Integrated Resource Plan and Master Plan

Volume 1 Integrated Resource Plan

Columbia Water and Power

August 2021

This page intentionally left blank.

Siemens Industry, Inc.
Energy Business Advisory
12700 Fair Lakes Circle, Suite 250
Fairfax, VA 22033 USA
Tel: +1 (703) 818-9100
www.siemens.com

Table of Contents

List of Figures

List of Table

1 Executive Summary

Utilities around the U.S. are facing a variety of new challenges with the traditional business model being challenged from intermittent renewable energy, distributed generation, the push for environmental responsibility and ambitious environmental targets, among others. All within the objective to maintain or limit customer rate increases. The Integrated Resource Plan and Master Plan Study seeks to cover these challenges for Columbia Water and Light and evaluate different scenarios that the utility could face in the future, not only from the generation planning perspective and demand growth but also in terms of the transmission and distribution and metering infrastructure required to operate and manage the system in the future.

The Integrated Resource Plan and Master Plan Study report is organized in two volumes, this Volume 1 and Volume 2 that covers the Transmission and Distribution master plan and the supplementary assessments of spatial load forecast and review of engineering standards.

This Volume 1 discusses the Generation Plan including all the assumptions and the results of the Reference Case plus eight scenarios for the long-term resource generation plan developed by Siemens. It includes the load forecast for the next 20 years along with the outlook for Energy Efficiency and DSM programs, electric vehicle demand and distributed (customer owned) solar generation. Volume 1 also covers an evaluation of the status of CWL's current generating fleet, focusing on the assets' useful life, and the costs and benefits of potential upgrades or conversions. The assessment includes an overview of CWL's supply contracts and future resource technologies evaluated for the IRP.

Volume 1 provides an assessment on whether is economical to join the Southwest Power Pool (SPP) RTO instead of staying with the Midcontinent Independent System Operator (MISO) with a particular emphasis on the availability and potential costs of procuring new renewable resources. Finally, the last two sections of Volume 1 cover the value of distributed solar for CWL and an assessment of Advanced Metering Infrastructure and potential Smart Grid programs.

We summarize the results of these studies below.

Siemens evaluated eight scenarios in addition to the Reference Case plan to cover a range of potential market and regulatory conditions including earlier compliance with renewable and net zero carbon targets, high seasonal load and electrification, a recession economy, advance technological development, and a more stringent regulatory environment. Some of these scenarios were suggested by the City of Columbia's Task Force and others by Siemens. Overall, these plans considered aspects that are critical for the City of Columbia including:

- Compliance with the City of Columbia Ordinance requiring CWL to meet 15% of electricity demand coming from renewables at present, 25% by 2025, 30% by 2028. The City has also set a target for the IRP of 100% renewable by 2050, under the Reference Case and some scenarios.
- Reduce carbon emissions following the City of Columbia Climate Action and Adaptation Plan from May 2019 with a community wide target of 35% emissions reductions by 2035 and 80% by 2050.
- Increase Energy Efficiency for residential, commercial, municipal, and school buildings as a critical element to reduce energy consumption and GHG emissions.
- Encourage the use of low-to zero-emissions vehicles, mostly electric vehicles.

- Increase use of customer own solar panels on city buildings and residential customers via a community solar program offered through CWL.

CWL electricity demand is expected to grow at a modest rate through the study period even under high seasonal load and electrification, in particular through 2030. Gross demand driven by projected economic and population growth in the City is expected to grow at an annual rate of 0.7% thrugh the study period, under the expectation of normal weather. However, projected energy efficiency savings of around 0.4% per-year in the next ten years and significant growth in distributed solar generation will lower the growth rate to 0.3% per year over the study period. That is even after accounting for the impact of electric vehicle demand, which is expected to represent about 1.7% of the total gross load by 2040. Thus, system peak load is forecasted to grow from 273.5 MW in 2021 to 302.8 MW by 2040. Under the High Seasonal load, the growth rate is projected at 0.6% per year with peak demand reaching 350 MW by 2040, the most aggressive scenario. Other scenarios fall behind with demand in the Early and Mid-renewable scenarios, the Recession scenario and the High Technology scenario having slightly declining growth rates at -0.2% per year. The High Regulatory scenario has load falling at -0.7% per yar, the most regressive.

The results of the generation plan show common elements even under different market and regulatory conditions. The results under the Reference Case show 159 MW of new capacity additions, mostly solar additions. All capacity purchases and new renewable generation is selected after 2030 in the Reference Case driven by rising renewable targets, and the planned retirement of the Sikeston coal plant in 2030 and the end of the Bluegrass and Ameresco PPAs in the late 2020s. CWL will have a long position in generation after 2023 with the commercial operation of the Iron Star wind PPA and the Boone Stephens solar PPA. This long position will last through 2030, when the Sikeston PPA terminates, and the plant retires. This is common under most scenarios andthe end of the long position after 2030 including the selection of capacity market purchases, which are found to be economical instead of acquiring or developing further peaking generation resources.

The Early and Mid-renewable scenarios have the largest amount of future capacity additions among all scenarios in the range of 212 to 250 MW of new capacity, depending on the scenario. Most of the capacity additions are renewables with a combination of solar, wind and small amounts of battery storage needed to meet the accelerated renewable and carbon emission reduction targets. There is higher solar penetration under the Early Renewable Scenario (s) and more wind capacity under the Mid Renewable Scenario. In the Mid Renewable Scenario most of the build out happens in the 2030s with wind gaining a slight competitive advantage in the long-term due to an expected improvement in capacity factors in the future following NREL's ATB moderate case for wind resources in Missouri. Under these scenarios the amount of capacity market purchases is minimal due to the high levels of new renewable generation even considering the lower capacity credit contribution from renewables in MISO[1].

Some scenarios show the selection of an 18 MW reciprocating engine (RICE) natural gas peaker such as the High Seasonal Load scenario to meet the incremental peak demand during the summer or winter evenings driven by climate change (hotter summers and colder winters) and higher electric vehicle demand. Most of the scenarios show minimal or no selection of battery storage considering CWL existing fleet of gas-fired generation that even under the most stringent decarbonization scenarios are sufficient to meet peak demand without risking meeting the environmental targets.

[1] The capacity contribution to peak demand from solar is expected to decline from 54% in 2021 to 30% by 2033, according to MISO's 2019 renewable integration studies. Wind's capacity contribution is assumed to stay at 16% through the study period.

The scenarios with the lowest amount of new capacity additions are the Recession Economy, the High Technology, and the High Regulation Scenario. These three cases have lower demand levels in the long-term compared to the Reference Case, in particular the High Regulation Scenario. The Recession Economy and the High Technology scenarios have similar demand levels to the Early and Mid-Renewable scenarios; however, the former two do not have accelerated renewable and carbon emissions reduction targets. The High Regulation scenario has the lowest demand levels from all scenarios with only 71 MW of new capacity additions including 53 MW of renewables and an 18 MW RICE natural gas peaker in 2030. All the renewable capacity is selected after 2035.

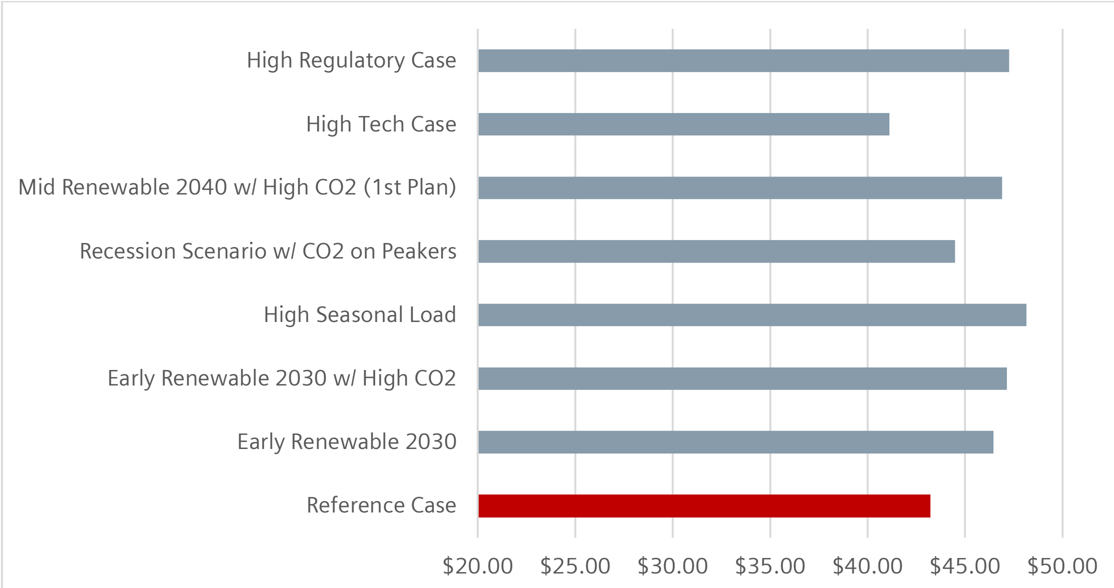
CWL is being proactive by signing the Iron Star and Boone Stephens PPAs to meet the 2025 and 2028 renewable targets mandated by the City's Ordinance. CWL will even exceed those targets and reach ~50% renewable energy in 2024-2030 under most scenarios unless the environmental targets are accelerated to 2030 or 2040. Under accelerated renewable and decarbonization targets, CWL needs to ramp up the procurement of renewable generation and follow the plan from the Early or Mid-Renewable scenarios.

In terms of system costs, the Reference Case has a Net Present Value of costs of $726 million dollars with 80% of the costs coming from the payments to the coal and renewable PPAs. The rest of the costs come from the operation and maintenance of CWL assets (including future generation assets) and market capacity and energy purchases. The total NPV of costs excluding revenues from market sales is $898 million with sales contributing to reduce net costs. In terms of annual costs, the Reference Case has forecast costs of $67 million in 2021 declining to $48 million by 2030, mostly driven by a reduction in PPA costs with the expiration of the Sikeston, Ameresco and Blue Grass contracts. System costs increase after 2030 with the new renewable and capacity market purchases ranging from $52 to $55 million in the 2030s, still below current costs (in real dollars).

Among the scenarios, the Recession Economy and the High Technology case have the lowest total system costs driven by lower demand and lower needs for future capacity additions. The High Seasonal Load has the highest net present value of costs driven by higher energy demand needs. The Early and Mid-Renewable scenarios are also on the high end of costs driven by a larger amount of new capacity additions to meet the accelerated environmental targets.

Similar conclusions are derived considering the average cost of supply determined by dividing the NPV of the total system cost by the present value of the demand served. As can be observed in Figure 1, the High Technology case has the lowest cost of supply ($41.12/MWh) driven by low cost of renewable, followed by the Reference Case ($43.37/MWh) and Recession Economy ($44.49/MWh). Early Renewable (base CO2 costs) follows in costs ($46.46/MWh) and this increases to $46.89/MWh when high CO2 prices are considered, and it is similar to the Mid Renewable at $ 46.89/MWh. Even when expressed as a cost por MWh, the High Seasonal Load has the highest costs at $48.14/MWh, followed by the High Regulation at $47.15/MWh.

Figure 1: System Cost per MWh of Demand ($/MWh) (2019$)



The assessment of the economic benefits or costs of joining SPP show that is recommended for CWL to stay in MISO primarily due to the transmission and wheeling costs that CWL would incur if joining SPP and maintaining the existing PPAs in MISO, which are economical. The costs of delivering energy from the existing PPAs in MISO to SPP are larger than the savings of procuring new renewable capacity only in SPP. That is under most scenarios of the IRP. The analysis assumes that all new incremental renewable generation to meet the RPS targets are procured in SPP at ~$13/MWh lower compared to MISO's PPA prices following a Siemens assessment. Administrative and membership fees on both RTOs account for 12-13% of total charges and should not be the driving decision factor for CWL.

In terms of distributed generation, the value of solar (VoS) was estimated to be 2.8 cents per kWh for a typical rooftop array, being the largest contributor the energy component with 2.4 cents per kWh.

CWL is recommended to invest on an AMI system in four key areas – Electric Meters & Installation, Water Meters & Installation, Communications Infrastructure and installation, and AMI software systems. The expected cost of such investment is $ 32.1 million.

Part 1

Integrated Resource Plan

2 Overview of IRP Methodology

The integrated resource planning exercise focuses on determining the portfolio of generation related supply and demand resources that best meets the electric service company (CWL in this case) long term planning objectives. The plan details what strategy needs to be pursued in context of future technological, market and regulatory conditions and if required what the pivot strategies need to be considered if conditions change and that alter the course that the utility should pursue.

Our IRP methodology is centered on eight steps as summarized below. The depth, duration, and level of detail of each step varies depending on the IRP being carried out but in general these are present in some form in all studies.

1 Establishment of objectives and metrics
2 Identification of key issues and requirements and how they will be analyzed
3 A reference case set of assumptions
4 Technology assessment
5 Definition of scenarios or sensitivities to properly account for uncertainty
6 Least cost screening analyses of options and identification of alternative portfolios
7 A risk assessment of portfolios against the range of uncertainty and portfolio selection
8 Selection of the best portfolio (investments) and supporting documentation

In the case of CWL, each of the steps above is carried out with iteration and communication between the IRP studio and the Master Plan Study, so that modeling methods and input assumptions are consistent and the results of one plan accounted for in the other, for example the need for a Non Wire Alternative (NWA)

Figure 2: IRP Tasks

2.1 Step 1. Define Key IRP Objectives and Metrics and Gather Data

As described above, the first step in our process is to work with the CWL to agree on objectives for the study and metrics; gather and warehouse input data for load forecasts, existing resource characteristics, fuel and power supply contracts, existing renewable resource characteristics and data such as the City's fuel forecasts, and power market forecasts where they are available.

2.2 Step 2. Discussion of Key IRP Issues

In this step, Siemens refines its understanding of the key issues that CWL is interested in addressing as part of this IRP, including:

a) load forecast modeling and the development of a ten year forecast
b) Evaluation of current contracts
c) Future use of local generation assets that located within the CWL's jurisdiction
d) Development of a resource portfolio plan and a resource utilization plan to meet the CWL's environmental objectives
e) Idenfify relevant and impacful uncertaities to be captured in the analysis
f) Assess impacts of Energy Effciency and Demand Side Management Measures
g) identify the expected levels of growth in distributed energy resources
h) Assess the convenincy of staying with MISO or moving to SPP considering the avilability of renewable resources

i) Assess the value of solar

2.3 Step 3. Develop Key Reference Case IRP Assumptions

In this step, Siemens develops key Reference Case IRP assumptions related to CWL load forecasts, and market conditions. Ultimately the reference forecast includes the econometric forecast with an overlay for the other external (i.e. DSM, EE, DR, DER) factors. Fuel forecasts are also defined in this step, either provided or developed as well as emissions costs forecasts. Other forecasts defined in this phase are the looking forward capacity prices in MISO.

2.4 Step 4. Characterization of Current Resources and Future Resource Alternatives

The objective of Step 4 is to identify current available resources and define appropriate energy resource technology alternatives and portfolios to meet the City's expected load and reserve margin requirements over time. The multi-task approach outlined below is the standard process Siemens follows in all its integrated resource planning efforts with slight adjustments to address the City's unique operating position and requirements. Naturally the technical portfolios arising from this process are unique to each client since the current generation mix, load and load growth, renewable energy potential, and policy drivers vary substantially by utility. The central tasks of this Step 4 are:

1. Understand current generation assets, generation, contracts, fuels, and plans.
2. Determine appropriate technology options and their operating and cost characteristics; thermal, renewable, storage.
3. Assess a Levelized Cost of Energy for Various Resource Options and produce an initial ranking accoruding to function; energy or capacity/peaking and options my be screened out.

2.5 Step 5. Development of Scenarios and Sensitivity Cases

Factors such as capital costs, fuel costs, interest rates, and load are inherently uncertain. They combine to produce a broad range of possible outcomes for a utility. Much of the implications of uncertainty are not captured by varying one isolated factor (like oil or gas prices). Rather, cases must be constructed that reflect the widest plausible range of these factors to test to assess whether if the best portfolio performs consistently well across a range of possible outcomes dictated by different views of the future. The arbitrary selection of a low and high (often taking a single variable that includes + or – 5%) case is often misleading and uninformative of the collective uncertainties and risks of the factors that should be driving the choice of portfolios. For this reason, Siemens constructs a limited number of "states of the world" scenarios that will place reasonable bounds on uncertainty in several key variables. These scenarios can be technology based, regulatory based or market based future states of the world (or combinations of these factors).

2.6 Step 6. Capacity Expansion, Production Cost and Economic Evaluations

Siemens uses AURORAxmp® for our analysis. AURORAxmp® is both a production model and a capacity expansion optimization model. Aurora is an hourly, chronological production cost model with an integrated long-term capacity expansion (LTCE) feature. The LTCE produces a resource expansion plan given resource options and constraints around those options. The options can include supply and demand resources, including storage, for inclusion in the expansion plan, existing resources and existing resources for economic retirement as desired. The full set of standard operational and cost parameters for new and existing resources are considered in the LTCE, providing a robust framework from which to evaluate different technologies with different operational (intermittent vs. baseload) cost and incentive profiles. The LTCE considers constraints such as reserve margin targets or requirements, renewable portfolio standards, carbon limits, and ancillary service constraints. Depending on the region or zone in AURORAxmp®, the model can be directed to meet a certain reserve margin constraint and build above that if economic or build based on economics alone without regard to reserve margins. This requirement can be imposed at a zonal level or at a power pool level.

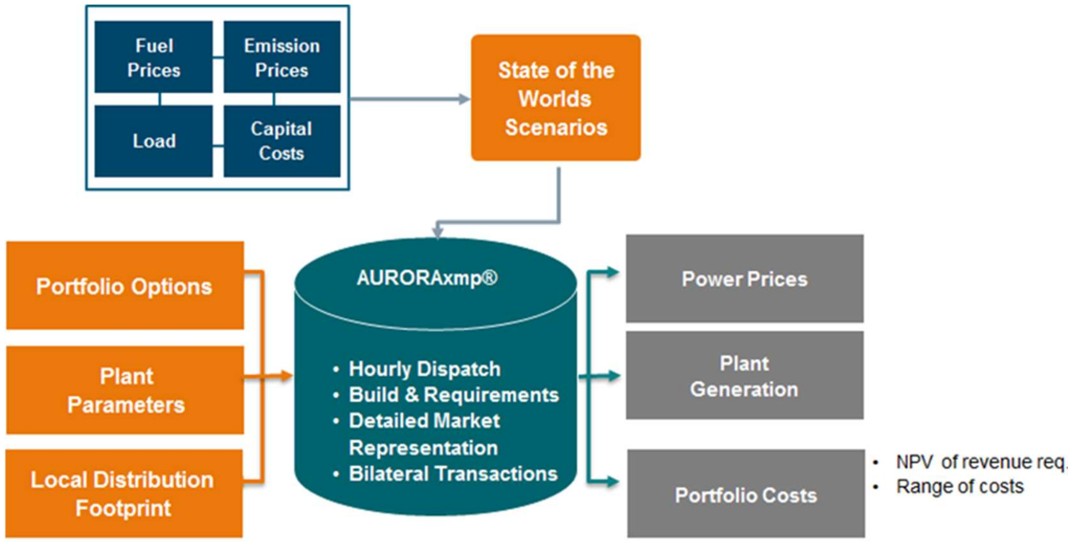
The LTCE makes use of an iterative logic to develop a regional capacity expansion plan. At the end of any given iteration, it has the information it needs to take retirement actions for existing uneconomic resources and to select economically viable new resource options. Convergence criteria reduce the total number of resource alternatives which are considered by the LTCE through the iterations, with a converged solution being defined as one in which system prices remain stable even with change in resource alternatives. In other words, the solution reflects an expansion plan that is at once both economically rational and stable. The LTCE utilizes mixed integer linear programming (MILP) concepts and can solve to a minimum cost solution or a maximize value solution.

For the long-term capacity expansion analysis, Siemens includes all remaining technology options from the screening analysis. All of the least cost modeling will be run with constraints that ensure resource adequacy and all environmental and renewable targets are met.

The figure below shows an overview of the overall modeling approach using AURORAxmp.

.

Figure 3 : Siemens' Process for Portfolio Decision Making under Uncertainty



2.7 Step 7. Risk Analysis and Portfolio Selection

Once all of the portfolios have been determined, we compare each other and assess its risk and identify commonalities, i.e., decisions that regardless of the scenario are likely to be optimal.

2.8 Step 8. IRP Recommendations and Action Plan

This is the last step in the process and consist of a model and this word-based report that fully documents the process, the assumptions, the issues, the findings and the recommendations based upon the analysis completed.

3 System Load and Energy Forecast

3.1 Gross System Load and Energy

The Siemens Team developed system and class load electric forecasts for Columbia Water and Light (CWL). Siemens developed the forecasts for system energy and peak by month to achieve two modeling objectives:

- Support the development of a spatial load forecast for further integrated distribution system planning; and,
- Establish a base and scenario demand forecast for long term and integrated resource planning.

To achieve these modeling objectives, Siemens first developed gross energy and peak forecasts at the system and class levels, and then a net energy and peak forecasts by applying supplemental forecasts for several load modifiers, namely, long term penetration and impacts of energy efficiency technologies, distributed solar technologies, and electric vehicles.

3.1.1 System- and Class-Level Load Forecast Methodology

Siemens reviewed all available data sources, considered different load forecast modeling options, and reviewed CWL's most recent internal system forecast for Fiscal Year 2020. Historical data sources considered in the analysis include:

- Customer counts
- System and class (residential and commercial/industrial) energy consumption
- System peak load and load factors
- Multiple weather data variables as reported at Sanborn Field (http://aes.missouri.edu/sanborn/weather/sanborn.stm)
- Economic indicators such as median income found in the most recent city ten-year trend manual (City of Columbia, 2018. FY2008-FY2017-Ten-Year-Trend-Manual.pdf).
- Other economic data provided by city Bureau of Economic Analysis such as gross metro product data.

Siemens reviewed the recent internal system forecast and determined that it followed good load forecast modeling practices and rigor. We recreated the internal CWL statistical forecast for total system energy and peak demand based on historical data, which also forecasted future values to 2034, using individual monthly regression models. After verifying the internal CWL statistical forecasts, we determined the best course of action for the overall project goals would be met by leveraging the internal CWL system forecast.

3.1.2 System Regression Model and Forecast

The methodology of the internal CWL system forecast is documented in spreadsheet outputs and a report. Key passages of the report narrative explain the approach and key data sources:

> *The Columbia Water & Light (CWL) long-term electric forecasts employ a multiple regression analysis for each month of the year. The main descriptive variables used in these analyses were historical weather data and the total electric customers...We developed a linear model to forecast our customer growth, and then used this model to provide the projected customer counts for future years.*
>
> *We forecast the number of future customers using a linear regression model. We plotted ten years of monthly average customer data, ending in September 2018, and used this data to construct the model. This analysis resulted in a correlation coefficient of 0.98 and standard error of 254 customers. Using the trend line, we then projected the monthly average customers for each month of the electric forecast period.*
>
> *To construct the demand forecast, for each we month we created a multiple regression model using the average customer count for each year and the maximum observed heating or cooling degree days (depending on the month being analyzed). Once the model is constructed, we used our forecasted average customer information with the historical average maximum heating or cooling degree day to forecast demand through 2032.*
>
> *For the energy forecast, we used our average customer information with the monthly total of heating or cooling degree days to construct the model. From this, we used the projected customer counts and the average monthly total of heating or cooling degree days to forecast our energy sales through 2032.*[2]

The internal CWL system forecast, and reports did not estimate load factors, but Siemens calculated them separately from the replicated energy and demand model outputs.

3.1.3 Class Level Regression Models and Forecasts

The internal CWL forecast did not model class level data or forecast class loads over time. Siemens applied the class load peak and energy data as the dependent variable to the same month-specific regression models and associated weather and economic data. Those models, however, did not uniformly perform as well when applying the customer class data. The commercial and industrial (C&I) customer class models performed better than the residential class models. The reason for this difference is grounded in many reasons, but primarily on account of:

[2] FY20 CWLD Load Forecast, Columbia Water and Light, 2019.

- C&I electricity demand is more closely correlated to economic drivers than residential demand
- The residential customer base is heavily populated by multi-family housing and transitory or tenant consumers and we did not have adequate data to separate these customers from residential customers in single family homes

Siemens developed individual econometric models by month for historical C&I customer class energy consumption using the system regression specification, or by slightly modifying or augmenting the system peak models. Siemens applied a C&I customer growth rate using the same regression-based methodology used for the system forecast and forecast monthly C&I energy consumption through the year 2040 using historical weather data and forecasted economic drivers where applicable. Based on historical C&I load factors, Siemens calculated forecasted peak loads associated with the forecasted energy values.

Residential customer class energy and peak load forecasts were calculated by taking the difference between the system and the C&I forecasts because residential correlations to system data were weak.

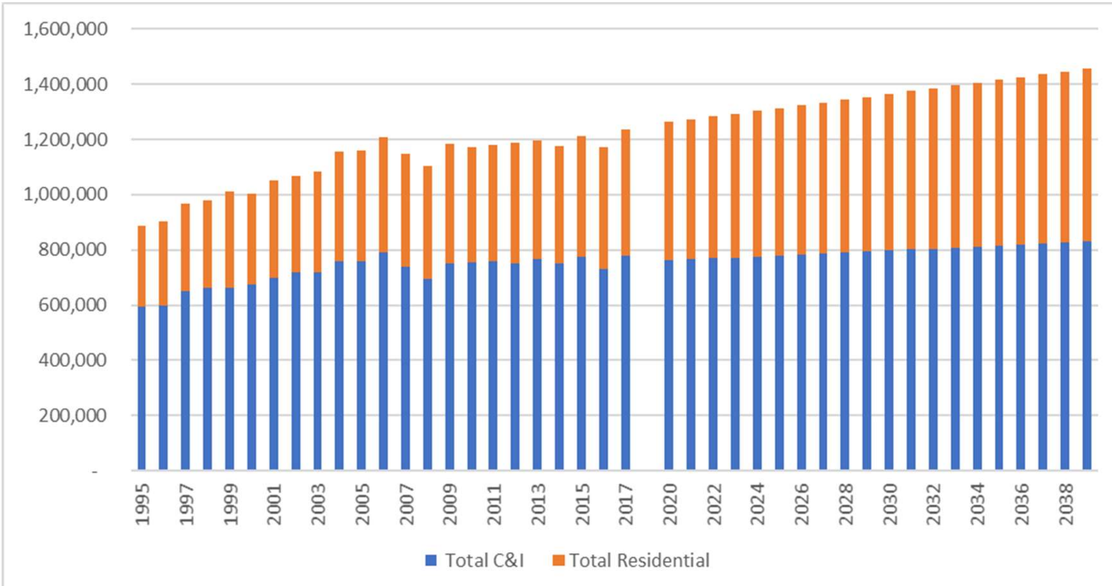
3.2 Gross Long-Term Energy and Peak Load Forecasts

This section presents the gross long-term energy and peak load forecasts for the system and by customer class.

3.2.1 Energy Forecast

System energy consumption is forecast at 1,264,150 MWh in 2021, rising to 1,456,980 MWh by 2040. Commercial and Industrial (C&I) energy consumption represents approximately 60% of energy consumption in 2021, declining to 57% by 2040. Residential energy consumption as a percent of total consumption is expected to rise slightly over the forecast period as the population grows and becomes increasingly densely settled.

Figure 4: Historical and Forecast (MWh) Energy Consumption (1995-2040)

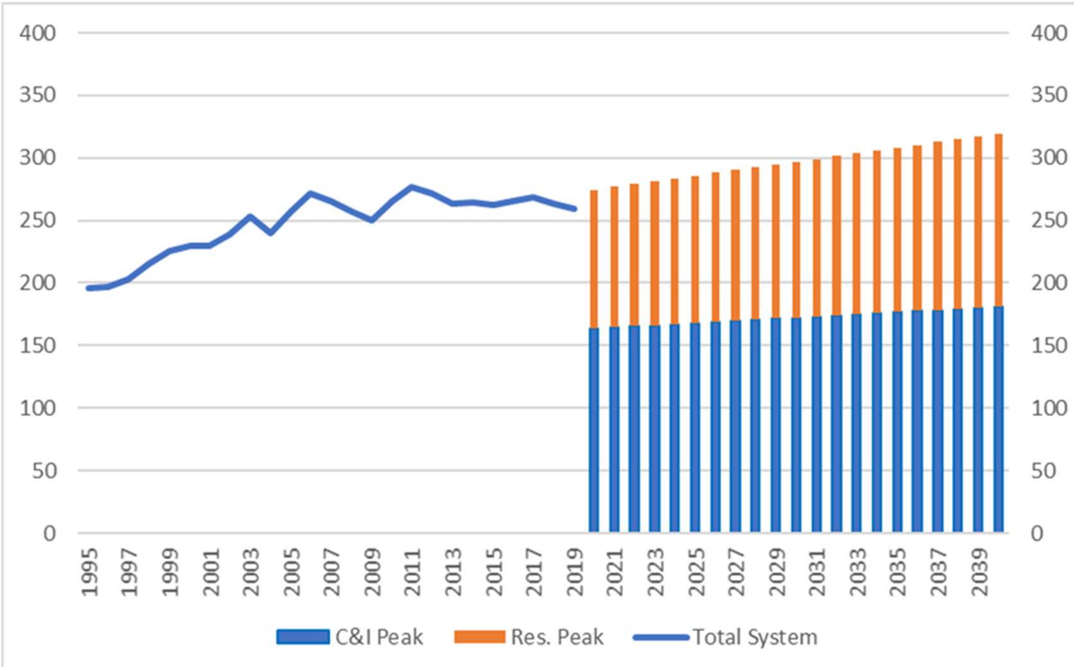


System energy consumption is expected to grow at a rate of 0.8% after 2020 but declining to 0.7% by the end of the forecast period. Growth rates in both the C&I and residential customer classes are expected to decline over the forecast period.

3.2.2 Peak Load Forecast

System peak load in 2020 is forecast for 277 MW, rising to 319 MW in 2040. C&I peak load represents approximately 60% of system peak in 2020 during the peak month of July, declining to 57% by 2040. Residential load peaks during the summertime, and as a percent of system peak (at 41% in July) is expected to rise slightly over the forecast period.

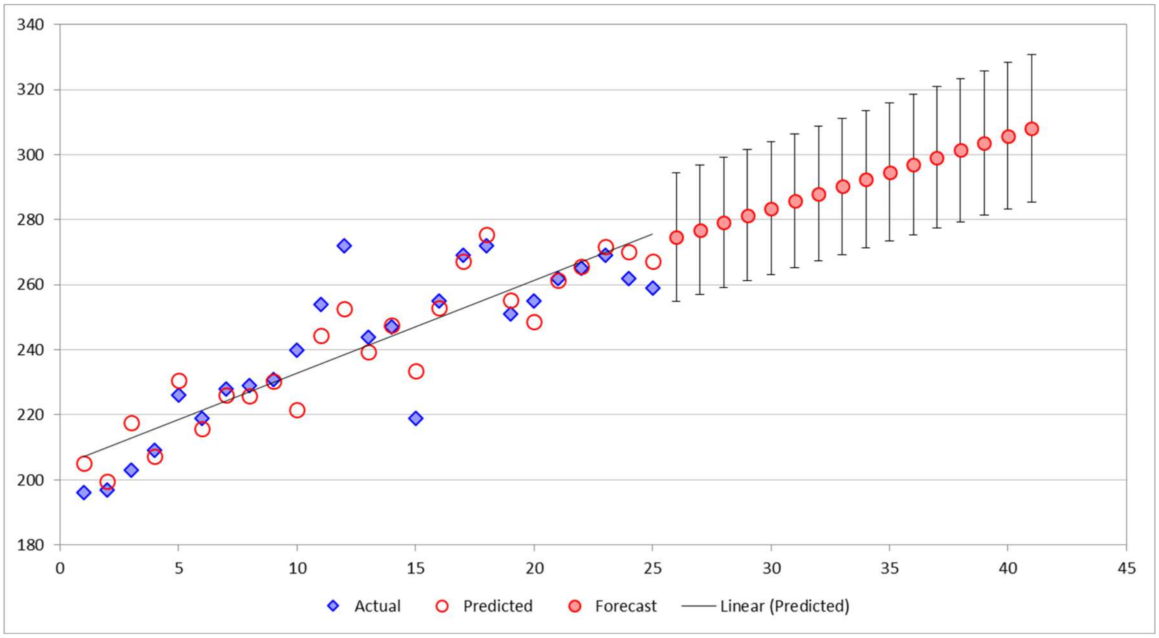
Figure 5: Historical System Peak Demand (MW) Profile (1995-2018) and Forecast (2020-2040)



System peak load is expected to grow at a rate of 0.8% after 2020 but decline to 0.7% by the end of the forecast period.

July is the peak demand month for the CWL system, and an important regression model to review more closely than other months. The internal CWL forecast specified six different regression models for July, and Model Six was selected as the best performing model—namely, it had the best combination of high regression "fit" (Adjusted R-squared of 0.87), low Mean Absolute Percentage Error (MAPE = 2.5%), and with a limited set of independent variables (average monthly temperature, monthly customer count, and average monthly minimum temperature).

Figure 6: Model Actual, Predicted and Forecast (n=25) @ 95% Confidence Limits (MW)



Siemens replicated the internal CWL July peak demand forecast and determined it to be rigorous and reliable for the larger IRP and spatial forecast modeling purposes.

3.3 DSM/Energy Efficiency

Over time, the gross load will be modified by several potential consumption trends or technologies. This section summarizes those penetration forecasts and impacts for energy efficiency, distributed solar technologies, and electric vehicles.

CWL has maintained and expanded an energy efficiency portfolio to serve its customers since 2012. The current energy efficiency portfolio includes incentives, educational resources and partnerships across the commercial, industrial, and residential customer segments, including multi-family housing and tenant housing. The programs with the higher impact within the portfolio, for which energy savings can be estimated include:

- Home Performance with ENERGY STAR
- Residential and Commercial Heating and Cooling
- Residential Energy Audit
- Commercial Lighting, Motors and Drives
- Custom Program for large customers

3.3.1 Methodology

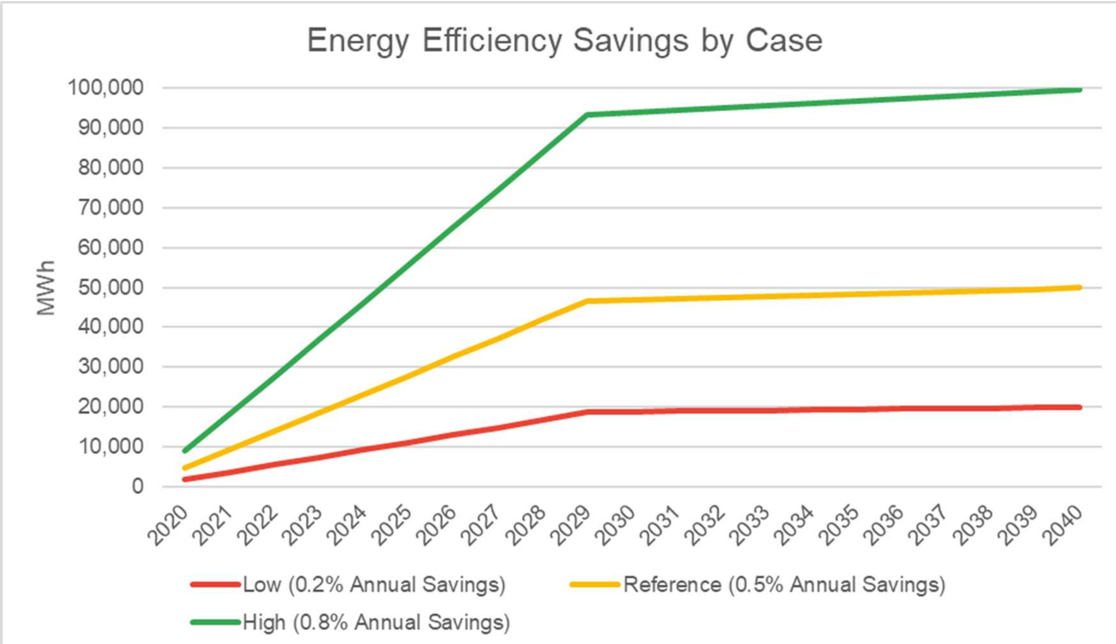
Siemens developed projections of energy efficiency savings for CWL's current portfolio of programs based on the two most recent years (2018-2019) of program history[3], or one year for more recently added programs. Based on those estimated annual program participation rates, annual energy savings across the portfolio is expected to be approximately 0.5% of annual total energy consumption and 0.7% of peak load contributions. Assuming a ten-year effective useful savings life across the portfolio for installed energy efficiency measures, Siemens projected the cumulative 2020-2040 energy efficiency impacts of energy savings at 3.4% of system consumption and 6% of corresponding peak reduction over the forecast period, under the Reference Case.

3.3.2 Service Territory Forecasts

In the reference case, where the energy savings resource represents approximately 0.5% of total energy consumption, cumulative new energy savings are expected to grow to about 47,000 MWh and about 17 MW of peak load reduction by 2030 as shown in the Figure 7. After 2030, the ongoing savings resource will level off without further expansion of the portfolio. Siemens also projected a low (0.2% annual savings) and high (0.8% annual savings) scenario in which the range of the actual savings resource would reach between approximately 19,000 MWh and 93,000 MWh by 2029.

[3] This analysis and forecasts was developed by Siemens in the Spring of 2020.

Figure 7: Projected Energy Savings (MWh) for High, Low, and Reference Cases



3.3.3 Future Potential Programs

Pending section.

3.4 Electric Vehicles

Siemens forecasts the energy and load impacts of increased electric vehicle adoption within a given service territory through 2050. Using deterministic methods to develop the forecasted estimates, Siemens estimates penetration forecasts for three electric vehicle adoption cases defined as: the reference case (Siemens), and two other cases to account for uncertainty in the reference case: a high case (DNVGL), and a low case (EIA). Siemens also estimated the electric vehicle load impacts for each associated forecast for integration into CWL's electric load forecast.

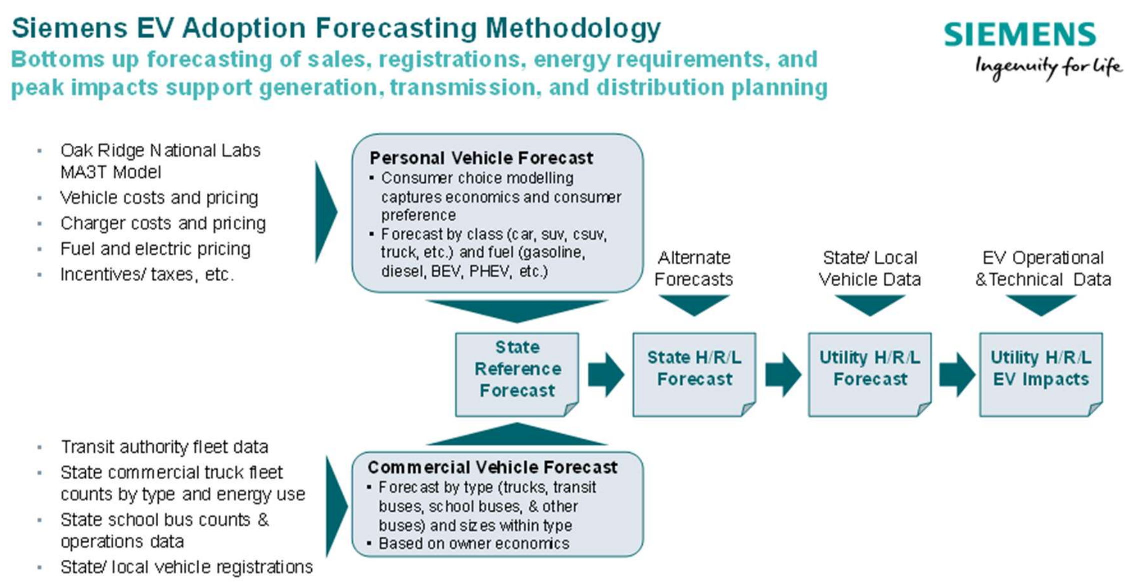
The following sections describe the key findings of the EV penetration and associated load impact forecasts. The findings are illustrated graphically, and the actual forecasted values were included in Siemens's load forecasts.

3.4.1 Methodology

Typically, publicly reported electric vehicle (EV) forecasts focus at a national level on light duty passenger vehicles only. They generally do not provide state, regional, or local projections, and ignore commercial vehicle classes and ownership. These forecasts frequently predict EV sales to the mass market, but not the cumulative number, or stock of EVs, and they typically stop with vehicle adoption and do not estimate electric energy and peak load impacts. To address this need, Siemens developed a proprietary approach and toolset to provide our clients seeking additional forecast detail to support infrastructure planning efforts.

Siemens applies our proprietary EV forecasting approach, which employs our market view, a leading Light Duty Vehicle (LDV) adoption tool, and our proprietary analytical models to project commercial and bus adoption and load calculations, to estimate the potential for EV adoption in a utility service territory. We use this approach, and combination of expertise and tools, to provide our clients with national, state, and local incremental load forecasts for light duty vehicles, commercial vehicles, and buses. A schematic of this approach is presented in Figure 8.

Figure 8: Schematic of EV Adoption Forecasting Methodology



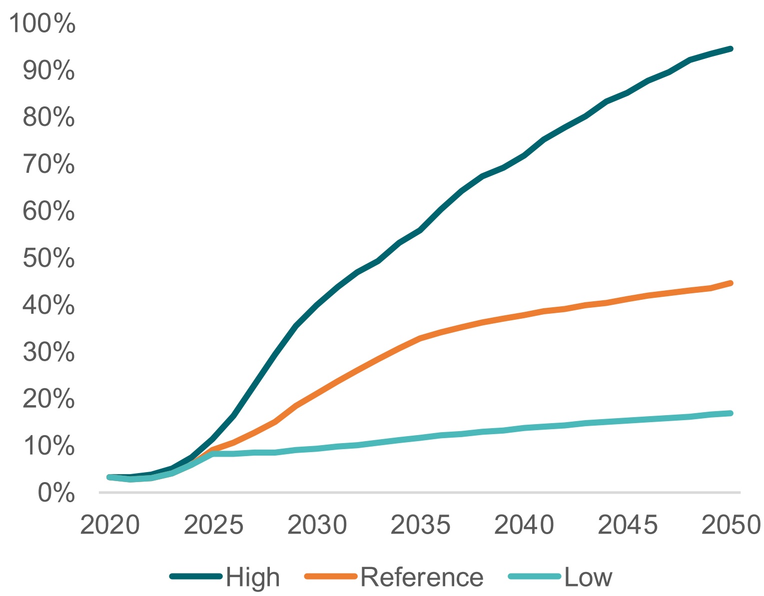
The Siemens' reference case LDV adoption forecast leverages proprietary inputs and adjustments to the latest version of the best-in-class customer choice model (MA3T Model) developed by Oak Ridge National Labs (ORNL). It is important to note that this model does not assume any adoption levels or shape, but rather calculates vehicle sales based on fundamentals. While we employ this model, we do not use all ORNL's inputs. Siemens conducts its own independent research to develop key input variables and customizes as needed for client needs. This model generates state forecasts for both battery electric vehicles (BEVs) and plug-in hybrid electric vehicles (PHEVs) by state, and Siemens allocates state forecasts derived from this model using our proprietary inputs to the utility service territory using either Department of Motor Vehicle (DMV) reported vehicle registrations, available vehicle counts provided by the American Community Survey (ACS) conducted annually by the Census Bureau, registrations from AutoAlliance.org, or client supplied vehicle registration data.

3.4.2 National, State, and Service Territory Forecasts

Strong interest in electric vehicles coupled with vehicle and charging incentives are expected to drive U.S. EV adoption in both private and commercial fleets. Manufacturers of private and commercial (truck, transit buses, school buses, etc.) vehicles are spending approximately $300 billion globally with a most new models expected to arrive in the early to mid-2020s. A further $61 billion has already been expended or committed for autonomous vehicles. EV price parity with internal combustion technology is approaching, but still requires federal EV incentives, which are phasing out for early movers.

Our reference case forecast for the U.S. private and commercial fleet is presented below. We expect private EV penetration will reach 21.1% of sales nationwide by 2030 and commercial penetration will reach 11.0% as displayed in Figure 9. In total, by 2030, 13.1 million EVs are expected to be registered across the U.S.

Figure 9: U.S. PEV Adoption, 2020-2050, % of New Sales



Source: Siemens
Notes:

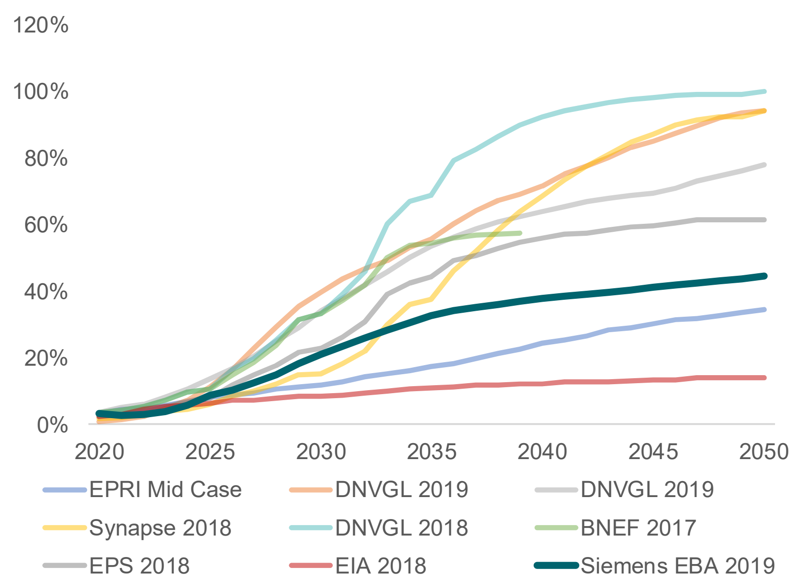
- PEV = Plug-in Electric Vehicles including battery (BEV) and plug-in hybrid electric vehicles
- LDV = light duty vehicles

For national EV penetration to reach 21.1% by 2030, EV adoption in some states will exceed this level while others will not. For example, our forecast suggests private fleet EV penetration will exceed 50% of sales in several west coast states by 2030, while remaining in the single digits for thirteen states. We expect private EV penetration in Missouri, for example, will reach 7.8% of sales by 2030 and commercial penetration will reach 4.2% as represented in Figure 11. In total, by 2030, 89.2 thousand EVs are expected to be registered in Missouri.

The commercial vehicle and bus forecasts are developed from third party sources. The reference case commercial vehicle forecast was derived from the Energy Information Administration's (EIA) Annual Energy Outlook EV adoption forecast, which we applied to the commercial vehicles operating in the utility's service territory. We leverage several public and private forecasts to develop a reference case bus forecast.

To establish high and low boundaries for developing high (DNVGL) and low (EIA) forecast estimates, Siemens' research identifies alternative EV adoption forecasts[4] for each vehicle class. The highest and lowest adoption forecasts are used to establish the widest range of potential outcomes. A comparison of national PEV adoption forecasts is presented in Figure 10.

Figure 10: Comparison of National PEV Adoption Forecasts, % of New Sales



Source: Siemens, EIA, BNEF, DNVGL, EPS, Synapse, EPRI
Notes:

DNVGL provides case for the most rapid EV adoption, largely driven by their view that EV costs will decline below those of traditional vehicles by the early 2020s. Conversely, the EIA takes a more conservative view of EV price declines resulting in their more conservative view, which provided the low case. These forecasts are then applied against local vehicle fleets and expected procurement within the service territory establish the widest range of potential annual EV sales within a service territory. We then adjust annual sales for the low, reference, and high adoption scenarios based on vehicle expected survivorship to develop a cumulative vehicle forecast by vehicle type. By applying vehicle energy requirements to typical driving

[4] Sources included: EIA AEO 2019, BNEF, DNVGL, Woodmac, EPS, Mass Transit Magazine

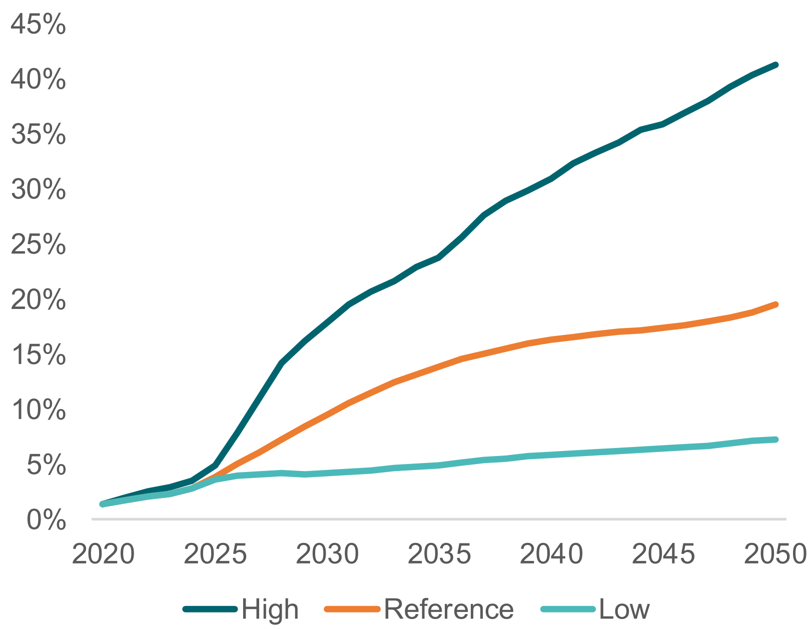
patterns, Siemens determines incremental vehicle energy requirements. These energy requirements are then shaped to typical 24-hour periods for both weekdays and weekends by applying charging patterns that result in peak load and coincident peak impact estimates from electric vehicle charging.

Income, state incentives/ disincentives, vehicle switching economics, and personal preference drive state EV adoption differences. It's important to note that state incentives can take other forms including tax credits, purchase rebates, income tax credits, excise tax credits, vehicle license taxes, carpool lanes, reduced electric rates for charging, rebates for chargers, insurance cost deductions, favored/ free parking, etc. Some states are pushing for increased vehicle registry costs for PEVs to offset lost fuel taxes. In MO these include a $75 annual fee on BEVs, and $37.50 on PHEVs. Further, the Missouri Department of National Resources (MODNR) is providing funding to replace diesel school buses with new cleaner burning vehicles. The MODNR will grant up to $22,000 per vehicle. Investor-owned utilities often seek to incent adoption with programs like Ameren Missouri's Charge Ahead program which plans to install 1,000 plus EV charging stations. Meanwhile, municipalities often include specific EV targets within their GHG reduction targets and focus on removing EV/ charging barriers like developing EV specific building codes, streamlining permits, and reducing interconnection costs and timing. While the City of Columbia has established a goal of developing an EV Roadmap in its Climate Action and Adaption Plan, there are no target penetration rates or dates yet identified5 that could be used to inform Siemens EV projections. As a result, in 2018, Missouri ranked 34th in the nation in terms of registered PEVS as a percent of all registered vehicles.

For reference, in 2018, 311,578 LDVs were sold in Missouri of which 2,267 were PEVs. Our forecast for Missouri is presented in Figure 11.

[5] See City's Climate Action and Adaption Plan, Strategy T-2.1: Encourage use of low- to zero-emission vehicles and it associated goals.

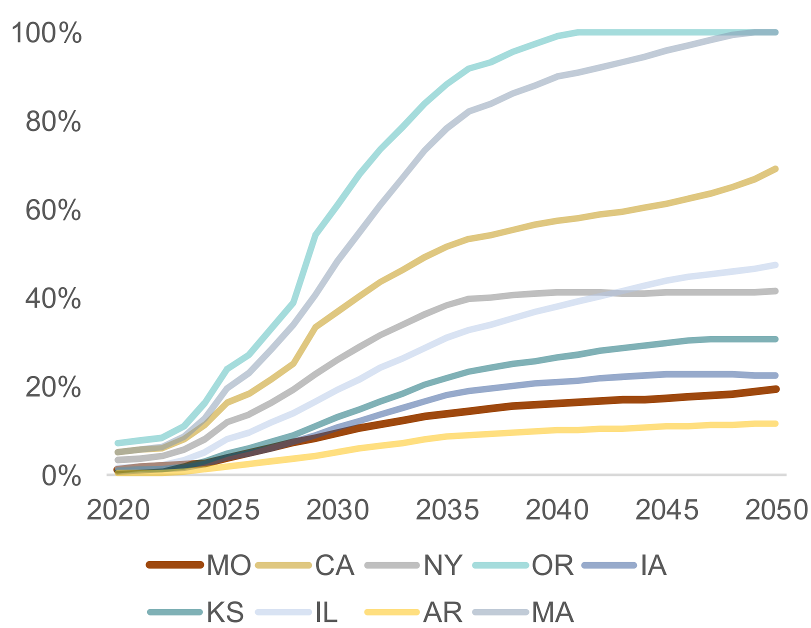
Figure 11: Missouri PEV Adoption, 2020-2050, % of New Sales



Source: Siemens

In the Figure below, Siemens provides a comparison of our Missouri PEV forecast with those of select states.

Figure 12: Missouri PEV Adoption, 2020-2050, % of New Sales

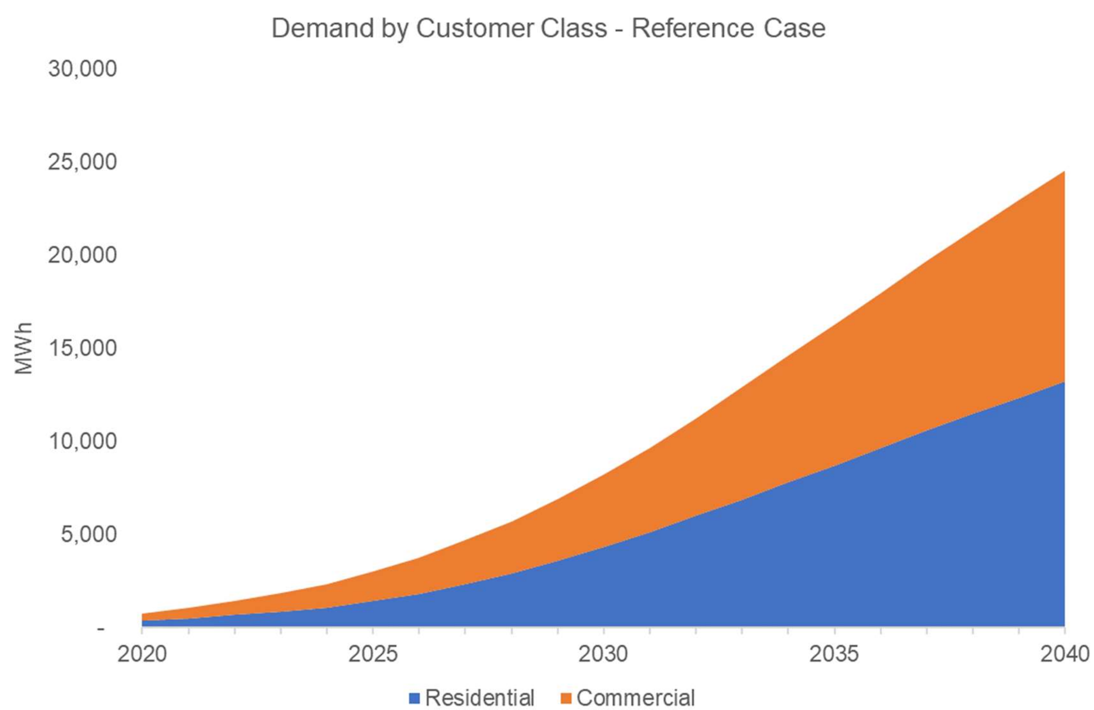


Source: Siemens

As discussed in the methodology section above, Siemens segmented the Missouri state forecast into the CWL service territories. This analysis provided the number of registered private and commercial vehicles in each case expected to be registered within CWL's service territory for each year. The energy consumption required to propel these vehicles was calculated and the resultant load calculated at the typical unconstrained peak charging time of 9 pm. These results are presented in Figure 13, Figure 14 and Figure 15. When overlaid with the system peak at the peak hour, the coincident peak impact of EV charging in each year is known.

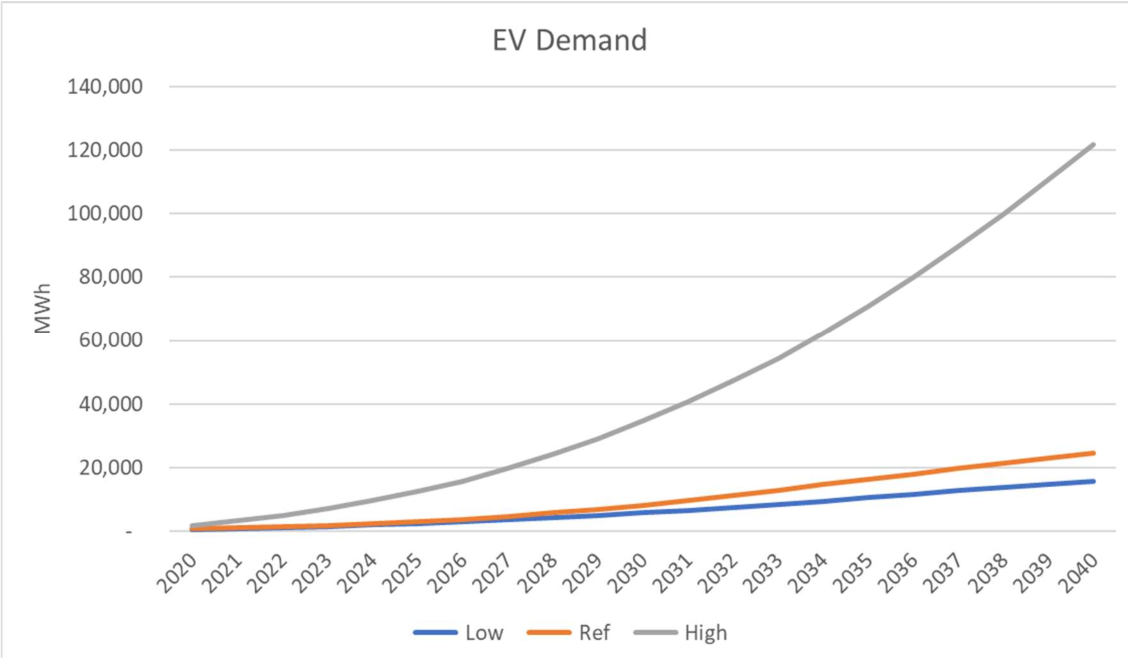
Under the Reference Case the EV demand is equivalent to 1.7% of the gross load by 2040 from 0.1% in 2020/2021. Under the high case, EV demand reaches 1.8% by 2028, twelve years earlier compared to the Reference Case. By 2040, EV demand is 8% of the gross load. In contrast, under the low case, EV demand reaches 1.2% of gross load by 2040.

Figure 13: CWL Service Territory PEV System Impact – Reference Case Energy



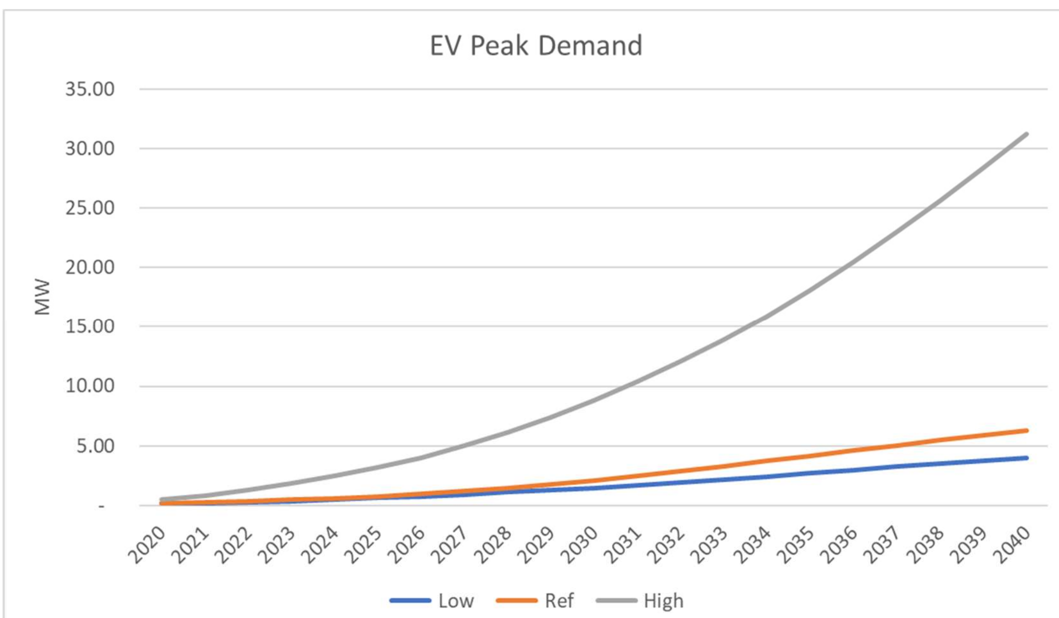
Source: Siemens

Figure 14: CWL Service Territory PEV System Impacts – All Cases



Source: Siemens

Figure 15: CWL Service Territory PEV System Impact - Load



Source: Siemens

3.5 Distributed Solar

To project the future penetration of distributed solar (DS) from an economic standpoint, Siemens has developed a proprietary DS penetration model based on the methodology described in National Renewable Energy Laboratory (NREL) SolarDS[6] and DGen[7] model documentation. The Siemens model applies a bass-diffusion penetration function incorporating multiple inputs including federal and state tax credits, incentive payments, tax savings on loan interest, retail electricity prices, debt/value ratio, financing parameters, marginal tax rates, and forecasted DS capital costs. The adoption rates and the maximum market penetration are a function of the payback period using an empirical formulation that has been thoroughly vetted in the industry. The payback period is based on the down-payment (equity portion), federal tax credits in the form of the ITC through 2022[8], and the net benefits accruing to the business or homeowner.

3.5.1 Methodology

For CWL net-metering program participants who have installed solar PV panels, the net benefits from distributed solar generation come in two forms: value from offset energy consumption and value from selling excess generation back to the electrical grid. To estimate offset energy consumed and excess generation, Siemens applied the average solar PV system size for commercial and residential customers to local conditions and participant history within the PVWatts model[9] and developed generation load shapes to subtract from the average net load shapes for those commercial and residential participants. To estimate net benefit dollar streams of both the offsetting energy consumption and the sale of excess generation, Siemens then applied the prevailing retail rate for energy during the time energy is produced or consumed from the distributed solar generation unit. Current energy rates are published on CWL's web site. For the purpose of modeling future penetration, Siemens assumed no change in energy rates over the future period of analysis as small changes in rates would likely not alter the payback calculations compared to other factors such as federal policy support, declining installation costs or program subsidy levels.

Siemens developed a Reference Case model based on historical market penetration and other local documented market conditions. Historical market penetration is from CWL's solar program since the program began in 2012. From 2012 to 2019, CWL counts 200 residential installations and 29 commercial installations.

While participation is spread across rate classes, Siemens developed average inputs for 69 residential and six commercial net metering participants based on available net load shape data from October 2017 to September 2018. For modeling purposes, we assumed that future

---

[6] https://www.nrel.gov/docs/fy10osti/45832.pdf
[7] https://www.nrel.gov/analysis/dgen/
[8] https://www.irs.gov/pub/irs-drop/n-18-59.pdf
[9] PVWatts is a model developed by NREL that estimates the energy production and cost of energy of grid-connected photovoltaic (PV) energy systems. https://pvwatts.nrel.gov/

participants will be net metering participants, mirroring the program design in place at the time of this study. Therefore, Siemens applied participation data inputs on offset consumption, excess generation, and average system size for those subsets of net metering customers only. For modeling installation costs, however, Siemens incorporated data from average installation costs in 2019 from all available participant data in one scenario.

Additional assumptions were necessary to complete the modeling inputs for the Reference Case. The federal ITC was applied historically and into the future according to the tax credit schedule in all scenarios. Although a small number of past projects may have included financing, loans for participation are assumed to be zero as installation cost decline because the priority is to simulate future market conditions rather than the past. The CWL installation cost subsidy is assumed, however, during the entire period of analysis at $500 per kilowatt for an average residential installation size of 7.65 kw and $400 per kilowatt for an average commercial installation size of 31.07 kw.

Finally, Siemens modeled estimated paybacks and the associated adoption rates from 2020 to 2040 for a Reference, High and Low Case scenario, given the market and policy conditions of CWL's net metering program participants. The period of analysis, however, began in 2012 and was broken into several sub-periods for estimating average paybacks:

- 2012-2014: Early program trends characterized by scant participation and rapid reduction in average installation costs.
- 2015-2019: Recent program trends characterized by steady but limited program activity and continued rapid reduction in average installation costs.
- 2020: Reduction of ITC to 26%.
- 2021: Reduction of ITC to 22%.
- 2022-2030: Market maturation, relative stability of declining installation cost trends, and reduction of ITC to 20% for commercial installations but 0% for residential installations.
- 2031-2040: Distant future market conditions based on low, stable installation costs and continued ITC and CWL policy support.

While average installation costs declined rapidly over the past 10 years, according to NREL, they will decrease at a decreasing rate over the period of analysis. To model this trend, Siemens selected the median installation cost input value during the sub-periods that covered multiple years. Siemens then developed a composite market penetration estimate for the period of analysis by estimating the penetration for each individual year corresponding with the payback period in which that year is associated.

The Bass diffusion penetration function calculates the new adoption fraction in time t (A_t) as shown in the equation below:

$$A_t = \frac{1 - e^{-(p+q)*t+2}}{1 + (\frac{q}{p})e^{-(p+q)*t+2}}$$

Then calculate the maximum market fraction:

$$M_t = e^{-Payback\ Sensitivity*Payback\ Years}$$

Finally, calculate the market share rate (S) as:

$$S_t = M_t * A_t$$

To develop high and low penetration cases, Siemens developed paybacks with low and high future installation cost scenarios based largely on differences in varying installation cost data from NREL. Adoption rates are lower for longer payback periods and higher for shorter payback periods.

Key assumptions incorporated into the model are listed in Table 1.

Table 1: Key Assumptions for the Distributed Solar Forecast

Data Input	Value or Description	Source
Energy rates for residential and commercial customers	E01 (Residential) Meter Code: $0.1079 E02 (Commercial) Meter Code: $0.1025	https://www.como.gov/utilities/water-and-light/electric/rates/
PV System Cost Curve 2017-2051	Modeled low, middle and constant cost stream forecasts	https://atb.nrel.gov/electricity/data.html
PV System Cost Curve 2010-2018	Modeled historic costs from 2010-2018	https://www.nrel.gov/docs/fy19osti/72133.pdf
Average residential installation costs 2019	$500 per kw	CWL Participation Data
Solar PV Capacity Factor, Output and Generation Shape	15.8%	Assumptions based on solar resource information from PVWatts (https://pvwatts.nrel.gov/pvwatts.php) and CWL Solar Customer Generation Data for Columbia, MO
Solar System Size	Residential: 7.65 kw Commercial: 31.07 kw	CWL Participation Data
Solar ITC	2010-2019: 30% 2020: 26% 2021: 22% 2022: 0% (residential) 10% (commercial)	https://www.seia.org/initiatives/solar-investment-tax-credit-itc
Solar Rebate	$500/kw installed	
Key NREL Modeling Parameters	Residential: p=1.7E-06; q=0.661 Commercial: p=1.60E-06; q=0.776	Used default values in NREL documentation for Missouri

The installation cost data was a significant input to the modeling process and developed from three different data sources. After reviewing the participant data, we averaged the 2019 installation cost data available from 44 residential participants. We also leveraged two different data streams from NREL, including a study covering 2010 to 2018, and a modeled forecast from 2017 to 2051 that included a low, middle and constant (or high) cost streams. Siemens joined the middle and low NREL cost streams with the historical cost stream through interpolation. For the high-cost stream, since the point value from average partial participant data in 2019 was the highest across the data sets, we rejected the NREL constant cost stream as an input and estimated a high installation cost stream from 2019 forward that was proportionate to the NREL middle cost forecast, and backwards from the NREL historical data.

3.5.2 Service Territory Forecasts

The following table presents payback values by sub-period for the Low, Reference and High Penetration Case Scenarios. While the payback period should decrease over time across all scenarios with declining installation costs, the drawdown of the ITC distorts that trend in the near term (2020-2021) for the Low and Reference Cases. Only the High Penetration Case shows a decreasing payback trend based on the overwhelming influence of low installation costs. For the Low Penetration Case Scenario, the payback for the Early Program period (2013-2014) could not be estimated and exceeds 25 years, which is the generally accepted expected useful life of solar panel technologies.[10]

[10] https://www.nrel.gov/docs/fy12osti/51664.pdf

Table 2: Commercial Payback and Installation Costs

Program Period Modeled	Description	Low Penetration Case Payback (Years)	Low Penetration Case Installation Costs ($/kW)	Reference Penetration Case Payback (Years)	Reference Penetration Case Installation Costs ($/kW)	High Penetration Case Payback (Years)	High Penetration Case Installation Costs ($/kW)
2012-2014	Early Program	>25.00	$4,819	>25.00	$4,389	>25.00	$3,470
2015-2019	Current Program	10.99	$1,960	9.55	$1,786	9.91	$1,832
2020	ITC Reduction to 26%	9.73	$1,733	8.47	$1,578	5.91	$1,231
2021	ITC Reduction to 22%	9.98	$1,693	8.67	$1,542	5.35	$1,108
2022-2030	Market Maturation; ITC Reduction to 10% for Commercial Owners and 0% for Residential Owners	9.70	$1,493	8.38	$1,359	4.61	$920
2031-2040	Distant Future Market Conditions	7.15	$1,226	7.15	$1,226	3.35	$750

For the residential market, the paybacks are longer than for the commercial market, reflecting the historically lower average system size installed under the CWL program and the higher assumed installation costs. In all cases, estimated payback values exceed the expected useful life of 25 years in the Early Program period. For the Reference Case, estimated payback values are below the expected useful life in the current period (2015-2019) at 20 years, dropping to 9 years in the 2031 to 2040 period. In the High Penetration case, estimated payback values begin at the same level as in the reference case in the current period but decrease at a higher rate to 3 years in the 2031-2040 period. In the Low Penetration Case, payback values fall to 9 years as in the Reference Case in the 2031-2040 period.

Table 3: Residential Payback and Installation Costs

Program Period Modeled	Description	Low Penetration Case Payback (Years)	Low Penetration Case Installation Costs ($/kW)	Reference Penetration Case Payback (Years)	Reference Penetration Case Installation Costs ($/kW)	High Penetration Case Payback (Years)	High Penetration Case Installation Costs ($/kW)
2012-2014	Early Program	>25.00	$6,625	>25.00	$6,034	>25.00	$4,550
2015-2019	Current Program	24.35	$3,041	19.77	$2,770	19.77	$2,770
2020	ITC Reduction to 26%	21.58	$2,757	17.75	$2,511	14.06	$2,217
2021	ITC Reduction to 22%	21.49	$2,636	17.65	$2,401	13.44	$2,076
2022-2030	Market Maturation; ITC Reduction to 10% for Commercial Owners and 0% for Residential Owners	18.58	$2,031	15.31	$1,849	8.80	$1,369
2031-2040	Distant Future Market Conditions	8.94	$1,382	8.94	$1,382	3.19	$784

3.5.3 Penetration Rates by Case

Table 4 summarizes historical participation in the CWL Net Metering Program compared to each of the modeled composite penetration scenarios. The composite penetration values are the combined estimated penetration across the various sub-periods and associated payback values and overlapping or step-change projections between subperiods are a function of those groupings. Furthermore, federal policy to reduce the ITC could be introducing variability into the market where the complete sunset of the ITC tax advantages in the residential market could temporarily accelerate demand in the next two years.

Table 4: Historical and Forecast Participation

	Commercial			Residential		
Year	Program	Ref.	High	Program	Ref.	High
2012	-	-	-	7	-	-
2013	2	-	-	6	-	-
2014	2	-	-	10	-	-
2015	1	-	-	16	-	-
2016	8	-	-	19	-	-
2017	3	-	-	80	-	-
2018	9	-	-	22	-	-
2019	4	-	-	40	-	-
2020	-	57	57	-	225	225
2021	-	55	55	-	53	53
2022	-	12	13	-	1	4
2023	-	24	47	-	2	44
2024	-	48	97	-	4	65
2025	-	86	184	-	7	78
2026	-	136	299	-	13	81
2027	-	185	414	-	22	85
2028	-	222	500	-	35	98
2029	-	245	550	-	49	119
2030	-	259	579	-	61	142
2031	-	59	272	-	143	366
2032	-	61	268	-	157	419
2033	-	62	264	-	166	457
2034	-	62	261	-	171	488
2035	-	63	259	-	175	512
2036	-	63	258	-	176	529
2037	-	64	256	-	177	540
2038	-	64	254	-	177	550
2039	-	65	254	-	177	559
2040	-	65	254	-	177	568

The following graphs illustrate the residential and commercial penetration curves for the individual payback functions compared to actual program history for the Reference Case Scenario. As installation costs decline, coupled with the continued support of the ITC for the commercial market, we expect the payback periods to decline over time. With improved payback periods, the average project size could increase which would only further improve project economics although this trend was not modeled.

The resulting behind the meter customer solar demand under the reference and high case is shown on Figure 18. Solar customer demand increases from 4,854 MWh in 2020 to 107,433 MWh by 2040 under the Reference Case. In the High case, the demand increases to 296,958 MWh by 2040 with a larger growth in installations after 2025 an in particular during the 2030s.

Figure 16: Commercial Customer Participation Over Time by Payback Period

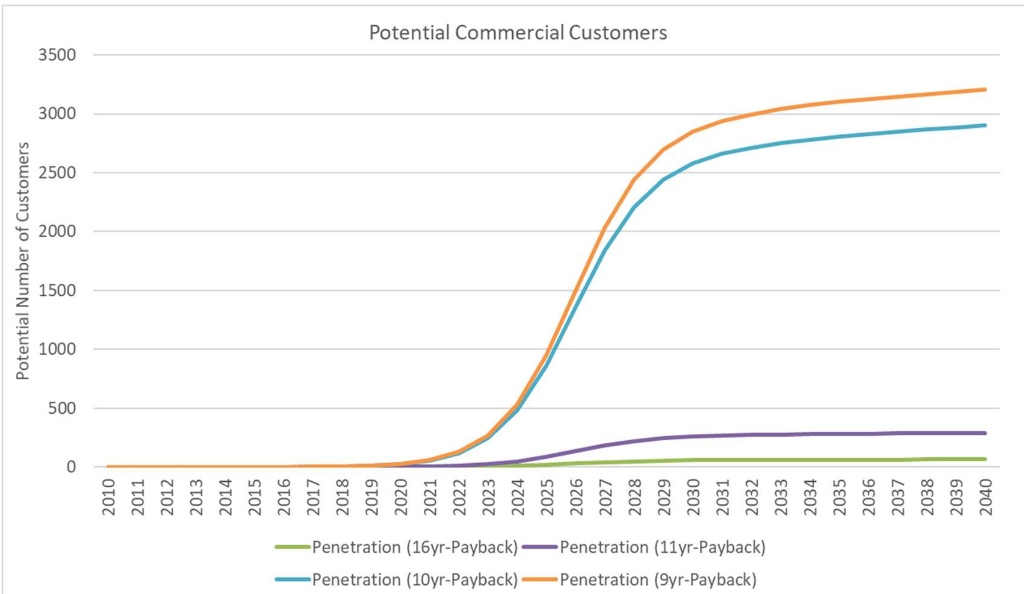


Figure 17: Residential Customer Participation Over Time by Payback Period

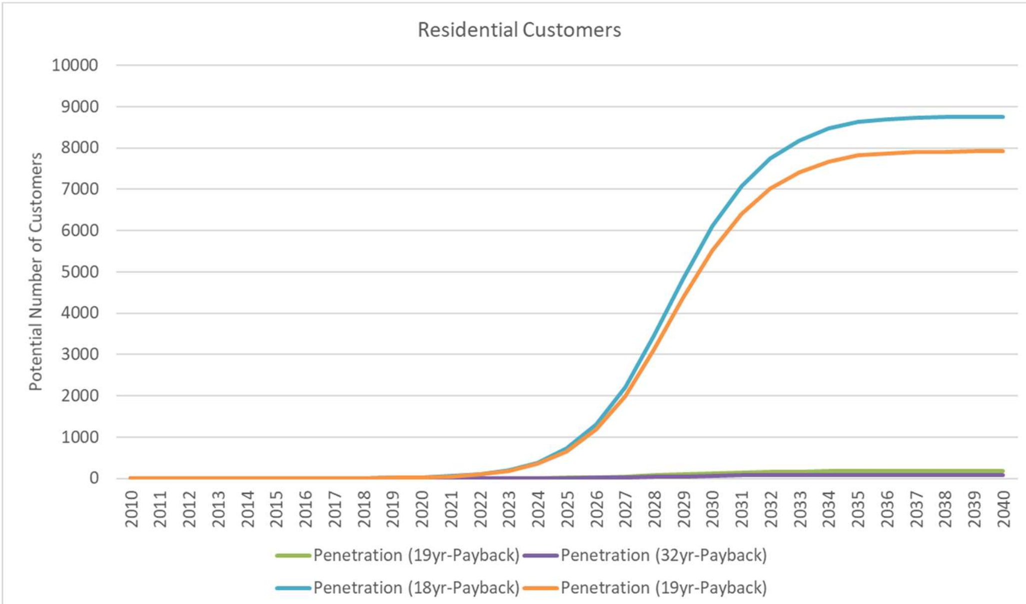
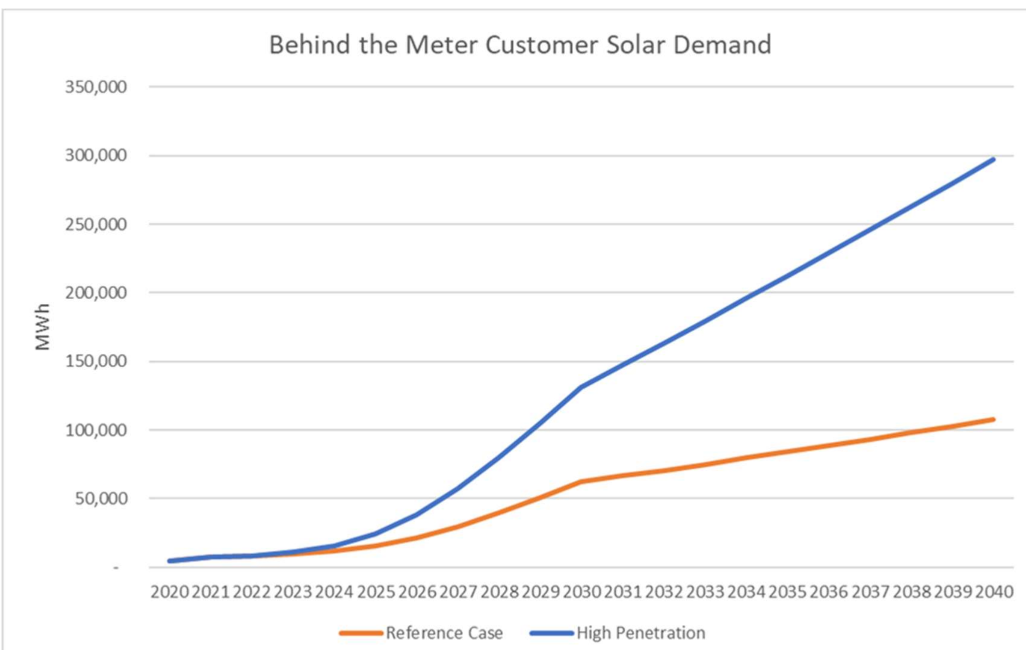


Figure 18: Behind the meter solar customer demand



3.6 Net System Load and Energy Forecast

The net energy and peak load forecasts are the result of applying the load modifiers to the gross forecasts. The load modifiers affect the gross forecasts in the following ways:

- Energy efficiency programs reduce energy usage
- Distributed solar technologies reduce energy usage
- Electric vehicles increase energy usage

This section presents the net energy and peak demand forecasts and the impacts of the load modifiers.

3.7 Net Long-Term Energy Forecast

Siemens validated the internal CWL forecast that gross system energy is expected to grow modestly over the next 20 years. As shown in Figure 19, net system energy is expected to decline largely due to energy efficiency and rising levels of Solar DG penetration. Electric Vehicle will rise throughout the forecast and is expected to offset about half of the Energy Efficiency savings by 2040, under the Reference Case.

Figure 19: Gross and Net Energy Forecasts (MWh) for 2020-2040

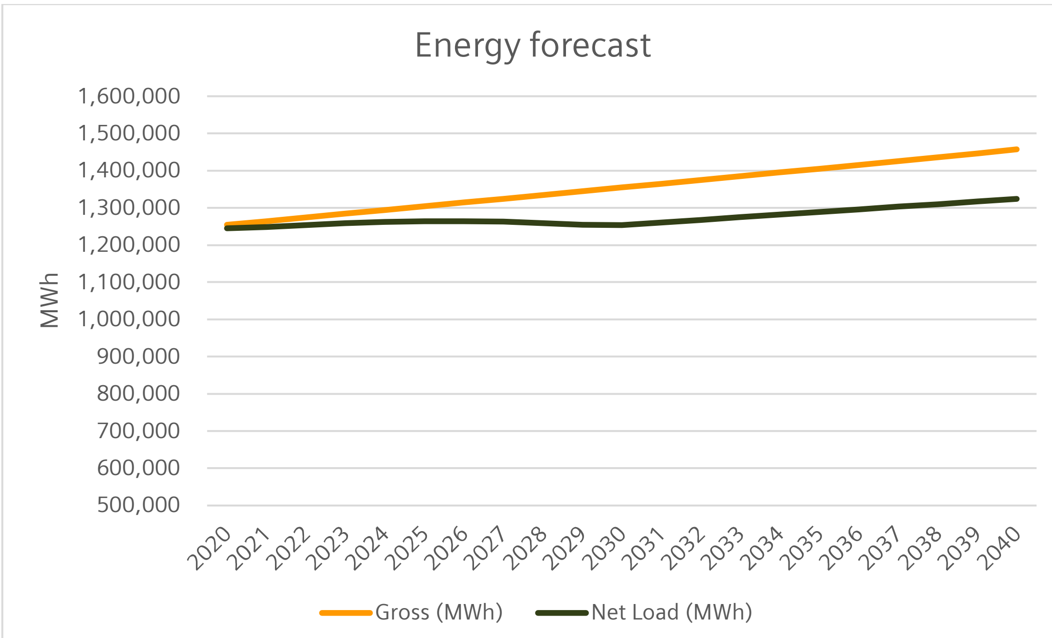


Table 5 presents the gross, net, and load modifiers energy forecasts for the period of analysis (2020 to 2040). While the gross energy forecast increases at an annual average rate of 0.7%, the net energy forecast increases at an annual rate of 0.3% due to the impact of energy efficiency and solar distributed generation[11]. Under the Reference Case, Energy Efficiency savings account for 3.4% of the gross load by 2040 and solar distributed generation for 7.4% of the gross load by 2040, becoming the main driver for the load reduction. Electric vehicle demand accounts for 1.7% of gross load by 2040, partially offsetting the reductions from EE and solar DG (see Table 6).

Under high penetration scenarios, energy efficiency accounts for up to 6.9% of gross load (high energy efficiency case) and solar DG up to 20.4% of gross load by 2040. Electric vehicle penetration accounts for 8.4% of gross demand offsetting the impact of EE savings and partially the impact of solar DG.

[11] To arrive at net energy for a given year, subtract PV generation and EE savings from the gross energy value, and add EV charging. Any remainders are due to rounding.

Table 5: Summary of Gross, Net, and Load Modifier Energy Forecasts (MWh) from 2020-2040

Year	Gross Energy	PV Generation	EE Savings	EV Charging	Net Energy
2020	1,254,092	4,854	4,546	738	1,245,429
2021	1,264,150	7,783	9,120	1,055	1,248,303
2022	1,274,209	8,301	13,720	1,433	1,253,620
2023	1,284,268	9,376	18,348	1,866	1,258,409
2024	1,294,326	11,499	23,004	2,363	1,262,185
2025	1,304,384	15,304	27,688	3,006	1,264,399
2026	1,314,442	21,304	32,399	3,778	1,264,518
2027	1,324,500	29,500	37,139	4,685	1,262,547
2028	1,334,558	39,448	41,907	5,731	1,258,935
2029	1,344,616	50,526	46,703	6,909	1,254,296
2030	1,354,674	62,328	46,982	8,219	1,253,582
2031	1,364,731	66,417	47,263	9,659	1,260,710
2032	1,374,789	70,710	47,546	11,229	1,267,762
2033	1,384,846	75,122	47,831	12,894	1,274,788
2034	1,394,924	79,624	48,117	14,592	1,281,775
2035	1,405,076	84,190	48,405	16,292	1,288,772
2036	1,415,304	88,802	48,696	17,993	1,295,800
2037	1,425,608	93,426	48,988	19,687	1,302,881
2038	1,435,988	98,071	49,282	21,357	1,309,992
2039	1,446,445	102,736	49,578	22,972	1,317,103
2040	1,456,980	107,433	49,876	24,532	1,324,203

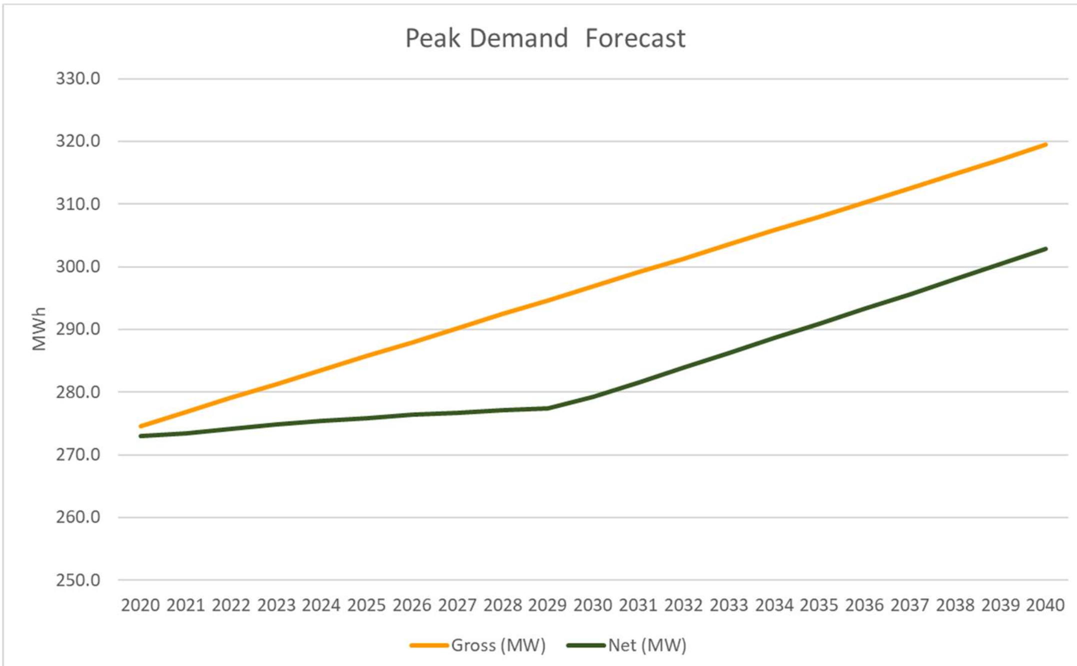
Table 6: Load Modifiers as Percent of Gross Energy from 2020-2040

Year	PV Generation	EE Savings	EV Charging	Net Energy
2020	0.4%	0.4%	0.1%	99.4%
2021	0.6%	0.7%	0.1%	98.9%
2022	0.7%	1.1%	0.1%	98.5%
2023	0.7%	1.4%	0.1%	98.0%
2024	0.9%	1.8%	0.2%	97.3%
2025	1.2%	2.1%	0.2%	96.3%
2026	1.6%	2.5%	0.3%	95.0%
2027	2.2%	2.8%	0.4%	93.3%
2028	3.0%	3.1%	0.4%	91.4%
2029	3.8%	3.5%	0.5%	89.3%
2030	4.6%	3.5%	0.6%	87.5%
2031	4.9%	3.5%	0.7%	85.7%
2032	5.1%	3.5%	0.8%	83.9%
2033	5.4%	3.5%	0.9%	82.1%
2034	5.7%	3.4%	1.0%	80.2%
2035	6.0%	3.4%	1.2%	78.4%
2036	6.3%	3.4%	1.3%	76.6%
2037	6.6%	3.4%	1.4%	74.9%
2038	6.8%	3.4%	1.5%	73.1%
2039	7.1%	3.4%	1.6%	71.4%
2040	7.4%	3.4%	1.7%	69.7%

3.8 Net Long-Term Peak Demand Forecast

Unlike the energy forecasts, both the gross and net peak demand forecasts increase over the period of analysis. Peak demand is based on the demand experienced by the system at the peak hour of the year which has historically occurred during July at 5PM. The major reason for the directional difference between the net energy and net peak demand forecasts is that distributed solar PV generation does not reduce overall system peak demand at the same rate because peak solar output is at noon rather than at the peak hour of 5 PM.

Figure 20: Gross and Net Peak Demand Forecasts (MW) for 2020-2040



The following table presents peak demand forecast data for the gross, net, and load modifiers for the period of analysis (2020 to 2040). The net peak demand forecast increases from 273 MW to 302 MW, representing an increase of 11% through the study period. The load modifiers reduce peak load by 16 MW despite gross peak demand growing 16% by 2040[12].

[12] To arrive at the net peak demand forecast for a given year, subtract PV generation and EE savings from the gross peak demand value, and add EV charging. Any remainders are due to rounding.

Table 7: Summary of Gross, Net, and Load Modifier Peak Demand Forecasts (MW) from 2020-2040

Year	Gross Peak Demand	PV Reduction	EE Savings	EV Charging	Net Peak Demand
2020	274.6	0.2	1.6	0.2	273.0
2021	276.8	0.4	3.3	0.3	273.5
2022	279.1	0.4	4.9	0.4	274.2
2023	281.3	0.4	6.6	0.5	274.8
2024	283.5	0.5	8.2	0.6	275.4
2025	285.8	0.7	9.9	0.8	275.9
2026	288.0	1.0	11.6	1.0	276.4
2027	290.2	1.3	13.3	1.2	276.8
2028	292.4	1.8	15.0	1.5	277.1
2029	294.7	2.3	16.8	1.8	277.4
2030	296.9	2.8	16.9	2.1	279.3
2031	299.1	3.0	17.0	2.5	281.6
2032	301.3	3.2	17.1	2.9	283.9
2033	303.6	3.4	17.2	3.3	286.3
2034	305.8	3.6	17.3	3.7	288.6
2035	308.0	3.8	17.4	4.2	290.9
2036	310.3	4.0	17.6	4.6	293.3
2037	312.5	4.2	17.7	5.1	295.7
2038	314.8	4.4	17.8	5.5	298.1
2039	317.1	4.7	17.9	5.9	300.4
2040	319.4	4.9	18.0	6.3	302.8

In terms of how the load modifiers affect the peak demand forecast, the following table summarizes their proportion of the gross peak demand forecast. The net peak demand forecast represents 99.4% of gross energy in 2020, decreasing to 90.4% by 2040. The largest contributor to the reduction in peak demand by 2040 is from energy efficiency at 5.7% followed by PV reductions at 1.5%. EV charging adds 2% to peak load by 2040 offsetting the impact of solar DG reductions.

Table 8: Summary of Gross, Net, and Load Modifier Energy Forecasts (MW) from 2020-2040

Year	PV Reduction	EE Savings	EV Charging	Net Peak Demand
2020	0.1%	0.6%	0.1%	99.4%
2021	0.1%	1.2%	0.1%	98.8%
2022	0.1%	1.8%	0.1%	98.3%
2023	0.2%	2.3%	0.2%	97.7%
2024	0.2%	2.9%	0.2%	97.1%
2025	0.2%	3.5%	0.3%	96.4%
2026	0.3%	4.0%	0.3%	95.7%
2027	0.5%	4.6%	0.4%	95.0%
2028	0.6%	5.1%	0.5%	94.1%
2029	0.8%	5.7%	0.6%	93.3%
2030	1.0%	5.7%	0.7%	93.0%
2031	1.0%	5.7%	0.8%	92.8%
2032	1.1%	5.7%	1.0%	92.5%
2033	1.1%	5.7%	1.1%	92.2%
2034	1.2%	5.7%	1.2%	92.0%
2035	1.2%	5.7%	1.4%	91.7%
2036	1.3%	5.7%	1.5%	91.4%
2037	1.4%	5.7%	1.6%	91.2%
2038	1.4%	5.7%	1.7%	90.9%
2039	1.5%	5.7%	1.9%	90.7%
2040	1.5%	5.7%	2.0%	90.4%

4 Existing Generation and Supply Contracts

4.1 Existing CWL Owned Generation Plants

As part of Task 3, Siemens was asked to review the status of CWL's current generating fleet, focusing especially on asset useful life, and the costs and benefits of potential power plant conversions. The intent was to understand the ongoing capabilities of CWL's assets to support future generation requirements.

CWL operates the following power generation assets.

Table 9: CWL Power Generation Assets

Location	Technology	Fuel	Capacity (MW)	Average Age (yr)
Municipal Power Plant (MPP)	1 x Combustion turbine, 1 x Steam boiler	Natural Gas	47.50	54.0
Columbia Energy Center (CEC)	4 x Combustion turbines	Natural Gas	144.00	19.0
Columbia Sanitary Landfill	3 x Reciprocating engines	Landfill Gas	3.18	10.3
Distributed	7 x Reciprocating engines	Diesel	10.50	15.4
Total			**205.18**	

In addition, CWL owns, but does not currently operate Boiler #7, a 22.0 MW coal/wood fired steam boiler located at the Municipal Power Plant, which was also reviewed in this analysis. It is important to note that the distributed diesels are only used for emergency service and are not offered as capacity in the market.

4.1.1 Methodology

CWL provided a wealth of information to support this analysis including power generation asset characteristics, recent operating history, maintenance histories, operating costs, and previous conversion and uprate analysis. Further, Siemens' technology and generation experts interviewed key CWL leaders to gain further understanding of asset condition, operations, and the previously conducted conversion studies. Siemens and CWL staff also contacted the University of Missouri-Columbia team operating their biomass fueled power plant to understand issues around local wood access.

Siemens combined this data and information into a single data set and analyzed the current key operating parameters of each asset to establish a cost and performance baseline. The asset conversion studies were analyzed to determine the incremental costs and performance impacts of potential up-rates and/or fuel conversions. Additional independent research was conducted to validate and update the assumptions and analysis contained in those studies.

4.1.2 Current Operations

CWL purchases most of its electricity requirement through long-term contracts from assets located outside the City limits. Thus, except for the landfill gas generation assets, which operated at a capacity factor of 62.7% and 57.1% in 2018 and 2019 respectively, CWL's generations assets serve peaking and emergency duties. The landfill is required by law to flare or otherwise consume the biogas generated from decaying matter (it cannot be vented), and at present that gas is a free fuel for three reciprocating engine power generators. The CEC units operate at single digit capacity factors, and the MPP units operate with a capacity factor less than 9%.

Assuming professional maintenance, power generation assets can be expected to be capable of technically operating well beyond their tax life, generally 30 years. Steam boiler plants have been known to operate when in excess of 65 or 70 years, so all of CWL's generation assets continue to be technically capable of continued operation. Thus, when power generation units are closed, it is usually for commercial or policy, not technical reasons.

While the MPP units are CWL's oldest, they operate at the highest capacity factors to serve City load where electric import capacity is in adequate to meet load. As import capacity increases, these older assets are unlikely to compete well and may be targets for closure. While this could reduce CWL's costs, Siemens understands several administrative functions are undertaken at the MPP which could continue regardless, so the entire costs of the MPP could be eliminated without relocated some functions.

The CEC operates in response to market signals, and thus only starts during times of excessive price, which judging by recent capacity factors, is rare. The plant provides a physical hedge against high prices and a source of local emergency generation. Siemens understands that closing the CEC would eliminate the costs associated with that facility, though some decommissioning costs may remain.

Siemens understands that the distributed diesel generators provide local emergency pumping capacity for the water utility. While the need for this service is apparent, since their function was out of the scope of this engagement, Siemens conducted no research or analysis into the operations of these assets.

4.1.3 Biomass Conversion of Boiler #7 at the Municipal Power Plant

CWL considered converting the currently closed number 7 boiler to wood fuel. The project concept would be to combust 100% wood fuel and to rehabilitate portions of the MPP to support the generation of reliable wood-fired renewable energy for a 15-year period. CWL has experience with operating the MPP on biomass fuel. CWL used a mixture of wood chips and bituminous coal to fire both Boilers 6 and 7 from 2008 to 2015.

In 2017 CWL commissioned a detailed thermal and computational fluid dynamics study to assess the cost and performance impacts of converting boiler 7 to burn 100% wood. The study concluded that after conversion, the biomass fired system would produce around 18.3 MW at an uprate cost of $1,510/kW in 2017 dollars. Siemens adjusted these costs to 2020 dollars based on Handy Whitman Index - North Central Region index. The study also estimated expected production which Siemens used to establish the uprated unit capacity and to calculate plant heat rate. The boiler was originally designed to combust Missouri coal and had capacity of 22.0 MW, however, when operating on woody biomass, unit capacity would decline to about 18.3 MW due to the lower heat content of the fuel and higher moisture content. Based on the production and fuel consumption data, Siemens calculated the heat rate to be about 16.39 MMBtu/MWh on a higher heating value basis. The study also provided estimated fixed and variable operating costs which were applied for dispatch analysis.

Biomass fuel-based projects are often challenged by a lack of reliably available low-cost fuel, so Siemens and CWL contacted plant personnel at the University of Missouri-Columbia to assess the viability of local biomass supply. The University obtains over 35% (on an energy basis) of its fuel from waste wood. Wood residues are gathered, processed and delivered from a Missouri based firm for a current price of $3.35-$3.50/ MMBtu. The plant uses about 120,000 tons wood residue per year which is delivered six days per week and they maintain about a 30-day supply within the state. In the University's opinion, their consumption closely matches regional supply, and any additional demand would be sold at a higher price as suppliers would need to travel further. It is also believed that CWL's stoker boiler will require a more highly refined chip than the University uses, further increasing fuel cost.

4.1.4 Upgrade of the Columbia Energy Center

In 2019 CWL contacted General Electric (GE), provider of the currently operating four Frame 6B combustion turbines, which comprise the Columbia Energy Center to determine what uprate alternatives existed for the units. GE offered three options to include:

- performance improvement package (PIP)
- advanced gas path upgrade (AGP)
- Frame 6F repower (Repower)

Each alternative offered a different level of performance improvement for a different cost as portrayed in Table 10. Note there are four units of 36 MW each providing a total capacity of 144 MWs which became operational in 2001 at the CEC.

Table 10: Columbia Energy Center Uprate Alternatives

	Per Unit			Total Plant			
	Output	Heat Rate	Budgetary	Added	Added	Budgetary	Cost
Upgrade	Increase	Decrease	Cost, $MM	Capacity	Capacity	Cost, $MM	$/kW
PIP	7.6%	-3%	$2.5	2.74	10.94	$10.0	$914
AGP	11.1%	-4%	$3.5	4.00	15.98	$14.0	$876
Repower	33.0%	-17%	$20.0	11.88	47.52	$80.0	$1,684

Siemens compared these costs with those of new frame combustion turbines and found the upgrades costs exceed the market price for new capacity. Further, installation of new assets would provide 30 years of useful life. While the upgraded parts of the original combustion turbines would also provide 30 years of useful life, the remaining original parts may have only ten years of useful life remaining. As a result, none of these upgrades were considered in the dispatch analysis.

4.2 CWL Supply Contracts

4.2.1 Existing Supply Contracts

CWL has over 200 MW of signed Power purchase agreements (PPAs) currently operating with coal and renewable assets located in MISO and SPP. These PPAs supply all of the base load energy for CWL.

The coal PPAs total 136 MW of capacity which supply over 70% of the total generation needs. CWL has three coal PPAs with the Sikeston power plant and the Iatan unit 2 both in Missouri, and the Prairie State Energy Campus in Illinois. Sikeston and Prairie State are interconnected to MISO, and Iatan unit 2 is interconnected to SPP. Sikeston is the oldest PPA signed back in the fall of 1983 and for planning purposes it is assumed that the power plant will retire by the end of 2030 reaching nearly 50 years in operation by then (came online in 1981). The Iatan Unit 2 and Prairie PPAs were signed in 2011 and 2012, respectively with both contracted with CWL through the operational life of the assets. Iatan unit 2 and the Prairie State Energy Campus are some of the latest coal-fired plants developed in the U.S. both using super critical technologies. Iatan 2 came became operational in 2010, and Prairie State in 2012.

CWL has 86 MW of renewable capacity contracted mostly with wind assets (54 MW) located in MISO, SPP and AECI. The Crystal Lake III located in Iowa and interconnected with MISO is the largest renewable PPA with 48 MW of capacity combined in two PPAs, the first signed in 2012, and the second in 2017. These PPAs provide over 10% of the generation needs on an annual basis currently. CWL also signed the Bluegrass (6.3 MW) wind project located in AECI service territory, which expires in 2027.

The latest signed PPA to start operation is the Truman Solar PPA (10 MW) which began operation at the end of 2020, making the first solar asset for CWL. The other renewable PPAs is the Ameresco landfill gas (3.2 MW), which started operation in 2009 and was signed for 20 years ending in April 2029.

CWL also has a capacity only contract with Dynegy for 10 years, which started for the 2017/2018 MISO planning year providing 5 MW of capacity and is currently providing 25 MW of capacity for the 2021/2022 planning year (June 1, 2021, through May 31, 2022). The contract is signed to provide increasing amount of capacity every year to reach a maximum of 45 MW by the 2023-2024 planning year and though the 2026/2027 planning year, when the contract ends.

Table 11: Existing CWL Power Purchase Agreements

Unit	Term	Fuel	PPA Begin Date	PPA End Date	(MW)	PPA Var Costs ($/MWh)	Historic Capacity Factor (%)
Sikeston	Life of Plant	Coal	October 1983	12/31/2030 [13]	66	$23.82	88%
Iatan 2	Life of Plant	Coal	January 2011	Life of Plant	20	$14.90	50%
Prairie State	Life of Plant	Coal	2012	Life of Plant	50	$11.48	75%
Ameresco	20-yr PPA	Landfill	April 2009	4/1/2029	3.2	$52.50	77%
Bluegrass Ridge (AECI)	20-yr PPA	Wind	June 2007	6/1/2027	6.3	$58.25	22%
Crystal Lake III (1st PPA)	20-yr (Under renewal extension & retrofit)	Wind	February 2012	12/31/2040	21.0	$45.01	36%
Crystal Lake III (2nd PPA)	20-yr (Under renewal extension)	Wind	January 2017	12/31/2040	27.0[14]	$20.41	36%
Truman Solar	20-yr PPA	Solar	December 31, 2020	12/31/2040	10.0	$44.8	25%[15]
Capacity Contract (Dynegy)	10-yr	N/A	2017/2018 Planning Year	2026/2027 Planning Year	5 - 45 [16]	$2.50 - $4.60/kW-month	N/A
Total Capacity					**203.5**		

4.2.2 New Supply Contracts

CWL has signed two new PPAs, the Boone Stephens 64 MW solar PPA planned to start commercial operation in December 2023, and the Iron Star wind PPA (35 MW), planned to start commercial operation in November 2024. The Boone Stephens solar asset will be interconnected to the Boldstad 69 kV substation in Columbia, providing local generation and voltage support. These two PPAs has been signed to meet Columbia's Renewable Energy Standard of 30% by 2028.

[13] Assumed retirement of the plant and the PPA for planning purposes. No confirmed date by the Operator
[14] The Crystal Lake III PPA with NextEra has been renegotiated and the combined PPA costs for both contracts declined to $29/MWh starting in 2021 falling to $24/MWh in 2022, and $22/MWh by 2023.
[15] Planned Capacity Factor under p50.
[16] Contract started at 5 MW of capacity for the 2017/2018 plan year rising to 45 MW by the 2023-2024 planning year and though the end of the contract for the 2026/2027 MISO planning year.

Table 12: New CWL Power Purchase Agreements

Unit	Term	Fuel	PPA Begin Date	PPA End Date	(MW)	PPA Var Costs ($/MWh)	Planned Capacity Factor (%)
Boone-Stephens	20-yr PPA	Solar	December 2023	December 2043	64.0	$31.7	26%
Iron Star	20-yr PPA	Wind	November 2024	November 2044	35.0	$21.0	40%
Total Capacity					**99.0**		

4.2.3 Options and Marketability of the Contracts

CWL has competitive PPAs compared to new PPA options in the market. CWL signed three coal PPAs at competitive pricing in the range of $12/MWh to $24/MWh for the energy component, which is in the range of the variable costs including fuel for existing coal plants in MISO. The capacity charges for these contracts (fixed charges) are in the range of $12/kW-month to $32/kW-month, which are on the high end in Siemens's opinion, in particular for the Prairie State Energy Campus. All three assets contracted are reliable coal-fired units dispatching historically at high-capacity factors even for Sikeston after 40 years in operation. As mentioned earlier, Prairie State in contrast is one of the newest coal plants in the U.S. generating fleet.

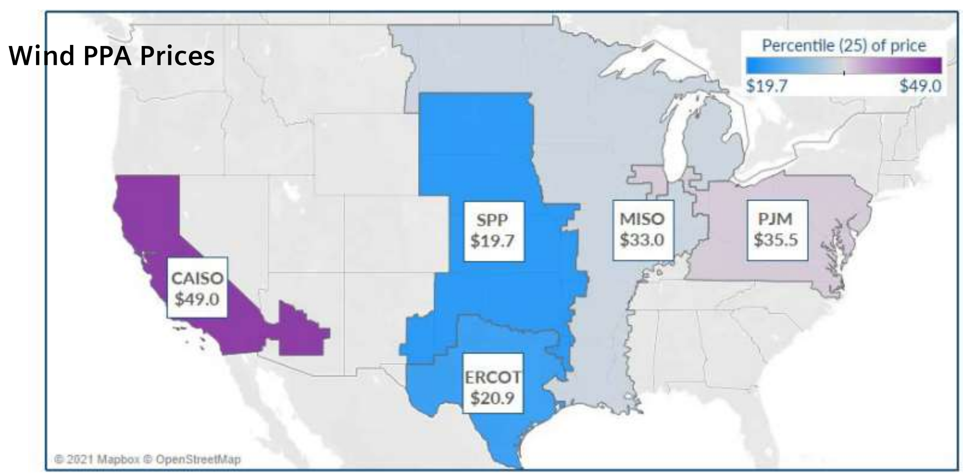
CWL renewable PPAs are in line with recent wind PPAs evaluated by Siemens both in MISO and SPP. As shown in Table 13, a sample of wind PPAs in MISO are in the range of $24-$42/MWh with a higher cost for units in Illinois due to higher labor and other costs in that state. In SPP, the wind PPAs evaluated show lower costs in the range of $18-$19/MWh, at a very competitive pricing compared to any other region in the U.S. However, contracting with assets in SPP incur point-to-point transmission charges from SPP to MISO upwards of $5 /MWh (including interruptible) thus eroding on the potential savings from contracting in SPP and putting them on an equal footprint with the most competitive in MISO. The Levelized Cost of Energy (LCOE) for new solar and wind generation coming online in 2022, evaluated in the generation expansion plan for CWL is within the range of new PPAs in MISO.

Level Ten Energy® publishes a quarterly PPA Index across the US. The index provides the 25th percentile price index for new PPAs in the U.S. (i.e., 25% of the PPA monitored had lower prices). The Wind PPA Index has value of $19.7/MWh for SPP and $33/MWh for MISO, similar to the prices seen by Siemens, confirming that wind generation in SPP could be cheaper. However, the PPA Index for solar shows a much smaller difference; $30.5/MWh in SPP versus $33.7/MWh in MISO (see Figure 21).

Table 13: Selected PPA Prices for Wind in MISO vs. SPP

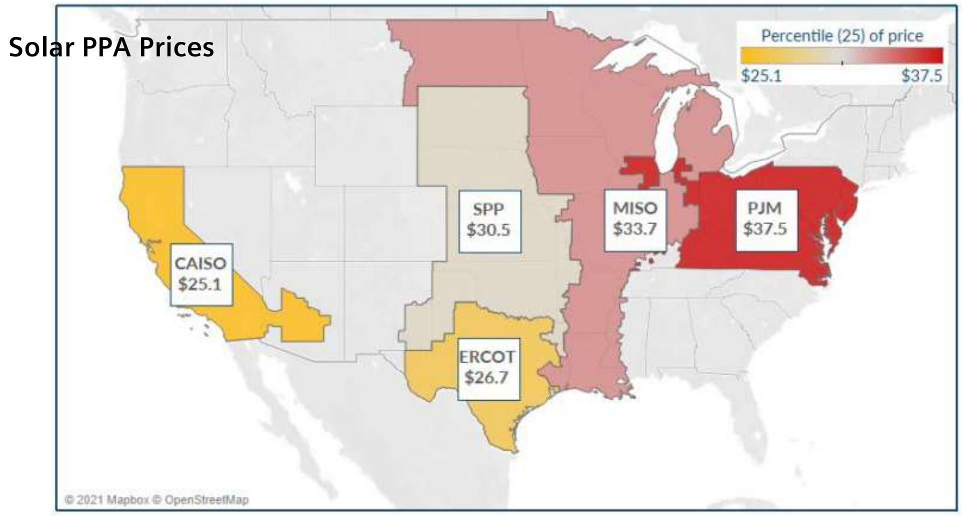
Technology	ISO	Size (MW)	Term (yrs.)	Energy Charge $/MWh	Commercial Operation Date
Wind	MISO Illinois	180	12	$40.00	n.a
Wind	MISO Illinois	190	12	$42.00	Dec-23
Wind	MISO MN	414	12	$25.00	Dec-22
Wind	MISO MN	275	12	$30.00	n.a
Wind	MISO MN	206	12	$24.00	n.a
Wind	SPP North	200	12	$19.00	n.a
Wind	SPP South	330	12	$18.00	Dec-22
Wind	SPP South	297	15	$19.00	n.a
Levelized Cost of Energy – New Generic Renewable Technologies					
Wind	MISO - Zone 5	50	N/A	$34.00	2022
Solar	MISO-Zone 5	25	N/A	$34.20	2022

Figure 21: Wind PPA Prices (25th percentile) $/MWh



* Source LevelTen Energy Q2020 Report

Figure 22: Solar PPA Prices (25th percentile) $/MWh



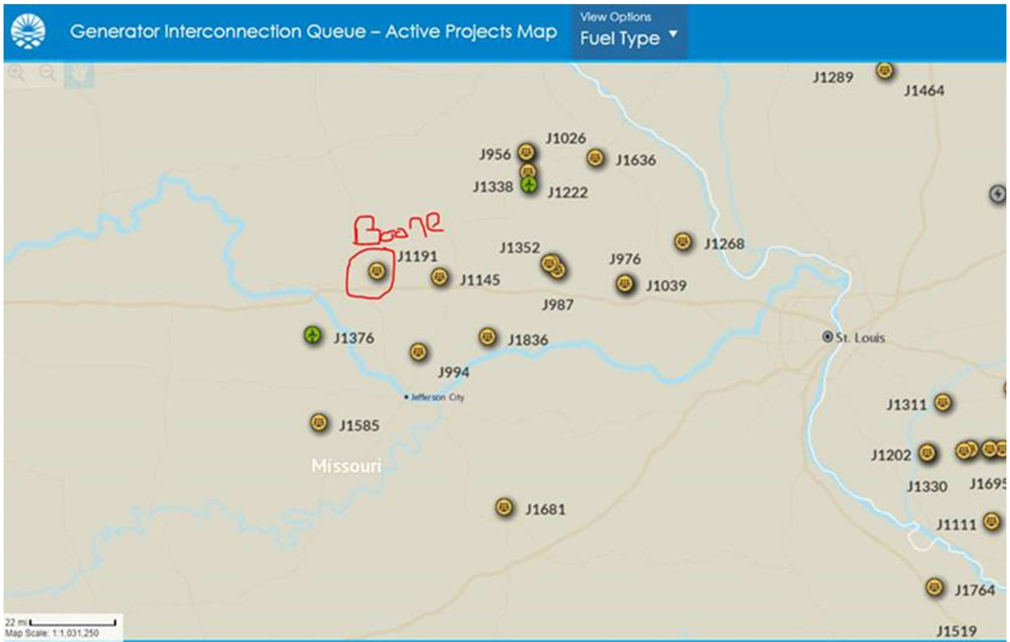
* Source LevelTen Energy Q2020 Report

CWL wind PPAs are in the range of $21/MWh to $58/MWh with the older PPAs Bluegrass Ridge and Crystal Lake (21 MW) signed back in 2007 and 2012 having the highest costs in line with contracts signed back then. Technology costs for both wind and solar have declined significantly in the last 10 years reflecting much lower PPA costs today. Crystal Lake has been renegotiated and the combined PPA costs for both contracts declined to $29/MWh starting in 2021 falling to $24/MWh in 2022, and $22/MWh by 2023, in line with current PPAs in MISO. The Bluegrass Ridge contract ends in 2027 and being the smallest size wind PPA might not be worth the re-negotiation or selling of the contract. The same applies to the Ameresco landfill gas contract.

The new solar PPAs, Truman Solar and Boone-Stephens were signed at $44/MWh and $32/MWh, respectively. The last at comparable market prices in MISO and SPP. The new wind PPA, the Iron Star was signed at $21/MWh at a very competitive price.

Under the Reference Case and most scenarios evaluated under the IRP (see Section 5) have a much larger composition of new solar compared to wind resources. There is also an increasing number of solar projects in the interconnection queue in MISO in closer proximity to the City of Columbia (see Figure 23) with 2,414 MW of capacity under development, from which 2,164 MW are solar projects including Boone Stephens (ID: J1191) planned to be connected to the Boldstad 69 kV substation.

Figure 23: MISO Interconnection Queue near City of Columbia



5 Identification Screening of Future Supply Options

Siemens evaluated future generation supply options expected to be available to CWL over the next 20 years as part of the long-term capacity expansion analysis. Siemens customized the analysis to the projected load and capacity needs for the City of Columbia and considered the observed and expected regional costs for Missouri. As such, Siemens evaluated relatively small thermal technologies including Small Aeroderivative Simple Cycle LM6000 and LM2500 units, and a Reciprocating internal combustion engine (RICE) plant comprised of two Wartsila units. These technologies can provide both capacity and energy needs, ramping to meet peak demand and load at night with higher levels of solar penetration in the future. There was no consideration for small gas-fired combined cycle technologies or gas steam turbines, as most of the base load for CWL is met with the existing coal PPAs and in the future with renewable generation alternatives.

Siemens also considered renewable generation technologies including single-axis tracking PV solar, wind, biomass, and landfill gas. Wind is assumed to be a Technology Resource Group 5, which is the most common seen in Missouri according to NREL's ATB forecast. In addition, four-hour Lithium-Ion battery storage technologies were considered. Table 14 illustrates the operational specifications and costs for new technologies evaluated under the long-term capacity expansion plan discussed on Section 5 of the report. The table also illustrates the construction time for each of the technologies with 2 years for the natural gas units and solar PV, 3 years for onshore wind and biomass and one and a half years for landfill gas and less than one year for battery storage.

Table 14: New Technologies for Long-Term Capacity Expansion Plan

Technology	Small Aero Simple Cycle	Small Aero Simple Cycle	RICE	Utility Solar PV - Single Tracking	Onshore Wind	Biomass	Landfill Gas	Lithium-Ion Batteries
Definition	1x0, LM6000	LM2500	2x0 Wartsila 18V50SG	Single Axis Tracking	Onshore Wind	Biomass	4x9.1 MW RICE, power only	4-hour battery
Fuel	Natural Gas	Natural Gas	Natural Gas	Sun	Wind	Woodchips	Landfill Gas	N/A
Construction Time, Years	2	2	2	2	3	3	1.5	<1
Size (MW)	47	30	36	25	25	25	35.6	20 MWh
Baseload Heat Rate, Btu/kWh, ISO, HHV	9,204	9367	8,290	N/A	N/A	13,300	8,513	N/A
Average Heat Rate, Btu/kWh, ISO, HHV	9,779	9508	8,927	N/A	N/A	13,300	8,513	N/A
VOM, 2019$/MWh	5.7	3.18	4.8	N/A	N/A	6.03	6.2	0
FOM, 2019$/kW-yr	24.62	63.51	11.33	19.54	37.57	116.64	120.1	20.8
Operating Life, yrs	30	30	30	30	25	40	30	10
Capacity Factor *	10%	10%	10%	25%	41%	85%	85%	14%

* Capacity Factors assumed in LCOE calculations based on expected performance in Missouri

Source: Siemens

The assumed all-in capital costs for the new technologies considered in the analysis are illustrated on Table 16. The costs assume a greenfield installation using an Engineering, Procurement, Contracting (EPC) construction approach in which the EPC, owner's, and AFUDC[17] costs are included in the all-in costs. All costs are in real 2019 dollars with the expectation for all technologies to have declining capital investment costs in the long-term with the thermal technologies falling at 0.9% per year in the next 10 years, and solar and battery storage declining at 2.1% and 3.9% per year, respectively. It is expected that both solar and battery storage continue to have significant improvements in efficiency and declining costs in the next ten years, in particular battery storage as demand rises and economies of scale improve.

[17] Allowance for funds used during construction and represents the cost of financing regulated construction projects and is capitalized to the cost of property, plant and equipment, where permitted by the regulator.

Table 15: All-In Capital Costs for New Technologies (2019$/kW)

Online Year	Small Aero Simple Cycle (1x0, LM6000)	Small Aero Simple Cycle (LM2500)	RICE (2x0 Wartsila)	Utility Solar PV - Single Tracking	Onshore Wind	Lithium-Ion Batteries	Biomass	Landfill Gas
2020	1,330	1,674	1,331	1,207	1,713	1,390	4,183	1,570
2021	1,316	1,657	1,317	1,180	1,694	1,307	4,183	1,554
2022	1,303	1,641	1,304	1,154	1,676	1,234	4,136	1,539
2023	1,292	1,626	1,293	1,127	1,659	1,169	4,093	1,525
2024	1,278	1,609	1,279	1,101	1,640	1,107	4,046	1,509
2025	1,266	1,594	1,267	1,075	1,623	1,051	4,002	1,495
2026	1,254	1,578	1,255	1,050	1,606	1,014	3,958	1,480
2027	1,244	1,565	1,245	1,025	1,590	982	3,920	1,468
2028	1,232	1,551	1,233	1,000	1,573	953	3,879	1,455
2029	1,220	1,535	1,221	976	1,556	927	3,834	1,440
2030	1,207	1,520	1,208	952	1,539	901	3,790	1,425
2031	1,195	1,504	1,196	934	1,522	883	3,746	1,411
2032	1,182	1,488	1,183	917	1,505	867	3,701	1,396
2033	1,170	1,472	1,171	900	1,488	850	3,656	1,381
2034	1,157	1,456	1,158	883	1,471	834	3,611	1,366
2035	1,145	1,441	1,145	866	1,455	819	3,567	1,351
2036	1,132	1,425	1,133	850	1,438	804	3,524	1,337
2037	1,119	1,409	1,120	834	1,421	789	3,478	1,322
2038	1,107	1,394	1,108	818	1,406	774	3,436	1,307
2039	1,096	1,379	1,096	803	1,390	760	3,395	1,294
2040	1,084	1,365	1,085	788	1,374	748	3,354	1,280

Source: Siemens – as developed from numerous public, private, and confidential sources

A levelized costs of energy (LCOE) was calculated for all new technologies to form a preliminary view of their respective costs for the IRP. The technology LCOE's were developed assuming a WACC of 5% in real 2019$ (7% nominal), which is consistent with Columbia's internal rate of return on capital. For the IRP modeling, the LCOE is calculated as the net present value of the unit-cost of energy over the lifetime of the asset, including variable, fuel, capital, and fixed costs. The LCOE calculation includes the production tax credit (PTC) for wind and the Investment Tax Credit (ITC) for solar based on the approved policies as of June of 2020.

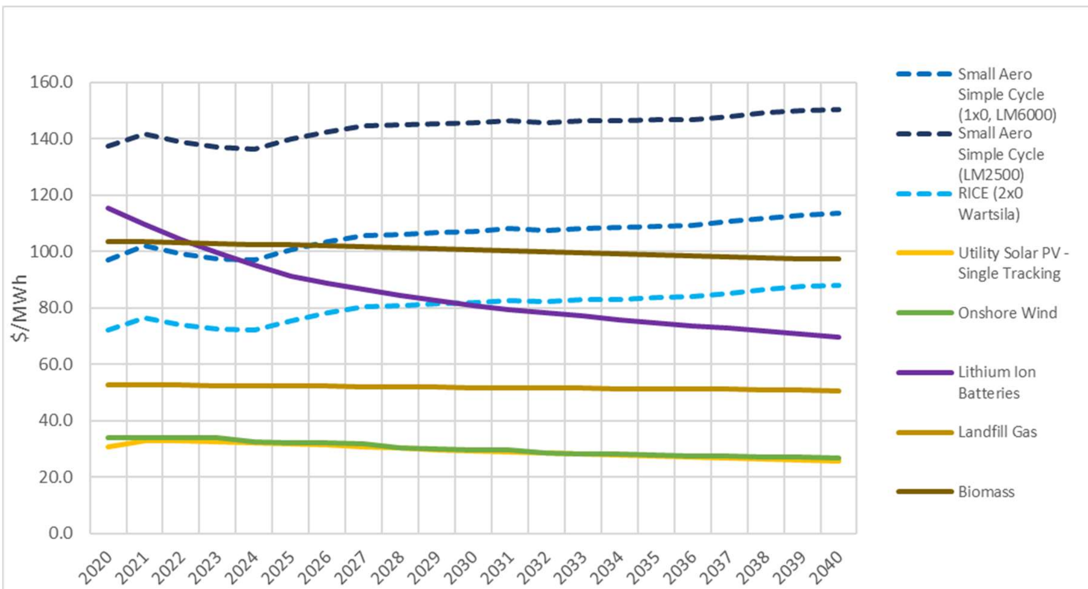
The LCOE varies by year depending upon when the asset becomes operational and can be compared to the annual payment for a PPA contract with a generation asset. In the case of renewables, sometimes the calculated LCOE's and market PPA prices do not align and PPA prices offered in the market are lower than the LCOE as a result of developers offering low PPAs in the early years knowing the assets could operate longer than the 20 or 30-year debt life and deliver greater returns in the long-term, especially in the case of solar.

Figure 20 illustrates the LCOE for all new technologies evaluated for the IRP. As shown, solar and wind are the most economical technologies with all in costs at $34/MWh for both technologies in 2021 falling to around $26/MWh by 2040. Both technologies compete head-to-head in Missouri through the study period with wind gaining a slight competitive edge after 2030 due to an assumed improvement in the capacity factor for new wind installations rising from 41% capacity factor in 2021 to 45% by 2028 following NREL ATB forecast for a TRG5 wind resource in Missouri. Solar is assumed to have a capacity factor of 25.5% throughout the forecast.

Battery storage costs decline significantly through the study period falling from $109/MWh in 2021 to $91/MWh by 2025 gaining competitive advantage over LM6000 units in that year and over RICE natural gas units after 2030 with LCOE all in costs below $80/MWh. While on an LCOE basis the natural gas RICE units is more expensive in the long-term, the ability to dispatch for bulk power needs longer than the 4-hour battery storage offers the utility longer duration dispatch during the day. In fact, in most of the scenarios the Aurora model selected a natural gas RICE unit over battery storage for peaking needs. These types of assets could be built by the utility within CWL service territory and be added to the rate base, or can be contracted for with an independent producer.

The small aero simple cycle technologies (LM6000 and LM2500) are more expansive in levelized terms and are not being selected in any of the scenarios simulated. Landfill gas is a competitive technology, but the availability of the fuel is limited at the landfill site in Columbia and provides limited flexibility to handle a greater penetration of renewables in the future.

Figure 24: Levelized Cost of Energy – Reference Case



Source: Siemens

6 Resource Generation Plan

6.1 Generation Plan Assumptions

This section presents the results of the Reference Case and Scenarios for the long-term resource generation plan. Siemens evaluated seven scenarios in addition to the Reference Case plan, including earlier compliance to the renewable and net zero carbon targets, high seasonal load and electrification, a recession economy, high technological development, and a stringent regulatory environment. Some of these scenarios were suggested by the City of Columbia Task Force and others suggested by Siemens driven by potential economic or energy market environments. Table 16 illustrates all the scenarios simulated for the IRP and their corresponding assumptions.

These plans considered aspects that are critical for the IRP and the city of Columbia including:

- Compliance with the City of Columbia Ordinance Section 27-106: Renewable Energy Standard of 25% of retail electric usage by December 31st 2022 and 30% by December 31st 2028. These are the targets based on current legislation. The City has also set target for the IRP of 100% renewable by 2050, under the Reference Case.
- Reduce carbon emissions following the City of Columbia Climate Action and Adaptation Plan from May 2019 with a comunity wide target of 35% emissions reductions by 2035 and 80% by 2050. Equivalent targets were set for electricity generation and Columbia Water and Light.
- Increase Energy Efficiency for residential, commercial, municipal and school builgings as a critical element to reduce energy consumption and GHG emissions.
- Encourage the use of low-to zero-emissions vechicles, mostly electric vehicles.
- Increase use of customer own solar panels on city buildings and residential customers via a community solar program offered through Columbia Water and Light.
- Rising future demand from electrification of the transportation sector.
- Increase use of renewable technolgies for Columbia Water and Light.

Table 16: IRP Generation Plan Scenarios

Scenario Element	Reference Case	Early Utility Renewable	Early Utility Renewable with High CO2 Price	Mid Term Utility Renewable with High CO2	High Seasonal Load	Recession Economy	High Technolog y case	High Regulatory case
City Goal of 80% Carbon Reduction **	2050	Prior to 2030	Prior to 2030	Prior to 2040	2050	2050	2050	2050
City Goal of 100% Carbon Reduction **	2060	2030	2030	2040	2060	2060	2060	2060
Electric Utility at 100% Renewable	2050	2030	2030	2040	2050	2050	2050	2050
Economic Growth	Base	Base	Base	Base	Base	Low	High	Low
Regional load	Base	Base	Base	Base	High	Low	Base	Low
Transmission Permitting hurdle	Base	Base	Base	Base	Base	Base	Base	Base
Thermal Capital costs	Base	Base	Base	Base	Base	Base	Base	Base
Renewables and Battery Storage Capital costs	Base	Base	Base	Base	Base	Base	Low	Base
DSM, EE, DR Penetration	Base	High	High	High	Base	Base	High	Low
Delivered coal prices	Base	Base	Base	Base	Base	Low	Base	High
Delivered natural gas prices	Base	Base	Base	Base	Base	Low	Low	High
CO2 Emission Prices *	Base	Base	High	High	Base	Low	Low	High
Electric Vehicle Penetration	Base	High	High	High	High	Low	High	Base
Electrification for Heating	Base	High	High	High	High	Low	High	Base
DER (Solar, CHP)	Base	High	High	High	Base	Base	High	High
Fracking and Methane regulations	Status Quo	Status Quo	Status Quo	Status Quo	Status Quo	Status Quo	Status Quo	Stringent
Coal Emissions and Waste Regulations	Status Quo	Status Quo	Status Quo	Status Quo	Status Quo	Status Quo	Status Quo	Stringent

* Base assumes Siemens Reference Case Carbon pricing starting in the mid-2020s at $3.53/Ton rising to $22/Ton by 2040. Low stands for no carbon pricing and high starts at $6.66/Ton in 2025 rising to $40/Ton by 2040 in real 2019$.
** Assumes a Net Zero Carbon Goal

6.1.1 Reference Case Assumptions

The Reference Case assumes the expected set of market, economic, technology and regulatory conditions in the future. The Reference Case is not a business as usual case. It includes the specific goals set by the City for renewable generation and carbon emissions reductions beyond current legislation. As described above, the Reference Case assumes not only Compliance with the City of Columbia Ordinance for the Renewable Energy Standard but also a long-term target of 100% renewable generation by 2050. It also assumes the carbon emission reduction targets as stated in the City of Columbia Climate Action and Adaptation Plan from May 2019.

Figure 25 shows the City of Columbia RPS target of 100% by 2050 with an interim target of 73% by 2040, following a linear patch from current compliance levels of 16% in 2020 to the goal in 2050.

Figure 25: City of Columbia RPS Targets

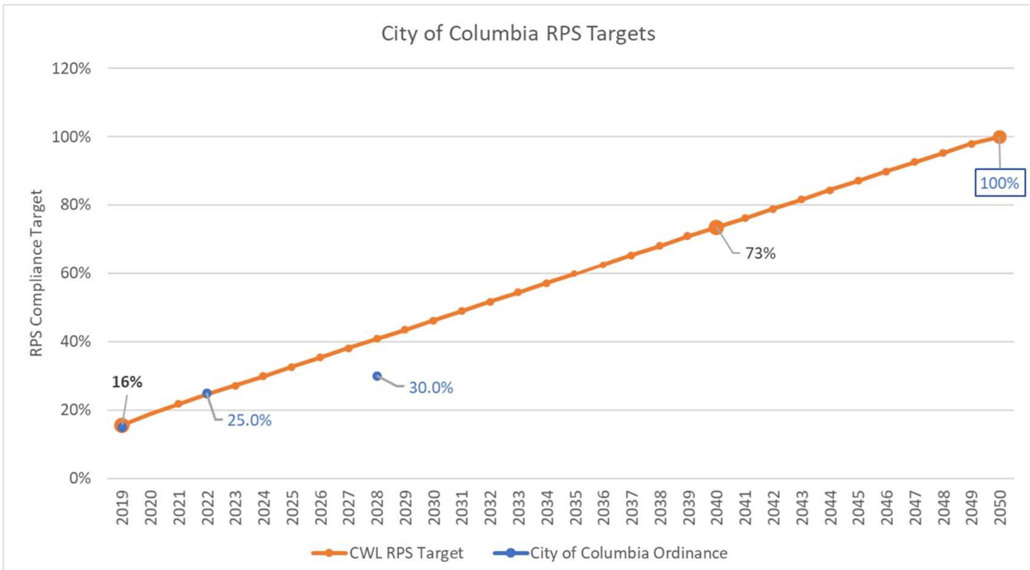
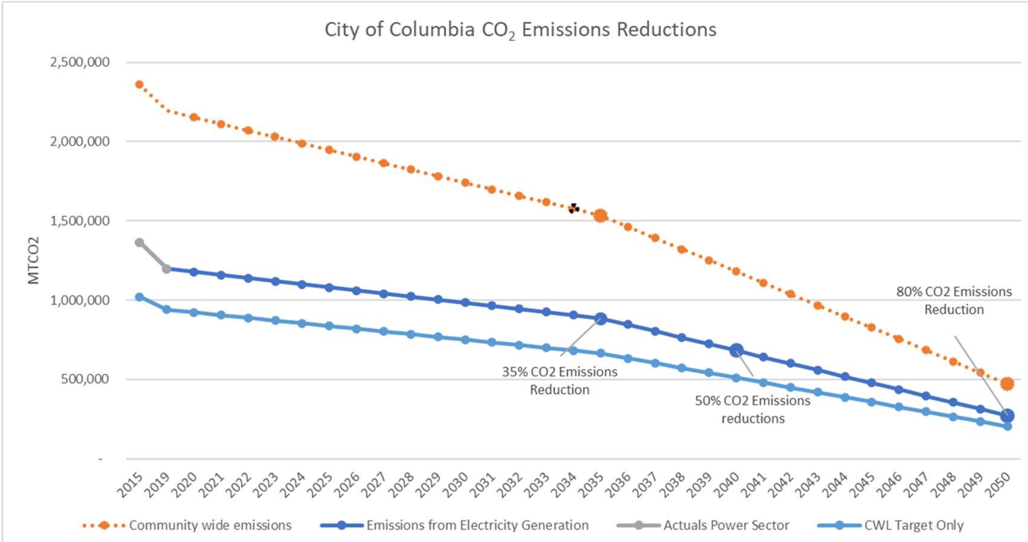


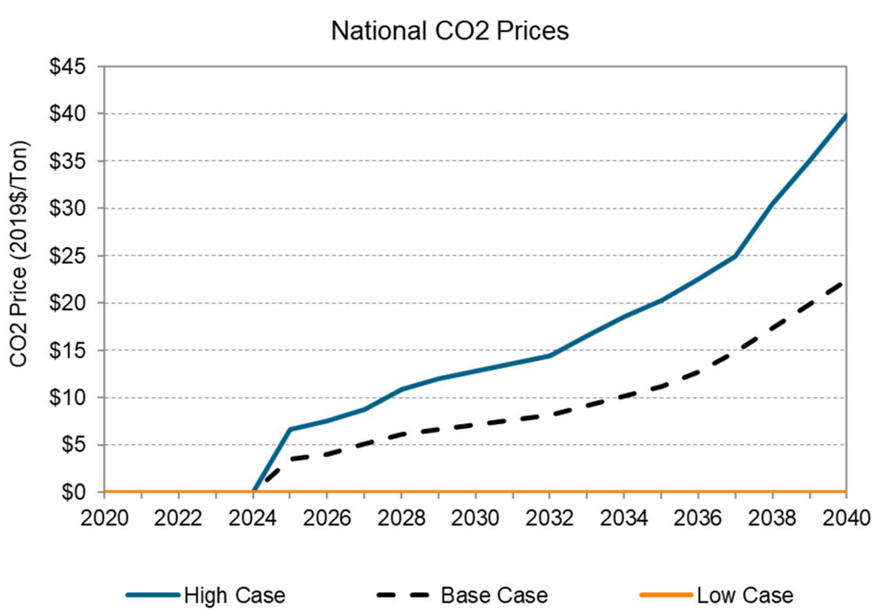
Figure 23 shows the CO2 emissions targets in Metric tons community wide, for the electric power sector and for Columbia Water and Light only. The community wide emissions include Ameren, Boone Electric Coop, the CWL, the MU Power Plant and the transportation, wastewater, solid waste and process and fugitive emissions. 55 percent of all emission come from the electricity generation (71% including Ameren) in 2019. Columbia Water and Light accounted for 42% of all emissions in 2019. For the IRP Siemens simulated emissions reduction targets for CWL only for generation planning purposes following the targets shown on Figure 26 (light blue line). The designed path of CO2 emissions seeks a reduction from 939,652 metric tons in 2019 to 664,000 by 2035 (35% reduction compared to 2015 levels) and 511,000 metric tons by 2040 by 2040 (equivalent to 50% emissions reductions).

Figure 26: City of Columbia CO_2 Emissions Reduction Targets



The plan also includes Siemens Reference Case forecast commodity prices including a national CO_2 pricing starting in 2025. In Siemens view, even though, there is no existing legislation or cap and trade program in the United States, it is assumed a 2025 start date with a moderate price that increases to ultimately reflect expected pricing to drive a reduction in power sector emissions nationally to ~45% below 2005 levels by 2040 (see Figure 27). Siemens forecast of commodity prices including natural gas, coal and emissions can be found in the Appendix of the report.

Figure 27: Siemens National CO2 Price Forecast



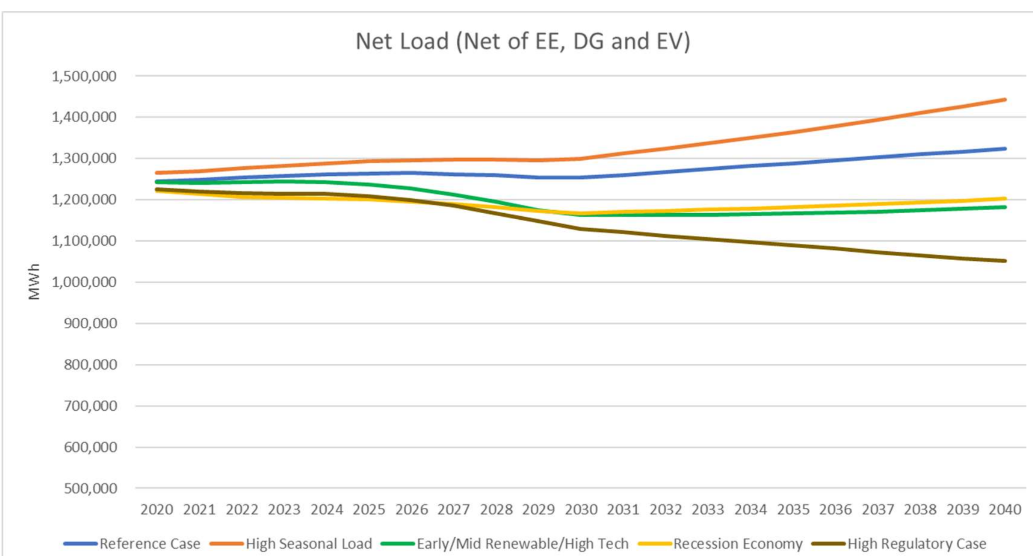
The Reference Case assumes future growth in electricity demand as described in Section 2 of the report, including energy efficiency penetration levels, growth in distributed solar generation, and rising electric vehicle demand. It also assumes future costs for new generation technologies as described in Section 4. The Reference Plan does not assume a significant change in the regulatory environment for fracking and methane regulations neither coal emissions nor waste regulations.

6.1.2 Scenario Assumptions

Siemens evaluated seven scenarios for the IRP, in addition to the Reference Case plan, including earlier compliance to the renewable and net zero carbon targets, high seasonal load, a recession economy, high technological development, and a stringent regulatory environment.

The early and mid-renewable scenarios assume accelerated compliance with the 100% renewable target and the net zero carbon targets. In the case of the Early Renewable scenario the compliance for both targets is achieved in 2030 instead of 2050, and in the Mid-renewable scenario in 2040. These two cases also assume higher penetration of solar distributed generation (2.6 times higher compared to the Reference Case and equivalent to 20% of gross electricity demand by 2040), twice the amount of EE penetration (0.7% annual EE savings with ~6.8% cumulative savings through 2040), and higher penetration of electric vehicle demand reaching 8% of gross load by 2040 compared to 1.7% in the Reference Case. The resulting impact of these factors is a net reduction of 10.7% in load compared to Reference Case by 2040 (green line in Figure 28). To achieve net zero carbon emissions under these two scenarios, the energy from the coal PPAs is fully sold back to market by 2030 in the Early Renewable Scenario, and by 2040 in the Mid-Renewable Scenario. Under these two scenarios it is assumed that rest of MISO or the country is not following the same aggressive renewable and decarbonization targets and the energy from the coal PPAs can be sold back to MISO. Under a different circumstance, such as the current plan to decarbonize the electric grid by 2035, a potential retirement of the coal plants could happen, or a renegotiation of the contracts might be needed. Siemens suggest that under these scenarios the coal PPAs could even be placed under a different commercial entity.

Figure 28: Net Load Forecast Across Scenarios



Under the High Seasonal Load scenario, it is assumed that hotter summers and colder winters will happen in the CWL territory and in the rest of the mid-west because of climate change. CWL have experienced milder summers since the last peak demand of 277 MW back in 2011 with peak loads in around 267 MW regularly. Customers growth at 1.3% per year, and 8% more transformers since 2016 points out to the possibility of a higher peak demand when the next hot spell happens in the Mid-west such as so far, in the summer of 2021. Under this scenario is also assumed that MISO regional demand is ~6% higher by 2040 compared to the reference case and there is high penetration of electric vehicle demand. As a result, net load is 9% higher compared to the Reference Case and peak demand 15% higher by 2040 (see orange line on Figure 28. The peak demand hour is not shifting and still happens on hour ending 17 (5pm) during the summer in July, and hour ending 9 in January during the winter (see Figure 58). This scenario was simulated using the base case energy efficiency savings. The Siemens team evaluated that the high EE savings case would offset much of the increase in load from climate change and EV demand combined eroding the purpose of the scenario.

The Recession economy scenario assumes that the U.S. enters a long recession that slows load growth, depress commodity markets and investments in new technologies including electric vehicles, and slow down decarbonization efforts nationwide. Under this scenario gross electricity demand is 7.7% lower compared to the reference case in CWL territory by 2040. Electric vehicle demand is on the low side (1.2% of gross load compared to 1.7% in the Reference Case by 2040), and commodity prices are low. There is not a CO2 pricing framework nationwide. Overall net demand (net of load modifiers) is 9.1% below the Reference Case by 2040 (see yellow line on Figure 28). Similar to the Early and Mid-renewable cases.

The High Regulatory Scenario assumes more stringent regulations on fracking and environmental policies including methane pollution, CO2 emissions and coal waste. As a result, commodity prices are higher for natural gas and coal, as well as CO2 emission prices. The more stringent regulatory environment drives lower economic growth and lower levels of energy efficiency penetration (more challenging to deploy conservation programs to customers). Regional gross demand is 7.7% below the Reference Case by 2040, in line with the Recession Scenario[18]. Higher commodity prices in turn drives higher electricity customer rates and higher installations of customer own solar panels with customers having more incentive to install their own solar panels and reduce their utility bill. The combined effect of all these impacts drive net energy demand 20% below the Reference by 2040, even below the Recession Scenario and the Early and Mid-renewable scenarios, as seen in Figure 28. The decline is particularly significant during the 2030s with electric vehicle demand assumed to be line with the Reference Case limiting the upside impact on demand growth compared to the Early and Mid-Renewable cases (the last have higher penetration of electric vehicle demand).

The High Technology Scenario assumes further developments in renewable technologies, natural gas extraction and fracking, electric vehicles, and energy efficiency. Renewables and battery storage technologies under this scenario follow improvements in efficiency, performance and lower installation costs following the 2020 NREL ATB Advanced technology innovation scenario. NREL describes this scenario as one where innovations that are far from market-ready today become successful and widespread in the marketplace. New technology

[18] Gross demand excludes the impact of Energy Efficiency programs, solar distributed generation and electric vehicle demand.

architectures could look different from those observed today and public and private R&D investment is higher under this case. As a result, capital costs for new wind-farm generation are 30% lower compared to the Reference Case, 18% lower for solar and 31% lower for battery storage by 2030. Assumed capacity factors are 1-3% higher compared to the Reference Case for new wind resources and 2-4% higher for solar PV. Natural gas resources also improve their competitive advantage from lower fuel costs with gas prices $1.25/MMBtu below the Reference Case on average in the long-term, driven by advancements in shale gas extraction.

The High Technology scenario also assumes high levels of energy efficiency, electrification, and penetration of Solar DG under base economic growth conditions. The resulting net load is 10.7% below the Reference Case by 2040, in line with the Early and Mid-renewable scenarios.

6.2 Generation Plan Results

6.2.1 Summary Results All Scenarios

Table 17 shows future generic capacity additions for all the scenarios modeled for the IRP. These generation capacity additions are incremental to the signed power purchase agreements (PPAs) by CWL. These generic additions are needed to meet future renewable and carbon emissions reduction goals, satisfy MISO's planning reserve margin requirement of 18% of peak demand, and meet energy demand in all hours. The future capacity selected by the Aurora model is assumed to be a mix of future PPAs for solar and wind located outside CWL service territory, and generation located within CWL service territory for gas peakers and battery storage to provide voltage support and reliability. However, the results are designed for planning purposes and CWL can choose to either develop renewable generation or contract PPAs in the future either within CWL service territory (such as Boone-Stephens) or outside its service territory such as the rest of current PPAs.

The simulations also evaluated for capacity market purchases as an option to meet MISO's capacity requirements and either reduce or complement the amount of new capacity selected to meet future energy requirements.

The results of the generation expansion plan show 159 MW of new capacity additions under the Reference Case, most of them solar additions. The plan also includes capacity market purchases found to be economical to meet MISO's 18% planning reserve margin requirement. All capacity purchases and new renewable generation is selected after 2030 in the Reference Case driven by load growth, rising renewable targets, and in particular the planned retirement of the Sikeston coal plant in 2030 and the end of the Bluegrass and Ameresco PPAs in the late 2020s. All of these combined ends the current long position in generation and capacity for CWL. In the case of renewables, the incremental solar generation is selected to meet the interim 73% renewable target by 2040 on the road to meet the 100% renewable target by 2050. Market capacity additions under the Reference Case are in the range of 23-45 MW per year.

The Early and Mid-renewable scenarios have the largest amount of future capacity additions among all scenarios with a range of 212 to 250 MW of capacity additions, depending on the scenario. Most of the capacity additions are renewables with a combination of solar, wind and small amounts of storage needed to meet accelerated renewable and carbon emission reduction targets of 2030 in the Early Renewable Scenario and 2040 for the Mid Renewable.

There is higher solar penetration under the Early Renewable Scenario (s) and higher wind selection under the Mid Renewable Scenario. In the Mid Renewable Scenario most of the build out happens in the 2030s with wind gaining a slight competitive advantage in the long-term due to an expected improvement in capacity factors in the future following NREL's ATB moderate case for TRG5 wind resources in Missouri.

Under these scenarios the amount of capacity market purchases is minimal due to the high levels of new renewable generation even with the lower capacity credit contribution from renewables in MISO[19].

The High Seasonal Load scenario has 198 MW of new capacity additions with 180 MW coming from renewables, mostly solar. There is an 18 MW RICE natural gas peaker selected in this scenario in 2031, designed to supply the incremental loads during the summer evenings due to climate change (hotter summers) and higher electric vehicle demand, and higher peak demands during the morning and evening hours during the winter. As in the Reference Case, most of the capacity selected is in the 2030s. This is the case with the largest amount of capacity market purchases in the range of 45-50 MW per year, to meet the increased peak demand requirements.

The scenarios with the lowest amount of new capacity additions are the Recession Economy, the High Technology, and the High Regulation Scenario. These three cases have lower demand levels in the long-term compared to the Reference Case, in particular the high regulation case. The Recession Economy and the High Technology scenarios have similar demand levels to the Early and Mid-Renewable scenarios; however, the former two do not have accelerated renewable and carbon emissions reduction targets requiring less renewable generation through 2040. The High Regulation scenario has the lowest demand levels from all scenarios and only 71 MW of new capacity additions including 53 MW of renewables and an 18 MW RICE natural gas peaker in 2030. All the renewable capacity is selected after 2035.

The Recession Economy scenario has 102 MW of new capacity generation with most of the capacity coming online starting in 2032 except for a small solar unit of 13 MW in 2022 taking advantage of the investment tax credit. Most of the capacity selected is solar with 81 MW and 22 MW of wind.

In the High Technology scenario, there is 108 MW of new capacity generation all coming online beginning in 2034 with all renewable generation coming from wind and three RICE gas peakers of 18 MW each selected under this scenario driven by low natural gas prices, which improved the competitiveness of this technology despite lower capital costs for renewables.

---

[19] The capacity contribution to peak demand from solar is expected to decline from 54% in 2021 to 30% by 2033, according to MISO's 2019 renewable integration studies. Wind's capacity contribution is assumed to stay at 16% through the study period.

Table 17: Future Capacity Additions by Scenario and Technology 2021-2041 (Capacity in MW)

Technology	Reference Case	Early Renewable 2030 Target	Early Renewable 2030 Target w/ High CO_2	Mid Renewable 2040 Target w/ High CO_2 (1st Plan)	Mid Renewable 2040 Target w/ High co_2 (2nd Plan)	High Seasonal Load	Recession Economy	High Technology Case	High Regulation Case
Wind	0	68	38	84	90	20	22	54	8
Solar	154	175	213	129	94	159	81	0	46
Gas Peaker	0	0	0	0	18	18	0	54	18
Battery Storage	4	2	0	1	10	1	0	0	0
Annual Capacity Purchases[20]	23-45	5	0	7-15	5	45-50	15-25	5-50	5-20
Total Installed Capacity [21]	**159**	**246**	**251**	**214**	**212**	**198**	**102**	**108**	**71**
Total Renewable + Storage	**159**	**246**	**251**	**214**	**194**	**180**	**102**	**54**	**53**

Figure 29 shows the Net Present Value (NPV) of the system costs across all scenarios simulated for the IRP. The system costs include all variable and fixed operating costs for CWL generation and the PPAs signed including capital payments, as applicable. The system costs also include the costs of future generation as simulated for each scenario. The NPV of system costs also include the costs of capacity and energy market purchases, and the revenues from energy sales to the MISO market.

The Reference Case has a NPV of $726 million dollars with 80% of the total costs coming from the payments to the coal and renewable PPAs. The rest of the costs come from the operation and maintenance of CWL assets (including future generation assets) and market capacity and energy purchases. The total NPV of costs excluding revenues from market sales is $898 million. The Reference Case has forecast annual costs of $67 million in 2021 with annual costs declining to $48 million by 2030 mostly driven by a reduction in PPA costs with the assumed retirement of the Sikeston coal plant and the expiration of the Ameresco and Blue Grass renewable contracts. These contracts are replaced by new solar capacity at lower costs in $/MWh. The system costs in $/MWh of energy demand fall from $54/MWh in 2021 to $37/MWh in 2030. System costs increase after 2030 with the new renewable and capacity market purchases rising to $38-40/MWh in the 2030s, still below current costs.

Among the scenarios, the Recession Economy and the High Technology case have the lowest total costs driven by lower demand and lower amount of future capacity additions with $668 million and $705 million in NPV costs for the High Tech and the Recession Economy scenario, respectively. In terms of $/MWh costs, the High Tech has the lowest costs at $41/MWh (average) compared to $43/MWh for the Reference Case.

The High Seasonal Load has the highest NPV of costs at $837 million driven by high energy demand and peaking needs. System cost in $/MWh of energy demand average $48/MWh. The Early and Mid-Renewable scenarios follow the High Seasonal load with NPV of costs in the

[20] Range of capacity market purchases per year selected to be economical
[21] Totals excludes capacity market purchases like the existing Dynegy contract for capacity in MISO.

range of $777 to $790 million and systems costs in $/MWh in the range of $46.5/MWh to $47.2/MWh (see Figure 30). The higher costs are driven by a larger amount of new capacity additions to meet the accelerated renewable and carbon reduction targets in both cases.

Figure 29: NPV of Total System Cost (Net of Market Sales) (Millions 2019$)

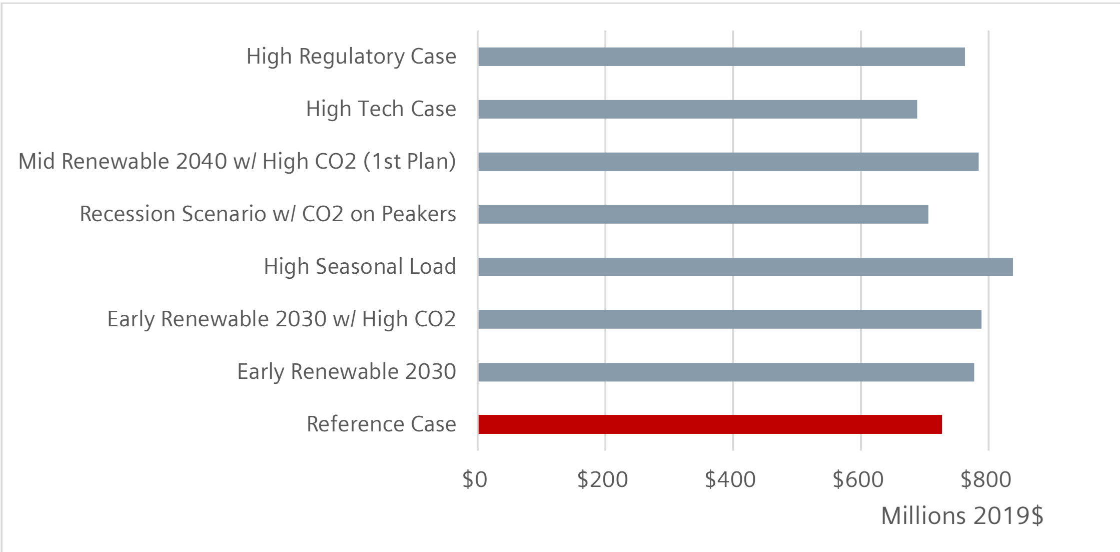
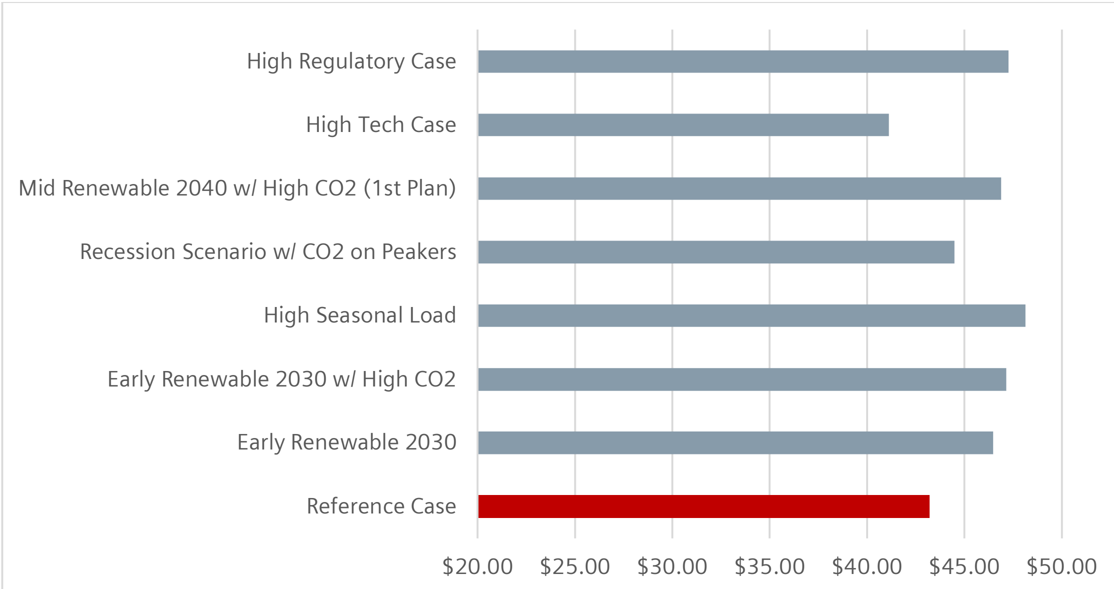


Figure 30: System Cost per MWh of Demand ($/MWh) (2019$)



6.2.2 Reference Case Results

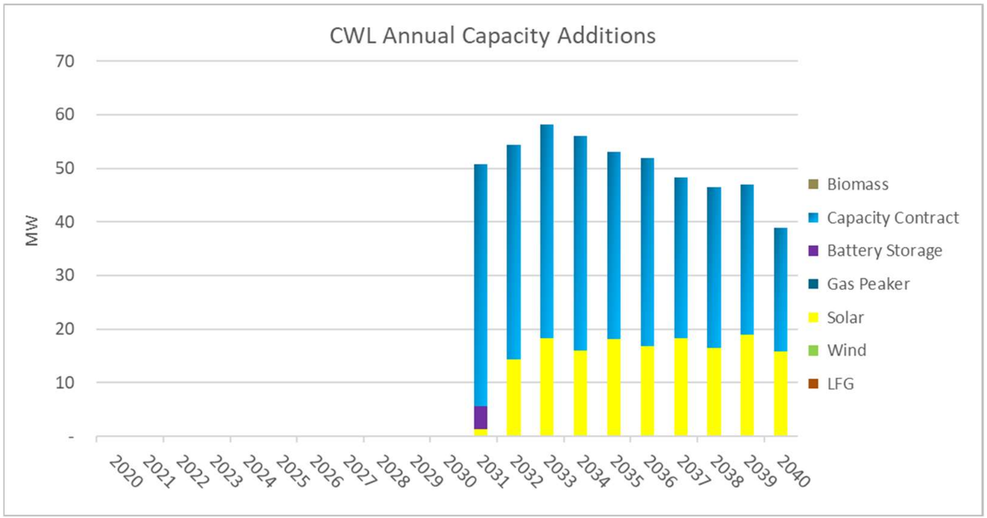
6.2.2.1 Future Capacity Additions and Generation Mix

Figure 31 shows future generic capacity additions under the Reference Case. These generation capacity additions are incremental to the new power purchase agreements (PPAs) signed by CWL. These generic additions are needed to meet future renewable and carbon emissions reduction goals, satisfy MISO's planning reserve margin requirement of 18% of peak demand, and meet energy demand in the future. The capacity selected by the Aurora model is assumed to be a mix of future PPAs for solar and wind located outside CWL service territory, and generation located within CWL service territory in the case of gas peakers and battery storage, the last to provide voltage support and reliability.

The results of the generation expansion plan show 159 MW of new capacity additions under the Reference Case, most of them solar PV additions. Solar installations are in the range of 14 to 19 MW of capacity per year starting in 2032 for a total of 154 MW. A small installation of 1 MW is selected in 2031, which can be postponed to 2032. The plan also includes a small battery storage unit of 4 MW found to be economical in 2031 which can be charged during the day using solar generation and dispatch at night to meet peak demand in the evening along with the existing gas peakers.

The plan also includes capacity market purchases in the range of 23 to 45 MW per year starting in 2031, found to be economical to meet MISO's 18% planning reserve margin requirement. All the base load energy needs for CWL are primarily met with renewable generation (new and existing) and the coal PPA generation. Peaking needs are met with the existing fleet of CWL peakers and the small battery storage selected by the expansion plan.

Figure 31: Reference Case Future Capacity Additions



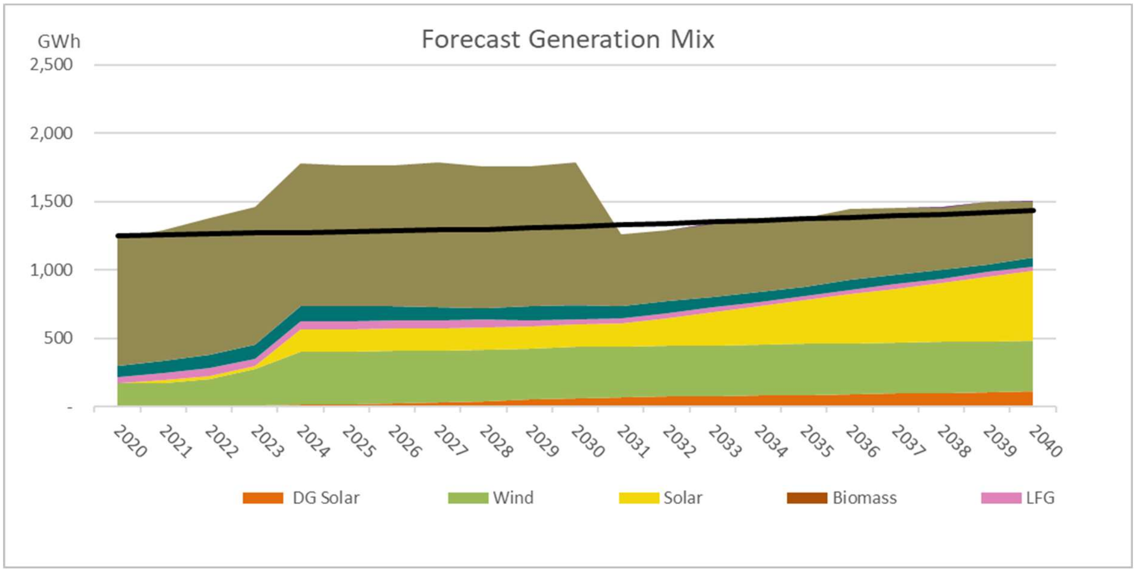
All capacity purchases and new renewable generation is selected after 2030 driven by a combination of factors including load growth, rising renewable targets, and the end of the Bluegrass and Ameresco PPAs in the late 2020s, and the planned retirement of the Sikeston coal plant in 2030. As a result, the current long (surplus) position of generation and capacity for CWL ends by 2030. In the case of renewables, the incremental solar generation is selected to meet the rising renewable target of 73% by 2040, on the road to meet the 100% renewable target by 2050.

CWL existing coal-based portfolio switches to a renewable based portfolio after 2030. Coal contributes with 76% of the total generation in 2021 with a projected increase in that share to reach 82% by 2024 driven by load growth. After 2030 with the expected retirement of the Sikeston coal plant and the end of its PPA contract, the coal share of total generation declines to 39% in 2031, and further down to 29% by 2040. Renewable generation accounts for 19% of the total in 2021 rising to 48% by 2024 with the beginning of operation of the Boone-Stephens and Iron Star PPAs. Renewable share is projected to say at similar levels for the rest of the decade and rise further in the 2030s with the new solar capacity additions reaching 73% of the total generation by 2040.

CWL own generation including the Columbia Energy Center contributes with 5% of the total in 2021 falling to 1% by 2024 and staying at low levels through 2030 due to the excess generation supply in the system. After 2030 with the end of the long generation position, the share of CWL own generation increases to 10-12% of the total during the 2030s.

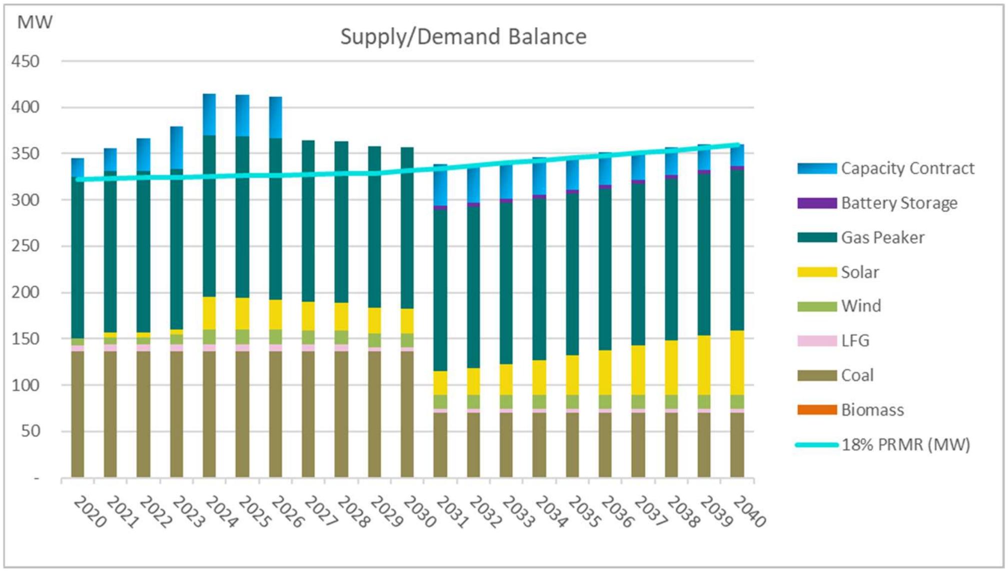
CWL becomes a net seller of energy in 2021 based on Siemens's simulation with the long position increasing in the next few years (see Figure 32). By 2024, CWL is forecast to sell over one third of the total generation back into the market, mostly from the coal PPAs, which have higher costs than renewables. CWL may also sell excess solar generation during the day as renewable penetration increases through time. The long position ends in 2031 with generation supply shortages being fulfill with spot market purchases in 2031-2032 for a more balanced position through the end of the study period.

Figure 32: Future Generation Mix – Reference Case



CWL has a long position not only in terms of energy but also in terms of capacity through 2030 as shown in Figure 33. The existing generation fleet and contracted generation provides enough capacity to meet the 18% planning reserve margin requirement from MISO. The existing capacity contract with Dynegy provides incremental capacity to CWL. The new solar and wind PPAs coming online in 2024 increases the long position for CWL. By 2030 with the assumed retirement of the Sikeston coal plant, the end of the Ameresco and Bluegrass Ridge PPAs and the end of the Dynegy capacity contract in 2027, the long position is over. A potential capacity deficit in the 2030s is met with capacity market purchases in the range of 23-45 MW per year.

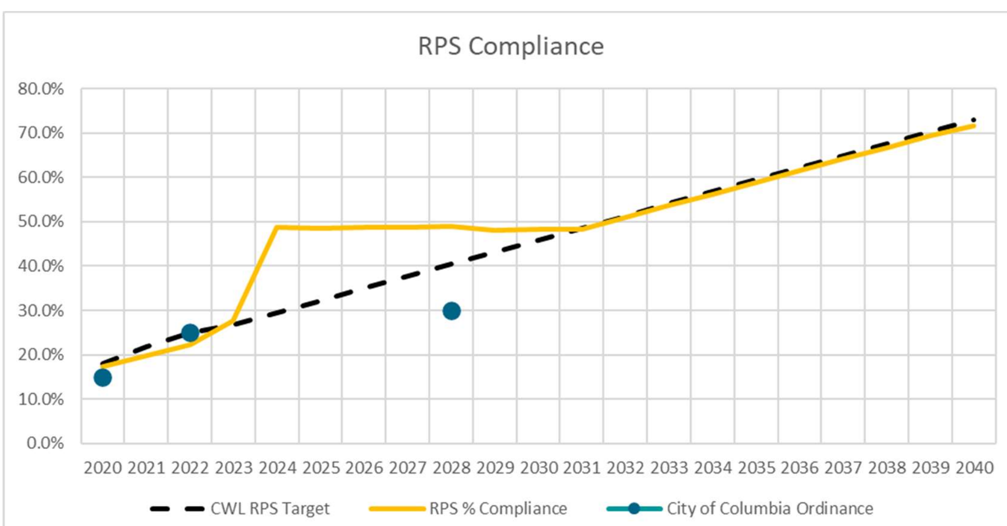
Figure 33: Future Capacity Balance – Reference Case



6.2.2.2 Environmental Compliance

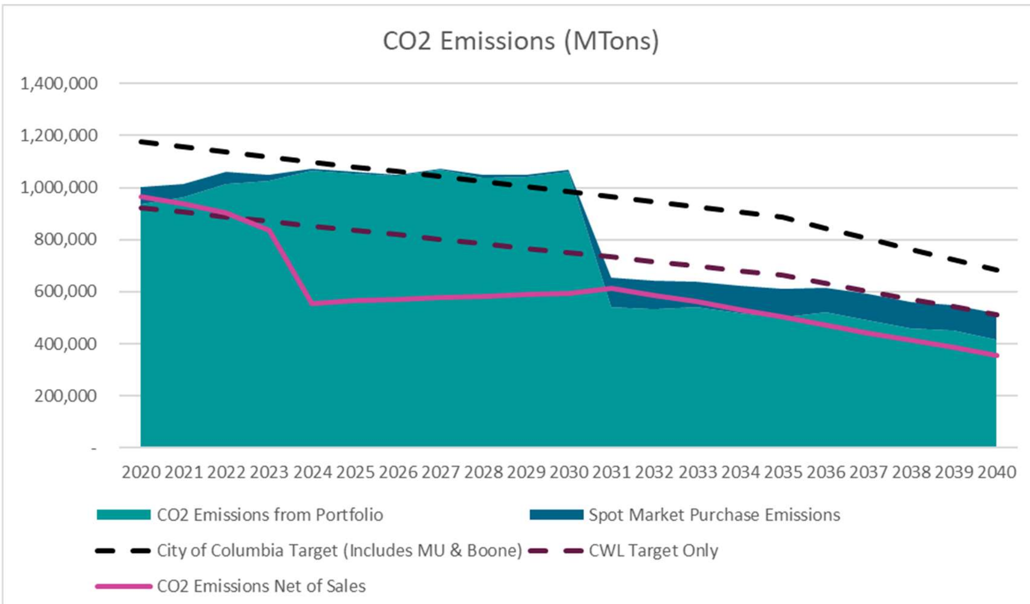
With the commercial operation of the Boone-Stephens solar PPA and the Iron Star wind PPA, the share of renewable generation jumps from 25% in 2023 to near 50% starting in 2024 and through the end of the decade exceeding the City of Columbia Ordinance requirement of 30% in 2028. After 2030, the new solar generation capacity is selected as the most economical option to meet a gradual installation of renewables to meet an interim 73% renewable target by 2040 on the road to meet the 100% renewable target by 2050 (see Figure 34).

Figure 34: RPS Compliance – Reference Case



CWL CO2 emissions from power generation including both emissions from CWL portfolio (owned generation and PPAs), and market purchases is shown on Figure 35. The emissions through the study period are compared to a linear path to reach 35% and 50% emissions reductions by 2035 and 2040, respectively for both the City of Columbia and CWL. As shown, gross emissions from CWL power generation are higher than CWL own generation target in this decade and even higher than the City of Columbia target for a few years in the late 2020s due to load growth, that is excluding energy sales into the market. Including the sales from excess generation into the market, the net emissions (pink line) are below both the City of Columbia and CWL targets through most of the study period. Most of CWL emissions come from the coal PPAs as well most of the market sales. After 2030 with the end of the Sikeston coal PPA, emissions fall significantly meeting both targets even excluding energy sales. After 2030 market purchases increase and its contribution to overall emissions[22].

Figure 35: CWL Emission Reductions – Reference Case



6.2.2.3 Portfolio Costs

The Reference Case has a NPV of $727 million dollars with 80% of the total costs coming from the payments to the coal and renewable PPAs. The rest come from the operation and maintenance of CWL assets (including future generation assets) and market capacity and energy purchases. The total NPV of costs excluding revenues from market sales is $898 million. The Reference Case has forecast annual costs of $67.5 million in 2021 rising to $76.9 million by 2024 with the commercial operation of the Boone-Stephens and Iron Star renewable PPAs. Total costs decline after 2025 with the expiration of the Blue Grass and Ameresco PPAs and with the end of the Sikeston PPA in 2030. Total costs decline to $60 million in 2031. Overall costs rise in the 2030s with the new solar generation capacity and capacity market purchases reaching $66.7 million by 2040.

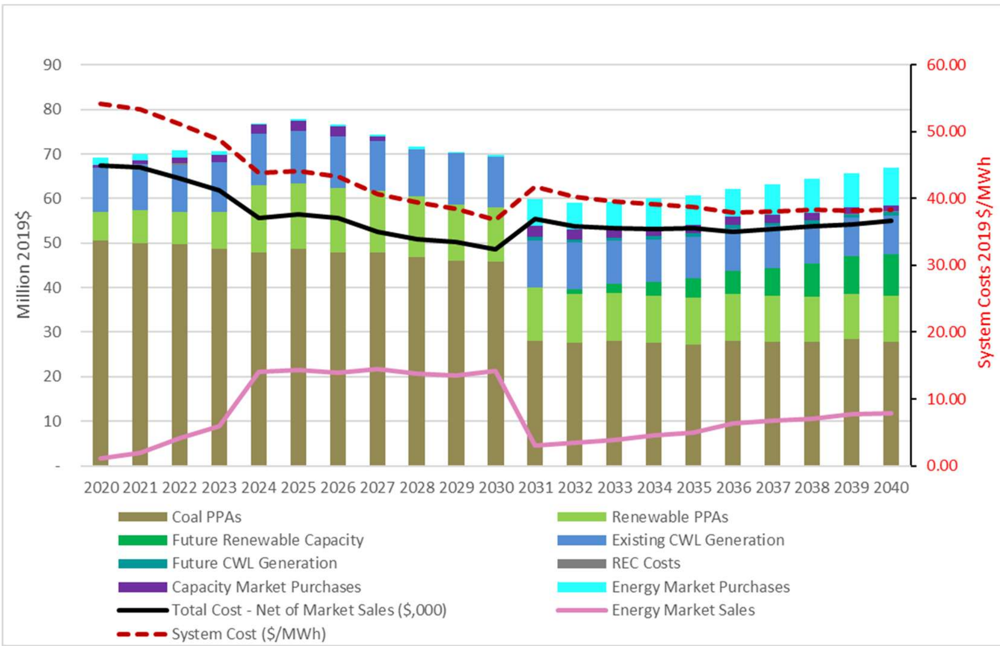
However, overall costs for CWL are lower due to forecast revenues from market sales of excess generation. Energy sales are in the range of $1.7 million and $21.7 million through the study

[22] Emissions from market purchases are estimated as the product of MISO's emissions rate times the energy purchased in MWh by CWL. The emissions rate for MISO is estimated by Siemens using the Aurora model and its own simulation of the MISO power market. The emissions rate is forecast to fall from 0.84 metric tons/MWh in 2021 to 0.56 metric tons/MWh by 2040.

period with the highest levels in 2024-2030. Thus, total costs net of market sales decline through 2030 with rising sales revenues reaching $48 million by 2030 (black line on Figure 36). Total costs net of market sales rise in 2031 to $55 million driven by reduced market sales and increased energy and capacity market purchases staying at similar levels through the end of the study period.

The system costs in $/MWh of energy demand fall from $54/MWh in 2021 to $37/MWh in 2030 (net or market sales). System costs increase after 2030 with the new renewable generation capacity and market purchases reaching $38-40/MWh in the 2030s, still below current costs (dotted red line).

Figure 36: CWL Portfolio Costs by Source – Reference Case



6.2.3 Early Renewable Scenario

The Early Renewable Scenario is characterized by accelerated renewable and net-zero carbon targets along with higher penetration of solar distributed generation, energy efficiency savings and electric vehicle demand. The scenario includes the following assumptions:

- 100% Renewable by 2030
- Net Zero Carbon by 2030
- Higher penetration of solar customer owned distributed generation, equivalent to 20% of the gross electricity demand by 2040 compared to 7.3% in the Reference Case.
- Near twice the amount of Energy Efficiency savings (0.7% annual EE savings first 10 years) with 6.8% cumulative savings through 2040 (11% of peak demand).
- Higher electric vehicle demand (8% of gross load by 2040 compared to 1.7% of gross load in the Reference Case)

- Resulting net load is 10.7% lower compared to Reference Case by 2040

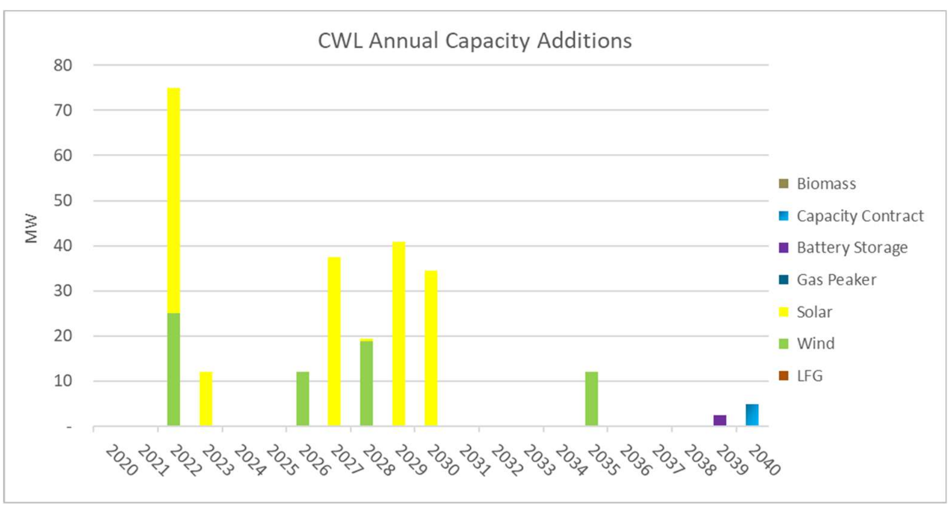
6.2.3.1 Future Capacity Additions and Generation Mix

Figure 37 shows future generic capacity additions under the Early Renewable Scenario. These generation capacity additions are incremental to the new power purchase agreements (PPAs) signed by CWL. These generic additions are needed to meet the 100% renewable target and net zero carbon goal by 2030. The capacity selected by the Aurora model is assumed to be a mix of future PPAs for solar and wind located outside CWL service territory, and generation located within CWL service territory in the case of the battery storage unit, the last to provide voltage support and reliability.

The results of the generation expansion plan show 246 MW of new capacity additions, including 175 MW of new solar generating capacity and 68 MW of wind. That is 87 MW higher than the Reference Case. Solar installations are in the range of 12 to 50 MW per year starting in 2022 with all the new solar capacity installed by 2030, in sharp contrast to the Reference Case where all the new capacity additions come online after 2030. This is driven by the need to meet the 100% renewable target in 2030 instead of 2050. Most of the wind additions happen in 2022-2028 with 56 MW installed in this period. The early additions in 2022 are driven by the existing tax incentives for renewables. The plan also includes a small battery storage unit of 2 MW found to be economical in 2039 which supports the dispatch in the evenings.

The plan includes a small capacity market purchase of 5 MW in 2040. The additional capacity requirements are minimal in this Scenario due the larger amount of new renewable generation and lower energy demand through the study period.

Figure 37: Early Renewable Future Capacity Additions

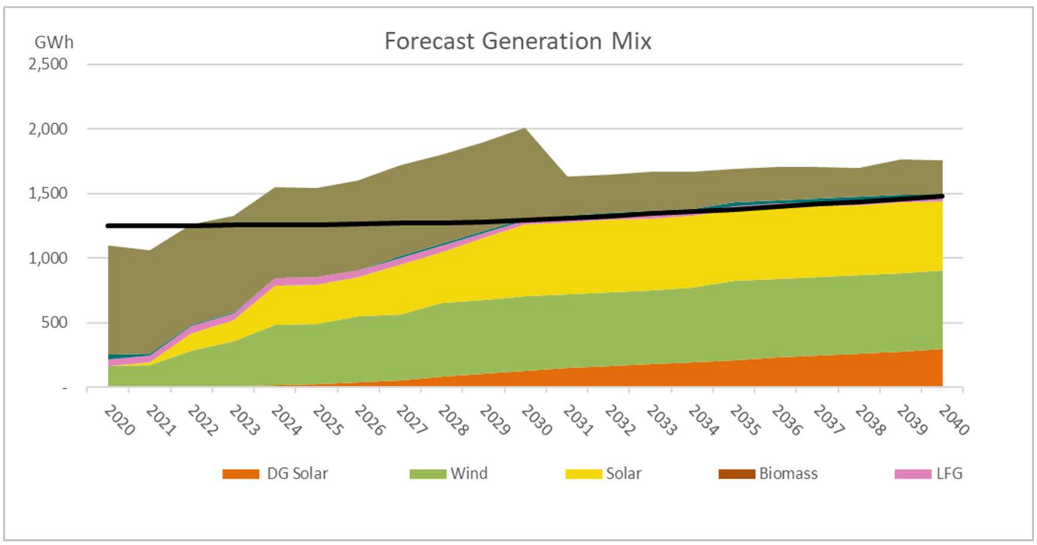


All the base load energy needs for CWL are met with renewable generation by 2030 (new and existing). Peaking needs are met with the existing fleet of CWL peakers and the small battery storage selected by the expansion plan.

As a result of the accelerated addition of renewable capacity CWL long (excess) generation position remains that way throughout the forecast. With renewable generation meeting most of the base load needs in the long-term, all the energy from the coal PPAs is sold back to the market after 2029. Selling all the energy from the coal PPAs also offset the carbon footprint from these assets to meet the 100% net zero carbon goal in 2030. Siemens suggests divesting the coal PPAs into a separate company as an option to decarbonize the fleet. After 2029, CWL does not require the energy from the coal PPAs to supply its electricity customers. Another option is to renegotiate these contracts if this scenario becomes a reality.

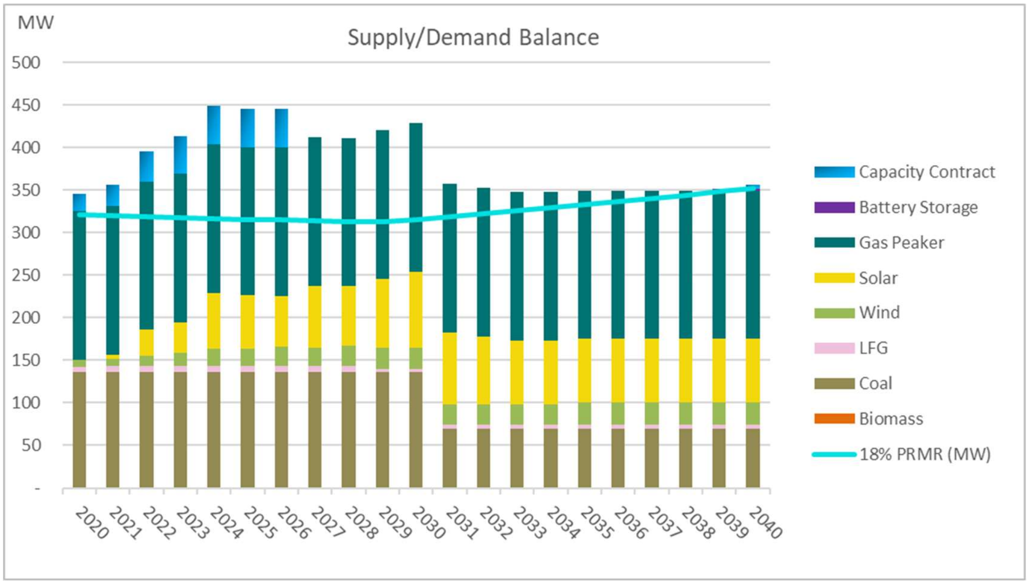
CWL own generation including the Columbia Energy Center contributes with 1% to 4% of the total generation through the study period serving peak demand needs at night.

Figure 38: Future Generation Mix – Early Renewable



CWL has a long position not only in terms of energy but also in terms of capacity through the mid-2030s as shown in Figure 39. CWL existing generation fleet, contracted generation, and new generating capacity provides enough supply to meet MISO’s 18% planning reserve margin requirement through the study period with a larger excess capacity position through 2030, compared to the Reference Case.

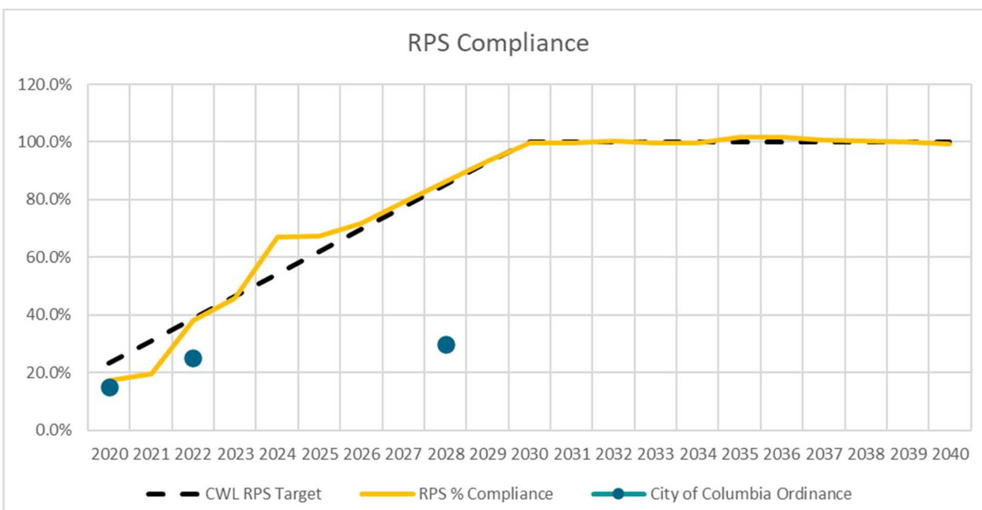
Figure 39: Future Capacity Balance – Early Renewable



6.2.3.2 Environmental Compliance

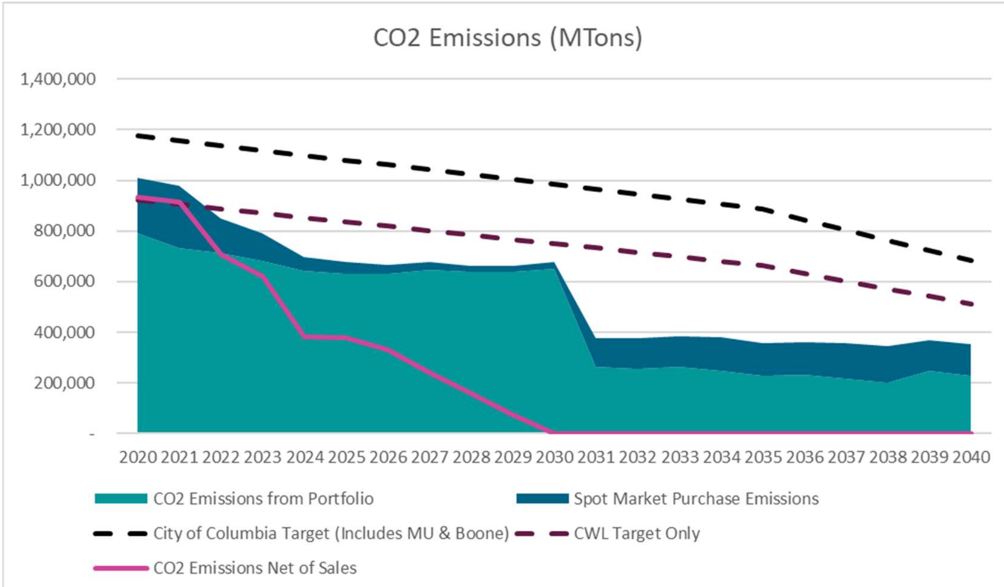
Renewable mandates are met at an accelerated pace under this scenario with the share of renewable generation reaching over 38% of load in 2023 and over 60% by 2024 with the commercial operation of the Boone-Stephens solar PPA and the Iron Star wind PPA along with the incremental new capacity additions. By 2030, renewable generation accounts for 100% of the total load needs (see Figure 40).

Figure 40: RPS Compliance – Early Renewable



CWL CO2 emissions from power generation including both emissions from CWL portfolio (owned generation and PPAs), and market purchases is shown on Figure 35. The emissions through the study period are compared to the Reference Case emissions reduction targets for the City of Columbia and CWL. As shown, gross emissions from CWL power generation decline significantly through the study period. Emissions decline further after 2030 with the end of the Sikeston coal PPA. With most or all the sales coming from the coal PPAs and renewable generation meeting the base load needs, the emissions reach zero by 2030 (pink line)[23].

Figure 41: CWL Emission Reductions – Early Renewable



6.2.3.3 Portfolio Costs

The Early Renewable Scenario has a NPV of $777 million dollars, $50 million higher than the Reference Case. Most of the total costs come from the payments to the coal and renewable PPAs, and the new renewable generation. The rest come from the operation and maintenance of CWL assets (including future generation assets) and market energy purchases. The total NPV of costs excluding revenues from market sales is $926 million.

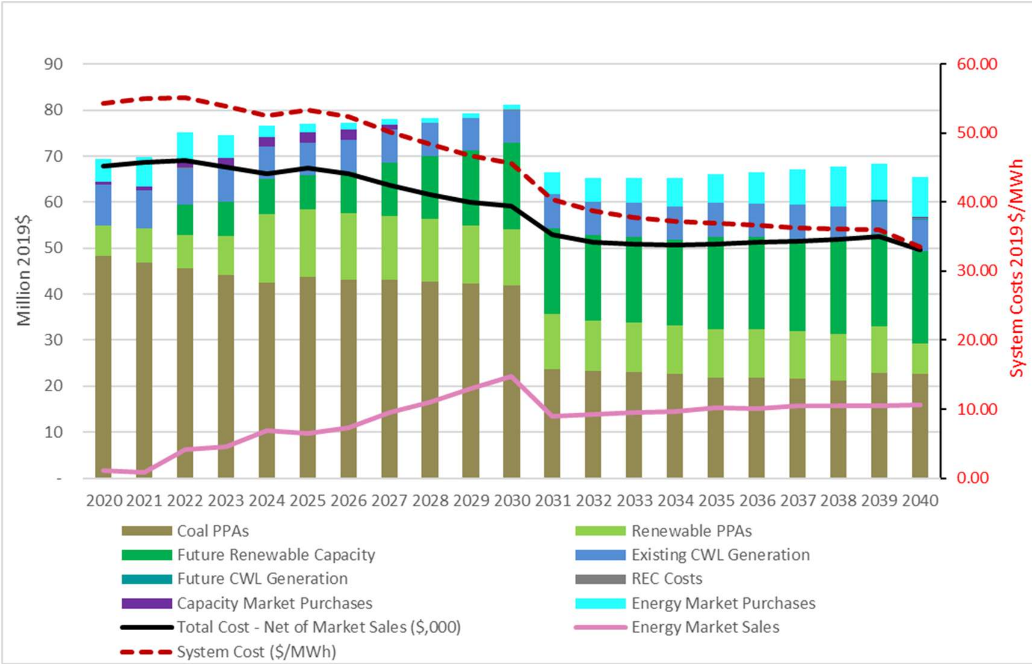
The Early Renewable Scenario has forecast annual costs of $69.8 million in 2021 rising to $81 million by 2030 driven by the new PPAs and the renewable capacity additions. Total costs decline after 2030 with the end of the Sikeston PPA in 2030 to $66.5 million in 2031. Overall costs stay around $65 million in the 2030s without a significant change in the generation mix.

Total costs net of market sales revenues declines through the study period driven by rising energy revenues through 2030. Energy sales increase from $1.2 million in 2021 to $22 million by 2030. Total costs net of sales revenues reaches $59 million by 2030 ($11 million higher than the Reference Case for the same year).

The system costs in $/MWh of energy demand fall from $54/MWh in 2021 to $46/MWh in 2030 (net or market sales). System costs in $/MWh continue falling through the 2030s (dotted red line).

[23] The Early Renewable scenario assumes the MISO is not under the same renewable and decarbonization targets implicating that there is market for the energy from the coal PPAs. Under different circumstances a renegotiation of the contracts would be needed or the retirement of the units could happen.

Figure 42: CWL Portfolio Costs by Source – Early Renewable



6.2.4 Early Renewable Scenario with High CO2 Prices

This scenario follows the same assumptions of the Early Renewable Scenario except for a high CO2 price curve instead of Siemens' Base Case projection. The CO2 prices assumed under this scenario start at $6.6/Ton in 2025 rising to $15/Ton by 2032 and reaching $40/Ton by 2040, as shown on Figure 27 and Appendix 2. The high CO2 price forecast is on average 80% higher compared to the Base Case projection.

As in the Early Renewable Scenario, this scenario is characterized by 100% renewable target and net-zero carbon by 2030 along with higher penetration of solar distributed generation, energy efficiency savings and electric vehicle demand.

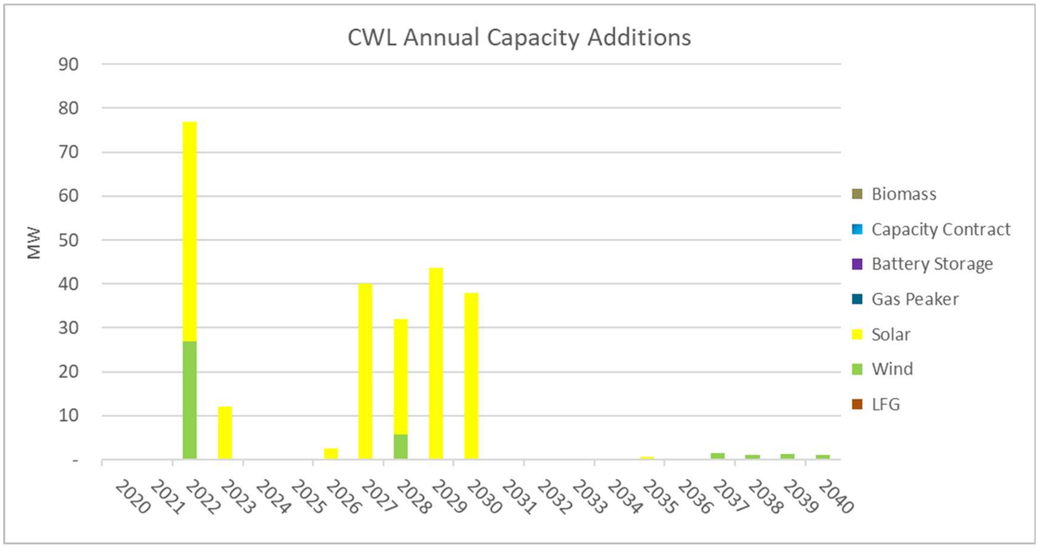
6.2.4.1 Future Capacity Additions and Generation Mix

Figure 43 shows future generic capacity additions under this scenario. These generation capacity additions are incremental to the new power purchase agreements (PPAs) signed by CWL. The capacity selected by the Aurora model is assumed to be a mix of future PPAs for solar and wind located outside CWL service territory, and generation located within CWL service territory in the case of the battery storage unit, the last to provide voltage support and reliability.

The results of the generation expansion plan show 251 MW of new capacity additions, including 213 MW of new solar generating capacity and 38 MW of wind. Total additions are only 5 MW higher compared to the Early Renewable Scenario with base CO2 prices and 92 MW higher than the Reference Case. Solar installations are in the range of 12 to 50 MW per year starting in 2022 with all the new solar capacity installed by 2030, in line to the Early Renewable Scenario with base CO2 prices. There is a 27 MW wind unit selected in 2022 and a smaller 6 MW unit in 2028. An additional 5 MW of wind capacity is selected in 2037-2040.

This plan does not include battery storage additions neither future capacity market purchases. The new renewable capacity selected along with the existing capacity is sufficient to meet reliability requirements through the study period.

Figure 43: Early Renewable with High CO2 Future Capacity Additions

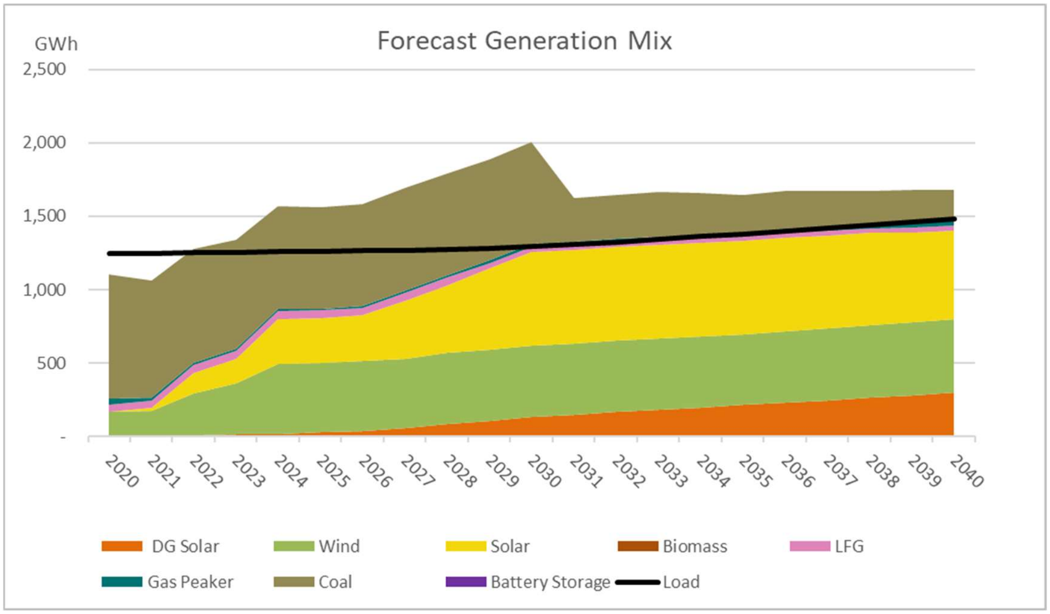


All the base load energy needs for CWL are met with renewable generation by 2030 (new and existing). Peaking needs are met with the existing fleet of CWL peakers.

As a result of the accelerated addition of renewable capacity CWL long (excess) generation position remains that way throughout the forecast. With renewable generation meeting most of the base load needs in the long-term, all the energy from the coal PPAs is sold back to the market after 2029. Selling all the energy from the coal PPAs also offset the carbon footprint from these assets to meet the 100% net zero carbon goal in 2030. Siemens suggests divesting the coal PPAs into a separate company as an option to decarbonize the fleet. After 2029, CWL does not require the energy from the coal PPAs to supply its electricity customers. Another option is to renegotiate these contracts if this scenario becomes a reality.

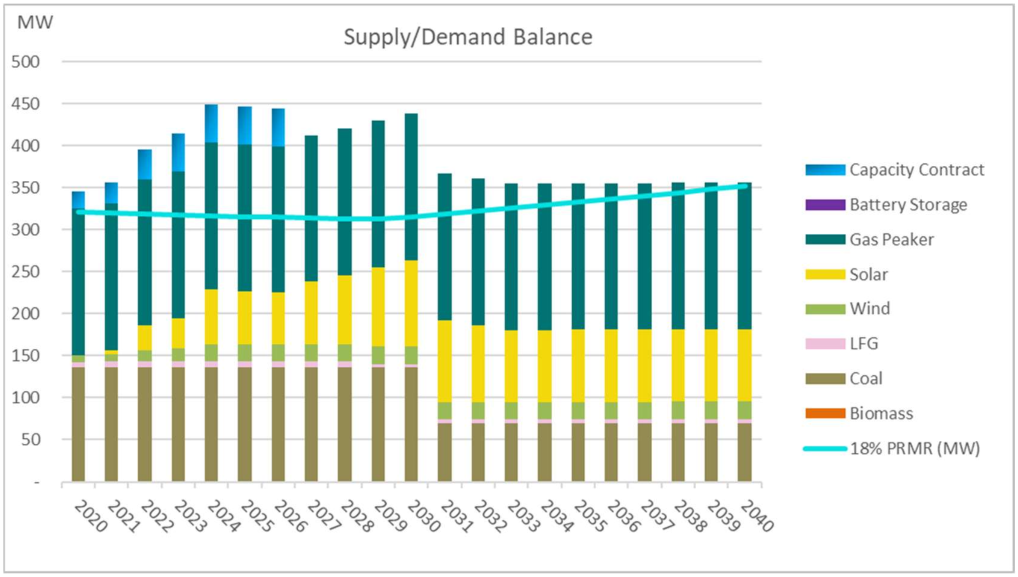
CWL own generation including the Columbia Energy Center contributes with 1% to 3% of the total generation through the study period serving peak demand needs at night.

Figure 44: Future Generation Mix – Early Renewable with High CO2



CWL has a long position not only in terms of energy but also in terms of capacity through the mid-2030s as shown in Figure 45. CWL existing generation fleet, contracted PPAs, and new generating capacity provides enough supply to meet MISO's 18% planning reserve margin requirement through the study period with a larger excess capacity position through 2030, compared to the Reference Case.

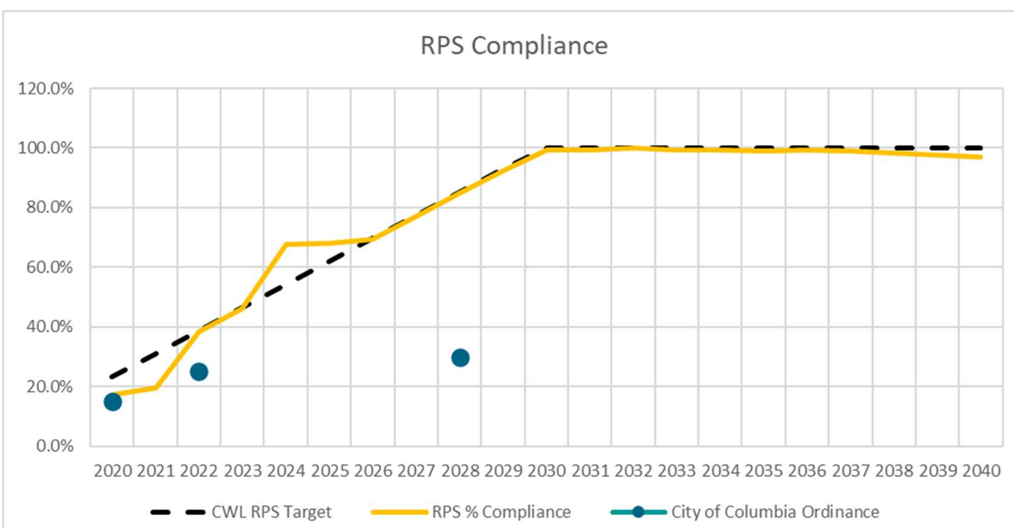
Figure 45: Future Capacity Balance – Early Renewable with High CO2



6.2.4.2 Environmental Compliance

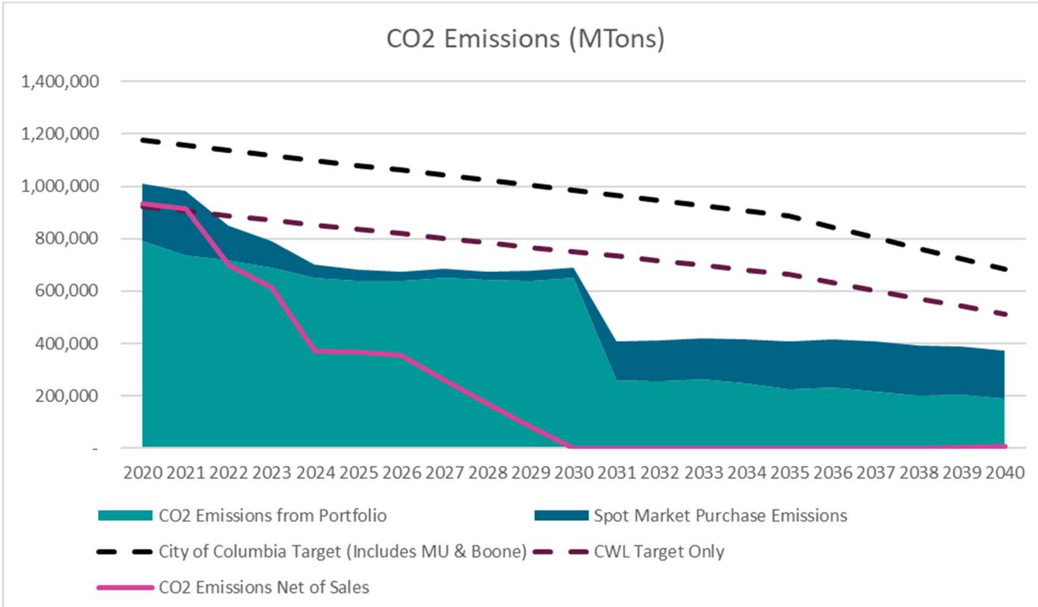
Renewable mandates are met at an accelerated pace under this scenario with the share of renewable generation reaching over 45% of load in 2023 and over 65% by 2024 with the commercial operation of the Boone-Stephens solar PPA and the Iron Star wind PPA along with the new capacity additions. By 2030, renewable generation accounts for 100% of the load needs (see Figure 46).

Figure 46: RPS Compliance – Early Renewable with High CO2



CWL CO2 emissions from power generation including both emissions from CWL portfolio (owned generation and PPAs), and market purchases is shown on Figure 47. The emissions through the study period are compared to the Reference Case emissions reduction targets for the City of Columbia and CWL. As shown, gross emissions from CWL power generation decline significantly through the study period. Emissions decline further after 2030 with the end of the Sikeston coal PPA. With most or all the sales coming from the coal PPAs and renewable generation meeting the base load needs, the emissions reach net zero by 2030 (pink line)[24].

Figure 47: CWL Emission Reductions – Early Renewable with High CO2



6.2.4.3 Portfolio Costs

The Early Renewable Scenario has an NPV of $789 million dollars, $11.5 million higher than the Early Renewable with base CO2 prices. Most of the total costs come from the payments to the existing PPAs, and the new renewable generation. The rest come from the operation and maintenance of CWL assets (including future generation assets) and market energy purchases. The total NPV of costs excluding revenues from market sales is $966 million, $28.6 million higher than the Early Renewable with base CO2 prices mostly driven by higher emission costs for the coal PPAs and CWL generation assets. Market purchase costs and energy sales revenues are higher than the original Early Renewable Scenario.

The Early Renewable Scenario has forecast annual costs of $69.8 million in 2021 rising to $86 million by 2030. Total costs decline after 2030 with the end of the Sikeston PPA in 2030 to $70.6 million in 2031. In contrast to the original Early Renewable scenario, annual costs increase after 2031 driven by rising CO2 emission prices with annual costs reaching $76 million by 2039.

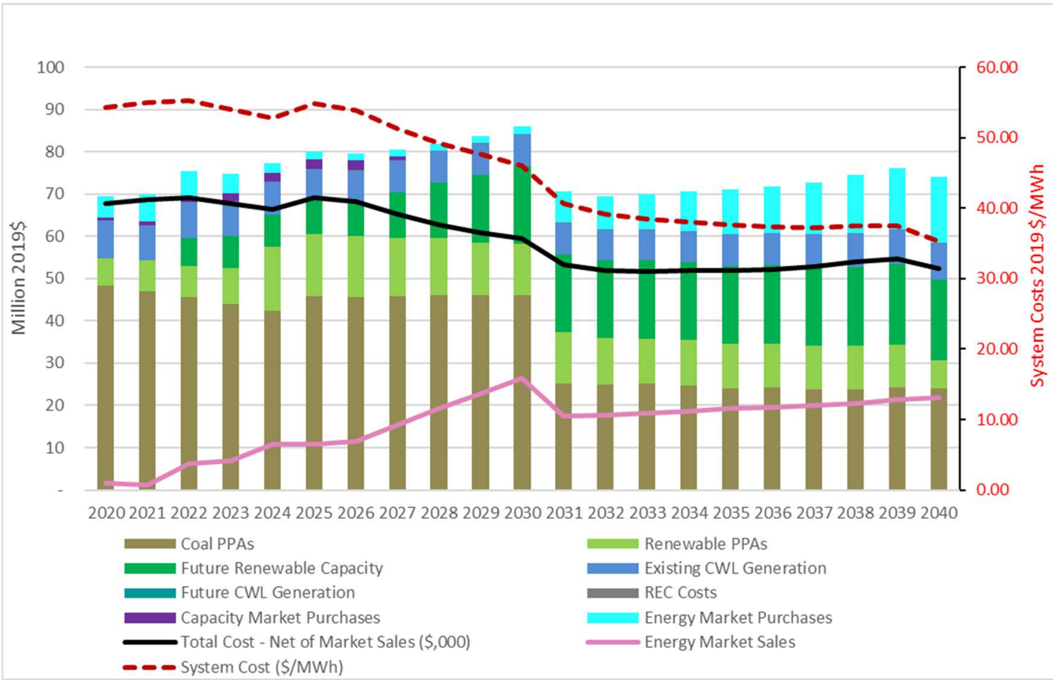
Total costs net of market sales revenues declines through the study period driven by rising energy revenues through 2030. Energy sales increase from $1.2 million in 2021 to $26 million by 2030. Total costs net of sales revenues reaches $59.5 million by 2030.

---

[24] The Early Renewable scenario assumes the MISO is not under the same renewable and decarbonization targets implicating that there is market for the energy from the coal PPAs. Under different circumstances a renegotiation of the contracts would be needed, or the retirement of the units could happen.

The system costs in $/MWh of energy demand fall from $54/MWh in 2021 to $46/MWh in 2030 (net or market sales). System costs in $/MWh continue falling through the 2030s (dotted red line).

Figure 48: CWL Portfolio Costs by Source – Early Renewable with High CO2



6.2.5 Mid Renewable Scenario with High CO2 Prices

The Mid Renewable Scenario is characterized by the following assumptions:

- 100% Renewable by 2040
- Net Zero Carbon by 2040
- Higher penetration of solar customer owned distributed generation, equivalent to 20% of the gross electricity demand by 2040 compared to 7.3% in the Reference Case.
- Near twice the amount of Energy Efficiency savings (0.7% annual EE savings first 10 years) with 6.8% cumulative savings through 2040 (11% of peak demand).
- Higher electric vehicle demand (8% of gross load by 2040 compared to 1.7% of gross load in the Reference Case)
- Resulting net load is 10.7% lower compared to Reference Case by 2040
- High CO2 prices

This scenario follows most of assumptions of the Early Renewable Scenario except for the environmental targets in 2040, instead of 2030. In line with the Early Renewable Scenario with high CO2 prices, carbon prices start at $6.60/Ton in 2025 rising to $15.00/Ton by 2032 and reaching a high of $40/Ton by 2040, as shown on Figure 27 and Appendix 2.

Siemens evaluated two expansion plans for the Mid Renewable Scenario, with similar net present value (NPV) of costs and both meeting the environmental compliance targets in 2040. We present a comparison of the results for both plans but focus on the results of the recommended plan by Siemens, which is the First Plan.

6.2.5.1 Future Capacity Additions and Generation Mix

Siemens evaluated two expansion plans for the Mid Renewable Scenario. The first plan is heavier on installations of renewable generation, which results in a lower NPV of costs and lower CO2 emissions, even though both plans comply with the environmental targets. The plan also includes higher market capacity purchases, which could carry a greater market risk (volatility in future capacity prices and availability of capacity).

The second plan in lieu of the earlier renewable added an 18 MW RICE natural gas peaker in 2031 and a small 10 MW battery storage unit in 2038, as shown on Table 18. However, both plans have a similar amount of total capacity additions with 214 MW for the First plan and 212 for the Second plan.

The First plan has more renewable generation (including storage) with 214 MW of new capacity (60% of total coming from solar), compared to 194 MW in the Second plan (50% solar). The first plan only has a small 1 MW battery storage unit online in 2037.

There are minimal capacity purchases under the Second plan, because of the RICE natural gas peaker addition, and a larger battery storage unit. Capacity purchases are similar to the Early Renewable Scenarios under the Second plan but in either of the two plans, the capacity purchases are lower than the Reference Case due to the higher amount of renewables.

Table 18: Comparison Capacity Additions Mid-Renewable Scenario

Technology	Reference Case	1st Plan	2nd Plan
LFG	0	0	0
Wind	0	84	90
Solar	154	129	94
Gas Peaker	0	0	18
Battery Storage	4	1	10
Max. Capacity Purchased Single Year	45	15	5
Biomass	0	0	0
Total Installed Capacity Excluding Capacity Market Purchases (MW)	**159**	**214**	**212**
Total Renewable + Storage	**159**	**214**	**194**

In terms of total costs, the first plan has higher fixed costs (i.e., need for greater commitments via PPA), which is offset via higher energy sales to the market. Total net present value of costs excluding energy sales total $912 million under the First Plan, $13 million higher than the second Plan. However, total costs net of energy sales is $784.6 million, $5.6 million lower than the Second plan, as shown on Table 19. Most of the total costs come from the payments to the existing PPAs, and the new renewable generation. The rest come from the operation and maintenance of CWL assets (including future generation assets) and market energy purchases.

The system costs in $/MWh are slightly lower under the First plan, Annual costs in $/MWh are almost identical through the early 2030s for both plans with the first Plan hiving lower costs after the mid-2030s driven by higher energy sales (see Chart in Appendix). However, under either plan, the overall NPV is higher than the Reference Case and the first plan is $4.2 million lower than the Early Renewable Scenario with High CO2 prices.

Based on the above observations, Siemens recommends the First plan with the caveat that during the 2030s, the decision to install a battery storage unit offsetting market capacity purchases should be evaluated in the future based on capital costs for batteries and market capacity prices.

Table 19: Comparison NPV of Costs Mid-Renewable Scenario (Thousand $)

	Reference Case	1st Plan	2nd Plan
Coal PPAs	$527,361	$499,984	$502,788
Renewable PPAs	$140,290	$138,916	$138,916
Future Renewable Capacity	$19,341	$72,905	$56,258
Existing CWL Generation	$134,672	$104,458	$98,305
Future CWL Generation	$3,547	$1,066	$12,136
REC Costs ($,000)	$528	$0	$220

Capacity Market Purchases ($000)	$18,369	$11,709	$9,733
Energy Market Purchases ($,000)	$36,743	$83,049	$80,357
Energy Market Sales ($,000)	$153,388	$127,517	$108,535
Total Cost ($,000)	$880,852	$912,088	$898,713
Total Cost - Net of Market Sales ($,000)	$727,464	$784,570	$790,178
System Costs - Net of Sales ($/MWh)	$43.29	$46.89	$47.23

Figure 49 shows future generic capacity additions under the First Plan. A large block of 50 MW of solar capacity is selected in 2022 to take advantage of the tax credits and achieve the 25% renewable Ordinance requirement in 2022. However, most of the new capacity is selected after 2030 to replace expired renewable PPAs and to meet the 2040 renewable target, including all the wind additions. Under this plan future capacity market purchases are in the range of 7 to 15 MW per year, all after 2030.

Figure 50 shows future generic capacity additions under the Second Plan. A block of 30 MW of solar capacity is selected in 2022 to take advantage of the tax credits. Likewise the First Plan, most of the new capacity is selected after 2030, including the 18 MW RICE gas Peaker in 2031 and the 10 MW battery storage unit in 2038.

Figure 49: Mid Renewable with High CO2 (First Plan) –Future Capacity Additions

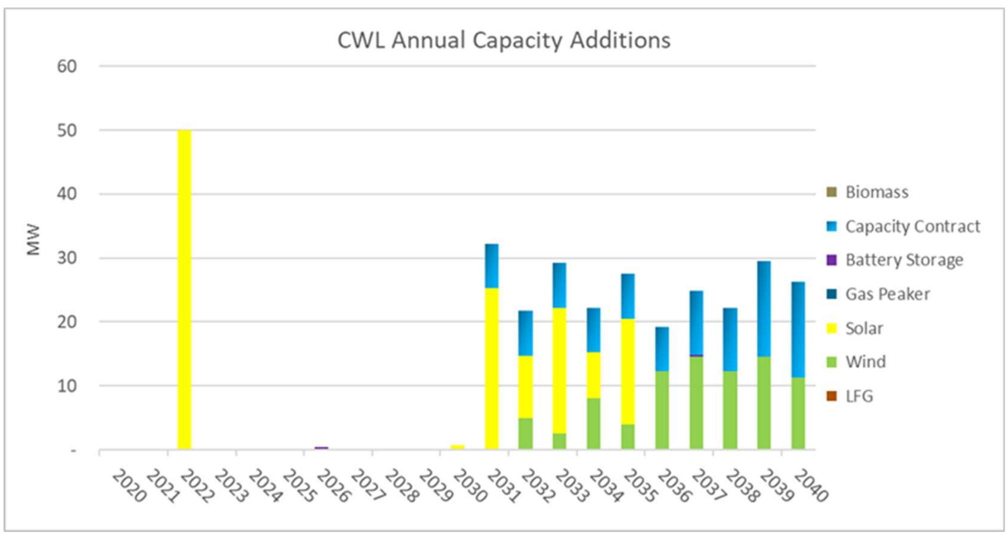
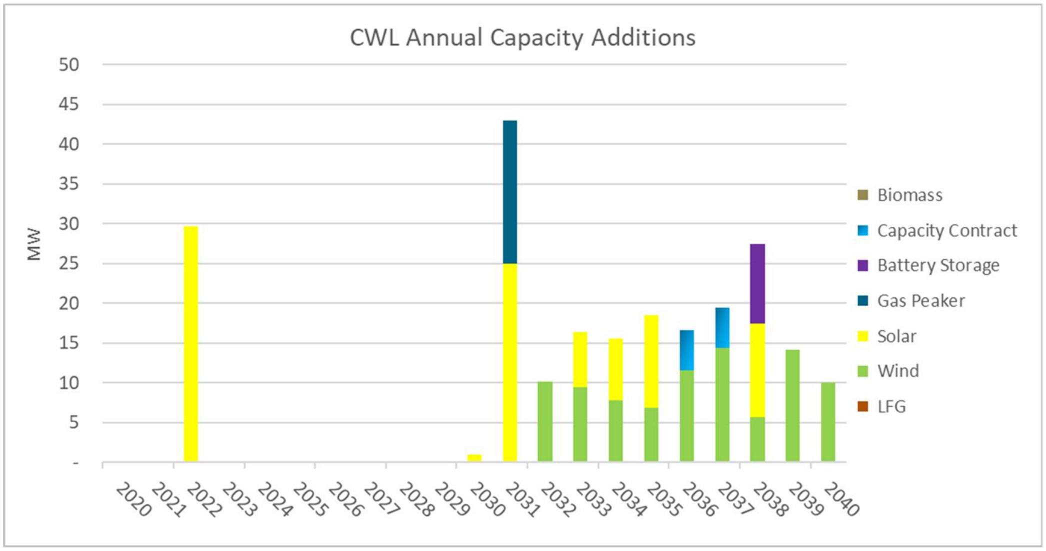


Figure 50: Mid Renewable with High CO2 (Second Plan) –Future Capacity Additions



As a result of the accelerated addition of renewable capacity CWL has a long (excess) generation position through most of the forecast. With renewable generation meeting an increasing share of the base load needs in the long-term, all the energy from the coal PPAs is sold back to the market by 2040. Selling all the energy from the coal PPAs also offset the carbon footprint from these assets to meet the 100% net zero carbon goal in 2040. Siemens suggests divesting the coal PPAs into a separate company as an option to decarbonize the fleet. Another option is to renegotiate these contracts if this scenario becomes a reality.

CWL own generation including the Columbia Energy Center contributes with 1% to 5% of the total generation through the study period serving peak demand needs during the non-solar hours.

The generation mix is relatively similar under the second Plan as shown on Figure 52 with a smaller excess generation position in the 2030s and a smaller share of solar generation.

Figure 51: Future Generation Mix – Mid Renewable with High CO2 – First Plan

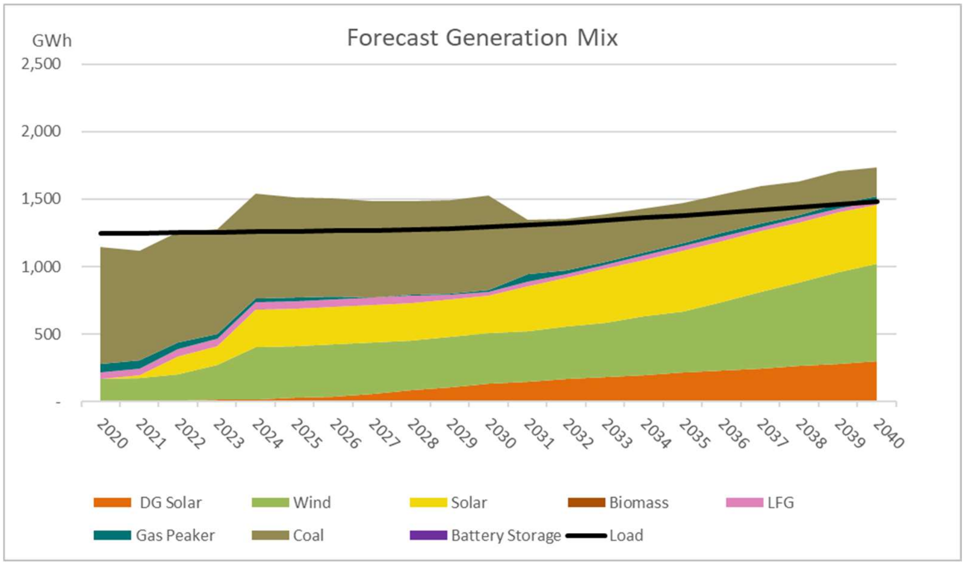
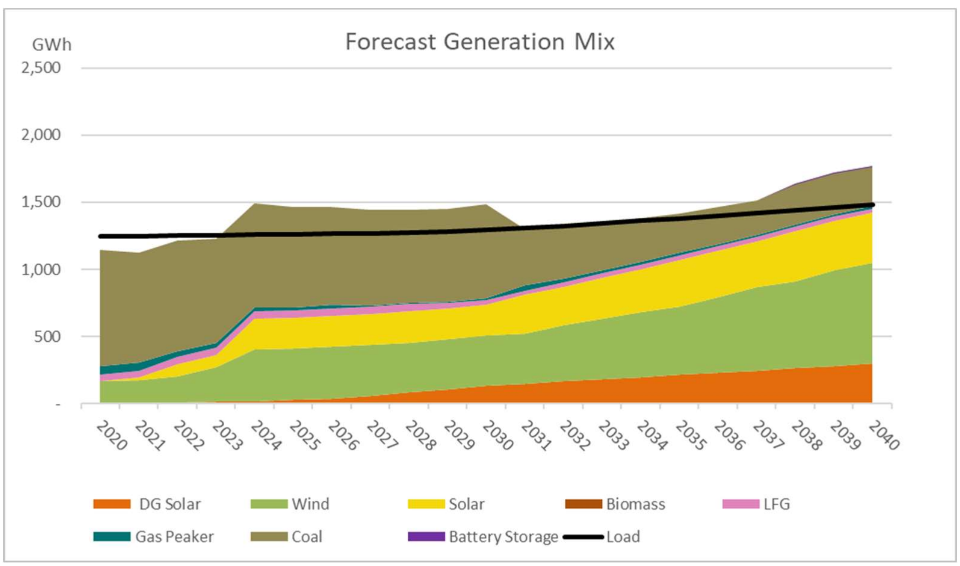
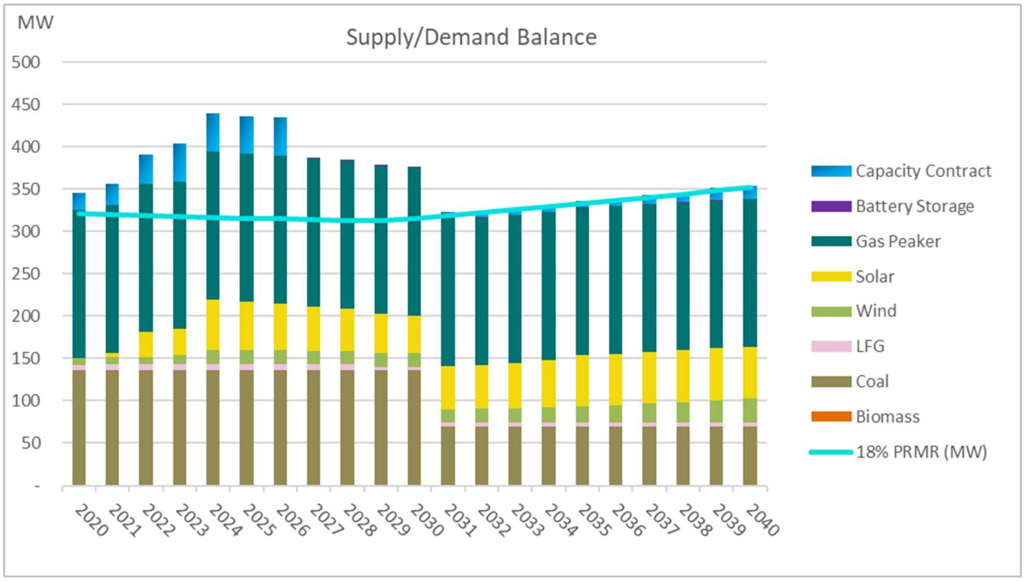


Figure 52: Future Generation Mix – Mid Renewable with High CO2 – Second Plan



CWL has a long position not only in terms of energy but also in terms of capacity through 2030, as shown in Figure 53. After 2030, the capacity market purchases are designed to maintain the 18% PRMR from MISO. The capacity supply demand balance is similar under both Plans.

Figure 53: Future Capacity Balance – Mid Renewable with High CO2 (First Plan)



6.2.5.2 Environmental Compliance

Renewable mandates are met at an accelerated pace under this scenario with the share of renewable generation reaching over 58.4% of load in 2024 with the commercial operation of the Boone-Stephens solar PPA and the Iron Star wind PPA along with the new solar capacity additions. The renewable share stays at 60% levels through 2030 then gradually rising to reach 100% by 2040 with all the remaining renewable capacity additions.

Figure 54: RPS Compliance – Mid Renewable with High CO2 (First Plan)

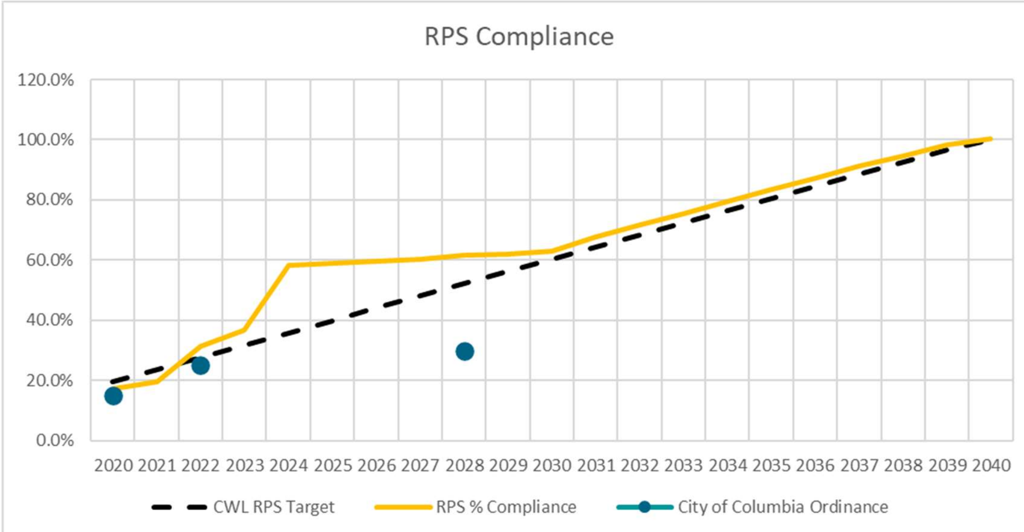
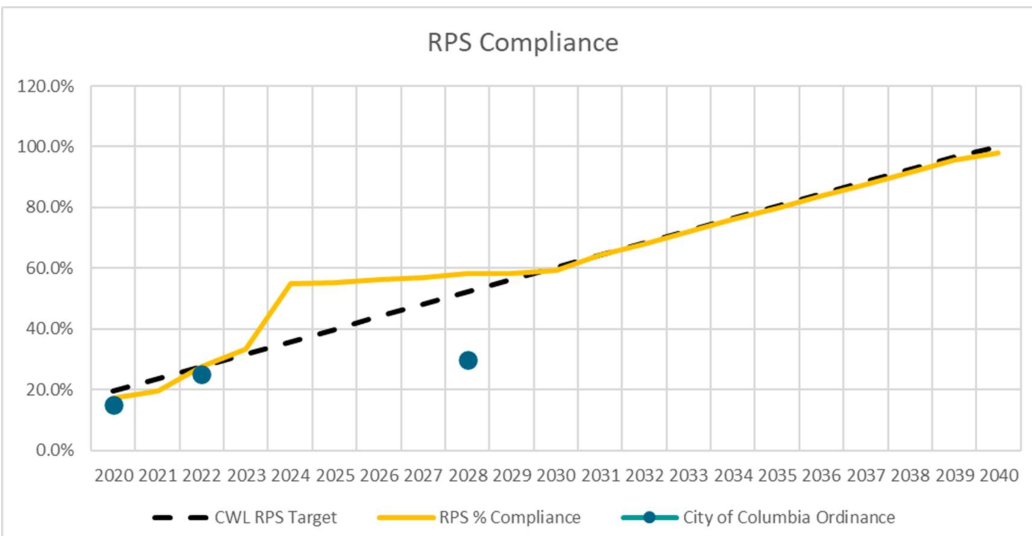
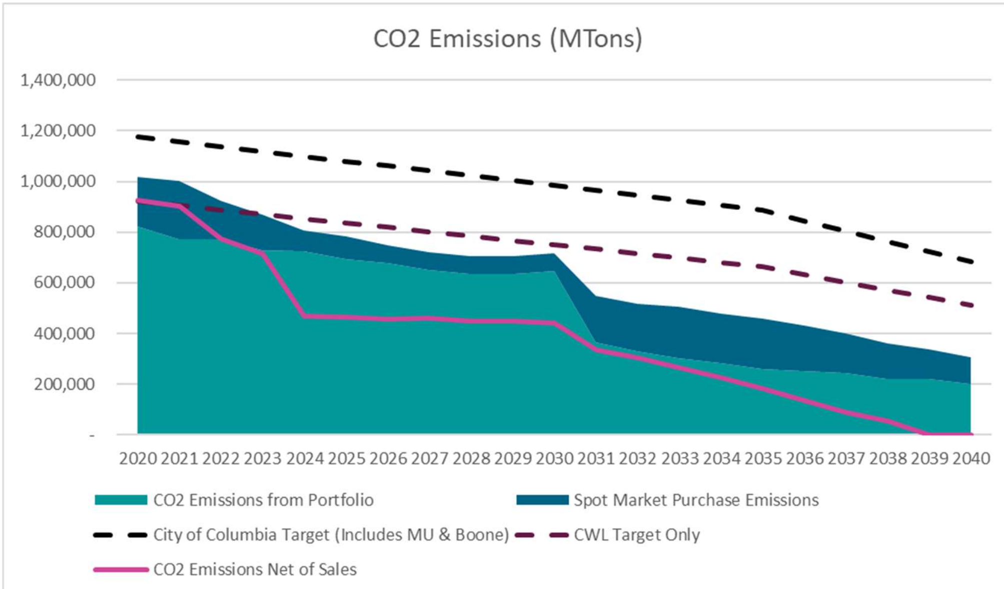


Figure 55: RPS Compliance – Mid Renewable with High CO2 (Second Plan)



CWL CO2 emissions from power generation including both emissions from CWL portfolio (owned generation and PPAs), and market purchases is shown on Figure 56. The emissions through the study period are compared to the Reference Case emissions reduction targets for the City of Columbia and CWL. As shown, gross emissions from CWL power generation decline significantly through the study period. Emissions decline further after 2030 with the end of the Sikeston coal PPA and the new renewable generation reaching net zero by 2040.[25] The emissions outlook is similar under both Plans.

Figure 56: CWL Emission Reductions – Mid Renewable with High CO2 (First Plan)



6.2.5.3 Portfolio Costs

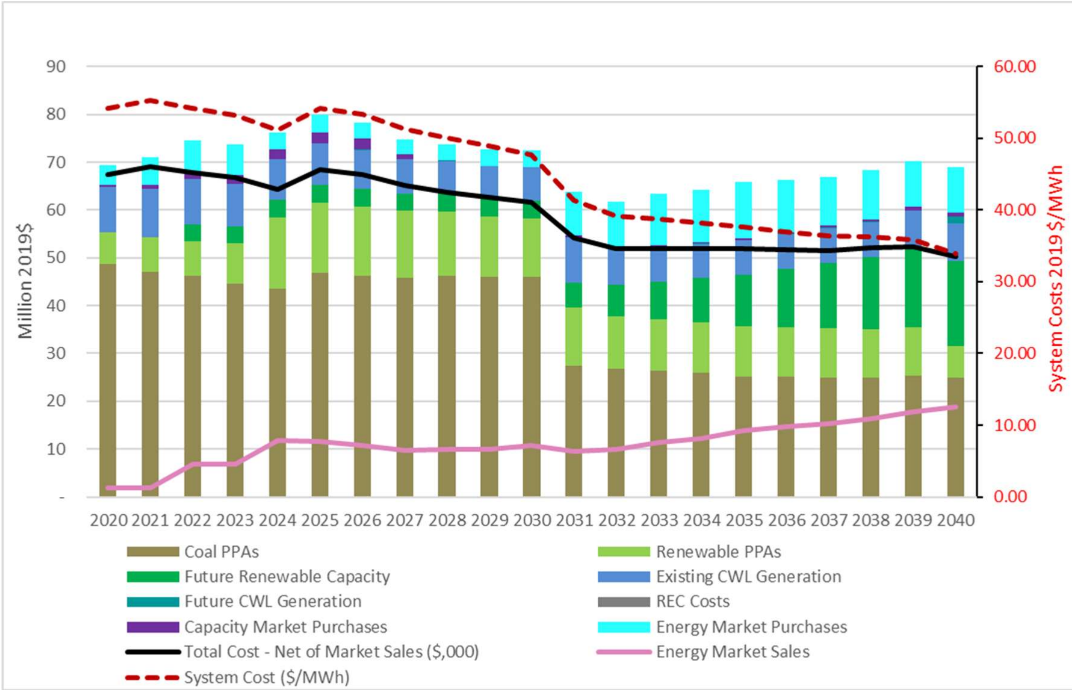
The Mid Renewable Scenario has forecast annual costs of \$69.0 million in 2021 rising to near \$80 million by 2026. Total costs decline after 2026 with the end of existing PPAs including the Sikeston coal PPA in 2030 to a low \$61.8 million in 2032. Annual costs increase after 2031 driven by new capacity additions and rising CO2 emission prices with annual costs reaching \$70 million by 2039.

Energy sales increase from \$1.9 million in 2021 to \$18 million by 2040, helping to maintain total costs net of energy sales at around \$51 million in the long-term.

The system costs in \$/MWh of energy demand fall from \$55/MWh in 2021 to \$34/MWh in 2040 (dotted red line). Under the Second Plan the system costs in \$/MWh are slightly higher at \$35/MWh by 2040.

[25] The Mid Renewable scenario assumes the MISO is not under the same renewable and decarbonization targets implicating that there is market for the energy from the coal PPAs. Under different circumstances a renegotiation of the contracts would be needed, or the retirement of the units could happen.

Figure 57: CWL Portfolio Costs by Source – Mid Renewable with High CO2 (First Plan)

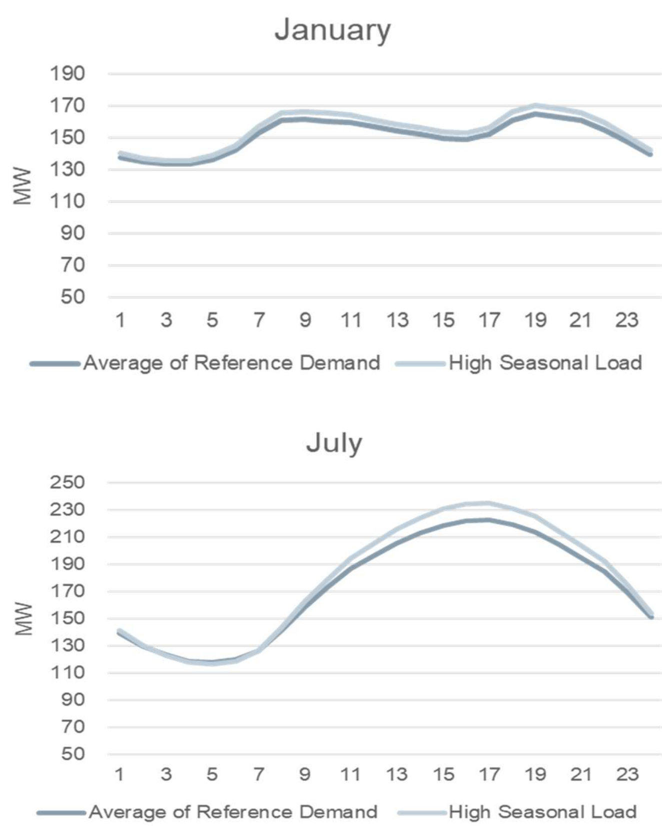


6.2.6 High Seasonal Load Scenario

Under the High Seasonal Load scenario, it is assumed that hotter summers and colder winters will happen in the CWL territory and in the rest of the mid-west because of climate change. CWL have not experienced a record peak demand since the one set back in 2011 at 277 MW with peak loads hovering around 267 MW since then. However, CWL is concerned that with customer count growth at 1.3% per year, and 8% more transformers since 2016 the possibility of a higher peak demand could demand when the next hot spell happens in the Mid-west. Under the High Seasonal Load scenario, it is assumed that MISO regional demand is ~6% higher compared to the reference case by 2040, and there is also high penetration of electric vehicle demand. As a result, net load is 9% higher compared to the Reference Case and peak demand 15% higher by 2040 (see orange line on Figure 28). Despite the changes in load, the peak demand hour does not shift and still happens on hour ending 17 (5pm) in July, and 9 am in January during the winter (see Figure 58).

This scenario was simulated using the base case energy efficiency savings assumptions. The Siemens team evaluated that the high EE savings case would offset much of the increase in load from climate change and EV demand combined eroding the purpose of the scenario.

Figure 58: Summer and Winter Average Hourly Demand High Seasonal Load Case



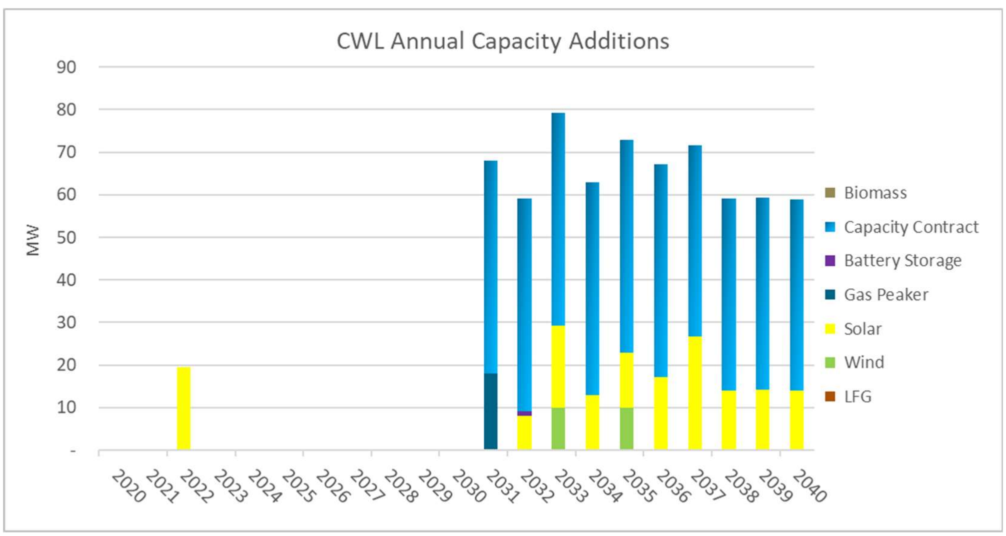
6.2.6.1 Future Capacity Additions and Generation Mix

Figure 59 shows future generic capacity additions under this Scenario. These generation capacity additions are incremental to the new power purchase agreements (PPAs) signed by CWL.

The results of the generation expansion plan show 198 MW of new capacity additions, which is 39 MW higher than the Reference Case. The new additions include 159 MW of new solar generating capacity and 20 MW of wind. Solar installations are in the range of 8 to 27 MW per year starting in 2022 with a block of 20 MW driven by the existing tax incentives for renewables. Most of the capacity is installed after 2030 in line with the Reference Case, with renewable additions selected to meet the 100% renewable and net zero carbon targets in 2050 (same assumption as the Reference Case).

The plan includes an 18 MW RICE natural gas unit selected in 2031 and a small battery storage unit (1 MW) selected in 2032 with both meeting load in the evenings. The RICE peaker is selected due to the larger peak demand needs during the evening (in the summer) and early morning hours (in the winter) under this scenario, compared to the Reference Case. For the same reason, this scenario has higher capacity market purchases in the range of 45 to 50 MW per-year starting in 2031, after the end of the Sikeston PPA in 2030.

Figure 59: High Seasonal Load Future Capacity Additions

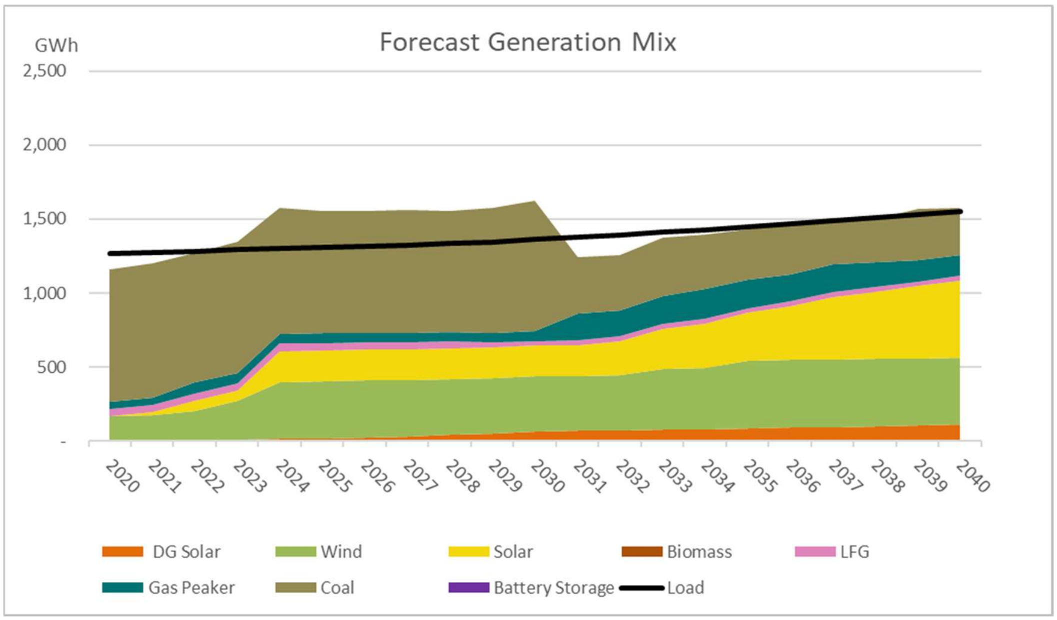


CWL existing coal-based portfolio switches to a renewable based portfolio in the long-term. Coal contributes with 71% of the total generation in 2021 falling throughout the forecast with new renewable generation and the expected retirement of the Sikeston coal plant to reach 28% by 2031, and further to 20% by 2040. Renewable generation accounts for 19% of the total in 2021 rising to 50% by 2024 with the operation of the Boone-Stephens and Iron Star PPAs. Renewable share is projected to say at similar levels for the rest of the decade and rise further in the 2030s with the new solar capacity additions reaching 73% of the total generation by 2040.

CWL own generation including the Columbia Energy Center contributes with 4% to 5% of the total generation in 2021-2030 serving peaking load needs only. With the retirement of the Sikeston coal plant in 2030 and the rising load from electric vehicles the share of CWL own generation jumps to 10-14% of the total in the 2030s, serving an increasing share of the peak demand needs during the evenings.

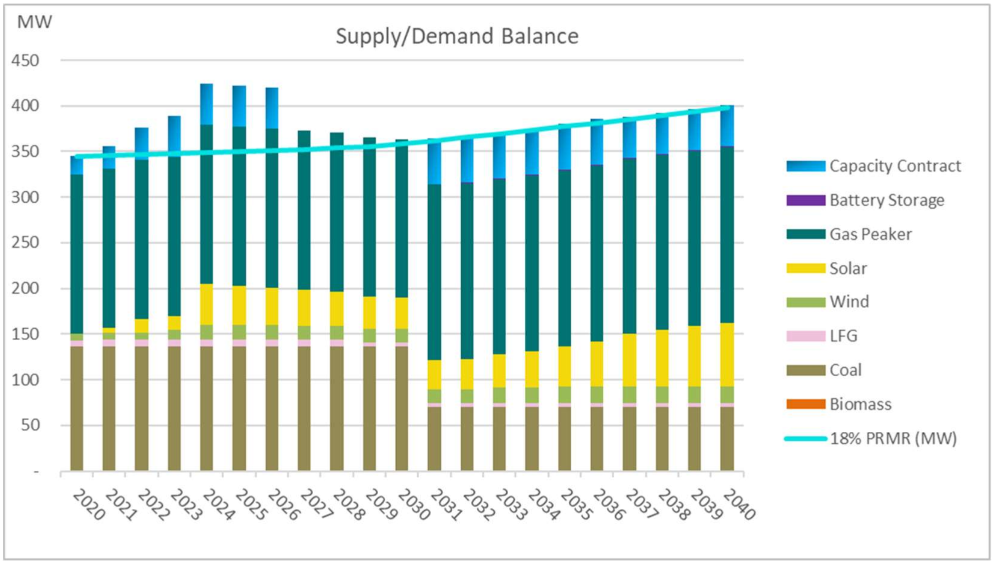
CWL becomes a net seller of energy in 2024-2030 with most of sales coming from the coal PPAs. The long position ends in 2031 with generation supply shortages being fulfill with spot market purchases in 2031-2034. A more balanced position is seen through the end of the study period.

Figure 60: Future Generation Mix – High Seasonal Load



CWL has a long position not only in terms of energy but also in terms of capacity through 2030, as shown in Figure 61. CWL existing generation fleet, contracted generation, and new generating capacity provides enough supply to meet MISO's 18% planning reserve margin requirement through the study period. Imbalances on capacity requirements are fulfill with capacity market purchases in the 2030s.

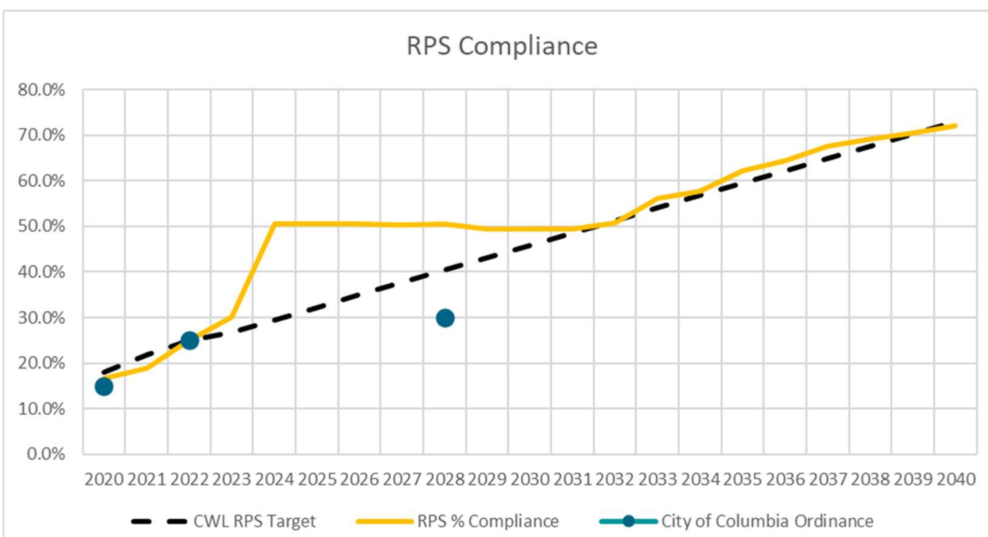
Figure 61: Future Capacity Balance – High Seasonal Load



6.2.6.2 Environmental Compliance

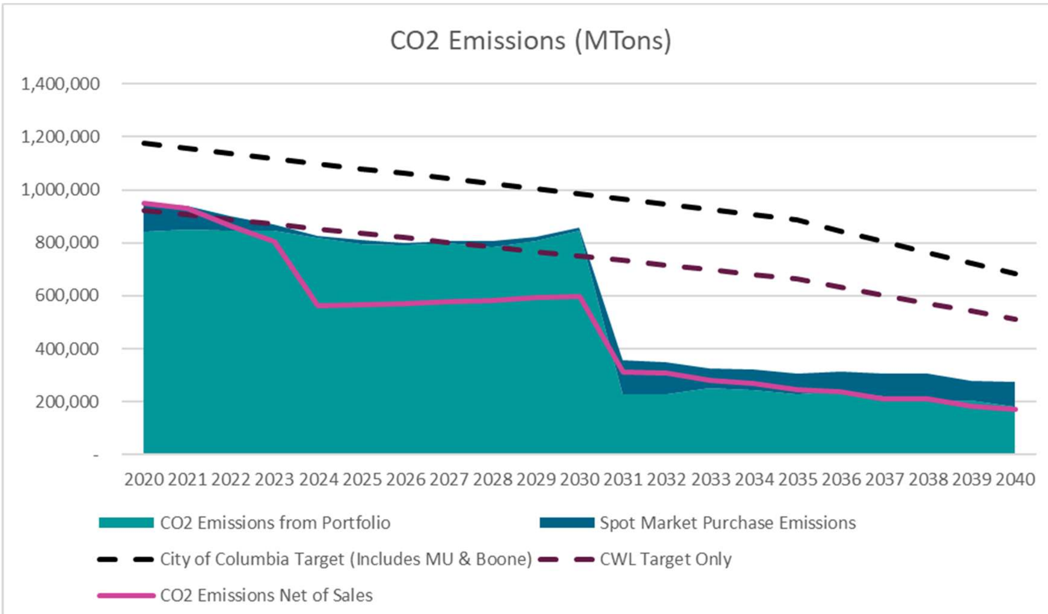
With the commercial operation of the Boone-Stephens solar PPA and the Iron Star wind PPA, the share of renewable generation jumps from 30% in 2023 to 50% in 2024, staying at similar levels through the end of the decade, exceeding the City of Columbia Ordinance requirement of 30% in 2028. After 2030, the new solar and wind generation capacity is selected as the most economical option to meet an interim 73% renewable target by 2040 on the road to meet the 100% renewable target by 2050.

Figure 62: RPS Compliance – High Seasonal Load



CWL CO2 emissions from power generation including both emissions from CWL portfolio (owned generation and PPAs), and market purchases is shown on Figure 63. The emissions through the study period are compared to a linear path to reach 35% and 50% emissions reductions by 2035 and 2040, respectively for both the City and CWL. Emissions from CWL own generation including market purchases do not decline significantly through 2030 due to the higher load needs despite an increasing share of renewables. However, accounting for market sales, the overall emissions are below a liner path to reach the 2035 target (pink line). Most of CWL emissions come from the coal PPAs as well most of the market sales. After 2030 with the end of the Sikeston coal PPA, emissions fall significantly staying much below the 2035 and 2040 targets, even excluding energy sales [26].

Figure 63: CWL Emission Reductions – High Seasonal Load



6.2.6.3 Portfolio Costs

The High Seasonal Load scenario has an NPV of $837.9 million dollars, $111.7 million higher than the Reference Case. The High Seasonal load scenario is the highest cost scenario in NPV terms and $/MWh driven by lower energy market sales and relatively high-capacity additions. Energy sales are lower due to hotter summers and colder winters, along with higher EV demand increasing peak demand needs as well.

There are some savings compare to the Reference Case in the form of lower variable and emissions costs.

The High Seasonal Load Scenario has forecast annual costs of $67.6 million in 2021 rising to $73.3 million by 2025 with the new PPAs and the 20 MW of additional solar capacity in 2022. Total costs decline in the later part of the 2020s driven by the expiration of some of the PPAs with annual costs falling to $65.9 million by 2031. Total costs rise again in the 2030s with the bulk of new capacity additions to reach a high of $77.2 million in 2039.

Market sales are lower in this scenario compared to the Reference Case reaching a high of $9.3 million in 2024, near $11 million below the highest level of sales in the Reference Case.

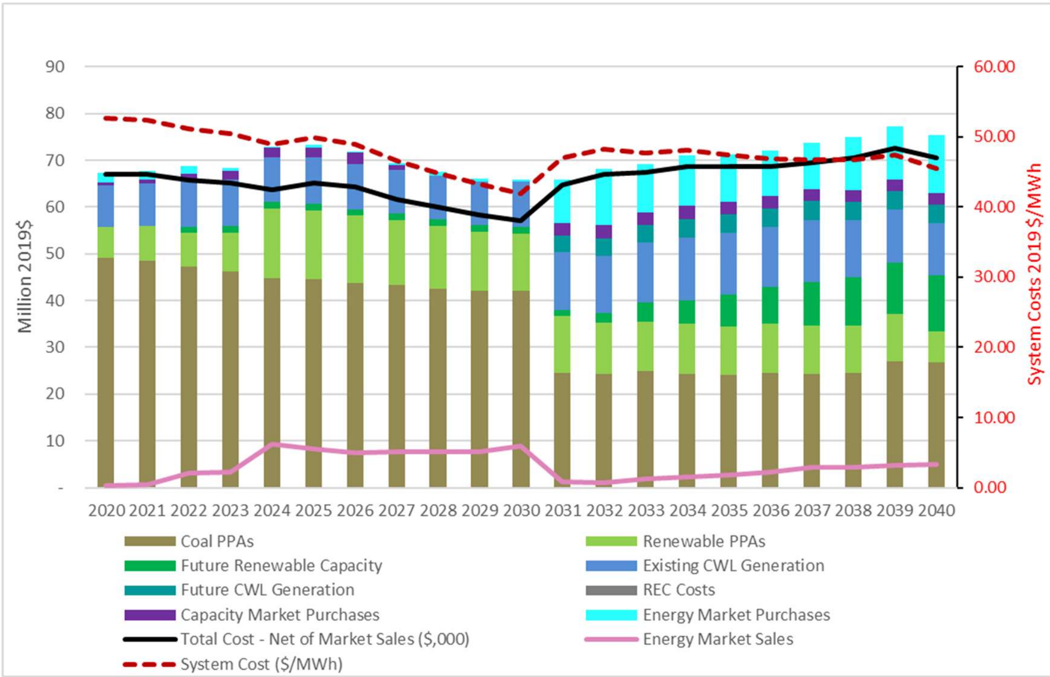
---

[26] Emissions from market purchases are estimated as the product of MISO's emission rate times the energy purchased by CWL in MWh. The emissions rate for MISO is estimated by Siemens using the Aurora model and its own simulation of the MISO power market. The emissions rate is forecast to fall from 0.84 metric tons/MWh in 2021 to 0.56 metric tons/MWh by 2040.

Total costs net of market sales revenues reach $56.7 million by 2030, $8.2 million higher than the Reference Case for the same year.

The system costs in $/MWh fall from $52.4/MWh in 2021 to $41.8/MWh by 2030 (net of market sales). In the 2030s system costs rise to be in the range of $45 to $48/MWh with the new capacity additions (dotted red line).

Figure 64: CWL Portfolio Costs by Source – High Seasonal Load



6.2.7 Recession Scenario

The Recession economy scenario assumes that the U.S. enters a long recession that slows load growth, depress commodity markets and investments in new technologies including electric vehicles, and slow down decarbonization efforts nationwide. Under this scenario gross electricity demand is 7.7% lower compared to the reference case in CWL territory by 2040. Electric vehicle demand is on the low side (1.2% of gross load compared to 1.7% in the Reference Case by 2040), and commodity prices are low. There is not a CO2 pricing framework nationwide. Overall net demand (net of EV demand, solar DG and energy efficiency) is 9.1% below the Reference Case by 2040 (see yellow line on Figure 28). Similar to the Early and Mid-renewable cases.

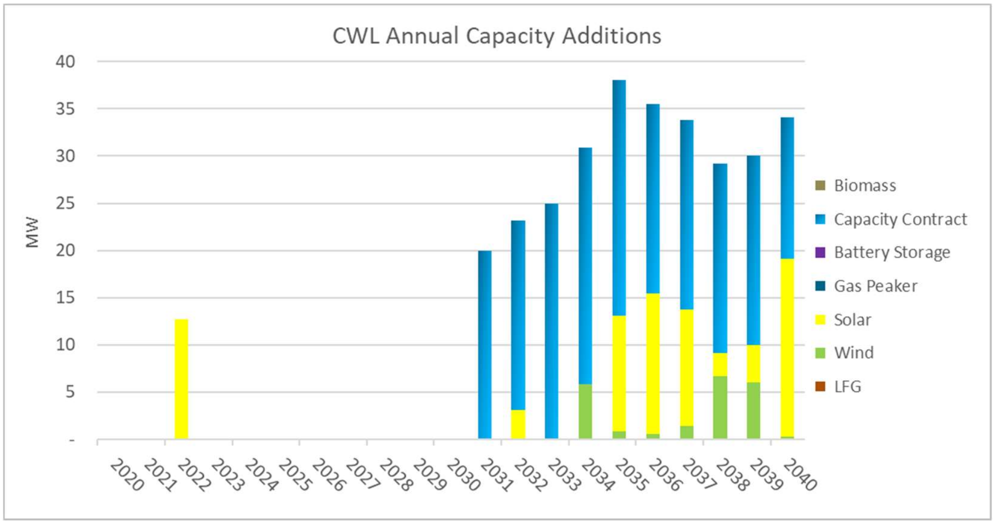
6.2.7.1 Future Capacity Additions and Generation Mix

Figure 65 shows future generic capacity additions under this Scenario. These generation capacity additions are incremental to the new power purchase agreements (PPAs) signed by CWL.

The results of the generation expansion plan show 102 MW of new capacity additions through 2040, 56 MW below the Reference Case. All the capacity additions come from renewables including 81 MW of solar and 22 MW of wind. Annual renewable installations are in the range of 3 to 19 MW starting in 2022 with a block of 13 MW of solar driven by the existing tax incentives. Most of the new capacity is selected after 2030 in line with the Reference Case, with renewable additions selected to meet the 100% renewable target and net zero carbon target in 2050 (same assumption as the Reference Case).

The Recession plan does not include RICE natural gas units neither small battery storage like other plans. All incremental capacity needs are met with capacity market purchases in the range of 15 to 25 MW per-year starting in 2031, after the end of the Sikeston coal PPA, which are found to be more economical than procuring or building further generation resources.

Figure 65: Recession Scenario Future Capacity Additions



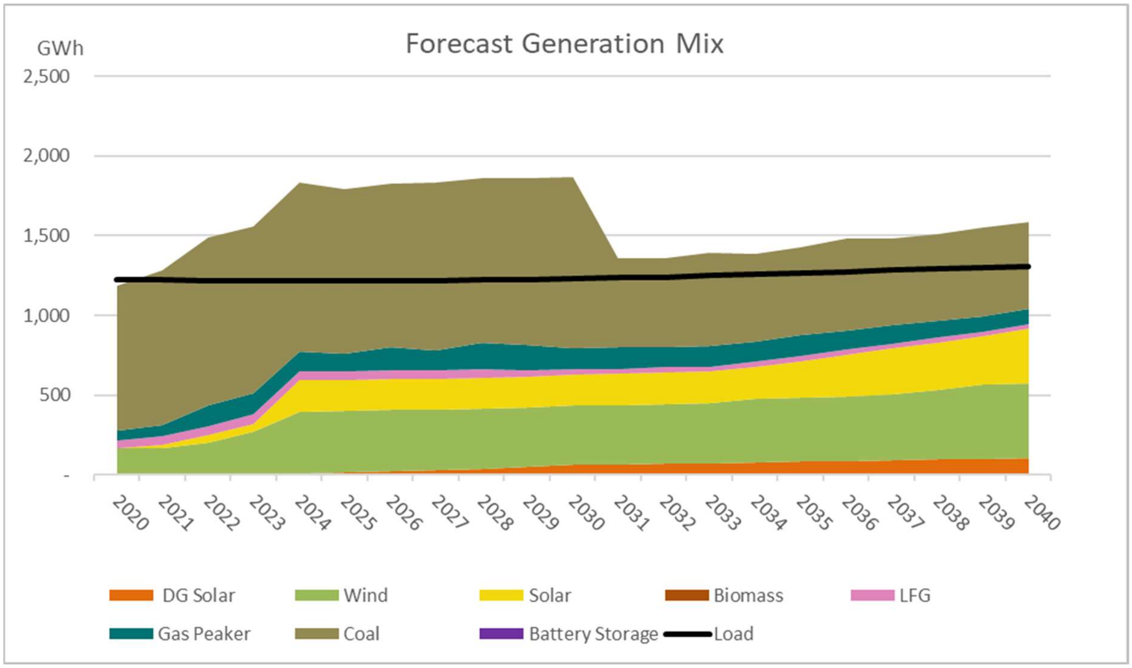
CWL existing coal-based portfolio switches to a renewable based portfolio in the long-term. Coal contributes with 75% of the total load in 2021 (net of sales) falling to 36% of the total after the retirement of the Sikeston coal plant in 2030. Coal generation share continue falling in the 2030s displaced by new renewable generation to reach 21% of the total load by 2040. In contrast renewable generation increases from 20% of the total in 2021 to 53% by 2024 with the commercial operation of the Boone-Stephens and Iron Star PPAs. Renewable share stays at similar levels through the second half of the 2020s to rise further after 2031 with the new renewable capacity additions to reach the interim target of 73% of load by 2040.

CWL own generation including the Columbia Energy Center contributes with 6% to 13% of the total generation over the study period serving mostly peaking demand needs. The share total generation coming from CWL assets is higher than the Reference Case, driven by the low natural gas prices. Even the coal PPAs dispatch at higher capacity factors with the corresponding coal plants dispatching at higher capacity factors in the MISO and SPP markets.

The Siemens team agreed with CWL and the City's Task Force to impose a CO2 tax on the gas peakers equivalent to Siemens' base case of CO2 prices to comply with the emissions targets. Without the tax, the gas peakers dispatched at higher levels making more challenging to meet the emission reduction targets.

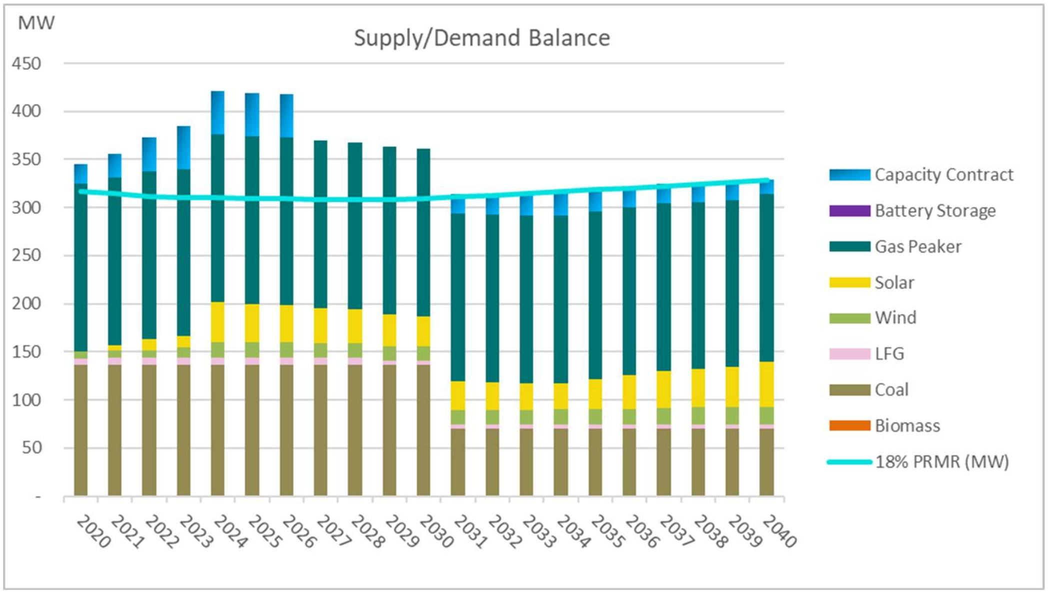
CWL is a net seller of energy through most of the study period with most of sales coming from the coal PPAs. The excess generation position is larger in 2023-2031 with the Boone-Stephens and Iron Star PPAs coming online.

Figure 66: Future Generation Mix – Recession Scenario



CWL has a long position not only in terms of energy but also in terms of capacity through 2030, as shown in Figure 67. The lower peak demand under this scenario drives a larger excess capacity position compared to the Reference Case. CWL existing generation fleet, contracted generation, and new generating capacity provides enough supply to meet MISO's 18% planning reserve margin requirement through the study period. Imbalances on capacity requirements are fulfill with capacity market purchases in the 2030s.

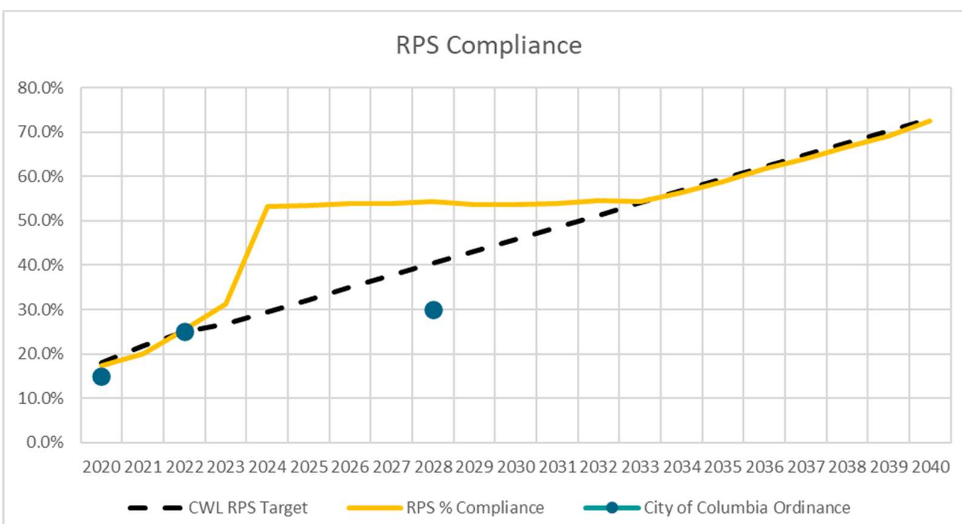
Figure 67: Future Capacity Balance – Recession Scenario



6.2.7.2 Environmental Compliance

With the commercial operation of the Boone-Stephens solar PPA and the Iron Star wind PPA, the share of renewable generation jumps from 30% in 2023 to 53% in 2024, staying at similar levels through the end of the decade, and exceeding the City of Columbia Ordinance requirement of 30% in 2028. After 2030, new solar and wind generation capacity drives higher compliance levels to reach an interim 73% renewable target in 2040 on the road to meet the 2050100% renewable target.

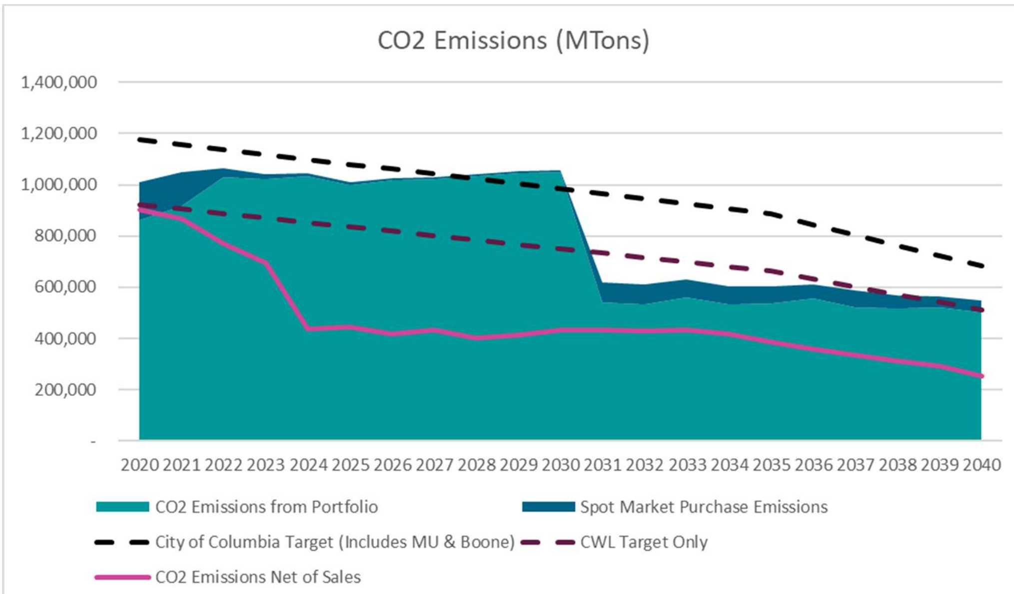
Figure 68: RPS Compliance – Recession Scenario



CWL CO2 emissions from power generation including both emissions from CWL owned generation and PPAs, as well as energy market purchases is shown on Figure 69. The emissions through the study period are compared to a linear path to reach 35% and 50%

emissions reductions by 2035 and 2040, respectively for both the City and CWL. Emissions from CWL own generation including market purchases stay at high levels through the 2020s due to the improved dispatch of the thermal generation assets combined with lower load. Overall emissions fall significantly after 2030 with the end of the Sikeston coal PPA and increased penetration of renewables, however the reductions are not as aggressive as other scenarios, including the Reference Case. However, accounting for market sales, the overall emissions are below the targets (pink line). Most of CWL emissions come from the coal PPAs as well most of the market sales.

Figure 69: CWL Emission Reductions – Recession Scenario



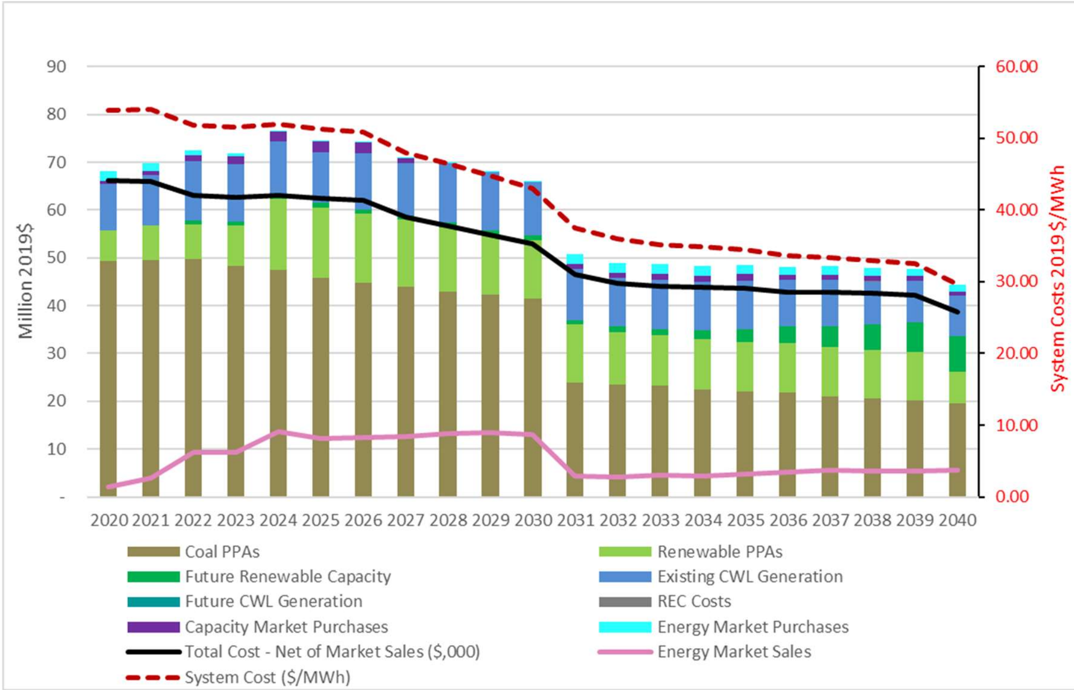
6.2.7.3 Portfolio Costs

The Recession scenario has an NPV of $705.5 million dollars, $21.9 million lower than the Reference Case. The Recession scenario is one of the lowest cost scenarios in NPV terms and $/MWh driven by lower energy demand. This scenario has forecast annual costs of $69.8 million in 2021 rising to $76.9 million by 2024 with the new PPAs and the 13 MW of additional solar capacity in 2022. Total costs decline in the later part of the 2020s driven by the expiration of some of the PPAs with annual costs falling to $50.7 million by 2031. Total costs stay relatively flat in the 2030s despite the new renewable capacity additions.

Market sales are higher under this this scenario compared to the Reference Case in terms of volume but are lower in terms of costs, driven by lower energy market prices (lower commodity prices).

Total costs net of market sales revenues falls from $65.9 million in 2021 to $46.4 million by 2031, $4.3 million higher than the Reference Case for the same year.

Figure 70: CWL Portfolio Costs by Source – Recession Scenario



6.2.8 High Regulatory Scenario

The High Regulatory Scenario assumes more stringent regulations on fracking and environmental policies including methane pollution, CO2 emissions and coal waste. As a result, commodity prices are higher for natural gas and coal, as well as CO2 emission prices. The more stringent regulatory environment drives lower economic growth and lower levels of energy efficiency penetration (more challenging to deploy conservation programs to customers). Regional gross demand is 7.7% below the Reference Case by 2040, in line with the Recession Scenario[27]. Higher commodity prices in turn drives higher electricity customer rates and higher installations of customer own solar panels with customers having more incentive to install their own solar panels and reduce their utility bill. The combined effect of all these impacts drive net energy demand 20% below the Reference by 2040, even below the Recession Scenario and the Early and Mid-renewable scenarios, as seen in Figure 28. The decline is particularly significant during the 2030s with electric vehicle demand assumed to be line with the Reference Case limiting the upside impact on demand growth compared to the Early and Mid-Renewable cases (the last have higher penetration of electric vehicle demand).

6.2.8.1 Future Capacity Additions and Generation Mix

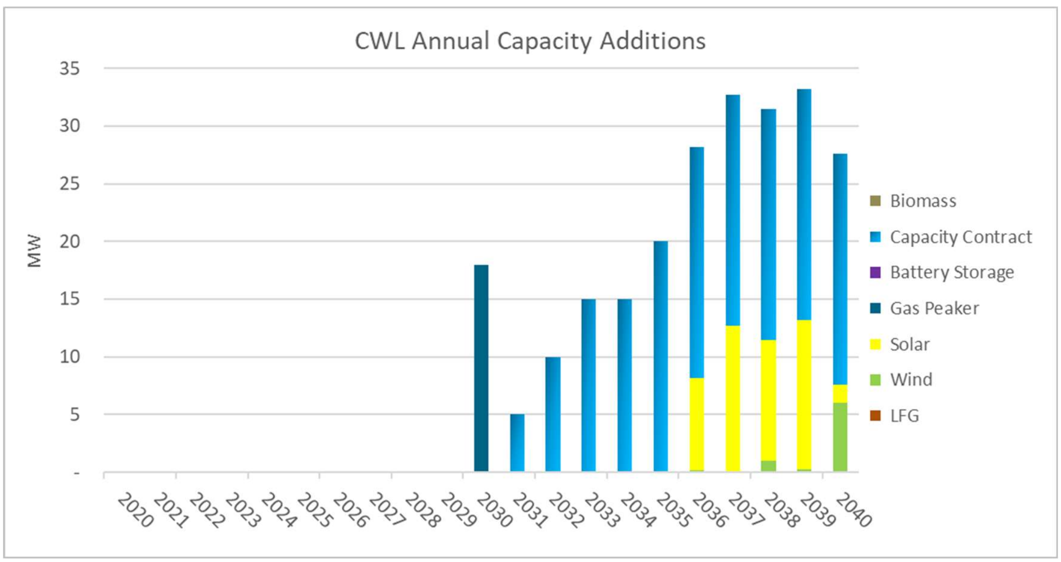
Figure 71 shows future generic capacity additions under this Scenario. These generation capacity additions are incremental to the new power purchase agreements (PPAs) signed by CWL.

[27] Gross demand excludes the impact of Energy Efficiency programs, solar distributed generation and electric vehicle demand.

The results of the generation expansion plan show 71 MW of new capacity additions through 2040, 55% (88 MW) below the Reference Case. Most of the capacity additions come from renewables including 46 MW of solar and 8 MW of wind, near a third of the combined renewable additions under the Reference Case. Annual renewable installations are in the range of 1 to 13 MW with new generation selected to come online until 2036, later than any other scenario due to the falling energy demand. Renewable and net zero carbon targets are the same as the Reference Case with a 2050 goal.

An 18 MW RICE gas peaker is selected in the simulation coming online in 2030 to meet capacity and energy requirements after the expiration of the Sikeston coal PPA. Future capacity market purchases under this scenario vary in the range of 5-20 MW per year after 2030 to meet MISO's planning requirement of 18%, which are found to be more economical than procuring or building further generation resources.

Figure 71: High Regulatory Scenario Future Capacity Additions



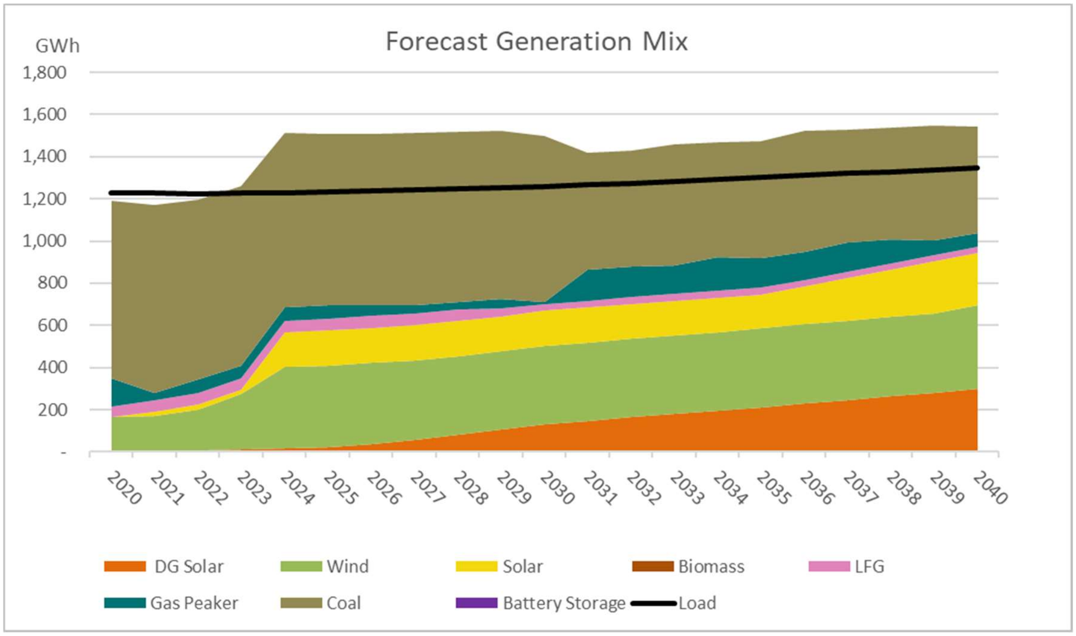
CWL existing coal-based portfolio switches to a renewable based portfolio in the long-term. Coal provides 69% of the load needs in 2021 (net of sales) falling to 27% of the total after the retirement of the Sikeston coal plant in 2030. Coal generation share continue falling in the 2030s displaced by new renewable generation to reach 14% of the total by 2040. In contrast renewable generation increases from 20% of the total in 2021 to 50% by 2024 with the commercial operation of the Boone-Stephens and Iron Star PPAs. Renewable share continues rising after 2024 due to the sustained reduction in load in this scenario and new renewable capacity additions reaching the interim target of 73% of load by 2040.

CWL own generation including the Columbia Energy Center contributes with 1% to 12% of the total generation over the study period serving mostly peaking demand needs. The share of total generation coming from CWL assets increases after 2030 with the new gas peaker and the existing fleet running at higher capacity factors.

CWL is a net seller of energy through most of the study period with most of sales coming from the coal PPAs. The excess generation position starts in 2024 with the Boone-Stephens and

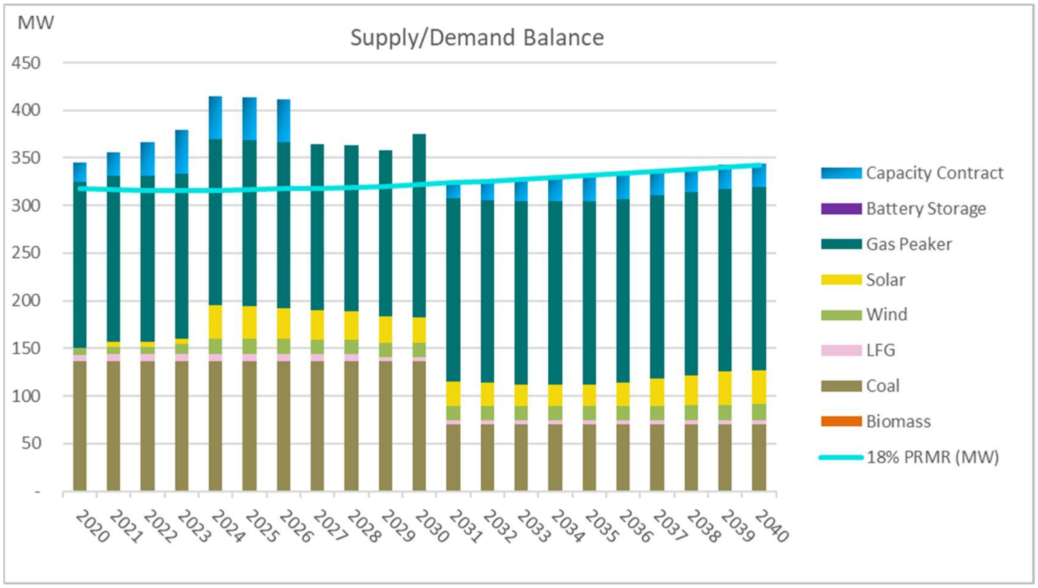
Iron Star PPAs coming online and stays through the end of the study period with the sustained reduction in load.

Figure 72: Future Generation Mix – High Regulatory Scenario



CWL has a long position not only in terms of energy but also in terms of capacity through 2030, as shown in Figure 73. The lower peak demand under this scenario drives a larger excess capacity position compared to the Reference Case. CWL existing generation fleet, contracted generation, and new generating capacity provides enough supply to meet MISO's 18% planning reserve margin requirement through the study period. Imbalances on capacity requirements are fulfill with capacity market purchases in the 2030s.

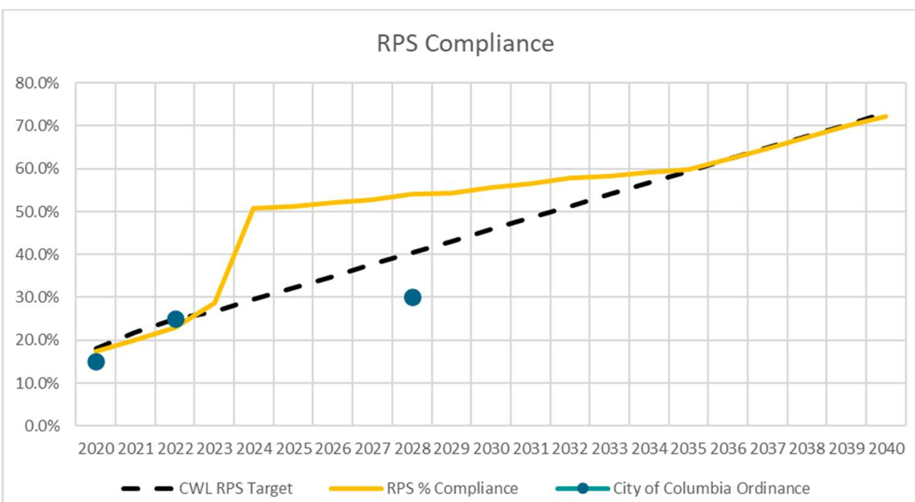
Figure 73: Future Capacity Balance – High Regulatory Scenario



6.2.8.2 Environmental Compliance

With the commercial operation of the Boone-Stephens and the Iron Star renewable PPAs, the share of renewable generation jumps from 28.6% in 2023 to 51% in 2024, and continue rising gradually through the mid-2030s with the sustained reduction in energy demand. After 2035, the new renewable capacity additions drives higher compliance levels to reach the interim 73% renewable target in 2040 on the road to meet the 2050 100% renewable target.

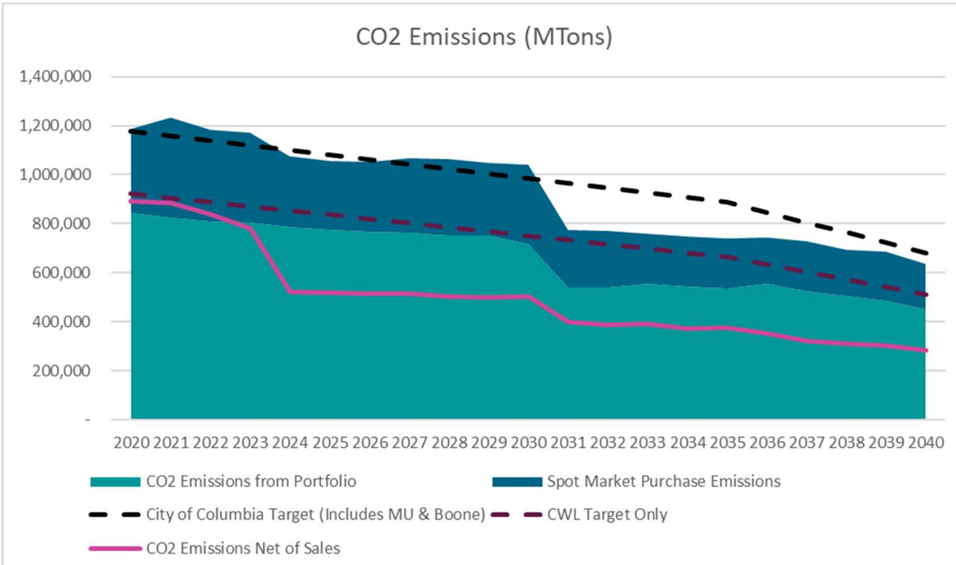
Figure 74: RPS Compliance – High Regulatory Scenario



CWL CO2 emissions from power generation including both emissions from CWL owned generation and PPAs, as well as energy market purchases is shown on Figure 75. The emissions through the study period are compared to a linear path to reach 35% and 50% emissions reductions by 2035 and 2040, respectively for both the City and CWL. Emissions from CWL own generation including market purchases stay at high levels through the

2020swith emissions falling after 2030 with the end of the Sikeston coal PPA and increased penetration of renewables in the late 2030s. However the reductions are not as aggressive as other scenarios, including the Reference Case. Accounting for the net impact of market sales (pink line), net emissions are below the CWL target path through the study period.

Figure 75: CWL Emission Reductions – High Regulatory Scenario



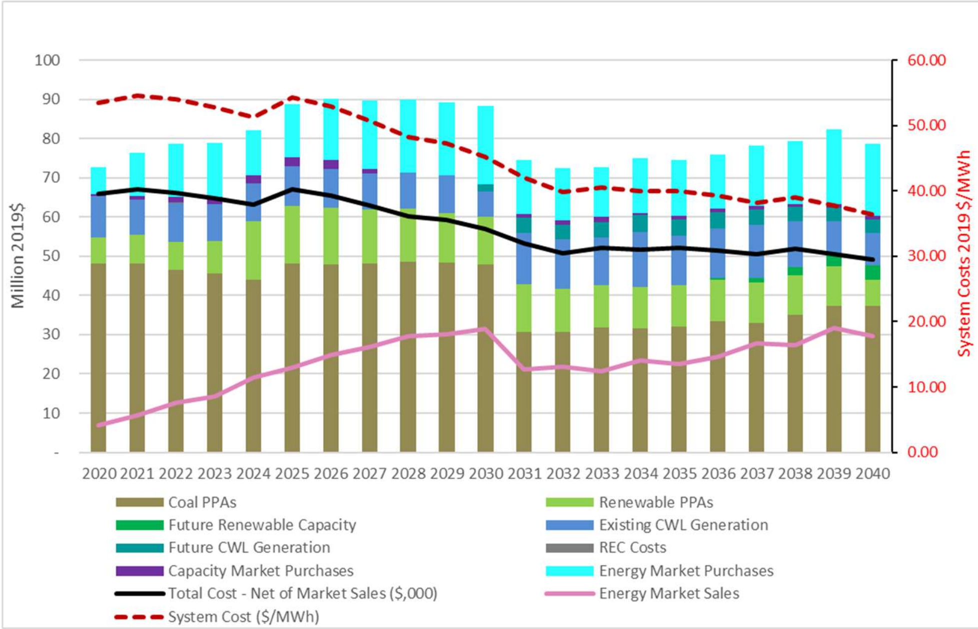
6.2.8.3 Portfolio Costs

The High Regulatory scenario has an NPV of $763.1 million dollars, $35.7 million higher than the Reference Case. The High Regulatory scenario also has higher costs than the Recession Scenario due to higher commodity prices. This scenario has forecast annual costs of $76.4 million in 2021 rising to a high of $90.1 million by 2026. Total costs decline in 2031 with the end of the Sikeston PPAs and annual costs falling to $74.4 million by 2031. Total costs increase gradually after 2032 with the capacity purchases and renewable generation.

Market sales are higher under this this scenario compared to the Reference Case both in volume and revenues due to larger excess generation and higher commodity and market prices.

Total costs net of market sales revenues falls from $66.9 million in 2021 to $50.7 million by 2031, $3.0 million higher than the Reference Case for the same year.

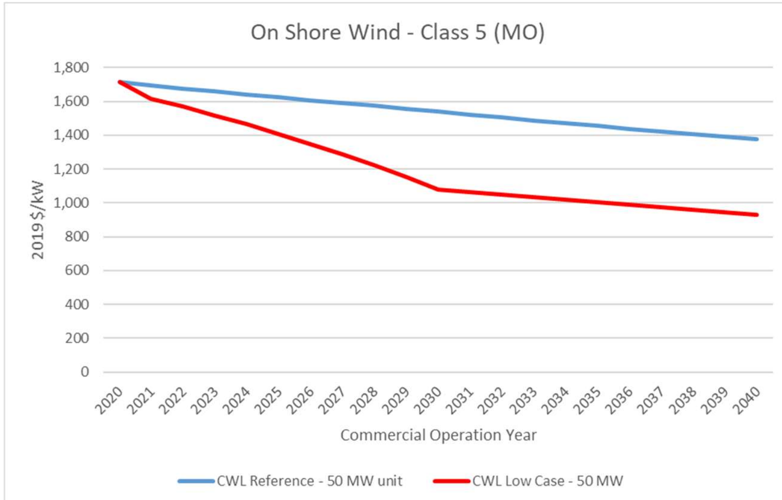
Figure 76: CWL Portfolio Costs by Source – High Regulatory Scenario

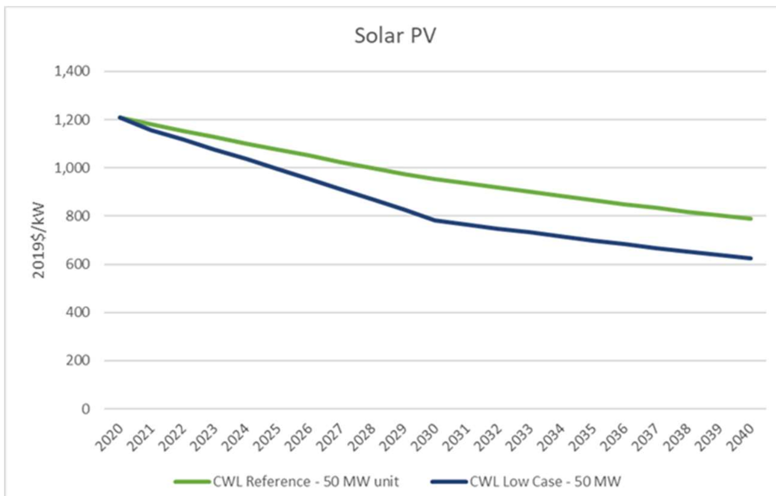


6.2.9 High Technology Scenario

The High Technology Scenario assumes further developments in renewable technologies, natural gas extraction and fracking, electric vehicles deployment, and energy efficiency. Renewables and battery storage technologies under this scenario follow improvements in efficiency, performance and capital costs costs from the 2020 NREL ATB Advanced technology innovation scenario. NREL describes this scenario as one where innovations that are far from market-ready today become successful and widespread in the marketplace. New technology architectures could look different from those observed today and public and private R&D investment is higher under this case. Assumed capacity factors are up to 3% higher compared to the Reference Case for wind technologies resource group 5 (TRG5), which is the most common resource in Missouri. Capacity factors for solar are up to 4% higher compared to the Reference Case. As a result, capital costs for new windfarms are 30% lower compared to the Reference Case, 18% lower for solar and 31% lower for battery storage by 2030. Figure 76 shows the assumed capital costs for renewables under the High Technology scenario and compared to the Reference Case.

Figure 77: Capital Costs Assumptions for Renewables – High Technology Case





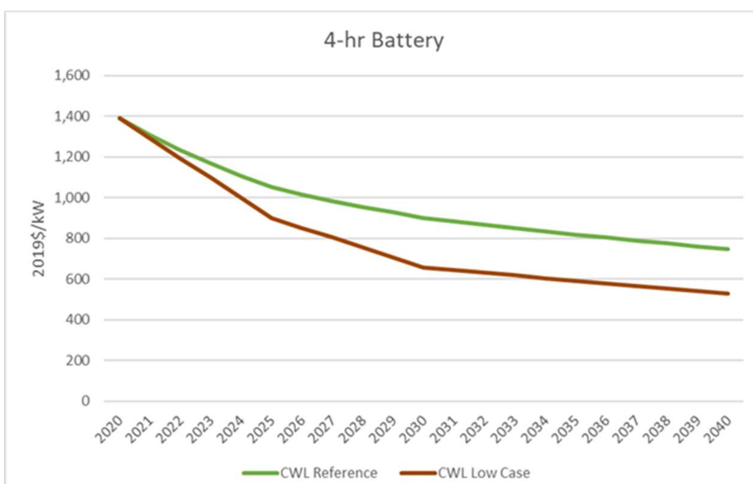
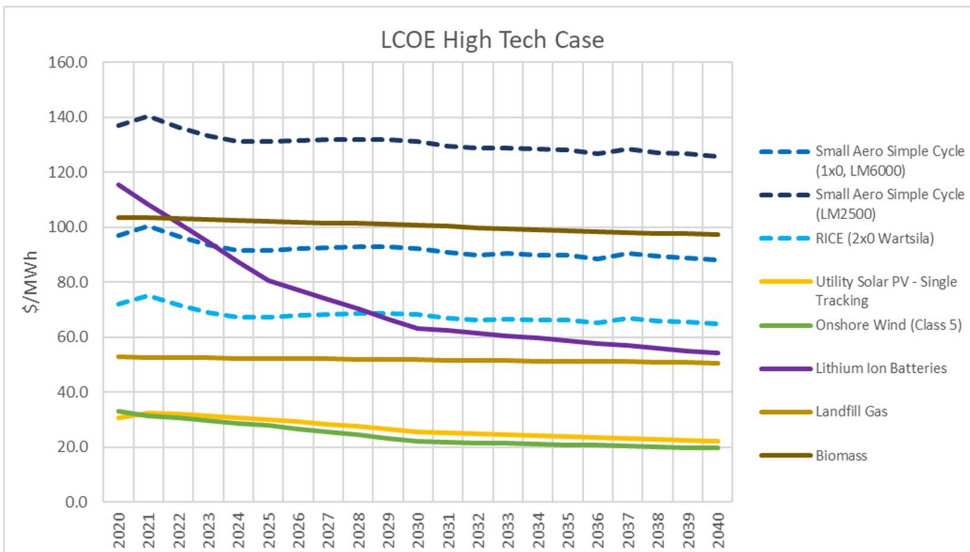


Figure 77 shows the resulting levelized costs of energy in $/MWh for all new technologies under this scenario. LCOE costs for renewables and battery storage are lower under this scenario improving their competitive advantage. As a result of the combined decline in capital costs and improved capacity factors wind gets a slightly lower levelized cost than solar in the long-term.

Natural gas resources also improve their competitive advantage with gas prices on average $1.25/MMBtu below the Reference Case in the long-term, driven by advancements in shale gas extraction.

The High Technology scenario also assumes high levels of energy efficiency, electrification, and penetration of Solar DG under base economic growth conditions. The resulting net load is 10.7% below the Reference Case by 2040, in line with the Early and Mid-renewable scenarios.

Figure 78: LCOE High Technology Scenario



6.2.9.1 Future Capacity Additions and Generation Mix

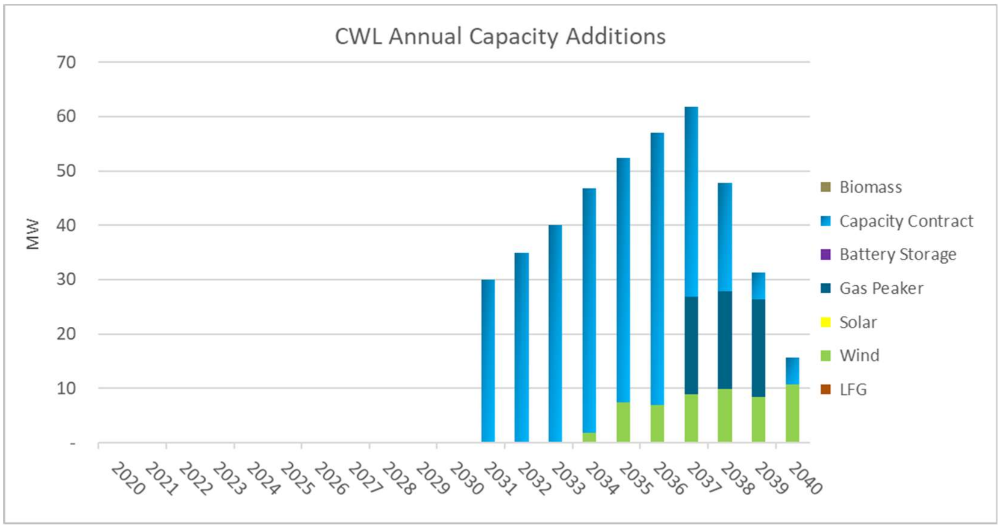
Figure 79 shows future generic capacity additions under this Scenario. These generation capacity additions are incremental to the new power purchase agreements (PPAs) signed by CWL.

The results of the generation expansion plan show 108 MW of new capacity additions through 2040, 51 MW below the Reference Case. One half of the capacity additions come from renewables, the lowest share among all the scenarios. All the new renewable capacity selected is wind. Annual renewable installations are in the range of 2 to 11 MW with new generation selected coming online until 2034. Renewable and net zero carbon targets are the same as the Reference Case with a 2050 goal.

Under this scenario, three 18 MW RICE gas peakers are selected with the first unit coming online until 2037. The relative higher penetration of new thermal generation under this scenario is driven by the low gas prices improving the competitiveness of RICE units.

Future capacity market purchases under this scenario vary in the range of 5-50 MW per year with the bulk of them happening in 2031-2037. These capacity purchases are found to be more economical than procuring or building further generation resources to meet MISO's planning reserve margin requirement.

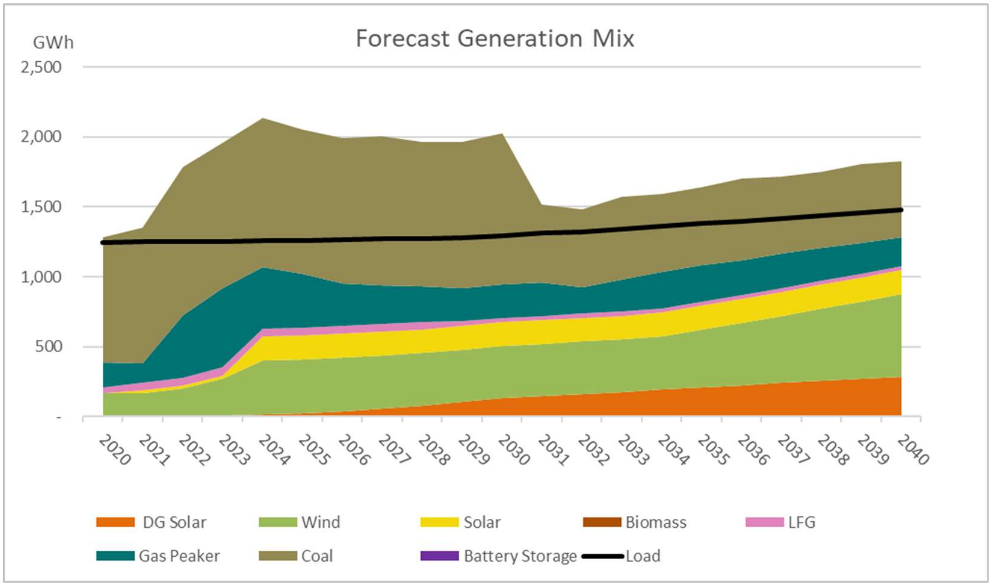
Figure 79: High Technology Scenario Future Capacity Additions



CWL existing coal-based portfolio switches to a renewable based portfolio in the long-term. Coal provides 69% of the load needs in 2021 (net of sales) falling to 27% of the total after the retirement of the Sikeston coal plant in 2030. Coal generation share continue falling in the 2030s displaced by new renewable generation to reach 14% of the total by 2040. In contrast, renewable generation share increases from 20% of the total in 2021 to 50% by 2024 with the commercial operation of the Boone-Stephens and Iron Star PPAs. Renewable share continues rising after 2024 due to the sustained reduction in load in this scenario and new renewable capacity additions to reach an interim target of 73% of load by 2040.

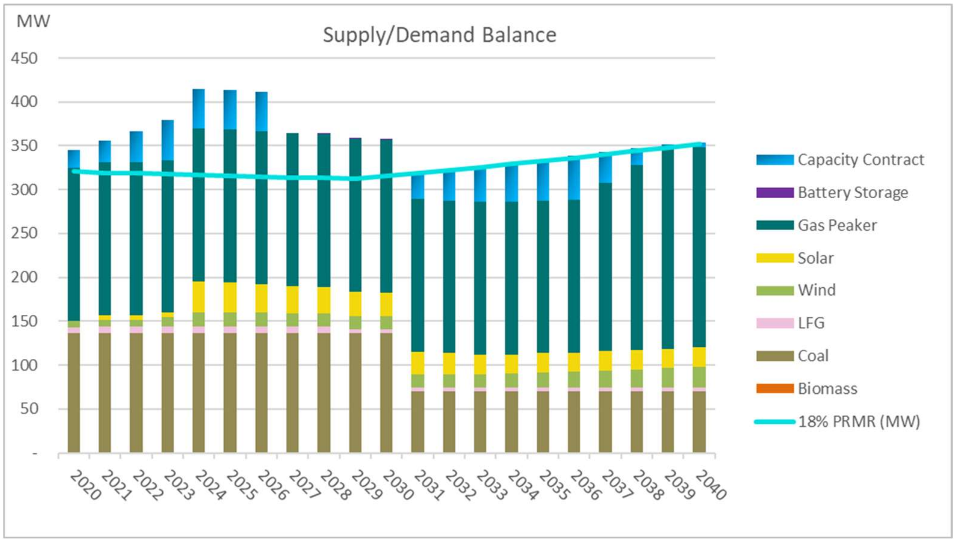
CWL own generation including the Columbia Energy Center contributes with a much higher share of the total generation under this scenario ranging from 11% to 45% of the total generation driven by the low gas prices with CWL assets running at higher capacity factors. As a result, the excess generation position starts early in 2021 compared to other scenarios, which increases rapidly with the decline in load and the commercial operation of the Boone-Stephens and Iron Star PPAs. Energy sales are the largest under this scenario accounting for over 30% of the total generation including the PPAs.

Figure 80: Future Generation Mix – High Technology Scenario



CWL has a long position not only in terms of energy but also in terms of capacity through 2030, as shown in Figure 81. The lower peak demand under this scenario drives a larger excess capacity position compared to the Reference Case. CWL existing generation fleet, contracted generation, and new generating capacity provides enough supply to meet MISO's 18% planning reserve margin requirement through the study period. Imbalances on capacity requirements are fulfill with capacity market purchases in the 2030s.

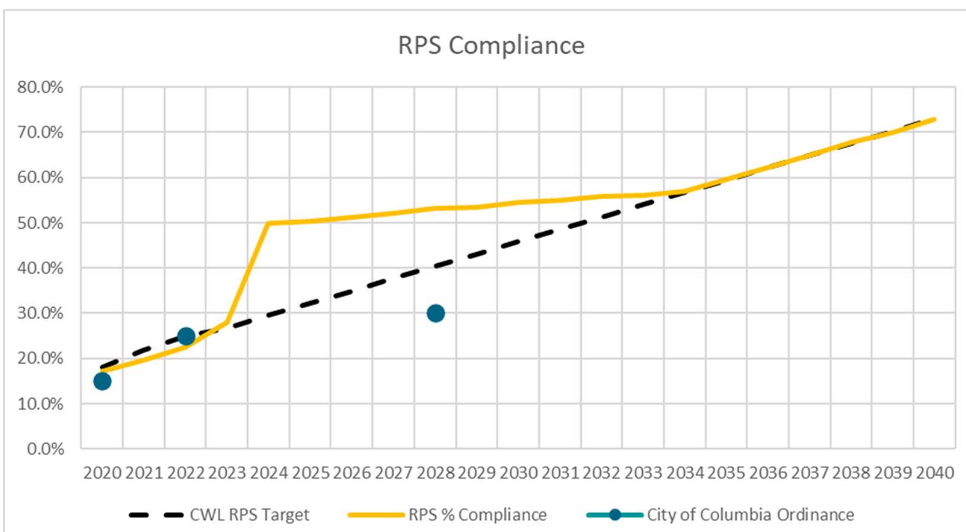
Figure 81: Future Capacity Balance – High Technology Scenario



6.2.9.2 Environmental Compliance

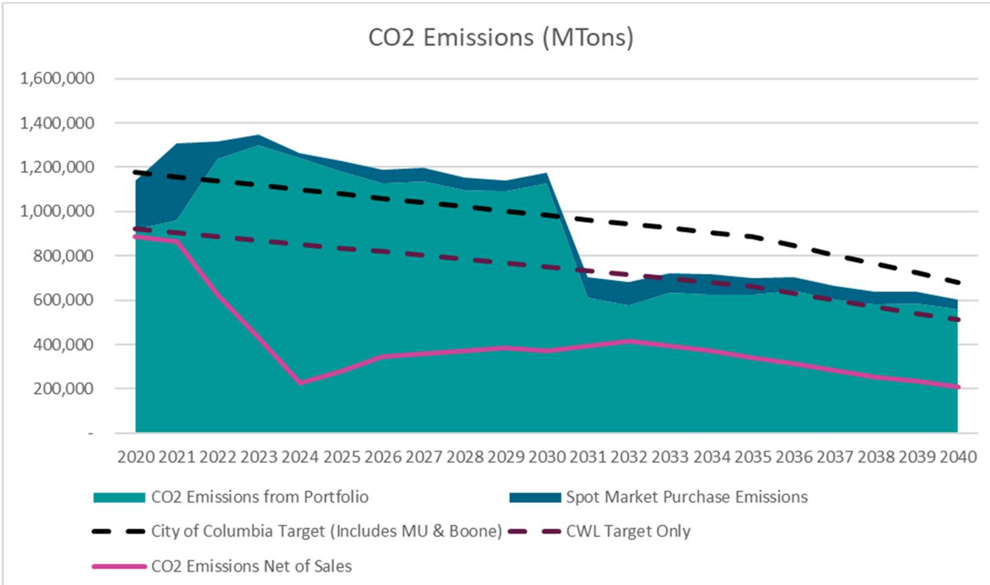
With the commercial operation of the Boone-Stephens and the Iron Star renewable PPAs, the share of renewable generation jumps from 28% in 2023 to 50% in 2024 and continue rising gradually through the mid-2030s with the sustained reduction in energy demand. After 2034, the new renewable capacity additions increase the renewable share to meet an interim 73% renewable target in 2040 on the road to the 100% target in 2050.

Figure 82: RPS Compliance – High Technology Scenario



CWL CO2 emissions from power generation including both emissions from CWL own generation portfolio and PPAs, including energy market purchases is shown on Figure 83. The emissions through the study period are compared to a linear path to reach 35% and 50% emissions reductions by 2035 and 2040, respectively for both the City and CWL. Portfolio emissions including market purchases stay above the targets through the 2020s and then fall after 2030 with the end of the Sikeston coal PPA, like other scenarios. However, accounting for the impact of market sales (pink line), net emissions are below the CWL target through the study period.

Figure 83: CWL Emission Reductions – High Technology Scenario



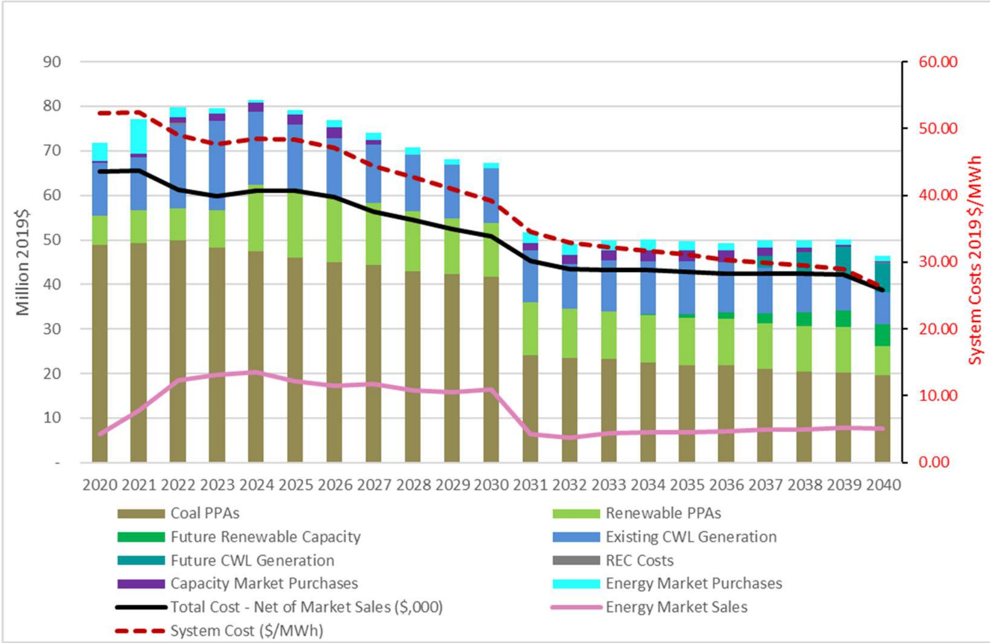
6.2.9.3 Portfolio Costs

The High Technology scenario has an NPV of $688 million dollars, $39.4 million below the Reference Case. The High Technology scenario has the lowest costs among all the scenarios. This scenario has forecast annual costs of $77.1 million in 2021 rising to a high of $81.3 million by 2024. Total costs decline in the second half of the 2020s driven by falling dispatch costs, coal PPAs volumes and expiring PPAs with annual costs falling to $51.6 million by 2031. Total costs stay relatively flat in the rest of the 2030s despite the new renewable capacity additions.

Market sales are among the highest under this this scenario in volume but not in revenues due to lower commodity and market prices.

Total costs net of market sales revenues fall from $65.5 million in 2021 to $45.2 million by 2031, $10.2 million below the Reference Case for the same year.

Figure 84: CWL Portfolio Costs by Source – High Technology Scenario



7 MISO vs. SPP Membership Assessment

This section of the IRP seeks to support CWL decision on whether is more economical to stay in the Midcontinent Independent System Operator (MISO) or join the Southwest Power Pool (SPP) RTO with a particular emphasis on the availability and potential costs of procuring new renewable resources and wheel the energy between RTOs, including significant transmission costs considerations.

7.1 Renewable capacity available for contracting

Siemens evaluated the availability of renewable capacity in both SPP and MISO, and the potential capacity available for procurement and potential PPA price ranges. Siemens's analysis indicates that both RTOs have sufficient capacity available to procure renewable energy, in particular wind resources which are the predominant renewable generation source in both regions. Solar generation has a very small share of both installed capacity and under construction compared to wind in both RTOs, but projects under development with applications for interconnection agreements show rising interest from developers to develop more solar in both regions.

Figure 85 shows the installed summer capacity by technology for both MISO and SPP. As of 2020, MISO had 23,349 MW of installed capacity compared to 20,953 MW in SPP. However, wind contributes with a much larger share of the total generation in SPP with 22.4% of the total generation in 2020 compared to 7% in MISO. Solar only contributed with less than 0.5% of the total in both RTOs with 1,565 MW installed in MISO and 413 MW in SPP.

Figure 85: Installed Summer Capacity in MISO and SPP

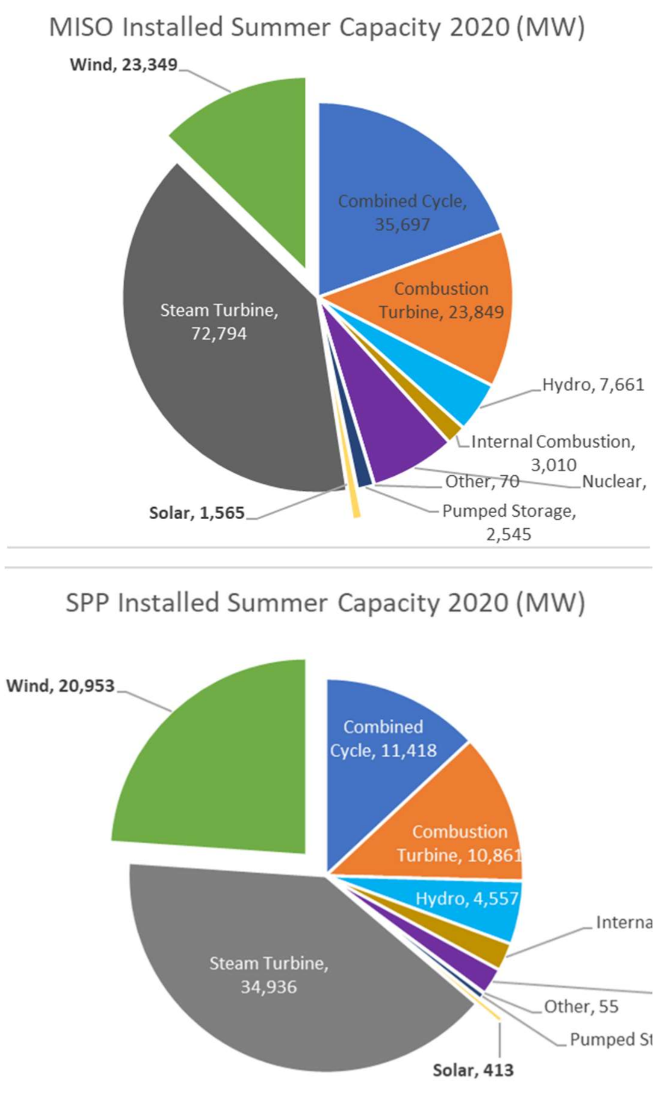
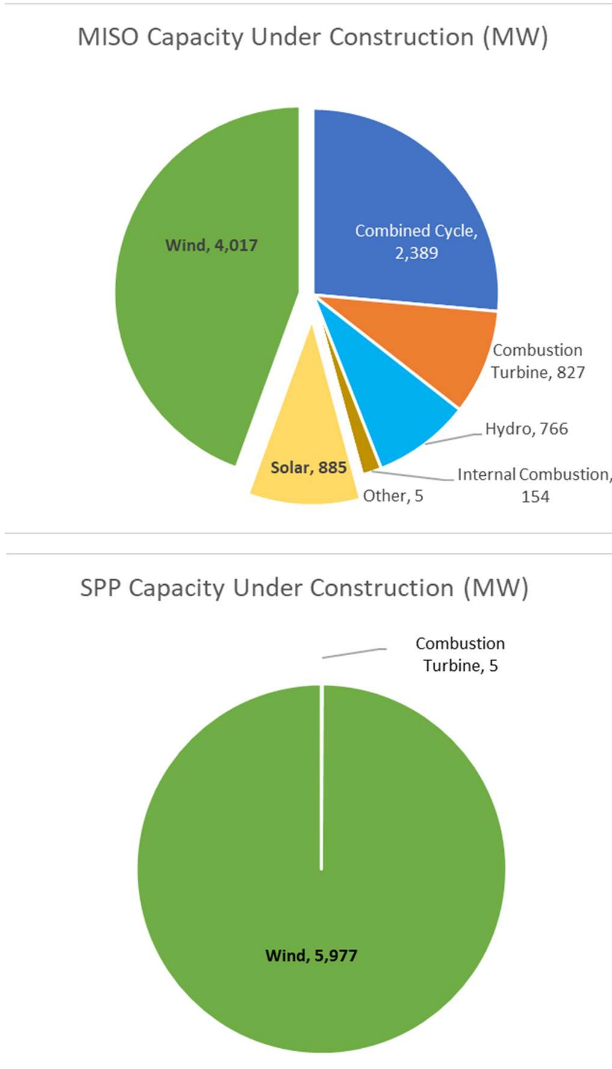


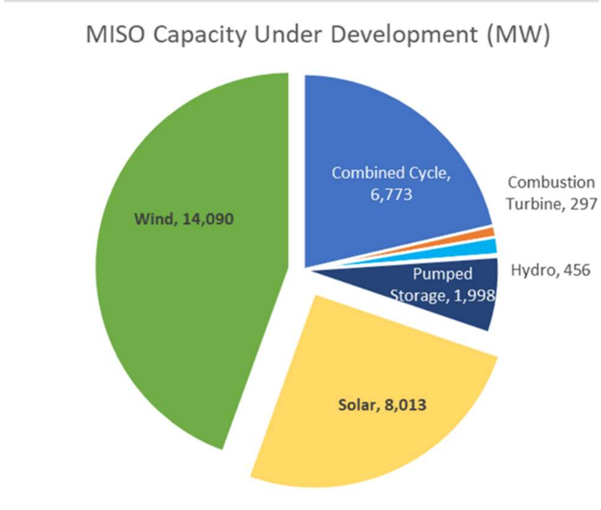
Figure 86 shows capacity under construction in both RTOs as of March 2021. In MISO wind represents 44% of total capacity under construction, and Solar 10% in MISO both combined contributing with over 50% of total capacity under construction. This is capacity expected to come online in the next few years with over 4,000 MW of additional wind capacity in MISO and near 6,000 MW in SPP. In SPP nearly 100% of the capacity is wind. In MISO there is over 800 MW of solar under construction. Just in Missouri, a total of 997 MW of wind is under construction.

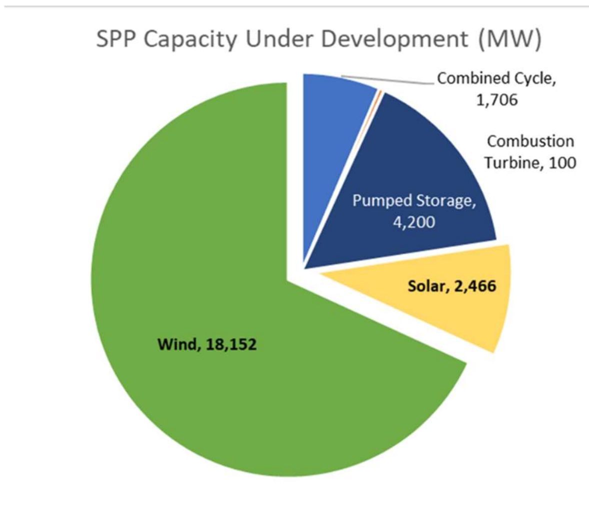
Figure 86: Capacity under construction in MISO and SPP



Siemens also evaluated the capacity under development in both RTOs. That is for projects under feasibility studies, in the process of getting financed or announced with applied interconnection agreements. As shown on Figure 84, in MISO 70% of the planned capacity are renewables with 14,000 MW of wind and 8,000 MW of solar. In SPP 77% of the planned capacity are renewables with over 18,000 MW of wind and near 2,500 MW of solar. Clearly the intend of developers is to increasingly focus on renewables and develop more solar in both RTOs. The capacity under development will pass the installed capacity for solar in both RTOs if they become a reality, keeping under consideration that solar projects can be constructed in two years and wind over a three-year period.

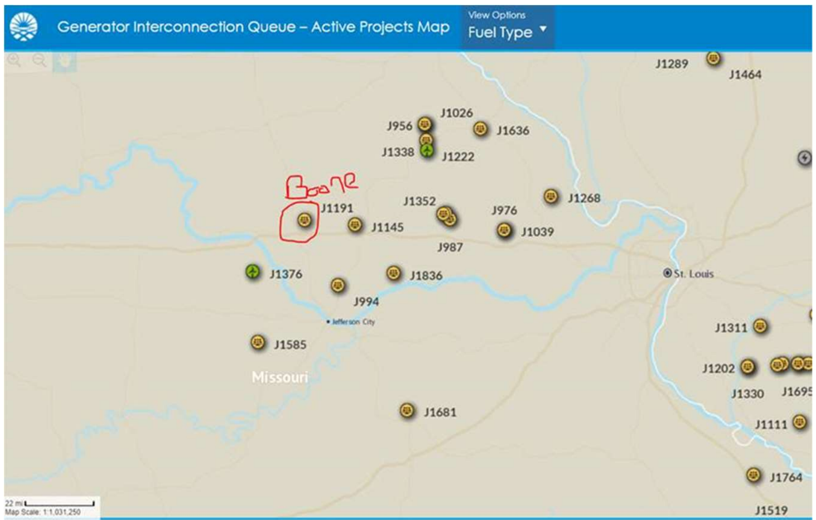
Figure 87: Capacity Under Development (in the Queue) in MISO and SPP (MW)





MISO's interconnection queue for projects in relative proximity to Columbia shows 2,414 MW of capacity under development, mostly solar projects (2,164 MW). The projects range in size from 64 to 300 MW including the 64 MW Boone Stephens (ID: J1191) solar project, planned to be interconnected to the Boldstad 69 kV substation and provide generation to CWL starting in 2024. In line with the Reference Case and most scenarios, solar appears to be the renewable technology of choice in the short to medium term for CWL.

Figure 88: Location of renewable projects in MISO's interconnection Queue



In MISO, 52% of the installed renewable capacity is merchant with 66% of that share contracted with a PPA. In MISO only 15% of the regulated capacity is available for contracting with most of the capacity used to serve utilities' own load needs. In SPP, 90% of renewable capacity is merchant with 76% of that under contract. Only 6% of the regulated capacity is available for contracting in SPP. At first sight, over 5,800 MW of renewable capacity is available for contracting in MISO and over 4,700 MW in SPP.

In terms of future capacity, over 90% of the renewable capacity under development in both RTOs are merchant capacity. In MISO 18% of the renewable capacity under development has a PPA signed and in SPP 14%, meaning that most of the merchant capacity under development is still available for contracting, assuming the projects become a reality (see

Table 20). Given that both RTOs are large regions, contracting depends on resource location, PPA costs and transmission costs.

Table 20: Existing and Future Renewable Capacity under contract in MISO and SPP (MW)

Wind and Solar Capacity	MISO **	SPP
Existing Capacity		
Total Installed Capacity (Nameplate) (MW)	23,131	21,238
Total Merchant Capacity	12,042	19,173
Merchant Capacity Contracted	7,890	14,536
Share of Merchant Capacity Contracted	**66%**	**76%**
Total Regulated Capacity	10,831	2,065
Regulated Capacity not Contracted *	1,675	131
Share of Regulated Not Contracted	**15%**	**6%**
Total Capacity Available for Contracting	**5,826**	**4,768**
Future Capacity		
Total Planned Capacity (MW) ***	27,812	25,686
Planned Capacity Under Construction	4,956	6,124
Merchant Capacity	25,512	24,591
Merchant Capacity Contracted	4,528	3,368
Share of Future Merchant Contracted	**18%**	**14%**

* Most capacity available from regulated utilities is used to supply their own load needs

** MISO reports 258 MW as Foreign not included in the table

*** Planned Capacity may include additional units to existing generating sites

7.2 Potential PPA Prices for New Renewables

A review of recent limited PPA bids in both regions for wind resources show that PPAs at SPP are offered at lower prices. However, in MISO, PPA prices could vary significantly by regional location with higher prices in Illinois compared to Minnesota or Missouri as shown on Table 21. The Levelized Cost of Energy (LCOE) for new solar and wind generation coming online in 2022, as evaluated for the long-term capacity expansion plan for CWL is within the range of the new PPAs in MISO.

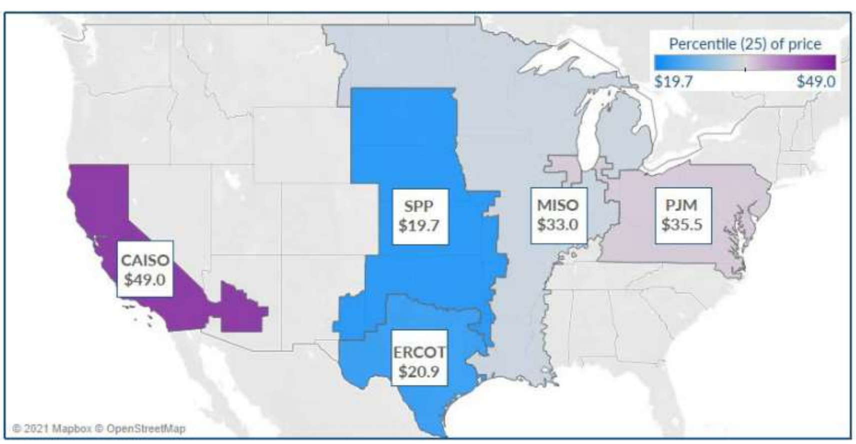
Table 21: Sample Proposals for Wind in MISO and SPP

Technology	Zone	Size (MW)	Term (yrs.)	Energy Charge $/MWh	COD
Wind	MISO Illinois	180	12	$40.00	n.a
Wind	MISO Illinois	190	12	$42.00	Dec-2023
Wind	MISO MN	414	12	$25.00	Dec-2022
Wind	MISO MN	275	12	$30.00	n.a
Wind	MISO MN	206	12	$24.00	n.a
Wind	SPP North	200	12	$19.00	n.a
Wind	SPP South	330	12	$18.00	Dec-2022
Wind	SPP South	200	12	$19.00	Dec-2022
Wind	SPP South	297	15	$19.00	n.a
LCOE Wind	MISO - Zone 5	50	N/A	$34.00	2022
LCOE Solar	MISO-Zone 5	25	N/A	$34.20	2022

Siemens also review other industry references for PPA prices in MISO and SPP. LevelTen Energy® publishes a quarterly PPA Index across the US. The index provides the 25th percentile price index (i.e. 25% of the PPA monitored had lower prices) for renewables across different regions of the U.S. The Wind PPA Index has value of $19.7/MWh for SPP and $33/MWh for MISO, very similar to the prices evaluated by Siemens for selected offers, confirming that wind generation in SPP could be ~ $13/MWh lower than in MISO (Figure 89). The Iron Star wind PPA signed by CWL is within the range shown for PPAs in SPP.

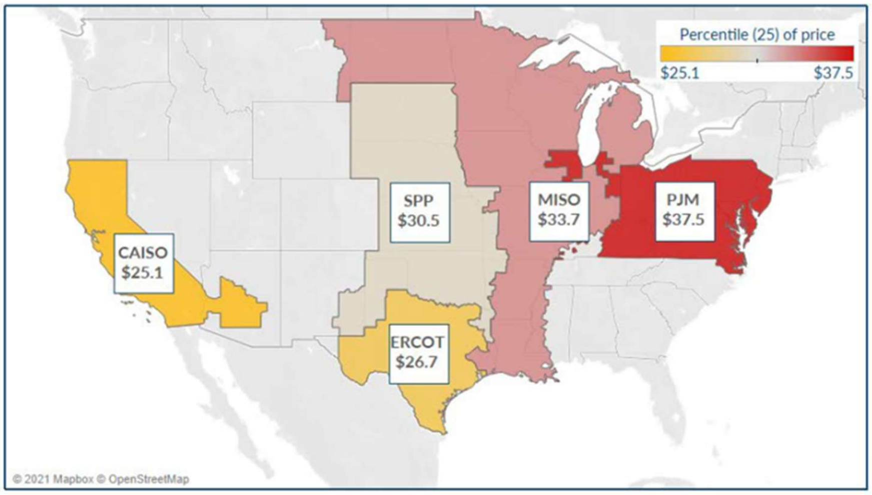
However, the PPA Index for solar projects shows a smaller difference with PPAs in MISO at $33.7/MWh compared to $30.5/MWh in SPP, only $3/MWh lower. The Boone Stephens solar PPA signed by CWL is within that range. Most of the expansion plans assessed under the IRP have a larger composition of new Solar.

Figure 89: Wind PPA Prices (25th percentile $/MWh)



* Source LevelTen Energy Q2020 Report

Figure 90: Solar PPA Prices (25th percentile $/MWh)



* Source LevelTen Energy Q2020 Report

7.3 Transmission Cost Considerations

Transmission customers need to pay for the transmission system they use and for administrative fees charged by the independent system operator. The transmission charges have different components which vary depending on the direction of the energy flows with a set of charges if the energy is flowing from delivery and receipt points within the ISO to a set of charges for a delivery point outside the ISO. Siemens evaluated two cases, one in which CWL belongs to MISO and resources are in MISO (case 1), and another case in which PPA resources are located in SPP (case 2).

Case 1 (resources in MISO) charges include the following:

- A Network Integration Transmission Service: a charge to cover the Annual Transmission Revenue Requirement of the transmission assets in a zone, which are charged as a function of the coincident peak. SPP uses the (Schedule 9) plus a zonal charge (Schedule 11) to cover aggregated transmission costs.
- Network Upgrade Charge: A charge to cover the shared transmission investments in the Zone. MISO uses Schedule 27.
- ISO Cost Recovery: a charge to cover the costs of the ISO to provide the services to the members and a FERC charge (Schedule 10 for MISO, and Schedule 1, Schedule 1A and Schedule 12 for SPP)

Case 2 (resources in SPP) charges typically include:

- A firm Point to Point (PtoP) transmission rate calculated to deliver the power from the neighboring ISO (SPP) to the ISO where the Transmission Customer is located (MISO). Schedule 7 in SPP.
- Interruptible PtoP charge. Schedule 8 in SPP which is sometimes used for renewable resources to lower costs.
- The PtoP can be complemented with a Zonal Charge for through flows (Schedule 11b in SPP)

- ISO Cost Recovery: a charge to cover the costs of the ISO to provide the services to the members (Schedule 10 for MISO and Schedule 1 and Schedule 1A for SPP), which includes a FERC assessed component.

CWL currently procures most of its energy from MISO. However, it has two PPA's outside the MISO footprint, the Iatan 20 MW Coal PPA located in SPP and the Bluegrass 6.3 MW wind project in AECI. CWL's related transmission costs paid to both MISO and SPP are in the order of $3.7 million combined with 77% of the costs paid to MISO and 13% to SPP. Most of these costs (88%) come from actual network transmission charges while the balance are ISO and FERC costs (see Figure 91).

Figure 91: CWL Transmission Costs 2020

Switching from MISO to SPP will change this situation. CWL will stop being a MISO member and would have to pay PtoP rates for the PPAs that remains in MISO, which are most of the existing contracts including the Sikeston and Prairie State coal PPAs, and the Crystal Lake and Iron Star wind PPAs. Using published MISO Rates (as of March 2021) Siemens estimated that for firm PtoP Drive-Through and Out the cost is $44,857/MW-yr. Thus, Siemens estimate a wheeling PtoP cost of $8.06/MWh for the Coal PPA's considering its average capacity factor of 65% and 100% firm capacity availability. In the case of renewables, given its lower capacity factor, it is more effective to do a combination of Firm PtoP and Interruptible which would cost around $5.12/MWh for the interruptible piece and $22.35 for the firm portion. Assuming a blend of 30% firm and 70% interruptible with a 33% average combined capacity factor for solar and wind, Siemens estimates that CWL would have to pay a weighted average wheeling PtoP cost of $10.29 /MWh, as shown on Table 22.

These charges could decline overtime as new PPAs are added within SPP territory, and the Coal PPA's are sold to MISO's market rather than being delivered to the CWL Load. These costs need to be compared with the potential benefit of lower PPA prices.

If CWL were to move to SPP would have to pay PtoP rates to MISO for the Coal PPA's located there (Sikeston and Prairie State) and for the renewable PPAs (the Crystal Lake contracts, and Iron Star wind). Using published MISO Rates (as of March 2021) for firm PtoP Drive-Through and Out is $44,857/MW-yr. We estimate a wheeling PtoP cost of $8.06/MWh for the Coal PPA's based on a combined average capacity factor of 61% and 100% firm capacity. For renewable, given its lower capacity factor it is more effective a combination of Firm PtoP and Interruptible (~$5.12/MWh). With a blend of 30% firm and 70% interruptible and 33% capacity factor (solar + wind), we estimate that CWL would have to pay a wheeling PtoP cost of $10.29 /MWh.

If CWL were to stay in MISO, as appears to be the case, then it would have to pay PtoP transmission rates to SPP for the renewable contracted in SPP. In general, the wheeling charges from SPP to MISO are lower than in the reverse direction and this is estimated to be upwards of $5 /MWh (including interruptible) thus eroding on the potential savings from contracting in SPP down from $13/MWh (as discussed earlier) to around $8/MWh or below.

Table 22: Wheeling Point to Point Transmissions cost charges in MISO if CWL joins SPP

Coal $/MWh @ Capacity Factor =		61%
Firm $/MWh	Interuptible $/MWh	Blended $/MWh
8.35	N/A	8.35
Renewable $/MWh @ Capacity Factor =		32%
Firm $/MWh	Interuptible $/MWh	Blended $/MWh
22.35	5.121	10.29

Siemens evaluated the potential savings for CWL of joining SPP instead of staying in MISO, in terms of contracting new renewable generation in SPP compared to incremental wheeling charges of moving the energy from the existing PPAs in MISO to SPP and sink into load.

In the case of the Reference Case, CWL is expected to require most of the coal generation throughout of the planning period to be delivered to the load and require PtoP wheeling if CWL were to join SPP. The only exception is during the period 2021 to 2030 where some surplus energy from Sikeston energy could be sold into MISO's market. In the Reference Case the new solar and wind capacity purchases occur after 2030, reducing the impact of the potential lower PPA costs in SPP at around $13/MWh assumed for screening purposes based on the observed differences in PPA prices for wind in SPP vs. MISO. Based on the above we observe that potential wheeling costs far exceed the potential savings from lower PPA prices by joining SPP. The PPA costs savings comprises only 10% of the incremental wheeling costs under the Reference Case, as shown on Table 23.

Among the scenarios, under the Early Renewable scenarios CWL has the most potential to benefit from joining SPP with 100% of the load being supply by renewable generation in 2030. Coal sales to the market are maximized with minimal requirements to deliver coal to the CWL load. In these scenarios the solar and wind capacity purchases occur much earlier (by 2030) and results in maximum impact of the potential lower cost in SPP. Wheeling costs are lower while the PPA costs savings are higher due to the amount of renewables. These scenarios still have a savings to cost ratio of bit under one (0.89-0.93) indicating that the switch is risky as it could result in higher cost than the potential savings.

Table 23: Cost-Benefit Analysis of Joining SPP and contracting New Renewable Capacity ($000)

Item	Reference Case	Early Renewable 2030	Early Renewable 2030 w/ High CO2	Mid Renewable 2040 (1st Plan)	Mid Renewable 2040 (2nd Plan)	High Seasonal Load	Recession Scenario	High Tech Case	High Regulatory Case
Energy Delivered (GWh)									
Coal PPAs in MISO to load	6,407	3,012	3,089	5,223	5,643	6,103	4,881	3,263	5,822
Renewable PPAs in MISO to load	4,104	4,095	4,097	4,100	4,102	4,104	4,104	4,093	4,100
SPP to MISO Wheeling Costs (NPV)									
Coal PPAs in MISO	$53,506	$25,156	$25,797	$43,621	$47,129	$50,970	$40,761	$27,251	$48,619
Renewable PPAs in MISO	$42,223	$42,135	$42,150	$42,181	$42,203	$42,223	$42,223	$42,112	$42,185
Total Wheeling Costs	**$95,729**	**$67,291**	**$67,947**	**$85,802**	**$89,332**	**$93,193**	**$82,984**	**$69,363**	**$90,805**
New Renewable Generation (GWh)	709	4,804	4,672	2,432	1,928	1,334	689	312	143
PPA Costs Savings ($13/MWh)	**$9,215**	**$62,455**	**$60,733**	**$31,621**	**$25,060**	**$17,338**	**$8,962**	**$4,053**	**$1,859**
Savings / Cost Ratio	0.10	0.93	0.89	0.37	0.28	0.19	0.11	0.06	0.02

The Mid Renewable scenarios have higher costs to savings ratio than the Reference Case but lower compared to the Early Renewable Scenarios coming from lower wheeling costs for the coal PPAs but greater PPA costs savings (compared to the Reference Case) driven by higher penetration of renewables and lower needs to sink the coal PPAs energy to load.

The rest of the scenarios show low savings to cost ratios for joining SPP. In the High Seasonal Load scenario there is about the same amount of coal generation delivered to the CWL load and while there are more renewable purchases, most of them happen late in the planning period with only 20 MW of solar entering in 2022. Wheeling costs for coal PPAs are near the levels of the Reference Case driven by a larger need to use them to serve load.

In the recession economy there are higher coal sales to market because of lower load but most of the renewable enters after 2030, with some limited solar (13 MW) entering in 2022. The High Technology and Regulatory scenarios have the lowest cost savings ratios due to limited savings from new renewable PPAs and lower new renewable generation.

Thus, Siemens recommends for CWL to stay at MISO primarily due to the transmission costs and wheeling charges. The costs of delivering energy from MISO to SPP are larger than the savings of joining SPP with existing Point to Point transmission charges, under most scenarios of the IRP. The analysis assumes that all new incremental renewable generation to meet the RPS targets are procured in SPP at lower PPA prices. Administrative and membership fees on both RTOs account for 12-13% of total charges and should not be the driving decision factor.

8 Value of Solar Study

8.1 Introduction

Utility Financial Solutions, LLC (UFS) as part of the Siemens team was engaged to provide guidance on the valuation of Solar for the City of Columbia Water & Light (CWL). UFS used the avoided cost / utility savings methodology to calculate the values, considering short-run marginal costs. The savings were calculated by solar weighted market pricing, variable transmission costs, predicted capacity purchases savings plus distribution system loss savings. The purpose of this report is to identify the average kWh value of electricity produced by customer installed fixed array rooftop solar. There are many factors and considerations for calculating the current and potential future value of solar. UFS recommends that the value be updated annually and updated as a part of the CWL rate making process or as significant assumptions change.

8.2 Summary Assumptions

The study was carried out under the following assumptions

- The following Solar Value Components to be assessed:
  - Average kWh Delivered - Energy Value (CWL hourly node pricing for 2020)
  - Average kWh Delivered - Capacity (Yearly Coincident Peak to MISO -1 CP- x 6 year average annual auction)
  - Average kWh Delivered - Transmission - Delivery (Monthly Utility Peak -non coincident with MISO - 12 NCP peak - based variable transmission)
  - Average kWh Delivered - Transmission - Delivery (26-A volumetric kWh based variable transmission)
- All of the value components above to be increased by the average distribution system loss of 2.64% (CWL Provided).
- Solar production profile was based on irradiance data for the CWL area obtained from National Renewable Energy Laboratory (NREL) system advisory modeling.
- Solar production estimates from NREL modeling were used to calculate the solar production impacts on the value components above.
- The calculated values of solar assumes a buy-all-sell-all or equivalent metering and billing methodology. Other metering and billing methods may result in utility cost over or under recovery.
- Smaller vs. Large solar defined by state and/or CWL policy.

- The table below shows the seasons considered in the study.

Table 24: Seasons considered in the study

Note: Seasons taken from CWL rate schedules	
January	Non-summer
February	Non-summer
March	Non-summer
April	Non-summer
May	Non-summer
June	Summer
July	Summer
August	Summer
September	Summer
October	Non-summer
November	Non-summer
December	Non-summer

8.3 Summary of Findings

For smaller, customer installed rooftop fixed array solar the value of solar was calculated to be 2.8 cents per kWh as detailed in the table below. The detail calculations and assumptions used in the analysis are listed in the subsequent sections of this report.

Table 25: fixed array: Value Breakdown

Solar NREL Fixed Roof Mount 7.95 KW DC With Loss Savings (behind customer meter)		
Annual	per kWh	
$ 265.20	$ 0.02422	Energy Value (CWLD hourly node pricing for 2020)
$ 16.98	$ 0.00155	Capacity (1 CP x 6 year average annual auction)
$ 3.31	$ 0.00030	Transmission - Delivery (12 NCP peak based variable transmission)
$ 19.43	$ 0.00178	Delivery (26-A volumetric kWh based variable transmission)
$ 304.92	$ 0.02785	Total Average kWh Value

Large solar installs (as defined by CWL policy) should be valued on a per case basis, the energy savings value portion of is expected to be 2.4 cents per kWh, as shown above.

8.4 Value Components Description

8.4.1 Energy Value (CWL hourly node pricing for 2020)

CWL sells excess energy and buys energy when they are short from their local market node CWLD. This node is priced on an hourly basis. The 2020 hourly market pricing was used to calculate the solar weighted value of the market. The solar weighting was calculated by using the NREL modeling for predicted hourly solar production. This hourly solar production was then compared to the hourly market pricing. This was weighted by the respective solar production and averaged for the total 2020 year. A sample of the hourly market node pricing is provided in the Assumptions / Project Approach sub-section later in this report. This should be updated and recalculated as market conditions materially change (normally annually at a minimum).

8.4.2 Capacity (1 CP x 6 year average annual auction)

CWL sells all of their capacity resources into the market. They also buy back all of their capacity requirements from the market. CWL provided six years of historical capacity closing prices for their annual auction. CWL is required to maintain capacity resources as a function of their annual, single hourly utility coincident peak to MISO. This is referred to as a 1 CP. This is a once per year look at the CWL load contribution to the highest MISO annual zonal peak. MISO annual peak is typically in August hour ending 17 as shown later in this report. This hour was used to compare to the NREL modeling solar production to calculate the ability for solar production to contribute to reducing the CWL single annual coincident peak. As a result, this respective solar production would have value to the extent that it may allow CWL to purchase less capacity if they are capacity short (or sell more if they are capacity long) at the annual auction. This solar production at the time of the 1 CP was then multiplied by the six year average capacity closing price to calculate the impact that the average solar production would contribute to the capacity purchase avoidance.

8.4.3 Transmission - Delivery (12 NCP peak based variable transmission)

CWL is billed for a variety of transmission (or wholesale power delivery) charges. The study looked at the two variable charges from the actual CWL transmission bills. The two variable charges were the 12 NCP (utility monthly peak KW based), and the schedule 26-A which was volumetric kWh based. The 12 NCP peak based charges look at the actual monthly peak demand set by CWL and base these charges on this monthly peak. To the extent that solar production timing can reduce the CWL monthly peaks, the respective KW based peak charges were passed along to the solar value.

8.4.4 Delivery (26-A volumetric kWh based variable transmission)

As mentioned above, CWL is billed for a variety of transmission (or wholesale power delivery) charges. The study looked at the two variable charges from the actual CWL transmission bills. The two variable charges were the 12 NCP (utility monthly peak KW based), and the schedule 26-A which was volumetric kWh based. The 26-A volumetric charges consider that the total solar production will contribute to save on this transmission charge. To the extent that all solar production can reduce the CWL monthly total purchased kWh, the respective volumetric charges were passed along to the solar value.

8.4.5 Effect of Local Transmission and Distribution losses in the kWh Value

All of the value components above were summed and individually increased to recognize the reduction in losses. The idea is that solar produced and used immediately on premise behind the customer meter would increase in value due to the savings from the distribution system losses being avoided. Average distribution system loss of 2.64% was used (CWL Provided). As a result, all of the value components in Table 25 were increased by 2.64% in the respective final calculated values. This is a generous increase in the calculated values since it is typical that 50% of residential solar production gets pushed back to the utility grid in excess of their needs, also the effect in capacity losses is different than the effect in energy losses unless the load factor is unity. The send back of power is caused by the timing of the solar production not aligning with the customer actual timing of their usage needs. The exported solar will incur distribution system losses as it is delivered throughout the grid. This study passes the full distribution system loss savings to the solar customer as if they used all of the solar production behind their meter. The table below provides details on the calculation of the sys

Table 26: Local Transmission and Distribution Losses Calculation

Process	
Estimate street light and dusk to dawn light usage according to wattage per hour of runtime	
Add Customer Usage from metered sales information	
Compare to Total System Energy Usage from Tie Line and Generation Information	
Dusk to Dawn Light Usage (Converted to MWH from KWH)	2,089
Street Light Usage (Converted to MWH from KWH)	6,530
Metered Customer Sales (Converted to MWH from KWH)	1,146,687
Total Customer Usage	1,155,306
Total System Load from Tie Lines	1,186,649
Real System Usage Percentage	97.4%
System Losses Estimate	2.6%

8.5 Value Determinations

The section that follows details the calculations and assumptions used to determine the value of Solar . The avoided cost was calculated using a short-run marginal cost methodology. This includes weighting the variable power supply cost savings plus increased for average 2.64% local transmission and distribution system loss savings. The energy value was based on the CWL node pricing.

8.5.1 Energy Value

Energy savings were based on timing of solar production compared to CWL hourly node pricing for 2020. CWL sells excess energy and buys energy when they are short from their local market node CWLD. This node is priced on an hourly basis. The 2020 hourly market pricing was used to calculate the solar weighted value of the market. The solar weighting was calculated by using the NREL modeling for predicted hourly solar production. This hourly solar production was then compared to the hourly market pricing. This was weighted by the respective solar production and averaged for the total 2020 year. A sample of the hourly market node pricing is shown below. This should be updated and recalculated as market conditions materially change (normally annually at a minimum).

Table 27: Sample of Market Hourly Data

From file: CWLD DA RT LMPs Apr 2005 - current.xlsx				M-F = 2-6		
Date	Year	Month	Day	Weekday	HourEnd	CWLD DA LMP
12/30/2020	2020	12	30	4	1	19.53
12/30/2020	2020	12	30	4	2	20.34
12/30/2020	2020	12	30	4	3	22.66
12/30/2020	2020	12	30	4	4	24.07
12/30/2020	2020	12	30	4	5	27.48
12/30/2020	2020	12	30	4	6	27.21
12/30/2020	2020	12	30	4	7	31.36
12/30/2020	2020	12	30	4	8	28.33
12/30/2020	2020	12	30	4	9	25.97
12/30/2020	2020	12	30	4	10	26.45
12/30/2020	2020	12	30	4	11	27.35
12/30/2020	2020	12	30	4	12	19.8
12/30/2020	2020	12	30	4	13	18.68
12/30/2020	2020	12	30	4	14	18.39
12/30/2020	2020	12	30	4	15	18.54
12/30/2020	2020	12	30	4	16	18.47
12/30/2020	2020	12	30	4	17	19.63
12/30/2020	2020	12	30	4	18	24.5
12/30/2020	2020	12	30	4	19	24.28
12/30/2020	2020	12	30	4	20	22.78
12/30/2020	2020	12	30	4	21	22.68
12/30/2020	2020	12	30	4	22	22.28
12/30/2020	2020	12	30	4	23	20.62
12/30/2020	2020	12	30	4	24	19.97
12/31/2020	2020	12	31	5	1	18.81

8.5.2 Capacity Value

The capacity value was calculated by comparing solar production to the yearly MISO Coincident Peak (1 CP) times the 6 year average annual capacity auction price. CWL sells all of their capacity resources into the market. They also buy back all of their capacity requirements from the market. CWL provided six years of historical capacity closing prices for their annual auction. CWL is required to maintain capacity resources as a function of their annual, single hourly utility coincident peak to MISO. This is referred to as a 1 CP. This is a once per year look at the CWL load contribution to the highest MISO annual zonal peak. MISO annual peak is typically in August hour ending 17 and this hour was used to compare to the NREL modeling solar production to calculate the ability for solar production to contribute to reducing the CWL single annual coincident peak. As a result, this respective solar production would have value to the extent that it may allow CWL to purchase less capacity if they are capacity short (or sell more if they are capacity long) at the annual auction. This solar production at the time of the 1 CP was then multiplied by the six year average capacity closing price to calculate the impact that the average solar production would contribute to the capacity purchase avoidance.

Table 28: Capacity Value – fixed solar only shown

Capacity based on utility coincident peak (1 CP) vs. MISO Summer Peaks							
Month	Season	Peak Day	Peak Hour Ending	Effective monthly per KW	Solar Production at Peak	Extended Value	Effective monthly per KW
January	Non-summer	1	USE 1 CP HE from August	$ 0.54	2.55	$ 1.38	$ 0.54101
February	Non-summer	1	USE 1 CP HE from August	$ 0.54	2.55	$ 1.38	$ 0.54101
March	Non-summer	1	USE 1 CP HE from August	$ 0.54	2.55	$ 1.38	$ 0.54101
April	Non-summer	1	USE 1 CP HE from August	$ 0.54	2.55	$ 1.38	$ 0.54101
May	Non-summer	1	USE 1 CP HE from August	$ 0.54	2.55	$ 1.38	$ 0.54101
June	Summer	1	USE 1 CP HE from August	$ 0.54	2.55	$ 1.38	$ 0.54101
July	Summer	1	USE 1 CP HE from August	$ 0.54	2.55	$ 1.38	$ 0.54101
August	Summer	1	17	$ 0.54	2.55	$ 1.38	$ 0.54101
September	Summer	1	USE 1 CP HE from August	$ 0.54	2.55	$ 1.38	$ 0.54101
October	Non-summer	1	USE 1 CP HE from August	$ 0.54	2.55	$ 1.38	$ 0.54101
November	Non-summer	1	USE 1 CP HE from August	$ 0.54	2.55	$ 1.38	$ 0.54101
December	Non-summer	1	USE 1 CP HE from August	$ 0.54	2.55	$ 1.38	$ 0.54101
						$ 16.54	<- Total Annual Demand Value
						10,948	<- Annual Produced Solar kWh's
						$ 0.00151	<- Average Annual Value per kWh Produced Solar
						2.64%	<- Average System Losses
						$ 0.00155	<- Average Value per kWh Produced Solar with System Losses

8.5.3 Transmission Value

Transmission savings were calculated on the transmission charges that are based on monthly utility peak (12 NCP) and 26-A (volumetric kWh based) variable transmission. CWL is billed for a variety of transmission (or wholesale power delivery) charges. The study looked at the two variable charges from the actual CWL transmission bills. The two variable charges were the 12 NCP (utility monthly peak KW based), and the schedule 26-A which was volumetric kWh based.

8.5.3.1 Transmission Value Peak Based

The 12 NCP peak based charges look at the actual monthly peak demand set by CWL and base these charges on this monthly peak. To the extent that solar production timing can reduce the CWL monthly peaks, the respective KW based peak charges were passed along to the solar value. The table below shows the calculated savings.

Table 29: Transmission Charges (peak based) – fixed solar only shown

Transmission Charges based on monthly non-coincident utility peak (12 NCP)							
Month	Season	Peak Date	Peak Hour Ending	Effective $ per kW-Month	Solar Production at Peak	Extended Value	Effective $ per kW-Month
January	Non-summ	30	19	$ 0.17	-	$ -	$ 0.17
February	Non-summ	7	19	$ 0.21	-	$ -	$ 0.21
March	Non-summ	4	8	$ 0.18	0.42	$ 0.08	$ 0.18
April	Non-summ	17	15	$ 0.24	2.79	$ 0.68	$ 0.24
May	Non-summ	24	16	$ 0.22	3.64	$ 0.80	$ 0.22
June	Summer	27	17	$ 0.16	1.70	$ 0.28	$ 0.16
July	Summer	19	17	$ 0.11	1.49	$ 0.16	$ 0.11
August	Summer	19	17	$ 0.14	2.48	$ 0.34	$ 0.14
September	Summer	18	17	$ 0.21	1.38	$ 0.29	$ 0.21
October	Non-summ	1	16	$ 0.19	3.24	$ 0.60	$ 0.19
November	Non-summ	27	19	$ 0.22	-	$ -	$ 0.22
December	Non-summ	10	8	$ 0.24	-	$ -	$ 0.24
						$ 3.22	<- Total Annual Demand Value
						10,948	<- Annual Produced Solar kWh's
						$ 0.00029	<- Average Annual Value per kWh Produced Solar
						2.64%	<- Average System Losses
						$ 0.00030	<- Average Value per kWh Produced Solar with System Losses

8.5.3.2 Transmission Value Volumetric Based

The volumetric kWh based charges $ per kWh Schedule 26-A was .00172 (.172 cents per kWh straight average). As mentioned above, CWL is billed for a variety of transmission (or wholesale power delivery) charges. The 26-A volumetric charges consider that the total solar production will contribute to save on this transmission charge. To the extent that all solar production can reduce the CWL monthly total purchased kWh, the respective volumetric charges were passed along to the solar value. A total kWh based transmission value was calculated to be .178 cents per kWh weighted by solar production and increased by distribution system losses.

8.5.4 Projected Solar Production

All value determinations above were derived considering a level of solar production. This sub-section provides some details on the modeling of solar.

The solar production projected was from NREL system advisory modeling historical irradiance data. The table below identifies the solar production would have an annual capacity factor of 16% for a fixed array, typical of a home or small commercial. CWL asked that estimated annual numbers be provided for a 7.95 KW dc array since it was their average size of customer installed solar. For example, a 7.95 KW dc fixed array on average would produce 10,947 kWh's over one year's time. You will see from the table below that the average annual kWh's produced is 1,377 kWh per KW dc of installed solar for a fixed array. Hence, using this value we obtain that 7.95 kW x 1,377 = 10,947 kWh. The chart below is also showing a summary of monthly and annual predicted solar production for a 1 KW dc fixed solar array and can be used similarly to above to find the monthly production. All of the value components calculated in this study can scale to other array sizing by calculating things down to the KW install sizing and the kWh production per KW of installed solar.

Table 30: 1.1.1 fixed array: Projected Solar Production for CWL 1 KW dc

Year 2020 with Month Below	Average Snow Days - Columbia MO	KW Unit	Days	Hours	Possible kWH	kWH Produced	Theoretical Capacity factor	Non Snow Days factor	Theoretical kWH Produced	Capacity factor reduced by Snow Days
1	1.6	1	31	744	744	87	12%	95%	82	11%
2	1.3	1	29	696	696	86	12%	96%	82	12%
3	0.9	1	31	744	744	124	17%	97%	121	16%
4	0.1	1	30	720	720	134	19%	100%	133	18%
5	0.0	1	31	744	744	141	19%	100%	141	19%
6	0.0	1	30	720	720	144	20%	100%	144	20%
7	0.0	1	31	744	744	149	20%	100%	149	20%
8	0.0	1	31	744	744	140	19%	100%	140	19%
9	0.0	1	30	720	720	124	17%	100%	124	17%
10	0.0	1	31	744	744	110	15%	100%	110	15%
11	0.4	1	30	720	720	86	12%	99%	84	12%
12	0.9	1	31	744	744	69	9%	97%	67	9%
Annual	5.2	12	366	8784	8,784	1,392.66	16%	99%	1,377	16%

8.6 Conclusions and Recommendations

The studies presented above identified the value of solar under a buy-all-sell-all (or equivalent) model is 2.8 cents per kWh for a smaller, customer installed rooftop fixed array solar. For large solar installs although should be valued on a per case basis, we estimate an energy savings value portion to be 2.4 cents per kWh. CWL should review and update the value of Solar and implementation methods as significant assumptions change, typically on a yearly basis.

UFS provides below general recommendations that CWL should consider when integrating distributed solar to its system:

a) Eventual move for all customers toward rate structures having a demand / TOU component

b) Right sizing - (within allowed sizing of CWL's interconnection policy), for example allow solar install up to lesser of 100% of a customer's peak demand "before solar" or 100% of a customer's average annual kWh usage "before solar" (net zero)

c) Metering, billing and strategies: Final metering and billing options selected by CWL is ultimately based on their Management and Governing Body preferences. It is often based on a combination of philosophy preference as well as metering and billing capabilities of CWL. Many utilities are adopting multiple approaches depending on the size of solar install. The most common method for smaller, rooftop solar installations is net billing. The most common method for larger solar installations is buy-all-sell-all – (This is the closest to provide services at cost of service.) Many utilities, however, are moving toward a more robust rate structure. At a minimum, all rates (including residential rates) should evolve to include demand component(s). In general, the closer CWL can get their kWh retail rate (energy component) to match their marginal power supply costs, CWL should be more indifferent to customer-installed generation.

d) It is critical to consider battery value based on utility demand management vs. power quality in future studies.

e) CWL Management should track and allocate future costs to be charged back in support of distributed solar for the basis of updating the future value of solar calculation.

We provide next recommendations for further studies and Appendix A provides an overview of Metering Options for distributed generation.

8.7 Recommendations for Additional Studies

8.7.1 Renewable energy credit (REC) or solar renewable energy credit (SREC)

The State of Missouri currently does not have a formal REC / SREC program. UFS recommends that CWL explore REC / SREC value for solar to be studied. If self-directed benefit by CWL this may need to be paid by other CWL rate payers.

8.7.2 Solar with Battery Considerations

The maximum battery value is usually calculated by charging and discharging the battery around reducing the utility capacity and/or transmission peaks ("utility demand management or peak shaving") or achieving energy arbitrage. If this cannot be accomplished, it is actually possible for a battery to have lower and even a negative value. This is due to energy loss when a battery is charged and discharged. This is often referred to as battery "round trip efficiency". It is common to lose around 15% of the electricity when storing and discharging a battery.

Depending on a variety of factors, it may be useful to configure an appropriately sized battery to be integrated with the renewable generation and configured to operate as a "power quality" battery vs. a "utility demand management or peak shaving" battery to support power quality. This often depends on a variety of factors such as the size of distributed generation resource, percent of renewables penetration vs. non-renewable, minimum and maximum feeder loadings vs. total renewables. Batteries run in power quality or blended mode generally do not realize as high of value due to their reduced ability to maximize utility demand management savings. UFS recommends that CWL explore value for solar with battery.

8.7.3 Environmental / Social Value

Potential environmental and social value was not considered in this study. This is due to these are not currently an actual expense to the utility. It is possible that future requirements may be introduced to have an actual dollar value to the costs of the utility. It is recommended that CWL consider adding this potential, future value if it becomes a true cost. Some utilities are electing to add this value on their own. This would be at the discretion of CWL Management and Governing Body. UFS recommends a study if this becomes the case.

9 AMI and Smart Grid Assessment

9.1 Smart Grid/Advanced Metering Infrastructure (AMI)

Intermittent renewable energy, distributed generation, ambitious environmental targets, and new market entrants as well as the push for level playing fields, environmental responsibility, and increased transparency – utilities are facing a variety of new challenges. By building smart grids or the "utilities of the future" and designing new business strategies, utilities can manage the demands of intermittent renewable energy sources, improve operational excellence, and reshape their businesses.

As Siemens works with utilities around the world, we increasingly see utility management and energy industry executives searching for ways to cut costs and unlock new value streams in domains where new market entrants are disrupting their business model. Utilities are intensely focused on streamlining their business processes, opening up new customer channels, and unlocking innovative value streams. In the face of the multiple, rapidly developing challenges on different fronts, utilities need to adapt quickly and in the right direction in order to successfully navigate the energy transformation. Around the world, it's clear that a paradigm shift is taking place – power grids are transforming into smart grids that are more transparent, more interactive, and more environmentally friendly than ever before.

One foundational component of the smart grid is Advanced Metering Infrastructure (AMI). The U.S. Department of Energy calls AMI an "integrated system of smart meters, communications networks, and data management systems that enables two-way communication between utilities and customers. The system provides a number of important functions that were not previously possible or had to be performed manually, such as the ability to automatically and remotely measure electricity use, connect and disconnect service, detect tampering, identify and isolate outages, and monitor voltage. Combined with customer technologies, such as in-home displays and programmable communicating thermostats, AMI also enables utilities to offer new time-based rate programs and incentives that encourage customers to reduce peak demand and manage energy consumption and costs."[1]

Instead of relying on a meter reader to collect a monthly meter reading, digital meters record information every 15 minutes and send the information back to the utility several times per day. With the additional data, utilities can provide customers new options for utility billing, including time-of-day rates, prepaid billing, and rates for solar customers. Digital meters enable customers to monitor consumption more precisely so they can make more informed energy choices. Advanced meters report power outages back to the utility, enabling enhanced service restoration. Electric meters can enable utilities to remotely switch electricity service on or off.

The AMI communications network can enable additional utility capabilities, including improved electric and water distribution operations. For electric operations, the network can be leveraged to monitor and improve voltage regulation, aggregate customer usage to better manage power supply agreements, and improve electric asset utilization using a wide range of remote equipment measurement and monitoring. For water operations, utilities can aggregate metered water consumption and compare it to distribution line metering or water tower discharge/production to identify water system losses. Water production can be better matched to water use, buy providing hourly consumption date to production. Better knowledge of water consumption positions improves wastewater treatment operations.

9.2 AMI Foundational Components

For the purposes of this report, a basic description of key AMI system components is provided as a basis for the subsequent discussion and recommendations. AMI is a mature technology and its components and capabilities have been extensively evaluated over the last decade by consultants, AMI system vendors, system integrators and the U.S. Department of Energy. A more detailed analysis of any of these foundational components is available in the public domain.

AMI Systems are comprised of several key components. While single-vendor solutions were common the past, improvements in standardization and interoperability over the last decade now enable utilities to use a “Best of Breed” approach to designing and operating their AMI systems.

Communications Network

At the heart of the AMI system is its Communications Network. Selection of the proper technology for the AMI network involves evaluating the geographic topology of the service territory, the meter density of the utility operations, and the number of applications expected to be supported by the network beyond the needs of AMI. Utilities should focus on their long range needs so as not to invest in a constrained communications technology from the onset of its AMI program.

Two types of AMI communications network technologies are currently available – Point-to-multipoint (or Tower-based) and Mesh Networks. While there are some advantages of tower-based systems, the market is currently dominated by mesh networks. These networks allow meters and other connected devices to communicate with one another along multiple paths leading back to the utility operations center. This inherent redundancy makes these networks highly reliable and allows for low latency communications to meters and other connected endpoints. CWL should consider selecting a meshing communications technology for its AMI deployment.

With continuing improvements in cellular technology, including recent investments in 5G by most of the major carriers, using public cellular networks is becoming increasingly cost competitive for small utilities or for pilot projects. While still prohibitively more expensive for deployments the size of CWL, it is expected that cellular communications may become a viable alternative to meshing networks in the future.

Electric Meters

While some communications networks were meter agnostic (allowing meter manufacturers to compete for a utility's business), the current trend is for electric meter and AMI network to be provided by the same manufacturer. By combining the the metering and the communications electronics internal to the meter itself, it is expected that manufacturers will continue to drive down the cost of AMI meters. Lower supply chain turnaround times result from simplified meter certification processes.

Electric meters typically read a meter every 15 minutes (interval data), and store that data locally inside the meter (typical storage capacity is 45 days) until the data is transferred several times per day. Electric meters can also provide a wide array of events to a utility's electric operations, including its power on/off status, high/low voltage, tamper events and high temperature. These events enable significant process reengineering and operating cost improvements.

Residential and some small commercial meters can be equipped with a remote disconnect switch, allowing CWL's customer servicer personnel to enable and discontinue electric service as directed by its customers. It also improves credit & collections costs by enabling meters to be disconnected, and subsequently reconnected, remotely.

CWL should selected an electric meter platform with the broadest event management capabilities and equip all residential and small commercial meters with remote disconnects.

Water Meters

Water meters come in a wide variety of designs and construction materials, closely related to hourly consumption and operating environments. Some meters are installed in subterranean pits to protect them from freezing or are installed in remote locations (like residential basements or deep inside commercial/industrial operations). For these reasons, water meters are typically connected to an external communications module to enable the water meter to communicate with the AMI network.

Like electric meters, modern water meters used in AMI applications can provide hourly water meter readings (interval data) and provide a variety of events like high/low usage, constant flow, and tamper. And like electric AMI meters, these water meters can enable significant process improvements and operating efficiencies.

Recommendations for CWL's water meter replacements will be discussed later in this report.

AMI Head-end System(s)

The data collected from the meters in a software product called the AMI Head End (AMI-HE). Each AMI Communications Network is paired with its own AMI-HE and some utilities manage multiple AMI-HEs due to the timing and age of its various metering platforms. For example, a utility may have been using an AMI water metering platform for several years before deciding to deploy for its electric meters and selecting a different manufacturer's product. Each AMI-HE stores collected interval and event data for extended periods of time, allowing some ad hoc retrieval of this information.

Meter Data Management System

A meter data management system (MDMS) is a software product that provides several key functions for an AMI system, including long-term storage of interval data and meter events from the AMIHE(s). Its primary function is to provide billing-quality data to the utility's Customer Information System (CIS) using a process known as Validation, Estimation and Editing (VEE). The VEE function is critical to ensuring accurate billing, and utilities typically have multiple criteria for accepting a meter reading for billing. These criteria may include weather-adjusted estimates for missing data, tests for evaluating inbound meter readings for accuracy, and filling in missing interval data until it can be obtained.

Beyond billing data management, the MDMS is used as the single source of meter interval data and events for a wide variety of a utilities operational systems. Outage management depends on the power on/off events to assist in the restoration of power to customers. A utility's voltage control systems use the voltage data collected by meters as an input to voltage regulation systems and processes. Meter tamper events are used to detect and respond to theft of utility service. Finally, the analytics capabilities present in modern MDM systems can provide a utility insight into its electric and water distribution business not readily available elsewhere.

In recent years, AMI Head-end vendors have developed basic MDMS functionality into their AMI-HEs. While adequate for very small utility operations, CWL should select a dedicated meter data management system for its AMI deployment.

Integrations to CWL's billing and other operational systems

Data contained in the MDMS is used by the utility's operating software systems which include, at a minimum, the Customer Information System (CIS), the Outage Management System (OMS), and the Geospatial Information System (GIS). The data required by these systems can vary from monthly for some simple billing requirements, to near real-time for applications like OMS. In order to manage these various requirements, a utility must consider the manner in which these systems are integrated.

Systems requiring infrequent updates can send and receive data at fixed intervals in a tabular format known as Flat File Integration. Operating systems with more real-time data requirements need integrations that allow information exchange to occur on state changes. Modern AMI, MDMS and utility operational systems exchange this data in standard formats. Some software vendor integrations have become so common that vendors develop an adaptor or connector product between the two systems. CWL should consider selecting vendors of these systems using standards-based, or productized, interfaces between systems.

Customer portals

One benefit of an AMI system is to engage consumers more fully in their use of utility services. The most effective way to accomplish this is through the use of customer portals applications. These websites provide secure access to the interval data for utility service consumption, allowing consumers to directly monitor their electric and water usage. Customers who implement energy savings measures in their homes and business have a direct manner in which to confirm the savings from these measures. Customer portals are also used as an effective communications vehicle during major storms and can provide status updates of restoration efforts.

CWL has a well-designed website today and should use this common platform as the basis for providing access to these extended services. AMI vendors can provide customer portals that can be accessed from CWL's website.

Analytics

The availability of interval usage date for every meter in a utility's operation unlocks a large potential for process improvements and operational efficiencies. One example is in the management of bulk power supply requirements for capacity and energy. Municipal utilities, in particular, can leverage this end use data to optimize their bulk power supply purchases. Historically, municipal utilities have relied on substation metering at the interconnection points to the bulk power system to provide a historical basis for forecasting future power supply requirements. With AMI in place, power supply requirements can be analyzed by customer class or groupings of individual customers (e.g., large industrial users) to determine their effect on the City's bulk power capacity and energy requirements. Another example is related to optimizing water production. By integrating weather data into their operations, water utilities can more accurately forecast water production requirements on a day ahead basis, rather than depending on monthly summaries of water consumption. Finally, by having hourly data available to wastewater operators, production scheduling and capacity management can be significantly improved.

9.3 CWL Progress to date & Current Situation

As utilities moved away from reliance on visually read meters, CWL should be considered an early adopter of Automated Meter Reading (AMR) technology. This technology involved replacing the electric meter with one that has a transmitter allowing the meter reading to be obtained wirelessly in close proximity. In the late 1990s or early 2000s, CWL began investing in the AMR technology and selected Itron as their AMR vendor. The AMR retrofit for electric meters was completed by 2001, allowing CWL to reduce its meter reading expenses. The system was initially a walk by system, requiring meter readers to walk by meters with a handheld wireless transceiver, and ultimately transitioned to drive-by AMR by equipping vehicles with the technology to drive by electric meters once monthly to obtain readings for billing. The

CWL's current electric meter vendor (Itron) has been providing a "Bridge" electric meter for CWL's expansion needs. The meters are enabled with AMR technology which allowed them to be read by the existing drive-by meter reading system. They are also equipped with an older version of Itron's AMI technology, which may need to be re-evaluated against the vendor's current technology roadmap and other solutions in the marketplace.

While AMR has been successful for electric meters, only a portion of the water meters were equipped to use the Itron AMR technology. Those water meters that could be readily equipped with an AMR device were retrofitted, while those that required meter replacement were deferred. Some water meters were never equipped with the AMR capability, and battery failures have caused the read rate on the AMR-equipped water meters to drop to less than 30%. The majority of water meters are visually read, and that number is growing due to continuing battery failures. Funding to replace the remaining 70% of the water meters with some type of remote meter reading technology has been deferred until an AMI strategy is developed.

CWL provides electric service to large apartment complexes totally nearly 1,000 apartments, requiring frequent turn on and off due to college student occupants.

The Siemens AMI engagement has identified gaps in CWL's ability to provide detailed information for some analyses, including Meter data availability for special load forecast. The city uses several, disparate data bases for meter and load data. Data from EMS exists on tie-line and power transformer loads. The city has a GIS database that has the potential to create network connectivity model. There is no system currently in place to tie all three of the data sources together.

While some interval data from customer meters is collected and stored, there is no programmatic use for the date. There is a 50-50 mix on some customer classes where interval data is used to set profile data for customer class rate structures. Demand data is collected on all commercial customers. Industrials have interval data and demand data. There's currently dedicated staff to processes interval data. All the interval data is collected using a cellular-based system running in parallel with the AMR electric meter reading system.

Rate riders are prevalent in the city with large general service and industrial customers. The city provides a high load factor incentive - about 75% load factor or higher drives a discount on it on the energy charge. An off-peak discount is also provided in some cases.

The city has a climate action and adoption plan, focused on adoption of renewable energy bulk power sources and CO_2 reduction. About 1/2 of 1% of residential customers have rooftop solar.

The city runs five utilities – water, electric, stormwater, sewer, and solid waste. To set wastewater rates, the city uses a winter quarter wastewater baseline developed by metering either December through March or November through April, rejecting the high and low months, and setting an average of the other three for the baseline sewer usage for the residents. Any water usage above that rate would be exempted from wastewater charges. A few large customers have metering on affluent discharge, with some more accurately tracking their input into the city's wastewater systems.

CWL's current metering capabilities limit rate design for its services. A single monthly meter reading summarizes the previous month's total consumption. Rates must factor in all operating costs for all customers and average the impact of these costs across all customers. With AMI in place, CWL can more accurately allocate its costs of operations to customer classes and eliminate much of the cost averaging and cross-subsidization present in today's rate structure.

CWL has had some energy efficiency and demand response programs in the past, but they are not an active part of services currently provided. The city had a QEI SCADA system that was recently replaced by OSI Monarch. The conversion caused the loss of ability to interrupt power to air conditioner compressors as part of a demand response program, as the functionality was not supported by OSI. The air conditioner switch technology in place was not compatible with modern AC units, and interrupting power to those air conditioners caused unit failure in some cases. The program was discontinued, as the incentive provided for air conditioner interruption was higher than the perceived benefits.

The CWL's distribution SCADA was also not compatible with its capacitor bank control system, which allowed remote control to managed distribution voltage levels. Current adjustments to capacitor bank settings are done manually, with field personnel driving to each capacitor bank location. The manual effort required has degraded CWL's ability to tightly control distribution voltages, resulting in higher than required distribution voltages and the cost of subsequent losses incurred by the City.

The city is interested in developing new customer programs. There has been interested in a customer portal to provide energy usage information to customers. Prior efforts stalled due to city security policies. There is support for leveraging the use of a city web presence beyond providing usage data to customers and include information about outage restoration.

CWL's electric operations are highly regarded and meet the public power industry's highest RP3 rating. While the City does not operate an outage management system, individual outage cases are detailed, and excellent records are kept manually.

9.4 Benefit areas

Advanced Metering Infrastructure has been deployed extensively for over a decade. As a result, the benefits from AMI are well documented and readily available from a variety of sources, including the U.S Department of Energy. A particularly useful reference document is the U.S. DOE's summary of findings and benefits from the ARRA Investment Grant program - *Advanced Metering Infrastructure and Customer Systems: Results from the Smart Grid Investment Grant Program*, published in September of 2016. A copy of that document is provided as a courtesy.

For the purposes of the AMI Study for CWL, Siemens evaluated specific areas of benefit that would immediately accrue value. Those areas can be divided into three groupings – Improved Customer Service, Electric Utility Operations Improvements, and Water Utility Operations Improvements. A summary of other benefits is provided.

Benefits to Customers

- Notify customers of service problems. AMI water meters can be equipped with high water flow/continuous water flow notification, allowing CWL's customer service representatives to proactively contact customers with potential water usage issues.
- On-demand meter readings. At times, customers call into the utility office with questions about their bill amount. Unresolved discussions usually result in an order for a field verification of a meter reading, and then a follow-up call to the customer. With on-demand access to meter readings during customer calls, these situations can be resolved in one call and greatly enhances customer interactions.
- Customer Usage Portal. By allowing customers to monitor their daily usage of water and electricity, utilities can avoid calls from customers and present a more modern image to customers.
- New rate structure enablement. Today's rates for electricity and water are primarily volumetric, with fixed charges for the commodity and peak demand for some customers. Advanced metering infrastructure allows CWL to align prices with supply costs and give customers options to purchase electricity when supply prices are low, and defer usage when prices are high.
- Prepaid metering options. The conventional monthly billing option for usage in the past is evolving to new methods of energy procurement. With seniors and with college students, prepaid metering allows customers to track their monthly spending throughout the month and make consumption adjustments so as to manage their total energy spending. AMI enables this outcome by integrating the interval data reporting with the remote disconnect capability.
- Home energy management solutions. AMI and interval metered data enables integration with customer's home automation platforms like Apple's iHome, Nest, and platforms like Control4. Energy management systems (smart thermostats, building energy management systems) provide customers a comprehensive view of their homes.
- Demand response programs. Unlike the direct control systems of the past, modern demand response programs can provide messaging to connected customer equipment (e.g., Nest Thermostats, smart appliances) to effect load reduction. Since AMI collects interval energy consumption before, during and after the demand response event, no need for a separate Measurement & Validation program to confirm load reduction is required.

Electric Utility Operations Improvements

- Service Restoration. Currently, when power is interrupted to customers from storms or equipment failure, CWL depends on customer telephone calls to assist with specifically locating trouble locations. With AMI, electric meter power off notification is sent directly to CWL operators. Once restoration activities are complete, the AMI meters can be interrogated to confirm that power has been restored to individual customers. This greatly enhances CWL's ability to find "nested" outages, an industry term used to describe multiple areas of damaged facilities on a single distribution line. After restoring one damaged area, AMI enables service workers to find the next damaged location without extensive line patrolling, effectively reducing the total outage duration experiences by customers.

- High/Low voltage notification. Most AMI electric meters provide a voltage reading every 15 minutes, enabling utility operators to control the voltage regulation of their distribution system and prevent damage to customer's equipment from high or low voltages. High/low voltage alarms alert operating personnel to abnormal conditions. Once communications capabilities have been restored to capacitor banks, AMI can affect Volt/VAR Optimization by using interval voltage data to send control settings remotely.
- Improved system monitoring. The presence of the AMI communications network can be leveraged for a wide range of measurement and instrumentation devices installed on the distribution system, ranging from fault indicators to end-of-line voltage sensors. These additional data points serve to improve electric system monitoring.
- Reduced utility revenue Loss. Tamper alarms prevent theft of electricity, while unbilled usage between tenants is eliminated.
- Reduced system demand & energy losses. System energy loss savings from more tightly controlled voltage at substations.

Water Utility Operations Improvements

- Eliminates visual reading for nearly 70% of meter population, allowing CWL to reduce meter reading staff in this area.
- Eliminates ad hoc replacement of failed batteries.
- On-demand water meter reading by customer service representatives eliminate check reading field trips.
- Improved system monitoring. Comparing water production to metered usage enables early leak detection and open hydrants. Daily reporting on water consumption enables improved water production & storage operations.
- Reduced utility revenue Loss. Tamper alarms prevent theft of water. Collected interval usage data confirms usage on "Fire Service" water accounts.
- Matching Storage Tank outflow to capacity limits and scheduling water production at lower energy cost period.
- Leveraging AMI communications network for additional instrumentation & telemetry on the water distribution system. Better pressure management resulting from better data at metered usage.

Other Benefit Areas

- Positive contribution to CWL's Climate Action and Adoption Plan from reduction in vehicle usage for meter operations
- Leveraging the AMI communications network to improvements in Wastewater telemetry from pumping stations.
- Sharing metered water usage on an hourly basis allows better scheduling of wastewater processing.

9.5 Investment description

Implementation of an AMI system for CWL will involve investments in four key areas – Electric Meters & Installation, Water Meters & Installation, Communications Infrastructure and installation, and AMI software systems.

Communications Infrastructure. CWL should immediately stop installing the Itron Bridge Electric meters. As discussed previously, this meter platform may be reliant on a communications technology in the process of being retired by the manufacturer. CWL should confirm Itron's technology roadmap for this product, compared to the vendor's current communications system offerings – Itron RIVA, the recently acquired Silver Spring Networks, etc.

The selected vendor's communications network should meet CWL's current smart grid communications needs beyond the near-term requirements for AMI. Emerging technologies such as electric vehicle charging stations and roof top solar generation will all require communications capabilities to these new endpoints. By evaluating communications vendor's technology roadmaps, and their current and future bandwidth capabilities, CWL will be able to select a communications vendor for their Smart Grid System requirements.

Electric Meters. At the time of this analysis, CWL had 50,422 electric meters in service, 231 of which were replaced with the Itron Bridge Meter. Electric meters should be selected on the basis of their compliance with the ANSI C21 standards family, and the portfolio of capabilities they provide. At a minimum, all meters should collect and store 15-minute interval data, 15-minute voltage data, have net metering capabilities, and produce a library of events for analysis by utility operations personnel. All residential meters should be equipped with remote disconnect capability, enabling improvements to provision of service and providing a foundation for future prepaid metering pursuits. Commercial & Industrial meters should also collect reactive measurements, voltage and current on all three phases, and provide differential events.

Water Meters. At the time of this analysis, CWL had upgraded 30,941 water meter installations with Itron's new 100W AMR endpoints. A decision to install a different communications network would involve replacing the Itron AMR end points with AMI endpoints from a different vendor. Our financial analysis does not consider this alternative and will be discuss later in this section.

There are and addition 19,983 visually read water meters where both the meter and any communications device will need replaced. There are 6,493 water meters with older AMRs devices that would need to be replaced.

CWL staff provided its existing replacement pricing for electric meters, water meters, and related components. CWL maintains contracts with third party contractors for installation services during mass upgrades of field equipment. Siemens conducted a review of these documents and used unit costs for meters and installation labor with pricing in hand for the AMI Financial Model provided as an adjunct this report. Using these existing contracts and unit prices, a summary of capital investment is shown on Table 31.

Table 31: Summary of Capital Investment

Electric Meter Infrastructure & Install Costs	**22,804,870**
Meters	7,339,392
Installation	15,465,478
Self-contained meter	13,305,085
Transformer-rated meter	2,160,393
Water Meter Infrastructure & Install Costs	**7,711,635**
Meters	6,625,315
Installation	1,086,320
Communication Infrastructure & Install Costs/ AMI Backt	**335,000**
Access Point routers with backhaul	192,000
Repeters	93,000
Installation	50,000
AMI Software	1,261,000
Software install and setup	80,000
Professional service study to implement	1,181,000
Total CAPEX	**32,112,505**

The AMI Financial Model quantifies a portion of the overall benefit using data from CWL staff that was available at the time of this study.

Based on Siemens' evaluation of CWL's existing arrangements with meter and installation labor providers, Siemens proposes that CWL issue a request for proposal for its AMI System Project. The likely savings to CWL could approach $6 – 8 million.

10 Appendix

10.1 Resource Plan Supplemental Tables

Appendix 1: Henry Hub Natural Gas Prices by Case
2019$/MMBtu

Year	Henry Hub Base Case	Henry Hub High Case	Henry Hub Low Case
2020	2.05	2.06	2.03
2021	2.59	2.76	2.43
2022	2.36	2.68	2.10
2023	2.24	2.77	1.83
2024	2.23	2.92	1.69
2025	2.45	3.35	1.74
2026	2.75	4.25	1.84
2027	2.97	4.44	1.94
2028	3.00	4.56	2.01
2029	3.08	4.82	2.06
2030	3.16	4.79	2.06
2031	3.27	5.01	1.95
2032	3.22	4.82	1.91
2033	3.29	4.93	2.01
2034	3.29	5.28	2.01
2035	3.33	5.19	2.06
2036	3.33	5.21	1.97
2037	3.40	5.56	2.21
2038	3.43	5.25	2.16
2039	3.44	5.45	2.16
2040	3.39	5.33	2.13

Appendix 2: CO_2 Annual Emission Prices - 2019$/short ton

Year	Base Case	High Case	Low Case
2020	0.00	0.00	0.00
2021	0.00	0.00	0.00
2022	0.00	0.00	0.00
2023	0.00	0.00	0.00
2024	0.00	0.00	0.00
2025	3.57	6.66	0.00
2026	4.08	7.54	0.00
2027	5.10	8.73	0.00
2028	6.12	10.86	0.00
2029	6.63	11.97	0.00
2030	7.14	12.81	0.00
2031	7.65	13.66	0.00
2032	8.16	14.44	0.00
2033	9.18	16.55	0.00
2034	10.20	18.56	0.00
2035	11.22	20.30	0.00
2036	12.75	22.56	0.00
2037	14.79	24.93	0.00
2038	17.34	30.49	0.00
2039	19.89	35.09	0.00
2040	22.44	39.88	0.00

Appendix 3: Coal Basin Price Forecast – Reference (2019$/MMBtu)

Year	CAPP	NAPP	ILB	PRB
2020	2.61	1.93	1.60	0.68
2021	2.53	1.90	1.58	0.69
2022	2.47	1.84	1.50	0.69
2023	2.40	1.77	1.42	0.70
2024	2.34	1.71	1.35	0.70
2025	2.28	1.64	1.28	0.70
2026	2.22	1.59	1.22	0.70
2027	2.16	1.53	1.15	0.71
2028	2.16	1.54	1.15	0.71
2029	2.16	1.54	1.14	0.71
2030	2.16	1.55	1.13	0.72
2031	2.16	1.55	1.13	0.72
2032	2.16	1.56	1.12	0.72
2033	2.16	1.57	1.11	0.72
2034	2.16	1.57	1.11	0.73
2035	2.16	1.58	1.10	0.73
2036	2.16	1.58	1.09	0.73
2037	2.16	1.59	1.09	0.74
2038	2.16	1.60	1.08	0.74
2039	2.16	1.60	1.07	0.74
2040	2.16	1.61	1.07	0.74

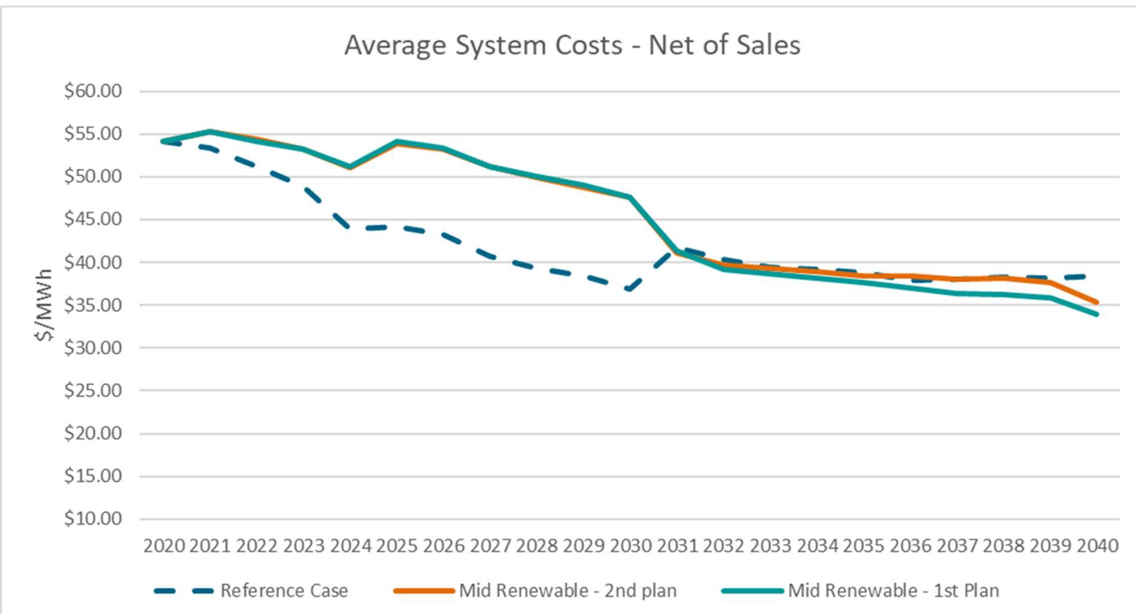
Appendix 4: Coal Basin Price Forecast – Low Case (2019$/MMBtu)

Year	CAPP	NAPP	ILB	PRB
2020	1.94	1.44	1.31	0.68
2021	1.96	1.45	1.33	0.69
2022	1.97	1.45	1.35	0.69
2023	1.98	1.45	1.38	0.70
2024	1.98	1.45	1.33	0.70
2025	1.98	1.45	1.29	0.70
2026	1.97	1.45	1.24	0.70
2027	1.97	1.45	1.20	0.70
2028	1.95	1.45	1.18	0.70
2029	1.94	1.45	1.17	0.70
2030	1.92	1.45	1.15	0.70
2031	1.91	1.45	1.14	0.71
2032	1.90	1.45	1.12	0.71
2033	1.88	1.45	1.10	0.71
2034	1.87	1.45	1.08	0.72
2035	1.85	1.45	1.06	0.72
2036	1.84	1.45	1.06	0.72
2037	1.84	1.45	1.05	0.71
2038	1.83	1.45	1.04	0.71
2039	1.82	1.45	1.03	0.71
2040	1.81	1.45	1.02	0.70

Appendix 5: Coal Basin Price Forecast – High Case (2019$/MMBtu)

Year	CAPP	NAPP	ILB	PRB
2020	3.27	2.41	1.89	0.68
2021	3.11	2.36	1.83	0.69
2022	2.97	2.22	1.65	0.70
2023	2.82	2.09	1.47	0.70
2024	2.71	1.96	1.38	0.70
2025	2.59	1.84	1.28	0.71
2026	2.47	1.72	1.19	0.71
2027	2.36	1.61	1.11	0.72
2028	2.37	1.62	1.11	0.72
2029	2.39	1.63	1.11	0.72
2030	2.40	1.64	1.12	0.73
2031	2.42	1.66	1.12	0.73
2032	2.43	1.67	1.12	0.73
2033	2.44	1.68	1.12	0.74
2034	2.46	1.69	1.13	0.74
2035	2.47	1.70	1.14	0.74
2036	2.48	1.71	1.13	0.75
2037	2.49	1.73	1.13	0.76
2038	2.50	1.74	1.12	0.77
2039	2.51	1.75	1.12	0.78
2040	2.51	1.76	1.11	0.79

Appendix 6: Mid Renewable Plans – System Costs



10.2 Value of Solar Appendix

Metering and billing options defined

Buy-all-sell-all – (This is the closest to provide services at cost of service. This method is common for larger installations.)

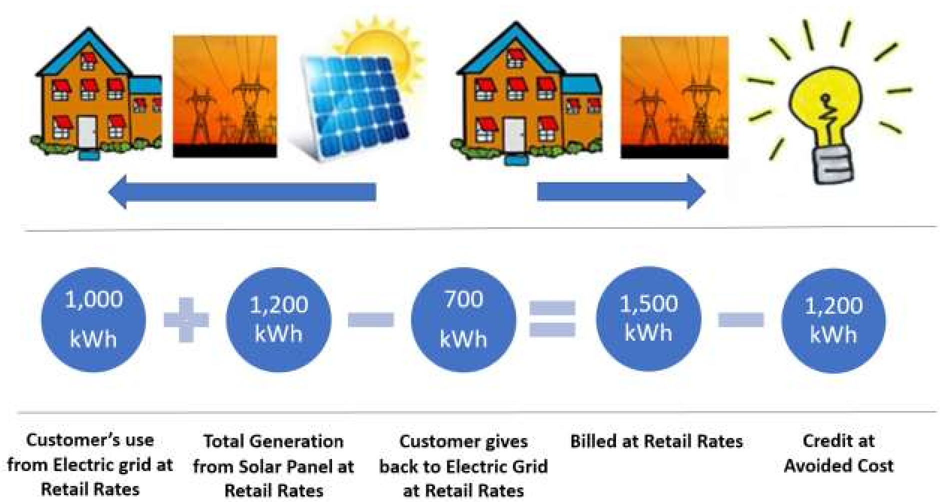
Under a buy-all-sell-all metering and billing scenario, two meters are required. All power consumed by the customer will be billed at regular retail rates from the utility. The consumed power will be the total power used by the customer from both the utility and the solar production. Solar production is metered by the second meter. All solar production will be credited at the current avoided cost. This option is occasionally used for larger solar installs. This option is typically not used for residential solar since a second meter is required to accurately measure the actual solar production. However, this option can also be done on a "theoretical buy-all-sell-all" agreement where the billing is netted on the customer bill. This allows the customer to maximize the solar production kept behind their meter.

Buy-all-sell-all summary

Metering: Two meters are required with a buy-all-sell-all scenario. One (dual register) meter is for tracking power supplied by the utility to the customer and excess customer solar pushed back to the grid. A second meter is used for tracking solar production generated by the customer.

Solar Production: All solar production gets credited to the customer at the avoided cost.

Billing: The utility bills all the power consumed by the customer at the normal retail rates. This includes all power supplied by the utility and all solar production used by the customer.



Summary: Customer billed on total customer consumption at retail - Utility credits customer on the total solar production at avoided cost.

Metering required:

- Meter on facility (tracking customer's use from the electric grid and customer gives back to electric grid)
- Meter on solar unit
-

Net metering (not recommended unless required by statute)

Under a net metering scenario only one meter will be required. Net metering can be done under two different metering options. The first option is a meter that "spins both ways". This type of meter will spin forward when power is being used from the utility. This meter will then spin in reverse when excess solar production is being sent back to the utility. The second option is a meter that tracks the "in and out" separately. The utility supplied power in will be tracked and the solar production excess sent back to the utility is tracked separately. These two numbers can be netted for billing at the current normal utility rates. Both metering options under net metering will be the same customer bill. At the end of the billing cycle the net usage will be billed at the current normal utility rates. If there is a billing cycle that there is more power sent back to the utility than power supplied by the utility, the excess solar production will be credited at the current normal utility rates. This option is generally only used if mandated by state or local requirements. Some utilities will limit the dollar amount and/or number of months that an over-production of solar will be allowed to be credited.

Net metering summary

Metering: Only one meter is required with a net metering scenario. One meter is for power supplied by the utility to the customer. The same meter is used for solar production sent back to the utility by the customer. The two most typical single net meter options are a meter that spins both ways or a meter that tracks the in and out separately. Both meters should allow for the same customer bill to be calculated.

Solar Production: Only excess solar production gets sent back to the utility. The customer only uses power supplied by the utility when solar production does not meet their usage needs.

Billing: The utility sells all the power to the customer at the normal rate. The utility buys the excess solar production at the normal rate. (Net usage based on two metering options above). The customer is credited at retail rates (or avoided cost if allowed by statute) if more solar production is sent to the utility then used from the utility.

Summary: Customer billed on total net customer usage at retail - Utility credits customer on the excess solar production at retail (if customer gives back more than they used from electric grid in a given month (over-production)).

Metering required:

- Meter on facility (tracking customer's use from the electric grid and customer gives back to electric grid)

Net billing (Common method for smaller residential rooftop solar installs)

Under a net billing scenario only one (dual register) meter is required. For a utility that has bi-directional (dual register) digital meters, the utility generated kWhs are billed at retail while the customer excess generated kWhs pushed back to the grid are credited at the current avoided cost. This option is generally used for smaller solar installs. Some utilities will elect this method for smaller installs while using a buy-all-sell-all method for larger installs.

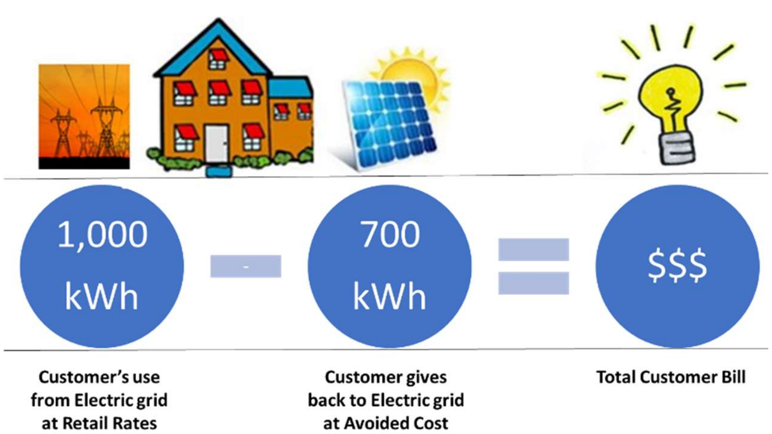
Net billing summary

Metering: Only one meter (dual register) is required with a net billing scenario. The first register is used for tracking power supplied by the utility to the customer. The same meter (register two) is used to track solar production sent back to the utility by the customer.

Solar Production: Only excess solar production gets sent back to the utility. The customer only uses power supplied by the utility when solar production does not meet their usage needs.

Billing: The utility sells all the utility delivered power to the customer at the normal retail rate. The utility buys the excess solar production pushed back to the grid at the avoided cost.

Net Billing - Digital Meter Example



Summary: Customer billed on customer usage from the utility at retail - Utility credits customer on the excess solar production pushed back to the grid at avoided cost.

Metering required:

Dual register, bi-directional meter on customer facility (tracking customer's use from the electric grid and excess customer gives back to electric grid)

