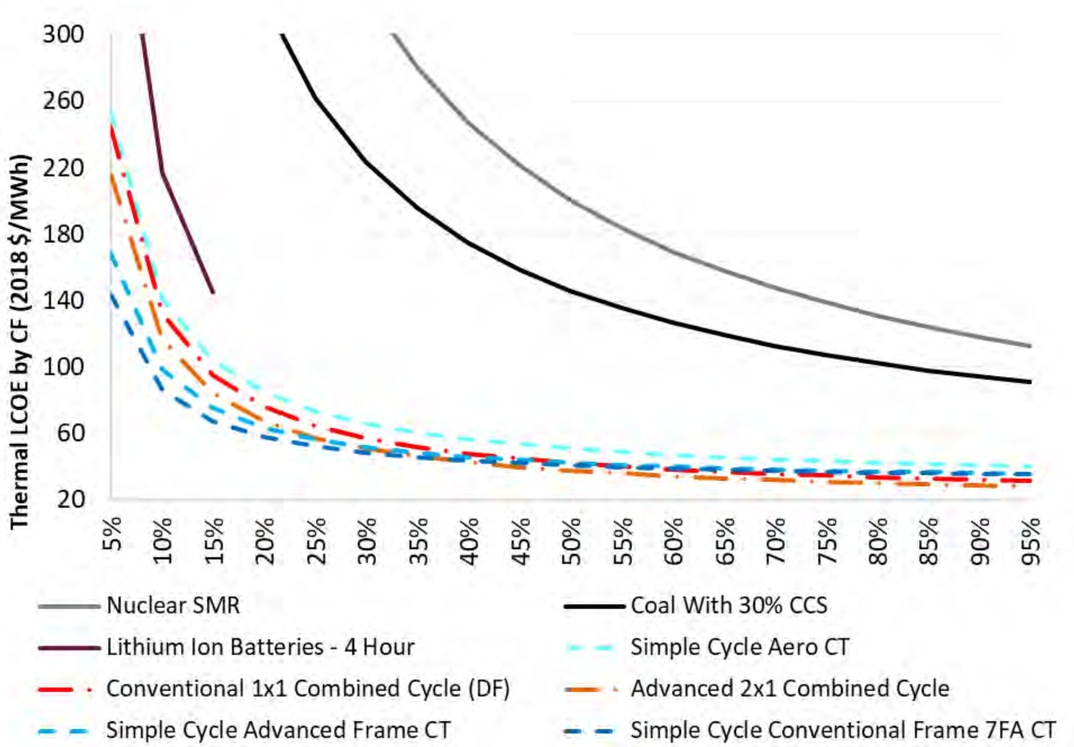
Technology	Advanced 2x1 Combined Cycle	Conventional 1x1 Combined Cycle	Simple Cycle Advanced Frame CT	Simple Cycle Conventional Frame 7FA CT	Simple Cycle Aero CT	Coal With 30% CCS	Utility Solar PV - Tracking	Onshore Wind	Lithium Ion Batteries - 4 Hour	Nuclear SMR
Assumed Capacity Factor (%)	60%	55%	10%	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 52.

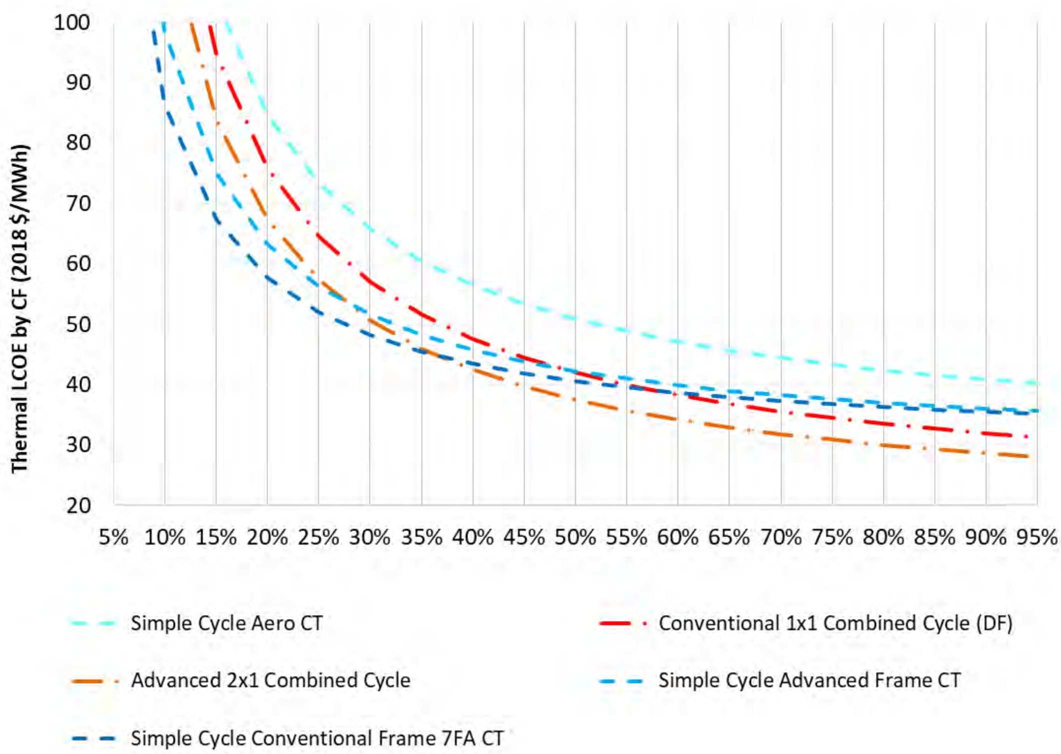
As can be observed in Exhibit 53, which focuses on CTs, for low capacity factors which are expected for peaking services, the simple cycle conventional frame 7FA CT and simple cycle advanced frame CT offer the lowest levelized cost, followed by the CCGT's and the aero CT. For base load services (higher 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 52: Thermal & Storage Technology 2019 LCOE Assumptions by Capacity Factor, 2018$/MWh



Source: Siemens

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



Source: Siemens

5.2.2 Combined Cycle Gas Turbine

Combined cycle gas turbines (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.

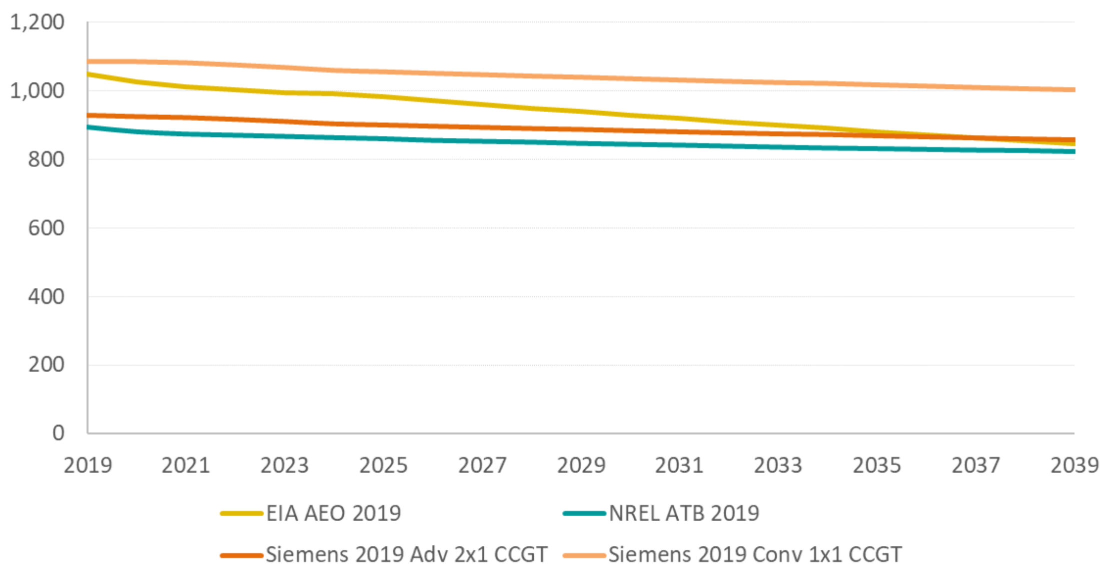
Favorable capital costs, operational flexibility, lower CO_2 emissions, and high plant efficiencies have allowed CCGTs to expand their role in power generation, serving as either baseload or intermediate generators.

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 54.

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 this unit operating in the comparably small MLGW market would be unacceptable. 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 54: Advanced Combined Cycle Capital Cost Forecast, 2018$/kW



Source: Siemens

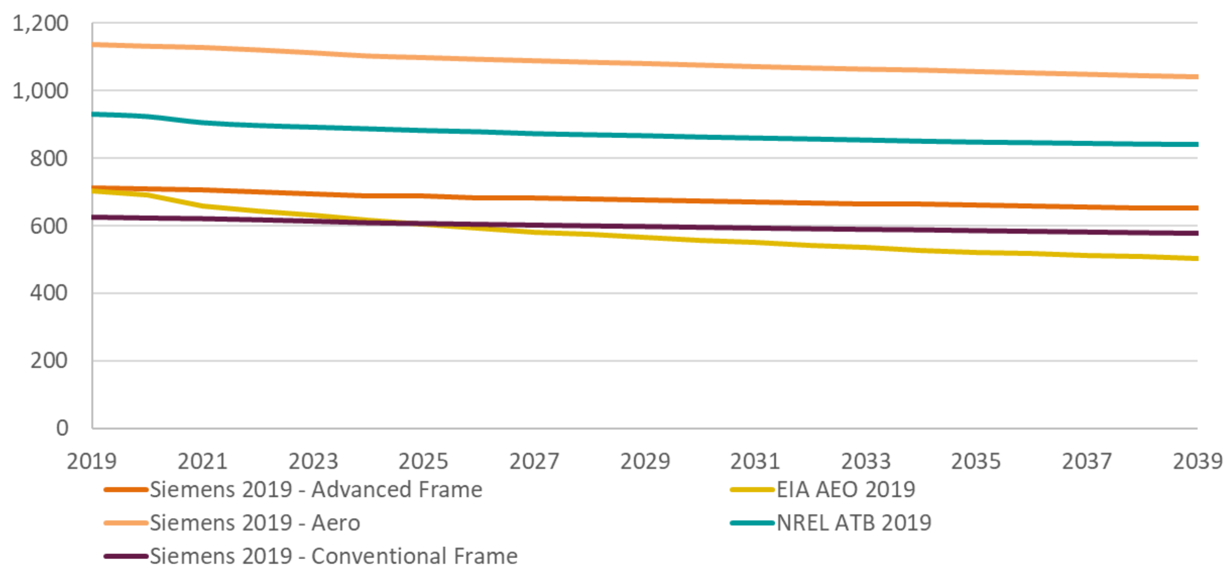
5.2.3 Simple Cycle Combustion Turbine

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 55. 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 55: Simple Cycle CT Capital Cost Forecast, 2018$/kW



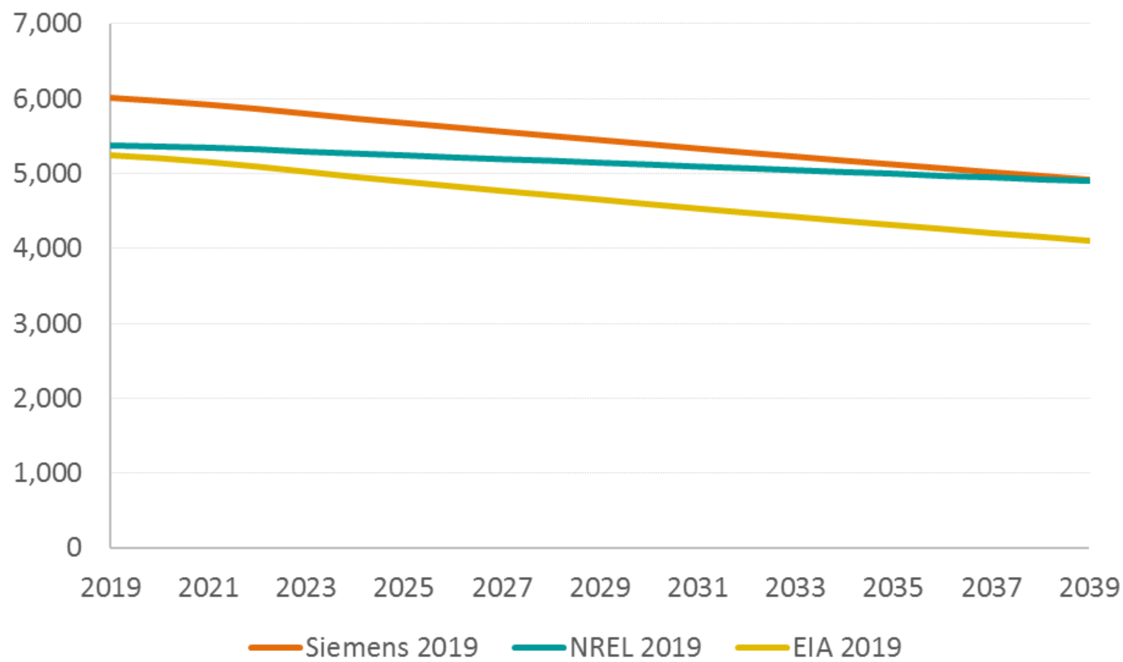
Source: Siemens

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 56.

Exhibit 56: Supercritical Coal with CCS Capital Cost Forecast, 2018$/kW



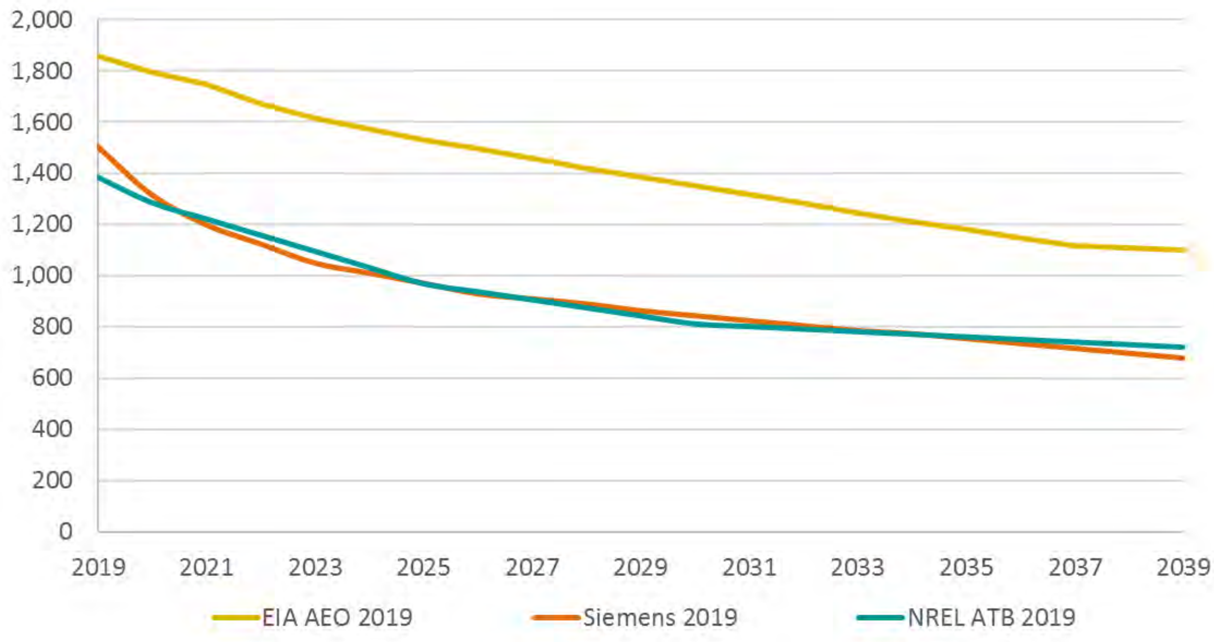
Source: Siemens

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

Exhibit 57: 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.[16] 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.[17]

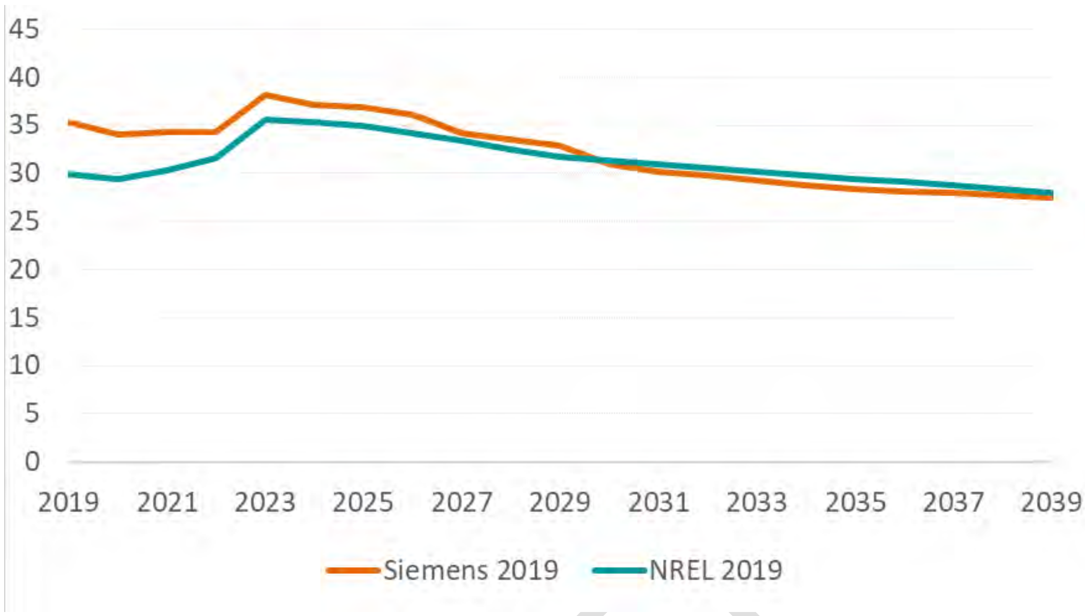
Siemens single-axis tracking solar technology forecast accounts for the increasing application of bifacial solar cells. While monofacial cells dominate the market today, bifacial cells are expected to comprise most solar cells sold by 2030. While bifacial cells cost slightly more than monofacial cells, they can deliver impressive generation gains over monofacial cells, so Siemens forecast accounts for a phasing in of bifacial technology. Exhibit 58 compares Siemens utility scale, single-axis tracking, solar levelized cost of energy assumptions to those of the NREL ATB[18] 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.

[16] SEIA U.S. Solar Market Insight: Q2 2019

[17] Siemens assumes two years of safe harboring in our LCOE calculations.

[18] NREL forecasts five LCOE scenarios based on different locations in the US. The most similar NREL reference case is in Kansas City.

Exhibit 58: 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 the exhibit below.

Exhibit 59: 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 [19] 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. [20] Further, the federal

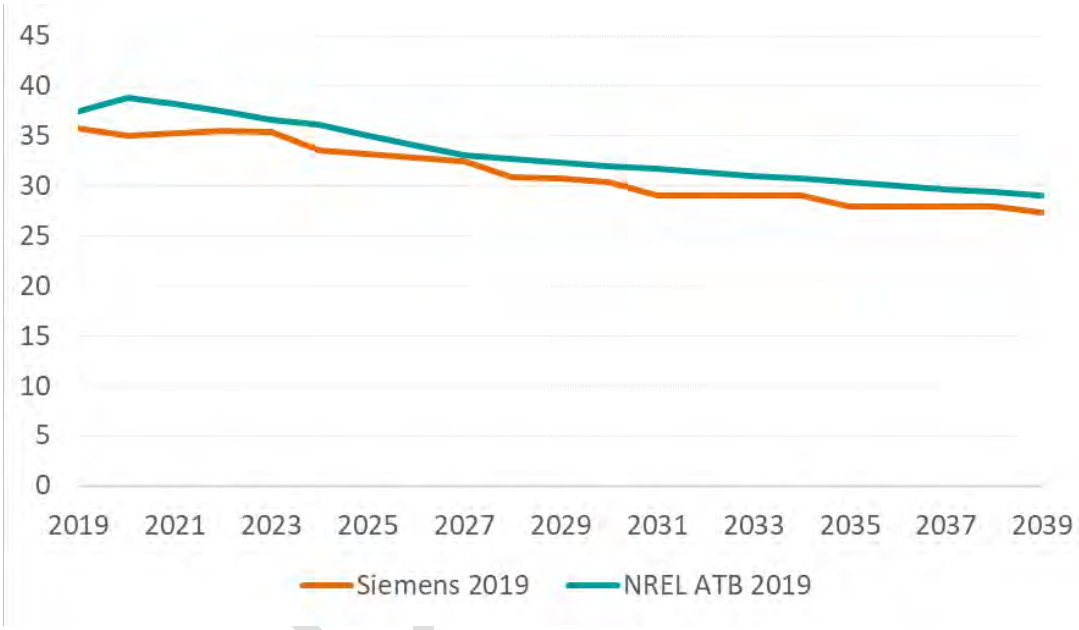
[19] NREL ATB 2018

[20] 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.[21]

Siemens compares our onshore wind levelized cost of energy assumptions to NREL ATB[22] similar technologies in Exhibit 60.

Exhibit 60: 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.

[21] Siemens assumes two years of safe harboring in our LCOE calculations.
[22] 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 61: 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

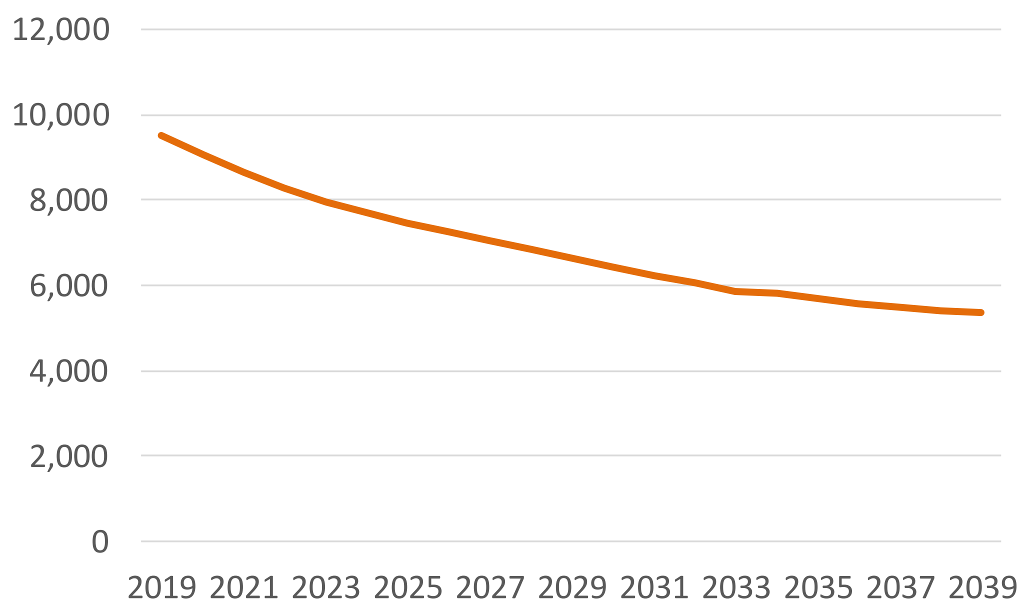
Small modular reactor (SMR) technology was initially developed for naval/shipping purposes and is being adapted for utility scale generation; however, it has not yet demonstrated commercial viability in the US. SMR modules range in size from 10 to 300 MW (compared to roughly 900 to 1,200 MW for conventional 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 62, the expected capital costs of the SMRs put them at disadvantage relative to other base load technologies on a unit cost basis.

Exhibit 62: 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[23]. 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[24]. 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[25]. 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:

[23] https://www.ferc.gov/industries/hydropower/enviro/eis/2019/P-13511-003-EA.pdf
[24] https://arpa-e-foa.energy.gov/FileContent.aspx?FileID=e5f68776-98a0-4088-8086-06e8f9de87e5
[25] 25 See Renewable Integration Impact Assessment (RIIA) Assumption Document V-6 December 2018, MISO.

Exhibit 63: 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[26].

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). 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 64 shows Siemens forecast of capacity prices. Beginning in the mid-2020s, Siemens forecast is close to CONE.

The Forecast shown in Exhibit 64 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).

[26] Slightly higher values were used for the adequacy assessment in agreement with MISO.

Exhibit 64: 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 65 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 65: 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[27] (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[28] (100% CF)	5,993	2,443 (Base) 3,163 (w/ DF)	2,882	2,271	435

Source: Siemens EBA

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 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[29] per day (Dth/d)

27 Winter to summer capacity adjustment ratio is 0.92 for CCGT, 0.91 for SCCT, 0.99 for Coal, and 0.94 for Nuclear.
28 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
29 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 66 provides the firm transportation service (FTS) tariffs for each of the three pipelines (ANR, Texas Gas, and Trunkline), which are also shown in Exhibit 75 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 66: 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 66, 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

Exhibit 67. 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 Exhibit 67, although conditions could change in five years.

Exhibit 67: 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 67, the unit rate of $0.3212/Dth is the least costly rate for interruptible transportation service, and therefore is the rate is used in the AURORA model.

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 68). 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.30

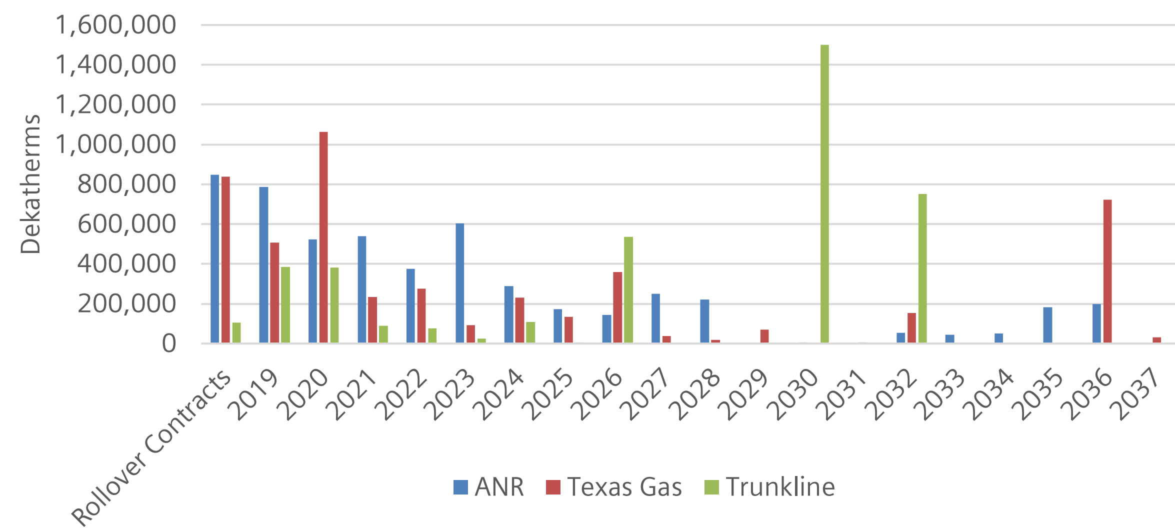
In addition, ANR (with one existing gate in MLGW service territory) provided an estimate of $10 million for a meter station upgrade or replacement. It is unclear at this time if Trunkline (two existing gates) or Texas Gas (five existing gates) would also need a similar upgrade. Based on the tariff analysis 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 68. ANR shows a steady decline in contract expirations through the 2020s, but not shown is 2,100,000 Dth of contract expirations post-2044. Texas

[30] 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.

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 68: Pipeline Contract Expirations



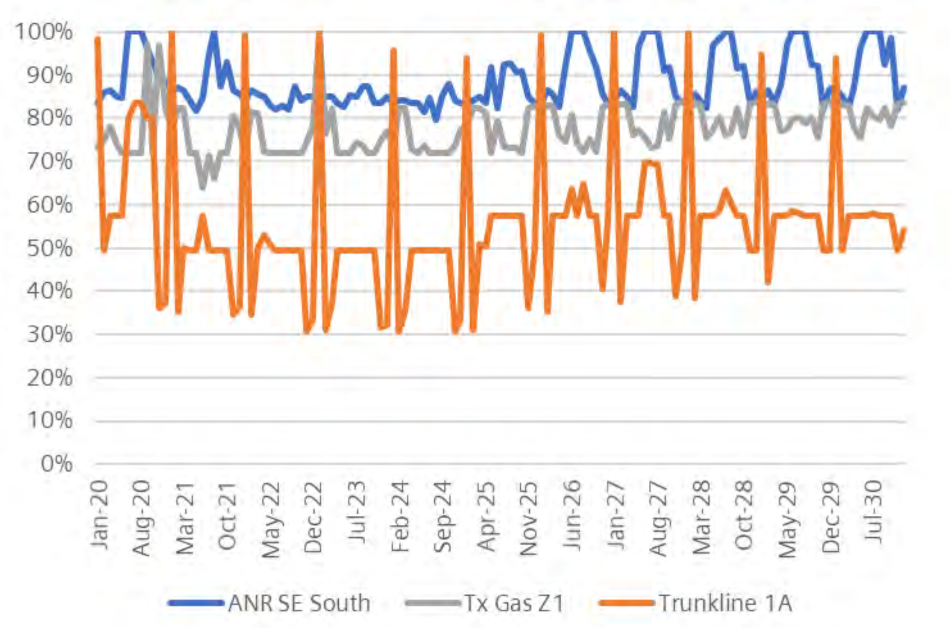
Source: Siemens, S&P Global. Note: Data is from 2019 Q3.

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 69. 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 69: 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 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).

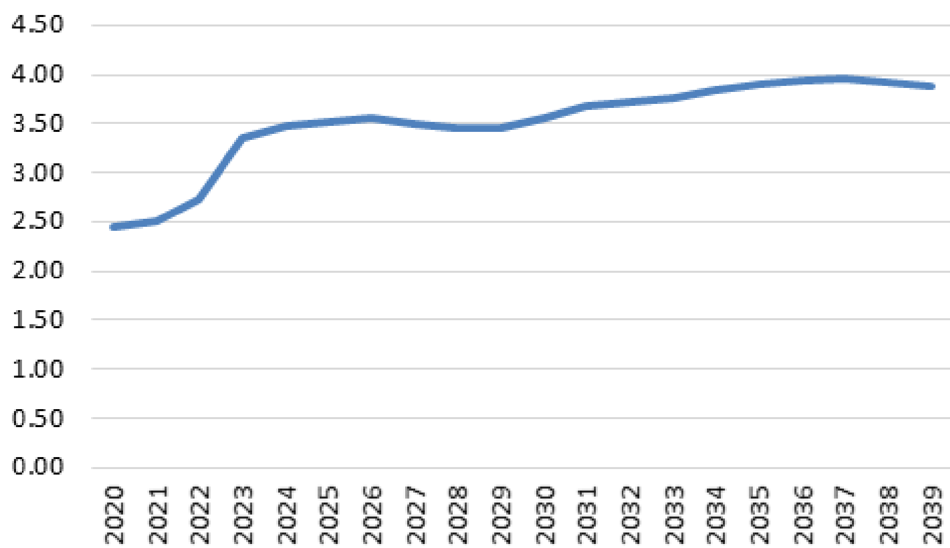
The 14.6 Bcf/d of LNG export capacity expected by 2024 is mostly under "take-or-pay" contracts, meaning demand for LNG feedstock gas will be baseload with liquefaction capacity expected to run at an 85% capacity factor or greater. LNG export demand is expected to put modest upward pressure on prices, 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 70 shows increasing real prices over time as declining associated gas production is coupled with rising marginal costs of production and extraction.

Exhibit 70: Annual Henry Hub Natural Gas Forecast (2018$/MMBtu)



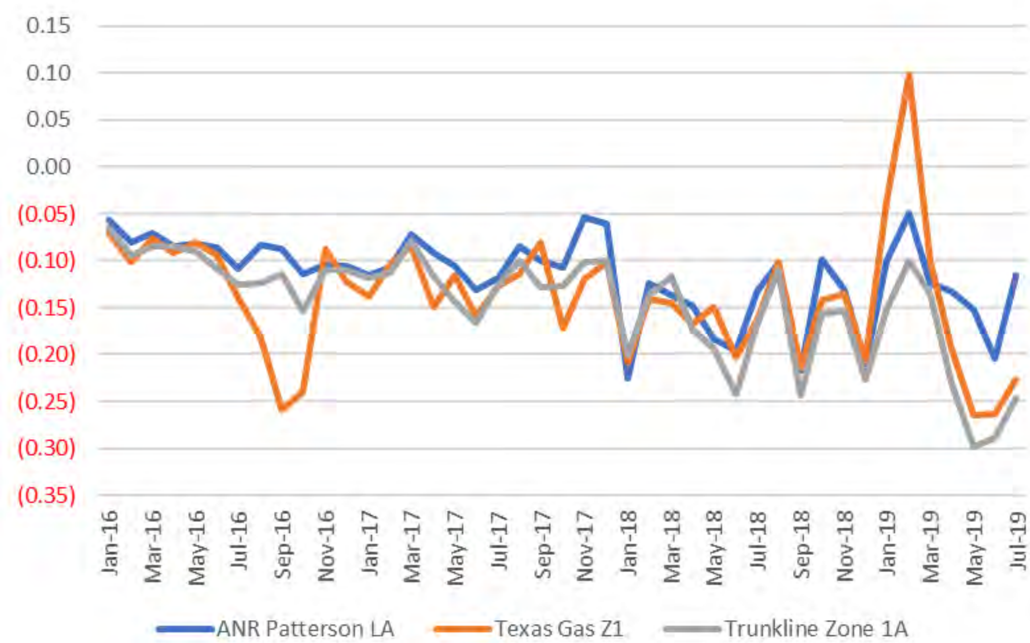
Source: Siemens

The Stochastic sections of this report (Section 11) present our 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

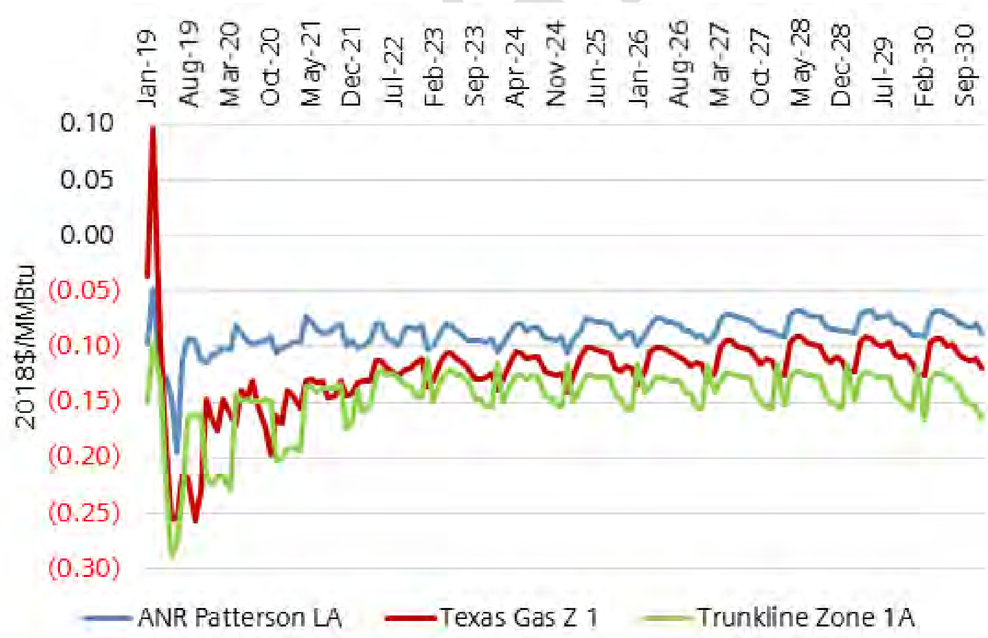
On a regional level, MLGW receives supply via three long-haul natural gas transmission pipelines that cross its service territory: Texas Gas, Trunkline, and ANR. The corresponding natural gas hubs include Texas Gas Zone 1, Trunkline Zone 1A, and ANR Patterson LA. In the past several years, these gas 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 68 shows the monthly average historical gas basis (regional market differential) of three key market points relative to benchmark Henry Hub prices. Exhibit 71 shows the monthly forecasted gas basis to the Henry Hub for the next decade.

Exhibit 71: Monthly Average Historical Gas Basis to Henry Hub (Nominal$/MMBtu)



Source: Siemens, S&P Global

Exhibit 72: Monthly Forecast Gas Basis to Henry Hub (2018$/MMBtu)



Source: Siemens

Exhibit 72 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 73: WTI, Diesel, and Heavy Fuel Oil Price Outlook

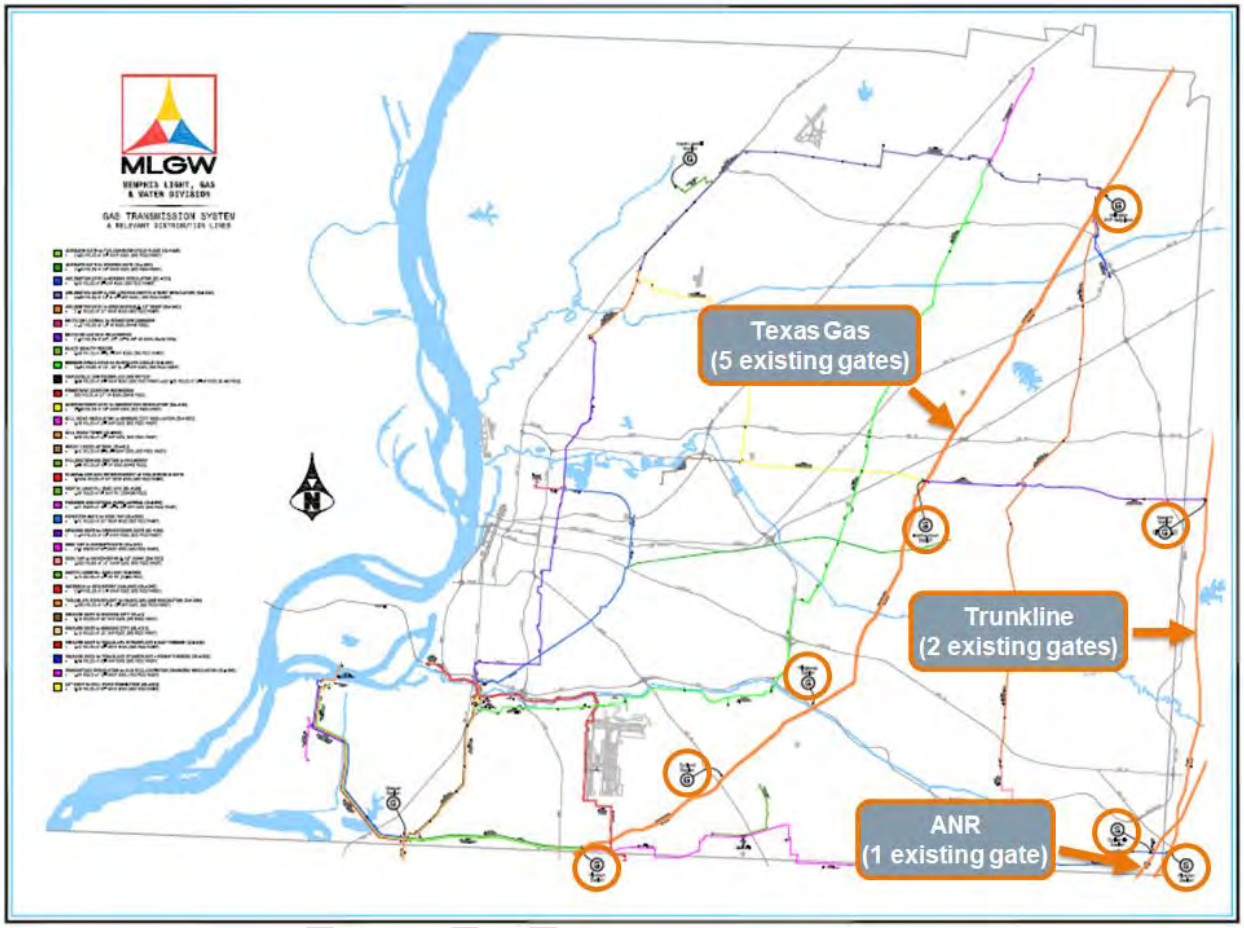
	WTI (Gulf Coast)		Diesel (Gulf Coast)		HFO (Gulf Coast)	
Year	2018$/bbl	Nom$/bbl	2018$/gal	Nom$/gal	2018$/bbl	Nom$/bbl
2020	30.67	32.14	0.98	1.03	20.04	20.98
2021	32.65	35.13	1.04	1.12	22.87	24.61
2022	41.60	45.89	1.31	1.45	34.17	37.71
2023	51.02	57.62	1.61	1.81	46.02	51.99
2024	53.69	62.05	1.69	1.95	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

Exhibit 74: 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 75: Map of Natural Gas Transmission Pipelines and Delivery Points (Gates) Crossing MLGW Service Territory



Source: Siemens

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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. These requirements also affect the interconnections to MISO, and whether MLGW would join MISO as a separate zone or part of an existing zone (Zone 8). 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 in terms of meeting a maximum Loss of Load Expectation (LOLE) of 1 in 10 years; that is, only once every 10 years there are 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 NERC resource adequacy criteria for decades which has provided adequate reliability for the grid.

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

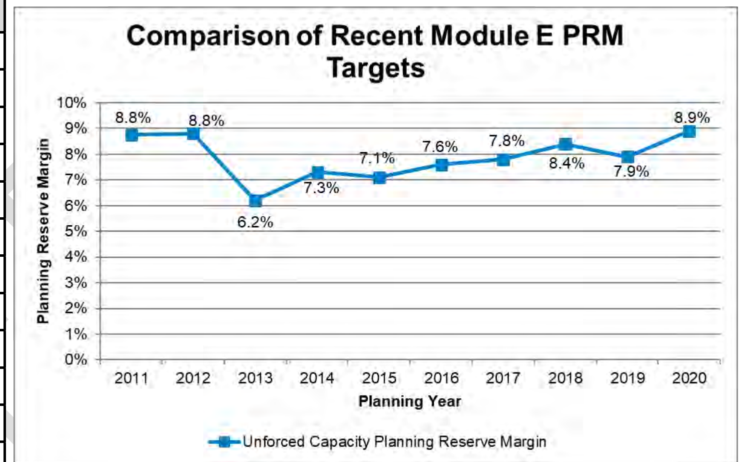
MISO's PRM is expressed both in terms of installed capacity (ICAP) and more commonly, the unforced capacity (UCAP), which is the installed capacity affected by the forced unavailability of the conventional units. Renewable generation is modeled both in the ICAP and UCAP (UCAPs load carrying capability is expressed as a percentage of the installed capacity). This is shown in Exhibit 76.

According to the latest MISO Resource Adequacy Study[31] MISO's PRM is currently 8.9%. Exhibit 76 shows MISO's calculations leading to the PRM, the historical PRM, and the projections to 2029. We note that at 8.9% the PRM is at the highest value since 2011.

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

Exhibit 76: MISO PRM Calculation

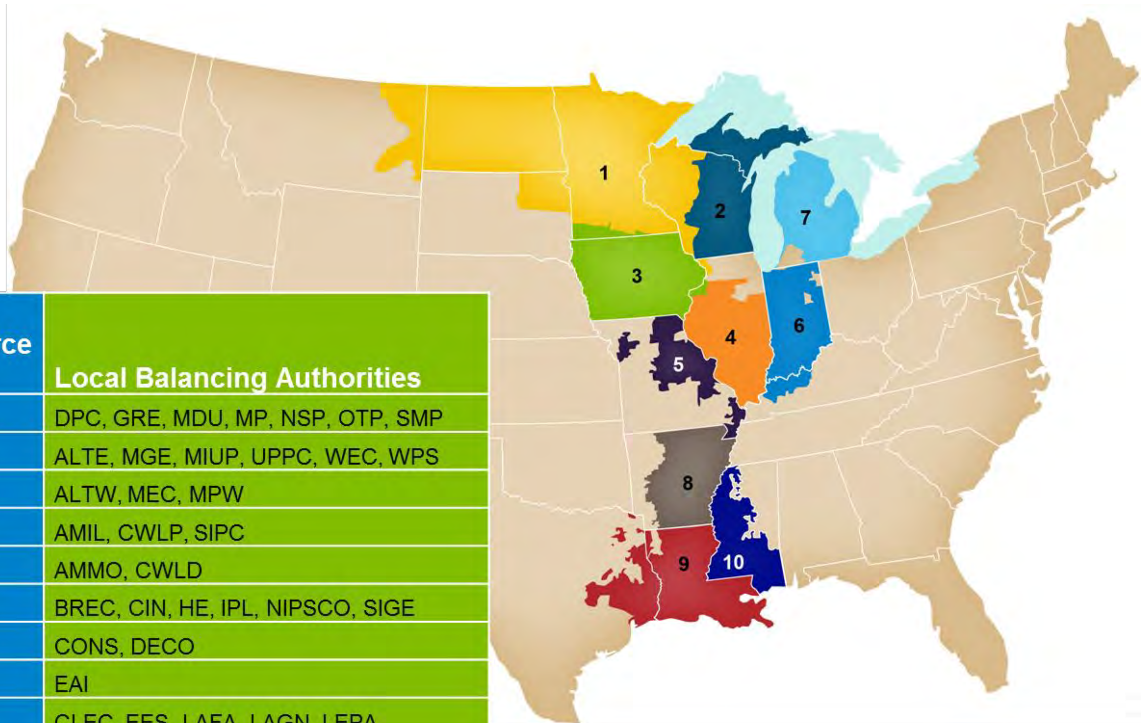
MISO Planning Reserve Margin (PRM)	2020/2021 PY (June 2020 - May 2021)	2023/2024 PY (June 2023 - May 2024)	2025/2026 PY (June 2025 - May 2026)	Formula Key
MISO System Peak Demand (MW)	124,625	125,308	125,600	[A]
Installed Capacity (ICAP) (MW)	156,426	160,125	161,228	[B]
Unforced Capacity (UCAP) (MW)	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: Siemens

Exhibit 77: 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 77). 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 required for the LRZ to meet the 1/10 year requirement if it were an 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[32]) 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.

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[32] 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. 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.[33]

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 load is much lower than the summer peak load as compared with LRZ-8 and MISO.

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 directly connected to MLGW system. The main parameters for this generation are shown in the exhibit below.

Exhibit 78: MLGW Generation Modeled

	Winter Capacity							
	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%	--	

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

Source: Siemens

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 100% dependable generation until the 1/10 Loss of Load Equivalent (LOLE) is met, thus the higher the amount of actual generation 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%.

Exhibit 79: 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)
System Peak Demand (MW)	125,600	3,197	128,505
Installed Capacity (ICAP) (MW)	161,228	1,758	162,986
Unforced Capacity (UCAP) (MW)	148,922	1,677	150,599
Firm External Support (ICAP) (MW)	1,626		1,626
Firm External Support (UCAP) (MW)	1,572		1,572
Adjustment to ICAP {1d in 10yr} (MW)	-11,360		-10,085
Adjustment to UCAP {1d in 10yr} (MW)	-11,360		-10,085
Non-Firm External Support (ICAP) (MW)	2,987		2,987
Non-Firm External Support (UCAP) (MW)	2,331		2,331
ICAP PRM Requirement (PRMR) (MW)	148,507		151,540
UCAP PRM Requirement (PRMR) (MW)	136,803		139,755
MISO PRM ICAP	18.24%		17.93%
MISO PRM UCAP	**8.90%**		**8.8%**

Source: 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 need to be added to the zone until the LOLE of 1/10 years is met. This requires 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 a capacity import limit (CIL) of 2,579 MW (same as the ZIA); for the case with 2 CCGTs and 1 CT, and the same 1000 MW of PV (Portfolio 1 or 6) the required system has a CIL of 2,783 MW; and finally, for the case with only 1 CCGT and 1000 MW of PV (Portfolio 5) the CIL is 3,445 MW.

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 this last value. 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 80: 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)
	TN	TN	TN
2025-2026 Planning Reserve Margin (PRM) Study			
Installed Capacity (ICAP) (MW)	1,758	1,344	714
Unforced Capacity (UCAP) (MW)	1,677	1,287	690
Adjustment to UCAP {1d in 10yr} (MW)	2,351	2,741	3,338
Local Reliability Requirement (LRR) (UCAP) (MW)	4,028	4,028	4,028
LRZ Peak Demand (MW)	3,197	3,197	3,197
LRR UCAP per-unit of LRZ Peak Demand	**126.0%**	**126.0%**	**126.0%**
Zonal Import Ability (ZIA)	2,579	2,783	3,445
Zonal Export Ability (ZEA)	1,500	1,500	1,500
Forecasted LRZ Peak Demand	3,197	3,197	3,197
Forecasted LRZ Coincident Peak Demand	3,197	3,197	3,197
Non-Pseudo Tied Exports UCAP (ignored as not available)	0	0	0
Local Reliability Requirement (LRR) UCAP	4,028	4,028	4,028
Local Clearing Requirement (LCR)	**1,449**	**1,245**	**583**
Zone's System Wide PRM	3,478	3,478	3,478
LRZ PRM (MW)	**3,478**	**3,478**	**3,478**
LRZ PRM %	8.8%	8.8%	8.8%
LCR % of Peak Demand	45%	39%	18%
MISO PRM	8.8%	8.8%	8.8%
UCAP > LCR	TRUE	TRUE	TRUE
UCAP Purchases (available for sale)	**1,801**	**2,192**	**2,788**

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%.[34] 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 the exhibit below where we observe that before MLGW joins LRZ-8 the UCAP in the zone (11,026 MW) exceeded the LRZ PRM (8,279 MW) by 2,747 MW 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 (the UCAP increased to 12,703 MW and the LRZ also increased to 11,420 MW). However, under this condition as shown in Exhibit 81 MLGW would need to acquire 1,801 MW 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 now can enter in sales up to 3,084 MW, a 12% increase.

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

Exhibit 81: MLGW Resource Adequacy as a Member of LRZ-8.

Local Resource Zone (LRZ)	LRZ-8	LRZ-8 + MLGW (3 CCGT)	LRZ-8 + MLGW (2 CCGT)	LRZ-8 + MLGW (1 CCGT)
	AR	AR+TN	AR+TN	AR+TN
2025-2026 Planning Reserve Margin (PRM) Study				
Installed Capacity (ICAP) (MW)	11,766	13,524	13,110	12,480
Unforced Capacity (UCAP) (MW)	11,026	12,703	12,313	11,716
Adjustment to UCAP {1d in 10yr} (MW)	-580	423	813	1,410
Local Reliability Requirement (LRR) (UCAP) (MW)	10,446	13,126	13,126	13,126
LRZ Peak Demand (MW)	7,883	10,884	10,884	10,884
LRR UCAP per-unit of LRZ Peak Demand	**132.5%**	**120.6%**	**120.6%**	**120.6%**
Zonal Import Ability (ZIA)	4,185	4,185	4,185	4,185
Zonal Export Ability (ZEA)	5,328	5,328	5,328	5,328
Forecasted LRZ Peak Demand	7,883	10,884	10,884	10,884
Forecasted LRZ Coincident Peak Demand	7,602	10,496	10,496	10,496
Non-Pseudo Tied Exports UCAP (ignored as not available)	0	0	0	0
Local Reliability Requirement (LRR) UCAP	10,446	13,126	13,126	13,126
Local Clearing Requirement (LCR)	**6,261**	**8,941**	**8,941**	**8,941**
Zone's System Wide PRM	8,279	11,420	11,420	11,420
LRZ PRM (MW)	8,279	11,420	11,420	11,420
LRZ PRM %	8.9%	8.8%	8.8%	8.8%
LCR % of Peak Demand	79%	82%	82%	82%
MISO PRM	8.9%	8.8%	8.8%	8.8%
UCAP > LCR	TRUE	TRUE	TRUE	TRUE
UCAP Purchases (available for sale)	(2,747)	(1,283)	(893)	(296)
Available for Sale + Sold to MLGW	**2,747**	**3,084**	**3,084**	**3,084**

Source: 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.[35]

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.
- If MLGW decides to join MISO, it should pursue the option to join LRZ-8.

[35] 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.