Clark Public Utilities

DRAFT 2020
Integrated Resource Plan

As Adopted by the Commission on MMMM DD, 2020

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Editor's Note

Caveats

This 2020 Integrated Resource Plan is a product of months of preparation including many sequential steps that require hundreds, if not thousands, of hours of data gathering, synthesizing, analyses, drafting, reviewing, and presentations that started in November 2019. Two issues have arisen that have further complicated the already complex effort in getting to a singular point in time that fully reflects the thoughts and associated plans of Clark Public Utilities staff, management, the Board of Commissioners and in turn our customers.

Commerce Rulemaking on the Clean Energy Transformation Act

In the 2019 Washington State Legislative Session, The Clean Energy Transformation Act (CETA) was passed. Within the CETA, there are many provisions and many instructions to the Department of Commerce to commence Rulemaking to implement the CETA. This rulemaking effort demands much time and effort from Commerce and all stakeholders.

The Rulemaking effort will not be complete by the deadline date for this Integrated Resource Plan submission. Clark Public Utilities has endeavored to meet the rules that may result from this process. If needed, Clark Public Utilities will submit an amended IRP once the CETA rules are completed.

COVID-19

Onset of the COVID-19 pandemic in early 2020 presents several challenges to the planning process. Both intensity and timing of economic recovery are still very big unknowns. At this time, Clark Public Utilities has factored COVID-19 into this Integrated Resource Plan only to the extent that the low load growth forecast case is more likely now than high load forecast case. No other external influences, such as State or Federal aid packages that might impact utility planning or any potential step function load changes that may occur as large industrial users assess their viabilities, have been included. Clark Public Utilities will continue to monitor and adjust its integrated resource planning as necessary due to the COVID-19 pandemic.

Executive Summary

Purpose

Washington State requires public utilities that are not full requirements purchasers of Bonneville Power Administration and that serve more than 25,000 customers to complete an Integrated Resource Plan (IRP) in accordance with RCW 19.280. This 2020 IRP meets that requirement. In addition, this IRP meets the requirements of the Energy Independence Act (EIA) and the Clean Energy Transformation Act (CETA). The required documentation will be transmitted to the Washington Department of Commerce by the September 1, 2020 deadline and made available to the public on Clark Public Utilities' web site. Please see the prior page (Editor's Note) regarding yet-to-be completed rulemaking for the CETA and impacts due to COVID-19 Pandemic.

Requirements of a Resource Plan

Below are the requirements per RCW 19.280.030, recently amended by the CETA, for a Resource Plan and the location in this IRP where each requirement is met.

1) A range of forecasts, for at least the next ten years or longer, of projected customer demand which takes into account econometric data and customer usage (Section 2);
2) An assessment of commercially available conservation and efficiency resources, as informed, as applicable, by the assessment for conservation potential under RCW 19.285.040. Such assessment may include, as appropriate, opportunities for development of combined heat and power as an energy and capacity resource, demand response and load management programs, and currently employed and new policies and programs needed to obtain the conservation and efficiency resources Section 3–Conservation and Demand Resource Potential Assessments
3) An assessment of commercially available, utility scale renewable and nonrenewable generating technologies(Section 4—Wholesale Supply-Side Resource Options Assessment) and a comparison of the benefits and risks of purchasing power or building new resources (Purchasing Output via Contract versus Asset Ownership) ;
4) A comparative evaluation of renewable and nonrenewable generating resources, including transmission and distribution delivery costs, and conservation and efficiency resources using "lowest reasonable cost" as a criterion (Section 5—Comparative Evaluation of Renewable and Nonrenewable Energy Resources);
5) An assessment of methods, commercially available technologies, or facilities for integrating renewable resources, including but not limited to battery storage and pumped storage, and addressing over-generation events, if applicable to the utility's resource portfolio (Assessment of Tools Available for Integrating Renewable Resources);

6) An assessment and ten-year forecast of the availability of regional generation and transmission capacity on which the utility may rely to provide and deliver electricity to its customers(Generation and Transmission Availability and Challenges);
7) A determination of resource adequacy metrics for the resource plan consistent with the forecasts (Appendix C – Resource Adequacy Metrics Determination);
8) A forecast of distributed energy resources that may be installed by the utility's customers and an assessment of their effect on the utility's load and operations (Appendix D – Distributed Energy and Resources);
9) An identification of an appropriate resource adequacy requirement and measurement metric consistent with prudent utility practice in implementing RCW 19.405.030 through 19.405.050 (Appendix C – Resource Adequacy Metrics Determination);
10) The integration of the demand forecasts, resource evaluations, and resource adequacy requirement into a long-range assessment describing the mix of supply side generating resources and conservation and efficiency resources that will meet current and projected needs, including mitigating over-generation events and implementing RCW 19.405.030 through 19.405.050, at the lowest reasonable cost and risk to the utility and its customers, while maintaining and protecting the safety, reliable operation, and balancing of its electric system; (for purposes of this 2020 IRP document this is called a Least Cost Plan; (Section 6—Least Cost Considerations and Alternatives and Section 8—Least Cost Action Plan)
11) An assessment, informed by the cumulative impact analysis conducted under RCW 19.405.140, of: Energy and non-energy benefits and reductions of burdens to vulnerable populations and highly impacted communities; long-term and short-term public health and environmental benefits, costs, and risks; and energy security and risk; (for purposes of this 2020 IRP, this assessment will be omitted as work products from requirements of RCW 19.050.140 are not available at this point) and
12) A ten-year clean energy action plan for implementing RCW 19.405.030 through 19.405.050 at the lowest reasonable cost, and at an acceptable resource adequacy standard, that identifies the specific actions to be taken by the utility consistent with the long-range integrated resource plan (Section 9—Clean Energy Action Plan).

In addition, Clark Public Utilities is required to consider the social cost of greenhouse gas emissions, as determined by the department of Commerce for consumer-owned utilities, when developing integrated resource plans and clean energy action plans. This IRP will use a 20-year outlook. For several years, Clark Public Utilities has focused on flexibilities and contingencies to the externalities that face the utility. This IRP will be a “snapshot” in time of these flexibilities and contingencies.

Future Load and Resource Balances

Tables ES.1 and ES.2 show existing resources along with forecast requirements that may result in the need for new resources. This is only a forecast, with all of the uncertainty that forecasts entail, but it provides the most reasonable basis for determining the rough magnitude of required acquisitions.

Year	Medium Case Incremental Energy Requirements (aMW)			Low Case Incremental Energy Requirements (aMW)			High Case Incremental Energy Requirements (aMW)		
	Annual Average Net Load Forcast	Existing Resource	Surplus(+) /Deficit (-)	Annual Average Net Load Forcast	Existing Resource	Surplus(+) /Deficit (-)	Annual Average Net Load Forcast	Existing Resource	Surplus(+) /Deficit (-)
2020	531	553	22	531	553	22	531	553	22
2021	531	553	22	531	553	22	531	553	22
2022	532	554	22	531	553	22	533	555	22
2023	533	555	22	532	554	22	535	557	22
2024	534	556	22	533	555	22	536	558	22
2025	536	558	22	533	555	22	539	561	22
2026	537	559	22	534	556	22	541	563	22
2027	539	561	22	535	557	22	543	564	21
2028	542	564	22	536	558	22	547	564	17
2029	544	562	18	537	555	18	551	569	18
2030	547	547	0	539	539	0	555	555	0
2031	550	550	0	540	540	0	558	558	0
2032	551	551	0	541	541	0	560	560	0
2033	554	554	0	542	542	0	563	563	0
2034	557	557	0	544	544	0	566	566	0
2035	559	559	0	545	545	0	570	570	0
2036	561	561	0	547	547	0	571	571	0
2037	563	563	0	548	548	0	572	572	0
2038	566	566	0	549	549	0	573	573	0
2039	568	568	0	551	551	0	575	575	0
2040	571	571	0	552	552	0	577	577	0

Table ES.1

Year	Medium Case Incremental Peak Requirements (MW)				Low Case Incremental Peak Requirements (MW)				High Case Incremental Peak Requirements (MW)			
	Annual Peak Net Load Forcast	Planning Margin	Existing Resource	Surplus(+) /Deficit (-)	Annual Peak Net Load Forcast	Planning Margin	Existing Resource	Surplus(+) /Deficit (-)	Annual Peak Net Load Forcast	Planning Margin	Existing Resource	Surplus(+) /Deficit (-)
2020	975	117	1119	27	975	117	1119	27	975	117	1119	27
2021	971	117	1119	31	971	117	1119	31	972	117	1119	31
2022	967	116	769	-314	965	116	769	-312	968	116	769	-316
2023	961	115	769	-307	958	115	769	-304	964	116	769	-311
2024	955	115	769	-300	950	114	769	-296	959	115	769	-305
2025	948	114	769	-293	942	113	769	-286	954	114	769	-299
2026	946	113	769	-290	938	113	769	-281	954	114	769	-299
2027	944	113	769	-289	934	112	769	-278	955	115	769	-300
2028	946	114	769	-291	933	112	769	-276	959	115	769	-305
2029	948	114	1062	0	933	112	1045	0	964	116	1080	0
2030	951	114	1066	0	933	112	1045	0	971	116	1087	0
2031	957	115	1072	0	935	112	1047	0	980	118	1097	0
2032	960	115	1076	0	936	112	1048	0	985	118	1104	0
2033	966	116	1082	0	938	113	1051	0	995	119	1114	0
2034	972	117	1088	0	941	113	1053	0	1004	120	1125	0
2035	978	117	1095	0	943	113	1056	0	1013	122	1135	0
2036	984	118	1102	0	945	113	1058	0	1023	123	1146	0
2037	989	119	1108	0	947	114	1061	0	1033	124	1157	0
2038	996	120	1116	0	950	114	1064	0	1044	125	1170	0
2039	1004	120	1124	0	953	114	1068	0	1056	127	1183	0
2040	1012	121	1134	0	957	115	1072	0	1070	128	1198	0

Table ES.2

Table ES.1 suggests that under medium load growth that Clark Public Utilities is in an annual average energy surplus position across the entire planning period. However, Table ES.2

suggests a need for continued purchases of current market supplies of annual and multi-year daily, monthly, and seasonal peaking supplies.

Resources to Meet Future Growth and the CETA Requirements

As indicated above, strategies are needed to meet peak needs. Under the mandates of the Energy Independence Act, conservation is the first resource used to meet load growth. Beyond conservation, supply side resources that could be chosen vary widely in their operating characteristics, cost, and availability. These aspects are covered in detail in this IRP.

Clark Public Utilities is required under the EIA to use increasing percentages of eligible renewable resources measured against its customer loads. This requirement can be met by purchasing eligible renewable resource output directly or by purchasing non-eligible power and supplementing with the purchase of RECs. Distributed generation also has preferred status under the EIA and should be considered when possible.

Least Cost Action Plan Summary

- ✓ Acquire all cost-effective conservation consistent with NWPCC models and Clark Public Utilities' Conservation Potential Assessment.
- ✓ Buy all available Bonneville Power Administration Tier 1 power in 2021-2040 to cover load growth.
- ✓ Develop a River Road Generating Plant Flexibility Analysis and Business Plan.
- ✓ Finalize Bonneville Power Administration Post-2028 Contract with the CETA requirements embedded.
- ✓ If load growth materializes, look for and acquire RECs to meet the EIA requirements, subject to EIA cost cap limits.
- ✓ Stay abreast of conservation and demand response programs, distributed generation, and renewable technologies and opportunities.

Clean Energy Action Plan Summary

Per the Clean Energy Transformation Act, a ten-year clean energy action plan for implementing RCW 19.405.030 through 19.405.050 at the lowest reasonable cost, and at an acceptable resource adequacy standard, that identifies the specific actions to be taken by the utility consistent with the long-range integrated resource plan must be part of any Integrated Resource Plan.

Actions Underway

- ✓ Establishment of funds from 2019 surplus net revenues that may be applied toward Resource Adequacy, compliance with CETA, or other uses the Board of Commissioners determines.
- ✓ Bringing Combine Hills II wind contract to load.
- ✓ Staying abreast of conservation and demand response programs, distributed generation, and renewable technologies and opportunities.
- ✓ Making River Road Generating Plant more efficient by auto-tuning.
- ✓ Engaging with Small Modular Nuclear Reactor (SMR) developers.

Ongoing and Future Action Plan

- ✓ Acquire all cost-effective conservation consistent with NWPCC models and Clark Public Utilities' Conservation Potential Assessment.
- ✓ Buy all available Bonneville Power Administration Tier 1 power in 2021-2040 to cover needs.
- ✓ Budget research and development funds to join groups that can help inform decisions regarding GHG-free resources, GHG-free shaping and storage, and GHG-free retrofitting.
- ✓ BPA Contract analyses and strategies.
- ✓ Join Small Modular Nuclear Reactor consortium.
- ✓ Develop a River Road Generating Plant Flexibility Analysis and Business Plan.
- ✓ BPA Post-2028 Contract finalized with the CETA Requirements embedded.
- ✓ Increase local efforts on Demand Response.
- ✓ In partnership with customers and vendors, develop programs and pilots in areas of Renewable Distributed Generation and Electric Vehicles.

Conclusions

- ✓ Under most reasonable scenarios, Clark Public Utilities has sufficient annual average energy capability to meet its annual average energy requirements.
- ✓ In the years 2023-2028 Clark Public Utilities continues to need peaking capability.
- ✓ All cost-effective conservation and Demand Side Management, regardless of need, is assumed to be implemented.
- ✓ Bonneville Power Administration Tier 1 power will be the lowest cost resource to cover load growth and to meet the CETA requirements.
- ✓ River Road Generating Plant will continue to serve load as marginal economics dictate.

Section 1—Organization, Overview, Objectives and Approach

Organization of the Report

This report is divided into the following sections:

Clark Public Utilities Overview

Clark Public Utilities is a customer-owned public utility that provides electric service to more than 193,000 customers throughout Clark County, and water service to about 30,000 homes and businesses in unincorporated areas. For more than 75 years, bringing the community the most reliable and affordable electricity and water services possible has been Clark Public Utilities' number one priority. Highlights of these efforts include:

- No rate increases for the past 9 years (https://www.clarkpublicutilities.com/about-cpu/public-documents/current-electric-water-rates/) Select Rate History
- An award-winning Web Site that meets customer needs of all types (https://www.clarkpublicutilities.com/community-environment/community-resource-center/ and https://www.clarkpublicutilities.com/community-environment/
- Consistently rated number one for mid-size utilities in the west for 12 years in a row by J.D. Power and ranking at the top amongst all utilities in national surveys for customer satisfaction.
- 2020 Diamond Level Reliable Public Power Provider designation.
- Smart Energy Provider Program Designee.

Objectives of the IRP

This document encompasses Clark Public Utilities' IRP in its entirety. It will serve as a road map to identify reliable, cost-effective, sustainable strategies to meet the electric power requirements of Clark Public Utilities' customers over the next 20 years - Calendar Years (2021-2040). This IRP is consistent with Clark Public Utilities' regulatory requirements under the CETA and the EIA for both conservation and renewable portfolio standards (RPS).

Using a resource planning process to develop a roadmap for the future not only makes sense from a good business and utility planning perspective, but it also provides an opportunity for the utility to involve its customers/stakeholders in the planning process for future energy supply. Resource planning involves studying a broad range of alternative strategies including investments in energy conservation and DSM options, and investments in renewable and non-renewable power generating resources.

Approach to Integrated Resource Planning

Clark Public Utilities sees itself in a constant mode of Integrated Resource Planning. Commission meetings are always open for public comment and citizens often take the opportunity to engage the Commission in various important topics of the day that almost invariably include long-term planning with an eye toward Greenhouse Gas (GHG) reduction, energy efficiency, and sustainability. In addition, an annual power supply workshop held every fall provides another two days for the Commission to engage with staff and public on issues of importance to the utility at the local, state, and federal levels.

As part of the IRP, utility staff were tasked with developing staff papers on issues relevant to the IRP. Some have been included as appendices to this IRP, while all can viewed on the Clark Public Utilities IRP web page. Hyperlinks are included in this document for easy reference.

https://www.clarkpublicutilities.com/wp-content/uploads/2020/01/Electrification-of-Clark-County-IRP-page.pdf

https://www.clarkpublicutilities.com/wp-content/uploads/2020/02/MicroGrids-IRP-Page.pdf

https://www.clarkpublicutilities.com/wp-content/uploads/2020/02/A-Functional-Replacement-of-Combined-Cycle-Combustion-Turbine-using-Renewable-Energy-and-Batteries.pdf

In addition to the staff papers, Clark Public Utilities provided ample opportunity for written comments on top of the twice monthly opportunity to comment at normal commission meetings.

For convenience, one can access the public comments along with utility responses at the web address here.

Clark followed the timeline below to complete the IRP.

- **September 1, 2020;** IRP due to Commerce
- **Tuesday August 4, 2020;** Proposed Resolution and Adoption
- **Thursday July 30, 2020;** Final Conformed Copy deliver to Board with summary of public comments and any proposed changes to draft
- **July 17, 2020;** Summary of public comments and any proposed changes to draft provided to senior management and Board.
- **July 10, 2020;** Public Comment Period Ends
- **June 2, 2020;** Draft IRP presented to Board; Posted to Web Page for Public Comment Period
- **May 29, 2020;** Comments due back from Board of Commissioners
- **May 22, 2020;** Draft IRP delivered to Board of Commissioners
- **February 18, 2020;** Board of Commissioners public meeting. Status update, reminder of upcoming timeline and available web page for comments.
- **January 7, 2020;** Board of Commissioners public meeting. Status update.
- **January 6, 2020;** Public IRP Web page open for comments and draft papers to be posted. https://www.clarkpublicutilities.com/about-cpu/public-documents/integrated-resource-plan/
- **December 3, 2019;** Board of Commissioners public meeting. Status update, delineation of plan timeline and announcement of public IRP web page.
- **September 23-24, 2019;** Public Kick-off Meeting, Annual Power Supply Workshop. Presentations available upon request.

This IRP represents a “snapshot” in time of the current thinking of the staff and Commission as the date of adoption by the Commission. It does not bind the utility to any particular strategy and it does not preclude decisions, choices, or actions that may be made based upon changes in strategy, externalities, or policies adopted before or after its publication.

Section 2—Forecasted Incremental Electric Power Requirements

Introduction

The cornerstone of any IRP is a forecast of incremental future electric power requirements obtained through load/resource balancing. Forecasts of gross future electric power loads are determined for the utility through the time frame of the IRP. These are econometric based forecasts using past weather, local and national economics, and past load consumption patterns to fit a forecast to past use and project it into the future. Once the gross power loads have been established, then contributions to the distribution system from many various local activities will be forecasted resulting in a net retail load forecast. This retail net load forecast will then be compared to forecasts of owned and contracted wholesale to determine the forecasted incremental electric power requirements. These incremental requirements can be met through a myriad of demand and/or supply-side resource options.

Incremental requirements may vary by the hour depending on time of year, day of week, and time of day. Standard industry practice has been to group the requirements into two categories: Average and Peak. For the purposes of this IRP, two different requirements will be modeled and planned for: an Annual Average Energy Requirement and an Annual Peak Requirement. The Annual Average Energy Requirement is the average of all forecasted requirements over a calendar year. The Annual Peak Requirement is the largest forecasted one-hour requirement within the calendar year.

This section first examines the forecast of gross electric power requirements for the study period 2021 through 2040. Assumptions regarding existing resources will then be outlined.

Gross Electric Power Load Forecasts

Gross electric power requirements are the amounts of electric energy Clark Public Utilities customers require for heating, lighting, motors and other end-uses prior to accounting for any distribution system resources such as demand-side management including energy or peak conservation, demand response management or peak load shaving, or supply-side resource contributions such as rooftop solar, community solar, on-site generation backup or other any other resource type.

In developing the IRP model, Clark Public Utilities staff developed low, medium and high case gross system load forecasts for the period 2021 through 2040. The low and high cases provide a reasonable representation of a range of possible outcomes for the service area.

Projected system loads include distribution system losses of 3.6 percent. Figure 2.1 shows the three forecasts of Gross Electric Power Load used in this IRP, in annual average megawatts.

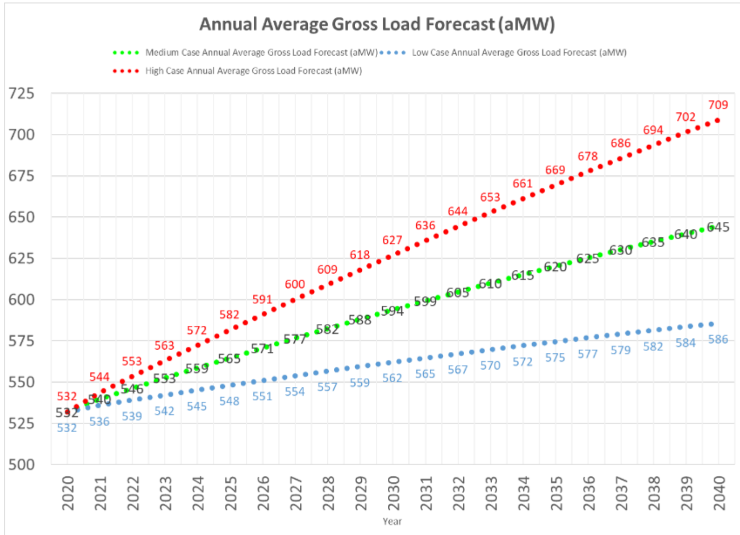


Figure 2.1
Forecast of Gross Electric Load – Annual Average Megawatts

* Note: An annual average megawatt (aMW) is calculated by dividing annual energy consumption in megawatt-hours (MWh) by the number of hours in a year.

Figure 2.2 shows the three forecasts of gross electric power annual peak requirements used in this IRP.

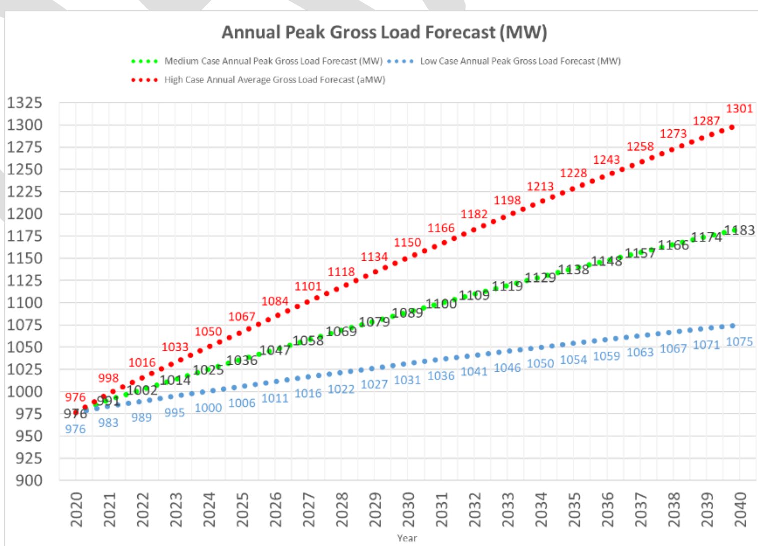


Figure 2.2
Forecast of Gross Electric Load – Annual Peak Megawatts

Net Electric Power Load Forecasts

The Gross Electric Power Load Forecasts provide insight to the potential magnitude of requirements by the system if no other activity were undertaken within the utility's retail service territory by the utility and/or its customers. These retail level contributions can be grouped into two categories: retail demand-side and retail supply-side. Within each category there are two different types of contributions, energy and peak.

Retail Demand-Side Contributions

Demand-side management achievements are derived from the 2019 Conservation Potential Assessment (CPA)/work plan and the 2020 Demand Response Potential Assessment. The CPA is attached to this IRP as Appendix A and the DRPA can be found in Appendix B. Both are summarized in Section 3. All cost effective programs when compared to market that are identified in the CPA and DRPA are also considered cost effective for purposes of planning in this IRP, regardless of need. Thus, no additional assessments or analyses of conservation resource options are required or necessary for consideration in meeting additional resource needs. Below are tables delineating the contributions of demand side retail programs to meeting energy and energy and peak loads under the medium case.

Retail Demand-Side Average Energy Contributors

Conservation

Medium Case Annual Energy Savings projected by 2019 CPA (aMW)							
Year	aMW	Year	aMW	Year	aMW	Year	aMW
2021	8	2026	30	2031	43	2036	52
2022	12	2027	34	2032	46	2037	53
2023	17	2028	37	2033	48	2038	54
2024	22	2029	39	2034	50	2039	54
2025	26	2030	41	2035	51	2040	54

Table 2.1

Retail Demand-Side Peak Contributors

Conservation

Medium Case Annual Peak Savings projected from Conservation (MW)							
Year	aMW	Year	aMW	Year	aMW	Year	aMW
2021	14	2026	55	2031	79	2036	96
2022	23	2027	62	2032	85	2037	98
2023	32	2028	67	2033	88	2038	99
2024	40	2029	72	2034	91	2039	100
2025	48	2030	76	2035	94	2040	99

Table 2.2

Demand Response

Medium Case Annual Peak Savings projected for Demand Response (MW)							
Year	aMW	Year	aMW	Year	aMW	Year	aMW
2021	1	2026	40	2031	62	2036	67
2022	5	2027	46	2032	63	2037	68
2023	13	2028	52	2033	64	2038	70
2024	21	2029	55	2034	65	2039	71
2025	30	2030	59	2035	66	2040	71

Table 2.3

Retail Supply-Side Resource Contributions

Average Energy Contributors

Retail Customer Generation (See Appendix D)

Medium Case Projected Annual Average Retail Customer Generation (aMW)							
Year	aMW	Year	aMW	Year	aMW	Year	aMW
2021	1	2026	3	2031	5	2036	10
2022	2	2027	3	2032	6	2037	12
2023	2	2028	4	2033	7	2038	14
2024	2	2029	4	2034	8	2039	16
2025	2	2030	5	2035	9	2040	18

Table 2.4

Net Load Forecast Results

Results from adjusting the Annual Average Gross Load forecasts by the retail demand-side and supply-side resources are shown below in Figure 2.3. The gross forecasts are included for comparisons.

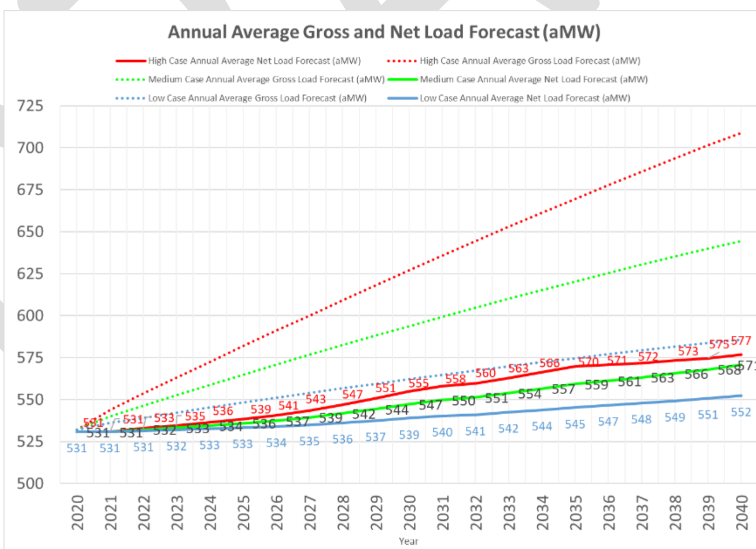


Figure 2.3
Forecast of Net Electric Load – Annual Average Megawatts

These efforts from the retail contributions reduce the 20-year load growth from an annual compounded growth rate of 0.96% for the gross forecast to 0.35% under the net forecast.

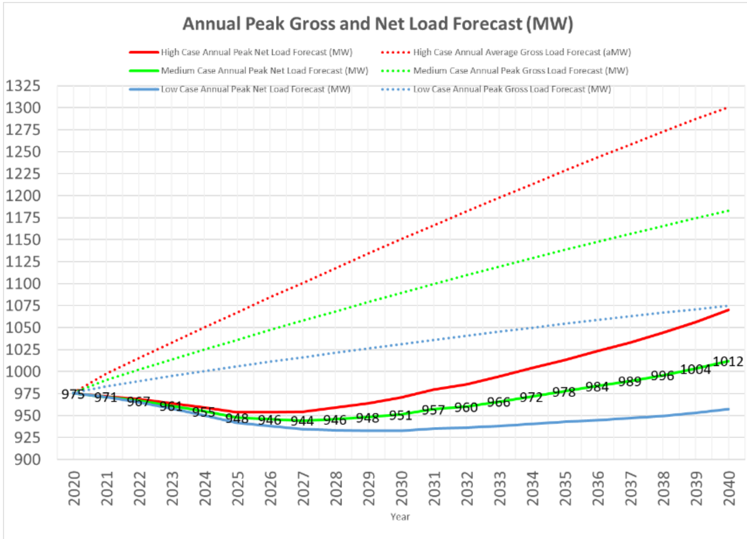


Figure 2.4
Forecast of Net Electric Load – Annual Peak Megawatts

Existing Resources

Clark Public Utilities owns and contracts for resources with different delivery periods and shapes. To forecast the incremental electric power requirements, the forecasted output from these resources must be subtracted from the forecasted gross electric power requirements. To forecast the output of these resources, both the average annual output plus the peak generation capability at the time of the gross electric power peak requirement must be modeled.

Existing Federal Resources

BPA Slice/Block Product – Present to Sep 30, 2028

Clark Public Utilities is currently a BPA Slice/Block customer. The Slice product provides a percentage of output similar to the actual production of the Federal Base System. The Block product provides a flat delivery of power to Clark Public Utilities across each month and is shaped throughout the year. Roughly, half of the BPA power is provided by the Slice product and the other half comes from Block. The Slice/Block resources constitute all of Clark Public Utilities' rights to Tier I power allocation or High Water Mark (HWM). Each utility's rate period HWM will be re-calculated for each rate case (every two years) based on the forecast of Federal-Based System output. For this study, it is assumed that Clark Public Utilities' HWM calculation will remain constant through September 30, 2028. In addition, for load/resource purposes, Clark Public Utilities will be planning to critical water for its Slice product. This is the standard approach for hydro resource planning.

After acquiring all cost-effective conservation and accounting for the social cost of carbon, Tier I product from BPA is by far the least expensive resource available to meet any annual energy needs of the utility. BPA Tier I power requires no additional transmission builds, provides long-term contract stability, and is largely GHG-free. In addition, to the extent Clark Public Utilities is in a situation where not all of the Contract High Water Mark (CHWM) energy has been utilized by Clark Public Utilities then any additional forecasted load growth must first be purchased from BPA up to the CHWM.

BPA Tier1 will be used as the first resource to meet any annual energy needs up to the limit imposed by the CHWM calculations.

BPA Product – October 1, 2028 – December 31, 2040

New BPA products and the opportunity to choose those products for delivery beginning October 1, 2028 are on the horizon. Much time and effort will be required between now and the decision date to enable Clark Public Utilities to make an informed decision. After that decision date, time and effort will be required to implement the product prior to the starting delivery date of October 1, 2028.

As the discussions regarding post 2028 BPA products and other attributes associated with those products such as the regional resource requirements under the Northwest Power Act paragraphs 5(b)/9(c) are very much in their infancy, some assumptions need to be made to be reflected in the expected resource contributions from BPA.

For the Forecasted Resource Net Requirements calculation, the assumption of average energy available from BPA will be based upon the operation of River Road Generating Plant under the CETA starting in 2030. River Road Generating Plant operations starting in 2030 are discussed in the following section. Of course, this assumption is not a given come 2030, so Clark Public Utilities is looking at other scenarios regarding the interplay between BPA power and River Road Generating Plant output. This discussion can be found in the Scenario Planning section.

Existing Non-Federal Resources

River Road Generating Plant (RRGP)

Clark Public Utilities owns and operates a combined cycle natural gas plant in Vancouver, Washington. RRGP connected to the grid in 1997 and provides base generation for Clark Public Utilities' customers. Air emissions from the plant are monitored continuously and are low enough that the facility is defined by state law as a minor source of emissions. The controls include a selective catalytic reduction system for control of nitrogen oxides that result from burning natural gas. Carbon monoxide emissions are controlled by using combustion controls and an oxidation catalyst. Water used in the plant is recycled extensively but must be replaced on a continuous basis. Two wells at the plant site serve as the water source. Water cycled through the plant is used to enhance nearby wetland areas and also to water lawns and landscaping at the nearby Vancouver Lake and Frenchman's Bar parks. Water not used for these purposes is discharged directly into the Columbia River after meeting appropriate water quality standards.

RRGP's status as a GHG emitting facility means additional scrutiny is required for planning purposes. The CETA language is very clear regarding the use of the social cost of GHG emissions. For convenience, the pertinent sections of the RCW 19.280 addressing Integrated Resource Planning and the social cost of GHG emissions are included below:

> *RCW 19.280.010*
> *Intent—Finding.*
> *It is the intent of the legislature to encourage the development of new safe, clean, and reliable energy resources to meet demand in Washington for affordable and reliable electricity. To achieve this end, the legislature finds it essential that electric utilities in Washington develop comprehensive resource plans that explain the mix of generation and demand-side resources they plan to use to meet their customers' electricity needs in both the short term and the long term. The legislature intends that information obtained from integrated resource planning under this chapter will be used to assist in identifying and developing: (1) New energy generation; (2) conservation and efficiency resources; (3) methods, commercially available technologies, and facilities for integrating renewable resources, including addressing any over-generation event; and (4) related infrastructure to meet the state's electricity needs.*
>
> *RCW 19.280.030*
> *(3)(a) An electric utility shall consider the social cost of greenhouse gas emissions, as determined by the commission for investor-owned utilities pursuant to RCW 80.28.405 and the department for consumer-owned utilities, when developing integrated resource plans and clean energy action plans. An electric utility must incorporate the social cost of greenhouse gas emissions as a cost adder when:*
> *(i) Evaluating and selecting conservation policies, programs, and targets;*

(ii) Developing integrated resource plans and clean energy action plans; and
(iii) Evaluating and selecting intermediate term and long-term resource options.

Clark Public Utilities will meet these legal requirements, which apply to the evaluation and selection of new energy resource options. As RRGP is neither a new resource, nor a resource option in the sense that Clark Public Utilities can walk away from its commitment to bond covenants, BPA contract energy declarations, or its commitment to maintain the physical location on which it sits, the consideration of the social cost of GHG emissions as considered in the CETA do not apply to RRGP. Other areas of the CETA will impact RRGP generation directly starting in 2030 as described in the section below.

Over the 5 years of 2014-2018, output from RRGP generated power equivalent to roughly 31 percent of Clark Public Utilities' annual average load requirements. Current all-in fully allocated costs for RRGP are in the $38 per MWh range absent any GHG taxes or penalties.

RRGP 2021 – 2029

During this period, marginal operating costs for RRGP will be the standard against which RRGP is measured when it comes to determining the planned generation for RRGP. Capital costs are "sunk costs" and must be paid whether the plant is running or not. Natural gas prices are projected to be less than $3/MMBtu throughout this timeframe. This puts the marginal cost for RRGP at less than $22.50/MWh. This cost is well below any long-term alternative replacement resource. Of course, this is just a planning assumption and actual RRGP generation will be much less as seasonal opportunities within each operating year during this period will present economic displacement opportunities.

RRGP 2030 – 2040

The year 2030 starts the first compliance period under the CETA. The CETA requires that Clark Public Utilities become carbon neutral, provided it does not impact Clark Public Utilities' revenue requirements by more than 2% each year. For the purpose of this IRP, the 2% revenue requirement impact will be ignored. This "cost cap" will become much more important in subsequent IRPs as Clark Public Utilities hones its Clean Energy Action and Clean Energy Implementation plans to meet the requirements of the first compliance period under the CETA. For this IRP, Clark Public Utilities assumes it will meet all compliance period obligations by limiting RRGP output to 20% of forecasted net load. To plan for any more than 20% would be under penalty of law per the CETA.

Packwood Project

The Packwood Lake hydroelectric project is located in Lewis County, Washington in the Gifford Pinchot National Forest. The project was constructed in the early 1960s and relicensed in 2008. The project is owned by Energy Northwest and output is purchased by several public utilities. Clark Public Utilities purchases 18 percent of project output, or approximately 10,370 MWh annually or a little over 1 aMW.

Combine Hills II Wind Project – Present to December 31, 2029

Combine Hills II is a 63 MW wind farm near Milton-Freewater, Oregon that began commercial operation in January 2010. Clark Public Utilities has a 20-year power purchase agreement with the project owners, Eurus Energy LLC. It is estimated that Clark Public Utilities will receive 160,308 MWh per year or 18 aMW from the Combine Hills II project. Past experience leads Clark Public Utilities to use 0 (zero) MW for the capacity contribution from CH II. This PPA expires on December 31, 2029. There are provisions in the current PPA that allow for the parties to extend the contract beyond 2029. For the Forecasted Resource Net Requirements calculation, the contract is assumed not to be renewed.

The following two tables, 2.6 and 2.7, delineate the expected generation from Clark Public Utilities' existing resources for average energy and peak respectively.

	Medium Case Existng Resources (aMW)				Low Case Existing Resources (aMW)				High Case Existing Resources (aMW)			
Year	BPA Net Requirements	RRGP	PackWood	Combine Hills II	BPA Net Requirements	RRGP	PackWood	Combine Hills II	BPA Net Requirements	RRGP	PackWood	Combine Hills II
2020	306	228	1	18	306	228	1	18	306	228	1	18
2021	306	228	1	18	306	228	1	18	306	228	1	18
2022	307	228	1	18	306	228	1	18	308	228	1	18
2023	308	228	1	18	307	228	1	18	310	228	1	18
2024	309	228	1	18	308	228	1	18	311	228	1	18
2025	311	228	1	18	308	228	1	18	314	228	1	18
2026	312	228	1	18	309	228	1	18	316	228	1	18
2027	314	228	1	18	310	228	1	18	317	228	1	18
2028	317	228	1	18	311	228	1	18	317	228	1	18
2029	315	228	1	18	308	228	1	18	322	228	1	18
2030	437	109	1	0	430	108	1	0	443	111	1	0
2031	439	110	1	0	431	108	1	0	446	112	1	0
2032	440	110	1	0	432	108	1	0	447	112	1	0
2033	442	111	1	0	433	108	1	0	449	113	1	0
2034	444	111	1	0	434	109	1	0	452	113	1	0
2035	446	112	1	0	435	109	1	0	455	114	1	0
2036	448	112	1	0	436	109	1	0	456	114	1	0
2037	450	113	1	0	437	110	1	0	456	114	1	0
2038	452	113	1	0	438	110	1	0	458	115	1	0
2039	453	114	1	0	440	110	1	0	459	115	1	0
2040	456	114	1	0	441	110	1	0	460	115	1	0

Table 2.6 Existing Resource Average Energy Contributions (aMW) Medium, Low and High Cases

Year	Medium Case Existing Resources (MW)				Low Case Existing Resources (MW)				High Case Existing Resources (MW)			
	BPA Net Requirements	RRGP	PackWood	Market	BPA Net Requirements	RRGP	PackWood	Combine Hills II	BPA Net Requirements	RRGP	PackWood	Combine Hills II
2020	508	260	1	350	508	260	1	300	508	260	1	350
2021	508	260	1	350	508	260	1	300	508	260	1	350
2022	508	260	1	0	508	260	1	0	508	260	1	0
2023	508	260	1	0	508	260	1	0	508	260	1	0
2024	508	260	1	0	508	260	1	0	508	260	1	0
2025	508	260	1	0	508	260	1	0	508	260	1	0
2026	508	260	1	0	508	260	1	0	508	260	1	0
2027	508	260	1	0	508	260	1	0	508	260	1	0
2028	508	260	1	0	508	260	1	0	508	260	1	0
2029	823	260	1	0	805	260	1	0	840	260	1	0
2030	823	260	1	0	802	260	1	0	845	260	1	0
2031	825	260	1	0	800	260	1	0	850	260	1	0
2032	823	260	1	0	796	260	1	0	851	260	1	0
2033	824	260	1	0	793	260	1	0	856	260	1	0
2034	825	260	1	0	790	260	1	0	861	260	1	0
2035	826	260	1	0	787	260	1	0	866	260	1	0
2036	828	260	1	0	785	260	1	0	872	260	1	0
2037	829	260	1	0	782	260	1	0	878	260	1	0
2038	831	260	1	0	779	260	1	0	886	260	1	0
2039	833	260	1	0	777	260	1	0	893	260	1	0
2040	836	260	1	0	775	260	1	0	901	260	1	0

Table 2.7 Existing Resource Peak Energy Contributions (MW) Medium, Low and High Cases

Planning Margin for Peak Requirement Planning

A planning margin for meeting peak requirement has been part of Clark Public Utilities' IRP for several years. Over the past 18 months, resource adequacy has taken a very visible role in many venues including legislation. Clark Public Utilities includes its planning margin in its Incremental Electric Power Requirements calculation as a means to account for resource adequacy. Appendix C – Resource Adequacy Metrics Determination delineates Clark Public Utilities position regarding calculation of a resource adequacy metrics.

Incremental Electric Power Requirements

With forecasts of net electric load and expected output from existing resources, the incremental electric power requirements can be forecast.

Annual Average Energy Results

Table 2.8 shows the results of these calculations on an annual energy basis. Clark Public Utilities is surplus or load/resource balance on an annual energy basis throughout the study period.

Year	Medium Case Incremental Energy Requirements (aMW)			Low Case Incremental Energy Requirements (aMW)			High Case Incremental Energy Requirements (aMW)		
	Annual Average Net Load Forcast	Existing Resource	Surplus(+) /Deficit (-)	Annual Average Net Load Forcast	Existing Resource	Surplus(+) /Deficit (-)	Annual Average Net Load Forcast	Existing Resource	Surplus(+) /Deficit (-)
2020	531	553	22	531	553	22	531	553	22
2021	531	553	22	531	553	22	531	553	22
2022	532	554	22	531	553	22	533	555	22
2023	533	555	22	532	554	22	535	557	22
2024	534	556	22	533	555	22	536	558	22
2025	536	558	22	533	555	22	539	561	22
2026	537	559	22	534	556	22	541	563	22
2027	539	561	22	535	557	22	543	564	21
2028	542	564	22	536	558	22	547	564	17
2029	544	562	18	537	555	18	551	569	18
2030	547	547	0	539	539	0	555	555	0
2031	550	550	0	540	540	0	558	558	0
2032	551	551	0	541	541	0	560	560	0
2033	554	554	0	542	542	0	563	563	0
2034	557	557	0	544	544	0	566	566	0
2035	559	559	0	545	545	0	570	570	0
2036	561	561	0	547	547	0	571	571	0
2037	563	563	0	548	548	0	572	572	0
2038	566	566	0	549	549	0	573	573	0
2039	568	568	0	551	551	0	575	575	0
2040	571	571	0	552	552	0	577	577	0

Table 2.8 Annual Average Incremental Energy Requirements

Annual Peak Load Results

Tables 2.9 show the results under Peak Load conditions.

Year	Medium Case Incremental Peak Requirements (MW)				Low Case Incremental Peak Requirements (MW)				High Case Incremental Peak Requirements (MW)			
	Annual Peak Net Load Forcast	Planning Margin	Existing Resource	Surplus(+) /Deficit (-)	Annual Peak Net Load Forcast	Planning Margin	Existing Resource	Surplus(+) /Deficit (-)	Annual Peak Net Load Forcast	Planning Margin	Existing Resource	Surplus(+) /Deficit (-)
2020	975	117	1119	27	975	117	1119	27	975	117	1119	27
2021	971	117	1119	31	971	117	1119	31	972	117	1119	31
2022	967	116	769	-314	965	116	769	-312	968	116	769	-316
2023	961	115	769	-307	958	115	769	-304	964	116	769	-311
2024	955	115	769	-300	950	114	769	-296	959	115	769	-305
2025	948	114	769	-293	942	113	769	-286	954	114	769	-299
2026	946	113	769	-290	938	113	769	-281	954	114	769	-299
2027	944	113	769	-289	934	112	769	-278	955	115	769	-300
2028	946	114	769	-291	933	112	769	-276	959	115	769	-305
2029	948	114	1062	0	933	112	1045	0	964	116	1080	0
2030	951	114	1066	0	933	112	1045	0	971	116	1087	0
2031	957	115	1072	0	935	112	1047	0	980	118	1097	0
2032	960	115	1076	0	936	112	1048	0	985	118	1104	0
2033	966	116	1082	0	938	113	1051	0	995	119	1114	0
2034	972	117	1088	0	941	113	1053	0	1004	120	1125	0
2035	978	117	1095	0	943	113	1056	0	1013	122	1135	0
2036	984	118	1102	0	945	113	1058	0	1023	123	1146	0
2037	989	119	1108	0	947	114	1061	0	1033	124	1157	0
2038	996	120	1116	0	950	114	1064	0	1044	125	1170	0
2039	1004	120	1124	0	953	114	1068	0	1056	127	1183	0
2040	1012	121	1134	0	957	115	1072	0	1070	128	1198	0

Table 2.9 Annual Peak Incremental Requirements

Section 3 - Conservation and Demand Response Potential Assessments

Introduction

Clark Public Utilities' most recent Conservation Potential Assessment (CPA) and Demand Response Potential Assessment (DRPA) are summarized in this section of the IRP. The CPA is attached to this IRP as Appendix A. The DRPA is attached to this IRP as Appendix B.

The CPA is meant to explore conservation resources in Clark Public Utilities' service area and to act as a planning document for meeting the requirements of the EIA. The CPA analysis provides conservation supply curves specific to Clark Public Utilities' service territory, defines near- and long-term conservation targets, and provides input to the IRP.

Similarly, The DRPA is meant to explore demand response opportunities in Clark Public Utilities' service area and to act as a planning document for meeting the requirements of the CETA. The CPA analysis provides conservation supply curves specific to Clark Public Utilities' service territory, defines near- and long-term conservation targets, and provides input to the IRP

Summary of CPA

Table 3.1 shows the high level results of the assessment.

Cost Effective Potential (aMW)				
	2-Year	6-Year	10-Year	20-Year
Residential	3.04	11.18	17.81	23.75
Commercial	4.08	11.42	16.10	21.22
Industrial	1.77	5.22	6.71	7.15
Distribution Efficiency	0.09	0.52	1.21	3.41
Total	**8.97**	**28.33**	**41.83**	**55.53**

Table 3.1

These estimates include energy efficiency achieved through Clark Public Utilities' own utility programs, and also through Clark Public Utilities' share of the Northwest Energy Efficiency Alliance (NEEA) accomplishments. In the later years (e.g., beyond 5 years), a portion of the potential could be achieved through codes and standards changes.

This potential is shown on an annual basis in Figure 3.1. This assessment shows the starting point at just under 4.5 aMW per year and increasing over the next six years.

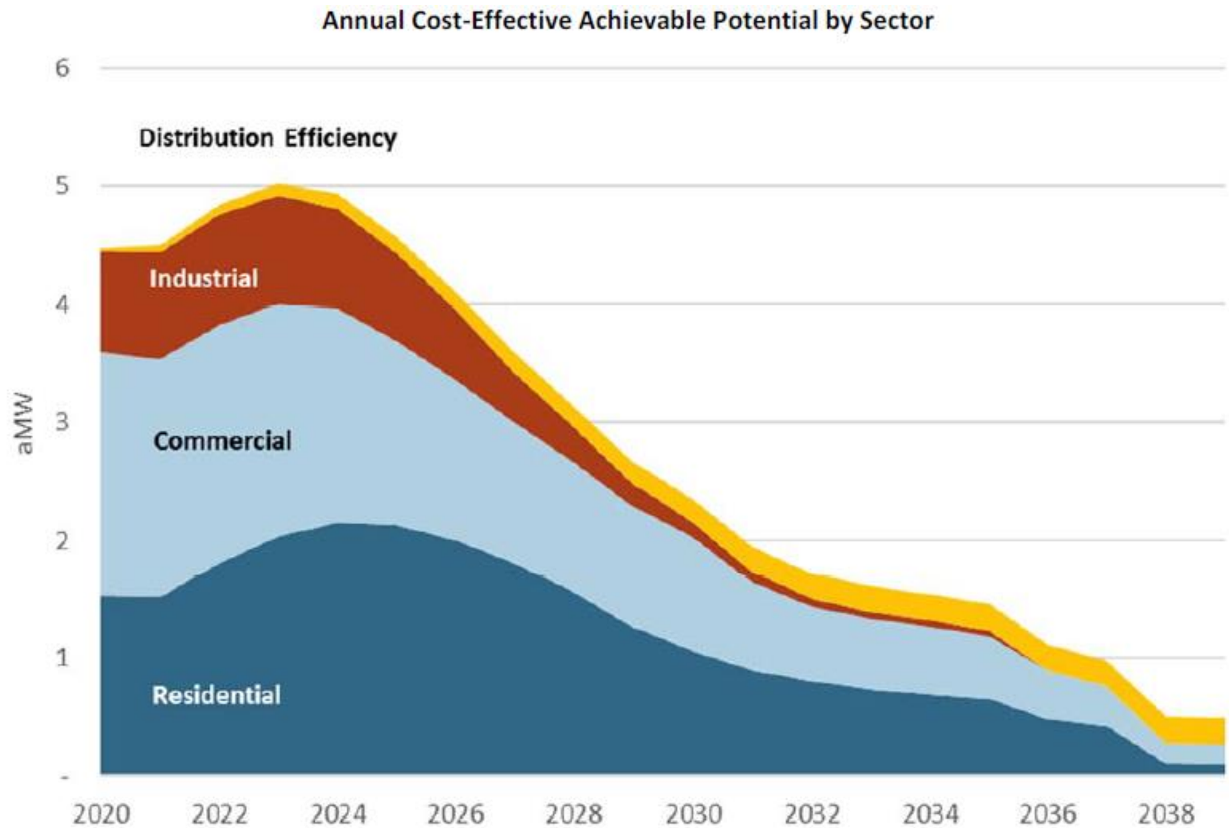


Figure 3.1 Annual Energy Efficiency Potential Estimates

The CPA shows that after many years of aggressive conservation programs coupled with lower electricity costs, more stringent building codes for residential and commercial, new codes and standards, and the cessation of lighting programs, the market for energy efficiency is being impacted. The result is lower overall long-term potential, which of course is an accomplishment to celebrate. However, the near-term potential and targets remain about the same as the previous assessment. Moving forward, achieving the same or greater levels of energy efficiency will likely become increasingly difficult and more expensive.

Section 4—Wholesale Supply-Side Resource Options Assessment

Overview of Supply-Side Resource Acquisition Alternatives

Clark Public Utilities has a number of options for purchasing power or acquiring output from generating resources to meet requirements in excess of its existing resource mix. The costs associated with the various supply side resource alternatives included in this report are the same regardless of whether Clark Public Utilities purchases a share of the output of a generating resource via a power purchase agreement or owns the resource outright. There are advantages to both options.

Purchasing Output via Contract versus Asset Ownership

The advantages to purchasing a share of the output from a generating resource rather than developing and owning a resource include:

- Economies of scale typically show that resources need to be fairly large (minimum of 70 to 100 MW) to be cost effective
- Resource development contains significant risk, such as capital expenditure overruns and delays in the commercial operation date (COD)
- Resource operation also includes significant risk, such as the potential for major unplanned outages and fuel price uncertainties

The most significant risks associated with resource development include capital expenditure overruns and delays in the commercial operation date (COD). Capital expenditure overruns can be caused by increased costs associated with plant equipment, fuel transportation infrastructure (i.e. gas pipeline interconnects) and transmission interconnections. Delays in the COD could require the utility to purchase market power to cover the months prior to the COD when the utility may be short resources due to the delay. This represents a significant risk because the utility would have no choice but to pay prevailing market prices. The complexity of arranging capital financing can also be very time consuming, complicated, and could lead to delays in the COD. The complexity and time required to set up financing is only exacerbated when multiple entities/utilities with different structures (municipalities, coops, public utilities, etc.) finance and build a resource together.

There are also significant risks associated with resource ownership after a project has achieved commercial operation. The most significant of these risks are fluctuating fuel prices and major plant outages. Both of these risks could leave a utility relying on fuel or power markets to provide power required to serve load. Historically, natural gas markets in particular have shown great volatility. This volatility requires utilities to closely manage the risks associated with their fuel purchases via risk management policies. Locking in fuel prices is the best way to hedge against a utility's exposure to fluctuating market prices; however, utilities that own gas-fired resources can never fully insulate themselves from market uncertainty. Major plant or pipeline outages could leave a utility with no other option but to purchase energy at prevailing electric market prices. This represents significant risk exposure for the utility during these periods.

There are also benefits to resource ownership including:

- the ability to economically dispatch the resource
- fewer transmission constraints if the resource is sited within the utility's service territory
- the ability to hedge market risks associated with fuel purchases
- the ability to manage fuel transportation costs
- the likelihood of greater flexibility to use the resource as a load following resource, particularly with respect to meeting peak demands

Generating Resources Assessment Overview

Current Landscape

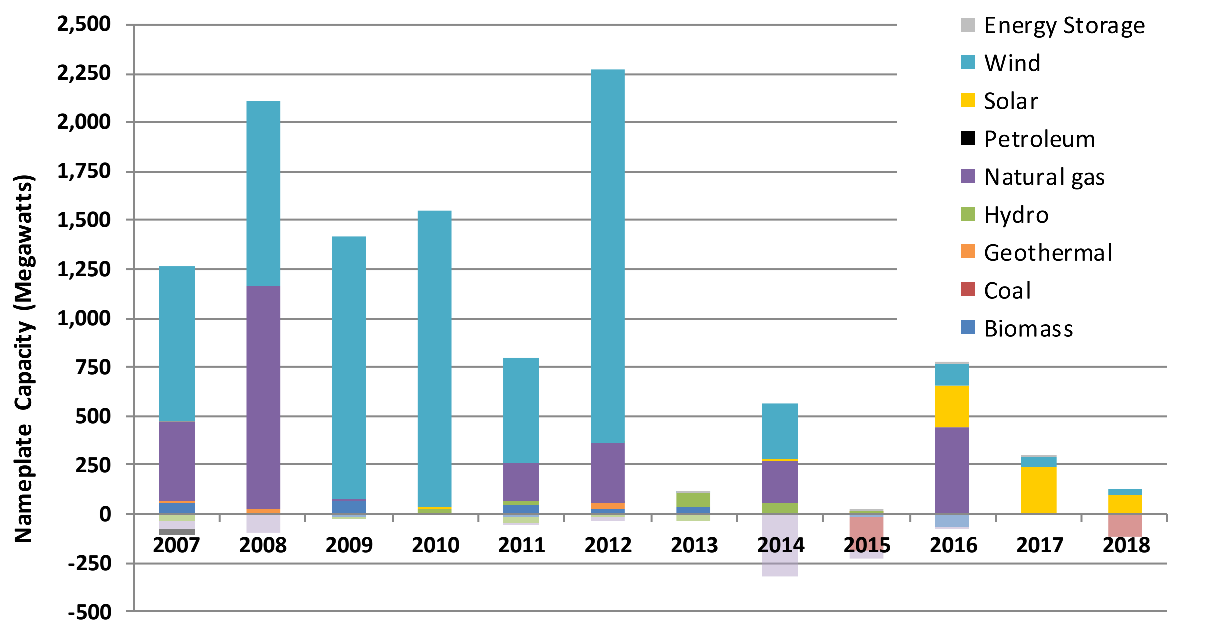
There are several legislative mandates that will play key roles in the development of new resources in the Northwest. While a wide range of supply side resource options are considered by utilities in the screening of resources, many are quickly eliminated from consideration due to legislative mandates.

Due to Renewable Portfolio Standard (RPS) requirements in Washington and elsewhere in the region (California, Oregon and Montana), there is currently a high demand for renewable resources. Utilities in Washington State with 25,000 customers or more are obligated to purchase eligible renewable energy on an annual basis in order to comply with the Energy Independence Act (EIA). The EIA requires utilities to obtain increasing percentages of their total retail load from eligible renewable resources, such as solar and wind. The renewable energy purchase requirements increased from 3 percent in 2012-15 to 9 percent in 2016-19 and 15 percent beginning in 2020. In addition, there are cost caps in the EIA that protect utilities from spending more than 1 percent or 4 percent of revenue requirements in meeting percentage of load requirements. Clark Public Utilities has, historically, met its EIA renewable energy purchase requirements using the Renewable Energy Credits associated with the Combine Hills II wind project and the wind projects included in BPA's Tier 1 resource pool in combination with the cost caps.

In addition, Oregon's largest utilities must currently acquire 20 percent of their energy from renewables. The requirements increase to 25 percent in 2025 and 50 percent in 2040.

As shown below in Figure 4.1, recent supply side resource development in the Northwest has primarily been limited to wind projects required to meet RPS requirements and natural gas plants. Figure 4.1 demonstrates that wind has been the most readily available and cost-effective renewable resource while natural gas-fired generation has been the most readily available and cost-effective non-renewable resource. According to the NWPCC approximately 7,500 MW of wind and 2,700 MW of natural gas-fired generation was developed between 2007 and 2018 compared to 250 MW of biomass, 175 MW of hydro, 550 MW of utility-scale solar, 60 MW of geothermal and 12 MW of energy storage.

Pacific Northwest Generation Additions and Retirements (MW)



* Projects considered additions if in service or construction is near complete. Retirements do not include plants that have been idled for potential future use.

Figure 4.1
Source: Northwest Power and Conservation Council (August 2019)

Supply-side resources can be divided into two categories – dispatchable and not dispatchable. Unless paired with batteries, wind and solar, which are renewable and carbon-free, are not dispatchable. Some renewable resources are dispatchable such as geothermal, landfill gas and biomass. Non-renewable resources typically are dispatchable. Table 4.1 below shows a summary of supply-side resource characteristics.

Supply-Side Resource Characteristics							
	Dispatchable	**Energy**	**Capacity**	**Flexibility**	**Renewable**	**Carbon-Free**	**New Builds**
Coal	Yes	Yes	No	No	No	No	No
Natural Gas – Base	Yes	Yes	Yes	Yes	No	No	Yes
Natural Gas – Peaker	Yes	No	Yes	Yes	No	No	Yes
Nuclear	Yes	Yes	No	No	No	Yes	No
Hydro	Yes	Yes	Yes	Yes	No	Yes	Limited
Wind	No	Yes	No	No	Yes	Yes	Yes
Solar - Photovoltaic	No	Yes	No	No	Yes	Yes	Yes
Solar – Thermal	Limited	Yes	Limited	No	Yes	Yes	Yes
Geothermal	Yes	Yes	Yes	Yes	Yes	Yes	No
Storage (e.g. Battery)	Yes	No	Yes	Yes	Yes	Yes	Yes
Energy Efficiency	No	Yes	No	No	No	Yes	Yes
Demand Response*	Yes	No	Yes	Yes	No	Yes	Yes

Table 4.1

*Including dispatchable load. Source: Northwest Power and Conservation Council

It should be noted that the supply-side resources developed in the Northwest over the past decade have primarily been wind projects and as such, have no dispatchability or contribution to meeting peak demands. While the region's hydroelectric system is capable of providing adequate generation to meet energy load requirements and peaking capacity requirements under base case conditions, the region will need additional winter peaking capacity to maintain system adequacy under low hydro and extreme weather conditions. As such, the potential for demand response programs that reduce the need for peaking resources and battery systems that can back up renewable resources will be assessed by most utilities over the next five to ten years.

Generating Resources Costs and Characteristics

Estimated cost information for both fossil fuel-fired and renewable resources is based on current market prices for plant equipment and a survey of published resource planning studies. The NWPCC's 2021 Power Plan (currently under development), annual data provided by the Energy Information Administration and IRPs developed by regional utilities in the Pacific Northwest in 2019 were surveyed to provide benchmarks for capital, fixed and variable operation and maintenance, and environmental mitigation costs.

Fossil fuel-fired resource cost estimates included in this section do not include environmental mitigation costs including costs associated with carbon dioxide (CO_2), mercury and nitrous oxide nor do they include an estimate of the social cost of carbon.

Natural Gas-Fired Combustion Turbines

Fuel costs typically represent 60 to 80 percent of combustion turbine (CT) project costs. Natural gas prices are currently low by historic standards due to the advancements in hydraulic fracking that occurred over the past decade. These advancements have significantly increased the supply of natural gas available in North America. Figure 4.2 below shows the range of natural gas price forecasts for the Sumas delivery point.

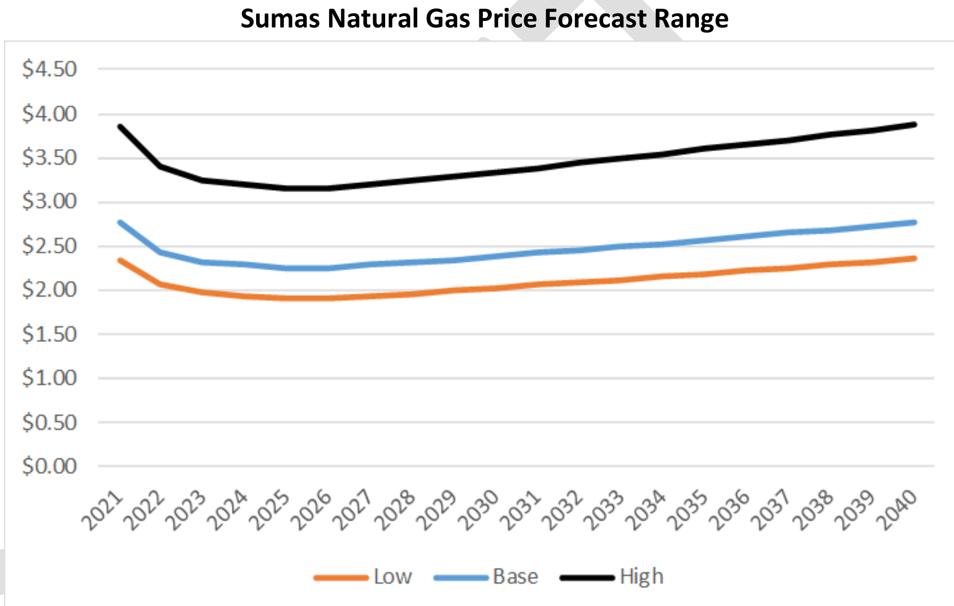


Figure 4.2
Source: S&P Global

The high natural gas price forecast recognizes the possibility that demand may outstrip supply in the future due to limited supplies. The supply of natural gas could become limited if global economic growth accelerates and/or if the use of gas-fired resources as "bridge resources" used to provide peaking capability and reliably serve base load until carbon-free resource technologies mature, is accelerated. A build-up of new natural gas-fired generating stations to be used as bridge resources could drive up natural gas market prices as could an increase in the amount of natural gas that is exported out of the U.S. as liquefied natural gas. The low case assumes slow world economic growth which reduces the pressure on energy supplies.

Two types of CTs are typically included in resource studies: simple-cycle combustion turbines (SCCTs) and combined-cycle combustion turbines (CCCTs). The primary difference between the two technologies is that a CCCT recovers the waste steam that is lost in a simple-cycle and uses this energy to turn an additional steam turbine. In base-load operations, a CCCT is preferred because of its greater thermal efficiency and lower cost on a per unit basis. A SCCT is more appropriate to ramp generation levels up and down to meet peak loads and back up intermittent renewable resources.

Coal

Coal combustion is one of the oldest and most well-established methods of generating electricity. Due to environmental regulations of the air emissions and other environmental impacts associated with coal-fired power plants, very large central station plants (1,000 megawatts or more) are no longer considered to be economically efficient. In addition, the development of coal plants is prohibited by legislation in Washington, Oregon, and California. Legislation also calls for the retirement of existing coal plants. The planned retirements of coal plants on the west coast are shown below in Figure 4.3.

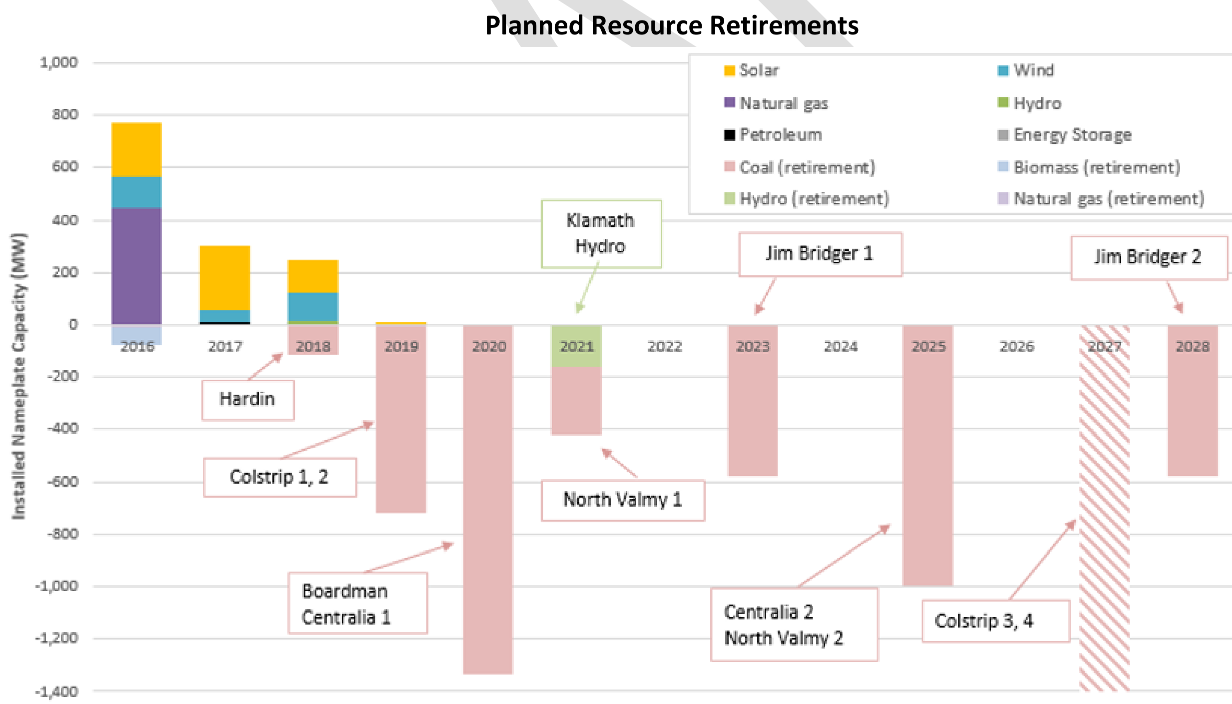


Figure 4.3

Source: NWPCC, Generating Resources Advisory Committee's December 2019 Meeting

According to the Sierra Club, 270 coal plants, or more than 50 percent of the 530 coal plants that were in operation in 2010 in the United States have been shut down. Coal plant retirements are likely to continue across the U.S. due to low natural gas prices and legislation regulating carbon emissions.

Nuclear

Due to the long lead-time, development and permitting timeframe, and issues related to the disposal of spent fuel, it is unlikely that new large-scale nuclear power plants will be developed. In addition, three nuclear power accidents have influenced the discontinuation of nuclear power: the 1979 Three Mile Island partial nuclear meltdown in the United States, the 1986 Chernobyl disaster in Russia, and the 2011 Fukushima nuclear disaster in Japan. Following the March 2011 Fukushima nuclear disaster, Germany permanently shut down eight of its 17 reactors and pledged to close the rest by the end of 2022. Italy voted overwhelmingly to keep their country non-nuclear. Switzerland and Spain have banned the construction of new reactors. Japan is also reducing its reliance on nuclear power.

In the United States, eight nuclear plants have shut down in the past six years because they could not compete with the lower running costs of natural gas projects. A ninth plant, the San Onofre Nuclear Generating Station (SONGS), shut down in 2013 due to the failed replacement of steam generators. Ten more nuclear plants are scheduled to shut down between now and 2025, including Diablo Canyon's two reactors in California in 2024 and 2025. Since nuclear plants are carbon-free, carbon dioxide emissions generally increase in regions where nuclear plants are shut down. Annual carbon dioxide emissions increased by an estimated 11 million tons due to the closure of SONGS, which had a capacity of near 1,100 MW.

BPA's Tier 1 resource pool includes the 1,190-megawatt Columbia Generating Station (CGS), a nuclear power plant that began operating in 1984. CGS is the only commercial nuclear energy facility in the region. All of its output is provided to BPA at the cost of production under a formal "net billing" agreement in which BPA pays the costs of maintaining and operating the facility.

Small Scale Modular Reactors

NuScale Power LLC submitted a design certification application to the Nuclear Regulatory Commission in January 2017. In December 2019, NuScale completed phase 4 of the NRC's six-phase safety review process for small modular reactor applications. Phases 5 and 6 are scheduled to be completed in May and September 2020, respectively. The modules can be combined in 12-part units producing as much as 720 megawatts in total. The systems are built in a factory and are scalable such that utilities can add modules as loads increase. NuScale is backed by the U.S. Department of Energy, which awarded $226 million to NuScale in 2013 to develop small scale nuclear modular reactor technology as a clean alternative to fossil fuels.

Utah Area Municipal Power System (UAMPS) selected NuScale and partner Energy Northwest to construct a small scale nuclear modular plant in Idaho, near the Department of Energy's Idaho National Energy Laboratory near Idaho Falls. The UAMPS project, scheduled for commercial operation in 2026, would be the first of its kind in the region.

Energy Northwest representatives have said that their experience with the plant in Idaho may lead the way toward siting a small modular reactor somewhere in the Northwest. Given the region's historical experience with nuclear power and the presence of ENW, the Tri-Cities would likely be first on the list of potential locations to site a small nuclear reactor in Washington. Modular reactors may provide a valuable future resource alternative in the state of Washington as utilities attempt to balance the need for carbon-free resources required to meet the CETA with the need for baseload resources that can reliably serve load.

There are currently no commercially operational SMRs. The NWPCC considers SMRs to be an "emerging" technology and will not include SMRs in the 2021 Plan's resource portfolios. According to NuScale the levelized cost of energy of the first commercially operational SMR will be near $55/MWh.

Renewable Energy Resources Overview

The primary benefit of renewable energy projects, such as wind and solar, is that they provide renewable, carbon-free energy that can be used to meet state RPS and carbon-free energy requirements. In addition, renewable projects allow utilities to diversify their risk portfolio by reducing their exposure to fuel price risk.

Due to RPS requirements in Washington state and elsewhere in the region, there was intense competition for wind projects during the period 2006 through 2012. However, loads dropped after the great recession and as shown in Figure 4.1 above, wind project development dropped as well. Most utilities have addressed their near-term RPS requirements and are now working toward identifying renewable resources that can help them meet carbon-free requirements such as the CETA.

There is a risk that, due to the renewable and carbon-free energy targets, large utilities in the Northwest and California may be purchasing much of the supply of the least cost/high capacity factor wind and solar projects. With large utilities purchasing large amounts of renewable generation and competition from out-of- region utilities with increasing RPS and carbon-free requirements, it may be difficult for small- and medium-sized utilities to find enough megawatts to meet their own requirements. There are a great number of uncertainties surrounding future state and federal renewable and carbon-free energy requirements and the impact on eligible renewable and carbon-free generation available in the market and Renewable Energy Credit (REC) prices.

Since 2005, various tax credits have been available to encourage the development of renewable generation. Each tax credit is discussed below.

The Energy Policy Act of 2005 provided for the renewal of the Production Tax Credit (PTC) for wind resources placed in service by December 2007. Since then, the PTC has been extended several times such that the PTC currently provides a credit of 2.5 cents per kWh of actual energy generated applicable to the first 10 years of operation. In December 2015, the expiration date for the full tax credit was extended to apply to wind facilities that commence construction before December 31, 2016.

The tax credit was phased down beginning in 2017 but will, on a reduced basis, be available to wind facilities that begin construction between January 1, 2017 and December 31, 2020. The PTC was reduced by 20 percent, 40 percent and 60 percent for wind facilities commencing construction in 2017, 2018 and 2019, respectively. Recent legislation will allow wind projects completed in 2020 to be eligible for 60 percent of the credit. For all other technologies, the credit is not available for systems whose construction commenced after December 31, 2017 and the credit is set to expire for wind projects at the end of 2020.

Investment Tax Credits (ITC) are similar to the PTC except that a share of project expenditures is available as a tax credit up front (rather than over the course of 10 years like the PTC). The ITC applies to solar, fuel cells, small wind turbines, geothermal, micro-turbines, and combined heat and power. Depending on the technology and timing of investment, it may be more beneficial for developers to pursue the ITC rather than the PTC. Based on current regulations, the current 30 percent credit was available to eligible wind facilities placed in service on or before December 31, 2016, after which time the credits ramped down by 6 percent per year until they expired on December 31, 2019.

The credit for equipment that uses solar energy to generate electricity, to heat or cool (or provide hot water for use in) a structure, or to provide solar process heat was 30 percent through 2019. The credit for solar projects decreased from 30 percent in 2019 to 26 percent in 2020 and will decrease to 22 percent in 2021 and 10 percent in 2022, where it will remain. The credit is not available for residential systems. The credit for geothermal generating projects will remain at 10 percent (does not expire).

The federal Renewable Energy Production Incentive (REPI) provides incentive payments similar to the PTC for electricity produced and sold by new qualifying renewable energy facilities owned by not-for-profit electrical cooperatives, public utilities and state governments. Qualifying systems are eligible for annual incentive payments for the first 10-year period of their operation just like the PTC; however, REPI benefits are subject to the availability of annual appropriations in each federal fiscal year of operation. The REPI program has been under-funded in recent years, with appropriations so low that utilities have not been able to utilize the program.

Wind Generation

Wind turbines convert wind energy into electricity by collecting kinetic energy generated when the blades that are connected to a drive shaft (rotor) turn a turbine generator. Individual wind turbines typically have a capacity of near 2.5 megawatts. Wind generation facilities typically range in size from 50 to 300 megawatts.
Wind generation developed rapidly in the Pacific Northwest over the past decade as shown above in Figure 4.1. Currently, there are over 9,000 megawatts of capacity from wind projects installed in the Pacific Northwest. According to the Renewable Northwest Project, only 240 megawatts of wind is currently under construction in south central Montana. However, due to RPS and carbon-free energy requirements, such as the CETA, wind will be a viable and feasible renewable resource in the future.

The capacity factors of wind projects located in the Columbia River Gorge vary from 30 to 40 percent. The average capacity factors of wind project located in eastern Montana vary from 35 to 45 percent. Due to transmission constraints, almost all of the wind projects developed over the past decade have a capacity factors of 30 to 35 percent. Due to the intermittency of wind and the unpredictability of the output, the amount of hourly generation is uncertain. The fact that wind power generation is variable, and not wholly predictable, means that electricity system operators must provide additional reserves to counter the additional risk in balancing power supply and demand. In addition, wind power output is often not available when it is most needed such as during summer heat waves, or winter arctic outbreaks, when wind turbine generation is low due to reduced wind velocities.

Since wind output cannot be assumed to be available in all hours, other generating resources need to be on call to be ramped down when wind resources provide generation and ramped up when wind resources do not provide generation. Providing within-hour balancing services for variable wind power, including additional reserve capacity and shifting generation patterns is known as wind integration. Typically, this requires larger utilities that operate control areas to use dispatchable resources to balance instantaneous generation and load levels. Currently, the capacity and flexibility for balancing intermittent wind in BPA's Balancing Authority Area comes almost entirely from the Federal Base System.

Based on a survey of capital costs, capacity factors and O&M costs included in the NWPCC's 2021 Power Plan (under development) and recent IRPs completed by IOUs in the region, the projected 20-year (2021-40) levelized cost of wind energy in the Northwest ranges from $44 per megawatt-hour for a project located in eastern Montana with a 43 percent capacity factor to $52 for a project located in the Columbia River Gorge with a 37 percent capacity factor. PTC credits were not included in the levelized cost calculations. The assumptions included in the levelized cost calculations are provided below in table 4.2.

Utility-Scale Solar Generation

Solar energy is the direct harnessing of the sun's energy. The major issues to overcome with respect to solar energy are: 1) the intermittent and variable manner in which sun energy arrives at the earth's surface and 2) the large area required to collect the sun's energy at a useful rate. In the case of solar Photovoltaic (PV) systems, the process is direct, via silicon-based cells. In the case of Concentrating Solar Power (CSP), the process involves heating a transfer fluid to produce steam to run a generator. Both of these technologies are discussed below.

PV systems use PV cells to convert sunlight into direct current electricity. PV cells are made from silicon and come wired together in 5 feet by 3 foot by 1.5-inch-deep panels. A group of panels mounted on a frame is called a PV array. There are numerous large-scale PV projects installed around the world. These installations include all sizes of commercial and public facilities (from a few to several hundred megawatts). A typical capacity factor for a PV system is near 20 percent.

CSP technologies use reflective materials such as mirrors to concentrate the sun's energy and convert it to electricity. CSP technologies are more efficient (approximately 30 percent capacity factor) than PV and have the potential to be more cost-effective and practical than PV for centralized plants. The general types of CSP technologies are:

Dish Systems: A dish system uses a mirrored dish (similar to a very large satellite dish) which collects and concentrates the sun's heat onto a receiver, which absorbs the heat and transfers it to fluid within an engine. The heat causes the fluid to expand against a piston or turbine to produce mechanical power. The mechanical power is then used to run a generator or alternator to produce electricity.

Parabolic Troughs: Parabolic-trough systems concentrate the sun's energy through long rectangular, curved (U-shaped) mirrors. The mirrors are tilted toward the sun, focusing sunlight on a pipe that runs down the center of the trough. This heats the oil flowing through the pipe. The hot oil then is used to boil water in a conventional steam generator to produce electricity.

Power Towers: A power tower system uses a large field of mirrors to concentrate sunlight onto the top of a tower, where a receiver sits. This process heats molten salt that is flowing through the receiver. The salt's heat is used to generate electricity through a conventional steam generator. Molten salt retains heat efficiently, so it can be stored for days before being converted into electricity. That means electricity can be produced on cloudy days or even several hours after sunset.

Concentrating Photovoltaic: Concentrating PVs use optics to concentrate sunlight onto a small area of solar cells. These photovoltaic cells convert the light into electricity. Most concentrators use tracking capability that allows concentrators to take advantage of as much daylight as possible from dawn until dusk.

CSP projects have higher costs than PV systems and take more time to construct. Due to these factors, CSP projects are most likely to be built in the Southwest. The relatively high costs and investment risk of long-distance transmission needed for the output of the highly efficient plants to reach Northwest load centers have made them less attractive in the Northwest.

The national solar energy market is changing rapidly. Over 10,000 megawatts of solar capacity was added in the U.S. in 2018 and near 13,000 megawatts in 2019. Figure 4.4 shows actual solar PV capacity installations in 2010 through 2018 and expected installations in 2019 through 2024.

U.S. PV Installation Forecast (2010-2024)

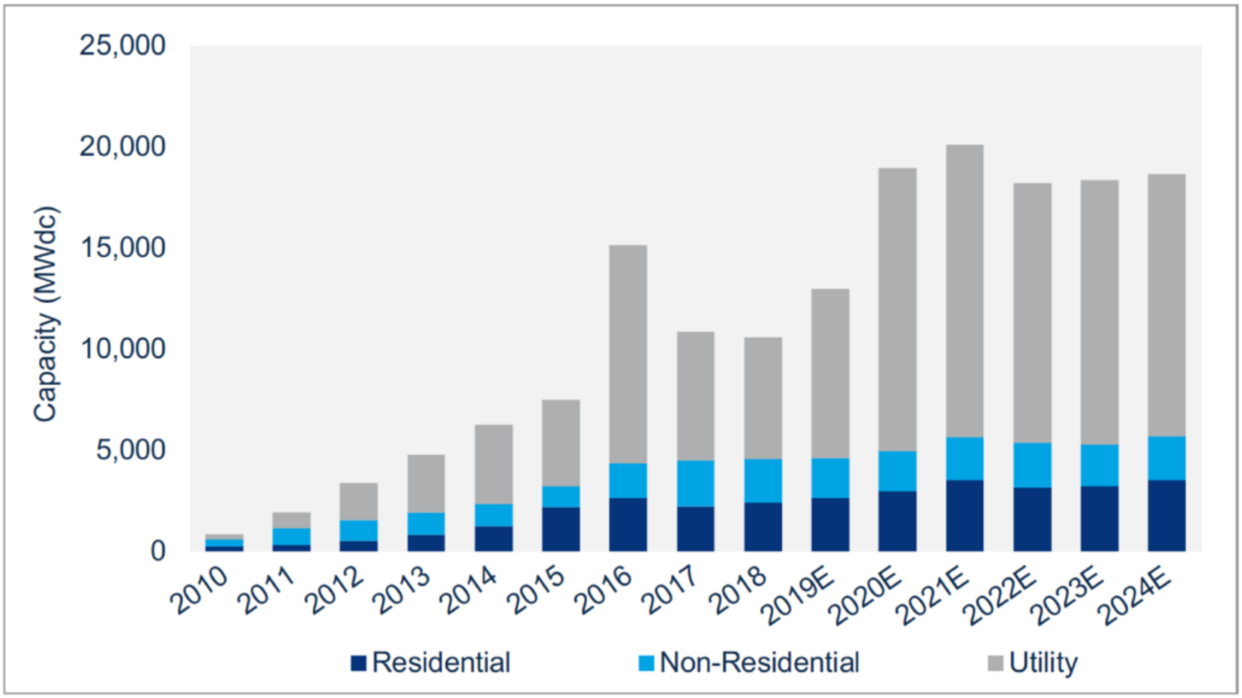


Figure 4.4

Source: Wood Mackenzie Power & Renewables

The cost of both small- and large-scale solar projects has been steeply declining over the past decade. As shown below in Figure 4.5, the current cost of utility-scale solar PV is less than $1/watt.

U.S. Solar PV Average System Costs by Market Segment

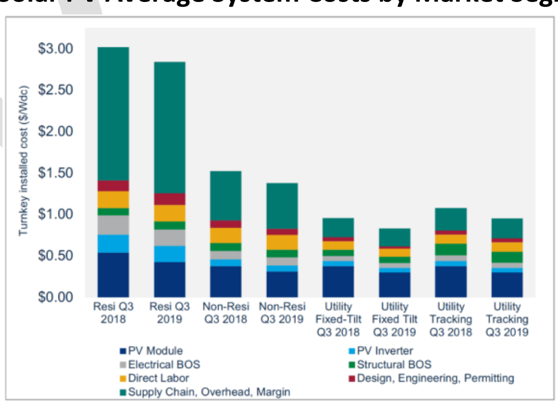


Figure 4.5

Source: Wood Mackenzie Power & Renewables

In addition to declining equipment costs, there are federal and state subsidies and incentives that decrease the cost of solar in the state of Washington.

Due to relatively low solar generating capacity, the cost effectiveness of solar is, however, reduced in Washington state compared to locations like southern California or Arizona. Figure 4.6 below demonstrates the important concept that solar generation is not an ideal match for Clark Public Utilities' residential loads.

Typical Monthly Residential Rooftop Solar Generation and Load (kWh)

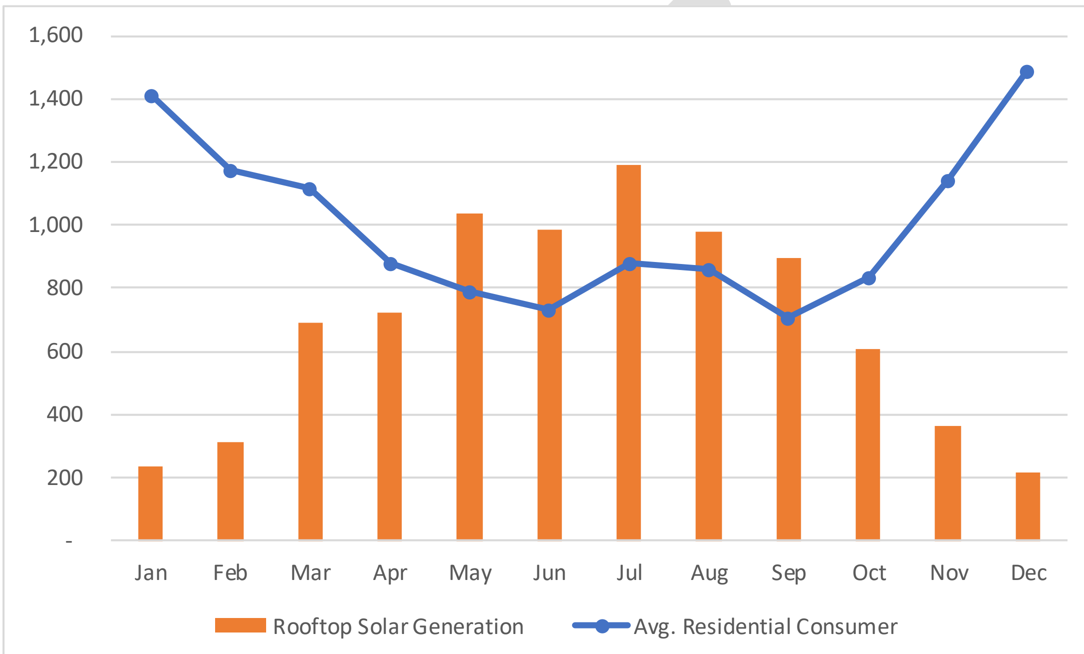


Figure 4.6

Note: Assumes average monthly residential load of 1,000 kWh, rooftop solar capacity of 7 kW and an average monthly capacity factor of 13.4 percent.

The blue line in Figure 4.6 above shows the typical seasonal load of a residential customer in Clark Public Utilities' service territory compared to the typical output expected from an 8-kilowatt rooftop solar installation. As shown above, loads exceed solar generation during 6 months of the year and solar generation exceeds loads during the other 6 months. Generally speaking, the seasonal shape of Clark Public Utilities' residential load is the opposite of the seasonal shape of solar generation and due to low solar generating potential, in November through February the generating capability of a typical 8-kilowatt installation is less than half the load of a typical residential home. The same mismatch of load and generation shapes would apply to a utility scale solar (greater than 1 MW) located in Clark Public Utilities' service territory.

Based on a survey of capital costs, capacity factors and O&M costs included in the NWPCC's 2021 Power Plan (under development) and recent IRPs completed by IOUs in the region, the projected 20-year (2021-40) levelized cost of solar energy located on the west-side of the Cascade mountains is near $71 per megawatt-hour. The levelized cost calculation assumes a 22 percent capacity factor. ITC credits were included in the calculations at 10 percent (as discussed above). The levelized cost of an east-side solar project with a capacity factor of 33 percent is near $48/MWh. All of the assumptions included in the levelized cost calculation are provided below in Table 4.2.

Wave Power

Wave energy is the result of the capacity of waves to do work. Ocean waves are generated by the influence of the wind on the ocean surface first causing ripples. As the wind continues to blow, the ripples become chop, then fully developed seas, and finally swells. In deep water, the energy in waves can travel for thousands of miles until that energy is finally dissipated on distant shores.

There are three main types of wave energy technologies. One type uses floats, buoys, or pitching devices to generate electricity using the rise and fall of ocean swells to drive hydraulic pumps. A second type uses oscillating water column devices to generate electricity at the shore using the rise and fall of water within a cylindrical shaft. The rising water drives air out of the top of the shaft, powering an air-driven turbine. Third, a tapered channel, or overtopping device can be located either on or offshore. These devices concentrate waves and drive them into an elevated reservoir, where power is then generated using hydropower turbines as the water is released. The vast majority of recently proposed wave energy projects would use offshore floats, buoys or pitching devices.

By producing wave energy from a range of different sites, possibly with different types of technology and taking advantage of the comparative consistency of the wave resource itself, studies have suggested that wave energy integration should be easier than that of wind energy. The reserve or backup generation necessary for wave energy integration should be less than that associated with wind generation. Wave power projects are still in the pilot program phase of development, and as such, not considered a viable option in the near future.

Tidal Power

Tidal in-stream energy is created by harnessing the power of the moving mass of water caused by the gravitational forces of the sun and the moon, and the centrifugal and inertial forces on the earth's waters. The gravitational forces of the sun and moon and the centrifugal/inertial forces caused by the rotation of the earth around the center of mass of the earth-moon system create two “bulges” in the earth's oceans: one closest to the moon, and the other on the opposite side of the globe.

Built in 1966, the Rance tidal power plant in northern France was the first tidal power station in the world. Total turbine capacity of the project is approximately 240 megawatts. This type of tidal power generation requires construction of a huge dam called a “barrage” which is built across an estuary. When the tide goes in and out, the water flows through tunnels in the dam. The ebb and flow of the tides is used to turn a turbine, or it can be used to push air through a pipe, which then turns a turbine. Large lock gates, like the ones used on canals, allow ships to pass. The largest tidal power plant in the world, the 254-megawatt Sihwa Lake tidal power plant in South Korea, began operating in 2011.

More recent technology, known as tidal in-stream energy conversion (TISEC) devices, use tidal current to drive turbines coupled to electrical generators. A typical tidal power plant involves a farm of multiple, underwater TISECs. Depending on the TISEC technology, the TISEC unit can be either rigidly fixed in place under the water surface or it may float inside the water column, tethered to a cable attached to the sea floor. This technology is evolving through a pre-commercial research phase but is expected to be commercially available within the next decade.

There are several locations in the Puget Sound area that have potential for tidal energy. However, due to funding challenges and the lengthy permitting and licensing process, to date, no pilot tidal energy projects have been deployed in the Puget Sound area. Tidal projects are still in the pilot program phase of development and, as such, not considered a viable option in the near future.

Assessment of Storage Systems

Battery Storage

Battery storage systems have the potential to help solve some of the larger-scale problems associated with connecting lots of intermittent, on-again, off-again renewable power (e.g. solar and wind) to the grid. For example, energy storage could help mitigate the distribution grid voltage sags and surges that can occur when clouds pass over neighborhoods with lots of rooftop solar. Lithium-ion batteries have the greatest potential storage capability and efficiency. The NWPCC's 2021 Plan will consider only lithium ion batteries.

Battery storage systems could also allow utilities to reduce wholesale market purchases when market prices spike. If utilities were able to control the use of the storage systems, they could store energy during low market price periods and use the energy during high market price periods.

Storage systems could also provide short-term solutions to transmission system constraints. BPA includes "demand reduction initiatives" in its non-wires solutions to building new transmission lines. Storage systems have the potential to reduce demand to the financial benefit of BPA and its customer utilities. Distribution and/or transmission system upgrades could be delayed if storage systems allowed utilities to reduce their peak loads. Figure 4.7 below illustrates how a 50-megawatt utility-scale solar system and a 10-megawatt lithium ion battery system could work together to reduce system peak load.

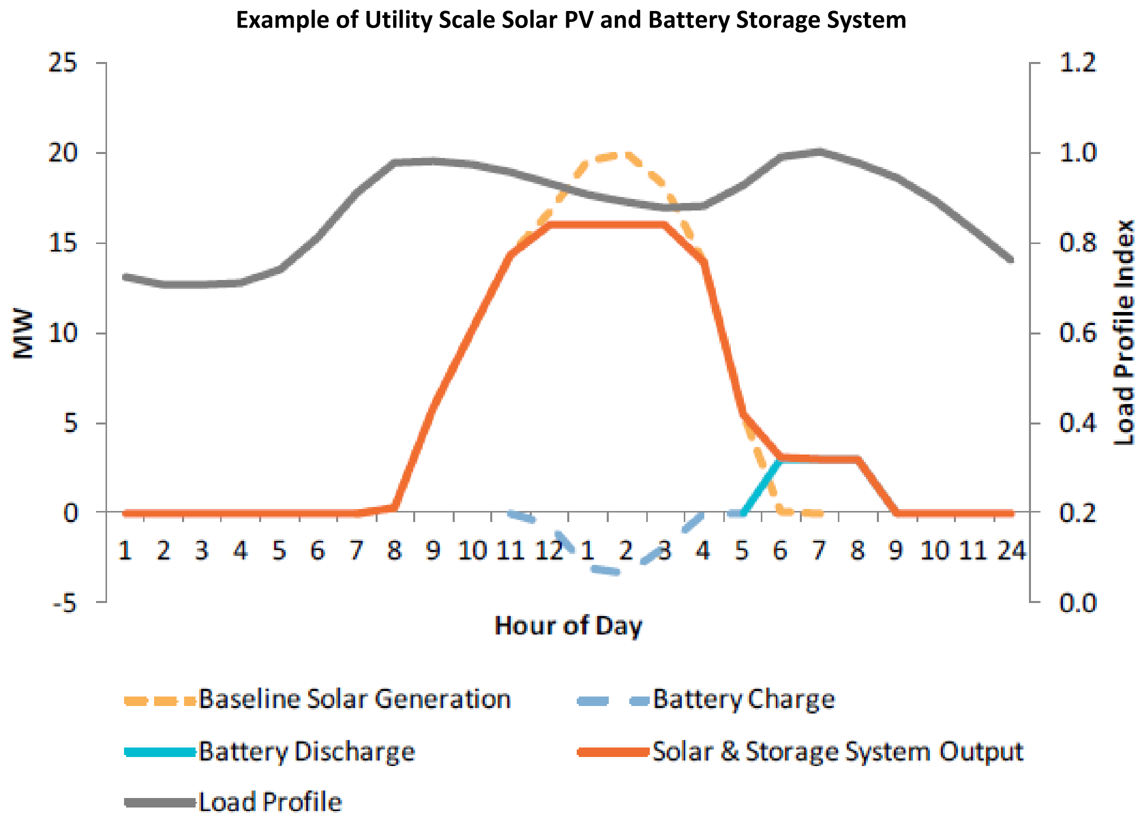


Figure 4.7

Source: Northwest Power and Conservation Council's 7th Power Plan

Figure 4.8 shows the decrease in lithium-ion battery prices since 2010 and the expected decrease in costs down to $62/MWh in 2030.

Lithium-ion Battery Price Outlook (Utility Scale Projects)

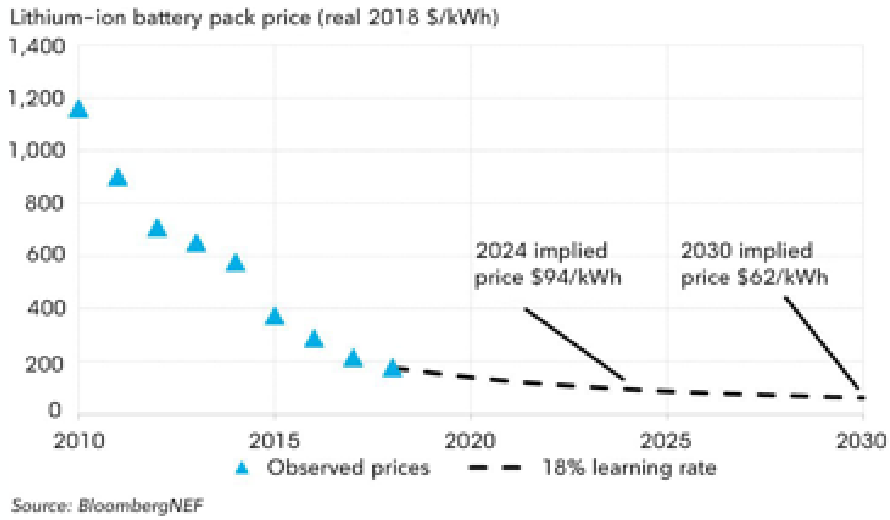


Figure 4.8

Source: NWPCC GRAC meeting 9/25/19

Despite the momentum battery systems have in the utility industry, and while the costs of battery systems have decreased significantly over the past 5 to 6 years, as shown above in figure 4.8, the cost of battery systems remains relatively high compared to wholesale market prices. Absent the continued increase of intermittent renewables on the grid and the need to back these resources up with carbon-free energy, batteries would not be a viable resource alternative. Smaller battery systems that could be combined with rooftop solar systems have higher costs than those shown above.

Currently the only way to make a battery storage system cost-effective is to secure grant money. The Washington State Legislature created the Clean Energy Fund to advance clean energy projects and technologies throughout the state. Grants are awarded to competitively chosen applicants and selection is based on the likelihood of a project's ability to demonstrate improvement in the reliability and/or lowered cost of distributed or intermittent renewable energy. Clean Energy Fund 1 (2013-15) set aside $15 million and awarded funds to three utilities to develop lithium ion/phosphate and vanadium flow batteries as well as two demonstration projects for energy storage control and optimization projects known as Modular Energy Storage Architecture or MESA. Clean Energy Fund 2 (2016-17) awarded $10.6 million to five utilities, including $7 million to Avista and Snohomish PUD for smart grid technologies and $3 million for Energy Northwest's 5-megawatt combined solar generation and battery storage facility. Clean Energy Fund 3 awarded $10.7 million to four utilities and Clean Energy Fund 4 will award $6.1 million.

The discharge capability of the lithium ion batteries included in the NWPCC's reference case for the 2021 Plan and the IOU's IRPs is 4 hours. The NWPCC includes reference cases for both a 100 MW solar project and 100 MW solar with a battery with 4-hour discharge capability of 400 MWh. The capital costs are 90 percent greater in the solar plus battery case ($1,350/kW compared to $2,568/kW) while the fixed O&M costs are more than double ($14.55/kW-year compared to $31/kW-year).

Pumped Storage

During spring months in the Northwest, hydroelectric resources produce significant amounts of energy from spring run-off. At the same time, windy spring conditions result in large quantities of wind energy available at the same time when demands for electricity are low. This oversupply of energy has been resolved in the past by generation curtailment, which can be highly contentious and disruptive.

Pumped storage may become the energy storage solution of choice as more wind and solar is added to the balancing area and curtailments increase. During periods of high wind and high water, water is pumped to a storage reservoir using wind energy to power the pumps. The water is then released through the hydroelectric facility once demand increases or there is less generation from renewable resources.

The cost-effectiveness of pumped storage is primarily determined by the price differential between heavy load hours (high demand) and low load hours (low demand) and the efficiency of the pumps and hydroelectric generators. As facilities become more efficient and require less energy, the cost-effectiveness increases. Pumped storage is a net consumer of energy in that it takes more energy to pump the water uphill than is recouped in the generation process when the water is released through the generator. Figure 4.9 below shows a depiction of closed- and open-looped pumped storage power plants.

Mechanics of Open- and Closed-Loop Pumped Storage Power Plants

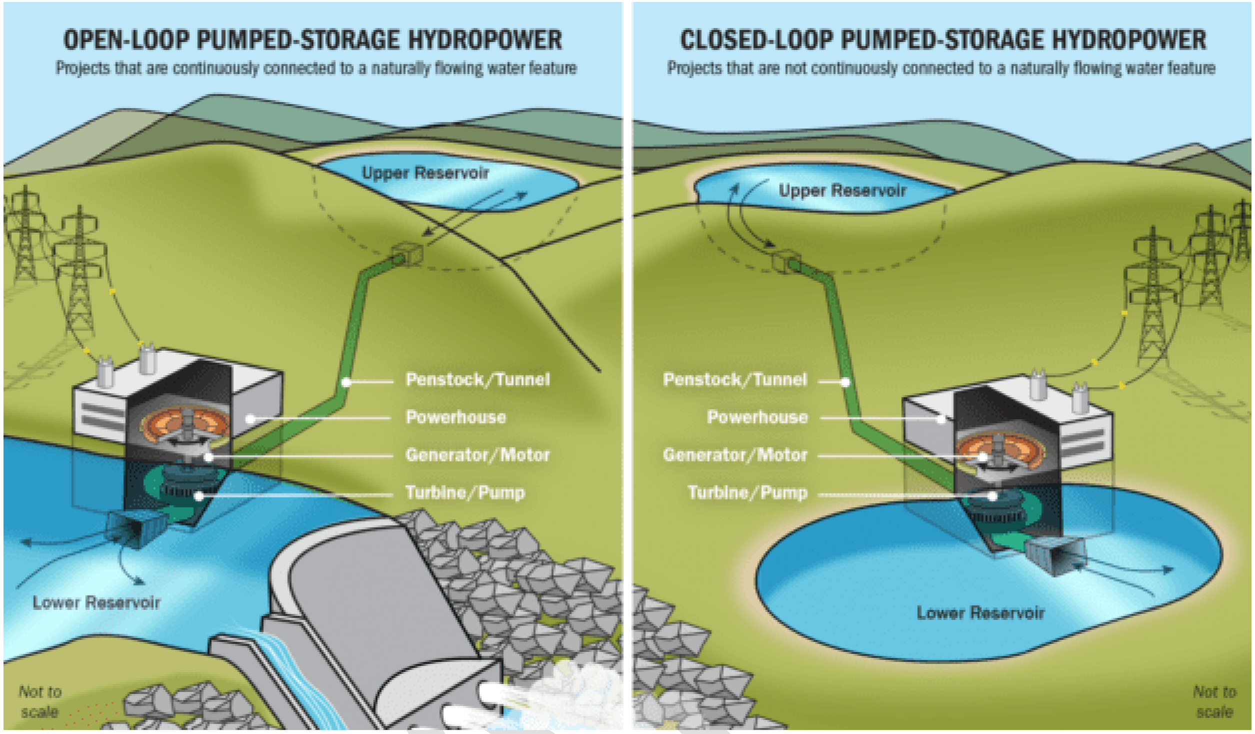


Figure 4.9

Source: Power Magazine Article, Four Projects Picked to Speed Up Pumped Storage Hydro Construction, 10/9/2019

America's Water Infrastructure Act of 2018 includes several provisions designed to ease the development of closed-loop pumped storage projects. Specifically, the provisions: amend the Federal Power Act by adding an expedited licensing process for issuing and amending licenses for closed-loop pumped storage projects and require FERC to establish an expedited licensing process that requires a final decision on applications within two years of FERC's receipt of a completed application.

The only pumped storage project located in the Northwest is the 314-megawatt John W. Keys III Pump-Generating Plant that pumps water from the Franklin D. Roosevelt Lake behind Grand Coulee dam 280 feet uphill to Banks Lake. Water in Banks Lake is used for agricultural irrigation and power generation. Nine pumped storage projects with 4,300 megawatts of capacity in aggregate are proposed in the Northwest. The largest proposed project is a 1,200-megawatt project in Goldendale, Washington. The project has been granted an operating license from FERC and could be on-line as early as 2025. The current estimate of construction costs is $2.9 billion.

Only two of the nine proposed projects, New Hydro LLC and GridAmerica's Swan Lake North Pumped Storage Project and Columbia Basin Hydropower's Banks Lake North

Dam Pump/Generation Project, are in active development. Swan Lake North is a proposed 393 MW closed-loop pumped storage project located in Klamath County, Oregon. After nearly a decade of project planning, development and review, the FERC issued a 50-year construction and operation license for the Swan Lake North project in April 2019. The project will begin construction in 2021 or 2022 and be commercially operational in 2025. Projected capital costs are $866 million or $2,203/kW.

Banks Lake North is a proposed 500 MW open-loop pumped storage project located on the west side of Lake Roosevelt upstream of Grand Coulee Dam on the Columbia River in Washington state. The project would use two existing reservoirs, Banks Lake and Lake Roosevelt. Projected capital costs are ~$1.5 billion or $2,880/kW. The target date for project completion is 2026.

One of the issues with pumped storage projects is that the projects are usually larger in size than the needs of a single entity. Finding multiple parties that are willing to commit to long-term financing can be difficult.

Costs for pumped storage facilities vary by site. According to the NWPCC's figures for the 2021 Power Plan, the estimated cost for new pumped storage projects ranges from $1,780 to $2,400 per kilowatt of installed capacity. The range in cost is driven by the length of the tunnel needed for the project, the amount of overall head (the lower the head, the higher the costs), the amount of above ground infrastructure required, and the variable speed technology selected for the pump/turbines. The council's reference plant includes the following characteristics:

- Configuration/Technology: Variable speed pump, closed-loop system
- Capacity: 400 MW
- Energy: 3,200 MWh, based on 8-hour generation capability
- Overnight capital cost: $2,300/kW
- Fixed O&M cost: $14/kW-year
- Development time: 4 years
- Construction time: 5 years

NWPCC notes that there is 4,000 MW of potential pump storage capacity in the region.

20-Year (2021-40) Levelized Costs

Table 4.2 below shows the assumed capital costs, fixed O&M, variable O&M, capacity, capacity factor and heat rates used to calculate 20-year levelized costs. The assumptions shown below are based on a survey of assumptions used in by IOUs in their recent IRPs and the reference cases provided by NWPCC as part of its preparation of the 2021 plan. The 20-year levelized costs shown below assume borrowing rates of 4 percent and borrowing terms of 20 years for all resources.

Supply-Side Resource Characteristics							
	Capital Cost ($/kW)	Fixed O&M ($/kW)	Variable O&M ($/MWh	Capacity (MW)	Capacity Factor	Heat Rate (Btu/kWh)	Levelized Cost (/MWh)
Natural Gas – CCCT	$1,140	$11.38	$2.11	383.30	75%	6,550	$46
Natural Gas Peaker – SCCT	$657	$3.06	$5.15	235.05	10%	9,793	$94
Natural Gas Peaker – Recip	$1,247	$6.98	$4.25	77.25	15%	8,350	$105
Natural Gas Peaker – Aero	$1,154	$6.57	$2.67	96.00	12%	8,930	$121
Wind - Gorge	$1,699	$39.85	$0.00	100.00	37%	NA	$52
Wind - Montana	$1,648	$39.85	$0.00	150.00	43%	NA	$44
Wind + Battery	$1,994	$69.16	$0.00	25.00	37%	NA	$70
Solar – Westside	$1,527	$31.00	$0.00	50.00	22%	NA	$71
Solar - Eastside	$1,527	$31.00	$0.00	50.00	33%	NA	$48
Solar – Eastside + Battery	$2,431	$42.50	$0.00	17.50	33%	NA	$74
Pumped Storage	$2,480	$11.31	$0.37	400.00	27%	NA	$83

Table 4.2

Figure 4.10 on the next page summarizes the levelized costs of the supply-side resources discussed above, including the levelized costs shown above in table 4.2. The 20-year levelized cost of energy efficiency is per Clark Public Utilites' 2019 CPA. The projected market price shown below is for wholesale power purchased at the Mid-Columbia (Mid-C) trading hub. Of course, as coal units retire and natural-gas fired units are run less and less, wholesale power from the market will become more and more GHG-free over time. Market prices for Mid-C were provided by TEA. Projected BPA Tier 1 rates are included for comparison purposes. Projected BPA Tier 1 rates are based on current rates through September 2021 and assumed rate increases of 3 percent every two years. The costs of all other resources are based on the operation and maintenance and capital costs included in the development of the 2021 Power Plan and recent PNW utility IRPs. As noted above, wind project costs do not include the PTC while solar projects include a 10 percent ITC.

Projected 20-year (2021-40) Levelized Costs ($/MWh)

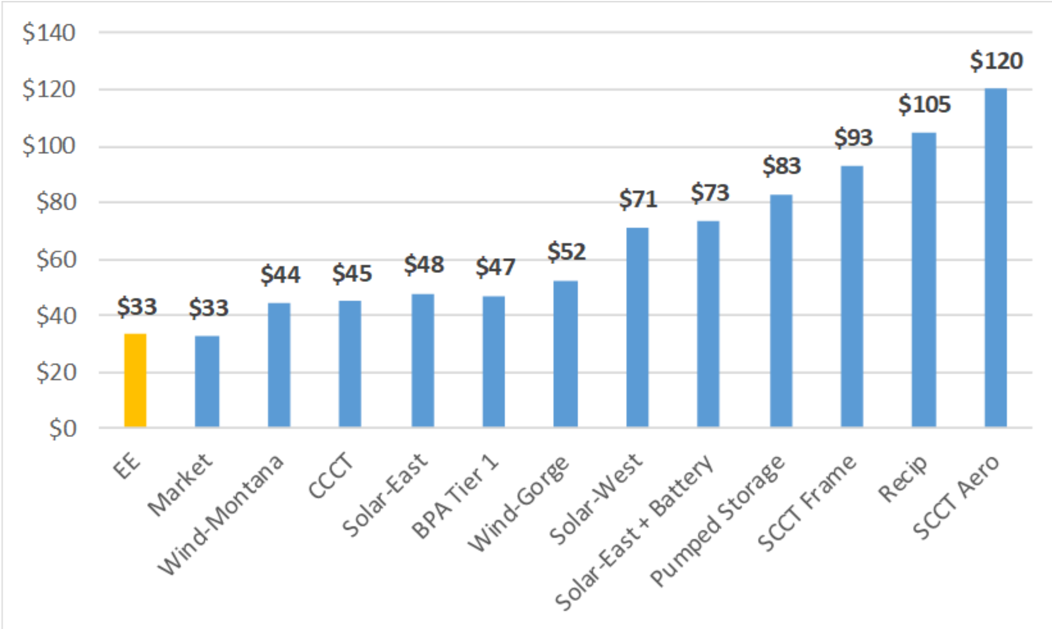


Figure 4.10

Source: PNW utility IRPs, NW Power Council Data and CPU Conservation Potential Assessment

Figure 4.10 shows that energy efficiency (EE) and the wholesale market are the lowest cost resources followed by utility-scale wind located in Montana, natural gas-fired CCCT and BPA Tier 1 rates. The wholesale market price forecast is simply a forecast of market prices at a point in time. Market prices are highly dependent on natural gas prices, the capability of the hydro system in a given year and many other factors. In addition to price volatility, relying on market purchases to serve load exposes utilities to uncertainty with respect to the availability of power that can be shaped to serve load.

The BPA Tier 1 rate shown above includes costs associated with load shaping and demand purchases, and as such, represents a power purchase that follows a load following BPA customer's daily, monthly and seasonal loads. Market prices are representative of the cost of a flat block of power that could not be used to serve load. As such, a comparison of Tier 1 rates to market prices is not an apples-to-apples comparison. The BPA Tier 1 product is far superior to the other resources shown on the chart when viewed through the lens of reliability, flexibility, and deliverability.

Social Cost of Carbon

The levelized costs shown above for natural gas-fired resources (CCCT, SCCT Frame, Recip and SCCT Aero) and the Mid-C wholesale market do not include the social cost of carbon. The CETA requires utilities to include the social cost of greenhouse gas emissions in resource evaluation, planning and acquisition [RCW 19.280.030(3)]. For investor-owned utilities, the statute establishes a specific set of cost values, which were developed by a federal interagency working group in 2016. The legislation directs the Department of Commerce to specify the cost values to be used by consumer-owned utilities. The Department of Commerce has determined that, in order to maintain consistency, customer-owned utilities should use the same cost values that the legislature has enacted for investor-owned utilities. The rule also establishes the inflation factor to be used in escalating costs to the base year used in the evaluation.

The calculated social cost of carbon includes the following assumptions:

- 2021 cost of carbon (per metric tons): $76.5/metric ton
- 2021 cost of carbon (per MMBtu): $4.06/MMBtu (assumes 53 kg of CO_2 per MMBtu)
- Assumed market heat rate: 7,195 Btu/kWh (used to calculate the social cost of carbon associated with market purchases)
- Marginal resource: calculation of social cost of carbon associated with market purchases assumes hydro or wind serve as marginal resource in spring/summer runoff season (no carbon content)

As shown below in Figure 4.11, including the projected social cost of carbon would add an estimated $23/MWh to the levelized cost of market purchases and between $32/MWh and $46/MWh to the levelized costs of natural gas-fired resources. Since the CCCT has the lowest assumed heat rate of the natural gas-fired resources (6,550 Btu/kWh) it has the lowest social cost of carbon. Since the SCCT has the highest assumed heat rate (9,773 Btu/kWh) it has the highest social cost of carbon.

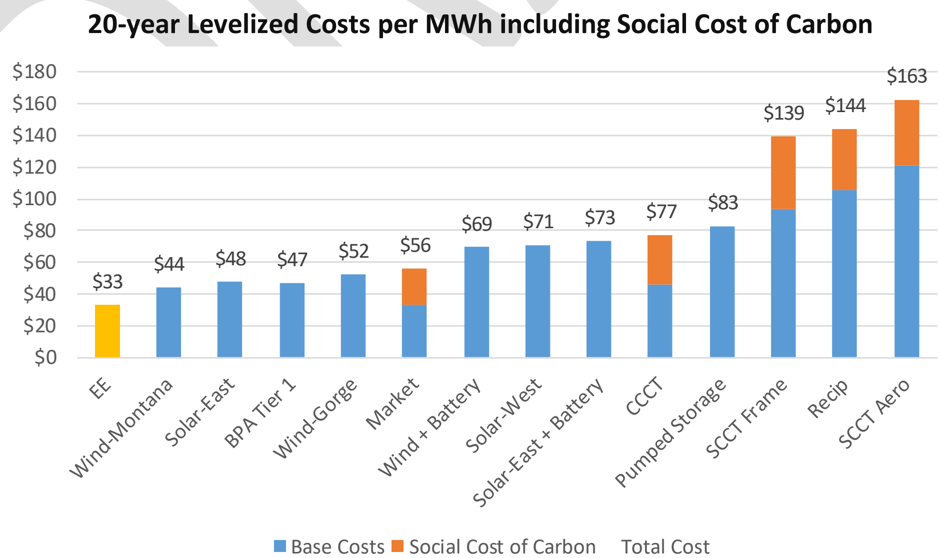


Figure 4.11

When the social cost of carbon is included in the cost comparison, energy efficiency is by far the least cost resource, followed by wind projects located in Montana, BPA Tier 1 power and solar projects located on the eastside of the Cascades. While BPA's fuel mix includes a small amount of carbon due to unspecified market purchases included in BPA's resource mix, the relatively small amount of carbon costs associated with BPA Tier 1 power is not included in this analysis.

Section 5—Comparative Evaluation of Renewable and Nonrenewable Energy Resources

Renewable Energy and Conservation Requirements

The Energy Independence Act established a Renewable Portfolio Standard for certain electric utilities in Washington State. To comply, utilities with 25,000 customers or more must ensure that a percentage of the electricity sold to retail customers in Washington State be derived from eligible renewable energy resources, such as solar and wind. In addition, these utilities must pursue all available conservation that is cost-effective, reliable, and available. The target for use of eligible renewable energy is nine percent increasing to 15 percent by 2020. Utilities were required to identify conservation targets starting in 2010 and every two years thereafter.

RPS compliance can also be demonstrated through the purchase of renewable energy credits (RECs) either bundled with, or purchased separately from, electricity contracts. RECs can be acquired from the target year, the year prior or the year subsequent to the target year. Compliance can also be achieved by the utility spending four percent or more of its annual retail revenue requirement on the incremental cost of eligible renewable energy resources or credits, or; a non-load growth scenario coupled with spending one percent or more of the utility's retail revenue requirement on the incremental cost of eligible renewable energy resources or credits.

Comparative Evaluation of Renewable and Nonrenewable Resources

Below in table 5.1, excerpted from a study performed by the Pacific Northwest Utilities Conference Committee (PNUCC), is a summary of different generation characteristics associated with both renewable and nonrenewable resources.

Resource Category	Sub-Category	Nameplate Rating (MW)	Peaking Capacity (MW)	Annual Energy (aMW)	Regu-lation (MW)	Spinning (MW)	Non-Spinning (MW)	Following Up (MW)	Following Down (MW)	Reactive Power (MVaR)	Storage (MWh)
Hydroelectric	Reservoir Storage	100	100	40	50	50	100	100	100	100	100
	Run-Of-River	100	100	40	50	50	100	100	100	100	100
	Pumped Storage	100	100	-15	50	50	100	100	100	100	100
Gas	Frame SCCT	100	100	90	15	15	100	15	15	50	0
	Aero SCCT	100	100	90	15	15	100	15	15	50	0
	Hybrid SCCT	100	100	90	20	15	100	20	20	50	0
	CCCT	100	100	95	15	20	0	15	15	50	0
	Boiler + STG	100	100	90	20	15	0	20	20	50	0
	Reciprocating Engine	100	100	90	25	25	100	25	25	50	0
Coal		100	100	85	5	5	0	10	10	100	0
Nuclear		100	100	85	5	5	0	10	10	100	0
Biomass	Boiler	100	100	85	5	5	0	25	25	100	0
	Reciprocating Engine	100	100	85	50	50	100	100	100	100	0
	Turbine	100	100	85	35	35	100	70	70	100	0
Geothermal		100	100	90	35	35	0	10	10	100	0
Solar	Photovoltaics	100	0	15	0	0	0	0	0	0	0
	Central Tower	100	0	15	0	0	0	0	0	0	50
Wind		100	0	30	0	0	0	0	0	0	0
Tidal		100	0	30	0	0	0	0	0	0	0
Distributed Generation	Wind	100	0	20	0	0	0	0	0	0	0
	Solar	100	0	15	0	0	0	0	0	0	0
Storage	Batteries	100	100	-10	50	50	100	100	100	0	100
	Hot Water	100	100	-10	50	50	100	100	100	0	50
	Refrigeration	100	100	-10	50	50	100	100	100	0	50
	Capacitors	100	100	0	0	0	0	0	0	100	100
Demand Reduction	Conservation	100	100	10	0	0	0	0	0	0	0
	Non-Utility	100	100	10	0	0	100	0	0	0	0
	Utility-Controlled	100	100	10	50	50	100	100	100	0	0

Table 5.1

The table provides an illustration of the energy, capacity and flexibility products of various generation and demand-side technologies. The information is illustrative and not intended to be comprehensive or accurate, as the ultimate capability of any resource is dependent on its design. For each listed resource, an assumed nameplate installation of 100 megawatts is used to facilitate comparisons across resource types.

The report in its entirety can be found at
http://pnucc.org/sites/default/files/CapabilitiesofResourcesReportandMemoweb.pdf

Assessment of Tools Available for Integrating Renewable Resources

Since the requirement that utilities must submit IRPs was first established, this type of assessment has been required as part of the IRP. Rather than re-write or re-interpret solid reports that have been recently published, Clark Public Utilities highlights several reports that cover the topic thoroughly and with great research.

From The Journal of Modern Power Systems and Clean Energy

KROPOSKI, B. Integrating high levels of variable renewable energy into electric power systems. J. Mod. Power Syst. Clean Energy 5, 831–837 (2017). National Renewable Energy Laboratory, Golden, CO, 80401, USA

Full report available at https://rdcu.be/b355Z

“Conclusion

As higher levels of VRE are integrated into electric power system, the main technical challenges deal with variability, uncertainty, and asynchronous operations. There are a variety of key technologies and management measures that can be used to increase the penetration levels of VRE. Geographic diversity, flexible conventional generation, load control, and curtailment can be used to deal with variability. Better renewable forecasting can help with uncertainty in generation and reserves. Energy storage can help deal with all aspects of the integration challenge, but also is one of the most expensive options. At the very highest levels of VRE penetration, energy storage is crucially important to allow for significant energy shifting and grid availability when the renewable resource is not available. In order to provide enough energy, VRE systems may need to be oversized and may require significant curtailment during some parts of the day. As the penetration of VRE increases, there is also typically a need to increase both energy storage requirements and the amount of energy that is curtailed due to over-production at certain times during the day. Another critical issue is that VRE will also need to be designed to provide a full range of essential grid reliability services to ensure system stability. This means that there must be some device (either the VRE or energy storage devices) that needs to be like a voltage source when there is not enough synchronous generation to maintain a voltage reference and respond to voltage and frequency deviations.

This paper also examined several real-world operating systems that operate at high levels of VRE penetration and showed that ultra-high levels have been achieved at small to medium sized grids. These systems often have very large VRE and energy storage compared to the load to account for operations during several days of low wind or solar availability. This should lay the foundation for how to achieve ultra-high levels of VRE at large-sized grids.”

From Energy and Environmental Economics (E3)

Pacific Northwest Low Carbon Scenario Analysis, Achieving Least-Cost Carbon Emissions Reductions in the Electricity Sector,

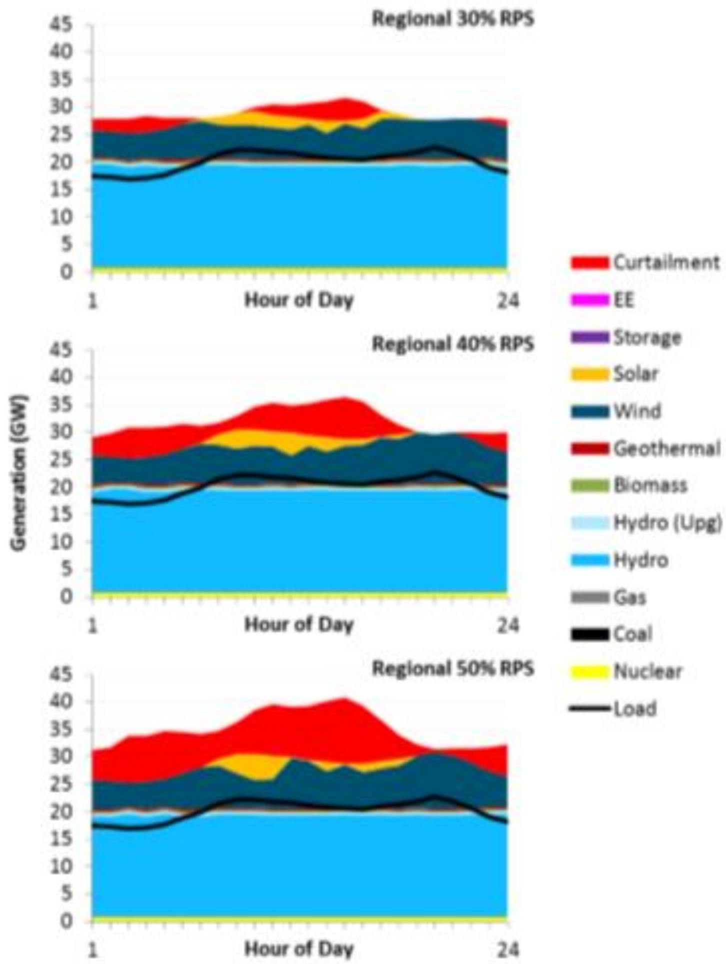
Project Team: Nick Schlag, Arne Olson, Kiran Chawla, and Jasmine Ouyang

"***Operational Impacts & Renewable Integration***

The portfolios developed under the Core Policy scenarios span a wide range of renewable penetration, ranging from the 20% RPS (Reference Case) to 50% RPS. This wide range highlights how increasing penetrations of renewables will impact system operations in the Northwest region, and, in particular, the emerging role of renewable curtailment as a crucial tool to manage the variability of renewables at high penetrations. While all scenarios show some amount of renewable curtailment, the High RPS scenarios, which span the largest range in renewable penetration, provide the best illustration of the role of renewable curtailment at higher renewable penetration. Figure vii shows a snapshot of hourly operations in each of the High RPS scenarios on a day with high hydro conditions, demonstrating the growing magnitude of renewable curtailment at increasing penetrations. These types of events become much more frequent and larger in magnitude as RPS policy increases: as the RPS policy increases from 20% (Reference Case) to 50%, the percentage of available renewable generation that is curtailed annually increases from 4% to 9%.

While this study's finding regarding the critical role of renewable curtailment is consistent with a range of studies of high renewable penetrations in other jurisdictions, the character of the renewable curtailment dynamics observed in this study are distinctly different from other areas and reflect the unique characteristics of the Pacific Northwest electricity system. In particular, the characteristics of curtailment events observed in the Pacific Northwest are distinctly different from those anticipated in California at high renewable penetrations. While the expected patterns of curtailment in California are likely to be driven by high penetrations of solar PV and will generally coincide with the hours of maximum solar PV production each day, curtailment events in the Pacific Northwest will be driven by high combined output from the hydro system and wind fleet, lasting for much longer periods—days, weeks, or event months depending on the underlying hydro conditions. The distinctive daily and seasonal patterns of curtailment characteristic to a region with significant hydro and wind resources explains why this study identifies limited value for new investments in energy storage as a facilitating technology for high renewable penetrations. This finding again distinguishes the Pacific Northwest from California, where previous analyses have identified significant potential value in new investments in energy storage to facilitate California's achievement of high *renewable policy goals. The reason for this distinction is rooted in the different characteristics of curtailment events. In California, curtailment events are expected to last on the order of four to eight hours during periods of oversupply and will recur on a daily basis—a dynamic well-suited to balancing with energy storage technologies. In contrast, such storage devices would find infrequent opportunities to cycle in the Northwest, as curtailment events with less predictability and significantly longer duration do not lend themselves to balancing with relatively short duration storage.*

Figure vii. Increasing renewable curtailment observed with increasing regional RPS goals



Section 6—Least Cost Considerations and Alternatives

Introduction

The purpose of this IRP is to identify reliable, cost-effective, and sustainable Least Cost and Clean Energy Action Plans that meet both the electric power requirements of Clark Public Utilities' customers and all legal requirements with specific emphasis on Washington States' EIA and the CETA over the next 20 years.

To accomplish this, Clark Public Utilities has developed three alternatives that meet these requirements. These alternatives inform and shape the Least Cost Plan and Clean Energy Plan is Section 8 and Section 9 respectively.

An associated portfolio of resources (both supply-side and demand-side) accompanies each alternative. Due to the transient nature of the planning environment, alternatives by necessity need to be very flexible in their approach. This is consistent with how Clark Public Utilities has approached planning opportunities for many years.

Development of Alternatives and Portfolios

From Sections 2 and 3, it is clear that DSM programs for annual energy purposes are economical. Thus all planned programs for DSM are included as part of all alternatives. Also, from Section 2, it is obvious that capacity is the driving need of Clark Public Utilities.

Three alternatives have been developed to meet these needs. These alternatives are not mutually exclusive and the costs of each are dependent upon market forces at the time of any contemplated purchases. It is not contemplated that Clark Public Utilities would execute one singular transaction associated within any particular alternative but rather execute a series of transactions to diversify amongst counterparties, time, terms, and types of acquisitions.

- Alternative 1: The first Alternative is the Medium Case as identified in the tables shown in the Incremental Electric Power Requirements subsections. This would rely upon market supplies for needed capacity in the mid-term and rely upon BPA in the long-term for capacity, energy and to meet the bulk of the CETA compliance. RRGP would run to the limits prescribed in the compliance periods under the CETA.
    - Description:
      For the period up to 2028, Clark Public Utilities would manage its resource portfolio by purchasing peaking capability. These types of market transactions may include physical call options, index-priced power purchases, and/or block

power fixed price purchases. Terms, amounts, counterparties, and types of contracts will be varied to diversify the portfolio. Price will be dictated by market and any purchases will be executed within the terms and limits of Clark Public Utilities' Risk Policies and Procedures.

Post 2028, Clark Public Utilities would purchase all its power needs beyond the ability of RRGP to produce energy equivalent to the 20% of load under the CETA. To get to GHG neutral, Clark Public Utilities will purchase RECs for the generation produced by RRGP.

- Associated Portfolio:
    - Existing resources as allowed under the CETA, contracts, and DSM, plus additional power purchase agreements to meet incremental annual peak requirements, plus REC purchases as necessary.

- Alternative 2: Alternative 2 is the same as Alternative 1 except RRGP would be replaced by either additional BPA PF power, if allowed post 2028, or by a combination of GHG-Free resources such as solar, wind, and Small Modular Reactor.
    - Description:
    Alternative 2 would remove RRGP from Clark Public Utilities' load-serving portfolio post 2028. This does not necessarily mean the plant would be retired from service nor does it mean that RRGP would no longer be owned by Clark Public Utilities. RRGP could serve a very meaningful service either as a means toward providing short-term bursts of capacity to maintain reliability to Clark Public Utilities or others, or its energy could be transmitted east to states that are shutting down coal-fired resources and are willing to use gas-fired electricity as a means to transition to a lower GHG emitting portfolio. Alternatively, RRGP may be disassembled and sold to another utility for assembly at another location.

    Given RRGP is not subjected directly to the social cost of carbon and assuming the price of natural gas remains in its current range, the impacts to removing RRGP from Clark Public Utilities will add costs to the portfolio. Either additional energy from BPA or other GHG-free resources will be more expensive than the current marginal cost of production from RRGP.

    - Associated Portfolio

- All DSM and 100% BPA or X% BPA plus (100-X)% of GHG-Free supply-side resources, plus additional power purchase agreements to meet incremental annual peak requirements, plus REC purchases when necessary.

- Alternative 3: Meet incremental annual peak requirements in the short-term through aggressive cost-effective Demand Response, Storage acquisition, and access to customer backup generation. Rely upon BPA in the long-term for capacity, energy, and to meet the bulk of the CETA compliance. RRGP would run to the limits prescribed in the compliance periods under the CETA.
  - Description: Alternative 3 focuses on Demand Response beyond that identified in the Appendix B – 2020 Demand Response Potential Assessment. This may be large industrials who may require significant incentives to allow for interruption to their service in times of stress. In addition, an added focus on Storage acquisition for economic and for experimental purposes would be pursued with preference on the storage being located in Clark Public Utilities' service territory. Another area of untapped resource capacity is the backup generation at various industrial and commercial facilities across Clark County.

    All these different types of resources focus on local solutions to capacity prior to purchasing from resources located outside the area. This encourages investment in assets for Clark County and also reduce the need for additional high voltage transmission.

  - Associated Portfolio
    Existing resources as allowed under the CETA, contracts, and DSM, Interruptible contracts, batteries, local backup generation, plus additional power purchase agreements to meet incremental annual peak requirements, plus REC purchases when necessary.

All three alternatives assume Clark Public Utilities purchases its full Tier 1 allocation from BPA. Also, any transactions executed under these strategies will be subject to the full force of the then current Risk Procedures as adopted by the Board of Commissioners.

In all three strategies, it is envisioned that Clark Public Utilities will purchase RECs to meet its EIA and the CETA carbon neutral obligations for any energy used that is not GHG-free, subject to cost cap alternative(s).

Section 7—Other Important Planning Considerations

The Clean Energy Transformation Act (CETA)

Many new requirements and planning considerations have emanated from the CETA. Figure 7.1 lays out the timeline for the years 2021-2025 as it relates to planning requirement dates.

SB 5116:
2020 – 2025 Requirements

	2020	2021	2022	2023	2024	2025
Compliance Requirements						
Low-Income Assistance Programs (Sec. 12.2)		7/31/2021				
Planning and Reporting Requirements						
Clean Energy Implementation Plan (Sec. 4.7)			1/1/22: 1st Plan Due			
IRP w/ 10 yr clean energy action plan (Sec. 14)	08/31/2020 IRP w/Clean Energy Plan				12/30/2024 Update	
*Low-Income Assistance Reporting (Sec 12.3)	7/31/2020		7/31/2022		7/31/2024	

**The date of 7/31/20 is when the Department must begin aggregating the required low income information. It is not specifically stated when utilities will have to provide the required information to the Department to do its aggregation.*

Figure 7.1

For IRP purposes, the first requirement to be met is this 2020 Plan. This IRP is required to have a Clean Energy Plan published with it. That plan can be found in Section 9—Clean Energy Action Plan.

Per the CETA, an assessment, informed by the cumulative impact analysis conducted under RCW 19.405.140, of: Energy and non-energy benefits and reductions of burdens to vulnerable populations and highly impacted communities; long-term and short-term public health and environmental benefits, costs, and risks; and energy security and risk should be part of future IRPs. However, the cumulative impact analysis conducted under 19.405.140 is not ready at this time.

Prior to January 1, 2022 a Clean Energy Implementation Plan is due. This plan, similar sounding in name to the Clean Energy Action Plan, requires:

- Interim targets for meeting the greenhouse gas neutral standard prior to 2030;
- Targets for meeting the standard between 2030 and 2045;
- Specific targets for energy efficiency, demand response, and renewable energy;
- Alignment of content with the utility's Clean Energy Action plan, or for the 10-year resource plan required for small utilities;

- Consistent plans with the utility's average annual incremental cost of compliance;
- Specific actions to be taken throughout the 4-year planning horizon of the CEIP that demonstrate progress toward meeting the greenhouse neutral standard outlined in RCW 19.405.040(1) and no-carbon standard outlined in RCW 19.405.050(1) and the interim targets. The specific actions must:
  - Be consistent with the utility's long-range resource plan;
  - Be consistent with the utility's resource adequacy requirements;
  - Be informed by the utility's historic performance under median water conditions and resource capability;
  - Be informed by the utility's participating in centralized markets; and
  - Consider any significant and unplanned loss or addition of load it may experience.

This CEIP will be undertaken by Clark Public Utilities staff and senior management in the Summer of 2021, hopefully after many of the rules regarding the CETA are settled and the reporting obligations become more clear.

The Rising Need for Resource Adequacy and Generation Flexibility

In the Pacific Northwest wholesale electricity industry, the focus on Resource Adequacy has intensified over the past 24 months. The Northwest Power Pool published a very comprehensive look at the issue in October of 2019. This document, https://www.nwpp.org/private-media/documents/2019.11.12_NWPP_RA_Assessment_Review_Final_10-23.2019.pdf highlights several significant issues:

- All the study groups who have published forecasts regarding Resource Adequacy have reached similar conclusions. The Pacific Northwest could experience very slim reserve margins in meeting load into the future increasing the likelihood of widespread short to long-term duration power outages. On the next page, Figure 7.2, a chart excepted from this assessment illustrates the consensus.
- The pursuit to a more GHG-free electric generation portfolio will continue to place pressure on the grid in a way to which only a handful of resources, those that are dispatchable, will be able to address. The need for flexible generating resources be they thermal, hydro, or battery based will be high.

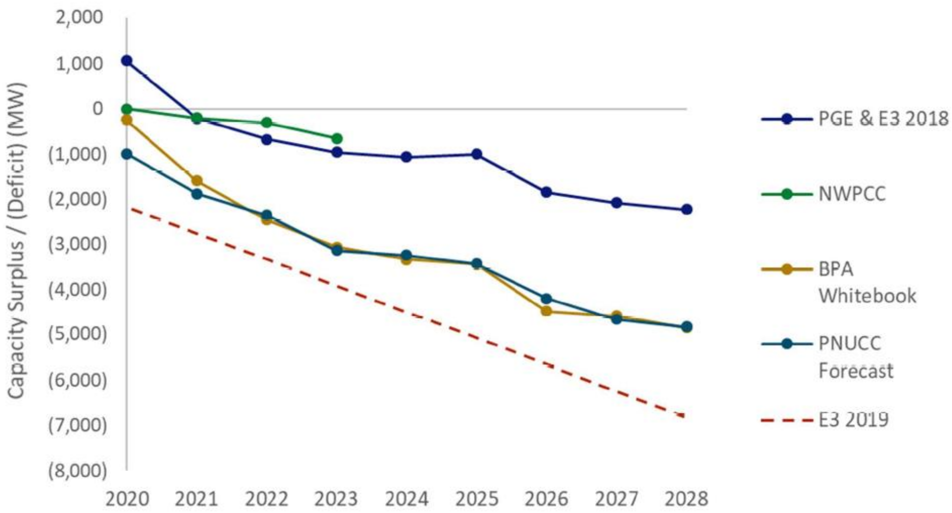


Figure 7.2

The rising need for flexible generating resources is best illustrated by what is now the most famous California Duck curve.

This phenomenon, represented by load curves in California and shown in Figure 7.3, create an enormous need for ramping, i.e. flexible resources. Sometimes, the need is greater than 15,000 MW over 3 hours. This is equivalent of 3 Grand Coulee Hydro projects or 15 typically-sized 1000 MW nuclear plants going from zero generation to maximum generation in 3 hours.

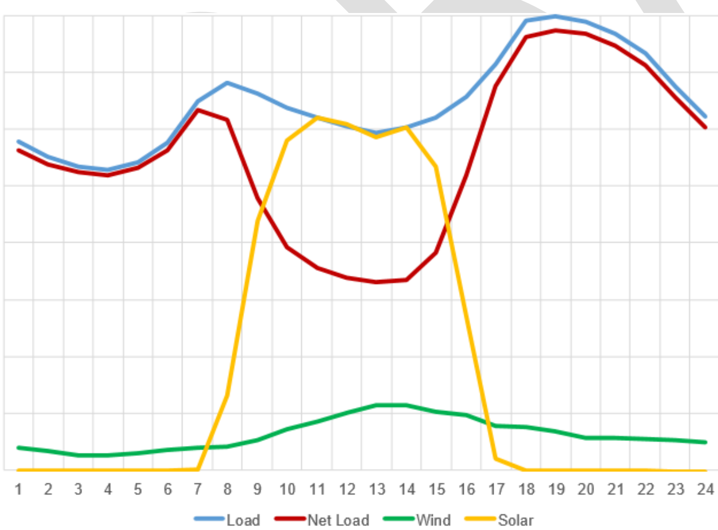


Figure 7.3

Figure 7.3 represents a typical 24 hour day. The blue line represents actual load on the system before any adjustments for electricity generated by renewable nondispatchable resources. Yellow and green lines represent generation (at a different scale) that contribute to the difference between the red and blue lines. The red line is the net load that must be met by remaining non-renewable resources.

The sharp red line between the hours of 13 and 19 are the ramping resources needed to keep the grid electrified. Over the years, this ramp rate need has increased. From a recent presentation by the CAISO, Draft2021FlexibleCapacityNeedsAssessment.pdf, Figure 7.4 shows by how much.

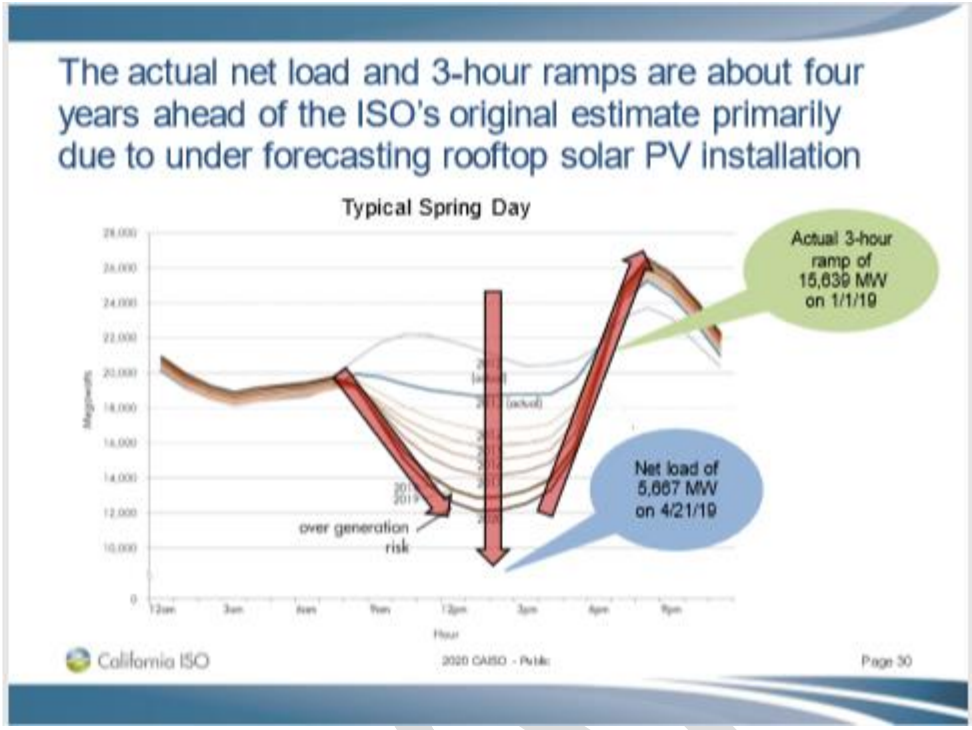


Figure 7.4

The reaction by most has been that batteries can help solve this dilemma. That may be the solution in the future, but the pace of projected battery installation for the nation as shown in figure 7.5 from the U.S. Energy Information Administration shows that even if all existing and projected battery installations were located in the CAISO, the number would be woefully short, about 2.5 Grand Coulees short.

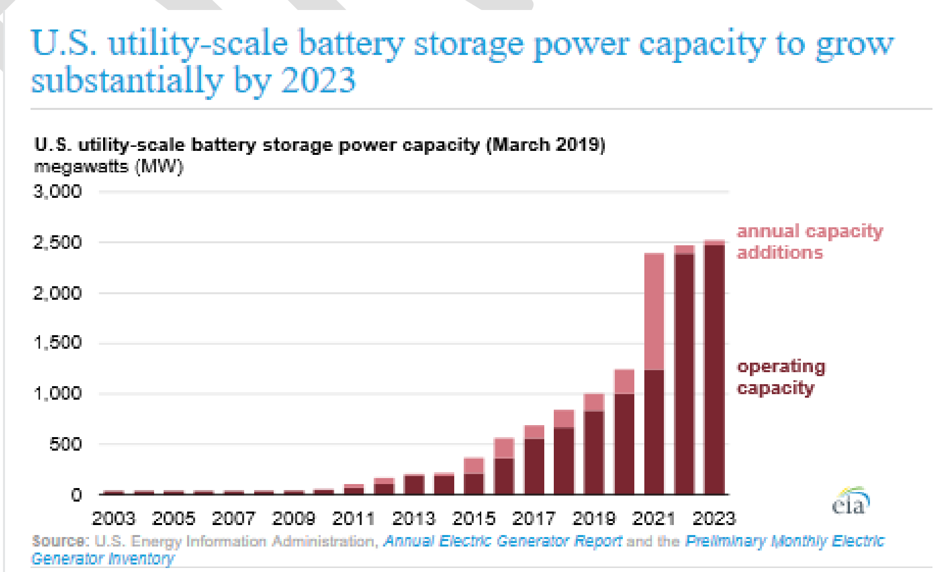
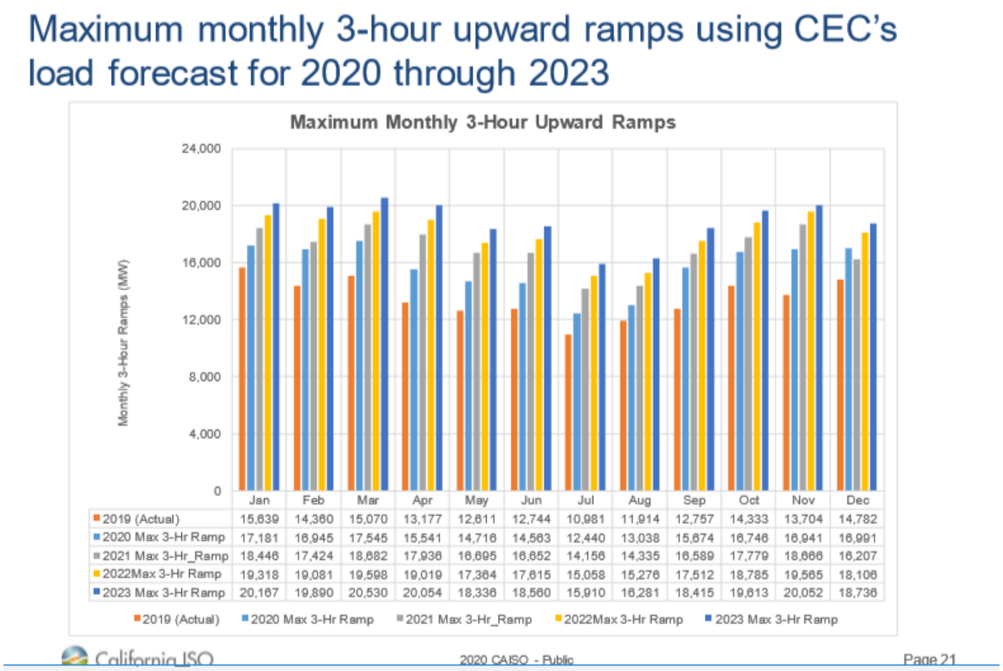


Figure 7.5

This need for ramping resources is currently met today mainly with hydrogenation and natural gas-fired generation located through the west, not just in California. The CAISO predicts this need for ramping to increase through time. Figure 7.6 from the same presentation referenced above illustrates this growing need.



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2019 (Actual)	15,639	14,360	15,070	13,177	12,611	12,744	10,981	11,914	12,757	14,333	13,704	14,782
2020 Max 3-Hr Ramp	17,181	16,945	17,545	15,541	14,716	14,563	12,440	13,038	15,674	16,746	16,941	16,991
2021 Max 3-Hr_Ramp	18,446	17,424	18,682	17,936	16,695	16,652	14,156	14,335	16,589	17,779	18,666	16,207
2022Max 3-Hr Ramp	19,318	19,081	19,598	19,019	17,364	17,615	15,058	15,276	17,512	18,785	19,565	18,106
2023 Max 3-Hr Ramp	20,167	19,890	20,530	20,054	18,336	18,560	15,910	16,281	18,415	19,613	20,052	18,736

Figure 7.6

Actual data from 2019 and the projections through 2023 highlight the need for resource flexibility. Utilities and Independent Power Producers are searching for economic, commercially viable, and dependable means to meet this growing need. At this time, batteries, hydro generation (traditional and pumped-storage), and simple-cycle natural gas-fired turbines are the only dependable and flexible resources available.

Scenario Planning

Beyond looking at the Incremental Net Electric Power Requirements under the low, medium, and high cases and developing a Least Cost and Clean Energy Action Plan to meet those needs, Clark Public Utilities acknowledges that externalities can require adjustments to those plans. In addition, Clark Public Utilities may recognize additional and/or different ways to optimize or more efficiently meet the overarching needs of its customers. Identifying and addressing potential alternative futures and discussing responses and reactions to those alternative futures (Scenario Planning) is addressed in this section. Please note that none of these scenarios are meant to be any more or less likely than the others to happen. Nor, does Clark Public Utilities endorse or favor any one more than the others. In addition, the scenarios are meant to be realistic, incremental changes to the planning landscape.

Voluntary or Mandatory implementation of Washington State Clean Air Rule (CAR)

On September 15, 2016, The Washington State Department of Ecology adopted emission standards (Chapter 173-442 WAC – Clean Air Rule) to cap and reduce greenhouse gas (GHG) emissions from significant in-state stationary sources, petroleum product producers, importers, and distributors and natural gas distributors operating within Washington. RRGP is included in this list of significant in-state stationary sources.

In March 2018, Thurston County Superior Court ruled that parts of the Clean Air Rule are invalid. The Superior Court's ruling prevents Ecology from implementing the Clean Air Rule regulations. This means that compliance with the rule currently is suspended.

On Jan. 16, 2020, the Washington State Supreme Court ruled that the portions of the rule that applied to stationary sources, such as a factory, were upheld, but that the portions that applied to indirect sources, such as natural gas distributors and fuel suppliers, were invalid. The Supreme Court remanded the case to Thurston County Superior Court to determine how to separate the rule.

This puts the CAR in limbo with respect to RRGP. If implemented, the CAR would require RRGP to reduce its annual production 1.7% based upon an average production over a four-year period. The 1.7% reduction per year would be in place for 20 years. Clark Public Utilities' calculations project that over that timeframe the average annual production would be reduced approximately 30% in year 20 compared to year 1. However, this also results in RRGP being allow to run no more that 50% of the time. Compared to the impending average generation limitation of approximately 45% when the first compliance period of the CETA starts in 2030, the end results economically and environmentally appear to be similar. When 2045 arrives, the CAR will be moot as the CETA requires all utilities to produce GHG free electricity for use by its customers.

Because the two periods associated with the CETA and the CAR overlap, it is unknown how these two requirements would interact. If the CAR is implemented in one form or fashion in the near future, either voluntarily or mandatorily, the economic impact to Clark Public Utilities would be somewhat muted in the earlier years. Small reductions of generation at RRGP could be replaced rather simply especially in high run-off years. As the years add up and especially under low snowpack years, the impact could become material.

As the CAR is still in abeyance and no additional legislative action from the 2020 session relating to the CAR was passed, Clark Public Utilities is not obligated to meet any of the CAR requirements. Staff stands ready to implement the CAR, should be rule be unsuspended. Staff also stands ready to analyze and report to the Board of Commissioners on a method to implement the CAR voluntarily should that be an item of interest.

2021 – 2028 Access to Unused BPA High Water Mark Energy

Every two years, BPA performs calculations to establish the maximum amounts each Priority Firm customer of BPA is eligible to purchase. In the most recent BPA Rate Period High Water Mark process, BPA indicates that roughly 265 aMW of Rate Period High Water Mark energy is going unused by public customers, including roughly 16 aMW by Clark Public Utilities. In order to be able to use this energy, PF customers must have loads that are eligible to receive this energy.

Because of the epic downturn in the economy at the start of the most recent BPA contract (2011), utility loads have not recovered to a point where this energy can be absorbed. Thus BPA is placed in the position of selling this power at market rates which may at times be much less than the current BPA PF rates. Clark Public Utilities would like to explore two alternatives over the next several years that may of be of benefit to both BPA and Clark Public Utilities.

Under the right circumstances, Clark Public Utilities may be willing to purchase up unused energy up to its High Water Mark or even perhaps purchase the sum of all BPA's unused High Water Mark. To accomplish this, Clark Public Utilities must be able to undeclare comparable amounts of RRGP in the BPA contract. This would provide Clark Public Utilities the ability, but not the obligation, to not run RRGP during the year for that commensurate amount of energy. This will reduce the output of RRGP at Clark Public Utilities discretion whether that be for economic and/or environmental reasons or other heretofore unknown reasons.

Both alternatives would require a major variance from the current contract and most likely would require consent of the other BPA PF customers. The end result of either of these issues have not been broached with BPA or its customers. Clark Public Utilities would have interest in these alternatives for several reasons:

- BPA PF Power is almost completely GHG Free.

- BPA PF Power is the most reliable power available for purchase.
- It would set the stage for progressing towards meeting the first year of the first compliance period under the CETA.
- RRGP may not generate nearly as much electricity for use by Clark Public Utilities across a year, but it would be available for short-term durations when loads are peaking. This reduces GHG emissions on behalf of Clark Public Utilities while helping Clark Public Utilities meet potential Resource Adequacy requirements.

Either scenario would present extra costs to Clark Public Utilities.

Accessing Clark Public Utilities unused HWM energy.

Roughly 16 aMW would be available to Clark Public Utilities. In the near term, BPA's PF rate, on average, is roughly $37/MWh. Marginal cost of generation from RRGP is in the $23/MWh range. In a simple approach, this implies an additional $14/MWh to make the switch from RRGP to BPA PF power. This does not account for other benefits that may be part of this tradeoff. RRGP is a single contingency resource, BPA is not. The added BPA power will increase Clark Public Utilities peaking capabilities provided RRGP is still maintained and available for peak load times. In year one using the approximate costs here, the incremental cost to Clark Public Utilities for this 16 aMW is $1.9 Million per year.

Using all foregone HWM of other customers

Current numbers from BPA's RHM process suggest that enough unused HWM energy by all of BPA's PF customer is available to allow all of RRGP to be undeclared. Using the same approach as in the subsection, the incremental annual cost to Clark Public Utilities in year one would be roughly $27 Million. This would increase the annual retail revenue requirement by roughly 7.5%.

These scenarios are rough estimates and are offered as potential opportunities to be pursued per direction from the Board of Commissioners.

Post 2028 BPA Contract Scenarios

September 30, 2028 is the last day of the current BPA Power Sales Contract. The current BPA PSC commenced October 1, 2011. It is likely that the next BPA PSC will be similar in form and function as the current contract. However, it is very early in the process. Clark Public Utilities would be prudent to start discussing the alternatives and options that may be available and how decisions made within this process may impact Clark Public Utilities in the future. In summary, Clark Public Utilities will have choices to make regarding its status as a BPA customer. The different options are discussed below as forerunners of many discussions and analysis at Clark Public Utilities to come. This particular issue will be of utmost importance to the future of power supply at Clark Public Utilities.

BPA takes great pains to make the different products as economically equal as possible. Past analyses have shown their efforts to be quite successful. Thus, decisions as to whether be a Slice/Block Customer or Load Following Customer are primarily based upon qualitative attributes and utility philosophies.

Clark Public Utilities customer status with respect to the BPA PSC

Slice/Block

Currently, Clark Public Utilities is a Slice/Block Customer. The Slice/Block product has proven beneficial to Clark Public Utilities especially in the interrelationship with RRGP. As the Slice portion of the Slice/Block product is a "virtual" rendering of the all the resources under BPA control including the Federal Columbia River Power System (FCRPS), Clark Public Utilities has direct access to above critical flow hydro generation. This generation usually occurs in the spring time if snowpacks are average to above average. Access to this generation helps displace RRGP generation when it is economic.

The Slice/Block product requires much more operational capabilities that cost additional dollars when compared to other options. Operational risks are introduced under the Slice/Block product. These operational attributes also provide valuable insight to markets, the wholesale power system, and regional interactions.

One particular challenge that the Slice/Block product presents is peak capacity. Allocation of Tier 1 power to BPA PF customers is an annual energy based calculation. The Slice/Block customers have committed to meet their load obligations as opposed to BPA Load Following Customers who have placed that obligation on BPA. Clark Public Utilities is a highly residential-based load. This means Clark Public Utilities' load during the winter can be very high. Since BPA allocates Slice/Block access on an annual average basis and not on an hourly peak basis, the Slice/Block product does not produce enough capacity by itself to allow Clark Public Utilities to cover extreme loads.

Load-Following

While BPA offering a Block/Slice product is probable, it is pretty much without doubt that BPA will offer a Load Following product. The Load Following product is aptly named. BPA will follow/meet the load needs at all times for any Load Following Customer. This allows a utility to leave day-to-day load following commitments to BPA but for a resource based utility like Clark Public Utilities, operational risks remain surrounding RRGP. Unless of course, Clark Public Utilities no longer owns RRGP. That will be discussed in the following subsection

No BPA purchases

Much is said and written regarding BPA's future and whether it will be able to compete with other resources and power providers. "Going off" of BPA has been a familiar slogan amongst PF customers for many years. BPA has been a constant and reliable wholesale power provider for many years. Absent any major upheaval, Clark Public Utilities does not see a future where BPA would not be a prominent part of its portfolio. However, BPA must remain committed to the customers who pay the bills and focus on costs and core services.

RRGP 5(b)/9(c) BPA Contract Status

This issue will have significant ramifications regarding the economics and future of RRGP as a resource for Clark Public Utilities. In summary, RRGP is a declared 5(b)/9(c) resource under the Northwest Regional Power Act. This designation creates certain obligations regarding the performance of RRGP under the BPA PSC. As a 5(b)/9(c) resource, Clark Public Utilities may only purchase BPA PF power for Clark Public Utilities load after electricity from RRGP or another equivalent resource has met Clark Public Utilities load obligations. This obligation is not easily shed for good reason. Long-term planning and acquisition of long-lived resources are the cornerstone of a dependable, stable, reliable, and cost-effective power supply. To that end, BPA PSCs have been typically long-term (10 years or longer) in duration. This provides much-needed stability for BPA and for its PF customers. Part of that stability is the "declaration" process regarding customer resources. BPA's position on the declaration and undeclaration of 5(b)/9(c) resources is complex and nuanced.

To change the RRGP from declared resource to undeclared is not a unilateral decision that can be made by Clark Public Utilities alone. It will be discussed with BPA over the next decade as the end of the current BPA PSC approaches. However, it is worth discussing potential alternatives as each scenario will impact Clark Public Utilities' portfolio.

No BPA Declared Resource reduction allowed

This scenario means that Clark Public Utilities would not have any ability to purchase additional BPA PF power in the new PSC. Clark Public Utilities would be obligated to bring electricity equivalent to RRGP's historical generation. Given the requirements under the CETA, this would place Clark Public Utilities in the unenviable position of declaring a resource under its BPA PSC that is in direct conflict with state law.

Under this scenario, RRGP would, of course, operate per the CETA and Clark Public Utilities would replace the difference between the RRGP generation under the CETA and the declared amount for RRGP in the BPA PSC with GHG-free electricity. Unfortunately, this precludes Clark Public Utilities from buying essentially GHG-free BPA PF power. Clark Public Utilities believes BPA PF power is by far more dependable, reliable, and likely more economical in the long-run than any other alternative.

Partial reduction Declared Resource amount allowed per the CETA

In the compliance periods of 2030-2044, per the CETA, the RRGP could potentially be able to run up to an amount equivalent to of 20% of Clark Public Utilities load. This equates to around 45% of the energy capability declared under the BPA PSC as a 5(b)/9(c) resource. BPA could look at this a reasonable amount that RRGP could be expected to run. This is the assumption for BPA Net Requirements supply in the medium case under existing power resources.

Complete removal of resource from contract

Some scenarios exist where complete removal of the RRGP from the BPA PSC could happen. These scenarios typically involve the demise of the plant physically, by regulations, or contractually for reasons that are out of control by Clark Public Utilities. Similar to the case in Using all foregone HWM of other customers section above, this will increase Clark Public Utilities' annual net revenue requirements significantly.

RRGP Operating Status post 2028/2030

The next decade will require decisions regarding how RRGP will be operated and even if it will be operated. Significant dates in 2028 and 2030 as well as ongoing current interest in RRGP's status as a GHG emitter mean that the days of depending upon RRGP as a reliable base load resource are most likely numbered. Below are discussions of potential operations of RRGP into the near future.

No significant changes to RRGP

A full description of RRGP can be found in River Road Generating Plant (RRGP). Looking beyond 2028/2030, it's difficult to envision that RRGP would remain in the same operation mode that it does today. Today, the unit has no regulatory requirements regarding GHG emission output totals and is dispatched at base load purely on economics. The unit is essentially in binary mode, either offline or running at full capacity. It typically runs anywhere from 55% to 90% of each year depending upon the price of replacement power and the value of natural of gas.

In 2030, to meet the CETA, RRGP will be limited in run-time to roughly 45% of each compliance period. To assume a binary base load operation would severely limit RRGP's contribution to Clark Public Utilities' needs. To assume RRGP will not operate at all in 2030 is a possibility to be discussed below. However, every responsible study performed that envisions a path to GHG-free electricity indicates that natural gas-fired generation will be needed at times for reliability. But the nature in which the generation is dispatched will change and with that change, RRGP will also likely need to be retooled.

If RRGP were not retooled the most likely operation for RRGP, would be to operate for two months in the wintertime, December and January, and for three months in the summertime from June 15 through September 15. The remaining seven months of the year would still require full staff, operations, maintenance, and security plus capital costs, and insurance. These are costs required whether plant is running or not.

Turn-down technology added to RRGP

If RRGP could be economically retrofitted to enable it to operate in a more hybrid peaker/baseload fashion, the results may enable Clark Public Utilities to meet several challenges that are on the horizon. The Duck

Curve and its attendant needs for generation ramping flexibility, the coming limitations on annual GHG limitations at RRGP, and even the need for additional capacity could be addressed by what is called turndown technology.

Turn-down technology is hardware and software advances that enable a baseload unit like RRGP to run at various levels from a minimum generation level to maximum level with relatively quick ramping response times. It would allow RRGP to move from generating at a baseload level for months at a time to a more flexible and accommodating dispatch that can take advantage of low off-peak prices, high value midday ramp needs, long weekends of low load demand, allow for integration of renewables, and perhaps even participation in within hour balancing markets.

An action item under least cost and clean energy action planning is described here.

RRGP site converted to other generation type

RRGP is in a very strategic location as the only generation station of significant size located in the Vancouver metropolitan area with immediate interconnection to Portland, Oregon. This location provides many unheralded benefits such as voltage support, transmission displacement, high paying jobs, and tax support to both the city of Vancouver and the state of Washington.

Electrically, its close proximity to BPA's Alcoa and Ross Switchyards, and its interconnection with PacifiCorp provide opportunity of any generation type to locate there. Any generation type would pale in size to the amount of energy produced by the current generation configuration. The energy density delivered by the natural gas pipeline cannot be matched by any GHG-free resource that would occupy the same surface area presently occupied by RRGP. To replace the functional equivalent of RRGP with a combination of Wind plus batteries, or Solar plus batteries is discussed in this paper prepared by Clark Public Utilities staff.

This does not prevent Clark Public Utilities from converting the current RRGP site to another form of generation. If done in the near-future, it would not be an economic decision but rather a policy one, driven either by the Board of Commissioners or State law. Currently state law does not rule out generation by natural gas until 2045. The carbon neutral requirement that begins in 2030 will allow for natural gas generation through 2045 as long as it is offset by renewable energy credits purchased from other resources.

If renewable energy credits become so expensive that running RRGP is not an economic option, this will mostly likely mean the 2% revenue requirement cost cap may be in play. That interplay will need to be explored should the situation arise.

Hydrogen-fired generation is a possibility but that is not a near-term solution. More research and work is needed before any decisions can be made in this area. Hydrogen-fired generation much like batteries should become a focus of research inquiry by Clark Public Utilities. As part of the Clean Energy Action Plan, Clark Public Utilities should invest time and money in a group(s) that are doing this type of work to help further the knowledge and to help Clark Public Utilities make good decisions regarding these types of resources. This is discussed further in Section 9—Clean Energy Action Plan

RRGP Retirement

It is likely that RRGP will retire prior to the 2045 deadline under the CETA as the plant would be close to 50 years old by then. Plant obsolescence will happen as replacement parts become unavailable, new technologies are not easily retrofitted, and costs become harder to control as mean-time-between-unit failures become smaller and smaller. In addition, the CETA requires all electricity delivered to Washington state retail loads to be GHG free by 2045. Unless that law changes or RRGP is sold to an entity that can make use of the electricity outside of the state of Washington, RRGP will not be of much use as a natural-gas fired electric generator. These two facts make retirement of RRGP prior to 2045 almost certain.

Of course, RRGP may be placed into retirement at any time between now and 2045 for reasons other than stated in the above paragraph. Catastrophic equipment failure, new laws, policy decisions, and even market advancements could place RRGP on a path to a quick unplanned retirement in the traditional sense. As these are all risks that RRGP has faced in the past and will continue to face in the future, these risks will not be explored in any great detail.

The outcome of an accelerated retirement and its impacts to Clark Public Utilities and the environment may not go as intended. While it may place Clark Public Utilities in the position of delivering GHG-free power to its customers albeit at an increased cost to its customers, the likelihood of the RRGP gas turbine and associated hardware going unused is low. A robust secondary market for well-maintained gas turbines and associated hardware exists. Most of this type of surplus generation equipment is sold to international companies for use in other parts of the world. Thus, while Clark Public Utilities may be GHG-free, RRGP's components would very likely remain operational elsewhere.

Step Function Load Changes

Electric Vehicle Load

In most scenarios, Electric Vehicle load will not present itself as a step-function load change. Our analysis, in Appendix E – Electric Vehicle Saturation, sees EV load gradually increasing over time. As these loads are not certain, nor looked at as "organic", the EV loads will be managed as other step functions that will be managed "in time". Even at very high saturation rates, Clark Public Utilities does not see the EV load as a significant impact to our overall load. Future policy decisions may change the timing of EV load increases and resource strategies will need to adjust but at this time, EV load will not drive resource acquisition decisions.

Opportunities to collaborate with EV customers abound. Over the next several years, the utility, with Board approval, will investigate tools and programs involving EVs, new charging infrastructure, and customer education.

Large Increase or Decrease in Industrial Load

Clark Public Utilities has provided stable electricity rates over the past decade. This helps in keeping existing industrial loads from moving to other communities or abroad and also helps attract new business to the area to help diversify the economic base. However, there are times when significant load changes happen due to industrial load leaving the area or new ones relocating here.

From an operational perspective, a reduction in load is easier to manage, but from an economic perspective, a reduction in industrial load can be significant. For Clark Public Utilities, fixed costs paid in rates by the exiting industrial load will be spread amongst the remaining ratepayers. From this perspective, Clark Public Utilities is not as exposed as other utilities as our existing industrial load is a smaller percentage of actual load and revenues compared to others.

A large increase in industrial load does present somewhat tougher challenges to any utility from an operational perspective. These challenges of course can be met with proper planning, early conversations with potential loads, and transparent rates, policies, expectations, and agreements. In certain situations, the load will place the utility in a position of having to acquire additional resources or contracts to maintain resource adequacy. Each utility handles these situations differently.

Clark Public Utilities is currently evaluating its policies and rates regarding large step function load increases. Balancing the needs of existing and new customers is paramount. Currently, Clark Public Utilities reserves the right to determine its ability to serve new potential large loads. Typically, with enough advance notice, Clark Public Utilities will be able to meet any new requirement provided no externalities limit or forbid interconnection and financial arrangements are suitable to Clark Public Utilities. Each case is handled individually with the type of excellent customer service for which Clark Public Utilities is known.

How either a large decrease or increase in industrial load affects Clark Public Utilities' power portfolio will largely depend on the current circumstances at the time of the change. Impacts to the BPA PSC are the most impacted by the timing. BPA PSC planning cycles are yearly for some attributes, every two years for others, and every contract term (10 to 20 year) for others.

As none of these are changes are predictable, advance notice and the timing between the announcement and actual implementation will influence the path Clark Public Utilities will take to mitigate and accommodate the change. Clark Public Utilities account managers play a pivotal role in these situations and their award winning service help immensely in these situations.

Economic downturn due to COVID-19

In the midst of the creation of this IRP, COVID-19 has impacted the world, the nation, state, and Clark County. Clark Public Utilities has seen some immediate impact/shift to loads and economics. However, these are believed to be short-term and will not impact planning across the 20-year horizon of this IRP. As data is gathered and time reveals the reach of this pandemic, Clark Public Utilities will adjust forecasts accordingly.

Generation and Transmission Availability and Challenges

This section describes the regional generation and transmission system utilized by Clark Public Utilities to move power from its origination point to the utility's service territory. In addition, this section will highlight uncertainties that exist within the generation and transmission system and issues facing the Northwest region relative to transmission.

Generation System

The 2020 PNUCC Regional Forecast provides a great look at the load and resource projections for the Pacific Northwest utilities including a comprehensive look at existing and planned generating resources either owned or under contract. The NRF suggests that, as has been the case over the past 10 to 20 years, utilities will rely upon short-term resources that are provided by out-of-region resources going unused due to load diversities between the regions or on Independent Power Producers or Power Marketers with access to generation within the region.

Clark Public Utilities has no need for additional generation on average across the year under any water or weather condition. There are times, however, Clark Public Utilities does require peaking capabilities and to this point, has contracted in the past for these types of resources under one, two, and three-year contracts from uncommitted resources. The focus on Resource

Adequacy places more emphasis on the need to get these resources lined up and contracted in a timely manner. The recent Resource Adequacy study by the Northwest Power and Conservation Council suggest that capacity will remain available but will shrink over the next four to five years. Years 2024 and beyond may see the picture change unless utilities or others ramp up resource acquisition.

Northwest Transmission System

Clark Public Utilities purchases all of its transmission services from BPA. BPA, in turn, is a member of ColumbiaGrid. ColumbiaGrid is a non-profit membership corporation formed in 2006 to improve the operational efficiency, reliability, and planned expansion of the Pacific Northwest transmission grid. The corporation itself does not own transmission, but its members and the parties to its agreements own and operate an extensive network of transmission facilities. Clark Public Utilities relies upon its partnership and active participation with BPA in managing its transmission requirements. BPA coordinates with ColumbiaGrid and the other members of ColumbiaGrid to actively plan for the needs of its members. Clark Public Utilities envisions no transmission issues under the current assumptions. However, attempts to limit RRGP anymore than it will be in 2030 or even before then will require Clark Public Utilities to revisit the issue. It will introduce the need to look at an I-5 corridor expansion that has proven very difficult so far to garner public support.

Risk and Uncertainty

Risk, for the purposes of this IRP, is defined as a situation where potential outcomes can be described in reasonably well known probability distributions. Risks such as the market price for electricity might be defined by historic standard deviations (or the variance of prices from their mean). Uncertainty refers to situations where potential outcomes cannot be defined by well-known probability distributions. An example of an uncertainty is the extreme price excursions realized the first weekend of March 2019.

Alternative 1 Uncertainties

Because this alternative includes a variety of different purchases it is exposed to risks associated with performance of counterparties. This includes both power supply purchases and those purchases needed for RECs to meet EIA requirements. Counterparty risk can be managed and mitigated through:

- Credit management
- Liquidity management
- Continued monitoring
- Strong contractual language with appropriate enforcement language for non-performance

This portfolio includes a rather significant assumption regarding access to BPA power in the post 2028 timeframe. This assumption may not come to fruition necessitating backup planning. It makes assumptions that BPA will be the least-cost alternative. This is not a given. Thus, flexibility and keeping options open during the time frame leading up to 2028 is essential.

Alternative 2 Uncertainties

Uncertainties introduced by Alternative 2 include the potential public pushback on pursuing a nuclear resource, actual performance of a yet-to-be tested SMR concept, and intermittency of the renewable resource components of the portfolio. Pairing batteries with the renewables to manage the intermittency issue introduces other uncertainties similar to the actual performance uncertainties associated with the SMR. Costs are a big uncertainty with this alternative. If cost curves continue their downward trajectory for these resources, then they will be very attractive compared to other alternatives.

Alternative 3 Uncertainties

The biggest uncertainty associated with Alternative 3 revolves around the "newness" of Demand Response. DR Potential assessments such as the one used in this IRP are just starting to take hold across the electric industry. Their effectiveness at identifying programs and opportunities are not as mature as the Conservation Potential Assessment process. An iterative process among analysts, modelers, consultants, and local utility operators will need to occur over the next several years to gain a fuller and perhaps more accurate picture of the Demand Response Potential.

Section 8—Least Cost Action Plan

Action Items by January 2021

RRGP Flexibility Analysis and Business Plan

Over the next 10 years, it is highly likely that RRGP will be an integral part of Clark Public Utilities asset base. Recent technological advances in hardware and software controls suggest that RRGP may be able to generate much less energy over time, thus reducing its overall GHG emissions while at the same increasing its generation and response times considerably. To the extent this can be accomplished more effectively and efficiently than other technologies, then this alternative should be considered.

Staff intends to analyze this opportunity at RRGP and compare it to other known commercially available alternatives such as hydro pump storage, battery storage of various types, and any other resource that can provide such flexibility. A business case will be developed along with recommendations that may result from the analysis. This task is targeted to be completed by the end of 2020

As this Action Item could impact the GHG profile of Clark Public Utilities, it will also be included as an Action Item in Section 9—Clean Energy Action Plan

Ongoing Action Items

Acquire all cost-effective conservation consistent with NWPCC models and Clark Public Utilities' Conservation Potential Assessment.

Clark Public Utilities has always pursued cost-effective conservation and associated peak reduction programs. Clark Public Utilities has always identified and defined cost-effective as that price which is below the price of power in the wholesale market. Thus, all cost-effective conservation is included all least cost alternatives identified in Section 6—Least Cost Considerations and Alternatives.

Buy all available BPA Tier 1 power in 2021-2028 to cover load growth.

BPA Tier I power is that power associated with the Federal Base System (FBS) in the most recent contracts signed between BPA and its customers. The FBS can produce only so much power and most BPA customers are at the upper limits of their rights to this Tier 1 power. Due to negative load growth during the first several years of the contract, Clark Public Utilities still has room to grow before its Tier I allocation cap amount is achieved. Any forecasted load growth must be, pursuant to the Slice/Block contract, served first by this available "headroom" prior to making any new purchases for annual average energy. The Tier I power is typically very competitive with the market and the associated attributes associated with delivery of power from BPA make it a superior power product compared to all other available power transactions in the market.

BPA Post-2028 Contract Finalized with the CETA Requirements Embedded

Absent the CETA, this is not necessarily a least cost action plan item. However, as the CETA is inextricably linked to resource planning for Clark Public Utilities, this action item becomes an overarching component of both Least Cost and Clean Energy Action Planning. Please see the sub section BPA Post-2028 Contract Finalized with the CETA Requirements Embedded in Section 9.

Section 9—Clean Energy Action Plan

Introduction

This Section 9 of this Integrated Resource Plan is intended to meet the requirements of the CETA as it relates to obligations regarding the creation of a Clean Energy Action Plan

Requirements of Consumer Owned Utilities for creating a Clean Energy Action Plan under the CETA.

Language in the CETA specifies that a utility develop a ten-year clean energy action plan for implementing RCW 19.405.030 through 19.405.050 at the lowest reasonable cost, and at an acceptable resource adequacy standard, that identifies the specific actions to be taken by the utility consistent with the long-range integrated resource plan. RCW 19.405.30 through 19.405.50 correspond to sections The path to 2025 – No coal in rates, The path to 2030-2044 – 100 Percent Carbon Neutral and #The path to post 2045 – 100 Percent of Electric Load is GHG-Free respectively.

The CETA is currently in its rulemaking phase as certain legislative language requires further clarity and implementation. The Washington Department of Commerce is tasked with rulemaking for consumer-owned utilities such as Clark Public Utilities. As most of the rules regarding the CETA are not finalized, there may be differences in the manner in which this IRP, including the Section 8—Least Cost Action Plan and this Section 9 – Clean Energy Plan, are interpreted or constructed when compared to the final rules as determined by Commerce. Clark Public Utilities will endeavor to correct those differences when and where appropriate.

Table 9.1 breaks down the most recent year (2018) of the resources that served Clark Public Utilities retail load as submitted for the Washington State Fuel Mix Report.

Clark County PUD #1		
Utility Fuel Mix		
Fuel	Percent	Total MWh
Biogas	0.00 %	0
Biomass	0.00 %	0
Coal	0.00 %	0
Geothermal	0.00 %	0
Hydro	57.12 %	2,675,396
Natural Gas	25.47 %	1,192,802
Nuclear	7.06 %	330,772
Other Biogenic	0.00 %	0
Other Non-Biogenic	0.00 %	0
Petroleum	0.00 %	0
Solar	0.00 %	0
Waste	0.00 %	0
Wind	0.00 %	0
Unspecified	10.35 %	484,652
Total	**100.00 %**	**4,683,622**

Table 9.1

The highlighted numbers which are GHG-free electric resources add up to 64% of Clark Public Utilities' resources used to meet its load. This number will vary from year-to-year due to hydro generation variability from year to year. This is the reason that the compliance periods as defined in the CETA are four year periods. It allows utilities like Clark Public Utilities some flexibility to meet the 80% resource requirement over a period of years due to the hydro variability. It is unclear at this point how exactly unspecified energy will be handled in the future. Thus, it will be ignored in this discussion.

Table 9.2 shows the fuel make-up of all utilities situated in the Pacific Northwest.

Table 4: 2018 Northwest Power Pool Generation by Fuel Category[1]

Fuel Category	Net Generation MWh	Fuel Category Share
Hydro	138,398,075	46.30%
Coal	69,290,606	23.18%
Natural Gas	46,119,633	15.43%
Wind	24,093,046	8.06%
Nuclear	9,708,441	3.25%
Solar	3,403,887	1.14%
Geothermal	3,016,844	1.01%
Biomass	2,223,073	0.74%
Other Non-Biogenic	1,201,810	0.40%
Biogas	686,323	0.23%
Petroleum	528,538	0.18%
Other Biogenic	136,355	0.05%
Waste	95,049	0.03%
Total	298,901,680	100.00%

Table 9.2

Comparing Clark Public Utilities in Table 9.1 to the make-up of the generation in the Northwest Power Pool, Clark Public Utilities GHG-free generation percentage is roughly about the same. However, when looking at actual CO2 per MWh, Clark Public Utilities is well under the NWPP as the bulk of Clark Public Utilities' GHG emissions are from its RRGP Gas plant which emits 55% less CO2 per MWh than coal-fired facilities. Data for 2018 as submitted to the Climate Registry established Clark Public Utilities' CO2 per MWh delivered to retail customers as 282 lbs/MWh.

Figure 9.1 from the Environmental Protection Agency shows the CO2 per MWh for the NWPP and the U.S. as a whole.

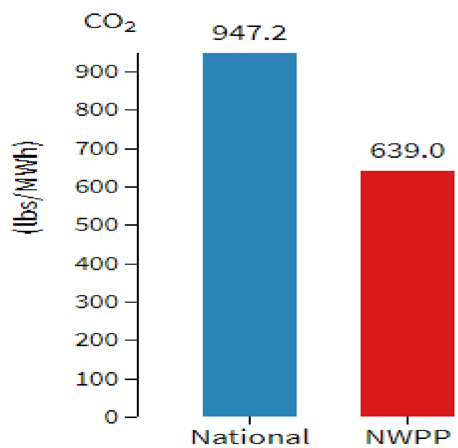


Figure 9.1

Clark Public Utilities emits roughly less than half of the CO2 per MWh as the Northwest Power Pool and less than one-third of the CO2 per MWh as the national average.

Summary of Actions taken after the CETA prior to 2020 IRP acceptance

Prior to the adoption of this IRP, Clark Public Utilities took concrete steps toward meeting the requirements of the CETA, including the following areas.

Bringing Combine Hills II wind contract to load.

Electricity produced by Combine Hills II up until January 1, 2020 had never been delivered to Clark Public Utilities' load. Wind energy is intermittent, hard to predict, and carries operational obligations that up until November 2019 made it very difficult to bring the electricity to load without incurring potential penalties under other contracts. Clark Public Utilities staff worked hard to better understand the roadblocks and found a path to allow for more flexibilities under the other power supply debt obligations. Now, Combine Hills II is being brought to load, increasing the GHG-Free power supply delivered to Clark Public Utilities roughly 3.4%.

Staying abreast of conservation and demand response programs, distributed generation, and renewable technologies and opportunities.

For years, Clark Public Utilities has followed a myriad of forums, policy groups, technical committees, and governmental efforts in order to provide the best programs and products to its customers. This is just a reaffirmation of this commitment to our customers.

Establishment of funds from 2019 surplus net revenues that may be applied toward Resource Adequacy, compliance with the CETA, or other uses the Board of Commissioners determines.

These funds, while not specifically designated, may be spent on several areas to advance the progress toward compliance such as:

- Advanced Metering Infrastructure
- Enhancing RRGP Physical Flexibility
- Funding R&D organizations that further renewable energy and storage infrastructure
- Compliance with the CETA.

Making RRGP more efficient by auto-tuning

Recently Clark Public Utilities added hardware and software tools to RRGP that enables the plant to run more efficiently every hour of every day. The process is called auto-tuning. By automatically keeping the unit in tune at all times compared to a manual twice-a-year tuning process, RRGP will run a bit more efficiently. Because the unit runs more efficiently more energy is produced with the same amount of fuel, reducing the CO2 per MWh burned. This reduction in CO2 for the same amount of energy produced does not matter under the CETA as the CETA does not differentiate between cleaner burning fuels or more efficient fossil-fueled power plants except under the disciplinary sections if utilities do not meet the requirements in the compliance periods. However, Clark Public Utilities sees it as its responsibility to be as efficient as possible for environmental and economic reasons.

Engaging with Small Modular Nuclear Reactor (SMR) developers

Clark Public Utilities has had preliminary discussions with SMR developers to investigate the progress being made and the potential viability of SMR. Discussions are very preliminary, non-committal, and are not indicative of any bias to the particular power supply. SMR is GHG-free and appears to be very dispatchable and this is the type of resource that Clark Public Utilities will likely find desirable under future resource acquisitions and thus requires interactions with those in the marketplace looking to develop these kinds of resources.

In progress efforts to meet 2030-2033 compliance window

Acquire all cost-effective conservation consistent with NWPCC models and Clark Public Utilities' Conservation Potential Assessment.

Clark Public Utilities has always pursued cost-effective conservation and associated peak reduction programs. Clark Public Utilities has always identified and defined "cost effective" as that price which is below the price of power in the wholesale market. A saturation of renewable power coupled with low natural gas prices has softened the wholesale market. Thus, the opportunities for conservation have diminished a bit compared to years past. However, Clark Public Utilities' Energy Resource staff continues to look for opportunities internal and external to the service territory to meet and beat the targets proffered by the Conservation Potential Assessment.

Budget research and development dollars to join groups that can help inform decisions regarding GHG-free resources, GHG-free shaping and storage, and GHG-free retrofitting.

Clark Public Utilities is not a Research and Design (R&D) company. Clark Public Utilities makes every effort to stay abreast of commercially available resources for consideration in its portfolio development. However, the brisk pace and the continuous pressure to reduce GHG emissions puts the utility often in a defensive posture when new advances are discussed as potential opportunities to meet these new requirements. Exciting areas such as hydrogen-based generation, all types of storage technologies, and demand-side supply opportunities show much promise. However, the access to defendable and repeatable research and design without membership in reputable organizations can lead discussions astray based upon the latest internet search. Thus, part of the Clean Energy Action Plan is a recommendation to budget funds for access to this type of information.

BPA Contract Analyses and strategies

The cases for resource supply are based upon a change in BPA's approach toward inclusion of customer-owned resources in the post-2028 contracts. Clark Public Utilities has been proactive on this issue and has begun to discuss with industry experts internal and external to BPA to discern a pathway that is fair to all.

Join Small Modular Nuclear Reactor consortium

Currently, Clark Public Utilities is a member of Energy Northwest who operates Columbia Generation Station and who has expressed interest in development of SMR. A couple other entities exist that have significant knowledge and interest in SMR. Clark Public Utilities should investigate potential membership or enhance membership in one of these groups.

Flexibility Analysis and Business Plan

Please see the description of this item in the prior section.

The path to 2025 – No coal in rates.

Clark Public Utilities does not own or forward contract for any electricity from coal-fired resources. Thus, no coal costs are imbedded in current retail rates. Clark Public Utilities has no plans to forward contract for any direct purchases or ownership of coal-fired generation.

The path to 2030-2044 – 100 Percent Carbon Neutral.

Getting to 100 Percent carbon neutral as defined under the CETA should be a fairly straight forward process for Clark Public Utilities. Until the CETA, there were no GHG-free emission requirements for Clark Public Utilities. Drawing a straight line from this 0 percent requirement in 2020 to a 100% carbon neutral requirement in 2030 and comparing that to Clark Public Utilities' projected GHG-free generation shows the head start that Clark Public Utilities has on the requirement. Figure 9.2 illustrates this situation. This figure is for illustrative purposes only and does not insinuate that Clark Public Utilities will be inactive on the CETA front until year 2027. Quite the contrary. First, Clark Public Utilities does not have any plans to degrade its GHG-free footprint on a go-forward basis, but there will be year-to-year variances due to snow pack run-off changes that impact hydro generation from one year to the next.

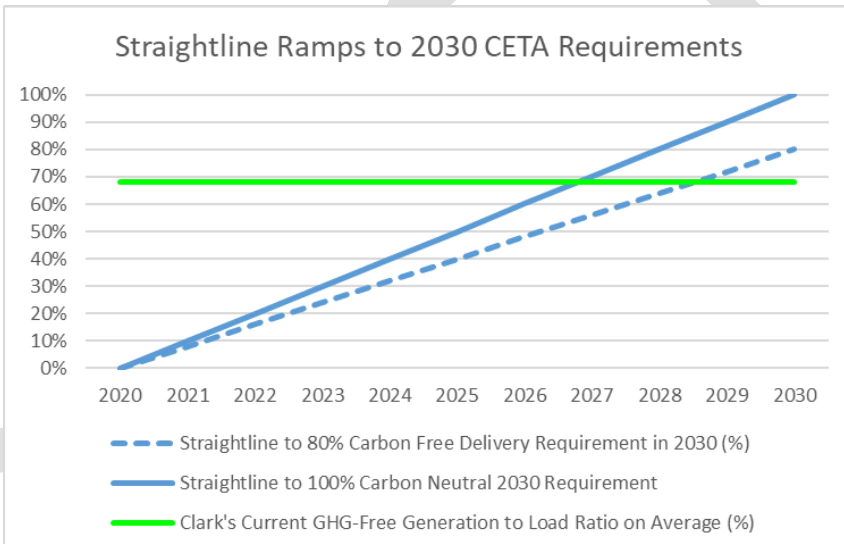


Figure 9.2

To get to the 2030 requirements, Clark Public Utilities envisions several very intense processes that must be completed, some as early as the 2025 timeframe.

BPA Post-2028 Contract Finalized with the CETA Requirements Embedded

As discussed in other areas of this IRP, the current BPA PSC expires in 2028. The details of a new BPA PSC have enormous implications for Clark Public Utilities. The different scenarios in Section 7 described choices and outcomes that may happen with respect to the BPA PSC. Negotiation of any new BPA PSC is a very time-consuming, labor-intensive, and potentially very costly endeavor depending upon the conflict management needed to get to resolution. BPA has roughly 125 PF customers who are represented by various trade associations as well as by their own staff during the PSC construction process. BPA must follow strict process controls to insure that all interactions with various stakeholders are public in nature. All this process with all the players requires time.

Getting to an agreeable contract is only half of the effort. Ratemaking on the new contract must occur and implementation efforts must take place prior to the first hour of delivery in October 2028. Thus, the timeline for completion of the Post-2028 Contract and its implementation, in many respects, has already begun and the consensus at this point is BPA is hoping to offer contracts for signature in mid-2025.

Clark must strategically work with BPA, customer groups, and other stakeholders to get to a fair contract for all. A fair contract would include the provisions in the CETA that impact RRGP operations and other program implementations. The ability to access additional BPA PF power up to at least 80% delivery requirement for 2030-2044 compliance periods is the least cost way for Clark Public Utilities to comply.

This effort will pay great dividends and will require much effort between now and the time at which BPA offers new contracts.

Increase local efforts on Demand Response

See Appendix B – 2020 Demand Response Potential Assessment as the starting point for our efforts regarding Demand Response. Demand Response holds great promise in helping Clark Public Utilities manage several different areas of concern: Resource Adequacy, distribution system reliability, and overall GHG reductions. Clark Public Utilities will focus a lot of attention in this area to execute the DRPA and to look for additional opportunities as well.

In Partnership with Customers and Vendors, Develop Programs and Pilots in areas of Renewable Distributed Generation and Electric Vehicles.

See the following Appendices for our current views on these topics; Appendix D – Distributed Energy and Resources and Appendix E – Electric Vehicle Saturation. Clark Public Utilities prides itself on its excellent customer satisfaction. If there is a way that we can serve our customers in these areas while helping the utility meet the goals of the CETA, we view that as win-win. These efforts must meet the scrutiny of our Board of Commissioners first and foremost as it is their responsibility to balance the needs of all Clark Public Utilities' customers.

Backup Plans to BPA PSC Option

The primary approach to meeting 2030-2044 compliance period requirements under the CETA involves a desirous outcome in the new Post-2028 BPA PSC. This outcome is not a given. The need for potential alternatives exists. The alternatives include but are not limited to the following:

- AMI-databased research and design to identify retail programs to reduce peak and average consumption.
- Small Modular Nuclear Reactor Participation
- Stepped-Up Renewable and Renewable/Battery Acquisition
- New Technology Investment such as Hydrogen-fueled Generation
- Partnering with or being acquired by other non-federal multi-state and low GHG-emitting utilities

Clark Public Utilities will endeavor to keep all options on the table. Utility staff will maintain data, perform research as needed, and keep up with technological and industry advances to provide as many options as possible to the Board of Commissioners. Clark Public Utilities, with guidance from its Board, endeavors to meet the CETA in a manner that is most favorable to its ratepayers. No potential alternatives will be dismissed out of hand without proper cost/benefit analyses that, of course, will include the social cost of carbon as delineated in price and application in the CETA.

Compliance of the CETA 2030-2044 and the CETA Revenue Requirements Cost Cap.

Clark Public Utilities will be in compliance in all compliance periods as defined under the language in the CETA. There are certain cost protections provided under the CETA that are in place to protect utilities from seeing their retail revenue requirements suffer from unseen inflationary pressures. Clark Public Utilities does not see this retail revenue protection as a governing attribute as this time. But, should the need arise, Clark Public Utilities will use the tool as a means to protect ratepayers from unreasonable rate increases as determined by the Board of Commissioners.

The path to post 2045 – 100 Percent of Electric Load is GHG-Free

While twenty-five years from today, Clark Public Utilities is compelled now to begin planning its future after 2045. RRGP will not have a place in Clark Public Utilities' portfolio at this time in the future unless renewable natural gas is plentiful and inexpensive, or it is able to convert to a hydrogen-based generating station at a reasonable cost with abundant hydrogen available. Even with either of these scenarios, RRGP will most likely be past its useful life span unless significant funds are spent between now and then on replacing the rotating and auxiliary equipment, essentially creating a "new" RRGP in the process.

Other resources will be needed to get to the lofty goal of 100% GHG-Free served load. The technologies to accomplish these, as known at this time, are nuclear power and those resources deemed renewable by policy such as wind, solar, and fuel-cells backed-up by massive amounts of storage. Storage based upon all possible technologies including new pumped-hydro, gravity-based storage, currently known chemical-based batteries and batteries of heretofore unknown chemical composition will be needed.

To get to this future, Clark Public Utilities is planning to take all the steps identified in the prior subsection The path to 2030-2044 – 100 Percent Carbon Neutral.

In addition, over the next ten years, Clark Public Utilities will continually keep RRGP in mind regarding any opportunities to further reduce GHG from the plant despite the lack of incentive to do so. Under the CETA, no discernment is made between a generating plant's emission rate of GHG per MWh despite the vast differences across fuel-types. It is a binary distinction that provides no incentives to reduce the emission rate of RRGP and, in fact, could be an inverse incentive to no longer spend any money on improvements.

As mentioned, Clark Public Utilities will also increase its spending on R&D in the areas of GHG-free energy production and over load reductions by joining independent and reputable research groups that focus on these areas.

Appendix A – 2019 Conservation Potential Assessment

Clark Public Utilities

Conservation Potential Assessment

Final Report

September 3, 2019

Prepared by:

EES Consulting

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September 3, 2019

Mr. Larry Blaufus
Clark Public Utilities
P.O. Box 8900
Vancouver, Washington 98668

SUBJECT: 2019 Conservation Potential Assessment – Final Report

Dear Mr. Blaufus:

Please find attached the final report summarizing the 2019 Clark Public Utilities Conservation Potential Assessment (CPA). This report covers the 20-year period from 2020 through 2039. The potential has decreased from the 2017 CPA, largely due to standards impacting many residential lighting measures and changes in the avoided cost assumptions.

We would like to thank you and your staff for the excellent support in developing and providing the baseline data for this project.

Best Regards,

Ted Light

Ted Light
Senior Project Manager

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Kirkland, Washington 98033

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Executive Summary

This report describes the methodology and results of the Clark Public Utilities (CPU) 2019 Conservation Potential Assessment (CPA). This assessment provides estimates of energy and peak demand savings by sector for the period 2020 to 2039. The assessment considered a wide range of conservation resources that are reliable, available, and cost-effective within the 20-year time horizon.

Background

CPU provides electricity service to more than 203,000 customers located in Clark County, Washington. CPU's service territory covers 628 square miles and includes 6,600 miles of transmission and distribution lines.

Washington's Energy Independence Act (EIA), effective January 1, 2010 and modified October 4, 2016, requires that utilities with more than 25,000 customers (known as qualifying utilities) pursue all cost-effective conservation resources and meet conservation targets set using a utility-specific conservation potential assessment methodology.

The EIA sets forth specific requirements for setting, pursuing and reporting on conservation targets. The methodology used in this assessment complies with RCW 19.285.040 and WAC 194-37-070 Section 5 parts (a) through (d) and is consistent with the methodology used by the Northwest Power and Conservation Council (Council) in developing the Seventh Power Plan. Thus, this Conservation Potential Assessment will support CPU's compliance with EIA requirements.

This assessment was built on the same model used in the 2017 CPA, which was based on the completed Seventh Power Plan. The model was updated to reflect changes since the completion of the 2017 CPA. The primary model updates included the following:

- New Avoided Costs
  - Recent forecast of power market prices
  - Updated values for avoided generation capacity
  - New transmission and distribution capacity costs based on new values from the Council
- Updated Customer Characteristics Data
  - New residential home counts and characteristics
  - Updated commercial floor area
  - Updated industrial sector consumption
- Measure Updates
  - Measure savings, costs, and lifetimes were updated based on the latest updates available from the Regional Technical Forum (RTF)

    - New measures not included in the Seventh Plan but subsequently reviewed by the RTF were added
- Accounting for Recent Achievements
    - Internal programs
    - NEEA programs

The first step of this assessment was to carefully define and update the planning assumptions using the new data. The Base Case conditions were defined as the most likely market conditions over the planning horizon, and the conservation potential was estimated based on these assumptions. Additional scenarios were also developed to test a range of conditions.

Results

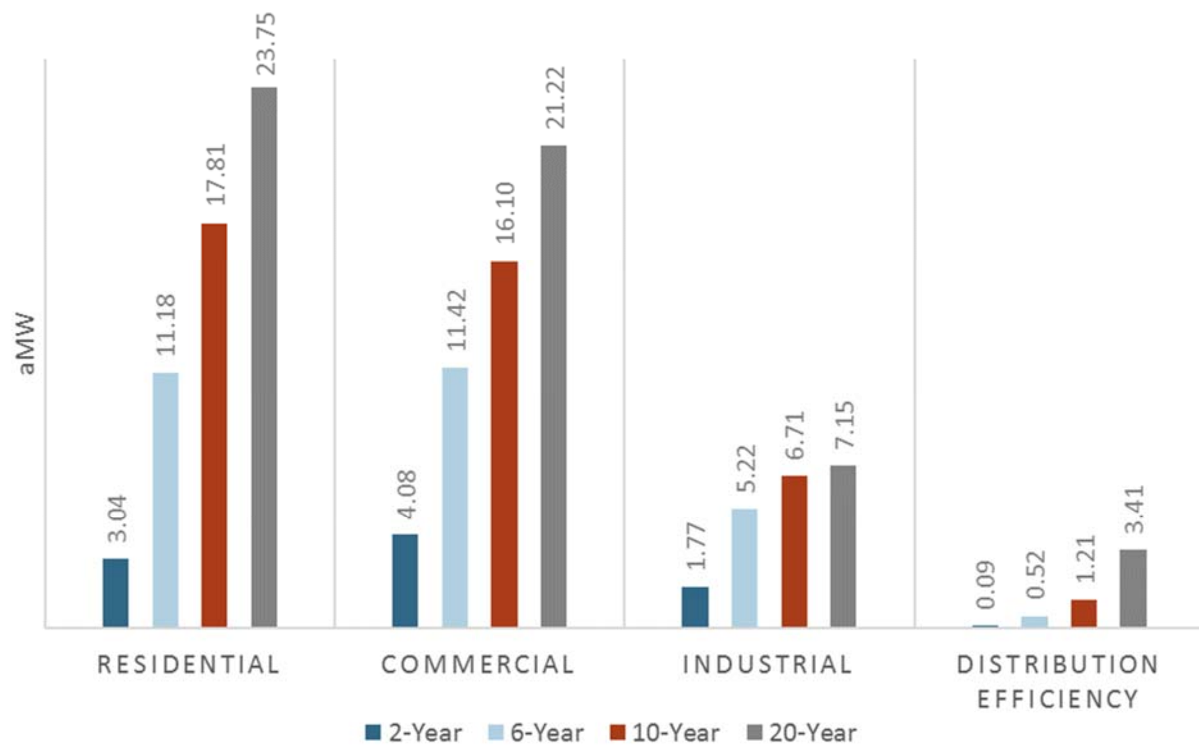
Table ES-1 and Figure ES-1 show the high-level results of this assessment. The economically achievable potential by sector in 2, 6, 10 and 20-year increments is included. The total 20-year cost-effective conservation potential is 55.53 aMW. The focus of the EIA requirement is on the 10-year potential, 41.83 aMW, and the 2-year potential, 8.97 aMW.

These estimates include energy efficiency achieved through CPU's own utility programs and through CPU's share of the Northwest Energy Efficiency Alliance (NEEA) accomplishments. Some of the potential may be achieved through code and standard changes, especially in the later years. In some cases, the savings from those changes will be quantified by NEEA or through BPA's Momentum Savings work.

Table ES-1
Cost Effective Potential (aMW)

	2-Year	6-Year	10-Year	20-Year
Residential	3.04	11.18	17.81	23.75
Commercial	4.08	11.42	16.10	21.22
Industrial	1.77	5.22	6.71	7.15
Distribution Efficiency	0.09	0.52	1.21	3.41
Total	**8.97**	**28.33**	**41.83**	**55.53**

Figure ES-1
Cost-Effective Potential



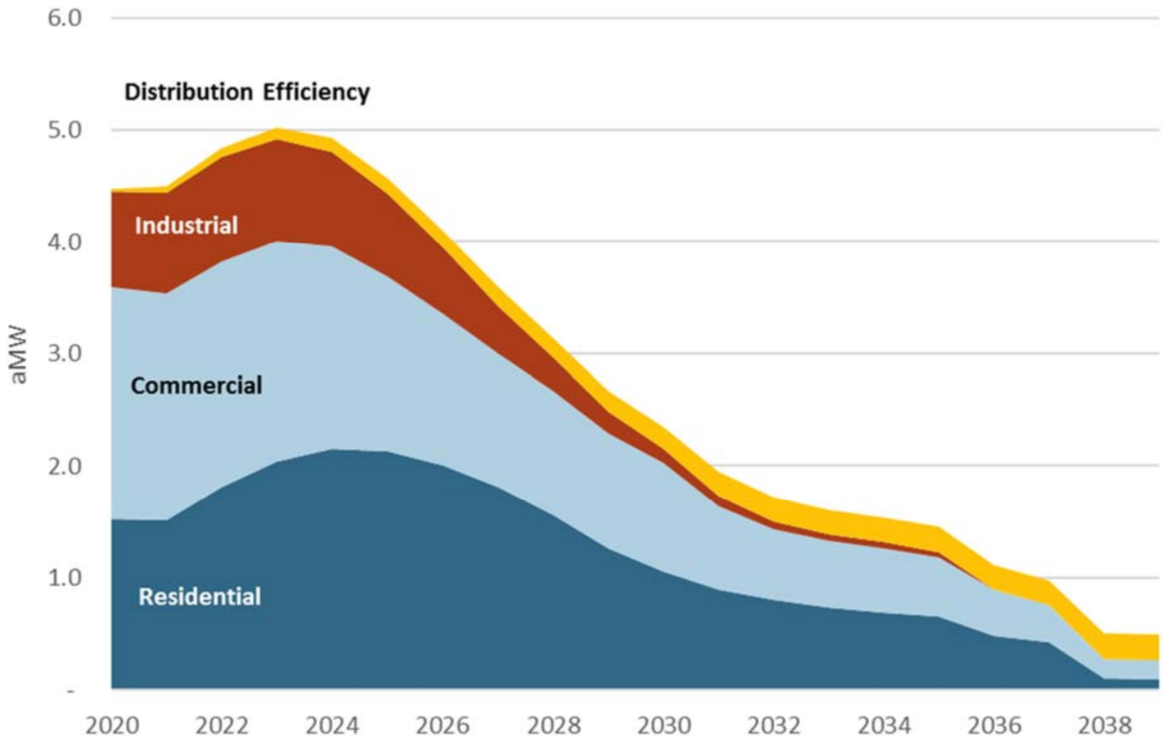
Energy efficiency also has the potential to reduce peak demands. Based upon hourly load profiles developed for the Seventh Power Plan and load data provided by CPU, the reductions in peak demand provided by energy efficiency are summarized in Table ES-2 below. Based on this table, the peak demand reduction, measured in MW, is approximately double the annual average energy savings. CPU's annual peak occurs most frequently in winter mornings, between 7 and 8 AM. In addition to these peak demand savings, demand savings would occur in varying amounts throughout the year.

Table ES-2
Cost Effective Demand Savings (MW)

	2-Year	6-Year	10-Year	20-Year
Residential	8.5	32.8	52.3	66.2
Commercial	6.9	19.6	27.2	35.2
Industrial	2.1	6.3	8.1	8.6
Agricultural	0.0	0.0	0.0	0.0
Total	**17.6**	**59.3**	**89.0**	**114.3**

The 20-year energy efficiency potential is shown on an annual basis in Figure ES-2. This assessment shows potential starting around 4.5 aMW in 2020, increasing to a maximum of 5 aMW in 2023, and then decreasing in the remaining years of the planning period as the remaining measure opportunities diminish over time.

Figure ES-2
Annual Energy Efficiency Potential Estimate



Relative to the 2017 CPA, the amount of cost-effective potential in the residential sector has decreased significantly. Much of the change is due to federal standards scheduled to take effect in 2020. These standards require efficiency levels only found in CFLs and LEDs; and with CFLs losing market share to LEDs, energy efficiency programs may not be necessary. EES has included only a small amount of savings from these residential lighting measures in 2020, acknowledging that programs will transition away from these measures over the course of the 2020 calendar year.

Further, changes in the value of capacity savings has resulted in a decrease in the cost effectiveness of some measures that contribute to reductions in peak demand. The remaining conservation potential in the residential sector is among the HVAC and water heating end uses. Some notable measures in these areas include:

- Water heating measures like heat pump water heaters, low-flow showerheads, and clothes washers
- Weatherization measures, including insulations and windows
- Behavior-based programs

There is also a significant amount of cost-effective conservation available in CPU's commercial sector, although the remaining potential decreases notably in the early years of the study period. The potential in this sector has also decreased due to the changes discussed above as well as a decrease in the estimated commercial floor area in CPU's service territory. Notable areas for commercial sector achievement are among the main end uses in the sector:

- Lighting – including interior lighting, controls, exterior building lighting, and street lighting
- HVAC – such as rooftop unit controllers and energy management programs

The industrial sector continues to be a significant source of cost-effective potential. The potential in this sector increased over the results of the 2017 study, due to increases in the overall load and some changes in how industrial sector achievements were accounted for in the CPA model. Key measures in the industrial sector include measures specific to the hi-tech sector as well as strategic energy management measures.

Table ES-3 shows the comparison of the Base Case results in the 2017 and current 2019 assessments. Both 10-year and 20-year cost-effective achievable potential are shown.

Table ES-3
Comparison of 2017 and 2019 CPA Cost-Effective Potential

	10-Year			20-Year		
	2017	2019	% Change	2017	2019	% Change
Residential	25.2	17.8	-29%	42.6	23.8	-44%
Commercial	16.4	16.1	-2%	31.4	21.2	-32%
Industrial	3.8	6.7	76%	3.8	7.1	87%
Distribution Efficiency	1.1	1.2	7%	3.1	3.4	11%
Total	**46.5**	**41.8**	**-10%**	**80.9**	**55.5**	**-31%**

**Note that the 2017 columns refer to the CPA completed in 2017 for the period of 2018 through 2037. The 2019 assessment is for the years 2020 through 2039.*

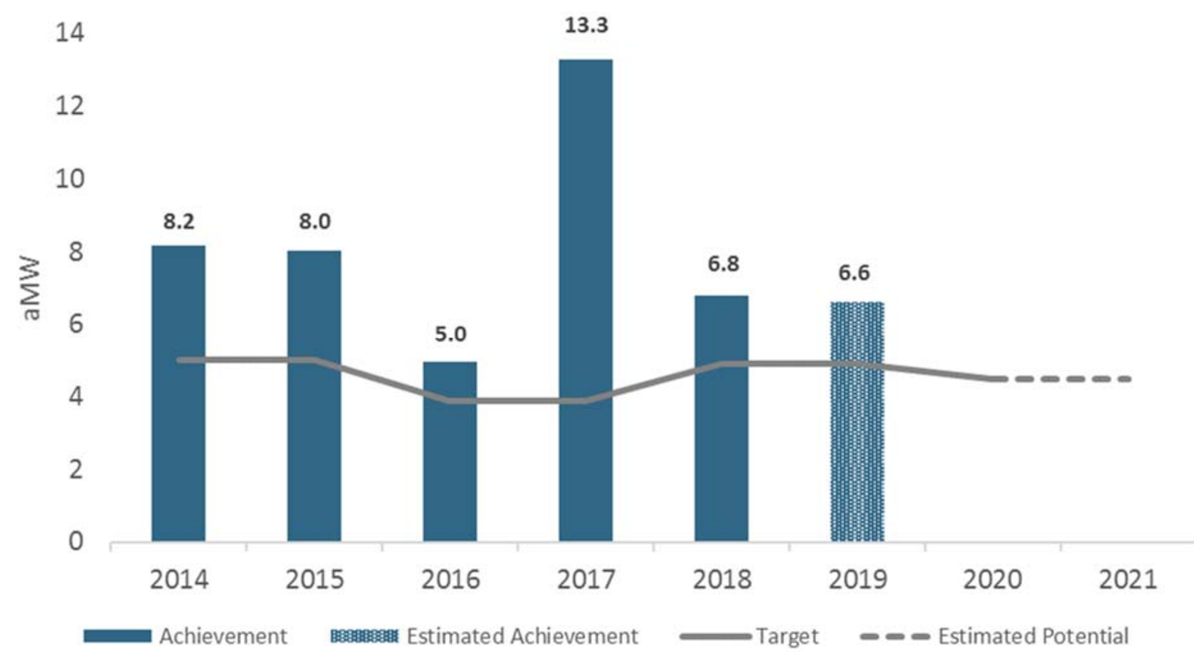
The differences between the 2017 and 2019 results are substantial and are driven by a variety of changes to measure assumptions and economic inputs. The two key changes include:

- The above-mentioned federal lighting standard impacts many residential lighting measures, which were not included after 2020. In the 2017 study, residential lighting measures accounted for nearly 25 aMW of cost-effective potential over the 20-year study period. Several commercial lighting measures were impacted by this change as well.
- The Council updated its assumptions on the value of deferred capital expenditures for transmission and distribution capacity, with the new values being significantly lower. The extent to which each measure realizes these values depends on its contribution to reducing peak demands, so measures in the residential and commercial sectors, which tend to contribute more to reducing system peaks, were more impacted. Savings in the industrial sector tend to be more evenly distributed across time, so the changes in assumptions had less of an impact to the industrial sector.

Targets and Achievement

Figure ES-3 below compares CPU's historic achievement with its targets. The estimated potential for 2020 and 2021 is based on the Base Case scenario presented in this report and represents approximately a 28% decrease over the 2018-19 biennium. A decrease was expected given the likely changes to residential lighting programs, but the target is realistic as these savings were not considered when aligning potential with recent program history. The figure shows that CPU has consistently met its energy efficiency targets, and that the potential estimates presented in this report are achievable through CPU's utility conservation programs and the utility's share of NEEA savings. ES-3 shows projected achievement for 2019.

Figure ES-3
Comparison of Conservation Targets to Achievements



Conclusion

This report summarizes the CPA conducted for Clark Public Utilities for the 2020 to 2039 planning period. Based on the results of the Base Case scenario, the total 10-year cost effective potential is 41.83 aMW and the 2-year potential is 8.97 aMW. The results of this assessment are lower than the previous assessment, largely due to the exclusion of many residential lighting measures after 2020 as well as the change in the valuation of transmission and distribution capacity costs.

Introduction

Objectives

The objective of this report is to describe the results of the Clark Public Utilities' (CPU) 2019 Conservation Potential Assessment (CPA). This assessment provides estimates of energy savings by sector for the period 2020 to 2039, with the primary focus on the initial 10 years, 2020 to 2029. This analysis has been conducted in a manner consistent with requirements set forth in 19.285 RCW (EIA) and 194-37 WAC (EIA implementation) and is part of CPU's compliance documentation. The results and guidance presented in this report will also assist CPU in strategic planning for its conservation programs in the near future. Finally, the resulting conservation supply curves can be used in CPU's integrated resource plan (IRP).

The conservation measures used in this analysis are based on the measures included in the Council's Seventh Power Plan and were updated with subsequent changes and new measures approved by the Regional Technical Forum (RTF). The assessment considered a wide range of conservation resources that are reliable, available, and cost-effective within the 20-year planning period.

Electric Utility Resource Plan Requirements

CPU provides electricity service to more than 203,000 customers located in Clark County, Washington. CPU's service territory covers 628 square miles and includes 6,600 miles of transmission and distribution lines. CPU serves its loads with a variety of resources, including demand side resources.

According to Chapter 19.280 RCW, utilities with at least 25,000 customers are required to develop integrated resource plans (IRPs) by September 2008 and biennially thereafter. The legislation mandates that these resource plans include assessments of commercially available conservation and energy efficiency measures. This CPA is designed to assist in meeting these requirements for conservation analyses. The results of this CPA may be used in the next IRP due to the state by September 2020. More background information is provided below.

Energy Independence Act

Chapter 19.285 RCW, the Energy Independence Act (EIA), requires that, "each qualifying utility pursue all available conservation that is cost-effective, reliable, and feasible." The timeline for requirements of the Energy Independence Act are detailed below:

- By January 1, 2010 – Identify achievable cost-effective conservation potential through 2019 using methodologies consistent with the Pacific Northwest Power and Conservation Council's (Council) latest power planning document. At least every two years thereafter, the qualifying utility shall review and update this assessment for the subsequent ten-year period.

- Beginning January 2010, each utility shall establish a biennial acquisition target for cost-effective conservation that is no lower than the utility's pro rata share for the two-year period of the cost-effective conservation potential for the subsequent ten years.
- By June 2012, each utility shall submit an annual conservation report to the department (the Department of Commerce or its successor). The report shall document the utility's progress in meeting the targets established in RCW 19.285.040.
- Beginning on January 1, 2014, cost-effective conservation achieved by a qualifying utility in excess of its biennial acquisition target may be used to help meet the immediately subsequent two biennial acquisition targets, such that no more than twenty percent of any biennial target may be met with excess conservation savings.

This report summarizes the preliminary results of a comprehensive CPA conducted following the requirements of the EIA. A checklist of how this analysis meets EIA requirements is included in Appendix III.

Other Legislative Considerations

Washington state recently enacted several laws that impact conservation planning. Washington HB 1444 enacts efficiency standards for a variety of appliances, some of which are included as measures in this CPA. This law takes effect on July 28, 2019 and applies to products manufactured after January 1, 2021. As the law applies to the manufacturing date, products not meeting the efficiency levels set forth in the law could continue to be sold in 2021 and a reasonable time of six months or more may be necessary for product inventories to turn over. As such, the standards contained in this law will be addressed in the 2021 CPA.

Washington also recently enacted a clean energy law, SB 5116. The bill contains two provisions that would impact potential assessments: the use of a specific set of values for the social cost of carbon and the requirement that all sales should be greenhouse gas free beginning in 2030. This bill was in development but was not finalized until after the much of the analysis of this CPA was substantially completed. The specific provisions of the bill have therefore not been incorporated, but the analysis does consider similar values for the social cost of carbon and a more stringent renewable portfolio standard in scenarios discussed later in the report. EES also completed some preliminary modelling to provide some early guidance to CPU on the approximate impacts of this law and found that including the law's provisions would increase the long-term potential by approximately 20%, mostly in the residential sector.

Study Uncertainties

The savings estimates presented in this study are subject to the uncertainties associated with the input data. This study utilized the best available data at the time of its development; however, the results of future studies will change as the planning environment evolves. Specific areas of uncertainty include the following:

- Customer characteristic data – Residential and commercial building data and appliance saturations are in many cases based on regional studies and surveys. There are uncertainties related to the extent that CPU's service area is similar to that of the region, or that the regional survey data represent the population.
- Measure Data – In particular, savings and cost estimates (when comparing to current market conditions), as prepared by the Council and RTF, will vary across the region. In some cases, measure applicability or other attributes have been estimated by the Council or the RTF based on professional judgment or limited market research.
- Market Price Forecasts – Market prices (and forecasts) are continually changing. The market price forecasts for electricity and natural gas utilized in this analysis represent a snapshot in time. Given a different snapshot in time, the results of the analysis would vary. However, alternate scenarios are included in the analysis to identify the sensitivity of the results to variation in market prices and other avoided cost inputs over the study period.
- Utility System Assumptions – Credits have been included in this analysis to account for the avoided costs of transmission and distribution system expansion. Though potential transmission and distribution system cost savings are dependent on local conditions, the Council considers these credits to be representative estimates of these avoided costs. A value for generation capacity was also included but may change as the Northwest market continues to evolve.
- Discount Rate – The Council develops a real discount rate for each Power Plan based on the relative share of the cost of conservation and the cost of capital for the various program sponsors. The Council has estimated these figures using the most current available information. This study reflects the current borrowing market although changes in borrowing rates will likely vary over the study period.
- Forecasted Load and Customer Growth – The CPA bases the 20-year potential estimates on forecasted loads and customer growth. Each of these forecasts includes a level of uncertainty.
- Load Shape Data – The Council provides conservation load shapes for evaluating the value of time-differentiated energy savings. In practice, load shapes will vary by utility based on weather, customer types, and other factors. This assessment uses the hourly load shapes used in the Seventh Plan to estimate peak demand savings over the planning period, based on shaped energy savings. Since the load shapes are a mix of older Northwest and California data, peak demand savings presented in this report may vary from actual peak demand savings.
- Frozen Efficiency – Consistent with the Council's methodology, the measure baseline efficiency levels and end-using devices do not change over the planning period. In addition, it is assumed that once an energy efficiency measure is installed, it will remain in place over the remainder of the study period.

Due to these uncertainties and the changing environment, under the EIA, qualifying utilities must update their CPAs at least every two years to reflect the best available information.

Report Organization

The main report is organized with the following main sections:

- Methodology – CPA methodology along with some of the overarching assumptions
- Recent Conservation Achievement – CPU's recent achievements and current energy efficiency programs
- Customer Characteristics – Housing and commercial building data for updating the baseline conditions
- Results – Energy Savings and Costs – Primary base case results
- Scenario Results – Results of all scenarios
- Savings Shape and Demand Savings Results – Base Case potential results by month and by sector
- Summary
- References & Appendices

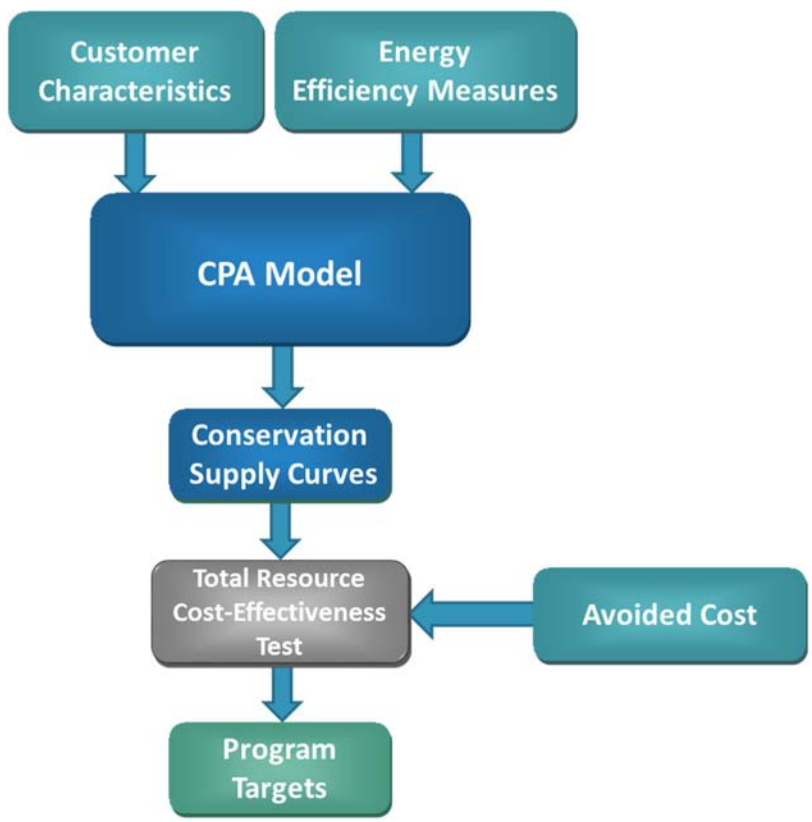
CPA Methodology

This study is a comprehensive assessment of the energy efficiency potential in CPU's service area. The methodology complies with RCW 19.285.040 and WAC 194-37-070 Section 5 parts (a) through (d) and is consistent with the methodology used by the Northwest Power and Conservation Council (Council) in developing the Seventh Power Plan. This section provides a broad overview of the methodology used to develop CPU's conservation potential target. Specific assumptions and details of methodology as it pertains to compliance with the EIA compliance are provided in Appendix III of this report.

Basic Modeling Methodology

The basic methodology used for this assessment is illustrated in Figure 1. A key factor is the kilowatt hours saved annually from the installation of an individual energy efficiency measure. The savings from each measure is multiplied by the total number of measures that could be installed over the life of the program. Savings from each individual measure are then aggregated to produce the total potential.

Figure 1
Conservation Potential Assessment Process



Customer Characteristic Data

Assessment of customer characteristics includes estimating both the number of locations where a measure could feasibly be installed, as well as the share—or saturation—of measures that have already been installed. For this analysis, the characterization of the District's service territory was determined using data from the Northwest Energy Efficiency Alliance (NEEA) commercial and residential building stock assessments. Details of data sources and assumptions are discussed for each sector later in the report.

This assessment also sourced baseline measure saturation data from the Council's Seventh Plan measure workbooks. The Council's data was developed from NEEA's Building Stock Assessments, studies, market research and other sources. This data was updated with NEEA's 2016 Residential Building Stock Assessment and CPU's historic conservation achievement data, where applicable. CPU's historic achievement is discussed in detail in the next section.

Energy Efficiency Measure Data

The characterization of efficiency measures includes measure savings, costs, and lifetime. Other features, such as measure load shape, operation and maintenance costs, and non-energy benefits are also important for measure definition. The Council's Seventh Power Plan is the primary source for conservation measure data. Where appropriate, the Council's Seventh Plan supply curve workbooks have been updated to include any subsequent updates from the RTF. New measures reviewed by the RTF were also added to the model.

The measure data include adjustments from raw savings data for several factors. The effects of space-heating interaction, for example, are included for all lighting and appliance measures, where appropriate. For example, if an electrically-heated house is retrofitted with efficient lighting, the heat that was originally provided by the inefficient lighting will have to be made up by the electric heating system. These interaction factors are included in measure savings data to produce net energy savings.

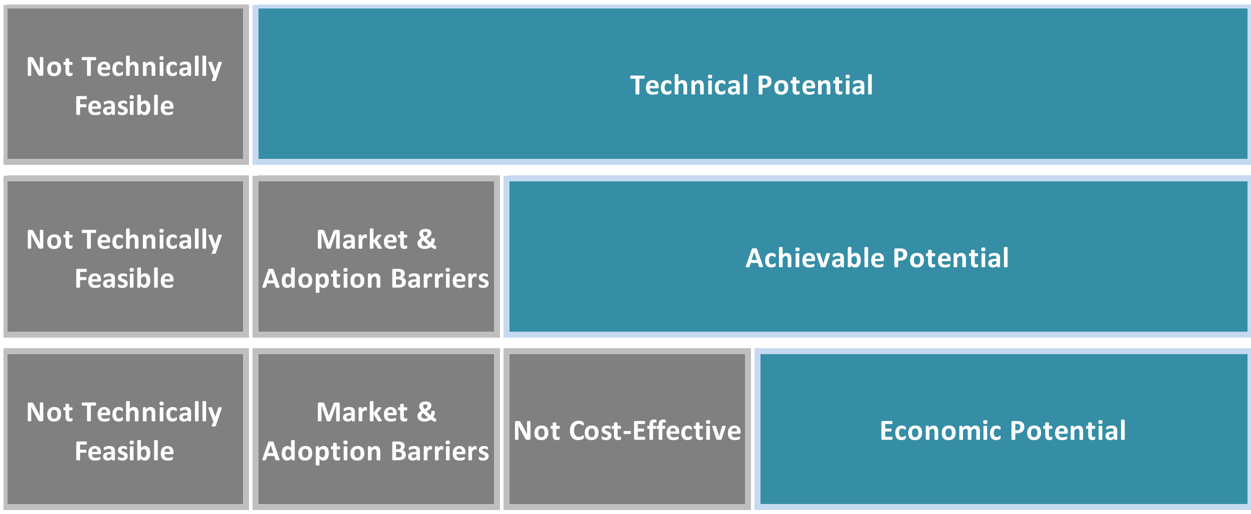
Other financial-related data needed for defining measure costs and benefits include: discount rate, line losses, and deferred capacity-expansion benefits.

A list of measures by end-use is included in this CPA in Appendix VI.

Types of Potential

Once the customer characteristics and energy efficiency measures are fully described, energy efficiency potential can be quantified. Three types of potential are used in this study: technical, achievable, and economic or cost-effective potential. Technical potential is the theoretical maximum efficiency available in the service territory if cost and market barriers are not considered. Market barriers and other consumer acceptance constraints reduce the total potential savings of an energy efficient measure. When these factors are applied, the remaining potential is called the achievable potential. Economic potential is a subset of the achievable potential that has been screened for cost effectiveness through a benefit-cost test. Figure 2 illustrates the four types of potential followed by more detailed explanations.

Figure 2
Types of Energy Efficiency Potential[1]



Technical – Technical potential is the amount of energy efficiency potential that is available, regardless of cost or other technological or market constraints, such as customer willingness to adopt a given measure. It represents the theoretical maximum amount of energy efficiency that is possible in a utility's service territory absent these constraints.

Estimating the technical potential begins with determining a value for the energy efficiency measure savings. Additionally, the number of applicable units must be estimated. Applicable units are the units across a service territory where the measure could feasibly be installed. This includes accounting for units that may have already been installed. The value is highly dependent on the measure and the housing stock. For example, a heat pump measure may only be applicable to single family homes with electric space heating equipment. A saturation factor accounts for measures that have already been completed.

In addition, technical potential considers the interaction and stacking effects of measures. For example, interaction occurs when a home installs energy efficient lighting and the demands on the heating system rise due to a reduction in heat emitted by the lights. If a home installs both insulation and a high-efficiency heat pump, the total savings of these stacked measures is less than if each measure were installed individually because the demands on the heating system are lower in a well-insulated home. Interaction is addressed by accounting for impacts on other energy uses. Stacked measures within the same end use are often addressed by considering the

[1] Adapted from U.S. Environmental Protection Agency. *Guide to Resource Planning with Energy Efficiency.* Figure 2-1, November 2007.

savings of each measure as if it were installed after other measures that impact the same end use.

The total technical potential is often significantly more than the amount of achievable and economic potential. The difference between technical potential and achievable potential is a result of the number of measures assumed to be affected by market barriers. Economic potential is further limited due to the number of measures in the achievable potential that are not cost-effective.

Achievable Technical – Achievable technical potential, also referred to as achievable potential, is the amount of potential that can be achieved with a given set of market conditions. It takes into account many of the realistic barriers to adopting energy efficiency measures. These barriers include market availability of technology, consumer acceptance, non-measure costs, and the practical limitations of ramping up a program over time. The level of achievable potential can increase or decrease depending on the given incentive level of the measure. The Council assumes that 85% of technical potential can be achieved over the 20-year study period. This is a consequence of a pilot program offered in Hood River, Oregon where home weatherization measures were offered at no cost. The pilot was able to reach over 90% of homes. The Council also uses a variety of ramp rates to estimate the rate of achievement over time. This CPA follows the Council's methodology, including both the achievability and ramp rate assumptions.

Economic – Economic potential is the amount of potential that passes an economic benefit-cost test. In Washington State, EIA requirements stipulate that the total resource cost test (TRC) be used to determine economic potential. The TRC evaluates all costs and benefits of the measure regardless of who pays a cost or receives the benefit. Costs and benefits include the following: capital cost, O&M cost over the life of the measure, disposal costs, program administration costs, environmental benefits, distribution and transmission benefits, energy savings benefits, economic effects, and non-energy savings benefits. Non-energy costs and benefits can be difficult to enumerate, yet non-energy costs are quantified where feasible and realistic. Examples of non-quantifiable benefits might include: added comfort and reduced road noise from better insulation or increased real estate value from new windows. A quantifiable non-energy benefit might include reduced detergent costs or reduced water and sewer charges from energy efficient clothes washers.

For this potential assessment, the Council's ProCost model was used to determine cost effectiveness for each energy efficiency measure. The ProCost model values measure energy savings by time of day using conservation load shapes (by end-use) and segmented energy prices. The version of ProCost used in the 2019 CPA evaluates measure savings on an hourly basis, but ultimately values the energy savings during two segments covering high and low load hour time periods.

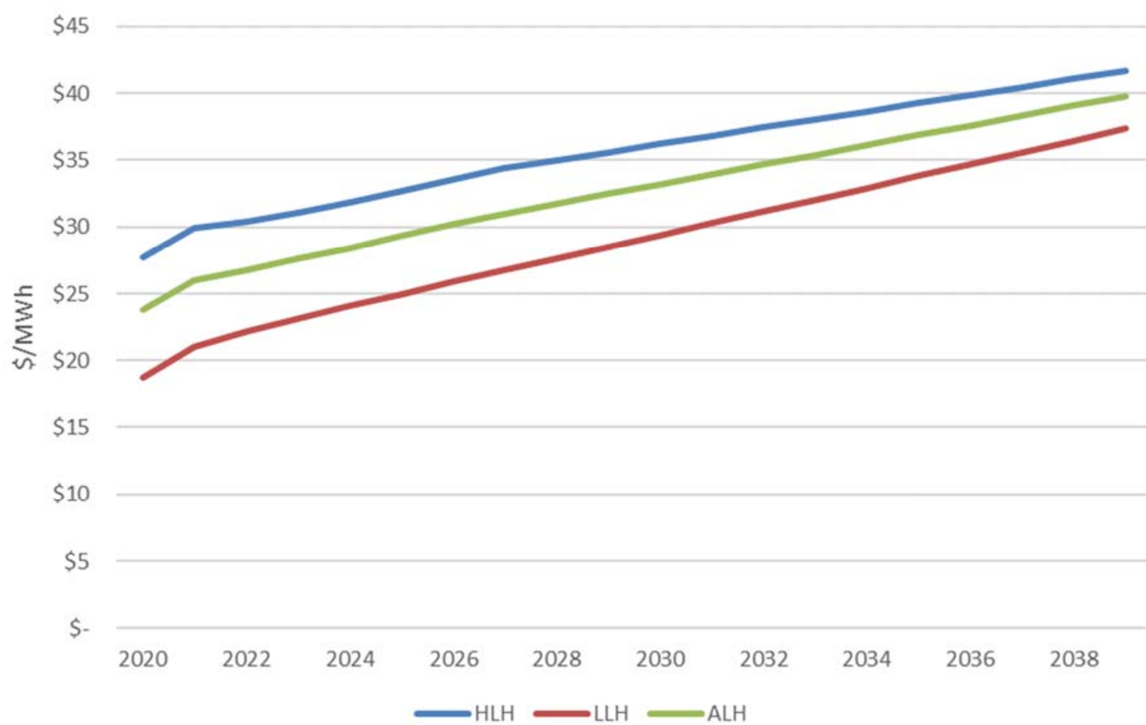
Avoided Cost

Energy

The avoided cost of energy is the cost that is avoided through the acquisition of energy efficiency in lieu of other resources. Avoided costs are used to value energy savings benefits when conducting cost effectiveness tests and are included in the numerator in a benefit-cost test. The avoided costs typically include energy-based values ($/MWh) and values associated with the demand savings ($/kW) provided by energy efficiency. These energy benefits are often based on the cost of a generating resource, a forecast of market prices, or the avoided resource identified in the resource planning process.

The EIA requires that utilities set avoided costs equal to a forecast of market prices. Figure 3 shows the Mid-Columbia market price forecast that was used as the primary avoided cost component for the planning period. The price forecast is shown for heavy load hours (HLH), light load hours (LLH), and average load hours (ALH).

Figure 3
20-Year Market Price Forecast



Social Cost of Carbon and Renewable Portfolio Standards

In addition to the avoided cost of energy, energy efficiency provides the benefit of reducing carbon emissions and lowering CPU's Renewable Portfolio Standard (RPS) requirements. The EIA rules require the inclusion of the social cost of carbon. While Washington's Clean Energy Act requires the use of a specific social cost of carbon, the details of the law were not certain during the development of this CPA. Because of the uncertainty around this value, a range of values was considered. These included a forecast of prices from California's cap and trade system, as well as the federal interagency workgroup values that were considered in the Seventh Plan.

Related to the social cost of carbon is the value of renewable energy credits. Washington's Energy Independence Act established a Renewable Portfolio Standard (RPS) for utilities with 25,000 or more customers. In 2020, CPU is required to source 15% of all electricity sold to retail customers from renewable energy resources or pursue one of several alternate compliance paths. Conservation can reduce the cost of this requirement by reducing CPU's load. Further details are discussed in Appendix IV.

Transmission and Distribution System Benefits

The EIA requires that deferred capacity expansion benefits for transmission and distribution systems be included in the cost-effectiveness analysis. To account for the value of deferred transmission and distribution system expansion, a distribution system credit value of $6.33/kW-year and a transmission system credit of $2.85/kw-year were applied to peak savings from conservation measures, at the time of the regional transmission and local distribution system peaks. These values were developed by Council staff in preparation for the 2021 Power Plan.

Generation Capacity

New to the Seventh Plan was the explicit calculation of a value for avoided generation capacity costs. The Council reasoned that in pursuing energy efficiency, in each year it was deferring the cost of a generation unit to meet the region's capacity needs. Based upon the cost savings of deferring this cost for 30 years, the Council estimated a generation capacity value of $115/kW-year. For CPU, the cost of generation capacity is best represented by call options for capacity that CPU has under contract. Currently, CPU has a call option for capacity for all months except April, May, and June and expects future prices of $2.50/kW-month, rising to approximately $10/kW-month as the region becomes more capacity constrained. These capacity costs were converted from a cost per kW-month to cost per kW-year by assuming an annual shape to the conservation savings and excluding months during which the capacity was not needed. An escalation rate of 5% was also applied, resulting value of $75.70/kW-year for the base case. In the low case, no escalation was assumed, resulting in a value of $44.44/kW-year. Finally, the Council's value of $115/kW-year was used in the high case scenario.

Risk Analysis

In the past, CPU's CPAs have included risk mitigation credits in the scenario analysis to account for risks that were not quantified. Rather than including an explicit risk credit in each of the scenarios, this CPA addresses the uncertainty of the inputs by varying the avoided cost values. The avoided cost components that were varied included the energy prices, generation capacity value, and the social cost of carbon. Through the variance of these components, implied risk credits of up to $28/MWh and $107/kW-year were included in the avoided cost. For reference, the Council has calculated risk credits using stochastic portfolio modeling resulting in risk mitigation credits of up to $55/MWh ($2016) depending on the value of the avoided cost inputs.

Additional information regarding the avoided cost forecast and risk mitigation credit values is included in Appendix IV.

Finally, a 10% benefit was added to these avoided cost components as required by the Pacific Northwest Electric Power Planning and Conservation Act.

Discount and Finance Rate

The Council develops real discount rate assumptions for each of its Power Plans. The Council used a discount rate of 4% in the Seventh Power Plan. This value was used in the 2017 CPA and was used again in the 2019 CPA. The discount rate is used to convert future cost and benefit streams into present values. The present values are then used to compare net benefits across measures that realize costs and benefits at different times and over different useful lives.

In addition, the Council uses a finance rate that is developed from two sets of assumptions. The first set of assumptions describes the relative shares of the cost of conservation distributed to various sponsors. Conservation is funded by the Bonneville Power Administration, utilities, and customers. The second set of assumptions looks at the financing parameters for each of these entities to establish the after-tax average cost of capital for each group. These figures are then weighted, based on each group's assumed share of project cost to arrive at a composite finance rate.

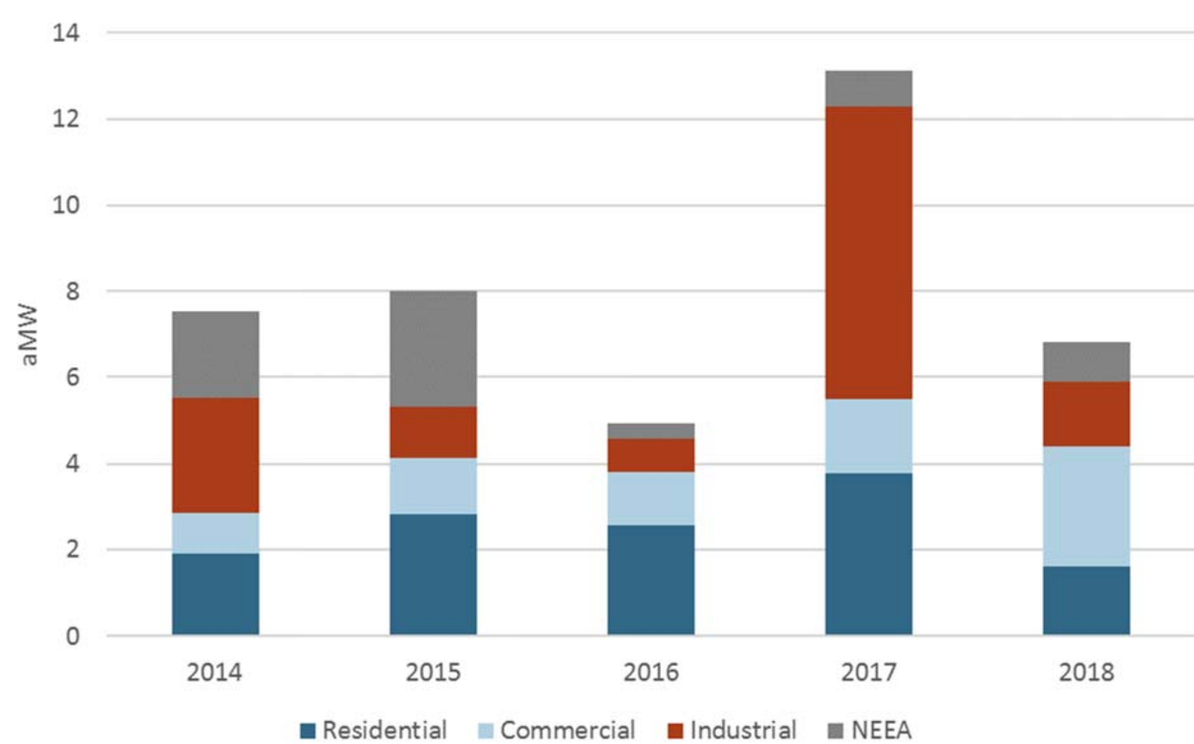
Recent Conservation Achievement

CPU has pursued conservation and energy efficiency resources since 1980. The utility offers several rebate and incentive programs for both residential and non-residential applications. CPU also provides information to customers in the form of energy-use tracking software and professional energy audits to inform customers of the types of energy efficiency applications that may be most suitable for their home or facility.

Figure 4 shows the distribution of conservation among the utility's customer sectors and through Northwest Energy Efficiency Alliance (NEEA) efforts over the past five years. This chart shows a large amount of industrial savings in 2017. More than 5 aMW of these savings came from a single project.

Savings from NEEA decline significantly in 2016. The decline was caused by the adoption of the Seventh Power Plan, which resets the baseline against which NEEA's market transformation savings are claimed. As NEEA's work to transform markets continues and its initiatives continue to build market share of efficient products, the savings will continue to grow, as is apparent below. Even with the decline in savings in 2016, savings from NEEA's initiatives remain very cost effective. Further, NEEA's work helps bring energy efficient emerging technologies, like ductless heat pumps and heat pump water heaters to the Northwest markets.

Figure 4
CPU Recent Conservation History by Sector



Current Conservation Programs

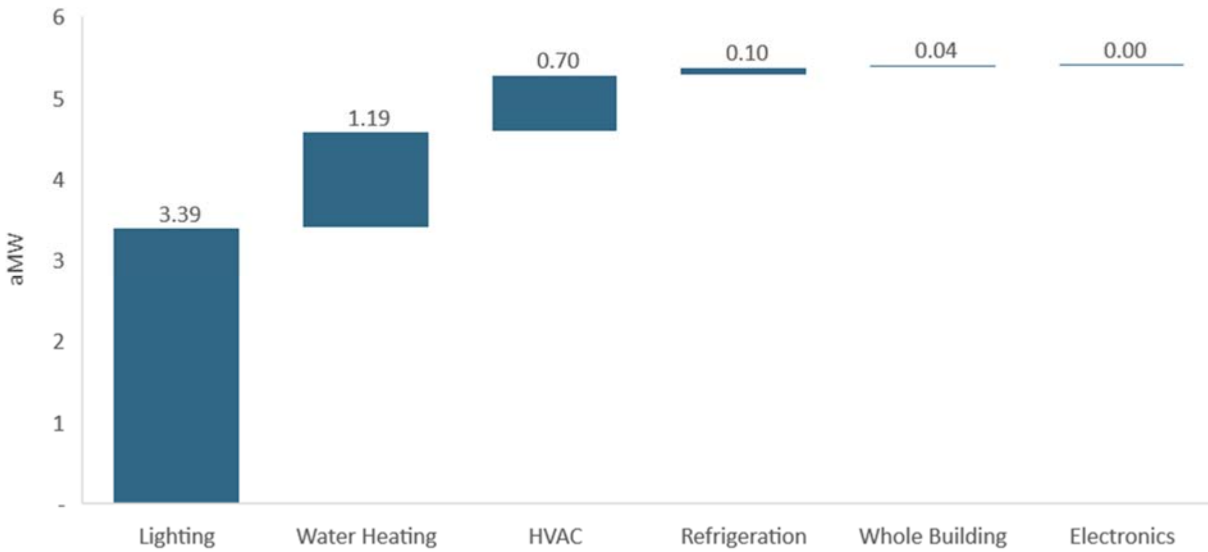
CPU offers a wide range of conservation programs to its customers. These programs include several residential loan programs, rebates, energy audits, and commercial projects. The current programs offered by CPU are detailed below followed by recent achievements for these programs.

Residential

- *Weatherization Loans* – This loan program provides five and seven-year low interest loans (3.5% minimum), up to $15,000 for air sealing, duct sealing, attic insulation, wall insulation, floor insulation and window replacement. Loan processing fees apply.
- *Weatherization Rebates* – Rebates of $0.25/Sqft, $0.20/Sqft, and $0.60/Sqft are available for floor, attic, or wall insulation improvements. Rebates of $2.00-$3.00/Sqft are available for energy efficient window replacements. CPU also offers up to $200 rebates for PTCS duct sealing and 50 % (up to $100) of the cost of air-sealing envelope.
- *Multifamily Weatherization* – CPU offers a range of rebates for weatherization improvements in electrically-heated multifamily housing. The utility currently offers incentives for attic, wall, and floor insulation, as well as improvements to windows and patio doors.
- *Weatherization & DHP Assistance* – Using state and public utility funds, CPU offers low-income weatherization and DHP grants. These programs offer insulation and minor weatherization-related repairs to Clark County families with income up to 125% of the federal poverty level. This program is open to customers with electrically-heated homes.
- *Heat Pump Loans* – The utility offers financing up to $20,000 for installation of air source or ductless heat pumps. Eligible customers include those with electrically heated homes in existing construction.
- *Heat Pump Rebates* – Rebates of up to $1,000 are available for energy efficient air-source heat pumps and up to $1,000 for ductless heat pumps.
- *Heat Pump Water Heater Rebates* – The utility offers $150 for Tier 1 qualifying heat pump water heaters and $300 for Tier 2 or greater qualifying heat pump water heaters.
- *Smart Thermostat Rebates* – The utility offers a $50 rebate for the installation of qualifying smart thermostats. Eligible customers include homes heated with an electric furnace or heat pump.
- *Photovoltaic Systems* – CPU offers financing up to $30,000 for installation of photovoltaic systems.
- *New Homes Performance Program* – Homes which exceed Washington state energy code are eligible for a sliding scale rebate, paid to the builder or rater/verifier company.

Figure 5 summarizes the recent savings achievement for the above utility-managed programs. While lighting has been a key source of savings, these measures were largely excluded from the 2017 CPA. Savings in the water heating and HVAC end uses make up the majority of the remaining achievements. Note that these savings do not include end-use savings from CPU's share of NEEA savings.

Figure 5
Residential Program Achievement by End-Use, 2017 – 2018



Commercial and Industrial

- *Commercial Lighting Improvement Program (CLIP)* – CPU offers rebates to commercial and industrial customers for approved LED lighting projects. A lighting audit is conducted to determine the upgrade opportunities and rebate amounts.
- *Refrigeration incentives* – CPU offers grocery customers, restaurants and other businesses with commercial refrigeration rebates to offset the cost of energy efficient upgrades and retrofit projects.
- *Energy Smart Industrial* – This program offers technical resources and incentives for industrial facility efficiency improvements. Current incentives may cover up to 50% of project cost for retrofit projects and 70% for new construction projects (capped at varying per kilowatt rates for verified savings).
- *Commercial Building Energy Audits* – Key account managers provide walk-throughs to identify opportunities for energy efficiency. This service is free and provides information to business owners regarding energy efficiency and bill reductions.
- *Green Motor Rewind* – Motors between 15 and 5,000 horsepower can be rewound to improve their efficiency. BPA offers incentives of at least $1 per horsepower for qualifying rewinds.
- *Compressed Air Audits* – CPU offers financial assistance to manufacturing customers to assist with the completion of compressed air audits. Professional energy specialists identify energy

efficiency gains that lead to improved air supply, enhanced maintenance cycles, and noise reductions.

- *Heat Pump Equipment Conversion and Upgrade in Commercial Buildings* – An incentive program is available for qualifying air source heat pump equipment conversions and upgrades in buildings with electric resistance heat and which meet additional program specifications.
- *Small Commercial Ductless Heat Pump (DHP)* – CPU's commercial DHP program offers reimbursement of $750 per ton of installed outdoor capacity for eligible DHP units and installations.
- *Web-Enabled Programmable Thermostats (WEPT)* – CPU offers incentives to help offset the costs of new and existing WEPTs installed in commercial buildings.
- *Energy Management Software* – CPU offers two software packages for energy tracking and analysis in commercial and industrial applications. Both E-Manager and Energy Expert are web-based programs that provide electricity consumption data to indicate areas where the facility may benefit most from energy efficiency improvements. E-Manager provides hourly consumption data and is designed for manufacturing and production facilities where electricity costs are due primarily to equipment load. Energy Expert provides building energy modeling solutions, based on daily energy consumption.
- *Custom Projects* – The custom project program provides incentives to commercial and industrial customers who install energy efficiency measures. The utility currently offers incentives for up to 50 % of project cost for retrofit projects and 70% for new construction projects (capped at varying per kilowatt rates for verified savings).

Figures 6 and 7 summarize the recent savings achievement by end-use for the commercial and industrial sectors, respectively. Lighting is a key source of savings for both sectors. These savings do not include end-use savings from CPU's share of NEEA savings. Note that Figure 7 contains the large industrial project savings discussed above, which was assigned to the HVAC category.

Figure 6
Commercial Program Achievement by End-Use, 2017 – 2018

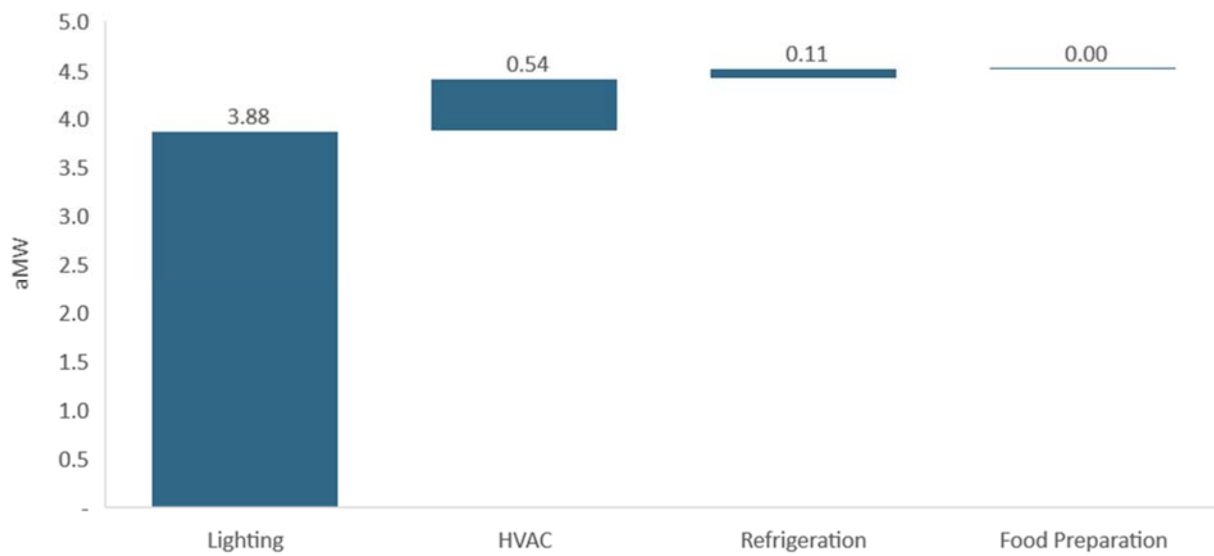
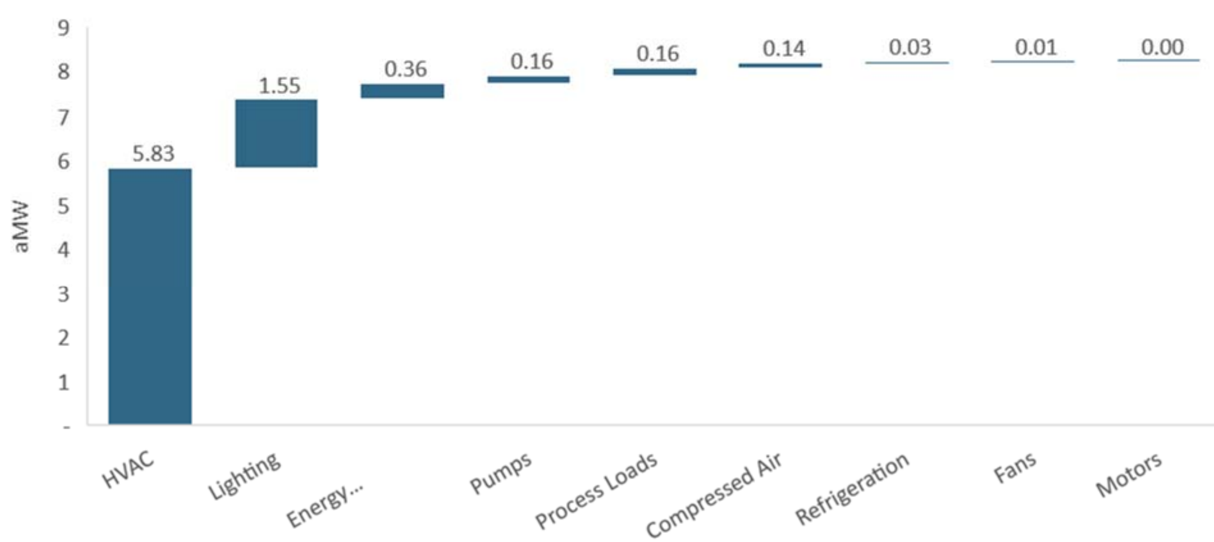


Figure 7
Industrial Program Achievement by End-Use, 2017 – 2018



Summary

CPU plans to continue offering incentives for energy efficiency investments. The results of this study will assist CPU program managers decide in strategic planning for energy efficiency program offerings, incentive levels, and program review.

Customer Characteristics Data

CPU serves approximately 203,000 electricity customers in Clark County, with a total service territory population of approximately 482,000. A key component of a conservation potential assessment is to understand the characteristics of these customers–primarily the building and end-use characteristics. Characteristics for each customer class are described below.

Residential

For the residential sector, the key characteristics include house type distribution, space-heating fuel type, and water heating fuel. Table 1 shows relevant residential data for single family, multi-family and manufactured homes in CPU's service territory. The data is based on the Northwest Energy Efficiency Alliance's (NEEA) 2016 Residential Building Stock Assessment (RBSA) as well as data from the US Census. RBSA data for homes in Clark County were used where access to natural gas may be relevant. For other data points, the RBSA stratum that included homes of BPA customer utilities in western Washington was used. These data provide an estimate of the current residential characteristics in Clark County and are utilized as the baseline in this study.

Table 1
Residential Building Characteristics

Heating Zone	Cooling Zone	Solar Zone	Residential Households	Total Population
1	1	2	178,733	482,499

	Single Family	Multifamily Low Rise	Multifamily High Rise	Manufactured
Existing Homes Heating / Cooling System Saturations				
Electric Forced Air Furnace (FAF)	3%	0%	0%	55%
Heat Pump (HP)	19%	5%	5%	26%
Ductless HP (DHP)	10%	0%	0%	6%
Electric Zonal (Baseboard)	26%	91%	91%	3%
Central AC	31%	0%	0%	0%
Room AC	11%	29%	29%	29%
% Electric Heat	59%	96%	96%	90%
New Homes - Heating / Cooling System Saturations				
Electric Forced Air Furnace (FAF)	3%	0%	0%	55%
Heat Pump (HP)	19%	5%	5%	26%
Ductless HP (DHP)	10%	0%	0%	6%
Electric Zonal (Baseboard)	26%	91%	91%	3%
Central AC	31%	0%	0%	0%
Room AC	11%	29%	29%	29%
% Electric Heat	59%	96%	96%	90%

Table 1 (continued) Residential Building Characteristics					
Heating Zone	Cooling Zone	Solar Zone	Residential Households	Total Population	
1	1	2	178,733	482,499	

	Single Family	Multifamily Low Rise	Multifamily High Rise	Manufactured
Existing Homes - Appliance Saturation				
Electric WH	58%	95%	95%	90%
Refrigerator	137%	104%	104%	126%
Freezer	44%	5%	5%	39%
Clothes Washer	97%	35%	35%	94%
Clothes Dryer	90%	29%	29%	94%
Dishwasher	87%	60%	60%	77%
Electric Oven	95%	98%	98%	100%
Desktop	68%	27%	27%	65%
Laptop	67%	29%	29%	29%
Monitor	81%	31%	31%	65%
New Homes - Appliance Saturations				
Electric WH	58%	95%	95%	90%
Refrigerator	137%	104%	104%	126%
Freezer	44%	5%	5%	39%
Clothes Washer	97%	35%	35%	94%
Clothes Dryer	90%	29%	29%	94%
Dishwasher	87%	60%	60%	77%
Electric Oven	95%	98%	98%	100%
Desktop	68%	27%	27%	65%
Laptop	67%	29%	29%	29%
Monitor	81%	31%	31%	65%

Commercial

Building floor area is the key parameter in determining conservation potential for the commercial sector, as many of the measures are based on savings as a function of building area. CPU provided 2018 commercial square footage and energy consumption (kWh) for each of the 18 building types shown in Table 2. The 2018 commercial sector square footage totaled 70.1 million square feet, a decrease of approximately 11 million square feet from the 2017 CPA.

Regional energy use intensity values (EUI) are often used to derive commercial sector square footage by segment if only energy consumption data is available. To establish square-footage using EUIs, annual kWh consumption by segment is divided by regional EUI data to produce square foot data. These figures are then benchmarked and adjusted to county building database figures. Since CPU provided square footage and energy consumption data, the EUI values shown in Table 2 were calculated based on the utility-provided data. Regional EUI values were used to benchmark building square footage for this assessment.

A 0.3% growth rate was assumed for the commercial sector. Demolition rates are based on Council assumptions, which vary by segment but average 0.4% annually.

Table 2
Commercial Building Data by Segment

Floor Space Type	2018 Commercial Load (MWh)	2018 Commercial Square Feet	2018 CPU EUI kWh/sq ft
Large Office Space	83,759	5,367,724	16
Medium Office Space	81,190	4,023,992	20
Small Office Space	112,969	8,034,781	14
Extra Large Retail Space	78,707	5,647,537	14
Large Retail Space	21,215	1,628,132	13
Medium Retail Space	39,266	2,734,671	14
Small Retail Space	49,080	3,521,689	14
School (K-12) Space	98,853	11,001,568	9
University Space	16,393	969,436	17
Warehouse Space	11,100	1,514,804	7
Supermarket Space	63,330	1,185,310	53
Mini Mart Space	26,523	327,765	81
Restaurant Space	90,345	1,783,101	51
Lodging Space	86,991	5,965,108	15
Hospital Space	82,400	3,005,107	27
Residential Care Space	5,099	342,732	15
Assembly Space	91,331	8,710,038	10
Other Commercial Space	54,533	4,369,991	12
Total	**1,093,084**	**70,133,487**	**16**

Industrial

The methodology for estimating industrial potential is different than approaches used for the residential and commercial sectors primarily because industrial energy efficiency opportunities are based on the distribution of electricity use among processes at industrial facilities. Industrial potential for this assessment was estimated based on the Council's top-down methodology that utilizes annual consumption by industrial segment and then disaggregates total electricity usage by process shares to create an end-use profile for each segment. Estimated measure savings are applied to each sector's process shares.

CPU provided energy consumption for each of the 20 industrial segments shown in Table 3. The 2018 industrial load totaled 926,059 MWh. This load is approximately 9 percent higher than the industrial load used in the 2017 CPA. Industrial sector consumption and growth rates by segment are shown in Table 3.

Table 3 Industrial Sector Load by Segment		
Industry	**Utility 2018 Industrial Load (MWh)**	**Base Case Growth Rate**
Paper	12,265	4%
Foundries	2,885	1%
Frozen Food	4,190	1%
Other Food	81,544	1%
Lumber	8,745	1%
Panel	1,049	1%
Wood	12,139	1%
Electric Fabrication	480,374	-10%
Silicon	2,873	1%
Metal Fabrication	51,594	1%
Equipment	9,734	1%
Cold Storage	25	-4%
Refinery	1,040	1%
Chemical	143,416	1%
Miscellaneous Manufacturing	106,709	1%
Indoor Agriculture	7,478	0.77%
Total	**926,059**	**-4.67%**

The indoor agriculture segment was added to CPU's 2015 CPA and included in subsequent CPAs. This segment is not part of the Council's standard industrial subsectors included in the Power Plan, so end-use electricity profiles were created based on industry research and other Council analyses. Specifically, the Council has conducted surveys of marijuana grow operations to begin modeling energy usage at these facilities.[2] The Council's research indicates that electricity use in marijuana grow operations is distributed as shown in Figure 8.

[2] Northwest Power and Conservation Council. *Impact of Cannabis Production in the Pacific Northwest on Regional Electricity Loads.* September 9, 2014. Available online: http://www.nwcouncil.org/media/7130334/p7.pdf

Figure 8
Indoor Agriculture Electricity End-Use Distribution

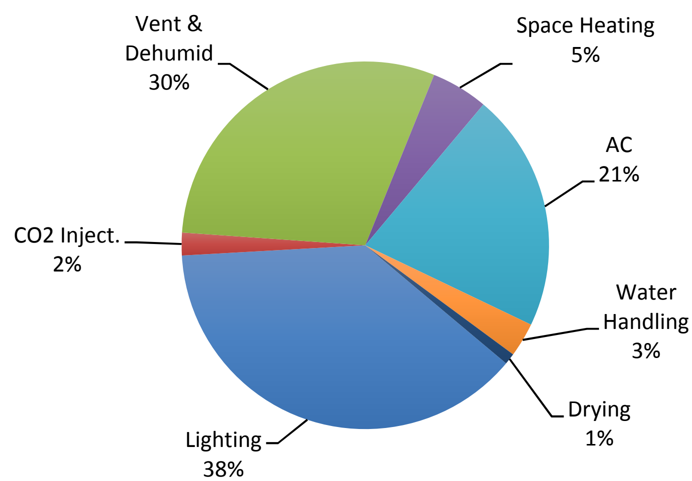


Table 4 shows the resulting end-use profile for indoor agriculture operations. Slow adoption is expected since this is a new area for energy efficiency applications; and anecdotal evidence from the region suggest indoor agriculture business owners can be difficult to reach and may be reluctant to adopt some of the measures at the risk of production volume or quality. At the same time, there is great interest in technology and what is considered baseline equipment may change quickly. Since non-medical marijuana grow operations are illegal at the federal level, CPU is not permitted to use BPA funds to pay for energy efficiency incentives for indoor agriculture customers.

Table 4
Process Shares – Indoor Agriculture Segment

Pumps	3%
Drying and Curing	1%
HVAC	51%
Lighting	38%
Other Process	7%
All Electric	100%
All Motors	44%

CPU provided load data based upon the 2018 calendar year. The 2017 assessment projected 5% annual load growth in the indoor agriculture segment for the first five years (2018-2022), and no growth for the remainder of the planning period. The 2019 CPA assumed that growth would continue from 2020-2022, which results in an effective growth rate of 0.77% over the 20-year study period.

Savings estimates were updated based upon Seventh Plan data. Total estimated conservation potential for indoor agriculture facilities is 510 MWh over the study period. This translates to 6% savings from baseline consumption for the indoor agriculture segment.

Distribution Efficiency

For this analysis, EES developed an estimate of distribution system conservation potential using the Council's Seventh Plan approach. The Seventh Plan estimates distribution potential for five measures as a fraction of end system sales ranging from 0.1 to 3.9 kWh per MWh, depending on the measure.

CPU provided a total system load for 2018. The forecast was then adjusted to account for transmission system losses only, since the savings happen at the distribution level. Distribution system potential is discussed in detail in the next section.

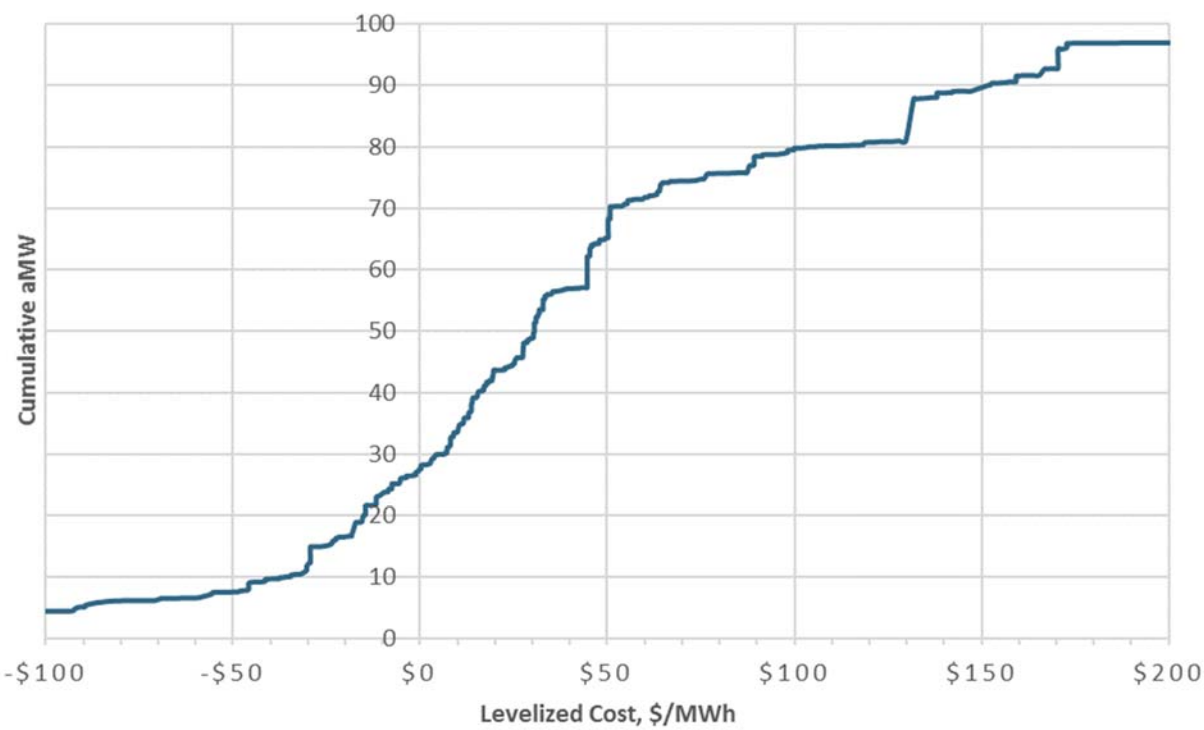
Results – Energy Savings and Costs

Achievable Conservation Potential

Achievable potential is the amount of energy efficiency potential that is available regardless of cost. It represents the theoretical maximum amount of achievable energy efficiency savings, without regard for cost.

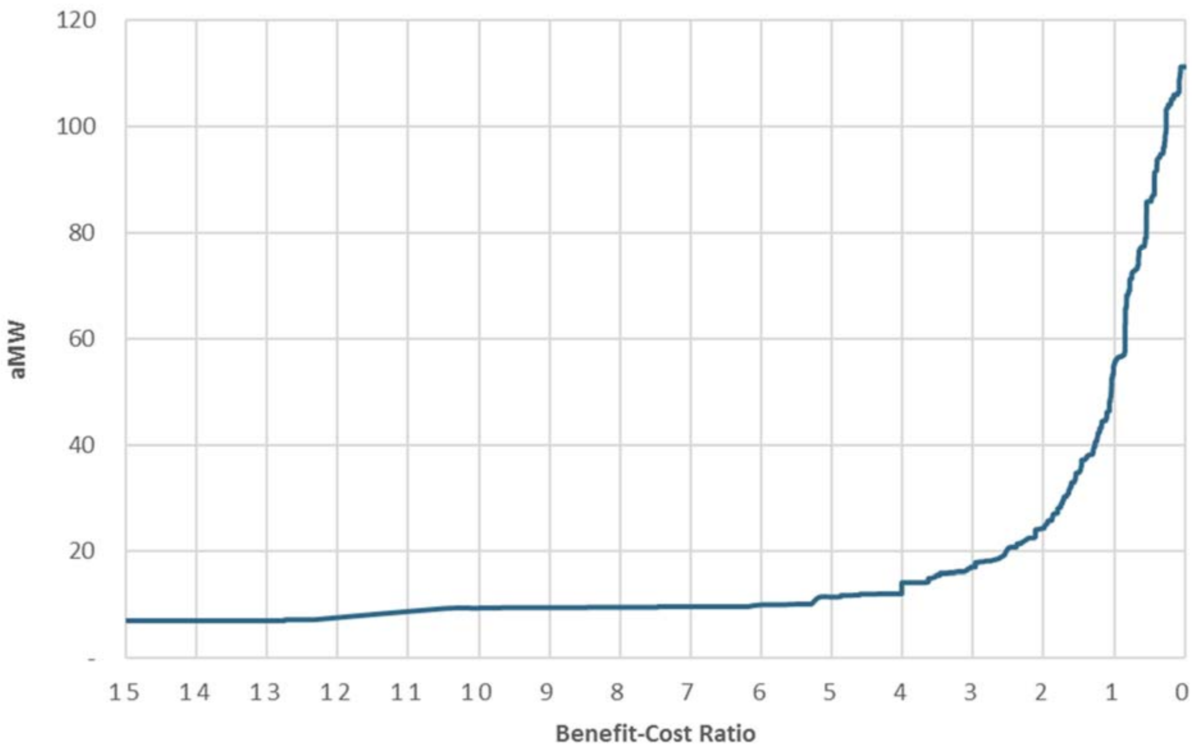
Figure 9, below, shows a supply curve of 20-year, achievable technical potential. The supply curve is developed by plotting cumulative energy efficiency savings potential (aMW) against the levelized cost ($/MWh) of the savings, when measures are sorted in order of ascending cost. The potential shown in Figure 8 has not been screened for cost effectiveness. Costs are levelized, allowing for the comparison of measures with different lifetimes. The supply curve facilitates comparison of demand-side resources to supply-side resources and is often used in conjunction with integrated resource plans. Figure 9 shows that approximately 48 aMW of potential is available for less than $30/MWh and approximately 75 aMW is available for under $80/MWh. Total achievable technical potential for CPU is approximately 111 aMW over the 20-year study period, not all of which is shown in the figure below.

Figure 9
20-Year Achievable Potential Levelized Cost Supply Curve



While useful for considering the costs of conservation measures, supply curves based on levelized cost are limited in that not all energy savings are equally valued. Another way to depict a supply curve is based on the benefit-cost ratio, as shown in Figure 10 below. This figure repeats the overall finding that approximately 55 aMW of potential is cost-effective with a benefit-cost ratio greater than or equal to 1.0. Immediately to the right of that line, the potential rises steeply, suggesting significant increases in potential if avoided cost parameters are increased.

Figure 10
20-Year Achievable Potential Benefit-Cost Ratio Supply Curve



Economic Achievable Conservation Potential

Economic achievable, also referred to as economic potential or cost-effective potential is the amount of potential that passes the Total Resource Cost (TRC) test. This means that the present value of the benefits exceeds the present value of the measure costs over its lifetime.

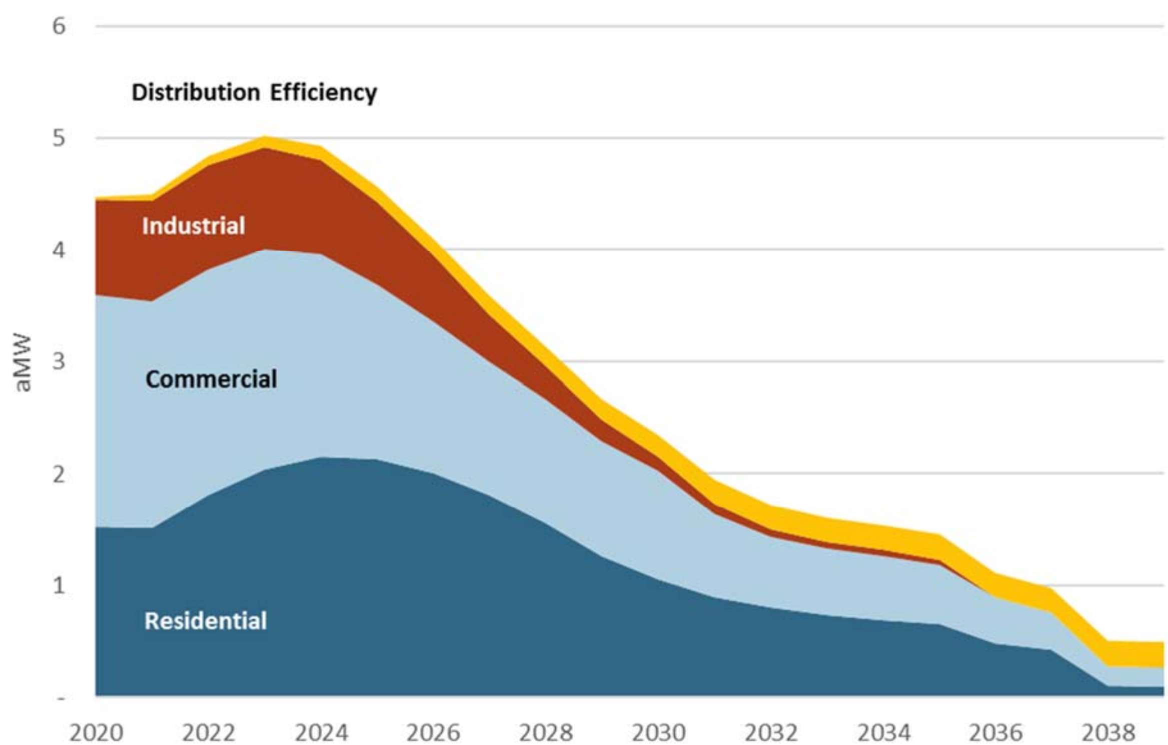
Table 5 shows aMW of economically achievable potential by sector in 2, 6, 10 and 20-year increments. Annual potential estimates by sector are included in Appendix VII. Compared with the technical and achievable potential, it shows that 38.4 aMW of the total 110 aMW is cost effective for CPU. The last section of this report discusses how these values could be used for setting targets.

Table 5 Cost-Effective Achievable Potential (aMW)				
	2-Year	**6-Year**	**10-Year**	**20-Year**
Residential	3.04	11.18	17.81	23.75
Commercial	4.08	11.42	16.10	21.22
Industrial	1.77	5.22	6.71	7.15
Distribution Efficiency	0.09	0.52	1.21	3.41
Total	**8.97**	**28.33**	**41.83**	**55.53**

Sector Summary

Figure 11 shows the cost-effective achievable potential by sector on an annual basis.

Figure 11
Annual Cost-Effective Achievable Potential by Sector



At the beginning of the study period, nearly half of the potential is in the commercial sector, followed by the residential and industrial sectors. Ramp rates from the Seventh Power Plan were used to establish reasonable annual conservation achievement levels. Adjustments to these ramp rates were made to reflect the timeline of this CPA. Additionally, alternate ramp rates were assigned to reflect CPU's current rate of program achievement. These changes were generally to accelerate the acquisition of potential. Achievement levels are affected by factors including timing and availability of measure installation (lost opportunity), program (technological) maturity, non-programmatic savings, and current utility staffing and funding. Ramp rates are further discussed in Appendix V.

Table 6 below shows how recent program history compares to the near-term program potential. Residential savings exclude lighting savings, as these measures were largely excluded from the program potential. Savings from NEEA have been allocated to the appropriate sectors. In addition, a very large industrial project is included the 2017 total, but not counted in the industrial average since it is a one-time project and not likely repeatable.

Table 6
Comparison of Program Achievement and Potential

	Program History				Potential		
	2017	**2018**	**2019**	**Average**	**2020**	**2021**	**2022**
Residential	4.4	2.4	2.9	3.2	1.5	1.5	1.8
Commercial	1.9	3.0	2.1	2.3	2.1	2.0	2.0
Industrial	6.8	1.5	1.6	1.5	0.9	0.9	0.9
Distribution Efficiency	-	-		-	0.0	0.1	0.1
Total	**13.1**	**6.8**	**6.6**	**7.1**	**4.5**	**4.5**	**4.8**

Residential

Residential conservation potential is lower than what was identified in the 2017 assessment. Savings potential has been impacted by the expected impact of federal lighting standards scheduled to take effect in 2020 as well as changes to the value of capacity savings in the avoided cost.

Figure 12 shows the distribution of annual residential potential across measure end uses for the first ten years of the planning period. As can be seen, the cost-effective potential is largely comprised of measures in the HVAC and water heating end uses. Residential lighting measures are impacted by the EISA standard that takes effect in 2020 in addition to a quickly-evolving market and were not included past 2020. In addition to these end uses, smaller savings are available from the electronics and food preparation end uses.

The HVAC end use includes both heating equipment and weatherization measures such as attic insulation, ductless heat pumps, and Wi-Fi-enabled thermostats.

Water heating is a growing area of potential, with heat pump water heaters providing the majority of cost-effective savings. Showerheads are also a significant contributor, though there are concerns with customer satisfaction. Other measures included in the water heating end use include aerators, behavior programs, clothes washers, and thermostatic shutoff valves.

In Figure 12, the Other category includes savings in the electronics and food preparation end uses.

Some measures such as Wi-Fi enabled thermostats and water heaters can also provide additional benefits as demand response resources. These benefits were not included in this conservation potential assessment.

Figure 12
Annual Residential Potential by End-Use

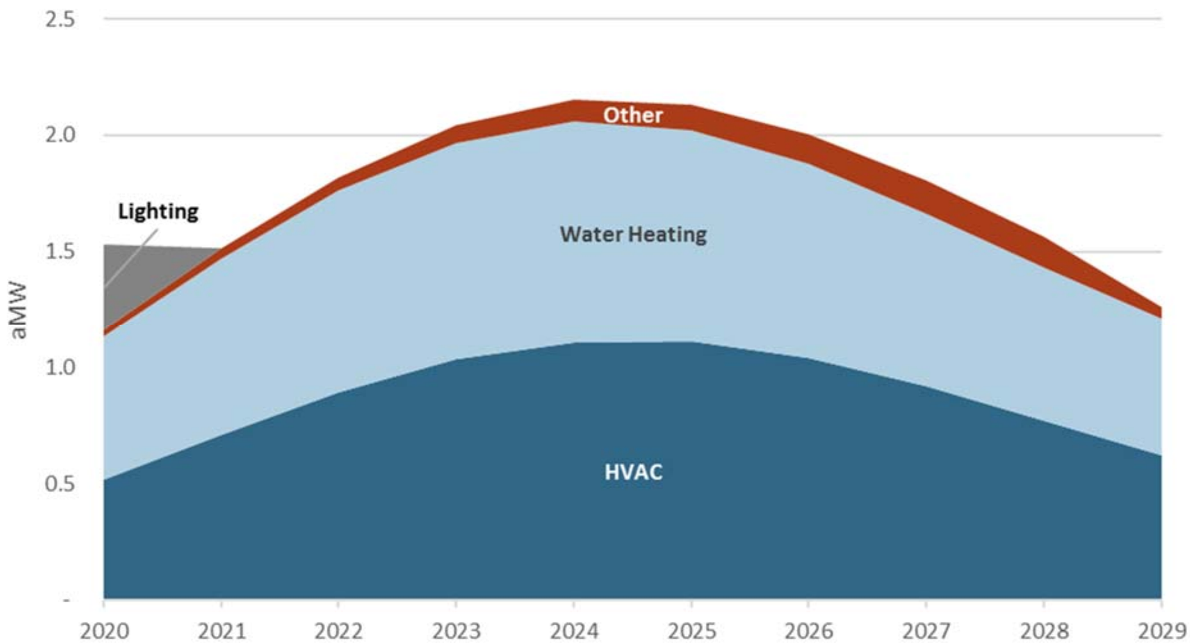
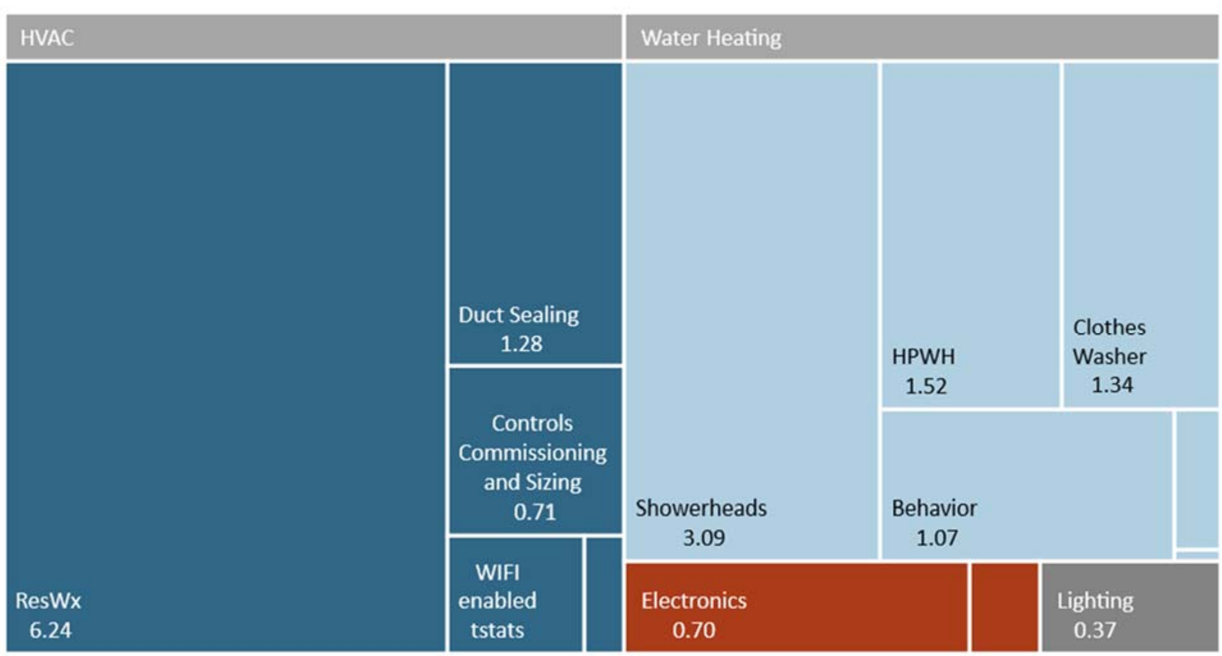


Figure 13 shows how the 10-year residential potential breaks down into end uses and key measure categories. The area of each block represents its share of the total 10-year residential potential.

Figure 13
Residential Potential by End Use and Measure Category (aMW)



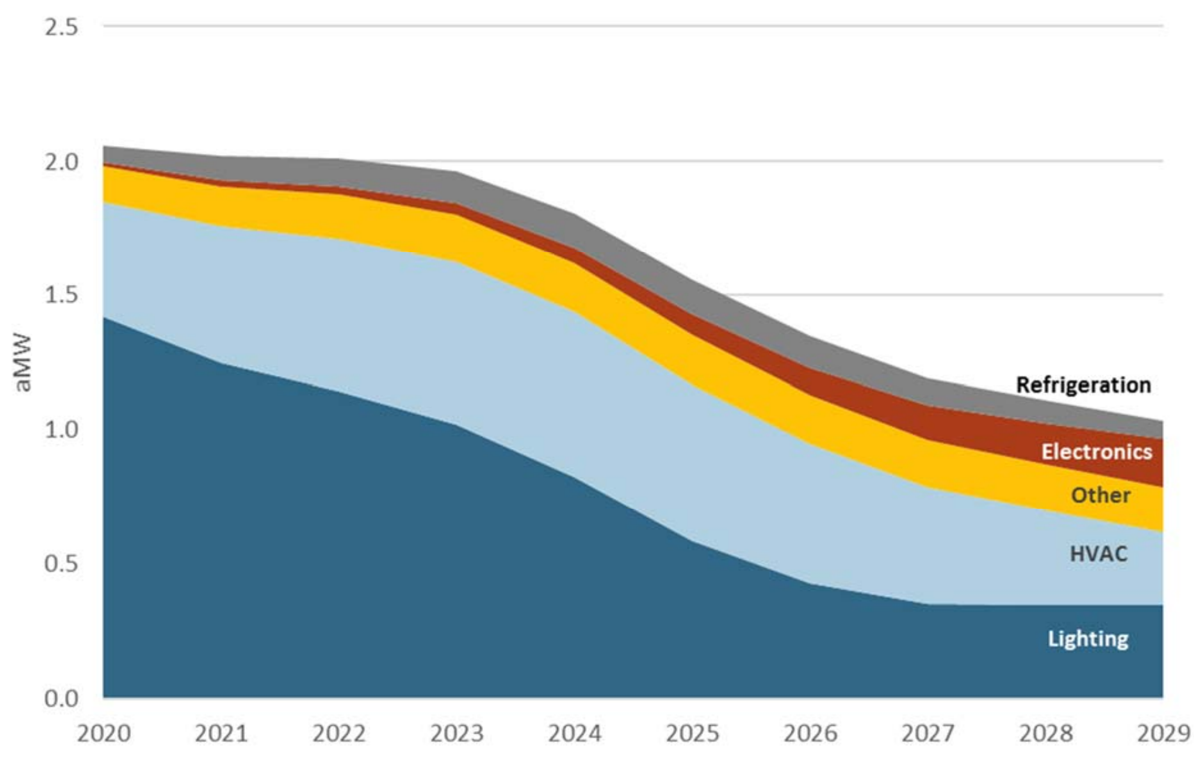
Commercial

Commercial lighting measures remain the largest contributors to commercial conservation potential (Figure 14), though this study does show potential beginning to diminish in the later years of the study as the remaining opportunities diminish. Lighting savings are lower in this assessment after accounting for the federal EISA standard, which impacts several commercial measures. Additionally, the lower value for peak capacity savings reduced the cost-effectiveness of some measures.

HVAC control measures continue to make up a substantial part of the balance of commercial conservation potential for this assessment period, although there is less potential in this category relative to the 2017 CPA. Measures in this category were also impacted by the change in capacity value, as most HVAC measures provide savings during times of peak demand.

Commercial HVAC measures are often more complicated and disruptive to install compared to lighting measures. As a result, adoption of HVAC measures will continue to be at a slower pace than that of lighting measures.

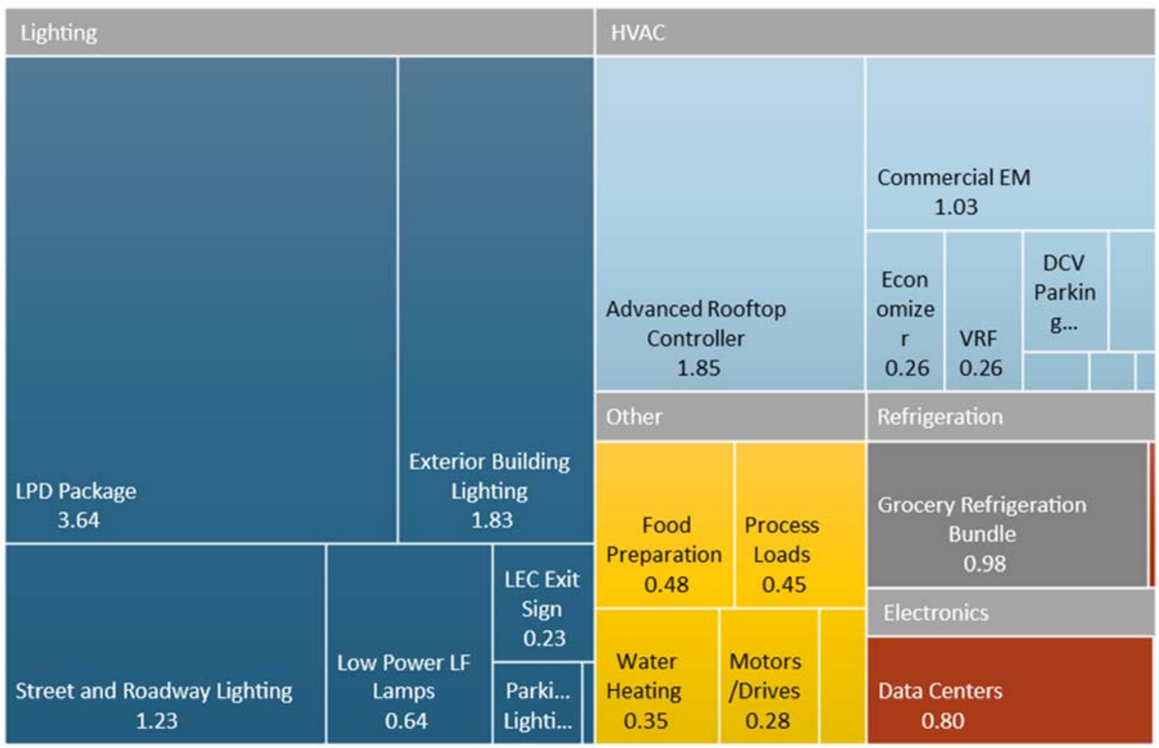
Figure 14
Annual Commercial Potential by End-Use



In Figure 14, the Other category includes measures in the food preparation, water heating, process loads, motors/drives, and compressed air end uses. Unlike residential potential, the commercial potential is characterized by a diverse set of measures and end uses due to the more varied nature of commercial buildings. Detail of the savings by these end uses can be found in Appendix V.

The key end uses and measures within the commercial sector are shown in Figure 15. The area of each block represents its share of the 10-year commercial potential.

Figure 15
Commercial Potential by End Use and Measure Category (aMW)



Industrial

Industrial conservation potential has increased from the 2017 CPA. The increases are due to higher industrial loads compared to what was used in the 2017 CPA as well changes to how the industrial achievements were accounted for.

A significant portion of the industrial sector conservation potential is in Energy Management (Figure 16). This area includes cross-segment Strategic Energy Management programs as well as the management of motor-driven systems such as pumps, fans, and air compressors.

Industrial process loads and lighting measures also account for a notable share of sector savings. Lighting measures are widely applicable across many of the industrial segments. Conservation potential for municipal wastewater treatment plants is included in Figure 16. Savings estimates for these measures are based on equipment upgrades and modifications to operations/processes and facilities. In Figure 16, the Other category includes small amounts of savings in fan and compressed air systems, as well as measures specific to the metals, paper, and wood products industries.

Figure 16
Annual Industrial Potential by End-Use

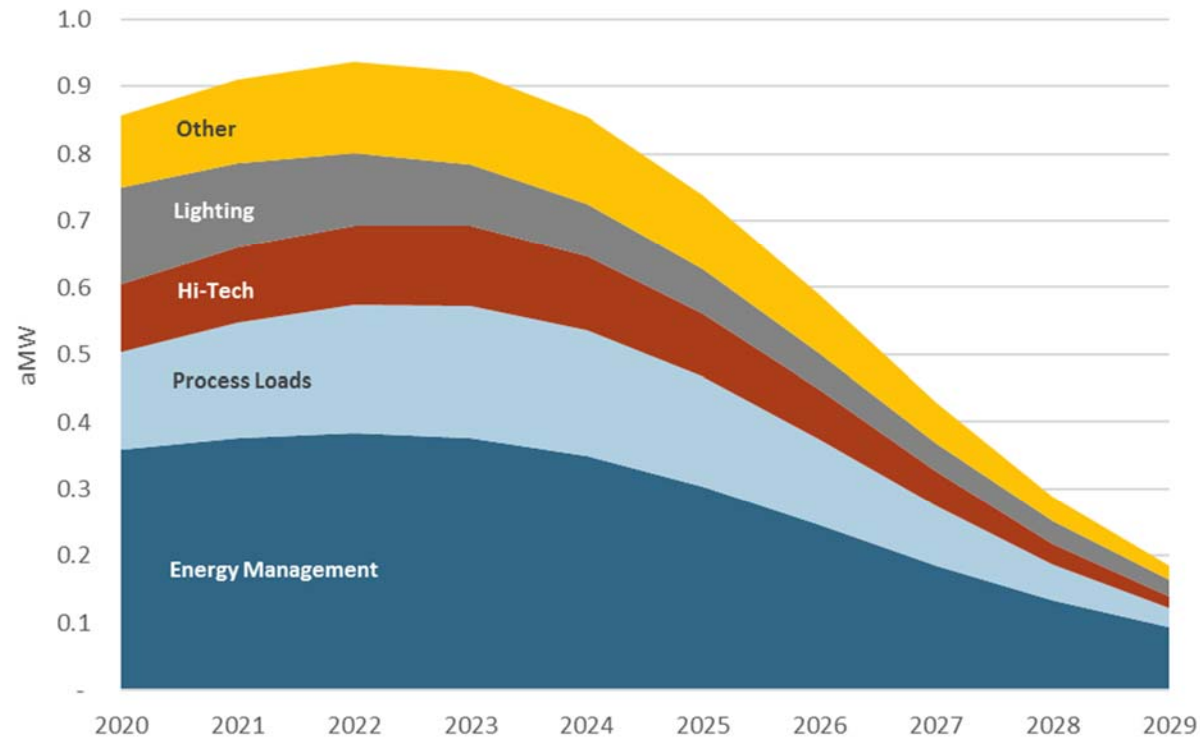
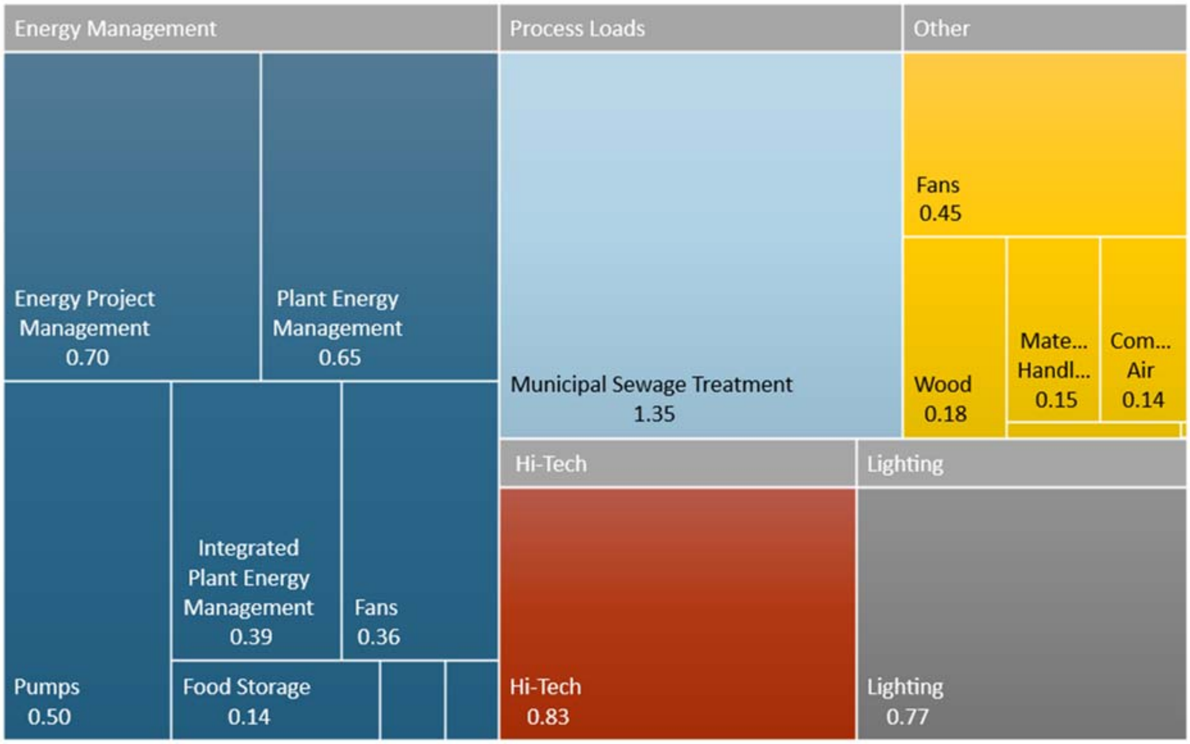


Figure 17 shows how the 10-year industrial potential breaks down by end use and measure categories.

Figure 17
Industrial Potential by End Use and Measure Category (aMW)

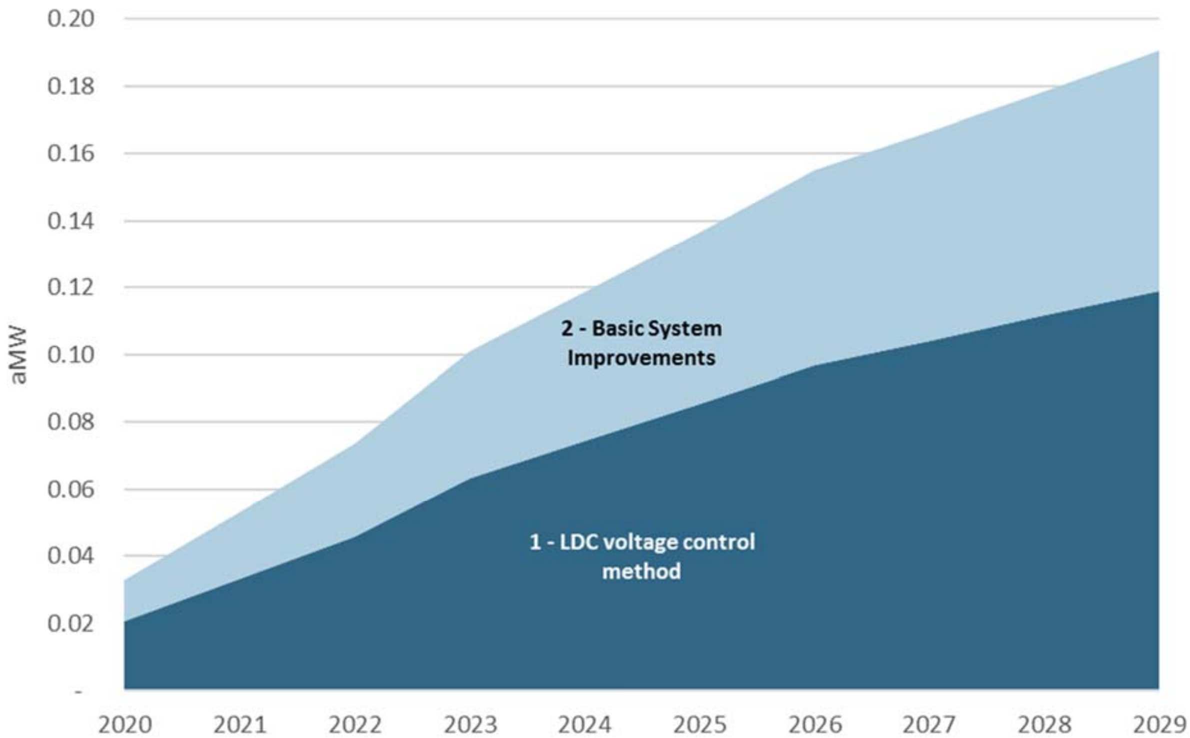


Distribution Efficiency

Distribution system energy efficiency measures regulate voltage and upgrade systems to improve the efficiency of utility distribution systems and reduce line losses. Distribution system potential was estimated using the Council's methodology, which considers five different measures. The Seventh Plan estimates distribution system potential based on end system energy sales.

Distribution system conservation potential is shown in Figure 18. Although five measures were considered in the analysis, only two measures were identified as cost effective. The cost estimates for distribution system potential shown in Table 7, in the next section, are also based on the end-system sales method.

Figure 18
Annual Distribution System Efficiency Potential



Cost

Budget costs can be estimated at a high level based on the incremental cost of the measures (Table 7). The assumptions used to estimate utility costs to acquire the conservation potential presented in this report include: 20% of measure capital cost for administrative expenditures and 35% of the incremental cost for incentives is assumed to be paid by the utility. A 20% allocation of measure costs to administrative expenses is a standard assumption for utility conservation potential assessments. This figure was used in the Council's analysis for the Seventh Power Plan. The 35% incentive cost assumption was not applied to the utility distribution efficiency sector, where incentives are unlikely and the utility is more likely to pay the whole cost of measures. Both the administrative cost allocation and the utility share assumptions are consistent with assumptions used in CPU's 2017 CPA.

This chart shows that CPU can expect to spend approximately $18 million to acquire estimated savings over the next two years. The bottom row of Table 7 shows the cost per MWh of first-year savings.

Table 7 Utility Program Costs (2019$)				
	2-Year	**6-Year**	**10-Year**	**20-Year**
Residential	$8,249,000	$34,775,000	$56,610,000	$69,601,000
Commercial	$7,741,000	$21,974,000	$31,668,000	$43,044,000
Industrial	$2,545,000	$7,658,000	$9,863,000	$10,464,000
Distribution Efficiency	$27,000	$159,000	$372,000	$1,052,000
Total	**$18,562,000**	**$64,566,000**	**$98,513,000**	**$124,161,000**
$/First Year MWh	$236	$260	$269	$255

The cost estimates presented in this report are conservative estimates for future expenditures since they are based on historic values. Future conservation achievement may be more costly than historic conservation achievement since utilities often choose to implement the lowest cost programs first. In addition, as energy efficiency markets become more saturated, it may require more effort from CPU to acquire conservation through its programs. The additional effort may result in increased administrative costs.

Cost Scenarios

To provide a range of program costs over the planning period, EES tested a Low and a High cost scenario relative to the Base Case conservation potential scenario. For the Low scenario, the utility share of measure capital cost is reduced to 30 percent. A situation where the utility is responsible for a lower share of measure capital cost may result from higher conservation achievement through programs for which the customer is responsible for a higher fraction of measure cost. An example of this scenario would be if more conservation were achieved through commercial or industrial custom projects where higher incentives may not be required to gain customer participation. For the High scenario, the utility share of measure costs was increased to 40 percent.

For the High Cost scenario, administrative costs were increased to 30 percent (compared with 20 percent in the Base Case). The High Cost scenario reflects the case where program administration costs may increase for CPU to connect with hard-to-reach customers.

Table 8 shows 2, 6, 10 and 20-year program costs for the Expected (Base Case), High and Low cost scenarios. Table 9 shows the cost per megawatt hour (first year savings) for each of the cost scenarios.

Table 8 Utility Cost Scenarios for Cost-Effective Potential (2019$)				
	2-Year	**6-Year**	**10-Year**	**20-Year**
Expected Case	$18,562,000	$64,566,000	$98,513,000	$124,161,000
Low Cost Case	$16,875,000	$58,696,000	$89,557,000	$112,874,000
High Cost Case	$23,624,000	$82,175,000	$125,380,000	$158,023,000

Table 9 Utility Cost Scenarios for Cost-Effective Potential (2019$/MWh)				
	2-Year	**6-Year**	**10-Year**	**20-Year**
Expected Case	$236	$260	$269	$255
Low Cost Case	$215	$237	$244	$232
High Cost Case	$300	$331	$342	$325

Tables 8 and 9 costs are presented as dollars per first year savings (MWh). These units do not consider the savings over the life of a measure, but they do provide an indication of the program costs per unit of savings that CPU could expect to acquire conservation going forward. Over the next two years, conservation programs are expected to cost between $215 and $342/MWh (first year savings). Overall, CPU can expect the biennium potential estimates presented in this report to cost between $16.9 and $23.6 million for utility incentives and administrative expenditures.

Besides looking at the utility cost, CPU may also wish to consider the total resource cost (TRC) cost of energy efficiency. The total resource cost reflects the cost that the utility and ratepayers will together pay for conservation, similar to how the costs of other power resources are paid. The TRC costs are shown below (Table 10), levelized over the measure life of each measure. Distribution efficiency measures are by far the cheapest resource, with other measures in the neighborhood of three to four cents per kilowatt-hour.

Table 10 TRC Levelized Cost (2019$/kWh)				
	2-Year	**6-Year**	**10-Year**	**20-Year**
Residential	$0.048	$0.052	$0.053	$0.051
Commercial	$0.050	$0.049	$0.049	$0.049
Industrial	$0.041	$0.042	$0.042	$0.042
Distribution Efficiency	$0.007	$0.007	$0.007	$0.007
Total	**$0.046**	**$0.047**	**$0.048**	**$0.046**

Scenarios

The costs and savings discussed throughout the report thus far describe the Base Case avoided cost scenario. Under this scenario, annual potential for the planning period was estimated by applying assumptions that reflect CPU's expected most likely future loads and avoided costs. In addition, the Council's 20-year ramp rates were applied to each measure and then adjusted to accelerate potential to more closely reflect CPU's recent historic conservation achievement.

Additional scenarios were developed to identify a range of possible outcomes that account for uncertainties over the planning period. In addition to the Base Case scenario, this assessment tested Low and High scenarios to test the sensitivity of the results to different future avoided cost values. The avoided cost values in the Low and High scenarios reflect values that are realistic and lower or higher, respectively, than the Base Case assumptions.

To understand the sensitivity of the identified savings potential to avoided cost values alone, all other inputs were held constant while varying avoided cost inputs.

Table 11 summarizes the Base, Low, and High avoided cost input values. Rather than using a single generic risk adder applied to each unit of energy, the Low and High avoided cost values consider lower and higher potential future values for each avoided cost input. These values reflect potential price risks based upon both the energy and capacity value of each measure. The final row tabulates the implied risk adders for the Low and High scenarios by summarizing all additions or subtractions relative to the Base Case values. Risk adders are provided in both energy and demand savings values. The first set of values is the maximum (or minimum in the case of negative values). The second set of risk adder values are the average values in energy terms. Further discussion of these values is provided in Appendix IV.

Table 11 Avoided Cost Assumptions by Scenario, $2012			
	Base	**Low**	**High**
Energy	Market Forecast	-50%-85% Confidence Interval	+50%-85% Confidence Interval
Social Cost of Carbon	California Carbon Market	No Cost	Federal/7th Power Plan Values
Value of REC Compliance	4% Cost Cap	1% Cost Cap	25% RPS
Distribution System Credit, $/kW-year	$6.33	$6.33	$6.33
Transmission System Credit, $/kW-year	$2.85	$2.85	$2.85
Deferred Generation Capacity Credit, $/kW-year	$75.70	$44.44	$115
Implied Risk Adder:	N/A	Up to -$33/MWh -$31/kW-year Average of -$20/MWh -$31/kW-year	Up to $28/MWh $39/kW-year Average of $21/MWh $39/kW-year

**As noted above prediction intervals were used based on the last 10 years of data for high and low estimates.*

Table 12 summarizes results across each avoided input scenario, using Base Case load forecasts and measure acquisition rates.

Table 12 Cost-Effective Potential - Scenario Comparison				
	2-Year	**6-Year**	**10-Year**	**20-Year**
Base Case	9.0	28.3	41.8	55.5
Low Scenario	3.8	11.7	17.5	26.0
High Scenario	12.7	35.9	50.9	72.2

In the table above, the change in cost-effective potential when going from the base to the low case is slightly more than change in potential when going from the base to the high case. This suggests that while there is sensitivity to changes in avoided costs in both directions, the amount of cost-effective potential gained by further increases in avoided costs diminishes.

This result is somewhat evident from the Benefit-Cost Ratio supply curve presented earlier in the report. The supply curve has a steep slope near the threshold of cost-effectiveness, where the BCR equals 1.0, suggesting a sensitivity to any changes in avoided cost parameters, but the steepness begins to decline further to the right.

Accelerated Base Scenario

The Accelerated Base scenario represents a case where CPU very quickly ramps up program savings. In this scenario, a subset of retrofit measures—those measures that are available at any time—were modeled with more aggressive ramp rates, beyond what is presented in the Base Case. The measures chosen were those where it would be possible to quickly ramp up programs. They include:

- Commercial Energy Management
- Commercial Interior Lighting
- Commercial Showerheads
- Industrial Lighting
- Residential Showerheads, Aerators, & Thermostatic Valves
- Residential Weatherization and Wi-Fi Thermostats

Aside from adjusted ramp rates, the assumptions for the Accelerated scenario are identical to the Base Case. The Accelerated Base 2-year potential is approximately 20% higher than the Base Case 2-year potential (Table 13).

Table 13
Cost-Effective Potential - Accelerated Scenario (aMW)

	2-Year	6-Year	10-Year	20-Year
Residential	4.2	12.5	17.8	23.0
Commercial	4.3	11.5	16.1	21.2
Industrial	2.2	5.4	6.8	7.1
Distribution Efficiency	0.1	0.5	1.2	3.4
Total	**10.8**	**29.9**	**41.9**	**54.8**

These savings also bring additional reductions in peak demand. The peak demand savings are summarized in Table 14 below. The accelerated scenario provides an additional 31% in peak demand reductions in the first two years of study period over the base case peak demand savings.

Table 14
Cost-Effective Demand Savings - Accelerated Scenario (MW)

	2-Year	6-Year	10-Year	20-Year
Residential	13.1	39.7	54.4	64.9
Commercial	7.1	19.6	27.1	35.3
Industrial	2.7	6.6	8.2	8.6
Distribution Efficiency	0.1	0.6	1.5	4.2
Total	**23.0**	**66.6**	**91.2**	**113.0**

Table 15 below compares the sector-level achievement of this scenario with recent program achievement. As before, note that 2017 includes a very large industrial project which has been omitted from the averages as it is an anomaly. The table shows that the accelerated case roughly begins near Clark's current level of achievement, although the program history contains high levels of residential lighting while the potential only includes a small amount of lighting in 2020.

Table 15 Comparison of Program Achievement and Accelerated Scenario Potential							
	Program History				Potential		
	2017	2018	2019	Average	2020	2021	2022
Residential	4.4	2.4	2.9	3.2	2.3	2.1	2.2
Commercial	1.9	3.0	2.1	2.3	2.2	2.1	2.0
Industrial	6.8	1.5	1.6	1.5	1.2	1.0	0.9
Distribution Efficiency	-	-	-	-	0.0	0.1	0.1
Total	**13.1**	**6.8**	**6.6**	**7.1**	**5.7**	**5.3**	**5.2**

Scenario Summary

Table 16 compares the Base, High and Low cost cases, and Accelerated scenarios of the 2019 CPA. Table 16 also shows the Base Case potential from CPU's 2017 CPA, which is provided for reference. Potential is compared on a program year basis to provide a better comparison between the 2019 and 2017 potential estimates.

Table 16 Cost-Effective Potential - Scenario Comparison				
	2-Year	6-Year	10-Year	20-Year
2017 Base Case	9.8	28.4	46.5	80.9
2019 Base Case	9.0	28.3	41.8	55.5
Accelerated Base	11.0	30.5	42.7	55.6
Low Scenario	5.4	15.9	23.3	32.8
High Scenario	12.7	35.9	50.9	72.2

In terms of the total 20-year potential, the high case from the 2019 CPA is most similar to the 2017 CPA Base Case. The 2019 high case features somewhat similar avoided costs, especially in terms of the value of capacity, as the 2017 base case. As a result of these higher avoided costs, additional measures are cost-effective. The increase in cost-effective measures in the high case is almost enough to counter the reduction in savings due to the exclusion of lighting measures impacted by the federal standard.

Savings Shape Results

The savings from energy efficiency measures are typically reported on an annual basis. However, savings occur throughout the day and year at different levels. The annual savings for each measure are distributed across the hours of the year, based on the load or savings shape of the measure. The measure load shapes are also used to estimate the economic value of the measure, based on projected time-differentiated savings and the value of the savings at those times. This CPA made use of load shapes developed for the Seventh Plan. They include more granular, hourly detail not present in the load shapes used in previous analyses. The load shapes can be found in the MC and Load Shape file.

Figures 20 and 21 show total monthly energy savings by sector for the 20-year planning period. Figure 20 shows heavy load hour (HLH) savings and Figure 21 shows savings during light load hour (LLH) time periods. Similar to the 2017 CPA, the savings are higher during the winter months due to heating-related measures like weatherization and HVAC equipment, but even lighting and water heating end uses have slightly higher energy use in the winter months due to less sunlight and colder water supplied by municipal water systems, respectively. However, the overall profile is flatter than in the 2017 CPA. This is likely a consequence of the lower values attributed to peak demand savings discussed earlier in the report.

Figure 20
CPU Monthly Energy Efficiency Savings, HLH

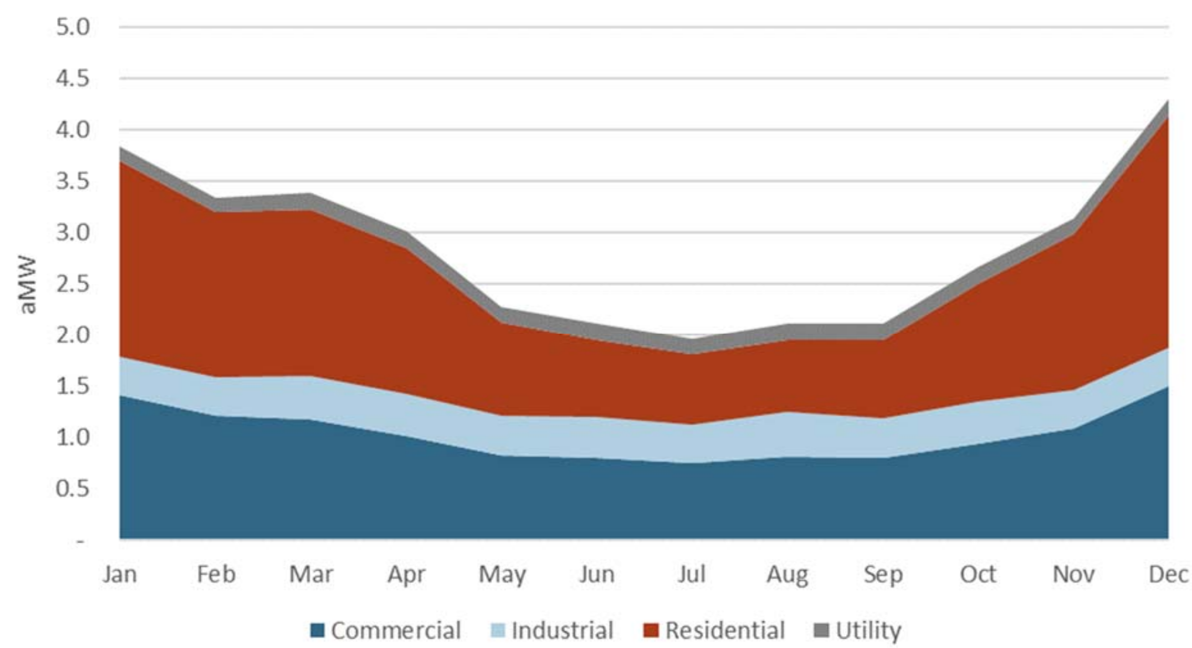


Figure 21
CPU Monthly Energy Efficiency Savings, LLH

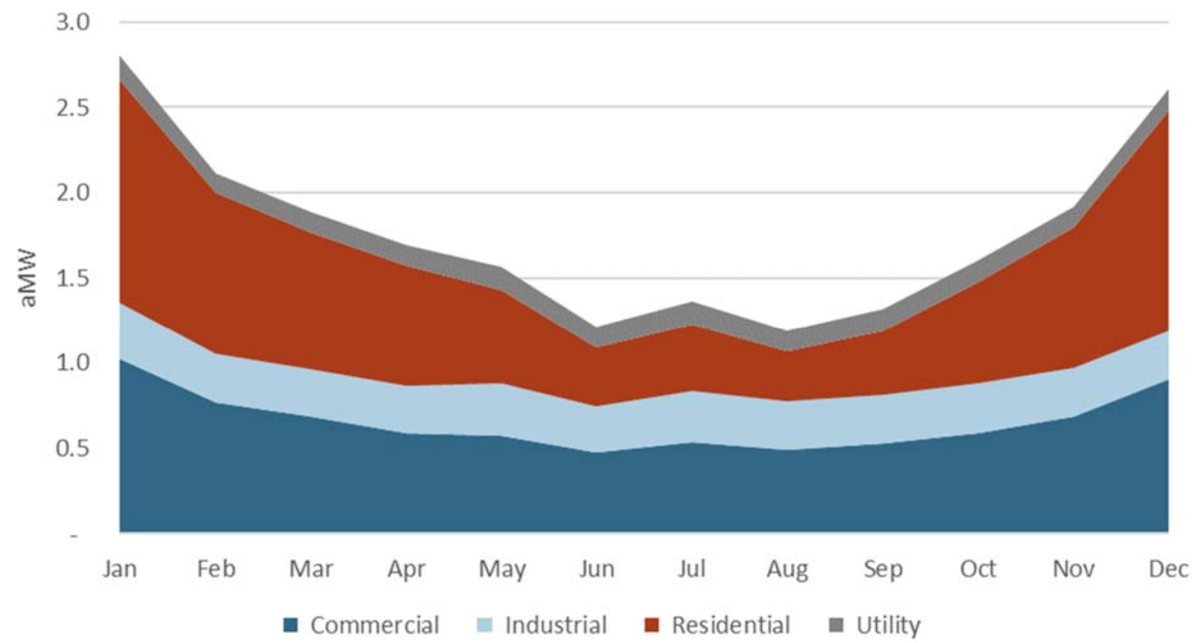
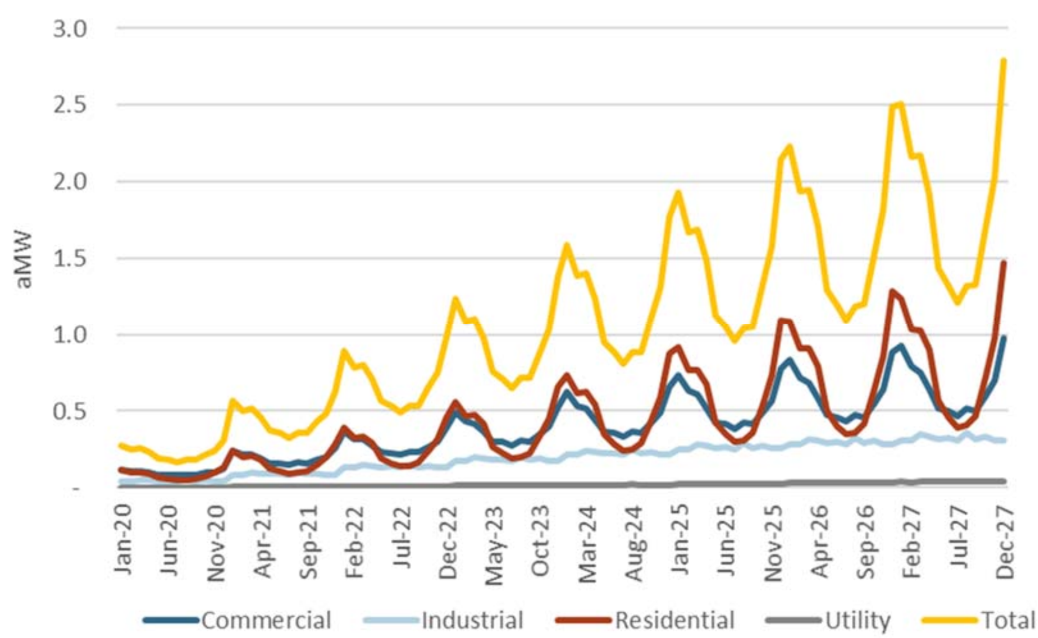


Figure 22 shows the cumulative heavy load hour monthly energy savings over the first eight years of the planning period. The overall shape of the savings is similar to the shape of seasonal utility demand.

Figure 22
CPU Monthly Energy Efficiency Savings, HLH, Cumulative



Peak Demand Savings

To estimate demand savings for this assessment, the hourly load profiles developed for the Seventh Plan were used, in addition to the timing of CPU's distribution system peak for each month. Table 17 below presents the assumed timing of CPU's monthly system peaks. CPU's system peak is most often in the morning during winter and shoulder season months, and in the evening during the summer months.

Table 17 CPU Monthly Peak Occurs at Hour Ending	
January	8
February	8
March	8
April	8
May	8
June	18
July	18
August	18
September	18
October	8
November	8
December	8

Figure 23 shows the cumulative peak demand savings by month over the 20-year study period. As with the savings shape above, the peak demand savings are greatest in the winter months. The end uses with the greatest potential peak demand reductions are residential water heating and HVAC. Commercial lighting also contributes to peak demand reductions, though it should be noted that this varies highly with the hours of operation within each business category.

Figure 23
Cumulative Peak Demand Savings by Month

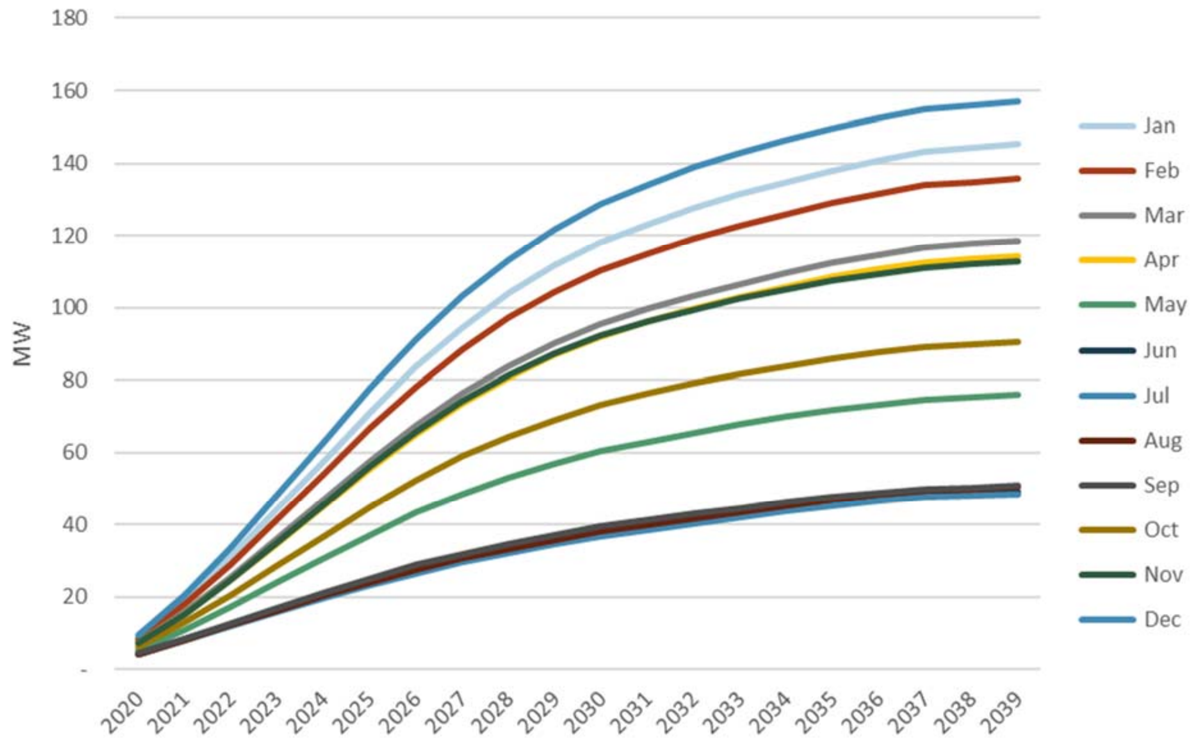


Figure 24 shows cumulative peak demand savings for the 20-year planning period for each month.

Figure 24
Monthly Peak Demand Savings, Cumulative (MW)

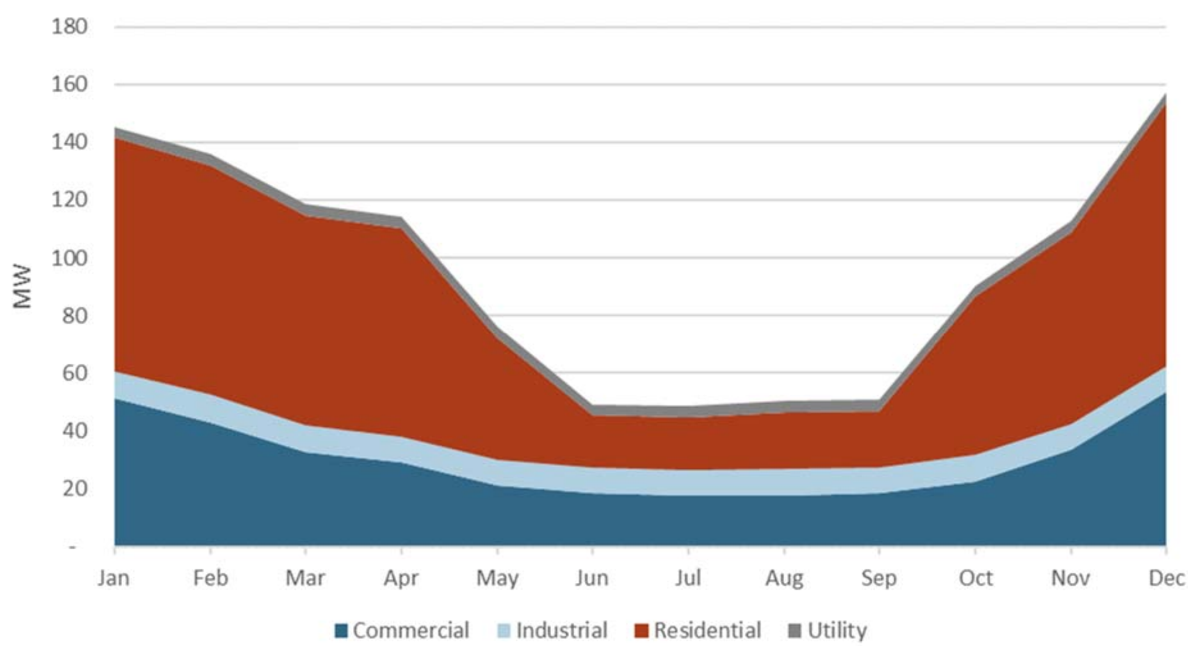


Figure 24 shows that demand savings are highest in December and are lower during the summer months.

Table 18 shows cumulative annual energy savings and peak winter and summer demand savings for the 20-year planning period. Summer and winter peaks were assumed to occur in August and December, respectively, based upon historical data provided by CPU. The costs shown in Table 18 are annual, incremental utility costs (administrative expenditures and incentive costs). The costs were modeled with the Base Case utility program assumptions described above.

Table 18
Cumulative Peak Demand Savings with Associated Energy Savings and Costs

Year	Cost	Energy Savings (aMW)	Peak Demand Savings (MW) Winter	Peak Demand Savings (MW) Summer
2020	$7,514,000	4.48	9	4
2021	$8,334,000	8.97	20	8
2022	$9,285,000	13.81	33	12
2023	$9,976,000	18.84	48	16
2024	$10,125,000	23.77	63	20
2025	$9,632,000	28.33	78	24
2026	$8,796,000	32.43	91	27
2027	$7,792,000	36.02	103	30
2028	$6,698,000	39.16	113	33
2029	$5,570,000	41.83	122	36
2030	$4,637,000	44.18	129	38
2031	$3,722,000	46.13	134	40
2032	$3,088,000	47.85	139	42
2033	$2,680,000	49.45	143	44
2034	$2,417,000	50.99	146	45
2035	$2,175,000	52.44	150	47
2036	$1,579,000	53.55	152	48
2037	$1,307,000	54.53	155	49
2038	$560,000	55.04	156	50
2039	$536,000	55.53	157	50

**Costs may vary slightly from Table 7 above due to rounding.*

The 20-year cumulative peak demand savings estimates for this assessment are 157 MW during CPU's winter peak and 50 MW during the summer peak. As discussed above, the decrease in peak demand savings as well as the exclusion of many residential lighting savings are two drivers of the reduction in peak demand savings relative to the 2017 CPA.

Summary

This report summarizes the results of the 2019 CPA conducted for Clark Public Utilities. The assessment provides estimates of energy savings by sector for the period 2020 to 2039 with a focus on the first 10 years of the planning period, as required by the EIA. The assessment considered a wide range of conservation resources that are reliable, available, and cost effective within the 20-year planning period.

Federal lighting standards impacting many residential lighting measures and new, lower values for capacity savings has resulted in less cost-effective potential than was identified in the 2017 CPA. The cost-effective potential identified in this report remains the lowest cost and lowest risk resource and will serve to keep future electricity costs to a minimum.

Methodology and Compliance with State Mandates

The energy efficiency potential reported in this document is calculated using methodology consistent with the Council's methodology for assessing conservation resources. Appendix III lists each requirement and describes how each item was completed. In addition to using methodology consistent with the Council's Seventh Power Plan, this assessment utilized many of the measure assumptions that the Council developed for the Seventh Regional Power Plan. Additional measure updates subsequent to the Seventh Plan were also incorporated. Utility-specific data regarding customer characteristics, service-area composition, and historic conservation achievements were used, in conjunction with the measures identified by the Council, to determine available energy-efficiency potential. This close connection with the Council methodology enables compliance with the Washington EIA.

Three types of energy-efficiency potential were calculated: technical, achievable, and economic. Most of the results shown in this report are the economic potential, or the potential that is cost effective in the CPU service territory. The economic and achievable potential considers savings that will be captured through utility program efforts, market transformation and implementation of codes and standards. Often, realization of full savings from a measure will require efforts across all three areas. Historic efforts to measure the savings from codes and standards have been limited, but regional efforts to identify and track savings are increasing as they become an important component of the efforts to meet aggressive regional conservation targets.

Conservation Targets

The EIA states that utilities must establish a biennial target that is "no lower than the qualifying utility's pro rata share for that two-year period of its cost-effective conservation potential for the subsequent ten-year period."[3] However, the State Auditor's Office has stated that:

> The term pro-rata can be defined as equal portions but it can also be defined as a proportion of an "exactly calculable factor." For the purposes of the Energy Independence Act, a pro-rata share could be interpreted as an even 20 percent of a utility's 10-year assessment but state law does not require an even 20 percent.[4]

The State Auditor's Office expects that qualifying utilities have analysis to support targets that are more or less than the 20 percent of the 10-year assessments. This document serves as support for the target selected by Clark Public Utilities and approved by its Commission.

Note on Uncertainty

This study shows a range of conservation target scenarios. These scenarios are estimates based on the set of assumptions detailed in this report and supporting documentation and models. Due to the uncertainties discussed in the Introduction section of this report, actual available and cost-effective conservation may vary from the estimates provided in this report.

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[3] RCW 19.285.040 Energy conservation and renewable energy targets.

[4] State Auditor's Office. Energy Independence Act Criteria Analysis. Pro-Rata Definition. CA No. 2011-03. https://www.sao.wa.gov/local/Documents/CA_No_2011_03_pro-rata.pdf

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Appendix I – Acronyms

ALH – Average Load Hours

aMW – Average Megawatt

BCR – Benefit-Cost Ratio

BPA – Bonneville Power Administration

CFL – Compact Fluorescent Light

CPA – Conservation Potential Assessment

CPU – Clark Public Utilities

EIA – Energy Independence Act

EUI – Energy Use Intensity

HLH – Heavy load hour energy

HPWH – Heat Pump Water Heater

HVAC – Heating, ventilation and air-conditioning

IRP – Integrated Resource Plan

kW – kilowatt

kWh – kilowatt-hour

LED – Light-emitting diode

LLH – Light load hour energy

MW – Megawatt

MWh – Megawatt-hour

NEEA – Northwest Energy Efficiency Alliance

NPV – Net Present Value

O&M – Operation and Maintenance

RPS – Renewable Portfolio Standard

RTF – Regional Technical Forum

TRC – Total Resource Cost

UC – Utility Cost

Appendix II – Glossary

7th Power Plan: Seventh Northwest Conservation and Electric Power Plan, Feb 2016. A regional resource plan produced by the Northwest Power and Conservation Council (Council).

Average Megawatt (aMW): Average hourly usage of electricity, as measured in megawatts, across all hours of a given day, month or year.

Avoided Cost: Refers to the cost of the next best alternative. For conservation, avoided costs are usually market prices.

Achievable Potential: Conservation potential that takes into account how many measures will actually be implemented after considering market barriers. For lost-opportunity measures, there is only a certain number of expired units or new construction available in a specified time frame. The Council assumes 85% of all measures are achievable. Sometimes achievable potential is a share of economic potential, and sometimes achievable potential is defined as a share of technical potential.

Cost Effective: A conservation measure is cost effective if the present value of its benefits is greater than the present value of its costs. The primary test is the Total Resource Cost test (TRC), in other words, the present value of all benefits is equal to or greater than the present value of all costs. All benefits and costs for the utility and its customers are included, regardless of who pays the costs or receives the benefits.

Economic Potential: Conservation potential that considers the cost and benefits and passes a cost-effectiveness test.

Levelized Cost: Resource costs are compared on a levelized-cost basis. Levelized cost is a measure of resource costs over the lifetime of the resource. Evaluating costs with consideration of the resource life standardizes costs and allows for a straightforward comparison.

Lost Opportunity: Lost-opportunity measures are those that are only available at a specific time, such as new construction or equipment at the end of its life. Examples include heat-pump upgrades, appliances, or premium HVAC in commercial buildings.

MW (megawatt): 1,000 kilowatts of electricity. The generating capacity of utility plants is expressed in megawatts.

Northwest Energy Efficiency Alliance (NEEA): The alliance is a unique partnership among the Northwest region's utilities, with the mission to drive the development and adoption of energy-efficient products and services.

Northwest Power and Conservation Council "The Council": The Council develops and maintains a regional power plan and a fish and wildlife program to balance the Northwest's environment and energy needs. Their three tasks are to: develop a 20-year electric power plan that will guarantee adequate and reliable energy at the lowest economic and environmental cost to the Northwest; develop a program to protect and rebuild fish and wildlife populations affected by hydropower development in the Columbia River Basin; and educate and involve the public in the Council's decision-making processes.

Regional Technical Forum (RTF): The Regional Technical Forum (RTF) is an advisory committee established in 1999 to develop standards to verify and evaluate conservation savings. Members are appointed by the Council and include individuals experienced in conservation program planning, implementation and evaluation.

Renewable Portfolio Standards: Washington state utilities with more than 25,000 customers are required to meet defined %ages of their load with eligible renewable resources by 2012, 2016, and 2020.

Retrofit (discretionary): Retrofit measures are those that can be replaced at any time during the unit's life. Examples include lighting, shower heads, pre-rinse spray heads, or refrigerator decommissioning.

Technical Potential: Technical potential includes all conservation potential, regardless of cost or achievability. Technical potential is conservation that is technically feasible.

Total Resource Cost Test (TRC): This test is used by the Council and nationally to determine whether or not conservation measures are cost effective. A measure passes the TRC if the ratio of the present value of all benefits (no matter who receives them) to the present value of all costs (no matter who incurs them) is equal to or greater than one.

Appendix III – Documenting Conservation Targets

References:

1) Report – "Clark Public Utilities 2019 Conservation Potential Assessment". Final Report – September 3, 2019.
2) Model – "EES CPA Model-v3.3" and supporting files
   a. MC_and_Loadshape-Clark-Base.xlsm – referred to as "MC and Loadshape file" – contains price and load shape data

WAC 194-37-070 Documenting Development of Conservation Targets; Utility Analysis Option		
NWPCC Methodology	**EES Consulting Procedure**	**Reference**
a) **Technical Potential:** Determine the amount of conservation that is technically feasible, considering measures and the number of these measures that could be physically be installed or implemented, without regard to achievability or cost.	The model includes estimates for stock (e.g. number of homes, square feet of commercial floor area, industrial load) and the number of each measure that can be implemented per unit of stock. The technical potential is further constrained by the amount of stock that has already completed the measure.	Model – the technical potential is calculated as part of the achievable potential, described below.
b) Achievable Potential: Determine the amount of the conservation technical potential that is available within the planning period, considering barriers to market penetration and the rate at which savings could be acquired.	The assessment conducted for Clark Public Utilities used ramp rate curves to identify the amount of achievable potential for each measure. Those assumptions are for the 20-year planning period. An additional factor of 85% was included to account for market barriers in the calculation of achievable potential.	Model – the use of these factors can be found on the sector measure tabs, such as 'Residential Measures'. Additionally, the complete set of ramp rates used can be found on the 'Ramp Rates' tab.
c) **Economic Achievable Potential**: Establish the economic achievable potential, which is the conservation potential that is cost-effective, reliable, and feasible, by comparing the total resource cost of conservation measures to the cost of other resources available to meet expected demand for electricity and capacity.	Benefits and costs were evaluated using multiple inputs; benefit was then divided by cost. Measures achieving a benefit-cost ratio greater than one were tallied. These measures are considered achievable and cost-effective (or "economic").	Model – BC Ratios are calculated at the individual level by ProCost and passed up to the model.

WAC 194-37-070 Documenting Development of Conservation Targets; Utility Analysis Option		
NWPCC Methodology	**EES Consulting Procedure**	**Reference**
d) **Total Resource Cost**: In determining economic achievable potential, perform a life-cycle cost analysis of measures or programs	The life-cycle cost analysis was performed using the Council's ProCost model. Incremental costs, savings, and lifetimes for each measure were the basis for this analysis. The Council and RTF assumptions were utilized.	Model – supporting files include all of the ProCost files used in the Seventh Plan. The life-cycle cost calculations and methods are identical to those used by the Council.
e) Conduct a total resource cost analysis that assesses all costs and all benefits of conservation measures regardless of who pays the costs or receives the benefits	Cost analysis was conducted per the Council's methodology. Capital cost, administrative cost, annual O&M cost and periodic replacement costs were all considered on the cost side. Energy, non-energy, O&M and all other quantifiable benefits were included on the benefits side. The Total Resource Cost (TRC) benefit cost ratio was used to screen measures for cost-effectiveness (I.e., those greater than one are cost-effective).	Model – the "Measure Info Rollup" files pull in all the results from each avoided cost scenario, including the BC ratios from the ProCost results. These results are then linked to by the Conservation Potential Assessment model. The TRC analysis is done at the lowest level of the model in the ProCost files.
f) Include the incremental savings and incremental costs of measures and replacement measures where resources or measures have different measure lifetimes	Savings, cost, and lifetime assumptions from the Council's 7th Plan and RTF were used.	Model – supporting files include all of the ProCost files used in the Seventh Plan. The life-cycle cost calculations and methods are identical to those used by the Council.
g) Calculate the value of energy saved based on when it is saved. In performing this calculation, use time differentiated avoided costs to conduct the analysis that determines the financial value of energy saved through conservation	The Council's Seventh Plan measure load shapes were used to calculate time of day of savings and measure values were weighted based upon peak and off-peak pricing. This was handled using the Council's ProCost program so it was handled in the same way as the Seventh Power Plan models.	Model – See MC file for load shapes. The ProCost files handle the calculations.
h) Include the increase or decrease in annual or periodic operations and maintenance costs due to conservation measures	Operations and maintenance costs for each measure were accounted for in the total resource cost per the Council's assumptions.	Model – the ProCost files contain the same assumptions for periodic O&M as the Council and RTF.

WAC 194-37-070 Documenting Development of Conservation Targets; Utility Analysis Option		
NWPCC Methodology	**EES Consulting Procedure**	**Reference**
i) Include avoided energy costs equal to a forecast of regional market prices, which represents the cost of the next increment of available and reliable power supply available to the utility for the life of the energy efficiency measures to which it is compared	A regional market price forecast for the planning period was created and provided by EES. A discussion of methodologies used to develop the avoided cost forecast is provided in Appendix IV.	Report –See Appendix IV. Model – See MC File ("TEA Base" worksheet).
j) Include deferred capacity expansion benefits for transmission and distribution systems	Deferred transmission capacity expansion benefits were given a benefit of \$2.85/kW-year in the cost-effectiveness analysis. A distribution system credit of \$6.33/kW-year was also used.	Model – this value can be found on the ProData page of each ProCost file.
k) Include deferred generation benefits consistent with the contribution to system peak capacity of the conservation measure	Deferred generation capacity expansion benefits were given a value of \$75.70/kW-year in the base case cost effectiveness analysis. This is based upon CPU's projected marginal cost for generation capacity. Alternate values were used for the low and high scenarios.	Model – this value can be found on the ProData page of the ProCost Batch Runner file. The generation capacity value was not originally included as part of ProCost during the development of the 7th Plan, so the value has been combined with the distribution capacity benefit, since the timing of CPU's system peak and the regional peak are different.
l) Include the social cost of carbon emissions from avoided non-conservation resources	The avoided cost data include estimates of future high, medium, and low CO_2 costs.	Multiple scenarios were analyzed and these scenarios include different levels of estimated costs and risk.
m) Include a risk mitigation credit to reflect the additional value of conservation, not otherwise accounted for in other inputs, in reducing risk associated with costs of avoided non-conservation resources	In this analysis, risk was considered by varying avoided cost inputs and analyzing the variation in results. Rather than an individual and non-specific risk adder, our analysis included a range of possible values for each avoided cost input.	The scenarios section of the report documents the inputs used and the results associated.
n) Include all non-energy impacts that a resource or measure may provide that can be quantified and monetized	Quantifiable non-energy benefits were included where appropriate. Assumptions for non-energy benefits are the same as in the Council's Seventh Power Plan. Non-energy benefits include, for example, water savings from clothes washers.	Model – the ProCost files contain the same assumptions for non-power benefits as the Council and RTF. The calculations are handled in by ProCost.

WAC 194-37-070 Documenting Development of Conservation Targets; Utility Analysis Option		
NWPCC Methodology	**EES Consulting Procedure**	**Reference**
o) Include an estimate of program administrative costs	Total costs were tabulated and an estimated 20% of total was assigned as the administrative cost. This value is consistent with regional average and BPA programs. The 20% value was used in the Fifth, Sixth, and Seventh Power plans.	Model – this value can be found on the ProData page of the ProCost Batch Runner file.
p) Include the cost of financing measures using the capital costs of the entity that is expected to pay for the measure	Costs of financing measures were included utilizing the same assumptions from the Seventh Power Plan.	Model – this value can be found on the ProData page of the ProCost Batch Runner file.
q) Discount future costs and benefits at a discount rate equal to the discount rate used by the utility in evaluating non-conservation resources	Discount rates were applied to each measure based upon the Council's methodology. A real discount rate of 4% was used, based on the Council's most recent analyses in support of the Seventh Plan	Model – this value can be found on the ProData page of the ProCost Batch Runner file.
r) Include a ten percent bonus for the energy and capacity benefits of conservation measures as defined in 16 U.S.C. § 839a of the Pacific Northwest Electric Power Planning and Conservation Act	A 10% bonus was added to all measures in the model parameters per the Conservation Act.	Model – this value can be found on the ProData page of the ProCost Batch Runner file.

Appendix IV – Avoided Cost and Risk Exposure

EES Consulting, Inc. (EES) has conducted a Conservation Potential Assessment (CPA) for Clark Public Utilities (CPU) for the period 2020 through 2039 as required under RCW 19.285 and WAC 194.37. According to WAC 197.37.070, CPU must evaluate the cost-effectiveness of conservation by setting avoided energy costs equal to a forecast of regional market prices. In addition, several other components of the avoided cost of energy efficiency savings must be evaluated, including generation capacity value, transmission and distribution costs, risk, and the social cost of carbon. This appendix describes each of the avoided cost assumptions and provides a range of values that was evaluated in the 2019 CPA. The 2019 CPA considered three avoided cost scenarios: Base, Low, and High. Each of these is discussed below.

Avoided Energy Value

For the purposes of the 2019 CPA, EES has prepared a forecast of market prices for the Mid-Columbia trading hub. This section summarizes the methodology and results of the market price forecast and compares the forecast to the market forecast used for CPU's 2017 CPA.

Methodology

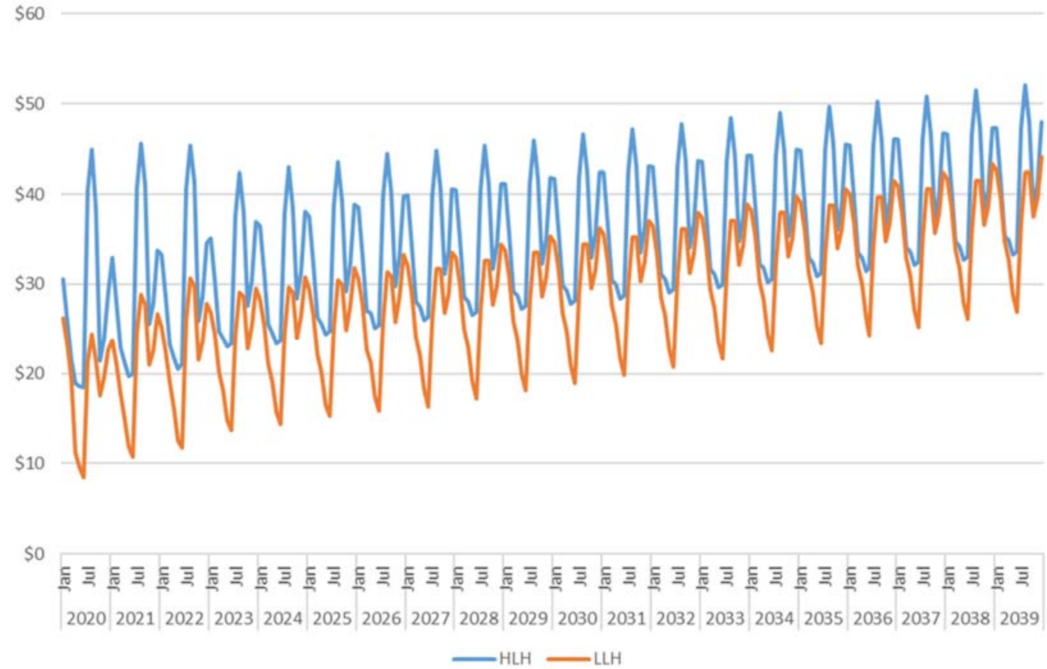
For the period January 2019 through December 2027, projected monthly on- and off-peak market prices were provided by CPU's scheduling agent. CPU's scheduling agent provides CPU with forward price projections on a daily basis. The forward market prices upon which the avoided costs are based were sourced in December 2018.

EES estimated a linear trend for the 9-year period 2019 through 2027 and then escalated rates in years 2028 through 2039 at the estimated trend rate. The estimated annual escalation rate is 1.8 percent.

Results

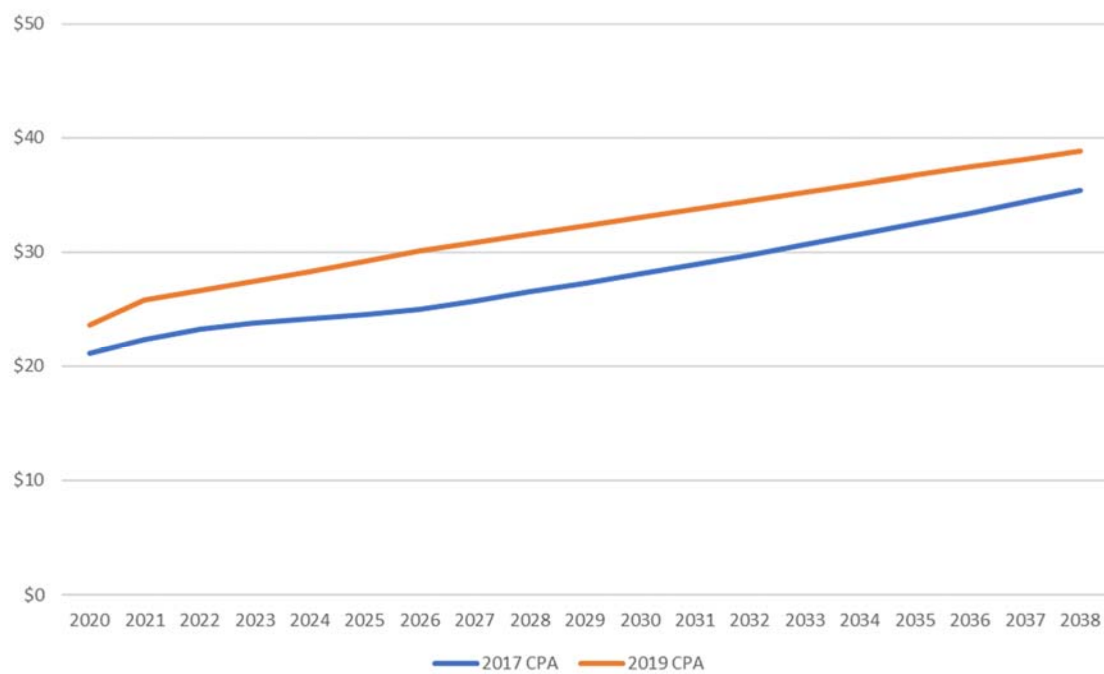
Figure IV-1 illustrates the resulting monthly, diurnal market price forecast. The levelized value of market prices over the study period is $32.36/MWh assuming a 4 percent real discount rate. As noted above, the average annual growth rate beginning in 2027 is 2.1 percent. These prices do not include any potential carbon costs, which are discussed below.

Figure IV-1
Forecast Market Prices (2012$/MWh)



This market price forecast (December 2018) is slightly higher than the market price forecast used in CPU's 2017 CPA. Figure IV-2 compares the two forecasts.

Figure IV-2
Forecast Market Prices in 2017 CPA and 2019 CPA (2012$/MWh)

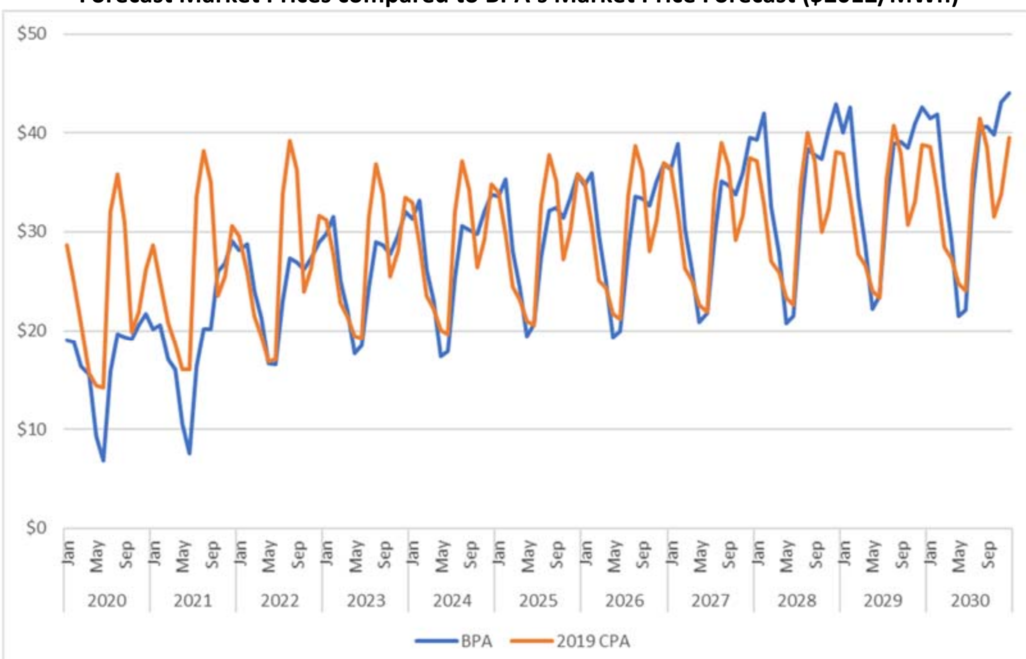


The 2019 CPA market price forecast for the period 2019 through 2039 is on average about $4 higher per month compared with the market price used in the 2017 CPA. This is in part driven by increased market prices in 2018.

Benchmarking

Figure IV-3 compares the 2019 CPA forecast with the forecast included in BPA's Initial Proposal for FY20-21 rates over the years 2020-2030. The monthly shapes differ in the short term as the BPA market price forecast is lower through June 2021. The forecasts are similar from summer 2021 forward, noting the BPA forecast peaks higher in winter months and the CPA forecast dips further in the fall.

Figure IV-3
Forecast Market Prices compared to BPA's Market Price Forecast ($2012/MWh)



**BPA's market price forecast is per the market price forecast included in BPA's 2020 Rate Analysis Model.*

High and Low Scenarios

To reflect a range of possible future outcomes, EES calculated high- and low-case market price forecasts. To do this, EES looked at a history of monthly mid-Columbia energy prices from the past ten years and fit a simple model controlling for monthly variation and a time trend. From this model a prediction interval was calculated moving from a 50% to 85% confidence interval over time to estimate the high and low market price forecasts.

Figures IV-4 and IV-5 compare the resulting price forecasts, for high and low load hours, respectively.

Figure IV-4
High Load Hour Market Price Forecast Comparison (2012$/MWh)

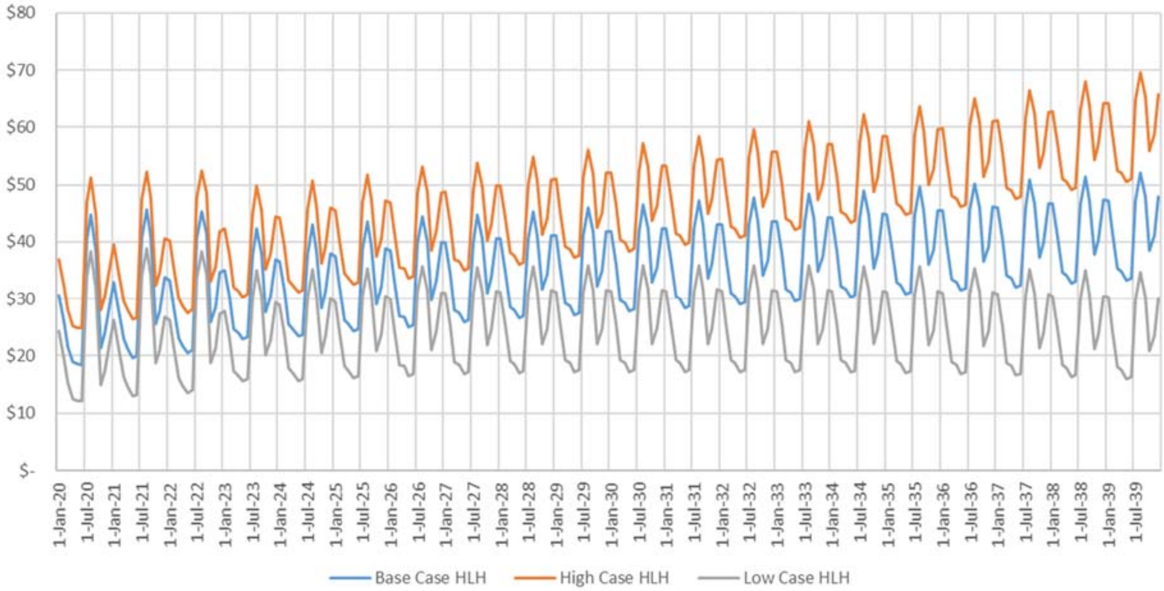
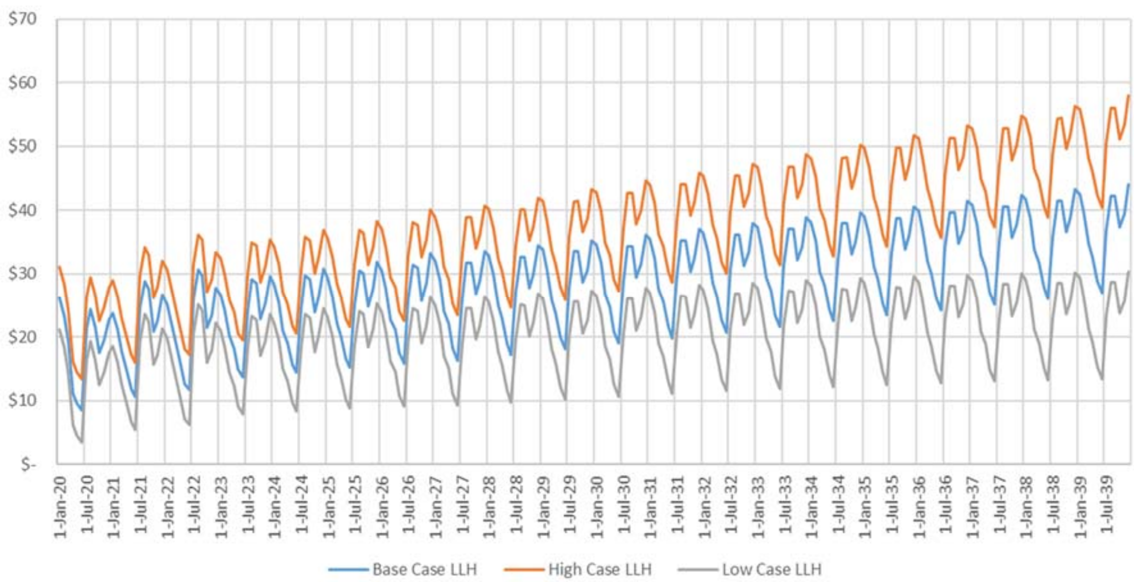


Figure IV-5
Low Load Hour Market Price Forecast Comparison (2012$/MWh)



Avoided Cost Adders and Risk

From a total resource cost perspective, energy efficiency provides multiple benefits beyond the avoided cost of energy. These include deferred capital expenses on generation, transmission, and distribution capacity; as well as the reduction of required renewable energy credit (REC) purchases, avoided social costs of carbon emissions, and the reduction of utility resource portfolio risk exposure. Since energy efficiency measures provide both peak demand (kW) and energy savings (kWh), these other benefits are monetized as value per unit of either kWh or kW savings.

Energy-Based Avoided Cost Adders:

1. Social Cost of Carbon
2. Renewable Energy Credits
3. Risk Reduction Premium

Peak Demand-Based Adders:

1. Generation Capacity Deferral
2. Transmission Capacity Deferral
3. Distribution Capacity Deferral

The estimated values and associated uncertainties for these avoided cost components are provided below. EES evaluated the energy efficiency potential under a range of avoided cost adders and identified the sensitivity of the results to changes in these values.

Social Cost of Carbon

The social cost of carbon is a value that society incurs when fossil fuels are burned to generate electricity. EIA rules require that the social cost of carbon be included in the total resource cost test (TRC). The value of the social cost of carbon is not defined by markets; therefore, the CPA includes the social cost of carbon in an uncertainty analysis through scenario modeling. The scenarios modeled include the value of the social cost of carbon from various resources. California's cap-and-trade carbon market prices were used in the base case, as these represent the closest available analogue to a carbon market and are similar to policies recently considered in Washington. Prices in the California market are currently near $15 per metric ton and are expected to rise to near $16 in 2020. The price floor in California's market is stipulated to rise at 5% plus inflation, so that escalation rate was used.

The Power Council used the federal Interagency Workgroup estimate of a social cost of carbon in scenarios of the Seventh Power Plan. The federal carbon cost estimates range from $46 to $65 (2012$) per metric ton over the 20-year planning period. In addition, a value of zero is included in the low avoided cost scenario analysis. The zero value is consistent with other resource planning done by CPU, in which a social cost of carbon is not considered.

In addition to these carbon costs, the nature of CPU's marginal generation source also needs to be considered. In the spring runoff season, hydropower and wind are the likely the marginal resources, while gas turbines serve as the marginal resource at other times of the year. Accordingly, EES has assumed zero pounds of CO_2 production per kWh in April through July, and 0.84 lbs. of CO_2 per kWh in the other months.

Value of Renewable Energy Credits

Related to the social cost of carbon is the value of renewable energy credits. Washington's Energy Independence Act established a Renewable Portfolio Standard (RPS) for utilities with 25,000 or more customers. Currently, utilities are required to source 9% of all electricity sold to retail customers from renewable energy resources. In 2020, the requirement increases to 15%.

The EIA allows two alternate modes of compliance. Utilities can comply by spending four percent or more of the annual retail revenue requirement on the incremental cost of renewable energy—essentially a four percent cost cap. Utilities with no load growth can also comply by spending one percent or more of the retail revenue requirement.

Accordingly, energy savings from conservation measures can reduce the cost of compliance in two ways:

1. Eliminates CPU's load growth, making the utility eligible for the reduced RPS requirement, and
2. Reducing the net retail revenue requirement.

CPU's 2018 IRP projects a small amount of load growth in the coming years, even after savings from energy efficiency are included. As such, in the base scenario, the first benefit—making the utility eligible for the reduced 1% requirement—is not applicable. Only the second benefit, the reduction in net retail revenue requirement is applicable.

Each unit of energy adds a variety of costs to CPU's revenue requirement, but for simplicity we assume that the cost of energy is the only change to the revenue requirement, as other infrastructure and administrative costs are unlikely to change with small increments of energy efficiency acquired. Therefore, we add 4% of the market price of energy to the avoided cost as energy efficiency's value of reducing CPU's RPS compliance cost. These prices were incorporated into the avoided costs of energy efficiency. With energy prices around $30/MWh, this has the effect of adding approximately $1.20/MWh to the market prices. In the low scenario, we assume that CPU is able to use the 1% compliance path. In the high scenario, a 25% RPS policy was assumed to account for potential increases in the cost of RECs plus potential increases in the stringency of Washington's RPS requirements.

Risk Adder

In general, the risk that any utility faces is that energy efficiency will be undervalued, either in terms of the value per kWh or per kW of savings, leading to an under-investment in energy efficiency and exposure to higher market prices or preventable investments in infrastructure. The converse risk—an over-valuing of energy and subsequent over-investment in energy efficiency—is also possible, albeit less likely. For example, an over-investment would occur if an assumption is made that economies will remain basically the same as they are today and subsequent sector shifts or economic downturns cause large industrial customers to close their operations. Energy efficiency investments in these facilities may not have been in place long enough to provide the anticipated low-cost resource.

In order to address risk, the Council includes a risk adder in its cost-effectiveness analysis of energy efficiency measures. This adder represents the value of energy efficiency savings not explicitly accounted for in the avoided cost parameters. The risk adder is included to ensure an efficient level of investment in energy efficiency resources under current planning conditions. Specifically, in cases where the market price has been low compared to historic levels, the risk adder accounts for the likely possibility that market prices will increase above current forecasts.

The value of the risk adder has varied depending on the avoided cost input values. The adder is the result of stochastic modeling and represents the lower risk nature of energy efficiency resources. In the Sixth Power Plan the risk adder was significant (up to $50/MWh for some measures). In the Seventh Power Plan, no risk adder was needed after the addition of the generation capacity credit. While the Council uses stochastic portfolio modeling to value the risk credit, utilities conduct scenario and uncertainty analysis. The scenarios modeled in CPU's CPA include an inherent value for the risk credit.

For CPU's 2019 CPA, the avoided cost parameters have been estimated explicitly, and, a scenario analysis is performed. Therefore, a risk adder of $0/MWh is recommended for the base case. Variation in other avoided cost inputs covers a range of reasonable outcomes and is sufficient to identify the sensitivity of the cost-effective energy efficiency potential to a range of outcomes. The scenario results present a range of cost-effective energy efficiency potential, and the identification of CPU's biennial target based on the range modeled is effectively selecting the utility's preferred risk strategy and associated risk credit.

Deferred Distribution and Transmission System Investment

Energy efficiency measure savings reduce capacity requirements on both the distribution and transmission system. The Council recently updated the values previously estimated for these capacity savings: $26/kW-year and $31/kW-year for transmission and distribution systems, respectively ($2012). The new values are $3.08/kW-year and $6.85/kW-year (2016$) or $2.85/kW-year and $6.33/kW-year (2012$) for transmission and distribution system deferral. These values are based on input provided to the Council by several regional utilities and will likely be used in the next Power Plan. These values were used in all scenarios of the CPA.

Deferred Investment in Generation Capacity

CPU's 2018 IRP progress report identified that the utility had sufficient resources for average annual energy requirements but showed a need for new resources to meet peak demands. Currently, CPU has a call option for capacity for all months except April, May, and June and expect to renew the contract at a price of $1/kW-month. Higher prices are expected in the future, however, so this CPA assumed a price of $2.50/kW-month for 2020 and then shifted to the charges in BPA's demand rates over the initial 10 years of the study period. BPA's demand charges are based on the cost of a gas plant and reflects that a new resource may need to be built at some point.

EES assumed a monthly shape to the demand savings realized through energy efficiency, recognizing that energy efficiency does not provide equal reductions of capacity in all months. For the base case, it was assumed the cost increase in real terms by 5% annually. Over twenty, years, the resulting cost of avoided capacity is $75.70/kW-year (2012$) in levelized terms. In the low scenario, no cost escalation was assumed, resulting in a 20-year levelized cost of $44.44/kW-yr. In the Council's Seventh Power Plan[5], a generation capacity value of $115/kW-year was explicitly calculated ($2012). This value will be used in the high scenario.

Summary of Scenario Assumptions

Table IV-1 summarizes the recommended scenario assumptions. The Base Case represents the most likely future.

Table IV-1
Avoided Cost Assumptions by Scenario, $2012

	Base	Low	High
Energy	Market Forecast	-50%-85% Confidence Interval*	+50%-85% Confidence Interval*
Social Cost of Carbon	California Carbon Market	No Cost	Federal/7th Power Plan Values
Value of RPS Compliance	4% Cost Cap	1% Cost Cap	25% RPS
Distribution System Credit, $/kW-year	$6.33	$6.33	$6.33
Transmission System Credit, $/kW-year	$2.85	$2.85	$2.85
Deferred Generation Capacity Credit, $/kW-year	$75.70	$44.44	$115
Implied Risk Adder:	N/A	Up to -$33/MWh -$31/kW-year Average of -$20/MWh -$31/kW-year	Up to $28/MWh $39/kW-year Average of $21/MWh $39/kW-year

**As noted above prediction intervals were used based on the last 10 years of data for high and low estimates.*

[5] https://www.nwcouncil.org/energy/powerplan/7/home/

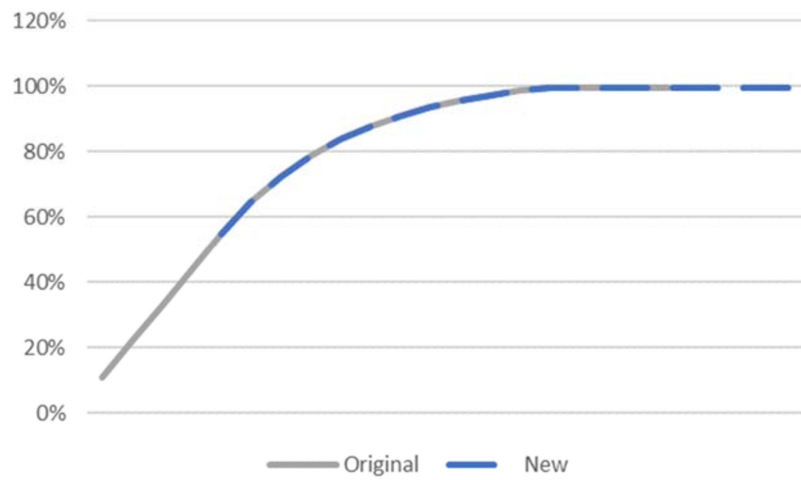
Appendix V – Ramp Rate Documentation

This section is intended to document how ramp rates were adjusted to align near term potential with recent achievements of CPU programs.

Modelling work began with the Seventh Plan ramp rate assignments for each measure. For new measures added to the model, an appropriate ramp rate was selected based on the maturity of each measure. Seventh Plan ramp rates were also adjusted to fit the 2020-2039 timeline of this CPA. The adjustment made to each ramp rate varied depending on the type of ramp rate, since different types of ramp rates are applied to retrofit and lost opportunity measures.

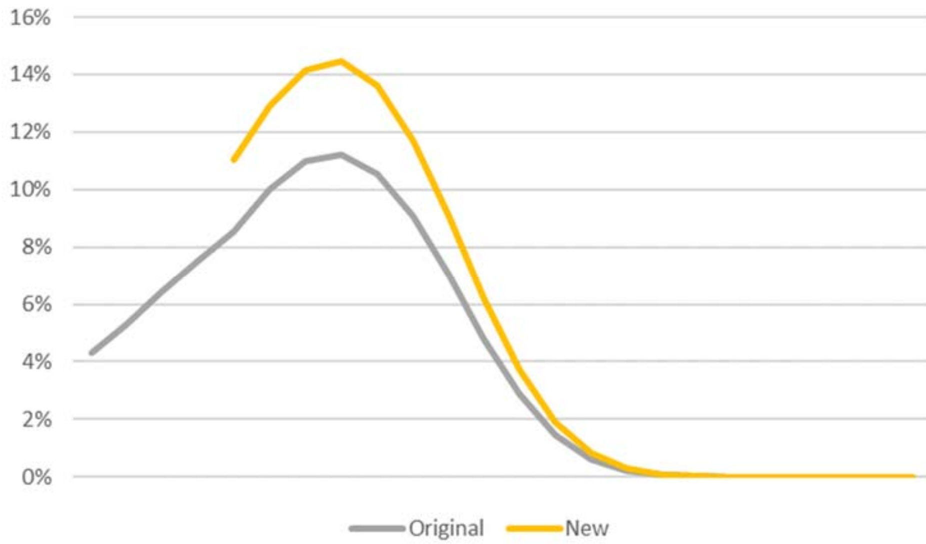
For lost opportunity measures, the ramp rates represent the share of equipment turning over in a given year that is achieved by efficiency programs. For these ramp rates, the only modification necessary was to extrapolate the final years to cover the time period relevant to the 2019 CPA. An example of this is shown in Figure V-1 below.

Figure V-1
Example Lost Opportunity Ramp Rate Modification



For retrofit ramp rates, a different adjustment was necessary. The ramp rates applied to retrofit measures describe the portion of the entire stock that is acquired in a given year. For these ramp rates, new values were calculated based on the original ramp rate values. The new value was set as the original ramp rate value for a given year, divided by the sum of original ramp rate values over the 2020-2039 timeframe. This approach reflects the fact that a portion of the stock has already been acquired and continuing with the pace projected by the Seventh Plan would mean acquiring a larger percentage of a smaller remaining stock. An example of this is shown below.

Figure V-2
Example Retrofit Ramp Rate Modification



With these modified ramp rates, CPU's program achievements from 2017-2018 and estimates for 2019 were compared at a sector level with the first three years of the study period, 2020-2022. Savings from NEEA's market transformation initiatives were allocated to the appropriate sectors. This allowed for the identification of sectors where ramp rate adjustments may be necessary.

Table V-1 below shows the results of the comparison by sector *after* ramp rate adjustments were made. Note that these totals exclude savings from CPU's residential lighting program, since these measures were excluded from the model due to the upcoming implementation of the federal EISA 2020 lighting standard. Further, the 2017 industrial savings includes one very large project. As such, this value was not included in the averages.

Table V-1
Comparison of Sector-Level Program Achievement and Potential (aMW)

	Program History				Potential		
	2017	**2018**	**2019**	**Average**	**2020**	**2021**	**2022**
Residential	2.1	1.2	2.4	1.9	1.5	1.5	1.8
Commercial	1.9	3.0	2.1	2.3	2.1	2.0	2.0
Industrial	6.8	1.5	1.6	1.5	0.9	0.9	0.9
Distribution Efficiency	-	-	-	-	0.0	0.1	0.1
Total	**10.8**	**5.7**	**6.1**	**5.8**	**4.5**	**4.5**	**4.8**

CPU provided measure detail for each sector, allowing for additional comparisons at the end use level, although savings from NEEA could not be allocated to individual measures or end uses.

Table V-2 below shows a comparison of historical accomplishments and future potential for the residential sector, by end use. Additional commentary is provided below.

Table V-2 Comparison of Residential Achievement and Potential (aMW)							
	Program History				Potential		
End Use	2017	2018	2019	Average	2020	2021	2022
Dryer	-	-	-	-	-	-	-
Electronics	-	0.00	-	0.00	0.02	0.03	0.04
Food Preparation	-	-	-	-	0.01	0.01	0.01
HVAC	0.35	0.35	0.64	0.45	0.52	0.71	0.89
Lighting	2.28	1.11	0.65	1.34	0.37	-	-
Refrigeration	0.06	0.04	0.04	0.04	-	-	-
Water Heating	1.09	0.10	1.05	0.75	0.62	0.76	0.87
Whole Bldg/Meter Level	0.01	0.02	0.02	0.02	-	-	-
NEEA	0.64	0.73	0.71	0.69	-	-	-
Total	**2.15**	**1.24**	**2.44**	**1.95**	**1.53**	**1.51**	**1.82**

HVAC – This category was set to align approximately with the historical savings. Additional savings from NEEA's market transformation may apply here. Less aggressive ramp rates were applied to some measures to align with program potential.

Lighting – Savings in this category were excluded from potential after 2020 due to the upcoming EISA 2020 standard implementation. A small amount of savings here acknowledges that some program transition will occur in 2020.

Water Heating – The potential in this end use was aligned with recent program history by applying slower ramp rates. In this category, NEEA savings also apply due to NEEA's work with heat pump water heaters.

Other Categories – CPU reported savings in other categories (e.g. refrigeration, whole building) but no cost-effective potential was identified.

The commercial sector ramp rate comparisons are shown in Table V-3, with additional commentary below.

Table V-3 Comparison of Commercial Achievement and Potential (aMW)							
	Program History				Potential		
End Use	**2017**	**2018**	**2019**	**Average**	**2020**	**2021**	**2022**
Compressed Air					0.01	0.01	0.01
Electronics					0.01	0.02	0.03
Food Preparation	-	0.00	0.03	0.01	0.02	0.02	0.03
HVAC	0.36	0.18	0.31	0.28	0.43	0.51	0.57
Lighting	1.27	2.61	1.62	1.83	1.42	1.25	1.14
Motors/Drives					0.02	0.02	0.03
Process Loads					0.05	0.06	0.06
Refrigeration	0.10	0.00	-	0.04	0.06	0.09	0.11
Water Heating					0.04	0.04	0.04
NEEA	0.15	0.17	0.16	0.16	-	-	-
Total	**1.87**	**2.96**	**2.12**	**2.32**	**2.06**	**2.02**	**2.01**

Lighting – Commercial lighting ramp rates were increased above Seventh Plan rates to more closely align with recent levels of program achievement. Ramp rates are

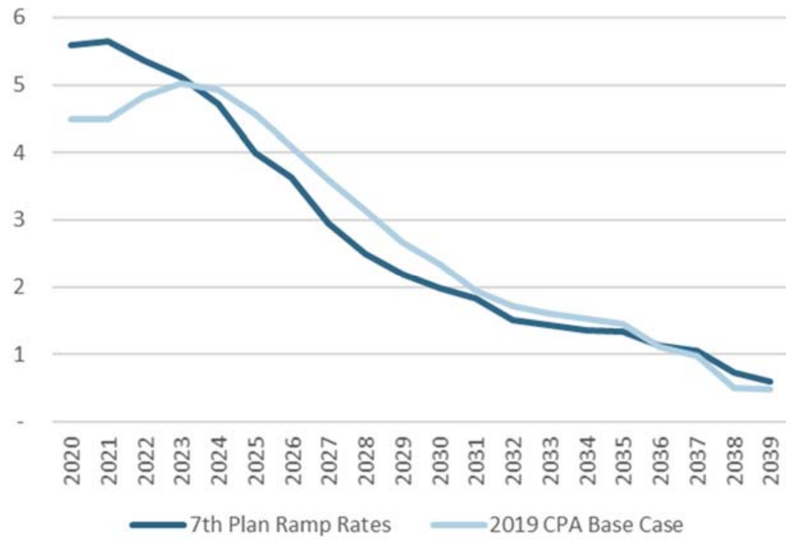
HVAC – Slower ramp rates were applied to several measures in this category to align program history and potential.

In the commercial sector, smaller ramp rate modifications were also made to other smaller end uses, including food preparation, refrigeration, and electronics.

In the industrial sector, EES ramp rates were slowed slightly across a variety of measures to align potential with program history.

Figure V-3 compares the annual acquisition of conservation potential with the ramp rates used in this potential assessment with the acquisition if the Seventh Plan ramp rates, adjusted to the timeline of this CPA, had been used. While the potential acquired under the Seventh Plan ramp rates begins at a higher level, the adjusted ramp rates acquire more potential over many of the subsequent years, resulting in a nearly identical cumulative potential over the 20-year study period.

Figure V-3
Effect of Adjusted Ramp Rates on Acquisition of Potential



Appendix VI – Measure List

This appendix provides a high-level measure list of the energy efficiency measures evaluated in the 2019 CPA. The CPA evaluated thousands of measures; the measure list does not include each individual measure; rather it summarizes the measures at the category level, some of which are repeated across different units of stock, such as single family, multifamily, and manufactured homes. Specifically, utility conservation potential is modeled based on incremental costs and savings of individual measures. Individual measures are then combined into measure categories to more realistically reflect utility-conservation program organization and offerings. For example, single-family attic insulation measures are modeled for a variety of upgrade increments: R-0 to R-38, R-0 to R-49, or R-19 to R-38. The increments make it possible to model measure savings and costs at a more precise level. Each of these individual measures are then bundled across all housing types to result in one measure group: attic insulation.

The measure list used in this CPA was developed based on information from the Regional Technical Forum (RTF) and the Northwest Power and Conservation Council (Council). The RTF and the Council continually maintain and update a list of regional conservation measures based on new data, changing market conditions, regulatory changes, and technological developments. The measure list provided in this appendix includes the most up-to date information available at the time this CPA was developed.

The following tables list the conservation measures (at the category level) that were used to model conservation potential presented in this report. Measure data was sourced from the Council's Seventh Plan workbooks and the RTF's Unit Energy Savings (UES) workbooks. Note that some measures may not be applicable to an individual utility's service territory based on characteristics of the utility's customer sectors.

Table VI-1 Residential End Uses and Measures		
End Use	**Measures/Categories**	**Data Source**
Dryer	Heat Pump Clothes Dryer	7th Plan
Electronics	Advanced Power Strips	7th Plan, RTF
	Energy Star Computers	7th Plan
	Energy Star Monitors	7th Plan
Food Preparation	Electric Oven	7th Plan
	Microwave	7th Plan
HVAC	Air Source Heat Pump	7th Plan, RTF
	Controls, Commissioning, and Sizing	7th Plan, RTF
	Ductless Heat Pump	7th Plan, RTF
	Ducted Ductless Heat Pump	7th Plan
	Duct Sealing	7th Plan, RTF
	Ground Source Heat Pump	7th Plan, RTF
	Heat Recovery Ventilation	7th Plan
	Attic Insulation	7th Plan, RTF
	Floor Insulation	7th Plan, RTF
	Wall Insulation	7th Plan, RTF
	Windows	7th Plan, RTF
	Wi-Fi Enabled Thermostats	7th Plan
Lighting	Linear Fluorescent Lighting	7th Plan, RTF
	LED General Purpose and Dimmable	7th Plan, RTF
	LED Decorative and Mini-Base	7th Plan, RTF
	LED Globe	7th Plan, RTF
	LED Reflectors and Outdoor	7th Plan, RTF
	LED Three-Way	7th Plan, RTF
Refrigeration	Freezer	7th Plan
	Refrigerator	7th Plan
Water Heating	Aerator	7th Plan
	Behavior Savings	7th Plan
	Clothes Washer	7th Plan
	Dishwasher	7th Plan
	Heat Pump Water Heater	7th Plan, RTF
	Showerheads	7th Plan, RTF
	Solar Water Heater	7th Plan
	Thermostatic Valve	RTF
	Wastewater Heat Recovery	7th Plan
Whole Building	EV Charging Equipment	7th Plan

Table VI-2 Commercial End Uses and Measures		
End Use	**Measures/Categories**	**Data Source**
Compressed Air	Controls, Equipment, & Demand Reduction	7th Plan
Electronics	Energy Star Computers	7th Plan
	Energy Star Monitors	7th Plan
	Smart Plug Power Strips	7th Plan, RTF
	Data Center Measures	7th Plan
Food Preparation	Combination Ovens	7th Plan, RTF
	Convection Ovens	7th Plan, RTF
	Fryers	7th Plan, RTF
	Hot Food Holding Cabinet	7th Plan, RTF
	Steamer	7th Plan, RTF
	Pre-Rinse Spray Valve	7th Plan, RTF
HVAC	Advanced Rooftop Controller	7th Plan
	Commercial Energy Management	7th Plan
	Demand Control Ventilation	7th Plan
	Ductless Heat Pumps	7th Plan
	Economizers	7th Plan
	Secondary Glazing Systems	7th Plan
	Variable Refrigerant Flow	7th Plan
	Web-Enabled Programmable Thermostat	7th Plan
Lighting	Bi-Level Stairwell Lighting	7th Plan
	Exterior Building Lighting	7th Plan
	Exit Signs	7th Plan
	Lighting Controls	7th Plan
	Linear Fluorescent Lamps	7th Plan
	LED Lighting	7th Plan
	Street Lighting	7th Plan
Motors/Drives	ECM for Variable Air Volume	7th Plan
	Motor Rewinds	7th Plan
Process Loads	Municipal Water Supply	7th Plan
Refrigeration	Grocery Refrigeration Bundle	7th Plan, RTF
	Water Cooler Controls	7th Plan
Water Heating	Commercial Clothes Washer	7th Plan, RTF
	Showerheads	7th Plan
	Tank Water Heaters	7th Plan

Table VI-3
Industrial End Uses and Measures

End Use	Measures/Categories	Data Source
Compressed Air	Air Compressor Equipment	7th Plan
	Demand Reduction	7th Plan
Energy Management	Air Compressor Optimization	7th Plan
	Energy Project Management	7th Plan
	Fan Energy Management	7th Plan
	Fan System Optimization	7th Plan
	Cold Storage Tune-up	7th Plan
	Chiller Optimization	7th Plan
	Integrated Plant Energy Management	7th Plan
	Plant Energy Management	7th Plan
	Pump Energy Management	7th Plan
	Pump System Optimization	7th Plan
Fans	Efficient Centrifugal Fan	7th Plan
	Fan Equipment Upgrade	7th Plan
Hi-Tech	Clean Room Filter Strategy	7th Plan
	Clean Room HVAC	7th Plan
	Chip Fab: Eliminate Exhaust	7th Plan
	Chip Fab: Exhaust Injector	7th Plan
	Chip Fab: Reduce Gas Pressure	7th Plan
	Chip Fab: Solid State Chiller	7th Plan
Lighting	Efficient Lighting	7th Plan
	High-Bay Lighting	7th Plan
	Lighting Controls	7th Plan
Low & Medium Temp Refrigeration	Food: Cooling and Storage	7th Plan
	Cold Storage Retrofit	7th Plan
	Grocery Distribution Retrofit	7th Plan
Material Handling	Material Handling Equipment	7th Plan
	Material Handling VFD	7th Plan
Metals	New Arc Furnace	7th Plan
Misc.	Synchronous Belts	7th Plan
	Food Storage: CO2 Scrubber	7th Plan
	Food Storage: Membrane	7th Plan
Motors	Motor Rewinds	7th Plan
Paper	Efficient Pulp Screen	7th Plan
	Material Handling	7th Plan
	Premium Control	7th Plan
	Premium Fan	7th Plan
Process Loads	Municipal Sewage Treatment	7th Plan
Pulp	Efficient Agitator	7th Plan
	Effluent Treatment System	7th Plan
	Premium Process	7th Plan
	Refiner Plate Improvement	7th Plan
	Refiner Replacement	7th Plan
Pumps	Equipment Upgrade	7th Plan
Transformers	New/Retrofit Transformer	7th Plan
Wood	Hydraulic Press	7th Plan
	Pneumatic Conveyor	7th Plan

Table VI-4 Distribution Efficiency End Uses and Measures		
End Use	**Measures/Categories**	**Data Source**
Distribution Efficiency	LDC Voltage Control	7th Plan
	Light System Improvements	7th Plan
	Major System Improvements	7th Plan
	EOL Voltage Control Method	7th Plan
	SCL Implement EOL w/ Improvements	7th Plan

Appendix VII – Annual Energy Efficiency Economic Potential by End-Use

Residential aMW

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Dryer	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Electronics	0.02	0.03	0.04	0.06	0.08	0.09	0.11	0.12	0.12	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Food Preparation	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HVAC	0.52	0.71	0.89	1.03	1.11	1.11	1.04	0.92	0.77	0.62	0.49	0.37	0.29	0.22	0.18	0.15	0.11	0.10	0.00	0.00
Lighting	0.37	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Refrigeration	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Water Heating	0.58	0.71	0.80	0.85	0.86	0.83	0.76	0.67	0.60	0.54	0.51	0.50	0.49	0.49	0.49	0.49	0.37	0.32	0.10	0.08
Whole Bldg/Meter L	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**1.49**	**1.46**	**1.74**	**1.96**	**2.06**	**2.04**	**1.92**	**1.73**	**1.50**	**1.21**	**1.02**	**0.88**	**0.78**	**0.72**	**0.68**	**0.65**	**0.49**	**0.43**	**0.11**	**0.09**

Commercial aMW

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Compressed Air	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00	-	-	-
Electronics	0.01	0.02	0.03	0.04	0.06	0.08	0.10	0.13	0.15	0.18	0.21	0.04	-	-	-	-	-	-	-	-
Food Preparation	0.02	0.02	0.03	0.04	0.04	0.05	0.06	0.07	0.07	0.08	0.08	0.09	0.09	0.09	0.09	0.07	-	-	-	-
HVAC	0.43	0.51	0.57	0.61	0.61	0.58	0.52	0.44	0.35	0.27	0.20	0.15	0.11	0.08	0.07	0.06	0.05	0.04	0.04	0.04
Lighting	1.42	1.25	1.14	1.02	0.83	0.59	0.43	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.34	0.33	0.25	0.10	0.10
Motors/Drives	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Process Loads	0.05	0.06	0.06	0.07	0.06	0.05	0.04	0.03	0.02	0.01	0.00	0.00	0.00	0.00	0.00	0.00	-	-	-	-
Refrigeration	0.06	0.09	0.11	0.12	0.13	0.13	0.12	0.10	0.08	0.07	0.05	0.03	0.02	0.01	0.01	0.01	-	-	-	-
Water Heating	0.04	0.04	0.04	0.03	0.04	0.04	0.04	0.03	0.03	0.03	0.03	0.03	0.02	0.01	0.01	0.00	-	-	-	-
Total	**2.06**	**2.02**	**2.01**	**1.96**	**1.80**	**1.56**	**1.35**	**1.19**	**1.11**	**1.03**	**0.98**	**0.74**	**0.64**	**0.60**	**0.58**	**0.52**	**0.40**	**0.32**	**0.17**	**0.17**

Industrial	aMW																			
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Compressed Air	0.02	0.02	0.02	0.02	0.02	0.02	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	-	-	-	-
Energy Managemen	0.36	0.38	0.38	0.38	0.35	0.30	0.25	0.19	0.13	0.09	0.07	0.06	0.05	0.05	0.05	0.04	-	-	-	-
Fans	0.05	0.06	0.07	0.07	0.06	0.05	0.04	0.03	0.02	0.01	0.00	0.00	0.00	0.00	0.00	0.00	-	-	-	-
Hi-Tech	0.10	0.11	0.12	0.12	0.11	0.09	0.07	0.05	0.03	0.02	0.01	0.00	0.00	0.00	0.00	0.00	-	-	-	-
Lighting	0.15	0.13	0.11	0.09	0.08	0.06	0.05	0.04	0.03	0.03	0.02	0.02	0.01	0.01	0.01	0.01	-	-	-	-
Low & Med Temp Re	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	-	-	-	-
Material Handling	0.02	0.02	0.02	0.02	0.02	0.02	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	-	-	-	-
Metals	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	-	-	-	-
Misc	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Motors	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Paper	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	-	-	-	-
Process Loads	0.14	0.17	0.19	0.20	0.19	0.16	0.13	0.09	0.05	0.03	0.01	0.00	0.00	0.00	0.00	0.00	-	-	-	-
Pulp	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Pumps	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Transformers	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Wood	0.02	0.02	0.03	0.03	0.03	0.02	0.02	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	-	-	-	-
Total	**0.86**	**0.91**	**0.94**	**0.92**	**0.85**	**0.74**	**0.59**	**0.43**	**0.29**	**0.19**	**0.12**	**0.09**	**0.07**	**0.06**	**0.06**	**0.05**	**-**	**-**	**-**	**-**

Distribution Efficienc	aMW																			
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
1 - LDC voltage control n	0.02	0.03	0.05	0.06	0.07	0.09	0.10	0.10	0.11	0.12	0.13	0.13	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
2 - Light system improve	0.01	0.02	0.03	0.04	0.04	0.05	0.06	0.06	0.07	0.07	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.09	0.09
3 - Major system improv	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4 - EOL voltage control n	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
A - SCL implement EOL w	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**0.03**	**0.05**	**0.07**	**0.10**	**0.12**	**0.14**	**0.15**	**0.17**	**0.18**	**0.19**	**0.20**	**0.21**	**0.22**	**0.22**	**0.22**	**0.22**	**0.22**	**0.23**	**0.23**	**0.23**

Appendix VIII – Measure Detail

Column Heading Definitions

- Sector – Customer sector: Residential, Commercial, Industrial, or Distribution Efficiency
- End-Use – Highest level measure category
- Measure Name – Measure name as defined by the Seventh Power Plan
- Measure Life – Assumed life of the measure, in years
- Initial Capital Cost – The incremental capital cost of the measure. It is the initial cost associated with the savings value
- TRC Levelized Cost ($/MWh) – Total Resource Cost (TRC) levelized costs include the same components as the TRC benefit-cost ratio. All costs minus all benefits regardless of which sponsor incurs the cost or accrues the benefit. Benefits are subtracted from costs and then levelized over the life of the program.
- Total Sponsor Levelized Cost ($/MWh) – This levelized cost includes the capital, maintenance, and administrative costs of the measure. It does not include any adjustment for benefits. Costs are levelized over the life of the program.
- TRC B/C Ratio – The benefit-cost ratio based on the Total Resource Cost test. It includes the present value of all benefits divided by the present value of all costs.
- Bulk Energy (kWh/unit) – Energy savings of the measure at the bulk system level (busbar), including line losses.
- Wholesale demand (kW) – Measure demand savings coincident with the wholesale power system annual peak

Sector	End Use	Measure Name	Measure Life (Years)	Initial Capital Cost	TRC Levelized Cost ($/MWh)	Total Sponsor Levelized Cost ($/MWh)	TRC B/C Ratio	Bulk Energy (kWh/unit)	Wholesale Demand (kW)
Commercial	HVAC	Advanced Rooftop Controller-Retro-Assembly	15	$0.18	$0.12	$27.03	2.25	0.75	0.0001
Commercial	HVAC	Advanced Rooftop Controller-Retro-Hospital	15	$0.06	$37.32	$57.70	0.93	0.12	0.0000
Commercial	HVAC	Advanced Rooftop Controller-Retro-Large Off	15	$0.09	$59.90	$80.17	0.68	0.12	0.0000
Commercial	HVAC	Advanced Rooftop Controller-Retro-Large Ret	15	$0.18	-$0.53	$16.95	3.04	1.22	0.0001
Commercial	HVAC	Advanced Rooftop Controller-Retro-Lodging	15	$0.06	$30.73	$57.64	1.06	0.12	0.0000
Commercial	HVAC	Advanced Rooftop Controller-Retro-Medium Off	15	$0.32	$66.54	$86.81	0.62	0.41	0.0000
Commercial	HVAC	Advanced Rooftop Controller-Retro-Medium Ret	15	$0.12	$13.72	$31.20	1.65	0.42	0.0000
Commercial	HVAC	Advanced Rooftop Controller-Retro-MiniMart	15	$0.29	$14.83	$33.75	1.55	0.97	0.0001
Commercial	HVAC	Advanced Rooftop Controller-Retro-Other	15	$0.07	$23.19	$50.10	1.22	0.15	0.0000
Commercial	HVAC	Advanced Rooftop Controller-Retro-Residential Care	15	$0.22	$11.96	$32.34	1.65	0.75	0.0001
Commercial	HVAC	Advanced Rooftop Controller-Retro-Restaurant	15	$0.73	$17.59	$38.74	1.41	2.12	0.0003
Commercial	HVAC	Advanced Rooftop Controller-Retro-School K-12	15	$0.09	$75.83	$94.41	0.57	0.11	0.0000
Commercial	HVAC	Advanced Rooftop Controller-Retro-Small Off	15	$0.20	$59.77	$80.04	0.68	0.28	0.0000
Commercial	HVAC	Advanced Rooftop Controller-Retro-Small Ret	15	$0.02	$66.93	$84.41	0.61	0.03	0.0000
Commercial	HVAC	Advanced Rooftop Controller-Retro-Supermarket	15	$0.29	$14.83	$33.75	1.55	0.97	0.0001
Commercial	HVAC	Advanced Rooftop Controller-Retro-University	15	$0.09	$67.58	$94.49	0.64	0.11	0.0000
Commercial	HVAC	Advanced Rooftop Controller-Retro-Warehouse	15	$0.04	$60.27	$86.19	0.69	0.05	0.0000
Commercial	HVAC	Advanced Rooftop Controller-Retro-Xlarge Ret	15	$0.18	$3.05	$20.53	2.51	0.99	0.0001
Commercial	Lighting	NR_LFStairwell3600_Fix_Repl_from LF_2019 to LF_Bi-Level_Fix	16	$2,033.45	$141.82	$167.67	0.36	1,396.60	0.2494
Commercial	Lighting	NR_LFStairwell8760_Fix_Repl_from LF_2018 to LF_Bi-Level_Fix	16	$2,033.45	$54.25	$80.10	0.75	3,398.40	0.6068
Commercial	Water Heating	Washer	11.3	$399.62	-$106.90	-$78.86	3.04	799.17	0.1377
Commercial	HVAC	Commercial EM-Retro-Assembly	5	$42.30	$23.34	$67.61	1.16	168.74	0.0320
Commercial	HVAC	Commercial EM-Retro-Hospital	5	$237.97	$7.10	$41.35	1.63	1,552.08	0.1882
Commercial	HVAC	Commercial EM-Retro-Large Off	5	$158.12	$31.32	$58.37	1.05	730.71	0.0867
Commercial	HVAC	Commercial EM-Retro-Large Ret	5	$143.75	$132.36	$167.46	0.41	231.55	0.0210
Commercial	HVAC	Commercial EM-Retro-Lodging	5	$19.91	$17.26	$46.19	1.36	116.29	0.0221
Commercial	HVAC	Commercial EM-Retro-Medium Off	5	$23.58	$44.80	$73.58	0.85	86.44	0.0103
Commercial	HVAC	Commercial EM-Retro-Medium Ret	5	$15.38	$86.69	$114.62	0.54	36.19	0.0033
Commercial	HVAC	Commercial EM-Retro-MiniMart	0	$0.00	$9,999.00	$9,999.00	9,999.00	-	-
Commercial	HVAC	Commercial EM-Retro-Other	5	$50.32	$15.81	$60.45	1.30	224.55	0.0426
Commercial	HVAC	Commercial EM-Retro-Residential Care	5	$21.26	$12.47	$36.64	1.56	156.49	0.0190
Commercial	HVAC	Commercial EM-Retro-Restaurant	5	$13.12	$41.36	$73.15	0.89	48.38	0.0063
Commercial	HVAC	Commercial EM-Retro-School K-12	5	$82.30	$74.46	$113.83	0.65	195.02	0.0191
Commercial	HVAC	Commercial EM-Retro-Small Off	5	$16.18	$158.70	$186.03	0.33	23.45	0.0028
Commercial	HVAC	Commercial EM-Retro-Small Ret	5	$25.46	$21.78	$46.96	1.26	146.26	0.0133
Commercial	HVAC	Commercial EM-Retro-Supermarket	5	$23.91	$23.45	$57.96	1.17	111.25	0.0118
Commercial	HVAC	Commercial EM-Retro-University	5	$216.82	$30.03	$67.90	1.06	861.32	0.1634
Commercial	HVAC	Commercial EM-Retro-Warehouse	5	$14.59	$64.93	$121.01	0.74	32.53	0.0056
Commercial	HVAC	Commercial EM-Retro-Xlarge Ret	5	$9.83	$45.61	$80.17	0.86	33.07	0.0030
Commercial	Compressed Air	Compressed Air-NR-Assembly	10	$11,453.52	-$1.32	$20.25	2.76	85,548.39	11.3582
Commercial	Compressed Air	Compressed Air-NR-Hospital	10	$692.85	-$1.32	$20.25	2.76	5,175.03	0.6871
Commercial	Compressed Air	Compressed Air-NR-Large Off	10	$147,934.05	-$1.42	$20.25	2.75	1,104,792.94	147.9816
Commercial	Compressed Air	Compressed Air-NR-Large Ret	0	$0.00	$9,999.00	$9,999.00	9,999.00	-	-
Commercial	Compressed Air	Compressed Air-NR-Lodging	10	$3,784.48	-$1.32	$20.25	2.76	28,266.98	3.7530
Commercial	Compressed Air	Compressed Air-NR-Medium Off	0	$0.00	$9,999.00	$9,999.00	9,999.00	-	-
Commercial	Compressed Air	Compressed Air-NR-Medium Ret	0	$0.00	$9,999.00	$9,999.00	9,999.00	-	-
Commercial	Compressed Air	Compressed Air-NR-MiniMart	0	$0.00	$9,999.00	$9,999.00	9,999.00	-	-
Commercial	Compressed Air	Compressed Air-NR-Other	10	$62,074.28	-$1.32	$20.25	2.76	463,643.76	61.5579
Commercial	Compressed Air	Compressed Air-NR-Residential Care	10	$692.85	-$1.32	$20.25	2.76	5,175.03	0.6871
Commercial	Compressed Air	Compressed Air-NR-Restaurant	10	$1,489.05	-$1.32	$20.25	2.76	11,121.97	1.4767
Commercial	Compressed Air	Compressed Air-NR-School K-12	10	$2,352.20	-$1.32	$20.25	2.76	17,569.02	2.3326
Commercial	Compressed Air	Compressed Air-NR-Small Off	0	$0.00	$9,999.00	$9,999.00	9,999.00	-	-
Commercial	Compressed Air	Compressed Air-NR-Small Ret	0	$0.00	$9,999.00	$9,999.00	9,999.00	-	-
Commercial	Compressed Air	Compressed Air-NR-Supermarket	10	$10,295.74	-$1.32	$20.25	2.76	76,900.69	10.2101
Commercial	Compressed Air	Compressed Air-NR-University	10	$2,352.20	-$1.32	$20.25	2.76	17,569.02	2.3326
Commercial	Compressed Air	Compressed Air-NR-Warehouse	10	$328,333.16	-$1.97	$20.25	2.79	2,452,245.33	342.4996
Commercial	Compressed Air	Compressed Air-NR-Xlarge Ret	10	$315,553.24	-$4.16	$20.24	2.91	2,357,517.77	383.6622
Commercial	Compressed Air	Compressed Air-Retro-Assembly	10	$53,876.73	-$8.80	$12.77	4.37	1,329,888.67	176.5690
Commercial	Compressed Air	Compressed Air-Retro-Hospital	10	$3,259.14	-$8.80	$12.77	4.37	80,448.23	10.6811
Commercial	Compressed Air	Compressed Air-Retro-Large Off	10	$695,873.41	-$8.90	$12.78	4.37	17,174,508.47	2,300.4415
Commercial	Compressed Air	Compressed Air-Retro-Large Ret	0	$0.00	$9,999.00	$9,999.00	9,999.00	-	-
Commercial	Compressed Air	Compressed Air-Retro-Lodging	10	$17,802.00	-$8.80	$12.77	4.37	439,423.10	58.3421
Commercial	Compressed Air	Compressed Air-Retro-Medium Off	0	$0.00	$9,999.00	$9,999.00	9,999.00	-	-
Commercial	Compressed Air	Compressed Air-Retro-Medium Ret	0	$0.00	$9,999.00	$9,999.00	9,999.00	-	-
Commercial	Compressed Air	Compressed Air-Retro-MiniMart	0	$0.00	$9,999.00	$9,999.00	9,999.00	-	-
Commercial	Compressed Air	Compressed Air-Retro-Other	10	$291,993.91	-$8.80	$12.77	4.37	7,207,552.97	956.9452
Commercial	Compressed Air	Compressed Air-Retro-Residential Care	10	$3,259.14	-$8.80	$12.77	4.37	80,448.23	10.6811
Commercial	Compressed Air	Compressed Air-Retro-Restaurant	10	$7,004.40	-$8.80	$12.77	4.37	172,896.09	22.9554
Commercial	Compressed Air	Compressed Air-Retro-School K-12	10	$11,064.63	-$8.80	$12.77	4.37	273,118.36	36.2619
Commercial	Compressed Air	Compressed Air-Retro-Small Off	0	$0.00	$9,999.00	$9,999.00	9,999.00	-	-
Commercial	Compressed Air	Compressed Air-Retro-Small Ret	0	$0.00	$9,999.00	$9,999.00	9,999.00	-	-
Commercial	Compressed Air	Compressed Air-Retro-Supermarket	10	$48,430.57	-$8.80	$12.77	4.37	1,195,456.19	158.7204
Commercial	Compressed Air	Compressed Air-Retro-University	10	$11,064.63	-$8.80	$12.77	4.37	273,118.36	36.2619

Sector	End Use	Measure Name	Measure Life (Years)	Initial Capital Cost	TRC Levelized Cost ($/MWh)	Total Sponsor Levelized Cost ($/MWh)	TRC B/C Ratio	Bulk Energy (kWh/unit)	Wholesale Demand (kW)
Commercial	Compressed Air	Compressed Air-Retro-Warehouse	10	$1,544,460.61	-$9.45	$12.78	4.42	38,121,268.37	5,324.3121
Commercial	Compressed Air	Compressed Air-Retro-Xlarge Ret	10	$1,484,344.62	-$11.63	$12.77	4.62	36,648,685.35	5,964.2027
Commercial	Food Preparation	Combi Oven (Wt Average)	10	$774.33	-$86.33	$24.15	5.99	5,624.30	0.9663
Commercial	Food Preparation	Convection Oven (Wt Average)	10	$482.64	$66.43	$91.69	0.65	865.13	0.1489
Commercial	Food Preparation	Fryers	8	$1,682.07	$205.64	$230.89	0.26	1,779.49	0.3063
Commercial	Food Preparation	HFHC (Wt Average Size)	20	$551.59	-$0.39	$24.87	2.39	2,612.50	0.4497
Commercial	Food Preparation	Steamer (Wt Average Size)	9	-$256.45	-$117.59	-$2.41	9,999.00	18,499.80	3.1816
Commercial	Electronics	Best Practice	5	$30.96	$9,999.00	$9,999.00	-	-	-
Commercial	Electronics	Commercial Technology	7.880681	$43.37	$13.92	$34.75	1.55	218.44	0.0274
Commercial	Electronics	Cutting Edge	6.228585	$6.27	$7.67	$28.50	1.89	51.63	0.0065
Commercial	HVAC	DCV Parking Garage-Retro	15	$0.39	$24.54	$51.45	1.18	0.98	0.0002
Commercial	HVAC	DCV Parking Garage-Retro	15	$0.39	$24.54	$51.45	1.18	0.98	0.0002
Commercial	HVAC	DCV Parking Garage-Retro	15	$0.39	$24.54	$51.45	1.18	0.98	0.0002
Commercial	HVAC	DCV Parking Garage-Retro	15	$0.39	$24.54	$51.45	1.18	0.98	0.0002
Commercial	HVAC	DCV Parking Garage-Retro	15	$0.39	$24.54	$51.45	1.18	0.98	0.0002
Commercial	HVAC	DCV Parking Garage-Retro	15	$0.39	$24.54	$51.45	1.18	0.98	0.0002
Commercial	HVAC	DCV Parking Garage-Retro	15	$0.39	$24.54	$51.45	1.18	0.98	0.0002
Commercial	HVAC	DCV Parking Garage-Retro	15	$0.39	$24.54	$51.45	1.18	0.98	0.0002
Commercial	HVAC	DCV Parking Garage-Retro	15	$0.39	$24.54	$51.45	1.18	0.98	0.0002
Commercial	HVAC	DCV Parking Garage-Retro	15	$0.39	$24.54	$51.45	1.18	0.98	0.0002
Commercial	HVAC	DCV Parking Garage-Retro	15	$0.39	$24.54	$51.45	1.18	0.98	0.0002
Commercial	HVAC	DCV Parking Garage-Retro	15	$0.39	$24.54	$51.45	1.18	0.98	0.0002
Commercial	HVAC	DCV Parking Garage-Retro	15	$0.39	$24.54	$51.45	1.18	0.98	0.0002
Commercial	HVAC	DCV Parking Garage-Retro	15	$0.39	$24.54	$51.45	1.18	0.98	0.0002
Commercial	HVAC	DCV Parking Garage-Retro	15	$0.39	$24.54	$51.45	1.18	0.98	0.0002
Commercial	HVAC	DCV Parking Garage-Retro	15	$0.39	$24.54	$51.45	1.18	0.98	0.0002
Commercial	HVAC	DCV Parking Garage-Retro	15	$0.39	$24.54	$51.45	1.18	0.98	0.0002
Commercial	HVAC	DCV Parking Garage-Retro	15	$0.39	$24.54	$51.45	1.18	0.98	0.0002
Commercial	HVAC	DCV Hood 5 hp	18	$8,305.14	$61.08	$83.75	0.67	9,863.55	1.4412
Commercial	HVAC	DCV Hood w/ MUA 5 hp	18	$8,305.14	$23.85	$46.53	1.21	17,754.39	2.5941
Commercial	HVAC	Demand Control Ventilation-Retro-Assembly	15	$218.76	$338.11	$365.45	0.17	67.20	0.0127
Commercial	HVAC	Demand Control Ventilation-Retro-Hospital	15	$113.97	$1,399.10	$1,422.67	0.04	8.99	0.0011
Commercial	HVAC	Demand Control Ventilation-Retro-Large Off	15	$114.12	$68.64	$89.10	0.61	143.78	0.0171
Commercial	HVAC	Demand Control Ventilation-Retro-Large Ret	15	$368.92	$64.25	$81.90	0.63	505.71	0.0459
Commercial	HVAC	Demand Control Ventilation-Retro-Lodging	15	$113.29	$36.75	$63.81	0.96	199.32	0.0378
Commercial	HVAC	Demand Control Ventilation-Retro-Medium Off	15	$117.16	$105.78	$126.32	0.43	104.12	0.0124
Commercial	HVAC	Demand Control Ventilation-Retro-Medium Ret	15	$270.66	$54.73	$72.31	0.71	420.18	0.0381
Commercial	HVAC	Demand Control Ventilation-Retro-MiniMart	15	$250.75	$11.26	$30.21	1.74	931.67	0.0987
Commercial	HVAC	Demand Control Ventilation-Retro-Other	15	$105.23	$142.85	$170.19	0.36	69.41	0.0132
Commercial	HVAC	Demand Control Ventilation-Retro-Residential Care	15	$101.05	$65.52	$86.11	0.62	131.73	0.0160
Commercial	HVAC	Demand Control Ventilation-Retro-Restaurant	15	$298.98	$53.92	$75.26	0.73	445.97	0.0577
Commercial	HVAC	Demand Control Ventilation-Retro-School K-12	0	$0.00	$9,999.00	$9,999.00	9,999.00	-	-
Commercial	HVAC	Demand Control Ventilation-Retro-Small Off	15	$109.31	$105.74	$126.32	0.43	97.15	0.0115
Commercial	HVAC	Demand Control Ventilation-Retro-Small Ret	15	$160.46	$54.65	$72.31	0.71	249.10	0.0226
Commercial	HVAC	Demand Control Ventilation-Retro-Supermarket	15	$495.45	$57.24	$76.20	0.69	729.89	0.0774
Commercial	HVAC	Demand Control Ventilation-Retro-University	0	$0.00	$9,999.00	$9,999.00	9,999.00	-	-
Commercial	HVAC	Demand Control Ventilation-Retro-Warehouse	15	$21.79	$563.69	$596.47	0.11	4.10	0.0007
Commercial	HVAC	Demand Control Ventilation-Retro-Xlarge Ret	15	$530.18	$63.18	$80.78	0.64	736.84	0.0669
Commercial	Electronics	ENERGY STAR Desktop	5	$0.00	-$22.77	$0.00	9,999.00	130.74	0.0190
Commercial	HVAC	DHP-NEW-Assembly	20	$3.82	$47.69	$83.98	0.83	4.24	0.0012
Commercial	HVAC	DHP-NEW-Hospital	20	$3.82	$60.72	$84.14	0.66	4.23	0.0006
Commercial	HVAC	DHP-NEW-Large Off	20	$3.82	$49.34	$84.05	0.81	4.24	0.0011
Commercial	HVAC	DHP-NEW-Large Ret	20	$3.82	$30.12	$83.83	1.05	4.25	0.0020
Commercial	HVAC	DHP-NEW-Lodging	20	$3.82	$49.07	$83.99	0.81	4.24	0.0011
Commercial	HVAC	DHP-NEW-Medium Off	20	$3.82	$49.34	$84.05	0.81	4.24	0.0011
Commercial	HVAC	DHP-NEW-Medium Ret	20	$3.82	$30.12	$83.83	1.05	4.25	0.0020
Commercial	HVAC	DHP-NEW-MiniMart	20	$3.82	$45.19	$83.92	0.86	4.24	0.0013
Commercial	HVAC	DHP-NEW-Other	20	$3.82	$47.69	$83.98	0.83	4.24	0.0012
Commercial	HVAC	DHP-NEW-Residential Care	20	$3.82	$60.72	$84.14	0.66	4.23	0.0006
Commercial	HVAC	DHP-NEW-Restaurant	20	$3.82	$13.38	$83.82	1.25	4.25	0.0027
Commercial	HVAC	DHP-NEW-School K-12	20	$3.82	$35.76	$83.78	0.98	4.25	0.0017
Commercial	HVAC	DHP-NEW-Small Off	20	$3.82	$16.91	$83.78	1.21	4.25	0.0025
Commercial	HVAC	DHP-NEW-Small Ret	20	$3.82	$30.12	$83.83	1.05	4.25	0.0020
Commercial	HVAC	DHP-NEW-Supermarket	20	$3.82	$45.19	$83.92	0.86	4.24	0.0013
Commercial	HVAC	DHP-NEW-University	20	$3.82	$55.54	$84.03	0.74	4.24	0.0009
Commercial	HVAC	DHP-NEW-Warehouse	20	$3.82	$58.03	$84.09	0.72	4.23	0.0008
Commercial	HVAC	DHP-NEW-Xlarge Ret	20	$3.82	$30.12	$83.83	1.05	4.25	0.0020
Commercial	HVAC	DHP-Retro-Assembly	20	$3.82	$47.69	$83.98	0.83	4.24	0.0012
Commercial	HVAC	DHP-Retro-Hospital	20	$3.82	$60.72	$84.14	0.66	4.23	0.0006
Commercial	HVAC	DHP-Retro-Large Off	20	$3.82	$49.34	$84.05	0.81	4.24	0.0011
Commercial	HVAC	DHP-Retro-Large Ret	20	$3.82	$30.12	$83.83	1.05	4.25	0.0020
Commercial	HVAC	DHP-Retro-Lodging	20	$3.82	$49.07	$83.99	0.81	4.24	0.0011
Commercial	HVAC	DHP-Retro-Medium Off	20	$3.82	$49.34	$84.05	0.81	4.24	0.0011

Sector	End Use	Measure Name	Measure Life (Years)	Initial Capital Cost	TRC Levelized Cost ($/MWh)	Total Sponsor Levelized Cost ($/MWh)	TRC B/C Ratio	Bulk Energy (kWh/unit)	Wholesale Demand (kW)
Commercial	HVAC	DHP-Retro-Medium Ret	20	$3.82	$30.12	$83.83	1.05	4.25	0.0020
Commercial	HVAC	DHP-Retro-MiniMart	20	$3.82	$45.19	$83.92	0.86	4.24	0.0013
Commercial	HVAC	DHP-Retro-Other	20	$3.82	$47.69	$83.98	0.83	4.24	0.0012
Commercial	HVAC	DHP-Retro-Residential Care	20	$3.82	$60.72	$84.14	0.66	4.23	0.0006
Commercial	HVAC	DHP-Retro-Restaurant	20	$3.82	$13.38	$83.82	1.25	4.25	0.0027
Commercial	HVAC	DHP-Retro-School K-12	20	$3.82	$35.76	$83.78	0.98	4.25	0.0017
Commercial	HVAC	DHP-Retro-Small Off	20	$3.82	$16.91	$83.78	1.21	4.25	0.0025
Commercial	HVAC	DHP-Retro-Small Ret	20	$3.82	$30.12	$83.83	1.05	4.25	0.0020
Commercial	HVAC	DHP-Retro-Supermarket	20	$3.82	$45.19	$83.92	0.86	4.24	0.0013
Commercial	HVAC	DHP-Retro-University	20	$3.82	$55.54	$84.03	0.74	4.24	0.0009
Commercial	HVAC	DHP-Retro-Warehouse	20	$3.82	$58.03	$84.09	0.72	4.23	0.0008
Commercial	HVAC	DHP-Retro-Xlarge Ret	20	$3.82	$30.12	$83.83	1.05	4.25	0.0020
Commercial	Motors/Drives	ECM-VAV-New-Assembly	18	$0.04	$7.33	$29.11	1.78	0.13	0.0000
Commercial	Motors/Drives	ECM-VAV-New-Hospital	18	$0.08	$12.82	$27.74	1.61	0.29	0.0000
Commercial	Motors/Drives	ECM-VAV-New-Large Off	18	$0.12	$17.35	$34.16	1.44	0.35	0.0000
Commercial	Motors/Drives	ECM-VAV-New-Large Ret	0	$0.00	$9,999.00	$9,999.00	9,999.00	-	-
Commercial	Motors/Drives	ECM-VAV-New-Lodging	18	$0.01	$14.88	$40.15	1.46	0.02	0.0000
Commercial	Motors/Drives	ECM-VAV-New-Medium Off	18	$0.01	$17.65	$34.60	1.43	0.03	0.0000
Commercial	Motors/Drives	ECM-VAV-New-Medium Ret	0	$0.00	$9,999.00	$9,999.00	9,999.00	-	-
Commercial	Motors/Drives	ECM-VAV-New-MiniMart	0	$0.00	$9,999.00	$9,999.00	9,999.00	-	-
Commercial	Motors/Drives	ECM-VAV-New-Other	18	$0.04	$8.45	$30.75	1.72	0.14	0.0000
Commercial	Motors/Drives	ECM-VAV-New-Residential Care	18	$0.01	$19.14	$36.93	1.35	0.02	0.0000
Commercial	Motors/Drives	ECM-VAV-New-Restaurant	0	$0.00	$9,999.00	$9,999.00	9,999.00	-	-
Commercial	Motors/Drives	ECM-VAV-New-School K-12	18	$0.03	$15.94	$29.28	1.55	0.10	0.0000
Commercial	Motors/Drives	ECM-VAV-New-Small Off	0	$0.00	$9,999.00	$9,999.00	9,999.00	-	-
Commercial	Motors/Drives	ECM-VAV-New-Small Ret	0	$0.00	$9,999.00	$9,999.00	9,999.00	-	-
Commercial	Motors/Drives	ECM-VAV-New-Supermarket	0	$0.00	$9,999.00	$9,999.00	9,999.00	-	-
Commercial	Motors/Drives	ECM-VAV-New-University	18	$0.09	$7.51	$29.52	1.77	0.29	0.0001
Commercial	Motors/Drives	ECM-VAV-New-Warehouse	0	$0.00	$9,999.00	$9,999.00	9,999.00	-	-
Commercial	Motors/Drives	ECM-VAV-New-Xlarge Ret	18	$0.01	$16.48	$28.41	1.52	0.02	0.0000
Commercial	Motors/Drives	ECM-VAV-NR-Assembly	18	$0.04	$3.93	$26.56	1.98	0.14	0.0000
Commercial	Motors/Drives	ECM-VAV-NR-Hospital	18	$0.08	$3.22	$25.45	2.02	0.31	0.0001
Commercial	Motors/Drives	ECM-VAV-NR-Large Off	18	$0.12	$6.41	$30.46	1.83	0.39	0.0001
Commercial	Motors/Drives	ECM-VAV-NR-Large Ret	0	$0.00	$9,999.00	$9,999.00	9,999.00	-	-
Commercial	Motors/Drives	ECM-VAV-NR-Lodging	18	$0.01	$9.23	$34.87	1.69	0.02	0.0000
Commercial	Motors/Drives	ECM-VAV-NR-Medium Off	18	$0.01	$6.62	$30.79	1.82	0.03	0.0000
Commercial	Motors/Drives	ECM-VAV-NR-Medium Ret	0	$0.00	$9,999.00	$9,999.00	9,999.00	-	-
Commercial	Motors/Drives	ECM-VAV-NR-MiniMart	0	$0.00	$9,999.00	$9,999.00	9,999.00	-	-
Commercial	Motors/Drives	ECM-VAV-NR-Other	18	$0.04	$4.75	$27.85	1.92	0.15	0.0000
Commercial	Motors/Drives	ECM-VAV-NR-Residential Care	18	$0.01	$7.71	$32.50	1.76	0.02	0.0000
Commercial	Motors/Drives	ECM-VAV-NR-Restaurant	0	$0.00	$9,999.00	$9,999.00	9,999.00	-	-
Commercial	Motors/Drives	ECM-VAV-NR-School K-12	18	$0.03	$4.03	$26.72	1.97	0.11	0.0000
Commercial	Motors/Drives	ECM-VAV-NR-Small Off	0	$0.00	$9,999.00	$9,999.00	9,999.00	-	-
Commercial	Motors/Drives	ECM-VAV-NR-Small Ret	0	$0.00	$9,999.00	$9,999.00	9,999.00	-	-
Commercial	Motors/Drives	ECM-VAV-NR-Supermarket	0	$0.00	$9,999.00	$9,999.00	9,999.00	-	-
Commercial	Motors/Drives	ECM-VAV-NR-University	18	$0.09	$4.13	$26.88	1.96	0.32	0.0001
Commercial	Motors/Drives	ECM-VAV-NR-Warehouse	0	$0.00	$9,999.00	$9,999.00	9,999.00	-	-
Commercial	Motors/Drives	ECM-VAV-NR-Xlarge Ret	18	$0.01	$3.56	$25.99	2.00	0.03	0.0000
Commercial	HVAC	Economizer-Retro-Assembly	18	$0.22	$35.06	$80.62	0.99	0.33	0.0001
Commercial	HVAC	Economizer-Retro-Hospital	18	$0.30	$82.89	$126.75	0.61	0.28	0.0000
Commercial	HVAC	Economizer-Retro-Large Off	18	$0.18	$28.92	$63.34	1.08	0.46	0.0001
Commercial	HVAC	Economizer-Retro-Large Ret	18	$0.32	$64.66	$89.96	0.66	0.41	0.0000
Commercial	HVAC	Economizer-Retro-Lodging	18	$0.10	-$5.05	$28.28	2.36	0.56	0.0001
Commercial	HVAC	Economizer-Retro-Medium Off	18	$0.18	$24.70	$59.05	1.15	0.40	0.0001
Commercial	HVAC	Economizer-Retro-Medium Ret	18	$0.19	$13.43	$35.75	1.58	0.68	0.0001
Commercial	HVAC	Economizer-Retro-MiniMart	18	$0.18	$24.21	$54.26	1.17	0.43	0.0001
Commercial	HVAC	Economizer-Retro-Other	18	$0.17	$13.72	$54.31	1.37	0.41	0.0001
Commercial	HVAC	Economizer-Retro-Residential Care	18	$0.13	$9.86	$35.52	1.65	0.53	0.0001
Commercial	HVAC	Economizer-Retro-Restaurant	18	$0.25	$40.33	$70.08	0.90	0.43	0.0001
Commercial	HVAC	Economizer-Retro-School K-12	18	$0.20	$38.27	$80.48	0.96	0.32	0.0000
Commercial	HVAC	Economizer-Retro-Small Off	18	$0.13	-$4.76	$40.71	1.96	0.46	0.0001
Commercial	HVAC	Economizer-Retro-Small Ret	18	$0.17	$8.50	$31.23	1.82	0.70	0.0001
Commercial	HVAC	Economizer-Retro-Supermarket	18	$0.26	$71.96	$102.54	0.62	0.31	0.0000
Commercial	HVAC	Economizer-Retro-University	18	$0.21	$33.64	$76.86	1.00	0.34	0.0001
Commercial	HVAC	Economizer-Retro-Warehouse	18	$0.07	-$5.86	$38.31	2.04	0.31	0.0001
Commercial	HVAC	Economizer-Retro-Xlarge Ret	18	$0.29	$54.27	$80.00	0.75	0.42	0.0000
Commercial	Lighting	Exterior Lighting: Façade - HID 150W - New	16.27907	$0.75	-$36.43	-$5.08	61.03	70.71	0.0165
Commercial	Lighting	Exterior Lighting: Façade - HID 400W - New	16.27907	$0.93	-$32.72	-$1.37	20.77	30.51	0.0071
Commercial	Lighting	Exterior Lighting: Parking Lot - HPS 250W - New	11.62791	$14.54	-$20.09	$11.26	4.62	137.55	0.0321
Commercial	Lighting	Exterior Lighting: Parking Lot - MH 1000W - New	11.62791	$1.05	-$11.26	$20.08	2.99	6.60	0.0015
Commercial	Lighting	Exterior Lighting: Parking Lot - MH 400W - New	11.62791	$5.31	-$21.37	$9.98	5.01	54.31	0.0127
Commercial	Lighting	Exterior Lighting: Walkway - CFL 26W - New	6.676279	$0.14	-$59.27	-$27.93	8.78	2.44	0.0006
Commercial	Lighting	Exterior Lighting: Walkway - HID 150W - New	16.27907	$0.69	-$36.17	-$4.82	66.30	70.55	0.0165

Sector	End Use	Measure Name	Measure Life (Years)	Initial Capital Cost	TRC Levelized Cost ($/MWh)	Total Sponsor Levelized Cost ($/MWh)	TRC B/C Ratio	Bulk Energy (kWh/unit)	Wholesale Demand (kW)
Commercial	Lighting	Exterior Lighting: Walkway - INC 75W - New	6.676279	$0.03	-$147.65	-$116.31	53.56	1.81	0.0004
Commercial	Lighting	Exterior Lighting: Façade - HID 150W - NR	16.27907	$19.27	-$8.61	$22.73	2.38	70.71	0.0165
Commercial	Lighting	Exterior Lighting: Façade - HID 400W - NR	16.27907	$5.97	-$15.17	$16.17	3.24	30.51	0.0071
Commercial	Lighting	Exterior Lighting: Parking Lot - HPS 250W - NR	11.62791	$45.54	$10.30	$41.65	1.47	137.55	0.0321
Commercial	Lighting	Exterior Lighting: Parking Lot - MH 1000W - NR	11.62791	$1.95	$6.99	$38.34	1.61	6.60	0.0015
Commercial	Lighting	Exterior Lighting: Parking Lot - MH 400W - NR	11.62791	$13.39	-$1.31	$30.04	1.99	54.31	0.0127
Commercial	Lighting	Exterior Lighting: Walkway - CFL 26W - NR	6.676279	$0.14	-$59.27	-$27.93	8.78	2.44	0.0006
Commercial	Lighting	Exterior Lighting: Walkway - HID 150W - NR	13.95349	$15.90	-$10.34	$21.00	2.55	69.71	0.0163
Commercial	Lighting	Exterior Lighting: Walkway - INC 75W - NR	6.676279	$0.03	-$147.65	-$116.31	53.56	1.81	0.0004
Commercial	Refrigeration	Anti Sweat Heater Controls	8	$53.04	$8.20	$24.94	1.87	280.03	0.0340
Commercial	Refrigeration	ECM Controllers on Walk-In Evaporator Motors	16	$208.55	$57.00	$77.33	0.69	302.77	0.0367
Commercial	Refrigeration	Floating Head Pressure Control	15	$327.87	$27.28	$47.61	1.12	773.16	0.0938
Commercial	Refrigeration	Grocery Retrocommisioning	15	$0.26	$7.05	$27.37	1.95	1.06	0.0001
Commercial	Refrigeration	LED Case Lighting	5.976291	$21.04	$39.04	$55.75	0.90	73.39	0.0089
Commercial	Refrigeration	LED Motion Sensors on Display Case	8	$3.65	$19.33	$39.65	1.34	16.64	0.0020
Commercial	Refrigeration	Replace Shaded Pole with ECM in Walk-in Cooler	15	$6,748.72	$11.51	$31.83	1.68	23,804.47	2.8867
Commercial	Refrigeration	Strip Curtains: Walk-In Coolers/ Freezers	2	$10.14	$20.50	$40.82	1.31	155.70	0.0189
Commercial	Electronics	ENERGY STAR Laptop	4	$0.00	-$22.77	$0.00	9,999.00	39.02	0.0057
Commercial	Lighting	LEC Exit Sign-Double-New	15	$52.50	-$3.79	$17.04	1.39	63.08	0.0079
Commercial	Lighting	LEC Exit Sign-Single-New	15	$52.50	$13.36	$34.19	1.10	31.44	0.0039
Commercial	Lighting	LEC Exit Sign-Double-NR	15	$52.50	-$3.79	$17.04	1.39	63.08	0.0079
Commercial	Lighting	LEC Exit Sign-Single-NR	15	$52.50	$13.36	$34.19	1.10	31.44	0.0039
Commercial	Lighting	Lighting Controls Interior-New-Assembly-Integrated	15	$0.00	$9,999.00	$9,999.00	-	-	-
Commercial	Lighting	Lighting Controls Interior-New-Assembly-Unitary	15	$0.00	$9,999.00	$9,999.00	-	-	-
Commercial	Lighting	Lighting Controls Interior-New-Hospital-Integrated	15	$0.00	$9,999.00	$9,999.00	-	-	-
Commercial	Lighting	Lighting Controls Interior-New-Hospital-Unitary	15	$0.00	$9,999.00	$9,999.00	-	-	-
Commercial	Lighting	Lighting Controls Interior-New-Large Off-Integrated	15	$221.70	$136.36	$148.64	0.37	167.44	0.0289
Commercial	Lighting	Lighting Controls Interior-New-Large Off-Unitary	15	$341.08	$71.41	$91.47	0.61	418.60	0.0722
Commercial	Lighting	Lighting Controls Interior-New-Large Ret-Integrated	15	$221.70	$126.17	$123.91	0.39	200.85	0.0335
Commercial	Lighting	Lighting Controls Interior-New-Large Ret-Unitary	15	$341.08	$62.30	$76.25	0.68	502.13	0.0839
Commercial	Lighting	Lighting Controls Interior-New-Lodging-Integrated	15	$0.00	$9,999.00	$9,999.00	-	-	-
Commercial	Lighting	Lighting Controls Interior-New-Lodging-Unitary	15	$0.00	$9,999.00	$9,999.00	-	-	-
Commercial	Lighting	Lighting Controls Interior-New-Medium Off-Integrated	15	$221.70	$222.48	$219.13	0.24	113.57	0.0196
Commercial	Lighting	Lighting Controls Interior-New-Medium Off-Unitary	15	$341.08	$121.04	$134.85	0.40	283.94	0.0489
Commercial	Lighting	Lighting Controls Interior-New-Medium Ret-Integrated	15	$221.70	$138.94	$131.95	0.36	188.61	0.0315
Commercial	Lighting	Lighting Controls Interior-New-Medium Ret-Unitary	15	$341.08	$69.14	$81.20	0.63	471.53	0.0787
Commercial	Lighting	Lighting Controls Interior-New-MiniMart-Integrated	15	$0.00	$9,999.00	$9,999.00	-	-	-
Commercial	Lighting	Lighting Controls Interior-New-MiniMart-Unitary	15	$0.00	$9,999.00	$9,999.00	-	-	-
Commercial	Lighting	Lighting Controls Interior-New-Other-Integrated	15	$221.70	$157.72	$167.72	0.32	148.39	0.0237
Commercial	Lighting	Lighting Controls Interior-New-Other-Unitary	15	$341.08	$84.76	$103.21	0.53	370.98	0.0593
Commercial	Lighting	Lighting Controls Interior-New-Residential Care-Integrated	15	$0.00	$9,999.00	$9,999.00	-	-	-
Commercial	Lighting	Lighting Controls Interior-New-Residential Care-Unitary	15	$0.00	$9,999.00	$9,999.00	-	-	-
Commercial	Lighting	Lighting Controls Interior-New-Restaurant-Integrated	15	$0.00	$9,999.00	$9,999.00	-	-	-
Commercial	Lighting	Lighting Controls Interior-New-Restaurant-Unitary	15	$0.00	$9,999.00	$9,999.00	-	-	-
Commercial	Lighting	Lighting Controls Interior-New-School K-12-Integrated	15	$221.70	$255.29	$219.47	0.20	113.40	0.0151
Commercial	Lighting	Lighting Controls Interior-New-School K-12-Unitary	15	$341.08	$136.35	$135.06	0.35	283.51	0.0377
Commercial	Lighting	Lighting Controls Interior-New-Small Off-Integrated	15	$221.70	$219.34	$224.79	0.25	110.72	0.0212
Commercial	Lighting	Lighting Controls Interior-New-Small Off-Unitary	15	$341.08	$119.89	$138.33	0.42	276.79	0.0530
Commercial	Lighting	Lighting Controls Interior-New-Small Ret-Integrated	15	$221.70	$202.41	$183.12	0.26	135.91	0.0227
Commercial	Lighting	Lighting Controls Interior-New-Small Ret-Unitary	15	$341.08	$105.55	$112.69	0.45	339.78	0.0567
Commercial	Lighting	Lighting Controls Interior-New-Supermarket-Integrated	15	$0.00	$9,999.00	$9,999.00	-	-	-
Commercial	Lighting	Lighting Controls Interior-New-Supermarket-Unitary	15	$0.00	$9,999.00	$9,999.00	-	-	-
Commercial	Lighting	Lighting Controls Interior-New-University-Integrated	15	$221.70	$243.94	$219.93	0.23	113.16	0.0245
Commercial	Lighting	Lighting Controls Interior-New-University-Unitary	15	$341.08	$127.25	$135.34	0.41	282.91	0.0612
Commercial	Lighting	Lighting Controls Interior-New-Warehouse-Integrated	15	$209.58	$391.35	$359.47	0.14	65.45	0.0119
Commercial	Lighting	Lighting Controls Interior-New-Warehouse-Unitary	15	$158.98	$84.11	$90.89	0.55	196.35	0.0356
Commercial	Lighting	Lighting Controls Interior-New-Xlarge Ret-Integrated	15	$221.70	$60.76	$70.22	0.69	354.45	0.0592
Commercial	Lighting	Lighting Controls Interior-New-Xlarge Ret-Unitary	15	$341.08	$24.57	$43.21	1.19	886.13	0.1480
Commercial	Lighting	Lighting Controls Interior-NR-Assembly-Integrated	15	$0.00	$9,999.00	$9,999.00	-	-	-
Commercial	Lighting	Lighting Controls Interior-NR-Assembly-Unitary	15	$0.00	$9,999.00	$9,999.00	-	-	-
Commercial	Lighting	Lighting Controls Interior-NR-Hospital-Integrated	15	$0.00	$9,999.00	$9,999.00	-	-	-
Commercial	Lighting	Lighting Controls Interior-NR-Hospital-Unitary	15	$0.00	$9,999.00	$9,999.00	-	-	-
Commercial	Lighting	Lighting Controls Interior-NR-Large Off-Integrated	15	$221.70	$121.64	$135.38	0.40	183.84	0.0317
Commercial	Lighting	Lighting Controls Interior-NR-Large Off-Unitary	15	$341.08	$62.67	$83.31	0.67	459.59	0.0792
Commercial	Lighting	Lighting Controls Interior-NR-Large Ret-Integrated	15	$221.70	$128.01	$123.79	0.38	201.05	0.0336
Commercial	Lighting	Lighting Controls Interior-NR-Large Ret-Unitary	15	$341.08	$63.01	$76.18	0.67	502.63	0.0839
Commercial	Lighting	Lighting Controls Interior-NR-Lodging-Integrated	15	$0.00	$9,999.00	$9,999.00	-	-	-
Commercial	Lighting	Lighting Controls Interior-NR-Lodging-Unitary	15	$0.00	$9,999.00	$9,999.00	-	-	-
Commercial	Lighting	Lighting Controls Interior-NR-Medium Off-Integrated	15	$221.70	$210.67	$211.79	0.25	117.51	0.0203
Commercial	Lighting	Lighting Controls Interior-NR-Medium Off-Unitary	15	$341.08	$114.74	$130.33	0.42	293.78	0.0506
Commercial	Lighting	Lighting Controls Interior-NR-Medium Ret-Integrated	15	$221.70	$118.89	$116.40	0.41	213.82	0.0357
Commercial	Lighting	Lighting Controls Interior-NR-Medium Ret-Unitary	15	$341.08	$57.77	$71.63	0.71	534.56	0.0893
Commercial	Lighting	Lighting Controls Interior-NR-MiniMart-Integrated	15	$0.00	$9,999.00	$9,999.00	-	-	-

Sector	End Use	Measure Name	Measure Life (Years)	Initial Capital Cost	TRC Levelized Cost ($/MWh)	Total Sponsor Levelized Cost ($/MWh)	TRC B/C Ratio	Bulk Energy (kWh/unit)	Wholesale Demand (kW)
Commercial	Lighting	Lighting Controls Interior-NR-MiniMart-Unitary	15	$0.00	$9,999.00	$9,999.00	-	-	-
Commercial	Lighting	Lighting Controls Interior-NR-Other-Integrated	15	$221.70	$157.96	$165.44	0.32	150.44	0.0240
Commercial	Lighting	Lighting Controls Interior-NR-Other-Unitary	15	$341.08	$84.36	$101.81	0.54	376.09	0.0601
Commercial	Lighting	Lighting Controls Interior-NR-Residential Care-Integrated	15	$0.00	$9,999.00	$9,999.00	-	-	-
Commercial	Lighting	Lighting Controls Interior-NR-Residential Care-Unitary	15	$0.00	$9,999.00	$9,999.00	-	-	-
Commercial	Lighting	Lighting Controls Interior-NR-Restaurant-Integrated	15	$0.00	$9,999.00	$9,999.00	-	-	-
Commercial	Lighting	Lighting Controls Interior-NR-Restaurant-Unitary	15	$0.00	$9,999.00	$9,999.00	-	-	-
Commercial	Lighting	Lighting Controls Interior-NR-School K-12-Integrated	15	$221.70	$263.58	$229.84	0.20	108.28	0.0144
Commercial	Lighting	Lighting Controls Interior-NR-School K-12-Unitary	15	$341.08	$141.89	$141.44	0.34	270.71	0.0360
Commercial	Lighting	Lighting Controls Interior-NR-Small Off-Integrated	15	$221.70	$227.49	$225.53	0.24	110.35	0.0211
Commercial	Lighting	Lighting Controls Interior-NR-Small Off-Unitary	15	$341.08	$123.31	$138.79	0.41	275.89	0.0528
Commercial	Lighting	Lighting Controls Interior-NR-Small Ret-Integrated	15	$221.70	$199.66	$180.73	0.26	137.71	0.0230
Commercial	Lighting	Lighting Controls Interior-NR-Small Ret-Unitary	15	$341.08	$103.93	$111.22	0.46	344.26	0.0575
Commercial	Lighting	Lighting Controls Interior-NR-Supermarket-Integrated	15	$0.00	$9,999.00	$9,999.00	-	-	-
Commercial	Lighting	Lighting Controls Interior-NR-Supermarket-Unitary	15	$0.00	$9,999.00	$9,999.00	-	-	-
Commercial	Lighting	Lighting Controls Interior-NR-University-Integrated	15	$221.70	$253.81	$229.40	0.22	108.49	0.0235
Commercial	Lighting	Lighting Controls Interior-NR-University-Unitary	15	$341.08	$133.24	$141.17	0.39	271.23	0.0587
Commercial	Lighting	Lighting Controls Interior-NR-Warehouse-Integrated	15	$209.58	$415.91	$358.83	0.14	65.57	0.0119
Commercial	Lighting	Lighting Controls Interior-NR-Warehouse-Unitary	15	$158.98	$92.35	$90.73	0.51	196.70	0.0357
Commercial	Lighting	Lighting Controls Interior-NR-Xlarge Ret-Integrated	15	$221.70	$68.69	$84.10	0.63	295.94	0.0494
Commercial	Lighting	Lighting Controls Interior-NR-Xlarge Ret-Unitary	15	$341.08	$30.73	$51.75	1.06	739.84	0.1236
Commercial	Lighting	Market Average HP Low Power T8 Shift	6.666667	$0.90	$8.02	$30.17	1.76	6.28	0.0011
Commercial	Lighting	Market Average HP Low Power T8 Shift	6.666667	$0.90	$8.02	$30.17	1.76	6.28	0.0011
Commercial	Lighting	Market Average HP Low Power T8 Shift	6.666667	$0.90	$8.02	$30.17	1.76	6.28	0.0011
Commercial	Lighting	Market Average HP Low Power T8 Shift	6.666667	$0.90	$8.02	$30.17	1.76	6.28	0.0011
Commercial	Lighting	Market Average HP Low Power T8 Shift	6.666667	$0.90	$8.02	$30.17	1.76	6.28	0.0011
Commercial	Lighting	Market Average HP Low Power T8 Shift	6.666667	$0.90	$8.02	$30.17	1.76	6.28	0.0011
Commercial	Lighting	Market Average HP Low Power T8 Shift	6.666667	$0.90	$8.02	$30.17	1.76	6.28	0.0011
Commercial	Lighting	Market Average HP Low Power T8 Shift	6.666667	$0.90	$8.02	$30.17	1.76	6.28	0.0011
Commercial	Lighting	Market Average HP Low Power T8 Shift	6.666667	$0.90	$8.02	$30.17	1.76	6.28	0.0011
Commercial	Lighting	Market Average HP Low Power T8 Shift	6.666667	$0.90	$8.02	$30.17	1.76	6.28	0.0011
Commercial	Lighting	Market Average HP Low Power T8 Shift	6.666667	$0.90	$8.02	$30.17	1.76	6.28	0.0011
Commercial	Lighting	Market Average HP Low Power T8 Shift	6.666667	$0.90	$8.02	$30.17	1.76	6.28	0.0011
Commercial	Lighting	Market Average HP Low Power T8 Shift	6.666667	$0.90	$8.02	$30.17	1.76	6.28	0.0011
Commercial	Lighting	Market Average HP Low Power T8 Shift	6.666667	$0.90	$8.02	$30.17	1.76	6.28	0.0011
Commercial	Lighting	Market Average HP Low Power T8 Shift	6.666667	$0.90	$8.02	$30.17	1.76	6.28	0.0011
Commercial	Lighting	Market Average HP Low Power T8 Shift	6.666667	$0.90	$8.02	$30.17	1.76	6.28	0.0011
Commercial	Lighting	Market Average HP Low Power T8 Shift	6.666667	$0.90	$8.02	$30.17	1.76	6.28	0.0011
Commercial	Lighting	Market Average HP Low Power T8 Shift	6.666667	$0.90	$8.02	$30.17	1.76	6.28	0.0011
Commercial	Lighting	All Btype_New_CAN_FIX_REPL_from CFL to LED_FIX_KIT	13.43071	$39.00	-$31.34	-$10.34	2.62	126.94	0.0205
Commercial	Lighting	All Btype_New_CAN_FIX_REPL_from INC_HAL to LED_FIX_KIT	13.11199	$1.86	-$92.83	-$71.93	24.24	100.00	0.0160
Commercial	Lighting	All Btype_New_DISP_FIX_REPL_from CFL to LED_FIX_KIT	9.401498	$110.78	$142.55	$163.55	0.78	34.55	0.0056
Commercial	Lighting	All Btype_New_DISP_FIX_REPL_from INC_HAL to LED_FIX_KIT	8.328906	$8.77	-$47.16	-$27.87	2.45	29.33	0.0047
Commercial	Lighting	All Btype_New_HIGHBAY_FIX_REPL_from HID to LED_FIX_KIT	20.85597	$24.32	$17.43	$37.57	1.34	49.52	0.0081
Commercial	Lighting	All Btype_New_HIGHBAY_FIX_REPL_from HID to LF2018	20	$2.73	-$2.36	$17.78	2.10	8.83	0.0015
Commercial	Lighting	All Btype_New_HIGHBAY_FIX_REPL_from LF2018 to LED_FIX_KIT	19.55876	$54.26	$28.43	$48.15	1.06	61.11	0.0100
Commercial	Lighting	All Btype_New_LF_FIX_REPL_from LF2018 to LED_FIX_KIT	15.89193	$501.65	$31.71	$52.34	1.03	738.34	0.1199
Commercial	Lighting	All Btype_NR_CAN_FIX_REPL_from CFL to LED_FIX_KIT	13.86169	$23.09	-$30.66	-$9.89	2.59	73.04	0.0118
Commercial	Lighting	All Btype_NR_CAN_FIX_REPL_from INC_HAL to LED_FIX_KIT	12.91756	$1.28	-$92.42	-$71.59	23.81	70.51	0.0113
Commercial	Lighting	All Btype_NR_DISP_FIX_REPL_from CFL to LED_FIX_KIT	9.905444	$65.85	$140.51	$161.62	0.79	19.55	0.0031
Commercial	Lighting	All Btype_NR_DISP_FIX_REPL_from INC_HAL to LED_FIX_KIT	8.627286	$17.07	-$47.65	-$27.92	2.41	53.72	0.0086
Commercial	Lighting	All Btype_NR_HIGHBAY_FIX_REPL_from HID to LED_FIX_KIT	21.25284	$33.81	$18.37	$38.52	1.31	66.34	0.0109
Commercial	Lighting	All Btype_NR_HIGHBAY_FIX_REPL_from HID to LF2018	0	$0.00	$9,999.00	$9,999.00	9,999.00	-	-
Commercial	Lighting	All Btype_NR_HIGHBAY_FIX_REPL_from LF2018 to LED_FIX_KIT	20.25163	$45.54	$30.30	$49.83	1.04	48.63	0.0080
Commercial	Lighting	All Btype_NR_LF_FIX_REPL_from LF2018 to LED_FIX_KIT	16.125	$259.11	$32.75	$52.74	1.02	372.06	0.0606
Commercial	Lighting	All Btype_NR_LF_FIX_REPL_from LF2018 to LED_FIX_KIT_RDX	16.125	$57.26	-$5.32	$14.67	2.12	198.62	0.0323
Commercial	Lighting	All Btype_NR_LF_FIX_REPL_from LF2018 to LF_FIX_KIT_RDX	20	$27.85	-$9.66	$10.33	2.00	65.88	0.0107
Commercial	Lighting	All Btype_NR_LF_FIX_REPL_from LF2018 to TLED_PIN	13.4375	$26.58	$13.00	$32.99	1.28	45.17	0.0074
Commercial	Lighting	All Btype_NR_LF_FIX_REPL_from LF2018 to TLED_PIN_RDX	13.4375	$17.20	-$15.27	$4.72	2.55	75.91	0.0124
Commercial	Lighting	All Btype_Retro_CAN_FIX_REPL_from CFL to LED_FIX_KIT	13.86169	$81.37	$63.46	$84.23	0.78	73.04	0.0118
Commercial	Lighting	All Btype_Retro_CAN_FIX_REPL_from INC_HAL to LED_FIX_KIT	12.91756	$13.44	-$71.00	-$50.16	4.89	70.51	0.0113
Commercial	Lighting	All Btype_Retro_CAN_LAMP_REPL_from CFL to LED_CAN_LAMP	13.86169	$33.64	-$13.22	$7.55	1.77	69.10	0.0111
Commercial	Lighting	All Btype_Retro_CAN_LAMP_REPL_from INC_HAL to LED_CAN_LAMP	12.91756	$5.56	-$85.56	-$64.72	10.07	69.79	0.0112
Commercial	Lighting	All Btype_Retro_DISP_FIX_REPL_from CFL to LED_FIX_KIT	9.905444	$132.08	$651.82	$672.94	0.40	19.55	0.0031
Commercial	Lighting	All Btype_Retro_DISP_FIX_REPL_from INC_HAL to LED_FIX_KIT	8.627286	$31.68	-$2.03	$17.71	1.35	53.72	0.0086
Commercial	Lighting	All Btype_Retro_DISP_LAMP_REPL_from CFL to LED_PAR_MR	9.905444	$60.26	$79.10	$100.22	0.89	23.13	0.0037
Commercial	Lighting	All Btype_Retro_DISP_LAMP_REPL_from HID_CMH to LED_PAR_MR	0	$0.00	$9,999.00	$9,999.00	9,999.00	-	-
Commercial	Lighting	All Btype_Retro_DISP_LAMP_REPL_from INC_HAL to HID_CMH	2.957927	$1.78	-$19.32	$0.41	1.66	9.91	0.0016
Commercial	Lighting	All Btype_Retro_DISP_LAMP_REPL_from INC_HAL to LED_PAR_MR	8.627286	$11.56	-$55.16	-$35.43	2.83	43.78	0.0070
Commercial	Lighting	All Btype_Retro_HIGHBAY_FIX_REPL_from HID to LED_FIX_KIT	21.25284	$45.99	$34.95	$55.10	0.99	66.34	0.0109
Commercial	Lighting	All Btype_Retro_HIGHBAY_FIX_REPL_from HID to LF2018	0	$0.00	$9,999.00	$9,999.00	9,999.00	-	-
Commercial	Lighting	All Btype_Retro_HIGHBAY_FIX_REPL_from LF2018 to LED_FIX_KIT	20.25163	$112.45	$156.93	$176.45	0.44	48.63	0.0080
Commercial	Lighting	All Btype_Retro_LF_FIX_REPL_from LF2018 to LED_FIX_KIT	16.125	$892.21	$171.23	$191.23	0.37	446.47	0.0727

Sector	End Use	Measure Name	Measure Life (Years)	Initial Capital Cost	TRC Levelized Cost ($/MWh)	Total Sponsor Levelized Cost ($/MWh)	TRC B/C Ratio	Bulk Energy (kWh/unit)	Wholesale Demand (kW)
Commercial	Lighting	All Btype_Retro_LF_FIX_REPL_from LF2018 to LED_FIX_KIT_RDX	16.125	$376.52	$98.45	$118.44	0.54	297.93	0.0485
Commercial	Lighting	All Btype_Retro_LF_FIX_REPL_from LF2018 to LF_FIX_KIT_RDX	20	$80.92	$65.37	$85.36	0.74	65.88	0.0107
Commercial	Lighting	All Btype_Retro_LF_LAMP_REPL_from LF2018 to TLED_PIN	0	$0.00	$9,999.00	$9,999.00	9,999.00	-	-
Commercial	Lighting	All Btype_Retro_LF_LAMP_REPL_from LF2018 to TLED_PIN_RDX	13.4375	$496.67	$47.83	$67.83	0.86	630.04	0.1026
Commercial	Lighting	All Btype_Retro_OTHER_LAMP_REPL_from CFL to LED_OMNI	7.547368	$47.43	-$22.62	-$2.23	1.56	85.50	0.0131
Commercial	Lighting	All Btype_Retro_OTHER_LAMP_REPL_from EISA_2020 to CFL_OMNI	0	$0.00	$9,999.00	$9,999.00	9,999.00	-	-
Commercial	Lighting	All Btype_Retro_OTHER_LAMP_REPL_from EISA_2020 to LED_OMNI	7.207131	$12.04	-$23.06	-$2.57	2.05	41.99	0.0064
Commercial	Lighting	All Btype_Retro_OTHER_LAMP_REPL_from HID to LED_OMNI	0	$0.00	$9,999.00	$9,999.00	9,999.00	-	-
Commercial	Electronics	ENERGY STAR Display	4	$0.00	-$22.77	$0.00	9,999.00	32.45	0.0047
Commercial	Motors/Drives	MotorsRewind-New-Assembly	10	$2.37	$22.49	$45.10	1.25	7.95	0.0011
Commercial	Motors/Drives	MotorsRewind-New-Hospital	10	$0.96	-$7.47	$15.15	3.74	9.56	0.0014
Commercial	Motors/Drives	MotorsRewind-New-Large Off	10	$3.11	$24.37	$46.98	1.20	10.01	0.0014
Commercial	Motors/Drives	MotorsRewind-New-Large Ret	10	$1.66	$8.71	$31.32	1.81	8.01	0.0012
Commercial	Motors/Drives	MotorsRewind-New-Lodging	10	$0.79	-$9.19	$13.42	4.22	8.95	0.0013
Commercial	Motors/Drives	MotorsRewind-New-Medium Off	10	$3.11	$24.37	$46.98	1.20	10.01	0.0014
Commercial	Motors/Drives	MotorsRewind-New-Medium Ret	10	$1.66	$8.71	$31.32	1.81	8.01	0.0012
Commercial	Motors/Drives	MotorsRewind-New-MiniMart	10	$4.42	-$3.82	$18.79	3.01	35.61	0.0051
Commercial	Motors/Drives	MotorsRewind-New-Other	10	$2.00	$14.97	$37.58	1.51	8.06	0.0012
Commercial	Motors/Drives	MotorsRewind-New-Residential Care	10	$0.85	-$9.19	$13.42	4.22	9.56	0.0014
Commercial	Motors/Drives	MotorsRewind-New-Restaurant	10	$5.34	$5.57	$28.19	2.01	28.64	0.0041
Commercial	Motors/Drives	MotorsRewind-New-School K-12	10	$1.24	$24.37	$46.98	1.20	3.98	0.0006
Commercial	Motors/Drives	MotorsRewind-New-Small Off	10	$3.11	$24.37	$46.98	1.20	10.01	0.0014
Commercial	Motors/Drives	MotorsRewind-New-Small Ret	10	$1.66	$8.71	$31.32	1.81	8.01	0.0012
Commercial	Motors/Drives	MotorsRewind-New-Supermarket	10	$4.42	-$3.82	$18.79	3.01	35.61	0.0051
Commercial	Motors/Drives	MotorsRewind-New-University	10	$1.24	$24.37	$46.98	1.20	3.98	0.0006
Commercial	Motors/Drives	MotorsRewind-New-Warehouse	10	$1.18	$24.37	$46.98	1.20	3.78	0.0005
Commercial	Motors/Drives	MotorsRewind-New-Xlarge Ret	10	$1.66	$8.71	$31.32	1.81	8.01	0.0012
Commercial	Motors/Drives	MotorsRewind-NR-Assembly	10	$2.37	$22.49	$45.10	1.25	7.95	0.0011
Commercial	Motors/Drives	MotorsRewind-NR-Hospital	10	$0.96	-$7.47	$15.15	3.74	9.56	0.0014
Commercial	Motors/Drives	MotorsRewind-NR-Large Off	10	$3.11	$24.37	$46.98	1.20	10.01	0.0014
Commercial	Motors/Drives	MotorsRewind-NR-Large Ret	10	$1.66	$8.71	$31.32	1.81	8.01	0.0012
Commercial	Motors/Drives	MotorsRewind-NR-Lodging	10	$0.79	-$9.19	$13.42	4.22	8.95	0.0013
Commercial	Motors/Drives	MotorsRewind-NR-Medium Off	10	$3.11	$24.37	$46.98	1.20	10.01	0.0014
Commercial	Motors/Drives	MotorsRewind-NR-Medium Ret	10	$1.66	$8.71	$31.32	1.81	8.01	0.0012
Commercial	Motors/Drives	MotorsRewind-NR-MiniMart	10	$4.42	-$3.82	$18.79	3.01	35.61	0.0051
Commercial	Motors/Drives	MotorsRewind-NR-Other	10	$2.00	$14.97	$37.58	1.51	8.06	0.0012
Commercial	Motors/Drives	MotorsRewind-NR-Residential Care	10	$0.85	-$9.19	$13.42	4.22	9.56	0.0014
Commercial	Motors/Drives	MotorsRewind-NR-Restaurant	10	$5.34	$5.57	$28.19	2.01	28.64	0.0041
Commercial	Motors/Drives	MotorsRewind-NR-School K-12	10	$1.24	$24.37	$46.98	1.20	3.98	0.0006
Commercial	Motors/Drives	MotorsRewind-NR-Small Off	10	$3.11	$24.37	$46.98	1.20	10.01	0.0014
Commercial	Motors/Drives	MotorsRewind-NR-Small Ret	10	$1.66	$8.71	$31.32	1.81	8.01	0.0012
Commercial	Motors/Drives	MotorsRewind-NR-Supermarket	10	$4.42	-$3.82	$18.79	3.01	35.61	0.0051
Commercial	Motors/Drives	MotorsRewind-NR-University	10	$1.24	$24.37	$46.98	1.20	3.98	0.0006
Commercial	Motors/Drives	MotorsRewind-NR-Warehouse	10	$1.18	$24.37	$46.98	1.20	3.78	0.0005
Commercial	Motors/Drives	MotorsRewind-NR-Xlarge Ret	10	$1.66	$8.71	$31.32	1.81	8.01	0.0012
Commercial	Process Loads	Municipal Water Supply-Retro	12	$13,829.18	$9.99	$33.62	1.72	54,168.45	8.5110
Commercial	Lighting	NR_PARKING_GARAGE_FIX_REPL_from MH to BI-LEVEL_LED_FIX	8.561644	$351.84	$11.73	$32.56	1.57	1,612.49	0.2025
Commercial	HVAC	Premium Fume Hood-NR	18	$7,972.94	$24.76	$51.66	1.18	15,349.29	2.9112
Commercial	Food Preparation	Pre-Rinse Spray Valve_0.61_to_0.8gpm	4	$86.67	-$523.83	$129.75	5.30	219.88	0.0370
Commercial	Food Preparation	Pre-Rinse Spray Valve_0.81_to_1.0gpm	4	$86.67	-$470.63	$212.30	3.38	134.38	0.0226
Commercial	HVAC	SGSWindow-High-rise Office (VAV with Central Chillers / Ele Boilers)-HZ3	30	$34.00	$66.13	$79.17	0.62	32.79	0.0016
Commercial	HVAC	SGSWindow-High-rise Office (VAV with Central Chillers / Ele Boilers)-HZ1	30	$34.00	$98.62	$111.65	0.44	23.25	0.0012
Commercial	HVAC	SGSWindow-High-rise Office (VAV with Central Chillers / Ele Boilers)-HZ2	30	$34.00	$82.66	$95.70	0.51	27.12	0.0014
Commercial	HVAC	SGSWindow-High-rise Office (VAV with Central Chillers / Gas Boilers)-HZ3	30	$34.00	$353.19	$455.89	0.30	5.69	0.0003
Commercial	HVAC	SGSWindow-High-rise Office (VAV with Central Chillers / Gas Boilers)-HZ1	30	$34.00	$631.53	$749.19	0.20	3.46	0.0002
Commercial	HVAC	SGSWindow-High-rise Office (VAV with Central Chillers / Gas Boilers)-HZ2	30	$34.00	$381.79	$469.95	0.26	5.52	0.0003
Commercial	HVAC	SGSWindow-Mid-rise Office (Apackaged VAV with Electric reheat)-HZ3	30	$34.00	$68.10	$81.13	0.60	32.00	0.0016
Commercial	HVAC	SGSWindow-Mid-rise Office (Apackaged VAV with Electric reheat)-HZ1	30	$34.00	$106.93	$119.96	0.41	21.64	0.0011
Commercial	HVAC	SGSWindow-Mid-rise Office (Apackaged VAV with Electric reheat)-HZ2	30	$34.00	$81.03	$94.06	0.52	27.60	0.0014
Commercial	HVAC	SGSWindow-Mid-rise Office (Apackaged VAV with Gas)-HZ3	30	$34.00	$360.75	$455.89	0.29	5.69	0.0003
Commercial	HVAC	SGSWindow-Mid-rise Office (Apackaged VAV with Gas)-HZ1	30	$34.00	$642.92	$749.19	0.19	3.46	0.0002
Commercial	HVAC	SGSWindow-Mid-rise Office (Apackaged VAV with Gas)-HZ2	30	$34.00	$385.89	$469.95	0.26	5.52	0.0003
Commercial	HVAC	SGSWindow-Small Office (AC with Ele Furnace)-HZ3	30	$34.00	$139.42	$152.46	0.32	17.03	0.0009
Commercial	HVAC	SGSWindow-Small Office (AC with Ele Furnace)-HZ1	30	$34.00	$170.25	$183.29	0.27	14.16	0.0007
Commercial	HVAC	SGSWindow-Small Office (AC with Ele Furnace)-HZ2	30	$34.00	$124.04	$137.08	0.36	18.94	0.0009
Commercial	HVAC	SGSWindow-Small Office (AC with Gas Furnace)-HZ3	30	$34.00	$294.78	$324.62	0.20	8.00	0.0004
Commercial	HVAC	SGSWindow-Small Office (AC with Gas Furnace)-HZ1	30	$34.00	$304.84	$326.38	0.18	7.95	0.0004
Commercial	HVAC	SGSWindow-Small Office (AC with Gas Furnace)-HZ2	30	$34.00	$263.41	$293.42	0.22	8.85	0.0004
Commercial	HVAC	SGSWindow-Small Office (Air-source Heat Pump)-HZ3	30	$34.00	$203.35	$216.38	0.23	12.00	0.0006
Commercial	HVAC	SGSWindow-Small Office (Air-source Heat Pump)-HZ1	30	$34.00	$229.88	$242.92	0.20	10.69	0.0005
Commercial	HVAC	SGSWindow-Small Office (Air-source Heat Pump)-HZ2	30	$34.00	$185.25	$198.29	0.25	13.09	0.0007
Commercial	Water Heating	Showerheads-Retro-Assembly	10	$12.58	-$322.72	$12.35	29.85	154.08	0.0266
Commercial	Water Heating	Showerheads-Retro-Hospital	10	$18.31	-$328.05	$26.71	14.53	103.68	0.0154

Sector	End Use	Measure Name	Measure Life (Years)	Initial Capital Cost	TRC Levelized Cost ($/MWh)	Total Sponsor Levelized Cost ($/MWh)	TRC B/C Ratio	Bulk Energy (kWh/unit)	Wholesale Demand (kW)
Commercial	Water Heating	Showerheads-Retro-Large Off	10	$18.31	-$202.71	$31.47	8.51	88.00	0.0152
Commercial	Water Heating	Showerheads-Retro-Large Ret	0	$12.58	$9,999.00	$9,999.00	-	-	-
Commercial	Water Heating	Showerheads-Retro-Lodging	10	$18.31	-$314.84	$17.98	20.36	154.04	0.0229
Commercial	Water Heating	Showerheads-Retro-Medium Off	10	$18.31	-$202.72	$31.47	8.51	88.00	0.0152
Commercial	Water Heating	Showerheads-Retro-Medium Ret	0	$12.58	$9,999.00	$9,999.00	-	-	-
Commercial	Water Heating	Showerheads-Retro-MiniMart	0	$12.58	$9,999.00	$9,999.00	-	-	-
Commercial	Water Heating	Showerheads-Retro-Other	10	$18.31	-$756.96	$19.61	41.31	141.19	0.0243
Commercial	Water Heating	Showerheads-Retro-Residential Care	10	$18.31	-$339.70	$26.71	14.97	103.68	0.0154
Commercial	Water Heating	Showerheads-Retro-Restaurant	0	$12.58	$9,999.00	$9,999.00	-	-	-
Commercial	Water Heating	Showerheads-Retro-School K-12	10	$18.31	-$253.06	$25.07	12.46	110.44	0.0110
Commercial	Water Heating	Showerheads-Retro-Small Off	10	$18.31	-$202.72	$31.47	8.51	88.00	0.0152
Commercial	Water Heating	Showerheads-Retro-Small Ret	0	$12.58	$9,999.00	$9,999.00	-	-	-
Commercial	Water Heating	Showerheads-Retro-Supermarket	0	$12.58	$9,999.00	$9,999.00	-	-	-
Commercial	Water Heating	Showerheads-Retro-University	10	$18.31	-$269.24	$25.07	13.11	110.44	0.0110
Commercial	Water Heating	Showerheads-Retro-Warehouse	0	$12.58	$9,999.00	$9,999.00	-	-	-
Commercial	Water Heating	Showerheads-Retro-Xlarge Ret	0	$12.58	$9,999.00	$9,999.00	-	-	-
Commercial	Electronics	Smart Plug Power Strips-Retro	4	$40.08	$166.63	$192.37	0.31	68.58	0.0121
Commercial	Lighting	Streetlight - HPS 100W - New	11.62791	-$8.59	-$138.73	-$107.39	9,999.00	322.54	0.0753
Commercial	Lighting	Streetlight - HPS 250W - New	11.62791	$2.01	-$78.81	-$47.46	287.25	704.13	0.1643
Commercial	Lighting	Streetlight - MH 1000W - New	11.62791	$532.07	-$19.24	$12.11	3.18	3,084.55	0.7197
Commercial	Lighting	Streetlight - MH 200W - New	11.62791	$2.01	-$111.31	-$79.96	221.00	417.94	0.0975
Commercial	Lighting	Streetlight - MH 400W - New	11.62791	$134.02	-$44.62	-$13.27	6.12	1,217.46	0.2841
Commercial	Lighting	Streetlight - HPS 100W - NR	11.62791	$113.41	-$87.74	-$56.40	3.51	322.54	0.0753
Commercial	Lighting	Streetlight - HPS 250W - NR	11.62791	$162.01	-$48.18	-$16.83	3.57	704.13	0.1643
Commercial	Lighting	Streetlight - MH 1000W - NR	11.62791	$972.07	-$0.01	$31.34	1.74	3,084.55	0.7197
Commercial	Lighting	Streetlight - MH 200W - NR	11.62791	$162.01	-$59.70	-$28.36	2.74	417.94	0.0975
Commercial	Lighting	Streetlight - MH 400W - NR	11.62791	$324.02	-$23.58	$7.77	2.53	1,217.46	0.2841
Commercial	HVAC	VRF-New-Assembly	20	$2.69	$37.86	$64.77	0.94	3.87	0.0007
Commercial	HVAC	VRF-New-Hospital	20	$4.58	$82.27	$102.65	0.52	4.16	0.0005
Commercial	HVAC	VRF-New-Large Off	20	$3.66	$55.52	$75.79	0.72	4.50	0.0005
Commercial	HVAC	VRF-New-Large Ret	20	$2.95	$108.49	$125.97	0.41	2.18	0.0002
Commercial	HVAC	VRF-New-Lodging	20	$2.77	$42.53	$69.44	0.88	3.72	0.0007
Commercial	HVAC	VRF-New-Medium Off	20	$1.70	$62.14	$82.41	0.66	1.92	0.0002
Commercial	HVAC	VRF-New-Medium Ret	20	$2.72	$98.76	$116.24	0.44	2.18	0.0002
Commercial	HVAC	VRF-New-MiniMart	20	$4.03	$55.10	$74.02	0.71	5.07	0.0005
Commercial	HVAC	VRF-New-Other	20	$2.71	$33.78	$60.68	1.00	4.16	0.0008
Commercial	HVAC	VRF-New-Residential Care	20	$3.27	$64.27	$84.65	0.63	3.60	0.0004
Commercial	HVAC	VRF-New-Restaurant	20	$4.90	$59.41	$80.56	0.68	5.67	0.0007
Commercial	HVAC	VRF-New-School K-12	20	$2.66	$103.63	$122.21	0.44	2.03	0.0002
Commercial	HVAC	VRF-New-Small Off	20	$1.70	$30.82	$51.09	1.06	3.09	0.0004
Commercial	HVAC	VRF-New-Small Ret	20	$2.72	$98.76	$116.24	0.44	2.18	0.0002
Commercial	HVAC	VRF-New-Supermarket	20	$5.09	$61.68	$80.60	0.65	5.88	0.0006
Commercial	HVAC	VRF-New-University	20	$2.68	$93.39	$120.30	0.51	2.07	0.0004
Commercial	HVAC	VRF-New-Warehouse	20	$2.82	$99.12	$125.04	0.48	2.10	0.0004
Commercial	HVAC	VRF-New-Xlarge Ret	20	$2.87	$106.15	$123.63	0.42	2.16	0.0002
Commercial	HVAC	VRF-Retro-Assembly	20	$3.11	$63.40	$90.31	0.67	3.21	0.0006
Commercial	HVAC	VRF-Retro-Hospital	20	$5.29	$98.19	$118.56	0.45	4.16	0.0005
Commercial	HVAC	VRF-Retro-Large Off	20	$4.23	$56.46	$76.73	0.71	5.14	0.0006
Commercial	HVAC	VRF-Retro-Large Ret	20	$3.41	$129.59	$147.07	0.35	2.16	0.0002
Commercial	HVAC	VRF-Retro-Lodging	20	$3.20	$48.86	$75.77	0.80	3.93	0.0007
Commercial	HVAC	VRF-Retro-Medium Off	20	$1.96	$63.16	$83.43	0.65	2.19	0.0003
Commercial	HVAC	VRF-Retro-Medium Ret	20	$3.14	$118.24	$135.72	0.38	2.15	0.0002
Commercial	HVAC	VRF-Retro-MiniMart	20	$4.66	$65.79	$84.70	0.62	5.12	0.0005
Commercial	HVAC	VRF-Retro-Other	20	$3.13	$38.30	$65.21	0.93	4.48	0.0008
Commercial	HVAC	VRF-Retro-Residential Care	20	$3.78	$68.85	$89.23	0.60	3.94	0.0005
Commercial	HVAC	VRF-Retro-Restaurant	20	$5.66	$62.92	$84.07	0.65	6.28	0.0008
Commercial	HVAC	VRF-Retro-School K-12	20	$3.08	$126.76	$145.34	0.37	1.97	0.0002
Commercial	HVAC	VRF-Retro-Small Off	20	$1.96	$31.46	$51.72	1.05	3.53	0.0004
Commercial	HVAC	VRF-Retro-Small Ret	20	$3.14	$118.24	$135.72	0.38	2.15	0.0002
Commercial	HVAC	VRF-Retro-Supermarket	20	$5.88	$73.32	$92.24	0.57	5.93	0.0006
Commercial	HVAC	VRF-Retro-University	20	$3.09	$112.04	$138.95	0.44	2.07	0.0004
Commercial	HVAC	VRF-Retro-Warehouse	20	$3.25	$79.84	$105.75	0.56	2.87	0.0005
Commercial	HVAC	VRF-Retro-Xlarge Ret	20	$3.31	$126.87	$144.35	0.36	2.14	0.0002
Commercial	Refrigeration	Market Average to ES 2.0 Upgrade	6	$35.00	$53.70	$74.53	0.72	108.07	0.0136
Commercial	Refrigeration	Timer on ES 2.0 Cold Only Water Cooler	6	$25.35	$127.39	$157.65	0.39	37.00	0.0085
Commercial	Refrigeration	Timer on ES 2.0 Hot & Cold Water Cooler	6	$25.35	$1.27	$31.53	1.96	185.01	0.0423
Commercial	HVAC	WEPT-Retro-Assembly	0	$0.00	$9,999.00	$9,999.00	9,999.00	-	-
Commercial	HVAC	WEPT-Retro-Hospital	0	$0.00	$9,999.00	$9,999.00	9,999.00	-	-
Commercial	HVAC	WEPT-Retro-Large Off	0	$0.00	$9,999.00	$9,999.00	9,999.00	-	-
Commercial	HVAC	WEPT-Retro-Large Ret	0	$0.00	$9,999.00	$9,999.00	9,999.00	-	-
Commercial	HVAC	WEPT-Retro-Lodging	5	$0.14	$38.00	$72.93	0.95	0.35	0.0001
Commercial	HVAC	WEPT-Retro-Medium Off	0	$0.00	$9,999.00	$9,999.00	9,999.00	-	-
Commercial	HVAC	WEPT-Retro-Medium Ret	5	$0.14	-$1.57	$52.14	1.46	0.49	0.0002

Sector	End Use	Measure Name	Measure Life (Years)	Initial Capital Cost	TRC Levelized Cost ($/MWh)	Total Sponsor Levelized Cost ($/MWh)	TRC B/C Ratio	Bulk Energy (kWh/unit)	Wholesale Demand (kW)
Commercial	HVAC	WEPT-Retro-MiniMart	0	$0.14	-$14.77	$23.96	2.35	1.06	0.0003
Commercial	HVAC	WEPT-Retro-Other	0	$0.00	$9,999.00	$9,999.00	9,999.00	-	-
Commercial	HVAC	WEPT-Retro-Residential Care	5	$0.14	$49.64	$73.05	0.84	0.35	0.0001
Commercial	HVAC	WEPT-Retro-Restaurant	0	$0.00	$9,999.00	$9,999.00	9,999.00	-	-
Commercial	HVAC	WEPT-Retro-School K-12	5	$0.14	$24.73	$72.74	1.09	0.35	0.0001
Commercial	HVAC	WEPT-Retro-Small Off	5	$0.14	$34.02	$100.90	1.00	0.25	0.0002
Commercial	HVAC	WEPT-Retro-Small Ret	5	$0.14	-$1.57	$52.14	1.46	0.49	0.0002
Commercial	HVAC	WEPT-Retro-Supermarket	0	$0.14	-$14.77	$23.96	2.35	1.06	0.0003
Commercial	HVAC	WEPT-Retro-University	0	$0.00	$9,999.00	$9,999.00	9,999.00	-	-
Commercial	HVAC	WEPT-Retro-Warehouse	0	$0.00	$9,999.00	$9,999.00	9,999.00	-	-
Commercial	HVAC	WEPT-Retro-Xlarge Ret	0	$0.00	$9,999.00	$9,999.00	9,999.00	-	-
Commercial	Water Heating	WHTanks-NR-Assembly	13	$31.28	$36.16	$61.39	0.96	63.28	0.0109
Commercial	Water Heating	WHTanks-NR-Hospital	13	$33.02	$37.66	$62.89	0.93	65.20	0.0112
Commercial	Water Heating	WHTanks-NR-Large Off	13	$27.92	$32.69	$57.93	1.02	59.87	0.0103
Commercial	Water Heating	WHTanks-NR-Large Ret	13	$26.94	$30.91	$56.15	1.05	59.59	0.0103
Commercial	Water Heating	WHTanks-NR-Lodging	13	$31.85	$36.92	$62.16	0.95	63.63	0.0110
Commercial	Water Heating	WHTanks-NR-Medium Off	13	$27.92	$32.69	$57.93	1.02	59.87	0.0103
Commercial	Water Heating	WHTanks-NR-Medium Ret	13	$26.94	$30.91	$56.15	1.05	59.59	0.0103
Commercial	Water Heating	WHTanks-NR-MiniMart	13	$25.85	$29.40	$54.63	1.08	58.75	0.0101
Commercial	Water Heating	WHTanks-NR-Other	13	$27.15	$30.48	$55.71	1.06	60.53	0.0104
Commercial	Water Heating	WHTanks-NR-Residential Care	13	$33.02	$37.66	$62.89	0.93	65.20	0.0112
Commercial	Water Heating	WHTanks-NR-Restaurant	13	$32.55	$38.05	$63.28	0.93	63.87	0.0110
Commercial	Water Heating	WHTanks-NR-School K-12	13	$25.75	$27.02	$52.26	1.13	61.19	0.0105
Commercial	Water Heating	WHTanks-NR-Small Off	13	$27.92	$32.69	$57.93	1.02	59.87	0.0103
Commercial	Water Heating	WHTanks-NR-Small Ret	13	$26.94	$30.91	$56.15	1.05	59.59	0.0103
Commercial	Water Heating	WHTanks-NR-Supermarket	13	$25.85	$29.40	$54.63	1.08	58.75	0.0101
Commercial	Water Heating	WHTanks-NR-University	13	$33.02	$37.66	$62.89	0.93	65.20	0.0112
Commercial	Water Heating	WHTanks-NR-Warehouse	13	$29.66	$33.84	$59.07	1.00	62.37	0.0107
Commercial	Water Heating	WHTanks-NR-Xlarge Ret	13	$26.94	$30.91	$56.15	1.05	59.59	0.0103
Distribution Efficie	Distribution Efficiency	1 - LDC voltage control method	15	$0.16	-$17.31	$5.38	10.47	4.37	0.0006
Distribution Efficie	Distribution Efficiency	2 - Light system improvements	15	$0.23	-$11.83	$10.86	5.18	2.62	0.0004
Distribution Efficie	Distribution Efficiency	3 - Major system improvements	15	$1.78	$45.26	$67.95	0.83	2.87	0.0004
Distribution Efficie	Distribution Efficiency	4 - EOL voltage control method	15	$1.31	$76.58	$99.27	0.57	1.48	0.0002
Distribution Efficie	Distribution Efficiency	A - SCL implement EOL w/ major system improvements	15	$0.35	$310.70	$333.39	0.17	0.11	0.0000
Industrial	Misc	Synchronous Belts	0	$0.00	$9,999.00	$9,999.00	9,999.00	-	-
Industrial	Compressed air	Air Compressor Demand Reduction	10	$4,894,983.53	$18.58	$39.59	1.38	58,090,860.34	7,405.4723
Industrial	Compressed Air	Air Compressor Equipment1	0	$0.00	$9,999.00	$9,999.00	9,999.00	-	-
Industrial	Compressed Air	Air Compressor Equipment2	10	$2,115,724.47	$16.02	$37.04	1.47	31,014,720.11	3,953.7829
Industrial	Energy Management	Air Compressor Optimization	10	$19,676,253.07	-$10.20	$60.88	1.72	90,302,151.09	11,511.7950
Industrial	Energy Management	Energy Project Management	11	$128,973,120.63	$30.84	$51.85	1.05	885,835,292.32	112,927.0361
Industrial	Energy Management	Fan Energy Management	10	$0.00	$10.69	$31.43	1.72	86,115,370.28	10,684.6555
Industrial	Energy Management	Fan System Optimization	10	$35,469,452.64	-$1.22	$59.93	1.57	254,161,358.49	35,332.3597
Industrial	Fans	Efficient Centrifugal Fan	10	$4,543,976.58	$11.65	$31.68	1.67	22,853,824.66	2,684.7256
Industrial	Fans	Fan Equipment Upgrade	10	$22,397,943.95	$25.17	$46.19	1.18	241,302,050.26	30,761.3905
Industrial	Low & Med Temp Ref	Food: Cooling and Storage	10	$47,171,855.74	$35.27	$53.99	0.97	139,203,370.72	14,537.8834
Industrial	Energy Management	Cold Storage Tuneup	3	$2,052,120.93	$15.15	$33.87	1.54	27,980,299.67	2,922.1587
Industrial	Energy Management	Food: Refrig Storage Tuneup	3	$5,503,383.17	$15.15	$33.87	1.54	75,037,639.47	7,836.6526
Industrial	Energy Management	Fruit Storage Tuneup	3	$9,263,486.50	$15.15	$33.87	1.54	126,305,971.99	13,190.9270
Industrial	Energy Management	Groc Dist Tuneup	3	$1,042,365.47	$15.15	$33.87	1.54	14,212,465.65	1,484.2972
Industrial	Low & Med Temp Ref	Cold Storage Retrofit	10	$12,702,023.23	$29.29	$48.01	1.09	42,155,811.74	4,402.5965
Industrial	Low & Med Temp Ref	Fruit Storage Refer Retrofit	10	$99,961,068.06	$22.42	$41.14	1.27	387,136,608.99	40,431.1108
Industrial	Low & Med Temp Ref	Groc Dist Retrofit	10	$3,622,119.39	$31.36	$50.08	1.04	11,523,620.80	1,203.4842
Industrial	Misc	CA Retrofit -- CO2 Scrub	0	$0.00	$9,999.00	$9,999.00	9,999.00	-	-
Industrial	MIsc	CA Retrofit -- Membrane	0	$0.00	$9,999.00	$9,999.00	9,999.00	-	-
Industrial	Energy Management	Clean Room: Chiller Optimize	10	$1,142,990.67	-$5.67	$15.35	3.55	11,866,292.88	1,512.7251
Industrial	Hi-Tech	Clean Room: Change Filter Strategy	1	$208,049.55	-$11.10	$9.92	5.50	27,883,392.65	3,554.5986
Industrial	Hi-Tech	Clean Room: Clean Room HVAC	20	$1,460,366.16	-$2.43	$18.59	2.93	7,533,994.16	960.4400
Industrial	Hi-Tech	Elec Chip Fab: Eliminate Exhaust	10	$427,437.59	$31.05	$52.07	1.05	1,307,967.15	166.7408
Industrial	Hi-Tech	Elec Chip Fab: Exhaust Injector	10	$19,826,163.56	-$91.34	$75.10	2.66	42,060,231.40	5,361.8741
Industrial	Hi-Tech	Elec Chip Fab: Reduce Gas Pressure	10	$0.00	-$36.25	$0.00	9,999.00	10,753,955.98	1,370.9235
Industrial	Hi-Tech	Elec Chip Fab: Solidstate Chiller	10	$25,097,668.17	-$69.28	$84.81	2.21	47,149,204.24	6,010.6206
Industrial	Energy Management	Integrated Plant Energy Management	11	$193,454,247.23	-$14.67	$74.29	1.65	780,283,446.85	99,471.1971
Industrial	Lighting	Efficient Lighting 1 Shift	20.97902	$17,023,461.45	$27.65	$54.70	1.09	21,036,116.31	4,025.0284
Industrial	Lighting	Efficient Lighting 2 Shift	12.27496	$18,650,682.54	$15.51	$41.98	1.30	40,222,733.92	7,451.5074
Industrial	Lighting	Efficient Lighting 3 Shift	8.675799	$22,214,004.58	$3.57	$24.59	1.66	87,406,502.66	11,142.6553
Industrial	Lighting	HighBay Lighting 1 Shift	26.57343	$36,176,265.27	$17.55	$44.60	1.27	48,402,730.16	9,261.3275
Industrial	Lighting	HighBay Lighting 2 Shift	15.54828	$34,861,440.05	$3.80	$30.27	1.63	82,252,259.47	15,237.7340
Industrial	Lighting	HighBay Lighting 3 Shift	8.675799	$42,199,695.58	$2.34	$23.36	1.75	181,605,197.63	23,151.1850
Industrial	Lighting	Lighting Controls	10	$77,919,911.05	$135.99	$157.01	0.38	74,581,257.62	9,507.6821
Industrial	Material Handling	Material Handling VFD1	0	$0.00	$9,999.00	$9,999.00	9,999.00	-	-
Industrial	Material Handling	Material Handling VFD2	10	$77,618,573.25	$29.28	$51.51	1.07	240,089,242.85	33,376.1179
Industrial	Material Handling	Material Handling1	0	$0.00	$9,999.00	$9,999.00	9,999.00	-	-
Industrial	Material Handling	Material Handling2	10	$32,341,072.19	$63.02	$85.25	0.65	60,441,875.57	8,402.3555

Sector	End Use	Measure Name	Measure Life (Years)	Initial Capital Cost	TRC Levelized Cost ($/MWh)	Total Sponsor Levelized Cost ($/MWh)	TRC B/C Ratio	Bulk Energy (kWh/unit)	Wholesale Demand (kW)
Industrial	Metals	Metal: New Arc Furnace	10	$226,213.72	-$2,099.06	$15.48	138.80	2,328,918.87	296.8926
Industrial	Motors	Motors: Rewind 101-200 HP	0	$0.00	$9,999.00	$9,999.00	9,999.00	-	-
Industrial	Motors	Motors: Rewind 201-500 HP	0	$0.00	$9,999.00	$9,999.00	9,999.00	-	-
Industrial	Motors	Motors: Rewind 20-50 HP	0	$0.00	$9,999.00	$9,999.00	9,999.00	-	-
Industrial	Motors	Motors: Rewind 501-5000 HP	0	$0.00	$9,999.00	$9,999.00	9,999.00	-	-
Industrial	Motors	Motors: Rewind 51-100 HP	0	$0.00	$9,999.00	$9,999.00	9,999.00	-	-
Industrial	Process Loads	Optimize Municipal Sewage ; <1 MGD Design Capacity	12	$50,893.14	$15.35	$38.98	1.28	98,564.44	15.4865
Industrial	Process Loads	Optimize Municipal Sewage ; >10 MGD Design Capacity	12	$8,953.66	-$24.52	-$0.89	3.09	41,928.34	6.5878
Industrial	Process Loads	Optimize Municipal Sewage ; 1 to 10 MGD Design Capacity	12	$47,324.29	$25.64	$49.27	1.11	79,601.54	12.5071
Industrial	Paper	Paper: Efficient Pulp Screen	10	$5,911,525.20	$9.16	$30.18	1.81	31,209,563.69	3,978.6217
Industrial	Paper	Paper: Large Material Handling	10	$14,100,897.33	$173.11	$194.13	0.28	11,572,673.66	1,475.2943
Industrial	Paper	Paper: Material Handling	10	$7,839,206.23	$145.78	$166.80	0.33	7,487,807.43	954.5521
Industrial	Paper	Paper: Premium Control Large Material	10	$15,510,987.07	$61.52	$82.54	0.66	29,940,445.94	3,816.8335
Industrial	Paper	Paper: Premium Fan	10	$7,431,903.08	$9.31	$30.32	1.80	39,049,473.30	4,978.0601
Industrial	Energy Management	Plant Energy Management	10	$10,075,823.31	$12.83	$33.84	1.61	422,179,997.67	53,819.8650
Industrial	Pulp	Kraft: Efficient Agitator	10	$5,162,724.54	-$6.73	$14.29	3.82	57,559,084.03	7,337.6810
Industrial	Pulp	Kraft: Effluent Treatment System	10	$548,217.72	-$8.65	$12.37	4.41	7,059,659.43	899.9714
Industrial	Pulp	Mech Pulp: Premium Process	5	$36,988.43	$13.73	$34.75	1.57	307,270.95	39.1712
Industrial	Pulp	Mech Pulp: Refiner Plate Improvement	1	$49,032.67	$29.52	$50.54	1.08	1,289,621.59	164.4021
Industrial	Pulp	Mech Pulp: Refiner Replacement	12	$12,065,631.31	$21.31	$42.33	1.14	19,538,053.41	2,490.7277
Industrial	Energy Management	Pump Energy Management	10	$0.00	$11.40	$31.43	1.68	127,181,598.48	14,940.5055
Industrial	Energy Management	Pump System Optimization	12	$104,734,384.70	-$29.75	$85.11	1.74	351,468,026.81	43,607.9502
Industrial	Pumps	Pump Equipment Upgrade	10	$47,032,776.18	$33.22	$53.25	0.99	343,391,153.15	40,339.4632
Industrial	Transformers	Transformers-New	0	$0.00	$9,999.00	$9,999.00	9,999.00	-	-
Industrial	Transformers	Transformers-Retrofit	0	$0.00	$9,999.00	$9,999.00	9,999.00	-	-
Industrial	Wood	Panel: Hydraulic Press	10	$1,588,802.03	$11.22	$33.45	1.66	7,567,525.34	1,052.0031
Industrial	Wood	Wood: Replace Pneumatic Conveyor	10	$2,740,983.10	-$83.19	$2.42	49.09	180,551,426.81	25,099.4407
Residential	Electronics	Infrared sensing advanced power strip	5	$35.47	$774.30	$803.47	0.08	10.73	0.0023
Residential	Electronics	Load sensing advanced power strip	5	$39.34	$258.41	$281.62	0.20	33.95	0.0053
Residential	Electronics	Occupancy sensing advanced power strip	5	$20.38	$1,859.36	$1,882.58	0.03	2.63	0.0004
Residential	Electronics	PC-interaction-sensing Home Office APS	5	$19.15	$2,814.90	$2,838.11	0.02	1.64	0.0003
Residential	Electronics	Infrared sensing advanced power strip	5	$35.47	$774.30	$803.47	0.08	10.73	0.0023
Residential	Electronics	Load sensing advanced power strip	5	$39.34	$258.41	$281.62	0.20	33.95	0.0053
Residential	Electronics	Occupancy sensing advanced power strip	5	$20.38	$1,859.36	$1,882.58	0.03	2.63	0.0004
Residential	Electronics	PC-interaction-sensing Home Office APS	5	$19.15	$2,814.90	$2,838.11	0.02	1.64	0.0003
Residential	Electronics	Infrared sensing advanced power strip	5	$35.47	$774.30	$803.47	0.08	10.73	0.0023
Residential	Electronics	Load sensing advanced power strip	5	$39.34	$258.41	$281.62	0.20	33.95	0.0053
Residential	Electronics	Occupancy sensing advanced power strip	5	$20.38	$1,859.36	$1,882.58	0.03	2.63	0.0004
Residential	Electronics	PC-interaction-sensing Home Office APS	5	$19.15	$2,814.90	$2,838.11	0.02	1.64	0.0003
Residential	Electronics	Infrared sensing advanced power strip	5	$35.47	$774.30	$803.47	0.08	10.73	0.0023
Residential	Electronics	Load sensing advanced power strip	5	$39.34	$258.41	$281.62	0.20	33.95	0.0053
Residential	Electronics	Occupancy sensing advanced power strip	5	$20.38	$1,859.36	$1,882.58	0.03	2.63	0.0004
Residential	Electronics	PC-interaction-sensing Home Office APS	5	$19.15	$2,814.90	$2,838.11	0.02	1.64	0.0003
Residential	Electronics	Infrared sensing advanced power strip	5	$35.47	$774.30	$803.47	0.08	10.73	0.0023
Residential	Electronics	Load sensing advanced power strip	5	$39.34	$258.41	$281.62	0.20	33.95	0.0053
Residential	Electronics	Occupancy sensing advanced power strip	5	$20.38	$1,859.36	$1,882.58	0.03	2.63	0.0004
Residential	Electronics	PC-interaction-sensing Home Office APS	5	$19.15	$2,814.90	$2,838.11	0.02	1.64	0.0003
Residential	Electronics	Infrared sensing advanced power strip	5	$35.47	$774.30	$803.47	0.08	10.73	0.0023
Residential	Electronics	Load sensing advanced power strip	5	$39.34	$258.41	$281.62	0.20	33.95	0.0053
Residential	Electronics	Occupancy sensing advanced power strip	5	$20.38	$1,859.36	$1,882.58	0.03	2.63	0.0004
Residential	Electronics	PC-interaction-sensing Home Office APS	5	$19.15	$2,814.90	$2,838.11	0.02	1.64	0.0003
Residential	Electronics	Infrared sensing advanced power strip	5	$35.47	$774.30	$803.47	0.08	10.73	0.0023
Residential	Electronics	Load sensing advanced power strip	5	$39.34	$258.41	$281.62	0.20	33.95	0.0053
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Residential	Electronics	PC-interaction-sensing Home Office APS	5	$19.15	$2,814.90	$2,838.11	0.02	1.64	0.0003
Residential	Electronics	Infrared sensing advanced power strip	5	$35.47	$774.30	$803.47	0.08	10.73	0.0023
Residential	Electronics	Load sensing advanced power strip	5	$39.34	$258.41	$281.62	0.20	33.95	0.0053
Residential	Electronics	Occupancy sensing advanced power strip	5	$20.38	$1,859.36	$1,882.58	0.03	2.63	0.0004
Residential	Electronics	PC-interaction-sensing Home Office APS	5	$19.15	$2,814.90	$2,838.11	0.02	1.64	0.0003
Residential	Water Heating	Manufactured Bathroom Aerator 1.0 GPM AnyWH	15	$4.57	-$146.73	$24.12	8.47	26.50	0.0052
Residential	Water Heating	Multifamily - High Rise Bathroom Aerator 1.0 GPM AnyWH	15	$4.57	-$141.46	$19.46	10.00	32.85	0.0064
Residential	Water Heating	Multifamily - Low Rise Bathroom Aerator 1.0 GPM AnyWH	15	$4.57	-$141.46	$19.46	10.00	32.85	0.0064
Residential	Water Heating	Single Family Bathroom Aerator 1.0 GPM AnyWH	15	$4.57	-$272.59	$47.27	7.48	13.52	0.0026
Residential	Water Heating	Single Family Bathroom Aerator 1.0 GPM HPWH	15	$4.57	-$208.26	$45.40	6.33	14.08	0.0030
Residential	Water Heating	Manufactured Bathroom Aerator 1.0 GPM AnyWH	15	$4.57	-$146.73	$24.12	8.47	26.50	0.0052
Residential	Water Heating	Multifamily - High Rise Bathroom Aerator 1.0 GPM AnyWH	15	$4.57	-$141.46	$19.46	10.00	32.85	0.0064
Residential	Water Heating	Multifamily - Low Rise Bathroom Aerator 1.0 GPM AnyWH	15	$4.57	-$141.46	$19.46	10.00	32.85	0.0064
Residential	Water Heating	Single Family Bathroom Aerator 1.0 GPM AnyWH	15	$4.57	-$272.59	$47.27	7.48	13.52	0.0026
Residential	Water Heating	Single Family Bathroom Aerator 1.0 GPM HPWH	15	$4.57	-$208.26	$45.40	6.33	14.08	0.0030
Residential	HVAC	HVAC Conversion - FAF to ASHP 8.5 HSPF/14SEER + HZ1CZ1	15	$4,632.69	$97.99	$145.16	0.57	3,205.07	1.0727
Residential	HVAC	HVAC Conversion - FAF to ASHP 8.5 HSPF/14SEER + HZ1CZ23	15	$3,914.63	$63.13	$115.48	0.77	3,091.94	1.0727
Residential	HVAC	HVAC Conversion - FAF to ASHP 8.5 HSPF/14SEER + HZ23CZ1	15	$4,748.46	$121.75	$165.96	0.49	2,891.44	0.8647
Residential	HVAC	HVAC Conversion - FAF to ASHP 8.5 HSPF/14SEER + HZ23CZ23	15	$4,018.45	$78.13	$127.25	0.68	2,916.08	0.9031

Sector	End Use	Measure Name	Measure Life (Years)	Initial Capital Cost	TRC Levelized Cost ($/MWh)	Total Sponsor Levelized Cost ($/MWh)	TRC B/C Ratio	Bulk Energy (kWh/unit)	Wholesale Demand (kW)
Residential	HVAC	HVAC Conversion - FAF w/CAC to ASHP 8.5 HSPF/14SEER + HZ1	15	$3,060.27	$51.83	$88.80	0.80	3,363.96	0.9534
Residential	HVAC	HVAC Conversion - FAF w/CAC to ASHP 8.5 HSPF/14SEER + HZ23	15	$3,122.54	$52.27	$89.25	0.82	3,109.42	0.8813
Residential	HVAC	HVAC Upgrade - Heat Pump Upgrade to 9.0 HSPF/14 SEER + HZ1CZ1	15	$89.69	$56.06	$91.71	0.80	95.70	0.0335
Residential	HVAC	HVAC Upgrade - Heat Pump Upgrade to 9.0 HSPF/14 SEER + HZ1CZ23	15	$89.69	$56.06	$91.71	0.80	95.70	0.0335
Residential	HVAC	HVAC Upgrade - Heat Pump Upgrade to 9.0 HSPF/14 SEER + HZ23CZ1	15	$89.69	$101.72	$127.81	0.58	65.55	0.0229
Residential	HVAC	HVAC Upgrade - Heat Pump Upgrade to 9.0 HSPF/14 SEER + HZ23CZ23	15	$89.69	$93.65	$119.73	0.61	69.41	0.0243
Residential	HVAC	New SF HVAC Upgrade - Central Heat Pump Upgrade to Variable Capacity (	15	$5,377.54	$865.63	$902.86	0.09	621.99	0.1800
Residential	HVAC	New SF HVAC Upgrade - Heat Pump Upgrade to 9.0 HSPF/14 SEER	15	$90.00	$27.44	$70.66	1.08	109.32	0.0383
Residential	HVAC	HVAC Conversion - FAF to ASHP 8.5 HSPF/14SEER + HZ1CZ1	15	$4,632.69	$97.99	$145.16	0.57	3,205.07	1.0727
Residential	HVAC	HVAC Conversion - FAF to ASHP 8.5 HSPF/14SEER + HZ1CZ23	15	$3,914.63	$63.13	$115.48	0.77	3,091.94	1.0727
Residential	HVAC	HVAC Conversion - FAF to ASHP 8.5 HSPF/14SEER + HZ23CZ1	15	$4,748.46	$121.75	$165.96	0.49	2,891.44	0.8647
Residential	HVAC	HVAC Conversion - FAF to ASHP 8.5 HSPF/14SEER + HZ23CZ23	15	$4,018.45	$78.13	$127.25	0.68	2,916.08	0.9031
Residential	HVAC	HVAC Conversion - FAF w/CAC to ASHP 8.5 HSPF/14SEER + HZ1	15	$3,060.27	$51.83	$88.80	0.80	3,363.96	0.9534
Residential	HVAC	HVAC Conversion - FAF w/CAC to ASHP 8.5 HSPF/14SEER + HZ23	15	$3,122.54	$52.27	$89.25	0.82	3,109.42	0.8813
Residential	HVAC	HVAC Upgrade - Heat Pump Upgrade to 9.0 HSPF/14 SEER + HZ1CZ1	15	$89.69	$56.06	$91.71	0.80	95.70	0.0335
Residential	HVAC	HVAC Upgrade - Heat Pump Upgrade to 9.0 HSPF/14 SEER + HZ1CZ23	15	$89.69	$56.06	$91.71	0.80	95.70	0.0335
Residential	HVAC	HVAC Upgrade - Heat Pump Upgrade to 9.0 HSPF/14 SEER + HZ23CZ1	15	$89.69	$101.72	$127.81	0.58	65.55	0.0229
Residential	HVAC	HVAC Upgrade - Heat Pump Upgrade to 9.0 HSPF/14 SEER + HZ23CZ23	15	$89.69	$93.65	$119.73	0.61	69.41	0.0243
Residential	HVAC	Existing Single Family Home HVAC Conversion - Convert FAF w/CAC to Heat	15	$3,531.74	$35.09	$78.28	0.99	3,934.79	1.3756
Residential	HVAC	Existing Single Family Home HVAC Conversion - Convert FAF w/CAC to Heat	15	$3,612.39	$37.25	$80.44	0.97	3,637.06	1.2715
Residential	HVAC	Existing Single Family Home HVAC Conversion - Convert FAF w/o CAC to He	15	$5,487.05	$87.89	$138.06	0.65	3,730.76	1.3756
Residential	HVAC	Existing Single Family Home HVAC Conversion - Convert FAF w/o CAC to He	15	$4,002.29	$29.81	$75.78	1.04	3,851.07	1.3756
Residential	HVAC	Existing Single Family Home HVAC Conversion - Convert FAF w/o CAC to He	15	$5,642.58	$102.49	$153.56	0.62	3,305.19	1.2268
Residential	HVAC	Existing Single Family Home HVAC Conversion - Convert FAF w/o CAC to He	15	$4,433.21	$32.21	$80.44	1.01	3,598.61	1.3076
Residential	HVAC	Existing Single Family Home HVAC Upgrade - Central Heat Pump Upgrade t	15	$5,853.86	$1,378.10	$1,416.55	0.06	431.98	0.1304
Residential	HVAC	Existing Single Family Home HVAC Upgrade - Central Heat Pump Upgrade t	15	$5,853.86	$1,089.31	$1,121.85	0.09	538.32	0.1304
Residential	HVAC	Existing Single Family Home HVAC Upgrade - Central Heat Pump Upgrade t	15	$5,853.86	$875.36	$915.45	0.11	659.70	0.2100
Residential	HVAC	Existing Single Family Home HVAC Upgrade - Central Heat Pump Upgrade t	15	$5,853.86	$858.18	$894.23	0.13	657.46	0.1825
Residential	HVAC	Existing Single Family Home HVAC Upgrade + HZ1	15	$99.08	$30.19	$73.38	1.04	115.73	0.0405
Residential	HVAC	Existing Single Family Home HVAC Upgrade + HZ23	15	$99.08	$60.71	$103.89	0.79	81.74	0.0286
Residential	Water Heating	Controled Optimization Program	5	$32.00	$13.55	$42.74	1.47	181.94	0.0383
Residential	Water Heating	Controled Optimization Program	5	$32.00	$13.55	$42.74	1.47	181.94	0.0383
Residential	Dryer	Heat Pump Dryer	16	$386.45	$50.15	$106.31	0.85	446.44	0.1782
Residential	Dryer	Heat Pump Dryer	16	$386.45	$50.15	$106.31	0.85	446.44	0.1782
Residential	Dryer	Heat Pump Dryer	16	$386.45	$50.15	$106.31	0.85	446.44	0.1782
Residential	Dryer	Heat Pump Dryer	16	$386.45	$50.15	$106.31	0.85	446.44	0.1782
Residential	Dryer	Heat Pump Dryer	16	$386.45	$50.15	$106.31	0.85	446.44	0.1782
Residential	Dryer	Heat Pump Dryer	16	$386.45	$50.15	$106.31	0.85	446.44	0.1782
Residential	Dryer	Heat Pump Dryer	16	$386.45	$50.15	$106.31	0.85	446.44	0.1782
Residential	Dryer	Heat Pump Dryer	16	$386.45	$50.15	$106.31	0.85	446.44	0.1782
Residential	Water Heating	Manufactured CEE Tier 1 Clothes Washer - Any DHW, Any Dryer - 54% ENE	14	$59.53	-$103.64	$45.61	4.01	143.18	0.0209
Residential	Water Heating	Manufactured CEE Tier 2 Clothes Washer - Any DHW, Any Dryer - 54% ENE	14	$0.00	-$23.57	$0.01	9,280.29	17.73	0.0026
Residential	Water Heating	Manufactured CEE Tier 3 Clothes Washer - Any DHW, Any Dryer - 54% ENE	14	$632.94	$45,442.35	$47,527.49	0.04	1.46	0.0002
Residential	Water Heating	Multifamily - High Rise CEE Tier 1 Clothes Washer - Any DHW, Any Dryer - 5	14	$59.53	-$103.64	$45.61	4.01	143.18	0.0209
Residential	Water Heating	Multifamily - High Rise CEE Tier 2 Clothes Washer - Any DHW, Any Dryer - 5	14	$0.00	-$23.57	$0.01	9,280.29	17.73	0.0026
Residential	Water Heating	Multifamily - High Rise CEE Tier 3 Clothes Washer - Any DHW, Any Dryer - 5	14	$632.94	$45,442.35	$47,527.49	0.04	1.46	0.0002
Residential	Water Heating	Multifamily - Low Rise CEE Tier 1 Clothes Washer - Any DHW, Any Dryer - 5	14	$59.53	-$103.64	$45.61	4.01	143.18	0.0209
Residential	Water Heating	Multifamily - Low Rise CEE Tier 2 Clothes Washer - Any DHW, Any Dryer - 5	14	$0.00	-$23.57	$0.01	9,280.29	17.73	0.0026
Residential	Water Heating	Multifamily - Low Rise CEE Tier 3 Clothes Washer - Any DHW, Any Dryer - 5	14	$632.94	$45,442.35	$47,527.49	0.04	1.46	0.0002
Residential	Water Heating	Single Family CEE Tier 1 Clothes Washer - Any DHW, Any Dryer - 54% ENER	14	$59.53	-$103.63	$45.61	4.01	143.18	0.0209
Residential	Water Heating	Single Family CEE Tier 2 Clothes Washer - Any DHW, Any Dryer - 54% ENER	14	$0.00	-$23.56	$0.01	9,280.00	17.73	0.0026
Residential	Water Heating	Single Family CEE Tier 3 Clothes Washer - Any DHW, Any Dryer - 54% ENER	14	$632.94	$45,442.49	$47,527.49	0.04	1.46	0.0002
Residential	Water Heating	Manufactured CEE Tier 1 Clothes Washer - Any DHW, Any Dryer - 54% ENE	14	$59.53	-$103.64	$45.61	4.01	143.18	0.0209
Residential	Water Heating	Manufactured CEE Tier 2 Clothes Washer - Any DHW, Any Dryer - 54% ENE	14	$0.00	-$23.57	$0.01	9,280.29	17.73	0.0026
Residential	Water Heating	Manufactured CEE Tier 3 Clothes Washer - Any DHW, Any Dryer - 54% ENE	14	$632.94	$45,442.35	$47,527.49	0.04	1.46	0.0002
Residential	Water Heating	Multifamily - High Rise CEE Tier 1 Clothes Washer - Any DHW, Any Dryer - 5	14	$59.53	-$103.64	$45.61	4.01	143.18	0.0209
Residential	Water Heating	Multifamily - High Rise CEE Tier 2 Clothes Washer - Any DHW, Any Dryer - 5	14	$0.00	-$23.57	$0.01	9,280.29	17.73	0.0026
Residential	Water Heating	Multifamily - High Rise CEE Tier 3 Clothes Washer - Any DHW, Any Dryer - 5	14	$632.94	$45,442.35	$47,527.49	0.04	1.46	0.0002
Residential	Water Heating	Multifamily - Low Rise CEE Tier 1 Clothes Washer - Any DHW, Any Dryer - 5	14	$59.53	-$103.64	$45.61	4.01	143.18	0.0209
Residential	Water Heating	Multifamily - Low Rise CEE Tier 2 Clothes Washer - Any DHW, Any Dryer - 5	14	$0.00	-$23.57	$0.01	9,280.29	17.73	0.0026
Residential	Water Heating	Multifamily - Low Rise CEE Tier 3 Clothes Washer - Any DHW, Any Dryer - 5	14	$632.94	$45,442.35	$47,527.49	0.04	1.46	0.0002
Residential	Water Heating	Single Family CEE Tier 1 Clothes Washer - Any DHW, Any Dryer - 54% ENER	14	$59.53	-$103.63	$45.61	4.01	143.18	0.0209
Residential	Water Heating	Single Family CEE Tier 2 Clothes Washer - Any DHW, Any Dryer - 54% ENER	14	$0.00	-$23.56	$0.01	9,280.00	17.73	0.0026
Residential	Water Heating	Single Family CEE Tier 3 Clothes Washer - Any DHW, Any Dryer - 54% ENER	14	$632.94	$45,442.49	$47,527.49	0.04	1.46	0.0002
Residential	Electronics	ENERGY STAR Desktops	5	$13.80	$27.50	$49.89	1.11	67.23	0.0098
Residential	Electronics	ENERGY STAR Laptops	4	$55.70	$822.81	$845.20	0.07	19.43	0.0028
Residential	Electronics	ENERGY STAR Desktops	5	$13.80	$27.50	$49.89	1.11	67.23	0.0098
Residential	Electronics	ENERGY STAR Laptops	4	$55.70	$822.81	$845.20	0.07	19.43	0.0028
Residential	Electronics	ENERGY STAR Desktops	5	$13.80	$27.50	$49.89	1.11	67.23	0.0098
Residential	Electronics	ENERGY STAR Laptops	4	$55.70	$822.81	$845.20	0.07	19.43	0.0028
Residential	Electronics	ENERGY STAR Desktops	5	$13.80	$27.50	$49.89	1.11	67.23	0.0098
Residential	Electronics	ENERGY STAR Laptops	4	$55.70	$822.81	$845.20	0.07	19.43	0.0028
Residential	Electronics	ENERGY STAR Desktops	5	$13.80	$27.50	$49.89	1.11	67.23	0.0098

Sector	End Use	Measure Name	Measure Life (Years)	Initial Capital Cost	TRC Levelized Cost ($/MWh)	Total Sponsor Levelized Cost ($/MWh)	TRC B/C Ratio	Bulk Energy (kWh/unit)	Wholesale Demand (kW)
Residential	Electronics	ENERGY STAR Laptops	4	$55.70	$822.81	$845.20	0.07	19.43	0.0028
Residential	Electronics	ENERGY STAR Desktops	5	$13.80	$27.50	$49.89	1.11	67.23	0.0098
Residential	Electronics	ENERGY STAR Laptops	4	$55.70	$822.81	$845.20	0.07	19.43	0.0028
Residential	Electronics	ENERGY STAR Desktops	5	$13.80	$27.50	$49.89	1.11	67.23	0.0098
Residential	Electronics	ENERGY STAR Laptops	4	$55.70	$822.81	$845.20	0.07	19.43	0.0028
Residential	Electronics	ENERGY STAR Desktops	5	$13.80	$27.50	$49.89	1.11	67.23	0.0098
Residential	Electronics	ENERGY STAR Laptops	4	$55.70	$822.81	$845.20	0.07	19.43	0.0028
Residential	HVAC	MH CC&S + HZ1	15	$568.25	$55.22	$105.93	0.80	568.09	0.1986
Residential	HVAC	MH CC&S + HZ23	15	$568.25	$11.10	$71.37	1.32	843.14	0.2948
Residential	HVAC	SF CC&S + HZ1	15	$568.25	$30.37	$90.07	1.04	668.13	0.2336
Residential	HVAC	SF CC&S + HZ23	15	$568.25	$4.91	$60.67	1.48	991.81	0.3467
Residential	HVAC	MH CC&S + HZ1	15	$568.25	$55.22	$105.93	0.80	568.09	0.1986
Residential	HVAC	MH CC&S + HZ23	15	$568.25	$11.10	$71.37	1.32	843.14	0.2948
Residential	HVAC	SF CC&S + HZ1	15	$568.25	$30.37	$90.07	1.04	668.13	0.2336
Residential	HVAC	SF CC&S + HZ23	15	$568.25	$4.91	$60.67	1.48	991.81	0.3467
Residential	HVAC	New SF Zonal to DHP	15	$3,764.98	$71.96	$137.72	0.72	2,895.05	1.0548
Residential	HVAC	Zonal to DHP No Screen + HZ1CZ1	15	$4,375.97	$131.71	$197.58	0.55	2,117.66	0.7869
Residential	HVAC	Zonal to DHP No Screen + HZ1CZ23	15	$4,037.59	$80.38	$137.63	0.73	2,452.80	0.7887
Residential	HVAC	Zonal to DHP No Screen + HZ23CZ1	15	$4,044.32	$69.83	$137.42	0.83	1,959.56	0.7291
Residential	HVAC	Zonal to DHP No Screen + HZ23CZ23	15	$3,888.66	-$21.69	$38.96	1.32	2,407.45	0.8193
Residential	HVAC	Install Ductless Heat Pump in House with Existing FAF - Manufactured Hom	15	$3,895.16	$64.08	$127.32	0.76	3,239.86	1.1852
Residential	HVAC	Install Ductless Heat Pump in House with Existing FAF - Manufactured Hom	15	$3,895.16	$65.73	$137.64	0.76	2,996.95	0.9555
Residential	HVAC	Install Ductless Heat Pump in House with Existing FAF - Single Family Home	15	$4,039.18	$55.33	$158.13	0.86	2,705.00	0.9896
Residential	HVAC	Install Ductless Heat Pump in House with Existing FAF - Single Family Home	15	$4,039.18	$84.58	$156.87	0.67	2,726.77	0.8694
Residential	Water Heating	Manufactured Energy Star Dishwasher - Any DHW	15.4	$5.28	-$13.34	$159.81	1.29	3.44	0.0007
Residential	Water Heating	Multifamily - High Rise Energy Star Dishwasher - Any DHW	15.4	$5.28	-$13.45	$179.09	1.26	3.07	0.0006
Residential	Water Heating	Multifamily - Low Rise Energy Star Dishwasher - Any DHW	15.4	$5.28	-$13.45	$179.09	1.26	3.07	0.0006
Residential	Water Heating	Single Family Energy Star Dishwasher - Any DHW	15.4	$5.28	-$15.84	$599.36	1.08	0.92	0.0002
Residential	Water Heating	Manufactured Energy Star Dishwasher - Any DHW	15.4	$5.28	-$13.34	$159.81	1.29	3.44	0.0007
Residential	Water Heating	Multifamily - High Rise Energy Star Dishwasher - Any DHW	15.4	$5.28	-$13.45	$179.09	1.26	3.07	0.0006
Residential	Water Heating	Multifamily - Low Rise Energy Star Dishwasher - Any DHW	15.4	$5.28	-$13.45	$179.09	1.26	3.07	0.0006
Residential	Water Heating	Single Family Energy Star Dishwasher - Any DHW	15.4	$5.28	-$15.84	$599.36	1.08	0.92	0.0002
Residential	HVAC	New MH Performance-based Duct Sealing - Heat Pump + HZ1	20	$631.58	$64.48	$107.66	0.72	523.52	0.1830
Residential	HVAC	New MH Performance-based Duct Sealing - Heat Pump + HZ23	20	$631.58	$18.83	$62.02	1.25	908.86	0.3177
Residential	HVAC	New SF Performance-based Duct Sealing - Heat Pump + HZ1	20	$631.58	$86.64	$129.83	0.60	434.15	0.1518
Residential	HVAC	New SF Performance-based Duct Sealing - Heat Pump + HZ23	20	$631.58	$37.16	$80.35	0.96	701.52	0.2452
Residential	HVAC	MH Performance-based Duct Sealing - Heat Pump + HZ1	20	$631.58	$8.82	$52.01	1.49	1,083.79	0.3789
Residential	HVAC	MH Performance-based Duct Sealing - Heat Pump + HZ23	20	$631.58	-$18.50	$24.69	3.14	2,282.91	0.7981
Residential	HVAC	SF Performance-based Duct Sealing - Heat Pump + HZ1	20	$631.58	$19.49	$62.68	1.24	899.23	0.3144
Residential	HVAC	SF Performance-based Duct Sealing - Heat Pump + HZ23	20	$631.58	-$11.47	$31.71	2.44	1,777.26	0.6213
Residential	Food Preparation	Non Self-Cleaning Oven	20	$307.20	$343.98	$406.93	0.24	67.37	0.0385
Residential	Food Preparation	Self-Cleaning Oven	20	$289.22	$412.70	$475.66	0.21	54.26	0.0310
Residential	Food Preparation	Non Self-Cleaning Oven	20	$307.20	$343.98	$406.93	0.24	67.37	0.0385
Residential	Food Preparation	Self-Cleaning Oven	20	$289.22	$412.70	$475.66	0.21	54.26	0.0310
Residential	Food Preparation	Non Self-Cleaning Oven	20	$307.20	$343.98	$406.93	0.24	67.37	0.0385
Residential	Food Preparation	Self-Cleaning Oven	20	$289.22	$412.70	$475.66	0.21	54.26	0.0310
Residential	Food Preparation	Non Self-Cleaning Oven	20	$307.20	$343.98	$406.93	0.24	67.37	0.0385
Residential	Food Preparation	Self-Cleaning Oven	20	$289.22	$412.70	$475.66	0.21	54.26	0.0310
Residential	Food Preparation	Non Self-Cleaning Oven	20	$307.20	$343.98	$406.93	0.24	67.37	0.0385
Residential	Food Preparation	Self-Cleaning Oven	20	$289.22	$412.70	$475.66	0.21	54.26	0.0310
Residential	Food Preparation	Non Self-Cleaning Oven	20	$307.20	$343.98	$406.93	0.24	67.37	0.0385
Residential	Food Preparation	Self-Cleaning Oven	20	$289.22	$412.70	$475.66	0.21	54.26	0.0310
Residential	Food Preparation	Non Self-Cleaning Oven	20	$307.20	$343.98	$406.93	0.24	67.37	0.0385
Residential	Food Preparation	Self-Cleaning Oven	20	$289.22	$412.70	$475.66	0.21	54.26	0.0310
Residential	Food Preparation	Non Self-Cleaning Oven	20	$307.20	$343.98	$406.93	0.24	67.37	0.0385
Residential	Food Preparation	Self-Cleaning Oven	20	$289.22	$412.70	$475.66	0.21	54.26	0.0310
Residential	Whole Bldg/Meter Le	EVSE Level 2	10	$750.00	$825.08	$849.07	0.07	123.53	0.0195
Residential	Refrigeration	Std Size Freezer - ENERGY STAR	21.73469	$45.28	$142.06	$157.60	0.31	24.52	0.0023
Residential	Refrigeration	Std Size Freezer - ENERGY STAR	21.73469	$45.28	$142.06	$157.60	0.31	24.52	0.0023
Residential	Refrigeration	Std Size Freezer - ENERGY STAR	21.73469	$45.28	$142.06	$157.60	0.31	24.52	0.0023
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Residential	Refrigeration	Std Size Freezer - ENERGY STAR	21.73469	$45.28	$142.06	$157.60	0.31	24.52	0.0023
Residential	Refrigeration	Std Size Freezer - ENERGY STAR	21.73469	$45.28	$142.06	$157.60	0.31	24.52	0.0023
Residential	Refrigeration	Std Size Freezer - ENERGY STAR	21.73469	$45.28	$142.06	$157.60	0.31	24.52	0.0023
Residential	HVAC	Ground Source Heat Pump Upgrade from Air Source Heat Pump - With Des	20	$9,375.51	$156.38	$199.56	0.39	4,192.69	1.4657
Residential	HVAC	Ground Source Heat Pump Upgrade from Air Source Heat Pump - With Des	20	$6,731.68	$160.66	$203.85	0.38	2,947.14	1.0303
Residential	HVAC	Ground Source Heat Pump Upgrade from Air Source Heat Pump - With Des	20	$10,628.69	$165.26	$208.45	0.37	4,550.47	1.5908
Residential	HVAC	Ground Source Heat Pump Upgrade from Air Source Heat Pump - With Des	20	$7,227.45	$151.61	$194.80	0.40	3,311.20	1.1576
Residential	HVAC	SF RNC HRV ACH3 HZ1CZ1	20	$1,270.04	$118.61	$162.51	0.48	697.44	0.2489
Residential	HVAC	SF RNC HRV ACH3 HZ1CZ2	20	$1,270.04	$114.48	$157.24	0.49	720.83	0.2489
Residential	HVAC	SF RNC HRV ACH3 HZ1CZ3	20	$1,270.04	$110.11	$151.65	0.50	747.38	0.2489
Residential	HVAC	SF RNC HRV ACH3 HZ2CZ1	20	$1,270.04	$69.13	$112.81	0.69	1,004.73	0.3563

Sector	End Use	Measure Name	Measure Life (Years)	Initial Capital Cost	TRC Levelized Cost ($/MWh)	Total Sponsor Levelized Cost ($/MWh)	TRC B/C Ratio	Bulk Energy (kWh/unit)	Wholesale Demand (kW)
Residential	HVAC	SF RNC HRV ACH3 HZ2CZ2	20	$1,270.04	$67.35	$110.23	0.70	1,028.25	0.3563
Residential	HVAC	SF RNC HRV ACH3 HZ2CZ3	20	$1,270.04	$65.41	$107.40	0.71	1,055.30	0.3563
Residential	HVAC	SF RNC HRV ACH3 HZ3CZ1	20	$1,270.04	$57.30	$100.96	0.77	1,122.70	0.3979
Residential	HVAC	SF RNC HRV ACH3 HZ3CZ2	20	$1,270.04	$55.94	$98.88	0.78	1,146.24	0.3979
Residential	HVAC	SF RNC HRV ACH3 HZ3CZ3	20	$1,270.04	$54.46	$96.60	0.79	1,173.29	0.3979
Residential	Water Heating	Manufactured Tier1_buffered	13	$629.17	$46.40	$75.85	0.83	964.55	0.2131
Residential	Water Heating	Manufactured Tier1_indor2_efaf	13	$629.17	$99.82	$101.43	0.40	721.34	0.0290
Residential	Water Heating	Manufactured Tier1_indor2_gfac	13	$629.17	$50.63	$63.68	0.79	1,148.88	0.2449
Residential	Water Heating	Manufactured Tier1_indor2_gfnc	13	$629.17	$50.63	$63.68	0.79	1,148.88	0.2449
Residential	Water Heating	Manufactured Tier1_indor2_hp85	13	$629.17	$45.60	$75.28	0.83	971.83	0.2536
Residential	Water Heating	Manufactured Tier1_indor2_zonl	13	$629.17	$91.31	$101.41	0.48	721.50	0.0939
Residential	Water Heating	Manufactured Tier2_buffered	13	$0.00	-$29.45	$0.00	9,999.00	501.94	0.1109
Residential	Water Heating	Manufactured Tier2_indor2_efaf	13	$0.00	$16.56	$0.00	1.73	245.20	(0.0191)
Residential	Water Heating	Manufactured Tier2_indor2_gfac	13	$0.00	-$7.67	$0.00	2.97	482.61	0.1025
Residential	Water Heating	Manufactured Tier2_indor2_gfnc	13	$0.00	-$7.67	$0.00	2.97	482.61	0.1025
Residential	Water Heating	Manufactured Tier2_indor2_hp85	13	$0.00	-$30.32	$0.00	12.76	377.33	0.1079
Residential	Water Heating	Manufactured Tier2_indor2_zonl	13	$0.00	$2.52	$0.00	2.92	245.29	0.0174
Residential	Water Heating	Single Family Tier1_buffered	13	$629.17	$44.51	$73.96	0.85	989.23	0.2186
Residential	Water Heating	Single Family Tier1_indor2_efaf	13	$629.17	$99.82	$101.43	0.40	721.34	0.0290
Residential	Water Heating	Single Family Tier1_indor2_gfac	13	$629.17	$50.63	$63.68	0.79	1,148.88	0.2449
Residential	Water Heating	Single Family Tier1_indor2_gfnc	13	$629.17	$50.63	$63.68	0.79	1,148.88	0.2449
Residential	Water Heating	Single Family Tier1_indor2_hp85	13	$629.17	$45.60	$75.28	0.83	971.83	0.2536
Residential	Water Heating	Single Family Tier1_indor2_zonl	13	$629.17	$91.31	$101.41	0.48	721.50	0.0939
Residential	Water Heating	Single Family Tier2_buffered	13	$0.00	-$29.45	$0.00	9,999.00	484.83	0.1071
Residential	Water Heating	Single Family Tier2_indor2_efaf	13	$0.00	$16.56	$0.00	1.73	245.20	(0.0191)
Residential	Water Heating	Single Family Tier2_indor2_gfac	13	$0.00	-$7.67	$0.00	2.97	482.61	0.1025
Residential	Water Heating	Single Family Tier2_indor2_gfnc	13	$0.00	-$7.67	$0.00	2.97	482.61	0.1025
Residential	Water Heating	Single Family Tier2_indor2_hp85	13	$0.00	-$30.32	$0.00	12.76	377.33	0.1079
Residential	Water Heating	Single Family Tier2_indor2_zonl	13	$0.00	$2.52	$0.00	2.92	245.29	0.0174
Residential	Water Heating	Manufactured Tier1_buffered	13	$629.17	$46.40	$75.85	0.83	964.55	0.2131
Residential	Water Heating	Manufactured Tier1_indor2_efaf	13	$629.17	$99.82	$101.43	0.40	721.34	0.0290
Residential	Water Heating	Manufactured Tier1_indor2_gfac	13	$629.17	$50.63	$63.68	0.79	1,148.88	0.2449
Residential	Water Heating	Manufactured Tier1_indor2_gfnc	13	$629.17	$50.63	$63.68	0.79	1,148.88	0.2449
Residential	Water Heating	Manufactured Tier1_indor2_hp85	13	$629.17	$45.60	$75.28	0.83	971.83	0.2536
Residential	Water Heating	Manufactured Tier1_indor2_zonl	13	$629.17	$91.31	$101.41	0.48	721.50	0.0939
Residential	Water Heating	Manufactured Tier2_buffered	13	$0.00	-$29.45	$0.00	9,999.00	501.94	0.1109
Residential	Water Heating	Manufactured Tier2_indor2_efaf	13	$0.00	$16.56	$0.00	1.73	245.20	(0.0191)
Residential	Water Heating	Manufactured Tier2_indor2_gfac	13	$0.00	-$7.67	$0.00	2.97	482.61	0.1025
Residential	Water Heating	Manufactured Tier2_indor2_gfnc	13	$0.00	-$7.67	$0.00	2.97	482.61	0.1025
Residential	Water Heating	Manufactured Tier2_indor2_hp85	13	$0.00	-$30.32	$0.00	12.76	377.33	0.1079
Residential	Water Heating	Manufactured Tier2_indor2_zonl	13	$0.00	$2.52	$0.00	2.92	245.29	0.0174
Residential	Water Heating	Single Family Tier1_buffered	13	$629.17	$44.51	$73.96	0.85	989.23	0.2186
Residential	Water Heating	Single Family Tier1_indor2_efaf	13	$629.17	$99.82	$101.43	0.40	721.34	0.0290
Residential	Water Heating	Single Family Tier1_indor2_gfac	13	$629.17	$50.63	$63.68	0.79	1,148.88	0.2449
Residential	Water Heating	Single Family Tier1_indor2_gfnc	13	$629.17	$50.63	$63.68	0.79	1,148.88	0.2449
Residential	Water Heating	Single Family Tier1_indor2_hp85	13	$629.17	$45.60	$75.28	0.83	971.83	0.2536
Residential	Water Heating	Single Family Tier1_indor2_zonl	13	$629.17	$91.31	$101.41	0.48	721.50	0.0939
Residential	Water Heating	Single Family Tier2_buffered	13	$0.00	-$29.45	$0.00	9,999.00	484.83	0.1071
Residential	Water Heating	Single Family Tier2_indor2_efaf	13	$0.00	$16.56	$0.00	1.73	245.20	(0.0191)
Residential	Water Heating	Single Family Tier2_indor2_gfac	13	$0.00	-$7.67	$0.00	2.97	482.61	0.1025
Residential	Water Heating	Single Family Tier2_indor2_gfnc	13	$0.00	-$7.67	$0.00	2.97	482.61	0.1025
Residential	Water Heating	Single Family Tier2_indor2_hp85	13	$0.00	-$30.32	$0.00	12.76	377.33	0.1079
Residential	Water Heating	Single Family Tier2_indor2_zonl	13	$0.00	$2.52	$0.00	2.92	245.29	0.0174
Residential	Lighting	All_NR_LF_FIX_REPL_from LF2018 to LED_FIX_KIT	20	$86.12	$608.31	$644.99	0.11	11.92	0.0031
Residential	Lighting	All_NR_LF_FIX_REPL_from T12 to LF_2018	20	$49.93	$137.95	$174.63	0.40	25.52	0.0067
Residential	Lighting	All_NR_LF_FIX_REPL_from LF2018 to LED_FIX_KIT	20	$86.12	$608.31	$644.99	0.11	11.92	0.0031
Residential	Lighting	All_NR_LF_FIX_REPL_from T12 to LF_2018	20	$49.93	$137.95	$174.63	0.40	25.52	0.0067
Residential	Lighting	All_NR_LF_FIX_REPL_from LF2018 to LED_FIX_KIT	20	$86.12	$608.31	$644.99	0.11	11.92	0.0031
Residential	Lighting	All_NR_LF_FIX_REPL_from T12 to LF_2018	20	$49.93	$137.95	$174.63	0.40	25.52	0.0067
Residential	Lighting	All_NR_LF_FIX_REPL_from LF2018 to LED_FIX_KIT	20	$86.12	$608.31	$644.99	0.11	11.92	0.0031
Residential	Lighting	All_NR_LF_FIX_REPL_from T12 to LF_2018	20	$49.93	$137.95	$174.63	0.40	25.52	0.0067
Residential	Lighting	2016 - LEDDecorative and Mini-Base1440 to 2600 lumensANY	12	$23.27	$270.60	$301.02	0.33	7.69	0.0020
Residential	Lighting	2016 - LEDDecorative and Mini-Base250 to 664 lumensANY	12	$4.29	-$43.06	-$13.49	3.30	17.17	0.0045
Residential	Lighting	2016 - LEDDecorative and Mini-Base665 to 1439 lumensANY	12	$8.26	-$36.74	-$6.84	1.92	13.26	0.0035
Residential	Lighting	2016 - LEDGeneral Purpose and Dimmable1440 to 2600 lumensANY	12	$11.03	$58.35	$89.15	0.75	13.18	0.0034
Residential	Lighting	2016 - LEDGeneral Purpose and Dimmable250 to 664 lumensANY	12	$0.81	-$37.39	-$6.72	2.47	2.08	0.0005
Residential	Lighting	2016 - LEDGeneral Purpose and Dimmable665 to 1439 lumensANY	12	$3.86	$22.92	$53.33	1.16	6.96	0.0018
Residential	Lighting	2016 - LEDGlobe1440 to 2600 lumensANY	12	$7.46	-$131.53	-$100.94	2.98	10.77	0.0028
Residential	Lighting	2016 - LEDGlobe250 to 664 lumensANY	12	$1.75	-$72.96	-$43.62	6.20	12.84	0.0034
Residential	Lighting	2016 - LEDGlobe665 to 1439 lumensANY	12	$0.56	-$171.61	-$142.02	18.70	9.16	0.0024
Residential	Lighting	2016 - LEDReflectors and Outdoor1440 to 2600 lumensANY	12	$12.55	-$53.73	-$20.86	5.31	75.96	0.0198
Residential	Lighting	2016 - LEDReflectors and Outdoor250 to 664 lumensANY	12	$7.99	-$68.97	-$39.35	2.87	18.33	0.0048
Residential	Lighting	2016 - LEDReflectors and Outdoor665 to 1439 lumensANY	12	$4.68	-$111.12	-$80.65	4.58	14.71	0.0038

Sector	End Use	Measure Name	Measure Life (Years)	Initial Capital Cost	TRC Levelized Cost ($/MWh)	Total Sponsor Levelized Cost ($/MWh)	TRC B/C Ratio	Bulk Energy (kWh/unit)	Wholesale Demand (kW)
Residential	Lighting	2016 - LEDThree-Way1440 to 2600 lumensANY	12	$13.57	-$53.28	-$23.91	3.08	42.26	0.0110
Residential	Lighting	2016 - LEDThree-Way250 to 664 lumensANY	12	$10.12	-$27.31	$1.88	2.88	42.53	0.0111
Residential	Lighting	2016 - LEDThree-Way665 to 1439 lumensANY	12	$4.66	-$43.17	-$13.92	5.67	46.24	0.0121
Residential	Lighting	2017 - LEDDecorative and Mini-Base1440 to 2600 lumensANY	12	$0.01	$9,999.00	$9,999.00	-	-	-
Residential	Lighting	2017 - LEDDecorative and Mini-Base250 to 664 lumensANY	12	$1.89	-$48.98	-$17.65	6.12	16.31	0.0043
Residential	Lighting	2017 - LEDDecorative and Mini-Base665 to 1439 lumensANY	12	$0.01	$9,999.00	$9,999.00	-	-	-
Residential	Lighting	2017 - LEDGeneral Purpose and Dimmable1440 to 2600 lumensANY	12	$1.64	-$35.05	-$3.37	4.39	10.58	0.0028
Residential	Lighting	2017 - LEDGeneral Purpose and Dimmable250 to 664 lumensANY	12	$0.73	-$41.36	-$9.82	9.69	13.81	0.0036
Residential	Lighting	2017 - LEDGeneral Purpose and Dimmable665 to 1439 lumensANY	12	$4.17	-$34.67	-$2.97	4.88	31.58	0.0083
Residential	Lighting	2017 - LEDGlobe1440 to 2600 lumensANY	12	$4.20	-$35.68	-$4.08	2.96	14.77	0.0039
Residential	Lighting	2017 - LEDGlobe250 to 664 lumensANY	12	$1.93	-$43.70	-$12.50	5.82	16.88	0.0044
Residential	Lighting	2017 - LEDGlobe665 to 1439 lumensANY	12	$2.66	-$50.71	-$19.43	8.74	37.90	0.0099
Residential	Lighting	2017 - LEDReflectors and Outdoor1440 to 2600 lumensANY	12	$4.16	-$41.10	-$7.91	9.56	61.03	0.0159
Residential	Lighting	2017 - LEDReflectors and Outdoor250 to 664 lumensANY	12	$0.25	-$48.83	-$17.34	15.71	9.51	0.0025
Residential	Lighting	2017 - LEDReflectors and Outdoor665 to 1439 lumensANY	12	$0.62	-$42.51	-$10.46	10.01	11.15	0.0029
Residential	Lighting	2017 - LEDThree-Way1440 to 2600 lumensANY	12	$1.64	-$35.05	-$3.37	4.39	10.58	0.0028
Residential	Lighting	2017 - LEDThree-Way250 to 664 lumensANY	12	$0.73	-$41.36	-$9.82	9.69	13.81	0.0036
Residential	Lighting	2017 - LEDThree-Way665 to 1439 lumensANY	12	$4.17	-$34.67	-$2.97	4.88	31.58	0.0083
Residential	Lighting	2016 - LEDDecorative and Mini-Base1440 to 2600 lumensANY	12	$23.27	$270.60	$301.02	0.33	7.69	0.0020
Residential	Lighting	2016 - LEDDecorative and Mini-Base250 to 664 lumensANY	12	$4.29	-$43.06	-$13.49	3.30	17.17	0.0045
Residential	Lighting	2016 - LEDDecorative and Mini-Base665 to 1439 lumensANY	12	$8.26	-$36.74	-$6.84	1.92	13.26	0.0035
Residential	Lighting	2016 - LEDGeneral Purpose and Dimmable1440 to 2600 lumensANY	12	$11.03	$58.35	$89.15	0.75	13.18	0.0034
Residential	Lighting	2016 - LEDGeneral Purpose and Dimmable250 to 664 lumensANY	12	$0.81	-$37.39	-$6.72	2.47	2.08	0.0005
Residential	Lighting	2016 - LEDGeneral Purpose and Dimmable665 to 1439 lumensANY	12	$3.86	$22.92	$53.33	1.16	6.96	0.0018
Residential	Lighting	2016 - LEDGlobe1440 to 2600 lumensANY	12	$7.46	-$131.53	-$100.94	2.98	10.77	0.0028
Residential	Lighting	2016 - LEDGlobe250 to 664 lumensANY	12	$1.75	-$72.96	-$43.62	6.20	12.84	0.0034
Residential	Lighting	2016 - LEDGlobe665 to 1439 lumensANY	12	$0.56	-$171.61	-$142.02	18.70	9.16	0.0024
Residential	Lighting	2016 - LEDReflectors and Outdoor1440 to 2600 lumensANY	12	$12.55	-$53.73	-$20.86	5.31	75.96	0.0198
Residential	Lighting	2016 - LEDReflectors and Outdoor250 to 664 lumensANY	12	$7.99	-$68.97	-$39.35	2.87	18.33	0.0048
Residential	Lighting	2016 - LEDReflectors and Outdoor665 to 1439 lumensANY	12	$4.68	-$111.12	-$80.65	4.58	14.71	0.0038
Residential	Lighting	2016 - LEDThree-Way1440 to 2600 lumensANY	12	$13.57	-$53.28	-$23.91	3.08	42.26	0.0110
Residential	Lighting	2016 - LEDThree-Way250 to 664 lumensANY	12	$10.12	-$27.31	$1.88	2.88	42.53	0.0111
Residential	Lighting	2016 - LEDThree-Way665 to 1439 lumensANY	12	$4.66	-$43.17	-$13.92	5.67	46.24	0.0121
Residential	Lighting	2017 - LEDDecorative and Mini-Base1440 to 2600 lumensANY	12	$0.01	$9,999.00	$9,999.00	-	-	-
Residential	Lighting	2017 - LEDDecorative and Mini-Base250 to 664 lumensANY	12	$1.89	-$48.98	-$17.65	6.12	16.31	0.0043
Residential	Lighting	2017 - LEDDecorative and Mini-Base665 to 1439 lumensANY	12	$0.01	$9,999.00	$9,999.00	-	-	-
Residential	Lighting	2017 - LEDGeneral Purpose and Dimmable1440 to 2600 lumensANY	12	$1.64	-$35.05	-$3.37	4.39	10.58	0.0028
Residential	Lighting	2017 - LEDGeneral Purpose and Dimmable250 to 664 lumensANY	12	$0.73	-$41.36	-$9.82	9.69	13.81	0.0036
Residential	Lighting	2017 - LEDGeneral Purpose and Dimmable665 to 1439 lumensANY	12	$4.17	-$34.67	-$2.97	4.88	31.58	0.0083
Residential	Lighting	2017 - LEDGlobe1440 to 2600 lumensANY	12	$4.20	-$35.68	-$4.08	2.96	14.77	0.0039
Residential	Lighting	2017 - LEDGlobe250 to 664 lumensANY	12	$1.93	-$43.70	-$12.50	5.82	16.88	0.0044
Residential	Lighting	2017 - LEDGlobe665 to 1439 lumensANY	12	$2.66	-$50.71	-$19.43	8.74	37.90	0.0099
Residential	Lighting	2017 - LEDReflectors and Outdoor1440 to 2600 lumensANY	12	$4.16	-$41.10	-$7.91	9.56	61.03	0.0159
Residential	Lighting	2017 - LEDReflectors and Outdoor250 to 664 lumensANY	12	$0.25	-$48.83	-$17.34	15.71	9.51	0.0025
Residential	Lighting	2017 - LEDReflectors and Outdoor665 to 1439 lumensANY	12	$0.62	-$42.51	-$10.46	10.01	11.15	0.0029
Residential	Lighting	2017 - LEDThree-Way1440 to 2600 lumensANY	12	$1.64	-$35.05	-$3.37	4.39	10.58	0.0028
Residential	Lighting	2017 - LEDThree-Way250 to 664 lumensANY	12	$0.73	-$41.36	-$9.82	9.69	13.81	0.0036
Residential	Lighting	2017 - LEDThree-Way665 to 1439 lumensANY	12	$4.17	-$34.67	-$2.97	4.88	31.58	0.0083
Residential	Lighting	2016 - LEDDecorative and Mini-Base1440 to 2600 lumensANY	12	$23.27	$270.60	$301.02	0.33	7.69	0.0020
Residential	Lighting	2016 - LEDDecorative and Mini-Base250 to 664 lumensANY	12	$4.29	-$43.06	-$13.49	3.30	17.17	0.0045
Residential	Lighting	2016 - LEDDecorative and Mini-Base665 to 1439 lumensANY	12	$8.26	-$36.74	-$6.84	1.92	13.26	0.0035
Residential	Lighting	2016 - LEDGeneral Purpose and Dimmable1440 to 2600 lumensANY	12	$11.03	$58.35	$89.15	0.75	13.18	0.0034
Residential	Lighting	2016 - LEDGeneral Purpose and Dimmable250 to 664 lumensANY	12	$0.81	-$37.39	-$6.72	2.47	2.08	0.0005
Residential	Lighting	2016 - LEDGeneral Purpose and Dimmable665 to 1439 lumensANY	12	$3.86	$22.92	$53.33	1.16	6.96	0.0018
Residential	Lighting	2016 - LEDGlobe1440 to 2600 lumensANY	12	$7.46	-$131.53	-$100.94	2.98	10.77	0.0028
Residential	Lighting	2016 - LEDGlobe250 to 664 lumensANY	12	$1.75	-$72.96	-$43.62	6.20	12.84	0.0034
Residential	Lighting	2016 - LEDGlobe665 to 1439 lumensANY	12	$0.56	-$171.61	-$142.02	18.70	9.16	0.0024
Residential	Lighting	2016 - LEDReflectors and Outdoor1440 to 2600 lumensANY	12	$12.55	-$53.73	-$20.86	5.31	75.96	0.0198
Residential	Lighting	2016 - LEDReflectors and Outdoor250 to 664 lumensANY	12	$7.99	-$68.97	-$39.35	2.87	18.33	0.0048
Residential	Lighting	2016 - LEDReflectors and Outdoor665 to 1439 lumensANY	12	$4.68	-$111.12	-$80.65	4.58	14.71	0.0038
Residential	Lighting	2016 - LEDThree-Way1440 to 2600 lumensANY	12	$13.57	-$53.28	-$23.91	3.08	42.26	0.0110
Residential	Lighting	2016 - LEDThree-Way250 to 664 lumensANY	12	$10.12	-$27.31	$1.88	2.88	42.53	0.0111
Residential	Lighting	2016 - LEDThree-Way665 to 1439 lumensANY	12	$4.66	-$43.17	-$13.92	5.67	46.24	0.0121
Residential	Lighting	2017 - LEDDecorative and Mini-Base1440 to 2600 lumensANY	12	$0.01	$9,999.00	$9,999.00	-	-	-
Residential	Lighting	2017 - LEDDecorative and Mini-Base250 to 664 lumensANY	12	$1.89	-$48.98	-$17.65	6.12	16.31	0.0043
Residential	Lighting	2017 - LEDDecorative and Mini-Base665 to 1439 lumensANY	12	$0.01	$9,999.00	$9,999.00	-	-	-
Residential	Lighting	2017 - LEDGeneral Purpose and Dimmable1440 to 2600 lumensANY	12	$1.64	-$35.05	-$3.37	4.39	10.58	0.0028
Residential	Lighting	2017 - LEDGeneral Purpose and Dimmable250 to 664 lumensANY	12	$0.73	-$41.36	-$9.82	9.69	13.81	0.0036
Residential	Lighting	2017 - LEDGeneral Purpose and Dimmable665 to 1439 lumensANY	12	$4.17	-$34.67	-$2.97	4.88	31.58	0.0083
Residential	Lighting	2017 - LEDGlobe1440 to 2600 lumensANY	12	$4.20	-$35.68	-$4.08	2.96	14.77	0.0039
Residential	Lighting	2017 - LEDGlobe250 to 664 lumensANY	12	$1.93	-$43.70	-$12.50	5.82	16.88	0.0044
Residential	Lighting	2017 - LEDGlobe665 to 1439 lumensANY	12	$2.66	-$50.71	-$19.43	8.74	37.90	0.0099
Residential	Lighting	2017 - LEDReflectors and Outdoor1440 to 2600 lumensANY	12	$4.16	-$41.10	-$7.91	9.56	61.03	0.0159

Sector	End Use	Measure Name	Measure Life (Years)	Initial Capital Cost	TRC Levelized Cost ($/MWh)	Total Sponsor Levelized Cost ($/MWh)	TRC B/C Ratio	Bulk Energy (kWh/unit)	Wholesale Demand (kW)
Residential	Lighting	2017 - LEDReflectors and Outdoor250 to 664 lumensANY	12	$0.25	-$48.83	-$17.34	15.71	9.51	0.0025
Residential	Lighting	2017 - LEDReflectors and Outdoor665 to 1439 lumensANY	12	$0.62	-$42.51	-$10.46	10.01	11.15	0.0029
Residential	Lighting	2017 - LEDThree-Way1440 to 2600 lumensANY	12	$1.64	-$35.05	-$3.37	4.39	10.58	0.0028
Residential	Lighting	2017 - LEDThree-Way250 to 664 lumensANY	12	$0.73	-$41.36	-$9.82	9.69	13.81	0.0036
Residential	Lighting	2017 - LEDThree-Way665 to 1439 lumensANY	12	$4.17	-$34.67	-$2.97	4.88	31.58	0.0083
Residential	Lighting	2016 - LEDDecorative and Mini-Base1440 to 2600 lumensANY	12	$23.27	$270.60	$301.02	0.33	7.69	0.0020
Residential	Lighting	2016 - LEDDecorative and Mini-Base250 to 664 lumensANY	12	$4.29	-$43.06	-$13.49	3.30	17.17	0.0045
Residential	Lighting	2016 - LEDDecorative and Mini-Base665 to 1439 lumensANY	12	$8.26	-$36.74	-$6.84	1.92	13.26	0.0035
Residential	Lighting	2016 - LEDGeneral Purpose and Dimmable1440 to 2600 lumensANY	12	$11.03	$58.35	$89.15	0.75	13.18	0.0034
Residential	Lighting	2016 - LEDGeneral Purpose and Dimmable250 to 664 lumensANY	12	$0.81	-$37.39	-$6.72	2.47	2.08	0.0005
Residential	Lighting	2016 - LEDGeneral Purpose and Dimmable665 to 1439 lumensANY	12	$3.86	$22.92	$53.33	1.16	6.96	0.0018
Residential	Lighting	2016 - LEDGlobe1440 to 2600 lumensANY	12	$7.46	-$131.53	-$100.94	2.98	10.77	0.0028
Residential	Lighting	2016 - LEDGlobe250 to 664 lumensANY	12	$1.75	-$72.96	-$43.62	6.20	12.84	0.0034
Residential	Lighting	2016 - LEDGlobe665 to 1439 lumensANY	12	$0.56	-$171.61	-$142.02	18.70	9.16	0.0024
Residential	Lighting	2016 - LEDReflectors and Outdoor1440 to 2600 lumensANY	12	$12.55	-$53.73	-$20.86	5.31	75.96	0.0198
Residential	Lighting	2016 - LEDReflectors and Outdoor250 to 664 lumensANY	12	$7.99	-$68.97	-$39.35	2.87	18.33	0.0048
Residential	Lighting	2016 - LEDReflectors and Outdoor665 to 1439 lumensANY	12	$4.68	-$111.12	-$80.65	4.58	14.71	0.0038
Residential	Lighting	2016 - LEDThree-Way1440 to 2600 lumensANY	12	$13.57	-$53.28	-$23.91	3.08	42.26	0.0110
Residential	Lighting	2016 - LEDThree-Way250 to 664 lumensANY	12	$10.12	-$27.31	$1.88	2.88	42.53	0.0111
Residential	Lighting	2016 - LEDThree-Way665 to 1439 lumensANY	12	$4.66	-$43.17	-$13.92	5.67	46.24	0.0121
Residential	Lighting	2017 - LEDDecorative and Mini-Base1440 to 2600 lumensANY	12	$0.01	$9,999.00	$9,999.00	-	-	-
Residential	Lighting	2017 - LEDDecorative and Mini-Base250 to 664 lumensANY	12	$1.89	-$48.98	-$17.65	6.12	16.31	0.0043
Residential	Lighting	2017 - LEDDecorative and Mini-Base665 to 1439 lumensANY	12	$0.01	$9,999.00	$9,999.00	-	-	-
Residential	Lighting	2017 - LEDGeneral Purpose and Dimmable1440 to 2600 lumensANY	12	$1.64	-$35.05	-$3.37	4.39	10.58	0.0028
Residential	Lighting	2017 - LEDGeneral Purpose and Dimmable250 to 664 lumensANY	12	$0.73	-$41.36	-$9.82	9.69	13.81	0.0036
Residential	Lighting	2017 - LEDGeneral Purpose and Dimmable665 to 1439 lumensANY	12	$4.17	-$34.67	-$2.97	4.88	31.58	0.0083
Residential	Lighting	2017 - LEDGlobe1440 to 2600 lumensANY	12	$4.20	-$35.68	-$4.08	2.96	14.77	0.0039
Residential	Lighting	2017 - LEDGlobe250 to 664 lumensANY	12	$1.93	-$43.70	-$12.50	5.82	16.88	0.0044
Residential	Lighting	2017 - LEDGlobe665 to 1439 lumensANY	12	$2.66	-$50.71	-$19.43	8.74	37.90	0.0099
Residential	Lighting	2017 - LEDReflectors and Outdoor1440 to 2600 lumensANY	12	$4.16	-$41.10	-$7.91	9.56	61.03	0.0159
Residential	Lighting	2017 - LEDReflectors and Outdoor250 to 664 lumensANY	12	$0.25	-$48.83	-$17.34	15.71	9.51	0.0025
Residential	Lighting	2017 - LEDReflectors and Outdoor665 to 1439 lumensANY	12	$0.62	-$42.51	-$10.46	10.01	11.15	0.0029
Residential	Lighting	2017 - LEDThree-Way1440 to 2600 lumensANY	12	$1.64	-$35.05	-$3.37	4.39	10.58	0.0028
Residential	Lighting	2017 - LEDThree-Way250 to 664 lumensANY	12	$0.73	-$41.36	-$9.82	9.69	13.81	0.0036
Residential	Lighting	2017 - LEDThree-Way665 to 1439 lumensANY	12	$4.17	-$34.67	-$2.97	4.88	31.58	0.0083
Residential	Lighting	2016 - LEDDecorative and Mini-Base1440 to 2600 lumensANY	12	$23.27	$270.60	$301.02	0.33	7.69	0.0020
Residential	Lighting	2016 - LEDDecorative and Mini-Base250 to 664 lumensANY	12	$4.29	-$43.06	-$13.49	3.30	17.17	0.0045
Residential	Lighting	2016 - LEDDecorative and Mini-Base665 to 1439 lumensANY	12	$8.26	-$36.74	-$6.84	1.92	13.26	0.0035
Residential	Lighting	2016 - LEDGeneral Purpose and Dimmable1440 to 2600 lumensANY	12	$11.03	$58.35	$89.15	0.75	13.18	0.0034
Residential	Lighting	2016 - LEDGeneral Purpose and Dimmable250 to 664 lumensANY	12	$0.81	-$37.39	-$6.72	2.47	2.08	0.0005
Residential	Lighting	2016 - LEDGeneral Purpose and Dimmable665 to 1439 lumensANY	12	$3.86	$22.92	$53.33	1.16	6.96	0.0018
Residential	Lighting	2016 - LEDGlobe1440 to 2600 lumensANY	12	$7.46	-$131.53	-$100.94	2.98	10.77	0.0028
Residential	Lighting	2016 - LEDGlobe250 to 664 lumensANY	12	$1.75	-$72.96	-$43.62	6.20	12.84	0.0034
Residential	Lighting	2016 - LEDGlobe665 to 1439 lumensANY	12	$0.56	-$171.61	-$142.02	18.70	9.16	0.0024
Residential	Lighting	2016 - LEDReflectors and Outdoor1440 to 2600 lumensANY	12	$12.55	-$53.73	-$20.86	5.31	75.96	0.0198
Residential	Lighting	2016 - LEDReflectors and Outdoor250 to 664 lumensANY	12	$7.99	-$68.97	-$39.35	2.87	18.33	0.0048
Residential	Lighting	2016 - LEDReflectors and Outdoor665 to 1439 lumensANY	12	$4.68	-$111.12	-$80.65	4.58	14.71	0.0038
Residential	Lighting	2016 - LEDThree-Way1440 to 2600 lumensANY	12	$13.57	-$53.28	-$23.91	3.08	42.26	0.0110
Residential	Lighting	2016 - LEDThree-Way250 to 664 lumensANY	12	$10.12	-$27.31	$1.88	2.88	42.53	0.0111
Residential	Lighting	2016 - LEDThree-Way665 to 1439 lumensANY	12	$4.66	-$43.17	-$13.92	5.67	46.24	0.0121
Residential	Lighting	2017 - LEDDecorative and Mini-Base1440 to 2600 lumensANY	12	$0.01	$9,999.00	$9,999.00	-	-	-
Residential	Lighting	2017 - LEDDecorative and Mini-Base250 to 664 lumensANY	12	$1.89	-$48.98	-$17.65	6.12	16.31	0.0043
Residential	Lighting	2017 - LEDDecorative and Mini-Base665 to 1439 lumensANY	12	$0.01	$9,999.00	$9,999.00	-	-	-
Residential	Lighting	2017 - LEDGeneral Purpose and Dimmable1440 to 2600 lumensANY	12	$1.64	-$35.05	-$3.37	4.39	10.58	0.0028
Residential	Lighting	2017 - LEDGeneral Purpose and Dimmable250 to 664 lumensANY	12	$0.73	-$41.36	-$9.82	9.69	13.81	0.0036
Residential	Lighting	2017 - LEDGeneral Purpose and Dimmable665 to 1439 lumensANY	12	$4.17	-$34.67	-$2.97	4.88	31.58	0.0083
Residential	Lighting	2017 - LEDGlobe1440 to 2600 lumensANY	12	$4.20	-$35.68	-$4.08	2.96	14.77	0.0039
Residential	Lighting	2017 - LEDGlobe250 to 664 lumensANY	12	$1.93	-$43.70	-$12.50	5.82	16.88	0.0044
Residential	Lighting	2017 - LEDGlobe665 to 1439 lumensANY	12	$2.66	-$50.71	-$19.43	8.74	37.90	0.0099
Residential	Lighting	2017 - LEDReflectors and Outdoor1440 to 2600 lumensANY	12	$4.16	-$41.10	-$7.91	9.56	61.03	0.0159
Residential	Lighting	2017 - LEDReflectors and Outdoor250 to 664 lumensANY	12	$0.25	-$48.83	-$17.34	15.71	9.51	0.0025
Residential	Lighting	2017 - LEDReflectors and Outdoor665 to 1439 lumensANY	12	$0.62	-$42.51	-$10.46	10.01	11.15	0.0029
Residential	Lighting	2017 - LEDThree-Way1440 to 2600 lumensANY	12	$1.64	-$35.05	-$3.37	4.39	10.58	0.0028
Residential	Lighting	2017 - LEDThree-Way250 to 664 lumensANY	12	$0.73	-$41.36	-$9.82	9.69	13.81	0.0036
Residential	Lighting	2017 - LEDThree-Way665 to 1439 lumensANY	12	$4.17	-$34.67	-$2.97	4.88	31.58	0.0083
Residential	Lighting	2016 - LEDDecorative and Mini-Base1440 to 2600 lumensANY	12	$23.27	$270.60	$301.02	0.33	7.69	0.0020
Residential	Lighting	2016 - LEDDecorative and Mini-Base250 to 664 lumensANY	12	$4.29	-$43.06	-$13.49	3.30	17.17	0.0045
Residential	Lighting	2016 - LEDDecorative and Mini-Base665 to 1439 lumensANY	12	$8.26	-$36.74	-$6.84	1.92	13.26	0.0035
Residential	Lighting	2016 - LEDGeneral Purpose and Dimmable1440 to 2600 lumensANY	12	$11.03	$58.35	$89.15	0.75	13.18	0.0034
Residential	Lighting	2016 - LEDGeneral Purpose and Dimmable250 to 664 lumensANY	12	$0.81	-$37.39	-$6.72	2.47	2.08	0.0005
Residential	Lighting	2016 - LEDGeneral Purpose and Dimmable665 to 1439 lumensANY	12	$3.86	$22.92	$53.33	1.16	6.96	0.0018
Residential	Lighting	2016 - LEDGlobe1440 to 2600 lumensANY	12	$7.46	-$131.53	-$100.94	2.98	10.77	0.0028
Residential	Lighting	2016 - LEDGlobe250 to 664 lumensANY	12	$1.75	-$72.96	-$43.62	6.20	12.84	0.0034

Sector	End Use	Measure Name	Measure Life (Years)	Initial Capital Cost	TRC Levelized Cost ($/MWh)	Total Sponsor Levelized Cost ($/MWh)	TRC B/C Ratio	Bulk Energy (kWh/unit)	Wholesale Demand (kW)
Residential	Lighting	2016 - LEDGlobe665 to 1439 lumensANY	12	$0.56	-$171.61	-$142.02	18.70	9.16	0.0024
Residential	Lighting	2016 - LEDReflectors and Outdoor1440 to 2600 lumensANY	12	$12.55	-$53.73	-$20.86	5.31	75.96	0.0198
Residential	Lighting	2016 - LEDReflectors and Outdoor250 to 664 lumensANY	12	$7.99	-$68.97	-$39.35	2.87	18.33	0.0048
Residential	Lighting	2016 - LEDReflectors and Outdoor665 to 1439 lumensANY	12	$4.68	-$111.12	-$80.65	4.58	14.71	0.0038
Residential	Lighting	2016 - LEDThree-Way1440 to 2600 lumensANY	12	$13.57	-$53.28	-$23.91	3.08	42.26	0.0110
Residential	Lighting	2016 - LEDThree-Way250 to 664 lumensANY	12	$10.12	-$27.31	$1.88	2.88	42.53	0.0111
Residential	Lighting	2016 - LEDThree-Way665 to 1439 lumensANY	12	$4.66	-$43.17	-$13.92	5.67	46.24	0.0121
Residential	Lighting	2017 - LEDDecorative and Mini-Base1440 to 2600 lumensANY	12	$0.01	$9,999.00	$9,999.00	-	-	-
Residential	Lighting	2017 - LEDDecorative and Mini-Base250 to 664 lumensANY	12	$1.89	-$48.98	-$17.65	6.12	16.31	0.0043
Residential	Lighting	2017 - LEDDecorative and Mini-Base665 to 1439 lumensANY	12	$0.01	$9,999.00	$9,999.00	-	-	-
Residential	Lighting	2017 - LEDGeneral Purpose and Dimmable1440 to 2600 lumensANY	12	$1.64	-$35.05	-$3.37	4.39	10.58	0.0028
Residential	Lighting	2017 - LEDGeneral Purpose and Dimmable250 to 664 lumensANY	12	$0.73	-$41.36	-$9.82	9.69	13.81	0.0036
Residential	Lighting	2017 - LEDGeneral Purpose and Dimmable665 to 1439 lumensANY	12	$4.17	-$34.67	-$2.97	4.88	31.58	0.0083
Residential	Lighting	2017 - LEDGlobe1440 to 2600 lumensANY	12	$4.20	-$35.68	-$4.08	2.96	14.77	0.0039
Residential	Lighting	2017 - LEDGlobe250 to 664 lumensANY	12	$1.93	-$43.70	-$12.50	5.82	16.88	0.0044
Residential	Lighting	2017 - LEDGlobe665 to 1439 lumensANY	12	$2.66	-$50.71	-$19.43	8.74	37.90	0.0099
Residential	Lighting	2017 - LEDReflectors and Outdoor1440 to 2600 lumensANY	12	$4.16	-$41.10	-$7.91	9.56	61.03	0.0159
Residential	Lighting	2017 - LEDReflectors and Outdoor250 to 664 lumensANY	12	$0.25	-$48.83	-$17.34	15.71	9.51	0.0025
Residential	Lighting	2017 - LEDReflectors and Outdoor665 to 1439 lumensANY	12	$0.62	-$42.51	-$10.46	10.01	11.15	0.0029
Residential	Lighting	2017 - LEDThree-Way1440 to 2600 lumensANY	12	$1.64	-$35.05	-$3.37	4.39	10.58	0.0028
Residential	Lighting	2017 - LEDThree-Way250 to 664 lumensANY	12	$0.73	-$41.36	-$9.82	9.69	13.81	0.0036
Residential	Lighting	2017 - LEDThree-Way665 to 1439 lumensANY	12	$4.17	-$34.67	-$2.97	4.88	31.58	0.0083
Residential	Lighting	2016 - LEDDecorative and Mini-Base1440 to 2600 lumensANY	12	$23.27	$270.60	$301.02	0.33	7.69	0.0020
Residential	Lighting	2016 - LEDDecorative and Mini-Base250 to 664 lumensANY	12	$4.29	-$43.06	-$13.49	3.30	17.17	0.0045
Residential	Lighting	2016 - LEDDecorative and Mini-Base665 to 1439 lumensANY	12	$8.26	-$36.74	-$6.84	1.92	13.26	0.0035
Residential	Lighting	2016 - LEDGeneral Purpose and Dimmable1440 to 2600 lumensANY	12	$11.03	$58.35	$89.15	0.75	13.18	0.0034
Residential	Lighting	2016 - LEDGeneral Purpose and Dimmable250 to 664 lumensANY	12	$0.81	-$37.39	-$6.72	2.47	2.08	0.0005
Residential	Lighting	2016 - LEDGeneral Purpose and Dimmable665 to 1439 lumensANY	12	$3.86	$22.92	$53.33	1.16	6.96	0.0018
Residential	Lighting	2016 - LEDGlobe1440 to 2600 lumensANY	12	$7.46	-$131.53	-$100.94	2.98	10.77	0.0028
Residential	Lighting	2016 - LEDGlobe250 to 664 lumensANY	12	$1.75	-$72.96	-$43.62	6.20	12.84	0.0034
Residential	Lighting	2016 - LEDGlobe665 to 1439 lumensANY	12	$0.56	-$171.61	-$142.02	18.70	9.16	0.0024
Residential	Lighting	2016 - LEDReflectors and Outdoor1440 to 2600 lumensANY	12	$12.55	-$53.73	-$20.86	5.31	75.96	0.0198
Residential	Lighting	2016 - LEDReflectors and Outdoor250 to 664 lumensANY	12	$7.99	-$68.97	-$39.35	2.87	18.33	0.0048
Residential	Lighting	2016 - LEDReflectors and Outdoor665 to 1439 lumensANY	12	$4.68	-$111.12	-$80.65	4.58	14.71	0.0038
Residential	Lighting	2016 - LEDThree-Way1440 to 2600 lumensANY	12	$13.57	-$53.28	-$23.91	3.08	42.26	0.0110
Residential	Lighting	2016 - LEDThree-Way250 to 664 lumensANY	12	$10.12	-$27.31	$1.88	2.88	42.53	0.0111
Residential	Lighting	2016 - LEDThree-Way665 to 1439 lumensANY	12	$4.66	-$43.17	-$13.92	5.67	46.24	0.0121
Residential	Lighting	2017 - LEDDecorative and Mini-Base1440 to 2600 lumensANY	12	$0.01	$9,999.00	$9,999.00	-	-	-
Residential	Lighting	2017 - LEDDecorative and Mini-Base250 to 664 lumensANY	12	$1.89	-$48.98	-$17.65	6.12	16.31	0.0043
Residential	Lighting	2017 - LEDDecorative and Mini-Base665 to 1439 lumensANY	12	$0.01	$9,999.00	$9,999.00	-	-	-
Residential	Lighting	2017 - LEDGeneral Purpose and Dimmable1440 to 2600 lumensANY	12	$1.64	-$35.05	-$3.37	4.39	10.58	0.0028
Residential	Lighting	2017 - LEDGeneral Purpose and Dimmable250 to 664 lumensANY	12	$0.73	-$41.36	-$9.82	9.69	13.81	0.0036
Residential	Lighting	2017 - LEDGeneral Purpose and Dimmable665 to 1439 lumensANY	12	$4.17	-$34.67	-$2.97	4.88	31.58	0.0083
Residential	Lighting	2017 - LEDGlobe1440 to 2600 lumensANY	12	$4.20	-$35.68	-$4.08	2.96	14.77	0.0039
Residential	Lighting	2017 - LEDGlobe250 to 664 lumensANY	12	$1.93	-$43.70	-$12.50	5.82	16.88	0.0044
Residential	Lighting	2017 - LEDGlobe665 to 1439 lumensANY	12	$2.66	-$50.71	-$19.43	8.74	37.90	0.0099
Residential	Lighting	2017 - LEDReflectors and Outdoor1440 to 2600 lumensANY	12	$4.16	-$41.10	-$7.91	9.56	61.03	0.0159
Residential	Lighting	2017 - LEDReflectors and Outdoor250 to 664 lumensANY	12	$0.25	-$48.83	-$17.34	15.71	9.51	0.0025
Residential	Lighting	2017 - LEDReflectors and Outdoor665 to 1439 lumensANY	12	$0.62	-$42.51	-$10.46	10.01	11.15	0.0029
Residential	Lighting	2017 - LEDThree-Way1440 to 2600 lumensANY	12	$1.64	-$35.05	-$3.37	4.39	10.58	0.0028
Residential	Lighting	2017 - LEDThree-Way250 to 664 lumensANY	12	$0.73	-$41.36	-$9.82	9.69	13.81	0.0036
Residential	Lighting	2017 - LEDThree-Way665 to 1439 lumensANY	12	$4.17	-$34.67	-$2.97	4.88	31.58	0.0083
Residential	Lighting	2016 - LEDDecorative and Mini-Base1440 to 2600 lumensANY	12	$23.27	$270.60	$301.02	0.33	7.69	0.0020
Residential	Lighting	2016 - LEDDecorative and Mini-Base250 to 664 lumensANY	12	$4.29	-$43.06	-$13.49	3.30	17.17	0.0045
Residential	Lighting	2016 - LEDDecorative and Mini-Base665 to 1439 lumensANY	12	$8.26	-$36.74	-$6.84	1.92	13.26	0.0035
Residential	Lighting	2016 - LEDGeneral Purpose and Dimmable1440 to 2600 lumensANY	12	$11.03	$58.35	$89.15	0.75	13.18	0.0034
Residential	Lighting	2016 - LEDGeneral Purpose and Dimmable250 to 664 lumensANY	12	$0.81	-$37.39	-$6.72	2.47	2.08	0.0005
Residential	Lighting	2016 - LEDGeneral Purpose and Dimmable665 to 1439 lumensANY	12	$3.86	$22.92	$53.33	1.16	6.96	0.0018
Residential	Lighting	2016 - LEDGlobe1440 to 2600 lumensANY	12	$7.46	-$131.53	-$100.94	2.98	10.77	0.0028
Residential	Lighting	2016 - LEDGlobe250 to 664 lumensANY	12	$1.75	-$72.96	-$43.62	6.20	12.84	0.0034
Residential	Lighting	2016 - LEDGlobe665 to 1439 lumensANY	12	$0.56	-$171.61	-$142.02	18.70	9.16	0.0024
Residential	Lighting	2016 - LEDReflectors and Outdoor1440 to 2600 lumensANY	12	$12.55	-$53.73	-$20.86	5.31	75.96	0.0198
Residential	Lighting	2016 - LEDReflectors and Outdoor250 to 664 lumensANY	12	$7.99	-$68.97	-$39.35	2.87	18.33	0.0048
Residential	Lighting	2016 - LEDReflectors and Outdoor665 to 1439 lumensANY	12	$4.68	-$111.12	-$80.65	4.58	14.71	0.0038
Residential	Lighting	2016 - LEDThree-Way1440 to 2600 lumensANY	12	$13.57	-$53.28	-$23.91	3.08	42.26	0.0110
Residential	Lighting	2016 - LEDThree-Way250 to 664 lumensANY	12	$10.12	-$27.31	$1.88	2.88	42.53	0.0111
Residential	Lighting	2016 - LEDThree-Way665 to 1439 lumensANY	12	$4.66	-$43.17	-$13.92	5.67	46.24	0.0121
Residential	Lighting	2017 - LEDDecorative and Mini-Base1440 to 2600 lumensANY	12	$0.01	$9,999.00	$9,999.00	-	-	-
Residential	Lighting	2017 - LEDDecorative and Mini-Base250 to 664 lumensANY	12	$1.89	-$48.98	-$17.65	6.12	16.31	0.0043
Residential	Lighting	2017 - LEDDecorative and Mini-Base665 to 1439 lumensANY	12	$0.01	$9,999.00	$9,999.00	-	-	-
Residential	Lighting	2017 - LEDGeneral Purpose and Dimmable1440 to 2600 lumensANY	12	$1.64	-$35.05	-$3.37	4.39	10.58	0.0028
Residential	Lighting	2017 - LEDGeneral Purpose and Dimmable250 to 664 lumensANY	12	$0.73	-$41.36	-$9.82	9.69	13.81	0.0036
Residential	Lighting	2017 - LEDGeneral Purpose and Dimmable665 to 1439 lumensANY	12	$4.17	-$34.67	-$2.97	4.88	31.58	0.0083

Sector	End Use	Measure Name	Measure Life (Years)	Initial Capital Cost	TRC Levelized Cost ($/MWh)	Total Sponsor Levelized Cost ($/MWh)	TRC B/C Ratio	Bulk Energy (kWh/unit)	Wholesale Demand (kW)
Residential	Lighting	2017 - LEDGlobe1440 to 2600 lumensANY	12	$4.20	-$35.68	-$4.08	2.96	14.77	0.0039
Residential	Lighting	2017 - LEDGlobe250 to 664 lumensANY	12	$1.93	-$43.70	-$12.50	5.82	16.88	0.0044
Residential	Lighting	2017 - LEDGlobe665 to 1439 lumensANY	12	$2.66	-$50.71	-$19.43	8.74	37.90	0.0099
Residential	Lighting	2017 - LEDReflectors and Outdoor1440 to 2600 lumensANY	12	$4.16	-$41.10	-$7.91	9.56	61.03	0.0159
Residential	Lighting	2017 - LEDReflectors and Outdoor250 to 664 lumensANY	12	$0.25	-$48.83	-$17.34	15.71	9.51	0.0025
Residential	Lighting	2017 - LEDReflectors and Outdoor665 to 1439 lumensANY	12	$0.62	-$42.51	-$10.46	10.01	11.15	0.0029
Residential	Lighting	2017 - LEDThree-Way1440 to 2600 lumensANY	12	$1.64	-$35.05	-$3.37	4.39	10.58	0.0028
Residential	Lighting	2017 - LEDThree-Way250 to 664 lumensANY	12	$0.73	-$41.36	-$9.82	9.69	13.81	0.0036
Residential	Lighting	2017 - LEDThree-Way665 to 1439 lumensANY	12	$4.17	-$34.67	-$2.97	4.88	31.58	0.0083
Residential	Lighting	all45lm/WGeneral Purpose and Dimmable1440 to 2600 lumensANY	7.487903	$0.07	$9,999.00	$9,999.00	2.81	(1.19)	(0.0003)
Residential	Lighting	all45lm/WGeneral Purpose and Dimmable250 to 664 lumensANY	8.539783	$0.05	-$94.60	-$64.31	29.54	10.78	0.0028
Residential	Lighting	all45lm/WGeneral Purpose and Dimmable665 to 1439 lumensANY	7.944554	$0.05	-$75.21	-$44.87	20.17	4.23	0.0011
Residential	Lighting	all45lm/WGeneral Purpose and Dimmable1440 to 2600 lumensANY	7.487903	$0.07	$9,999.00	$9,999.00	2.81	(1.19)	(0.0003)
Residential	Lighting	all45lm/WGeneral Purpose and Dimmable250 to 664 lumensANY	8.539783	$0.05	-$94.60	-$64.31	29.54	10.78	0.0028
Residential	Lighting	all45lm/WGeneral Purpose and Dimmable665 to 1439 lumensANY	7.944554	$0.05	-$75.21	-$44.87	20.17	4.23	0.0011
Residential	Lighting	all45lm/WGeneral Purpose and Dimmable1440 to 2600 lumensANY	7.487903	$0.07	$9,999.00	$9,999.00	2.81	(1.19)	(0.0003)
Residential	Lighting	all45lm/WGeneral Purpose and Dimmable250 to 664 lumensANY	8.539783	$0.05	-$94.60	-$64.31	29.54	10.78	0.0028
Residential	Lighting	all45lm/WGeneral Purpose and Dimmable665 to 1439 lumensANY	7.944554	$0.05	-$75.21	-$44.87	20.17	4.23	0.0011
Residential	Lighting	all45lm/WGeneral Purpose and Dimmable1440 to 2600 lumensANY	7.487903	$0.07	$9,999.00	$9,999.00	2.81	(1.19)	(0.0003)
Residential	Lighting	all45lm/WGeneral Purpose and Dimmable250 to 664 lumensANY	8.539783	$0.05	-$94.60	-$64.31	29.54	10.78	0.0028
Residential	Lighting	all45lm/WGeneral Purpose and Dimmable665 to 1439 lumensANY	7.944554	$0.05	-$75.21	-$44.87	20.17	4.23	0.0011
Residential	Food Preparation	Microwave Top Tier	10.91	$4.51	$2.67	$65.62	1.49	9.02	0.0052
Residential	Food Preparation	Microwave Top Tier	10.91	$4.51	$2.67	$65.62	1.49	9.02	0.0052
Residential	Food Preparation	Microwave Top Tier	10.91	$4.51	$2.67	$65.62	1.49	9.02	0.0052
Residential	Food Preparation	Microwave Top Tier	10.91	$4.51	$2.67	$65.62	1.49	9.02	0.0052
Residential	Food Preparation	Microwave Top Tier	10.91	$4.51	$2.67	$65.62	1.49	9.02	0.0052
Residential	Food Preparation	Microwave Top Tier	10.91	$4.51	$2.67	$65.62	1.49	9.02	0.0052
Residential	Food Preparation	Microwave Top Tier	10.91	$4.51	$2.67	$65.62	1.49	9.02	0.0052
Residential	Food Preparation	Microwave Top Tier	10.91	$4.51	$2.67	$65.62	1.49	9.02	0.0052
Residential	Electronics	ENERGY STAR Monitors	5	$8.00	$33.25	$61.84	1.00	31.44	0.0065
Residential	Electronics	ENERGY STAR Monitors	5	$8.00	$33.25	$61.84	1.00	31.44	0.0065
Residential	Electronics	ENERGY STAR Monitors	5	$8.00	$33.25	$61.84	1.00	31.44	0.0065
Residential	Electronics	ENERGY STAR Monitors	5	$8.00	$33.25	$61.84	1.00	31.44	0.0065
Residential	Electronics	ENERGY STAR Monitors	5	$8.00	$33.25	$61.84	1.00	31.44	0.0065
Residential	Electronics	ENERGY STAR Monitors	5	$8.00	$33.25	$61.84	1.00	31.44	0.0065
Residential	Electronics	ENERGY STAR Monitors	5	$8.00	$33.25	$61.84	1.00	31.44	0.0065
Residential	Electronics	ENERGY STAR Monitors	5	$8.00	$33.25	$61.84	1.00	31.44	0.0065
Residential	Refrigeration	Std Size Refrig and Refrig-Freezer - CEE Tier 1	15.18	$30.30	$302.12	$318.13	0.16	10.01	0.0011
Residential	Refrigeration	Std Size Refrig and Refrig-Freezer - CEE Tier 2	15.18	$104.83	$306.33	$322.33	0.16	34.18	0.0038
Residential	Refrigeration	Std Size Refrig and Refrig-Freezer - CEE Tier 3	15.18	$99.31	$159.12	$175.12	0.29	59.60	0.0067
Residential	Refrigeration	Std Size Refrig and Refrig-Freezer - CEE Tier 1	15.18	$30.30	$302.12	$318.13	0.16	10.01	0.0011
Residential	Refrigeration	Std Size Refrig and Refrig-Freezer - CEE Tier 2	15.18	$104.83	$306.33	$322.33	0.16	34.18	0.0038
Residential	Refrigeration	Std Size Refrig and Refrig-Freezer - CEE Tier 3	15.18	$99.31	$159.12	$175.12	0.29	59.60	0.0067
Residential	Refrigeration	Std Size Refrig and Refrig-Freezer - CEE Tier 1	15.18	$30.30	$302.12	$318.13	0.16	10.01	0.0011
Residential	Refrigeration	Std Size Refrig and Refrig-Freezer - CEE Tier 2	15.18	$104.83	$306.33	$322.33	0.16	34.18	0.0038
Residential	Refrigeration	Std Size Refrig and Refrig-Freezer - CEE Tier 3	15.18	$99.31	$159.12	$175.12	0.29	59.60	0.0067
Residential	Refrigeration	Std Size Refrig and Refrig-Freezer - CEE Tier 1	15.18	$30.30	$302.12	$318.13	0.16	10.01	0.0011
Residential	Refrigeration	Std Size Refrig and Refrig-Freezer - CEE Tier 2	15.18	$104.83	$306.33	$322.33	0.16	34.18	0.0038
Residential	Refrigeration	Std Size Refrig and Refrig-Freezer - CEE Tier 3	15.18	$99.31	$159.12	$175.12	0.29	59.60	0.0067
Residential	Refrigeration	Std Size Refrig and Refrig-Freezer - CEE Tier 1	15.18	$30.30	$302.12	$318.13	0.16	10.01	0.0011
Residential	Refrigeration	Std Size Refrig and Refrig-Freezer - CEE Tier 2	15.18	$104.83	$306.33	$322.33	0.16	34.18	0.0038
Residential	Refrigeration	Std Size Refrig and Refrig-Freezer - CEE Tier 3	15.18	$99.31	$159.12	$175.12	0.29	59.60	0.0067
Residential	Refrigeration	Std Size Refrig and Refrig-Freezer - CEE Tier 1	15.18	$30.30	$302.12	$318.13	0.16	10.01	0.0011
Residential	Refrigeration	Std Size Refrig and Refrig-Freezer - CEE Tier 2	15.18	$104.83	$306.33	$322.33	0.16	34.18	0.0038
Residential	Refrigeration	Std Size Refrig and Refrig-Freezer - CEE Tier 3	15.18	$99.31	$159.12	$175.12	0.29	59.60	0.0067
Residential	Refrigeration	Std Size Refrig and Refrig-Freezer - CEE Tier 1	15.18	$30.30	$302.12	$318.13	0.16	10.01	0.0011
Residential	Refrigeration	Std Size Refrig and Refrig-Freezer - CEE Tier 2	15.18	$104.83	$306.33	$322.33	0.16	34.18	0.0038
Residential	Refrigeration	Std Size Refrig and Refrig-Freezer - CEE Tier 3	15.18	$99.31	$159.12	$175.12	0.29	59.60	0.0067
Residential	Refrigeration	Std Size Refrig and Refrig-Freezer - CEE Tier 1	15.18	$30.30	$302.12	$318.13	0.16	10.01	0.0011
Residential	Refrigeration	Std Size Refrig and Refrig-Freezer - CEE Tier 2	15.18	$104.83	$306.33	$322.33	0.16	34.18	0.0038
Residential	Refrigeration	Std Size Refrig and Refrig-Freezer - CEE Tier 3	15.18	$99.31	$159.12	$175.12	0.29	59.60	0.0067
Residential	HVAC	Attic R0 - R22_Electric FAF	25	$1,102.94	$40.95	$109.02	0.94	804.84	0.4212
Residential	HVAC	Attic R0 - R22_Heat Pump	25	$1,102.94	$57.48	$109.12	0.79	804.11	0.2811
Residential	HVAC	Attic R0 - R30_Electric FAF	25	$1,246.47	$172.95	$241.02	0.42	411.41	0.2153
Residential	HVAC	Attic R0 - R30_Heat Pump	25	$1,246.47	$189.61	$241.24	0.36	411.03	0.1437
Residential	HVAC	Attic R11 - R30_Electric FAF	25	$1,049.12	$734.52	$802.59	0.13	103.99	0.0544
Residential	HVAC	Attic R11 - R30_Heat Pump	25	$1,049.12	$751.69	$803.32	0.11	103.89	0.0363
Residential	HVAC	CFM50 Infiltration Reduction_Electric FAF	25	$938.50	$241.46	$309.53	0.33	321.09	0.1681
Residential	HVAC	CFM50 Infiltration Reduction_Heat Pump	25	$938.50	$258.17	$309.81	0.28	320.80	0.1121
Residential	HVAC	Floor R0 - R22_Electric FAF	25	$1,775.44	$146.93	$214.99	0.47	656.94	0.3438
Residential	HVAC	Floor R0 - R22_Heat Pump	25	$1,775.44	$163.56	$215.19	0.40	656.35	0.2295
Residential	HVAC	Floor R11 - R22_Electric FAF	25	$1,653.13	$414.88	$482.95	0.21	272.30	0.1425
Residential	HVAC	Floor R11 - R22_Heat Pump	25	$1,653.13	$431.76	$483.39	0.18	272.06	0.0951

Sector	End Use	Measure Name	Measure Life (Years)	Initial Capital Cost	TRC Levelized Cost ($/MWh)	Total Sponsor Levelized Cost ($/MWh)	TRC B/C Ratio	Bulk Energy (kWh/unit)	Wholesale Demand (kW)
Residential	HVAC	WINDOW CL22 Prime Window Replacement of Double Pane Base_Electric	25	$3,179.68	$303.10	$371.17	0.27	681.49	0.3567
Residential	HVAC	WINDOW CL22 Prime Window Replacement of Double Pane Base_Heat Pu	25	$3,179.68	$319.87	$371.51	0.23	680.87	0.2380
Residential	HVAC	WINDOW CL22 Prime Window Replacement of Single Pane Base_Electric F	25	$3,179.68	$84.35	$152.42	0.67	1,659.55	0.8686
Residential	HVAC	WINDOW CL22 Prime Window Replacement of Single Pane Base_Heat Pum	25	$3,179.68	$100.92	$152.56	0.56	1,658.04	0.5796
Residential	HVAC	WINDOW CL30 Prime Window Replacement of Double Pane Base_Electric	25	$2,849.62	$302.08	$370.15	0.28	612.44	0.3205
Residential	HVAC	WINDOW CL30 Prime Window Replacement of Double Pane Base_Heat Pu	25	$2,849.62	$318.85	$370.48	0.23	611.88	0.2139
Residential	HVAC	WINDOW CL30 Prime Window Replacement of Single Pane Base_Electric F	25	$2,849.62	$72.31	$140.38	0.73	1,614.82	0.8452
Residential	HVAC	WINDOW CL30 Prime Window Replacement of Single Pane Base_Heat Pum	25	$2,849.62	$88.88	$140.51	0.61	1,613.36	0.5640
Residential	HVAC	ATTIC R0 - R19_Electric FAF	45	$225.01	-$16.35	$43.27	2.16	330.69	0.1731
Residential	HVAC	ATTIC R0 - R19_Electric Zonal	45	$223.85	-$11.87	$47.76	1.96	298.07	0.1560
Residential	HVAC	ATTIC R0 - R19_Heat Pump	45	$225.01	$53.81	$113.44	0.82	126.15	0.0660
Residential	HVAC	ATTIC R0 - R38_Electric FAF	45	$298.11	-$17.03	$42.60	2.19	445.04	0.2329
Residential	HVAC	ATTIC R0 - R38_Electric Zonal	45	$297.11	-$12.08	$47.55	1.97	397.42	0.2080
Residential	HVAC	ATTIC R0 - R38_Heat Pump	45	$298.11	$52.58	$112.21	0.83	168.97	0.0884
Residential	HVAC	ATTIC R0 - R49_Electric FAF	45	$340.44	-$13.41	$46.22	2.02	468.43	0.2452
Residential	HVAC	ATTIC R0 - R49_Electric Zonal	45	$341.88	-$7.74	$51.89	1.80	419.02	0.2193
Residential	HVAC	ATTIC R0 - R49_Heat Pump	45	$340.44	$62.39	$122.02	0.77	177.44	0.0929
Residential	HVAC	ATTIC R19 - R30_Electric FAF	45	$194.22	$86.43	$146.06	0.64	84.57	0.0443
Residential	HVAC	ATTIC R19 - R30_Electric Zonal	45	$195.36	$100.16	$159.79	0.59	77.76	0.0407
Residential	HVAC	ATTIC R19 - R30_Heat Pump	45	$194.22	$326.07	$385.70	0.24	32.03	0.0168
Residential	HVAC	ATTIC R19 - R38_Electric FAF	45	$225.01	$65.51	$125.14	0.75	114.36	0.0599
Residential	HVAC	ATTIC R19 - R38_Electric Zonal	45	$223.85	$77.69	$137.32	0.68	103.68	0.0543
Residential	HVAC	ATTIC R19 - R38_Heat Pump	45	$225.01	$274.55	$334.18	0.28	42.82	0.0224
Residential	HVAC	ATTIC R19 - R49_Electric FAF	45	$267.33	$63.81	$123.44	0.76	137.74	0.0721
Residential	HVAC	ATTIC R19 - R49_Electric Zonal	45	$268.62	$76.74	$136.37	0.69	125.27	0.0656
Residential	HVAC	ATTIC R19 - R49_Heat Pump	45	$267.33	$271.85	$331.48	0.28	51.29	0.0268
Residential	HVAC	FLOOR R0 - R19_Electric FAF	45	$358.02	-$12.83	$46.80	2.00	486.57	0.2547
Residential	HVAC	FLOOR R0 - R19_Electric Zonal	45	$358.80	-$12.51	$47.12	1.98	484.31	0.2535
Residential	HVAC	FLOOR R0 - R19_Heat Pump	45	$358.02	$75.69	$135.32	0.69	168.26	0.0881
Residential	HVAC	FLOOR R0 - R30_Electric FAF	45	$383.15	-$22.21	$37.42	2.50	651.30	0.3409
Residential	HVAC	FLOOR R0 - R30_Electric Zonal	45	$382.20	-$21.99	$37.64	2.48	645.74	0.3380
Residential	HVAC	FLOOR R0 - R30_Heat Pump	45	$383.15	$49.09	$108.72	0.86	224.15	0.1173
Residential	HVAC	WALL R0 - R11_Electric FAF	45	$504.28	-$34.82	$24.81	3.77	1,292.83	0.6767
Residential	HVAC	WALL R0 - R11_Electric Zonal	45	$506.48	-$31.56	$28.07	3.33	1,147.50	0.6006
Residential	HVAC	WALL R0 - R11_Heat Pump	45	$504.28	$6.28	$65.91	1.42	486.63	0.2547
Residential	HVAC	WINDOW CL22 Prime Window Replacement of Double Pane Base_Electric	45	$3,457.90	$10.33	$69.96	1.34	3,143.57	1.6453
Residential	HVAC	WINDOW CL22 Prime Window Replacement of Double Pane Base_Electric	45	$3,457.38	$19.17	$78.80	1.19	2,790.51	1.4605
Residential	HVAC	WINDOW CL22 Prime Window Replacement of Double Pane Base_Heat Pu	45	$3,457.90	$101.96	$161.58	0.58	1,361.03	0.7123
Residential	HVAC	WINDOW CL22 Prime Window Replacement of Single Pane Base_Electric F	45	$3,457.90	-$20.50	$39.13	2.39	5,620.64	2.9418
Residential	HVAC	WINDOW CL22 Prime Window Replacement of Single Pane Base_Electric Z	45	$3,457.38	-$15.61	$44.02	2.12	4,995.59	2.6146
Residential	HVAC	WINDOW CL22 Prime Window Replacement of Single Pane Base_Heat Pum	45	$3,457.90	$31.68	$91.30	1.02	2,408.66	1.2607
Residential	HVAC	WINDOW CL30 Prime Window Replacement of Double Pane Base_Electric	45	$3,098.96	$17.66	$77.29	1.21	2,550.02	1.3347
Residential	HVAC	WINDOW CL30 Prime Window Replacement of Double Pane Base_Electric	45	$3,098.94	$27.42	$87.05	1.07	2,264.18	1.1850
Residential	HVAC	WINDOW CL30 Prime Window Replacement of Double Pane Base_Heat Pu	45	$3,098.96	$113.03	$172.66	0.54	1,141.50	0.5975
Residential	HVAC	WINDOW CL30 Prime Window Replacement of Single Pane Base_Electric F	45	$3,098.96	-$20.42	$39.21	2.38	5,027.09	2.6311
Residential	HVAC	WINDOW CL30 Prime Window Replacement of Single Pane Base_Electric Z	45	$3,098.94	-$15.53	$44.10	2.12	4,469.25	2.3392
Residential	HVAC	WINDOW CL30 Prime Window Replacement of Single Pane Base_Heat Pum	45	$3,098.96	$30.40	$90.03	1.04	2,189.13	1.1458
Residential	HVAC	ATTIC R0 - R38_DHP	45	$1,557.62	-$41.56	$30.66	3.47	3,230.71	1.6029
Residential	HVAC	ATTIC R0 - R38_Electric FAF	45	$1,557.62	-$41.18	$28.15	3.69	3,519.41	1.6665
Residential	HVAC	ATTIC R0 - R38_Electric Zonal	45	$1,557.62	-$41.56	$30.66	3.47	3,230.71	1.6029
Residential	HVAC	ATTIC R0 - R38_Heat Pump	45	$1,557.62	-$8.53	$49.61	1.89	1,996.69	0.7714
Residential	HVAC	ATTIC R0 - R49_DHP	45	$1,778.78	-$37.70	$34.53	3.08	3,276.16	1.6256
Residential	HVAC	ATTIC R0 - R49_Electric FAF	45	$1,778.78	-$37.65	$31.69	3.28	3,569.47	1.6906
Residential	HVAC	ATTIC R0 - R49_Electric Zonal	45	$1,778.78	-$37.70	$34.53	3.08	3,276.16	1.6256
Residential	HVAC	ATTIC R0 - R49_Heat Pump	45	$1,778.78	-$2.24	$55.94	1.68	2,022.41	0.7818
Residential	HVAC	ATTIC R11 - R38_DHP	45	$1,336.47	$64.51	$137.57	0.78	617.86	0.3106
Residential	HVAC	ATTIC R11 - R38_Electric FAF	45	$1,336.47	$26.08	$98.05	1.08	866.87	0.4284
Residential	HVAC	ATTIC R11 - R38_Electric Zonal	45	$1,336.47	$64.51	$137.57	0.78	617.86	0.3106
Residential	HVAC	ATTIC R11 - R38_Heat Pump	45	$1,336.47	$169.21	$232.04	0.42	366.31	0.1549
Residential	HVAC	ATTIC R11 - R49_DHP	45	$1,557.62	$74.69	$147.76	0.73	670.43	0.3370
Residential	HVAC	ATTIC R11 - R49_Electric FAF	45	$1,557.62	$33.32	$105.30	1.01	940.75	0.4650
Residential	HVAC	ATTIC R11 - R49_Electric Zonal	45	$1,557.62	$74.69	$147.76	0.73	670.43	0.3370
Residential	HVAC	ATTIC R11 - R49_Heat Pump	45	$1,557.62	$186.65	$249.51	0.39	397.03	0.1680
Residential	HVAC	ATTIC R19 - R38_DHP	45	$1,175.63	$160.01	$233.64	0.46	320.03	0.1623
Residential	HVAC	ATTIC R19 - R38_Electric FAF	45	$1,175.63	$142.67	$214.59	0.49	348.43	0.1720
Residential	HVAC	ATTIC R19 - R38_Electric Zonal	45	$1,175.63	$160.01	$233.64	0.46	320.03	0.1623
Residential	HVAC	ATTIC R19 - R38_Heat Pump	45	$1,175.63	$348.82	$413.98	0.24	180.61	0.0797
Residential	HVAC	ATTIC R19 - R49_DHP	45	$1,396.79	$156.72	$230.35	0.47	385.65	0.1956
Residential	HVAC	ATTIC R19 - R49_Electric FAF	45	$1,396.79	$139.60	$211.53	0.50	419.97	0.2074
Residential	HVAC	ATTIC R19 - R49_Electric Zonal	45	$1,396.79	$156.72	$230.35	0.47	385.65	0.1956
Residential	HVAC	ATTIC R19 - R49_Heat Pump	45	$1,396.79	$343.38	$408.57	0.24	217.43	0.0960
Residential	HVAC	CFM50 Infiltration Reduction_DHP	15	$1,470.80	$89.12	$164.45	0.66	947.14	0.4928
Residential	HVAC	CFM50 Infiltration Reduction_Electric FAF	15	$1,470.80	$60.95	$136.09	0.80	1,144.53	0.5938

Sector	End Use	Measure Name	Measure Life (Years)	Initial Capital Cost	TRC Levelized Cost ($/MWh)	Total Sponsor Levelized Cost ($/MWh)	TRC B/C Ratio	Bulk Energy (kWh/unit)	Wholesale Demand (kW)
Residential	HVAC	CFM50 Infiltration Reduction_Electric Zonal	15	$1,470.80	$89.12	$164.45	0.66	947.14	0.4928
Residential	HVAC	CFM50 Infiltration Reduction_Heat Pump	15	$1,470.80	$232.94	$308.20	0.35	505.38	0.2627
Residential	HVAC	FLOOR R0 - R19_DHP	45	$1,952.17	$11.52	$88.32	1.25	1,405.70	0.7475
Residential	HVAC	FLOOR R0 - R19_Electric FAF	45	$1,952.17	$13.59	$91.59	1.22	1,355.54	0.7336
Residential	HVAC	FLOOR R0 - R19_Electric Zonal	45	$1,952.17	$11.52	$88.32	1.25	1,405.70	0.7475
Residential	HVAC	FLOOR R0 - R19_Heat Pump	45	$1,952.17	$408.04	$504.10	0.25	246.29	0.1680
Residential	HVAC	FLOOR R0 - R25_DHP	45	$2,026.92	$8.86	$85.70	1.29	1,504.30	0.8005
Residential	HVAC	FLOOR R0 - R25_Electric FAF	45	$2,026.92	$10.52	$88.60	1.26	1,454.97	0.7883
Residential	HVAC	FLOOR R0 - R25_Electric Zonal	45	$2,026.92	$8.86	$85.70	1.29	1,504.30	0.8005
Residential	HVAC	FLOOR R0 - R25_Heat Pump	45	$2,026.92	$395.53	$492.70	0.26	261.64	0.1807
Residential	HVAC	FLOOR R0 - R30_DHP	45	$2,089.22	$8.00	$84.87	1.30	1,565.61	0.8334
Residential	HVAC	FLOOR R0 - R30_Electric FAF	45	$2,089.22	$9.45	$87.58	1.28	1,517.15	0.8226
Residential	HVAC	FLOOR R0 - R30_Electric Zonal	45	$2,089.22	$8.00	$84.87	1.30	1,565.61	0.8334
Residential	HVAC	FLOOR R0 - R30_Heat Pump	45	$2,089.22	$392.44	$490.34	0.26	270.98	0.1887
Residential	HVAC	WALL R0 - R11_DHP	45	$2,773.45	-$14.70	$60.30	1.81	2,925.23	1.5147
Residential	HVAC	WALL R0 - R11_Electric FAF	45	$2,773.45	-$33.49	$41.28	2.63	4,272.94	2.2049
Residential	HVAC	WALL R0 - R11_Electric Zonal	45	$2,773.45	-$14.70	$60.30	1.81	2,925.23	1.5147
Residential	HVAC	WALL R0 - R11_Heat Pump	45	$2,773.45	$22.50	$95.63	1.12	1,844.57	0.9281
Residential	HVAC	WINDOW CL22 Prime Window Replacement of Double Pane Base_DHP	45	$4,329.02	$172.60	$244.22	0.43	1,127.36	0.5540
Residential	HVAC	WINDOW CL22 Prime Window Replacement of Double Pane Base_Electric	45	$4,329.02	$155.57	$223.81	0.46	1,230.17	0.5721
Residential	HVAC	WINDOW CL22 Prime Window Replacement of Double Pane Base_Electric	45	$4,329.02	$172.60	$244.22	0.43	1,127.36	0.5540
Residential	HVAC	WINDOW CL22 Prime Window Replacement of Double Pane Base_Heat Pu	45	$4,329.02	$278.02	$336.64	0.28	817.86	0.3190
Residential	HVAC	WINDOW CL22 Prime Window Replacement of Single Pane Base_DHP	45	$4,329.02	$75.42	$149.07	0.72	1,846.96	0.9368
Residential	HVAC	WINDOW CL22 Prime Window Replacement of Single Pane Base_Electric F	45	$4,329.02	$10.73	$84.13	1.28	3,272.55	1.6537
Residential	HVAC	WINDOW CL22 Prime Window Replacement of Single Pane Base_Electric Z	45	$4,329.02	$75.42	$149.07	0.72	1,846.96	0.9368
Residential	HVAC	WINDOW CL22 Prime Window Replacement of Single Pane Base_Heat Pum	45	$4,329.02	$121.35	$189.55	0.54	1,452.54	0.6750
Residential	HVAC	WINDOW CL30 Prime Window Replacement of Double Pane Base_DHP	45	$3,675.82	$170.32	$241.55	0.44	967.82	0.4727
Residential	HVAC	WINDOW CL30 Prime Window Replacement of Double Pane Base_Electric	45	$3,675.82	$152.55	$220.12	0.46	1,062.07	0.4884
Residential	HVAC	WINDOW CL30 Prime Window Replacement of Double Pane Base_Electric	45	$3,675.82	$170.32	$241.55	0.44	967.82	0.4727
Residential	HVAC	WINDOW CL30 Prime Window Replacement of Double Pane Base_Heat Pu	45	$3,675.82	$269.53	$326.76	0.28	715.45	0.2713
Residential	HVAC	WINDOW CL30 Prime Window Replacement of Single Pane Base_DHP	45	$3,675.82	$64.41	$138.04	0.78	1,693.62	0.8587
Residential	HVAC	WINDOW CL30 Prime Window Replacement of Single Pane Base_Electric F	45	$3,675.82	$4.54	$77.92	1.38	3,000.42	1.5155
Residential	HVAC	WINDOW CL30 Prime Window Replacement of Single Pane Base_Electric Z	45	$3,675.82	$64.41	$138.04	0.78	1,693.62	0.8587
Residential	HVAC	WINDOW CL30 Prime Window Replacement of Single Pane Base_Heat Pum	45	$3,675.82	$108.23	$176.27	0.58	1,326.22	0.6147
Residential	Water Heating	MH Showerhead Replace_1_50gpm_Any Shower_ AnyWH	10	$0.00	-$103.33	$0.00	9,999.00	156.14	0.0301
Residential	Water Heating	MH Showerhead Replace_1_50GPM_any shower_HPWH	10	$17.20	-$127.28	$14.18	12.34	169.62	0.0328
Residential	Water Heating	MH Showerhead Replace_1_75gpm_Any Shower_ AnyWH	10	$0.00	-$104.43	$0.00	9,999.00	65.03	0.0125
Residential	Water Heating	MH Showerhead Replace_2_00gpm_Any Shower_ AnyWH	10	$17.20	-$32.16	$25.21	3.61	95.43	0.0184
Residential	Water Heating	MF Showerhead Replace_1_50gpm_Any Shower_ AnyWH	10	$0.00	-$102.76	$0.00	9,999.00	156.37	0.0301
Residential	Water Heating	MF Showerhead Replace_1_75gpm_Any Shower_ AnyWH	10	$0.00	-$103.26	$0.00	9,999.00	65.13	0.0125
Residential	Water Heating	MF Showerhead Replace_2_00gpm_Any Shower_ AnyWH	10	$17.20	-$18.46	$39.25	2.33	61.28	0.0118
Residential	Water Heating	MF Showerhead Replace_1_50gpm_Any Shower_ AnyWH	10	$0.00	-$102.76	$0.00	9,999.00	156.37	0.0301
Residential	Water Heating	MF Showerhead Replace_1_75gpm_Any Shower_ AnyWH	10	$0.00	-$103.26	$0.00	9,999.00	65.13	0.0125
Residential	Water Heating	MF Showerhead Replace_2_00gpm_Any Shower_ AnyWH	10	$17.20	-$18.46	$39.25	2.33	61.28	0.0118
Residential	Water Heating	SF Showerhead Replace_1_50gpm_Any Shower_ AnyWH	10	$0.00	-$45.95	$0.00	9,999.00	155.42	0.0299
Residential	Water Heating	SF Showerhead Replace_1_50GPM_any shower_HPWH	10	$17.20	-$89.64	$8.59	15.34	280.08	0.0587
Residential	Water Heating	SF Showerhead Replace_1_75gpm_Any Shower_ AnyWH	10	$0.00	-$239.41	$0.00	9,999.00	64.73	0.0125
Residential	Water Heating	SF Showerhead Replace_2_00gpm_Any Shower_ AnyWH	10	$17.20	-$30.44	$24.24	3.64	99.24	0.0193
Residential	Water Heating	MH Showerhead Replace_1_50gpm_Any Shower_ AnyWH	10	$0.00	-$103.33	$0.00	9,999.00	156.14	0.0301
Residential	Water Heating	MH Showerhead Replace_1_50GPM_any shower_HPWH	10	$17.20	-$127.28	$14.18	12.34	169.62	0.0328
Residential	Water Heating	MH Showerhead Replace_1_75gpm_Any Shower_ AnyWH	10	$0.00	-$104.43	$0.00	9,999.00	65.03	0.0125
Residential	Water Heating	MH Showerhead Replace_2_00gpm_Any Shower_ AnyWH	10	$17.20	-$32.16	$25.21	3.61	95.43	0.0184
Residential	Water Heating	MF Showerhead Replace_1_50gpm_Any Shower_ AnyWH	10	$0.00	-$102.76	$0.00	9,999.00	156.37	0.0301
Residential	Water Heating	MF Showerhead Replace_1_75gpm_Any Shower_ AnyWH	10	$0.00	-$103.26	$0.00	9,999.00	65.13	0.0125
Residential	Water Heating	MF Showerhead Replace_2_00gpm_Any Shower_ AnyWH	10	$17.20	-$18.46	$39.25	2.33	61.28	0.0118
Residential	Water Heating	MF Showerhead Replace_1_50gpm_Any Shower_ AnyWH	10	$0.00	-$102.76	$0.00	9,999.00	156.37	0.0301
Residential	Water Heating	MF Showerhead Replace_1_75gpm_Any Shower_ AnyWH	10	$0.00	-$103.26	$0.00	9,999.00	65.13	0.0125
Residential	Water Heating	MF Showerhead Replace_2_00gpm_Any Shower_ AnyWH	10	$17.20	-$18.46	$39.25	2.33	61.28	0.0118
Residential	Water Heating	SF Showerhead Replace_1_50gpm_Any Shower_ AnyWH	10	$0.00	-$45.95	$0.00	9,999.00	155.42	0.0299
Residential	Water Heating	SF Showerhead Replace_1_50GPM_any shower_HPWH	10	$17.20	-$89.64	$8.59	15.34	280.08	0.0587
Residential	Water Heating	SF Showerhead Replace_1_75gpm_Any Shower_ AnyWH	10	$0.00	-$239.41	$0.00	9,999.00	64.73	0.0125
Residential	Water Heating	SF Showerhead Replace_2_00gpm_Any Shower_ AnyWH	10	$17.20	-$30.44	$24.24	3.64	99.24	0.0193
Residential	Water Heating	SHW Solar Zone 1	20	$8,617.59	$700.36	$725.29	0.08	1,126.47	0.1877
Residential	Water Heating	SHW Solar Zone 2	20	$8,617.59	$664.10	$689.02	0.08	1,185.76	0.1976
Residential	Water Heating	SHW Solar Zone 3	20	$8,617.59	$616.02	$640.95	0.09	1,274.69	0.2124
Residential	Water Heating	SHW Solar Zone 4	20	$8,617.59	$526.29	$551.22	0.11	1,482.20	0.2470
Residential	Water Heating	SHW Solar Zone 1	20	$8,617.59	$700.36	$725.29	0.08	1,126.47	0.1877
Residential	Water Heating	SHW Solar Zone 2	20	$8,617.59	$664.10	$689.02	0.08	1,185.76	0.1976
Residential	Water Heating	SHW Solar Zone 3	20	$8,617.59	$616.02	$640.95	0.09	1,274.69	0.2124
Residential	Water Heating	SHW Solar Zone 4	20	$8,617.59	$526.29	$551.22	0.11	1,482.20	0.2470
Residential	Water Heating	Multifamily GFHX DHW Preheat, Heat Pump	40	$627.25	$311.30	$340.49	0.18	121.38	0.0256
Residential	Water Heating	Multifamily GFHX DHW & Shower Preheat, Electric Resistance	40	$688.82	$152.20	$179.50	0.34	252.84	0.0489
Residential	Water Heating	Multifamily GFHX DHW & Shower Preheat, Heat Pump	40	$688.82	$344.72	$373.91	0.17	121.38	0.0256

Sector	End Use	Measure Name	Measure Life (Years)	Initial Capital Cost	TRC Levelized Cost ($/MWh)	Total Sponsor Levelized Cost ($/MWh)	TRC B/C Ratio	Bulk Energy (kWh/unit)	Wholesale Demand (kW)
Residential	Water Heating	Multifamily GFHX DHW Preheat, Electric Resistance	40	$627.25	$136.15	$163.46	0.37	252.84	0.0489
Residential	Water Heating	Multifamily GFHX DHW Preheat, Heat Pump	40	$627.25	$311.30	$340.49	0.18	121.38	0.0256
Residential	Water Heating	Multifamily GFHX DHW & Shower Preheat, Electric Resistance	40	$688.82	$152.20	$179.50	0.34	252.84	0.0489
Residential	Water Heating	Multifamily GFHX DHW & Shower Preheat, Heat Pump	40	$688.82	$344.72	$373.91	0.17	121.38	0.0256
Residential	Water Heating	Multifamily GFHX DHW Preheat, Electric Resistance	40	$627.25	$136.15	$163.46	0.37	252.84	0.0489
Residential	Water Heating	Single Family GFHX DHW Preheat, Heat Pump	40	$749.31	$377.56	$406.74	0.15	121.38	0.0256
Residential	Water Heating	Single Family GFHX DHW & Shower Preheat, Electric Resistance	40	$778.53	$175.58	$202.88	0.30	252.84	0.0489
Residential	Water Heating	Single Family GFHX DHW & Shower Preheat, Heat Pump	40	$778.53	$393.42	$422.61	0.15	121.38	0.0256
Residential	Water Heating	Single Family GFHX DHW Preheat, Electric Resistance	40	$749.31	$167.96	$195.27	0.31	252.84	0.0489
Residential	HVAC	Single Family WIFI Enabled Thermostat HZ1	10	$240.35	$28.56	$87.57	1.06	666.99	0.3448
Residential	HVAC	Single Family WIFI Enabled Thermostat HZ2	10	$240.35	$0.12	$58.58	1.58	996.99	0.5099
Residential	HVAC	Single Family WIFI Enabled Thermostat HZ3	10	$240.35	-$9.49	$48.17	1.91	1,212.44	0.6102
Residential	HVAC	Single Family WIFI Enabled Thermostat HZ1	10	$240.35	$28.56	$87.57	1.06	666.99	0.3448
Residential	HVAC	Single Family WIFI Enabled Thermostat HZ2	10	$240.35	$0.12	$58.58	1.58	996.99	0.5099
Residential	HVAC	Single Family WIFI Enabled Thermostat HZ3	10	$240.35	-$9.49	$48.17	1.91	1,212.44	0.6102

Appendix B – 2020 Demand Response Potential Assessment

Demand Response Potential Assessment

Clark Public Utilities

LIGHTHOUSE ENERGY CONSULTING

May 22, 2020

May 22, 2020

Ms. Debbie DePetris
Energy Services Manager
Clark Public Utilities
PO Box 8900
Vancouver, WA 98668

SUBJECT: Demand Response Potential Assessment

Ms. DePetris:

Lighthouse Energy Consulting is pleased to submit this report summarizing the demand response potential assessment for Clark Public Utilities. The assessment was based on the demand response products included in the draft 2021 Power Plan from the NW Power Council.

Thank you and your team for the excellent support in preparing this assessment.

Sincerely,

Ted Light

Principal

Lighthouse Energy Consulting
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(503) 395-5310

Contents

Introduction

This report summarizes the 2021 demand response potential assessment conducted for Clark Public Utilities (CPU). The assessment covered the period of 2021-2040 and utilized the products and methodology developed by the NW Power and Conservation Council (Council) for the draft 2021 Power Plan (2021 Plan). The assessment included demand response products applicable to the commercial, industrial, residential, and utility distribution sectors, impacting both summer and winter peak demands, and utilizing a range of strategies including direct load control, demand curtailment, and time-varying prices to effect reductions in peak demand. This report updates a similar assessment conducted for CPU in 2017.

Background

Demand response has not been widely used in the Northwest but has received increased interest in recent years. Demand response is defined in the Council's Seventh Power Plan (Seventh Plan) as "voluntary reductions in customer electricity use during periods of high demand and limited resource availability."[1] Growing capacity constraints associated with the closure of regional coal-fired power plants, increases in policies requiring the use of carbon-neutral or renewable energy, and operational limitations placed on the region's hydropower system are all driving a need for cost-effective capacity. Demand response offers a solution to reduce peak demands, help integrate renewable resources, and alleviate congestion on transmission and distribution systems.

CPU has a provided conservation programs for its customers since 2015 and achieved over 30 average megawatts from 2014-2018, which is approximately a 5% reduction in energy consumption. Like many utilities in the Northwest, CPU's demand response program is not as mature, as the need for demand response resources has only recently started to emerge. Regional utilities have been conducting pilots of different demand response program types in an effort to learn what types of programs would work well in the Northwest, and CPU has been an active participant in those programs. In 2017 and 2018, CPU participated in a regional pilot focused on using electric water heaters as a flexible resource to help integrate renewable energy resources. CPU also participated in a commercial demand response pilot program in 2015 and 2016 by facilitating conversations with its large commercial customers and providing metering data. In total, the program included nearly 1.5 MW of load and was successful in providing reduced energy demands when given a 20-minute notice.

Methodology

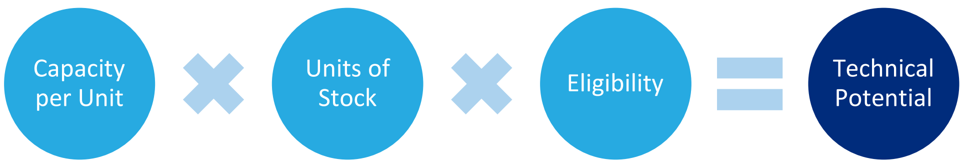
This assessment uses both bottom-up and top-down methods to quantify potential. Similar to a conservation potential assessment, the assessment begins with quantifying technical potential, which is the maximum amount of demand response capacity possible without regard to cost or market barriers. The assessment then considers market barriers, program participation rates, and other factors to quantify the achievable potential. This assessment did not include an economic screen, although possible thresholds for cost effectiveness are discussed. The methodology used to calculate technical and achievable potential is discussed below.

[1] Northwest Power and Conservation Council, 'Seventh Northwest Conservation and Electric Power Plan', 2016, https://www.nwcouncil.org/sites/default/files/7thplanfinal_allchapters_1.pdf.

Technical Potential

The technical demand response potential was quantified by a combination of bottom-up and top-down methodologies. The bottom-up method, illustrated in Figure 1 below, multiplies the per-unit demand response capacity associated with a single instance by the number of technically possible opportunities. The number of opportunities is determined by multiplying the units of stock, such as the number of homes, by an eligibility factor. This factor quantifies the share of units that are eligible to install the DR product or participate in a program. For example, in quantifying the potential associated with electric water heaters, the eligibility factor would be the number of electric water heaters per home in CPU's service territory.

Figure 1 - Bottom-Up Technical Potential Calculation



In this analysis, the capacity values were those determined by Council staff in the development of the draft 2021 Plan. Stock unit counts were developed from data provided by CPU. Finally, the eligibility factors were determined by a combination of data from CPU's 2019 Conservation Potential Assessment[2] (2019 CPA) and the draft 2021 Plan.

In the top-down method, the technical potential is determined by multiplying an assumption of the DR product's impact on load by an applicable load basis. The impact is expressed as a percentage and the load basis is measured in units of demand. The load basis is determined by multiplying the load by the share of load within the impacted end use. For example, with products controlling HVAC equipment, the customer segment's load used for HVAC would be the starting point and would be determined by multiplying an annual energy consumption value by an assumption of what percent of the load is consumed by HVAC equipment. Finally, a peak demand factor converts annual energy consumption values into an average peak demand, based on the expected number and duration of demand response events.

Figure 2 - Top-Down Technical Potential Calculation

In this equation, the load impact assumptions and end use shares were taken from the draft 2021 Plan while the segment loads within each sector were developed from updated sector-level forecasts from CPU and load shares within each segment determined in the 2019 CPA.

[2] EES Consulting, 'Clark Public Utilities Conservation Potential Assessment: Final Report', 2019, https://www.clarkpublicutilities.com/wp-content/uploads/2019/12/CPU-2019-CPA-Final-Report-with-Measure-Details.pdf

Achievable Potential

The achievable potential is quantified by adding considerations for program and event participation rates as well as program ramp up periods to the technical potential. Program participation is the proportion of eligible customers who participate in a demand response program. Event participation quantifies the share of program participants that participate in a given event. For DR products enabled through direct load control, the event participation rate is based on the success of equipment reducing the demand of equipment while for other types of programs this factor considers the likelihood of human intervention. The annual acquisition of DR programs is determined by ramp rates. Ramp rates consider whether a program is starting from scratch or already has traction and how long it will take to reach its maximum participation levels. In the 2021 Plan, most products were given a ramp rate that reflects a five- or ten-year ramp up period. The calculation of achievable is the same for both bottom-up and top-down methods and is shown in Figure 3 below.

Figure 3 - Achievable Potential Calculation

Demand Response Products

This assessment largely used the demand response products developed for the draft 2021 Plan, which covers a range of sectors, end uses, and product types. Modifications were made to these products to better reflect CPU's service territory. For example, agricultural DR products were excluded, since CPU does not have any irrigation loads. The 2021 Plan also evaluated the potential for demand voltage reduction (DVR), but this product was excluded from this analysis since CPU prefers to implement conservation voltage reduction (CVR) on its system. CVR employs the same types of voltage reductions as DVR, but does so on a continuous basis to achieve energy savings instead of only during times of peak demand, as is the case with DVR.

Finally, the demand response products that rely on pricing strategies to influence customer behavior or contractual agreements to curtail energy demand typically require advanced metering infrastructure (AMI) to record the time-based impacts. These products were given slower ramp rates, since CPU does not currently have AMI implemented in its service territory. This assessment also presents the results with and without these products, as the associated demand reduction potential would not be available until CPU implements AMI. The results that do include these products are intended to show what might be possible, in terms of both potential and cost, over a long-term basis if CPU were to implement AMI. The cost of these products does not include the AMI necessary for implementation.

The measures included in this assessment are summarized in Table 1 below, which organizes the measures by sector and implementation strategy.

Table 1 - Demand Response Products

	Commercial	Industrial	Residential
Direct Load Control	Space Heating Switch Space Cooling Switch Smart Thermostat		EV Charging DHW Controls Space Heating Switch Space Cooling Switch Smart Thermostat
Demand Curtailment	Demand Curtailment	Demand Curtailment	
Time-varying Prices	Critical Peak Pricing	Critical Peak Pricing Real Time Pricing	Critical Peak Pricing Time of Use Rates

Direct load control (DLC) are those in which the utility has direct control of the operation of applicable equipment. This category includes switches installed on equipment or other equipment with integrated controls such as smart thermostats or grid-enabled hot water heaters. DLC products typically include high event participation rates as the participation is only limited by the success of the controlled equipment receiving and implementing any instructions to change its operation. Demand curtailment is similar to direct load control but requires the intervention of customers to implement reductions in load. These products usually involve contracts between the customer and utility that detail the amount, duration, and frequency of load reductions. Price-based products rely on a variety of customer strategies to respond to higher energy or demand prices.

Some of the products in Table 1 impact a single season or can impact both seasons. The capacity reductions for each product were quantified for each applicable season and the results for the winter and summer seasons are discussed separately below. A complete list of the products used in this assessment is included in the Appendix of this report.

Customer and Load Forecasts

CPU provided updated load forecasts for each sector and customer counts for the commercial and residential sector. For the industrial sector, Lighthouse used regional data from the draft 2021 Plan to identify average loads per customer for each industrial segment and used this data to estimate the number of CPU's industrial customers. The resulting forecasts are shown in Figure 4 and Figure 5 below.

Figure 4 - Load Forecast by Sector

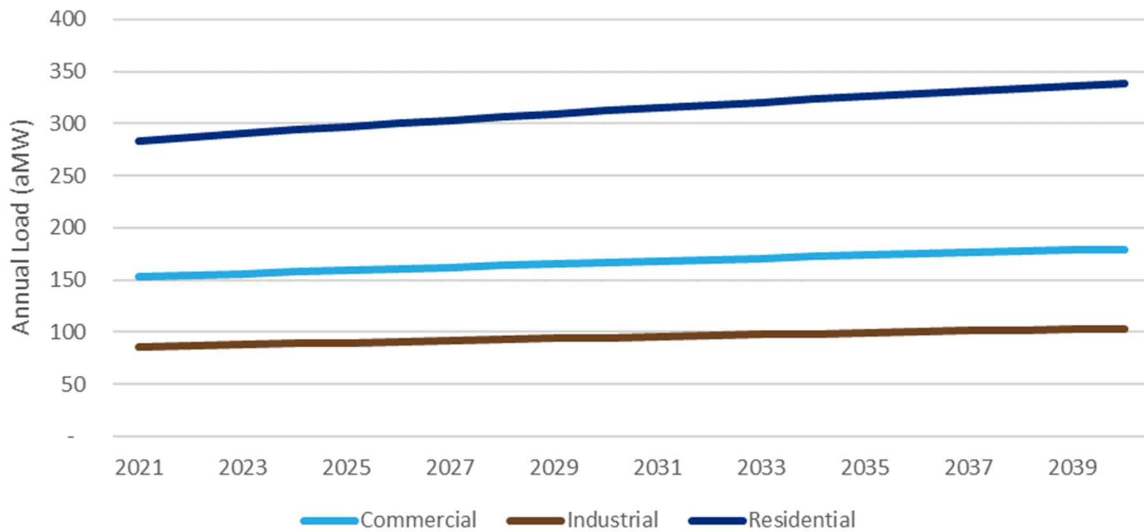
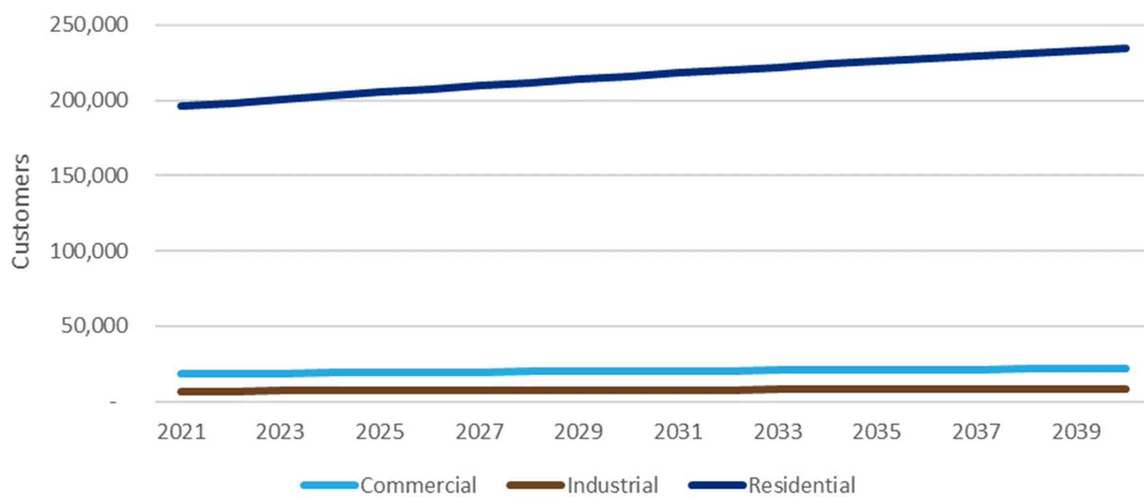


Figure 5 - Customer Count Forecast by Sector



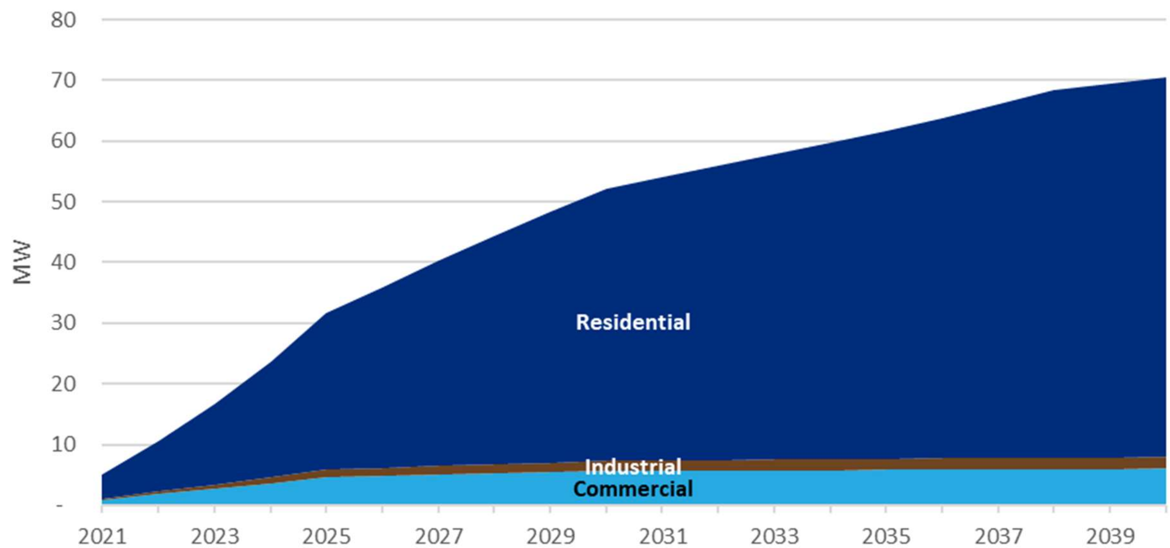
Results

Potential

The estimated achievable winter demand response potential for CPU is summarized by sector and year in Figure 6 below. The total winter potential is 71 MW, which is approximately 7% of CPU's estimated 2040 winter peak demand in.

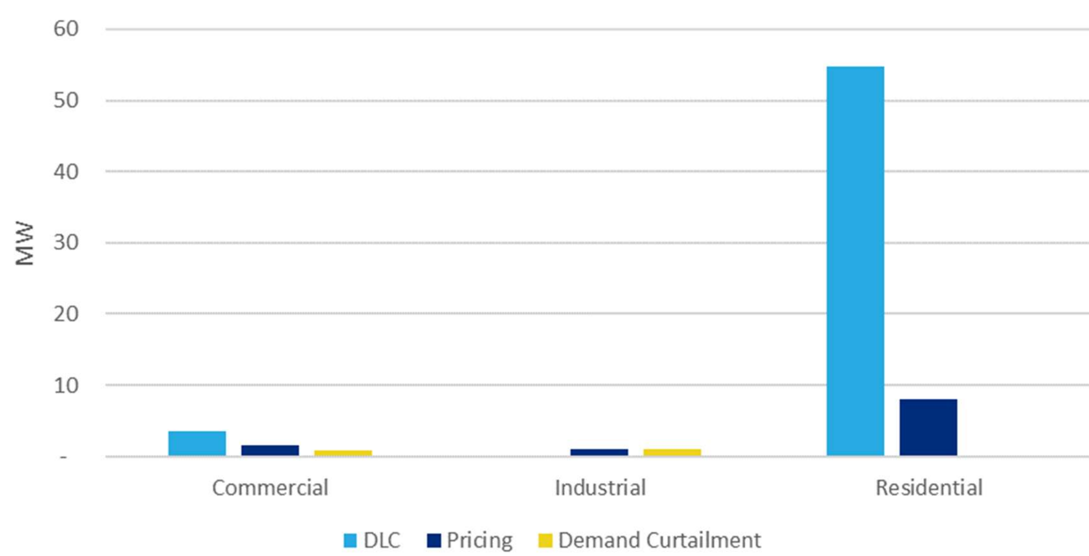
Most of the potential is in the residential sector, which totals 63 MW in the last year of the study period. The remaining potential in the commercial and industrial sectors totals 8 MW.

Figure 6 - Annual Achievable Winter DR Potential by Sector



Below, Figure 7 shows how this potential breaks down across the various program types within each sector. Most of the potential is from DLC products, with smaller amounts coming from the pricing and demand curtailment strategies that require AMI.

Figure 7 – Winter Achievable Potential by Sector and Type



The potential for summer demand response is shown in Figure 8. The distribution of potential across sectors and years is similar but note that the scale has changed. Total summer potential is 81 MW, which is 8% of CPU's estimated 2040 peak summer demand. Much of the increase is in the commercial sector where the potential nearly doubled due to higher summer air conditioning loads.

Figure 8 - Annual Achievable Summer DR Potential by Sector

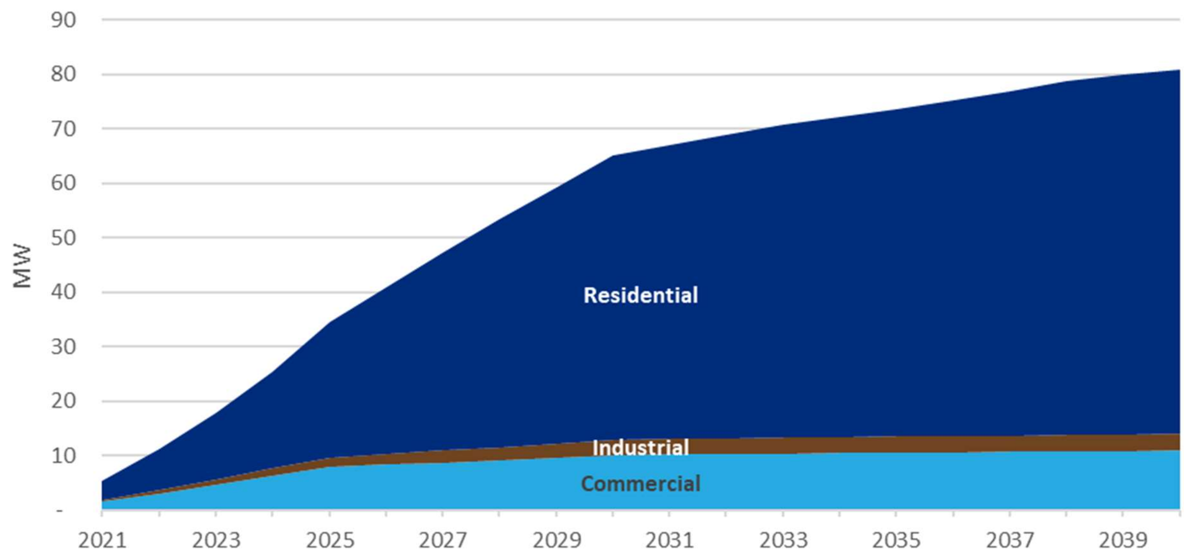


Figure 9 shows how the summer potential splits across sectors and program types. Unlike the winter potential, nearly 40% of the summer DR potential comes from pricing and demand curtailment programs that would require AMI.

Figure 9 - Summer Potential by Sector and Type

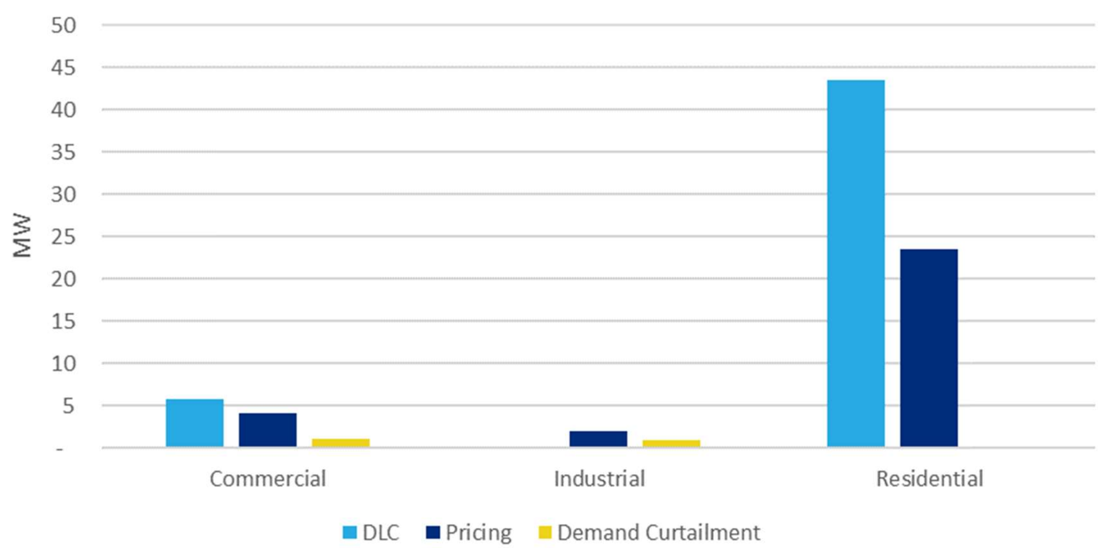
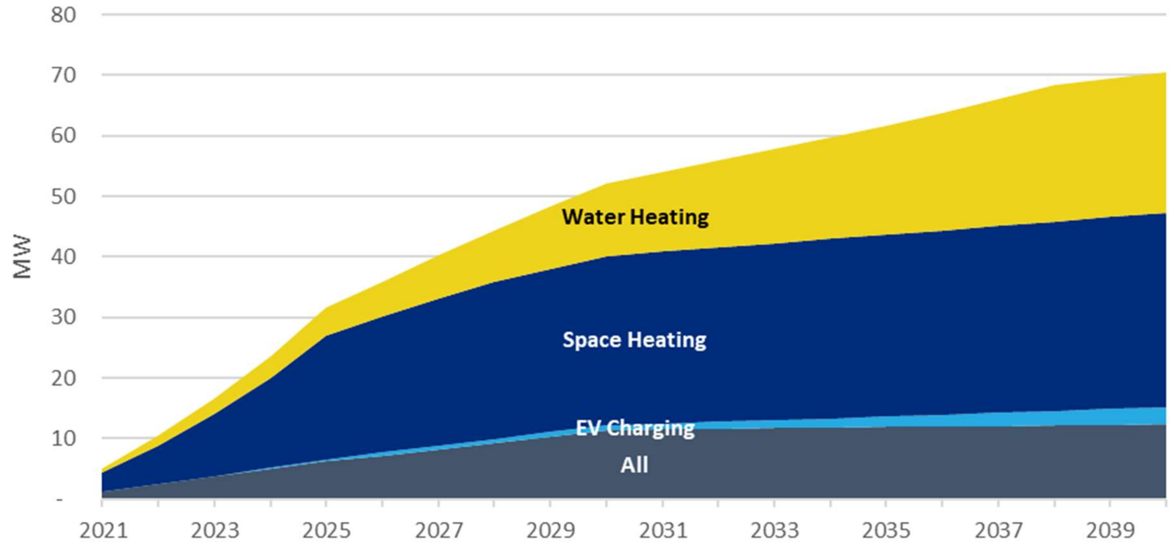


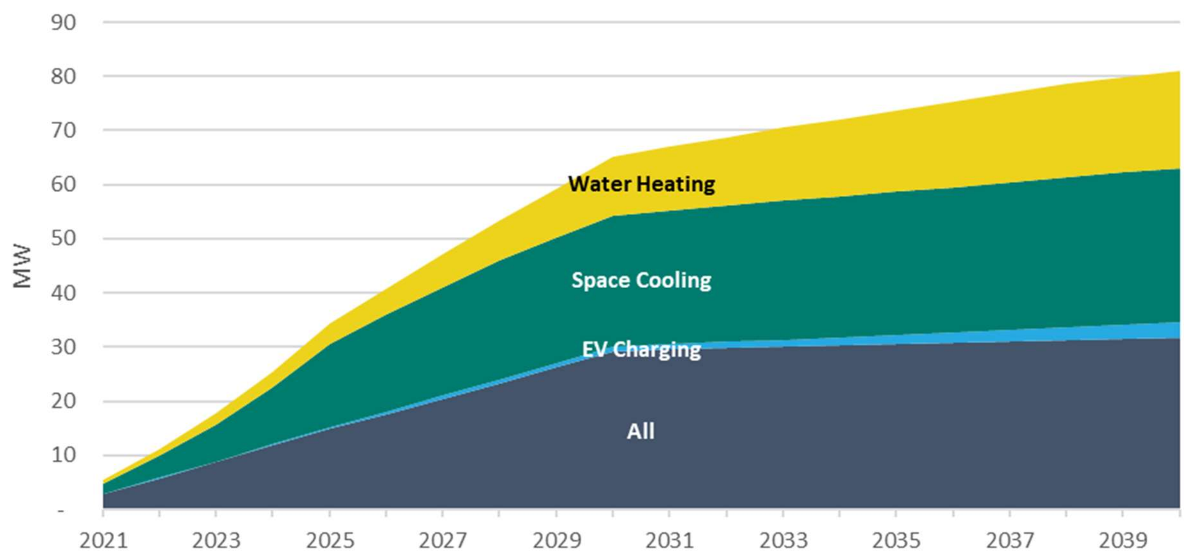
Figure 10 shows the annual achievable winter DR potential by end use. As would be expected, most of the potential is in the space and water heating end uses. Significant additional potential is in the All end use category, which includes products that are not specific to an end use, such as price-based products. The potential in the water heating category reflects both electric resistance and heat pump water heaters. Data from CPU's 2019 CPA was used to model the adoption of heat pump water heaters over the 20-year study period.

Figure 10 - Annual Achievable Winter DR Potential by End Use



A similar breakdown in summer potential by end use is shown in Figure 11. Here, most of the potential is in the All end use category, reflecting higher impact assumptions for the summer for products that impact both seasons, including pricing and demand curtailment strategies.

Figure 11 – Annual Achievable Summer DR Potential by End Use



Comparison to 2017 Assessment

Table 2 compares the 20-year potential from CPU's 2017 DR Potential Assessment and the results of this assessment. In Table 2, the column 2017 refers to the results of the 2017 assessment while 2020 refers to the results of this assessment. Table 2 includes all DR program types, including those requiring AMI.

Table 2 - Comparison of 2017 and 2020 DR Potential Assessments

	Winter Capacity (MW)		Summer Capacity (MW)	
	2017	2020	2017	2020
Commercial	4	6	7	11
Industrial	8	2	8	3
Residential	34	63	29	67
Total	**46**	**71**	**45**	**81**

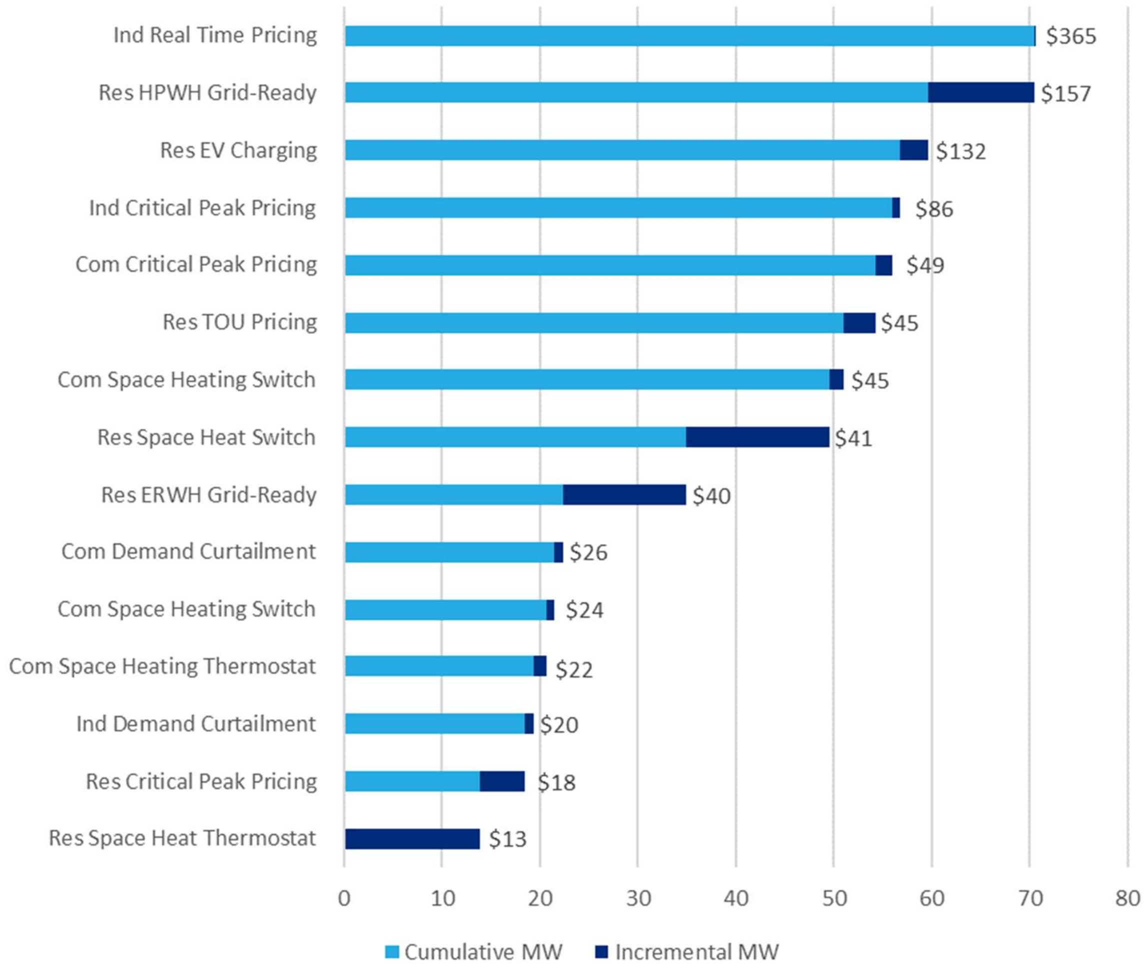
Table 2 shows that the DR potential has increased in nearly all sectors, except for in the industrial sector. In the residential sector, the potential has approximately doubled. These increases as well as the increases in other sectors are largely a result of the products included in the assessment. The 2017 assessment was based on the DR assessment conducted as part of the Seventh Power Plan, while the 2020 assessment used the results of the 2021 Power Plan, which included an entirely new model and different set of DR products.

Costs and Cost Effectiveness

The quantity of capacity and cost for each winter DR product is shown in Figure 12, below. The products are ranked by levelized cost ($/kW-year), with the lowest cost product at the bottom. As you move up, the incremental DR potential for each product is shown in dark blue, with the cumulative potential from all previous products shown in lighter blue. The levelized cost calculations include credits of $6.85/kW-year and $3.08/kW-year for deferred capacity costs for the distribution and transmission systems, respectively. These same credits were used in CPU's 2019 CPA. Figure 12 includes all DR product types. The supply curve without products requiring AMI is shown in subsequently, in Figure 13.

Figure 12 shows that the individual products with the highest potential are associated with residential space and water heating systems. With the demand response products in these categories, CPU could realize 52 MW of capacity. The thermostat product does not include the cost of the thermostat, as it assumes that it is provided by another entity, such as an energy efficiency program or the customer directly.

Figure 12 - Winter Demand Response Supply Curve: All Product Types (MW and $/kW-year)



CPU's 2019 CPA lists a levelized value of $75.70/kW-year for generation capacity.[3] This value represents a hypothetical cost-effectiveness threshold for CPU's demand response products. Based on Figure 12, CPU has approximately 56 MW of winter capacity under this cost. In the Seventh Plan, the Council identified a value of capacity of $115/kW-year. Very little additional capacity is available at this higher cost threshold.

In Figure 13, only DLC products are shown as these can be implemented without AMI. Approximately 45 MW of winter DR potential is available at the cost thresholds discussed above.

[3] EES Consulting, 'Clark Public Utilities Conservation Potential Assessment: Final Report', 2019, https://www.clarkpublicutilities.com/wp-content/uploads/2019/12/CPU-2019-CPA-Final-Report-with-Measure-Details.pdf, p. 42.

Figure 13 - Winter Demand Response Supply Curve Excluding AMI Products (MW and $/kW-year)

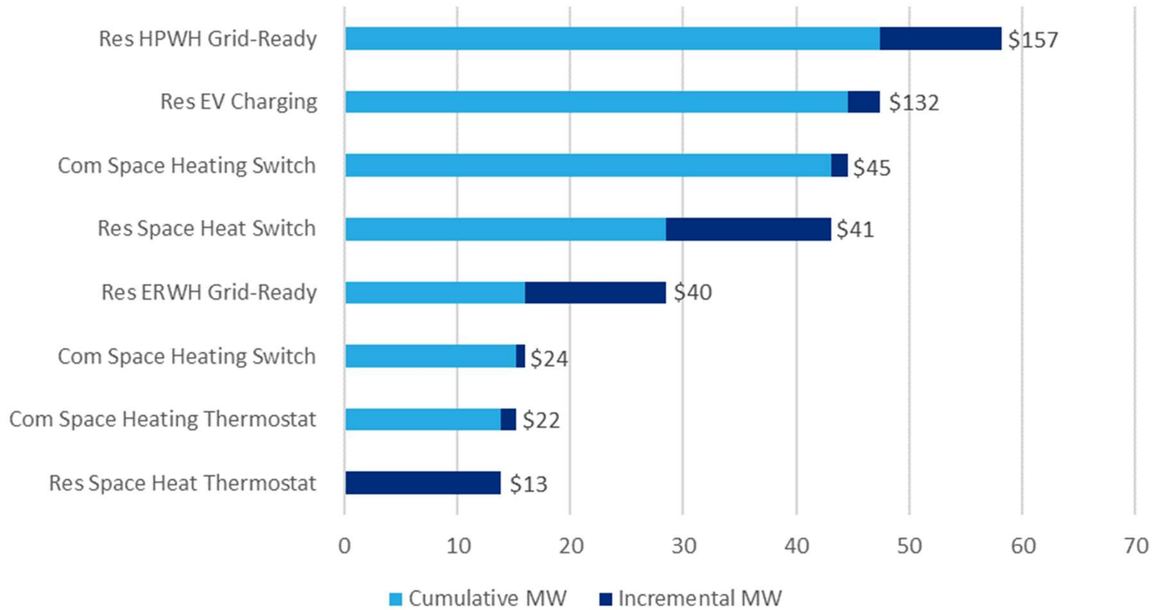


Figure 14 shows the supply curve for summer capacity across all product types. This figure shows that residential thermostats are again a product with high potential at a low cost. Grid-ready water heaters, time of use rates, and critical peak pricing also show higher potential.

CPU has approximately 70 MW of summer DR potential under $75/kW-year, and a total of 76 MW at the higher threshold of $115/kW-year. Residential critical peak pricing programs are shown with a cost of $0 per kW-year and the credits for transmission and distribution capacity offset the cost of implementing this program. This cost, however, does not include the cost of the AMI necessary to implement this program.

Figure 14 - Summer Demand Response Supply Curve: All Product Types (MW and $/kW-year)

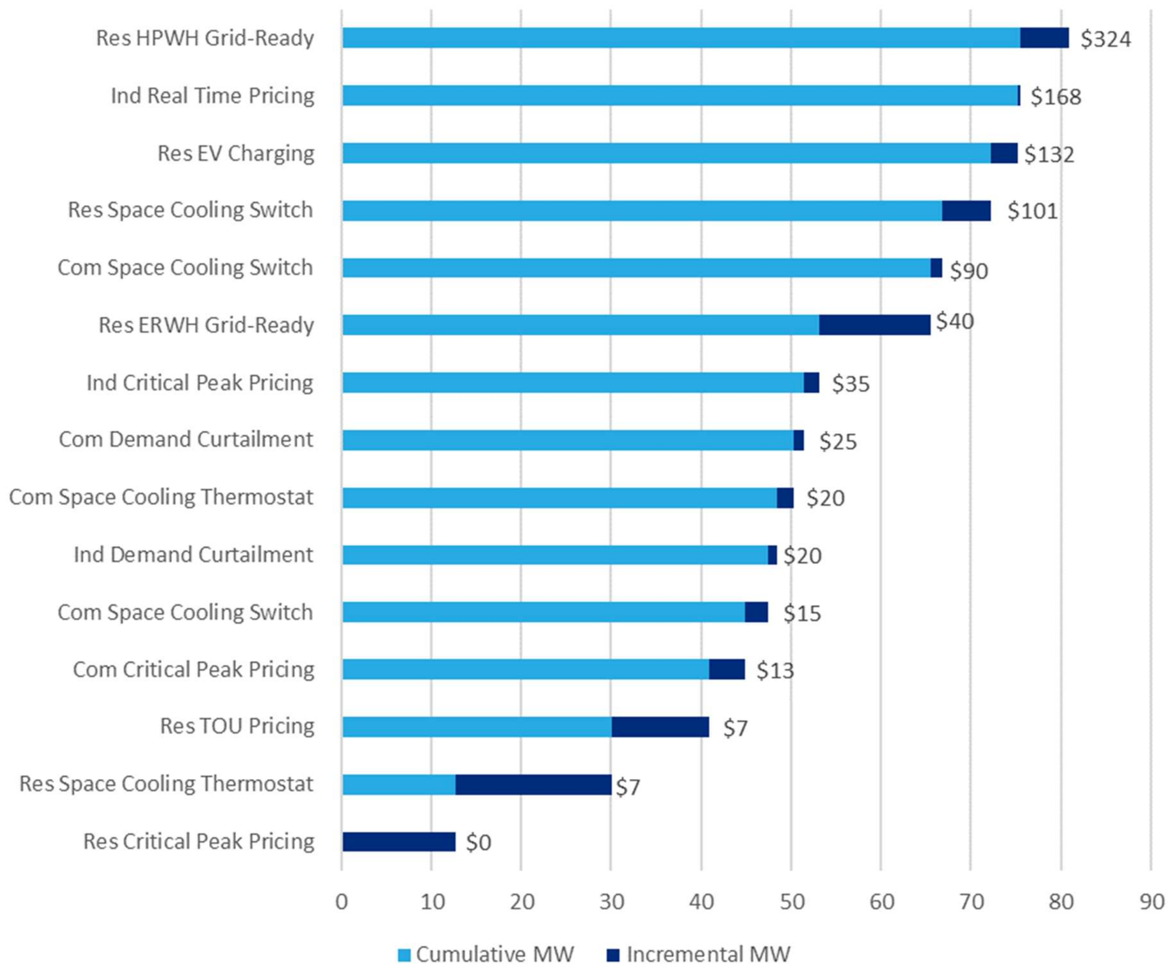
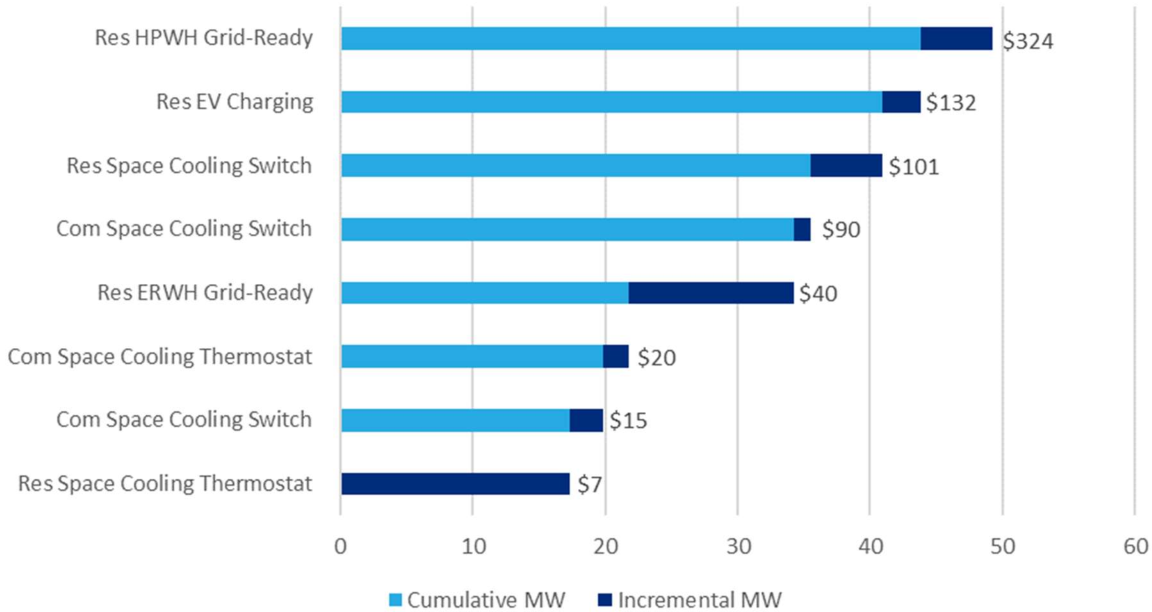


Figure 15 shows the supply curve for DLC products that do not require AMI. Based on this figure, approximately 34 MW of summer DR potential is available below the cost thresholds discussed above.

Figure 15 - Summer Demand Response Supply Curve Excluding AMI Products (MW and $/kW-year)



Summary

This assessment updates the demand response potential identified in CPU's 2017 Demand Response Potential Assessment. The assessment was based on the products and methodology used by the Council in the draft 2021 Plan and customized to CPU's service territory. It included products applicable to the commercial, industrial, and residential sectors, using a variety of DLC, demand curtailment, and price-based strategies and targeting a variety of end uses.

Overall, the assessment quantified 71 MW of winter DR capacity an increase of more than 50% above the 2017 assessment. Of that, 56 MW is under the levelized cost of capacity developed in CPU's 2019 CPA if DR products requiring AMI are included, although the majority of this potential is in DLC products that do not require AMI. Key DR products providing winter capacity include switches and smart thermostats used to control residential space heating equipment, as well as switches applied to grid-ready electric resistance and heat pump water heaters.

Appendix

Product Info					
Sector	**End Use**	**Product**	**Type**	**Impact**	**Methodology**
Residential	EV Charging	Res EV Charging - Winter	DLC	Winter	Bottom Up
Residential	EV Charging	Res EV Charging - Summer	DLC	Summer	Bottom Up
Residential	Water Heating	Res ERWH Switch - Winter	DLC	Winter	Bottom Up
Residential	Water Heating	Res ERWH Switch - Summer	DLC	Summer	Bottom Up
Residential	Water Heating	Res ERWH Grid-Ready - Winter	DLC	Winter	Bottom Up
Residential	Water Heating	Res ERWH Grid-Ready - Summer	DLC	Summer	Bottom Up
Residential	Water Heating	Res HPWH Switch - Winter	DLC	Winter	Bottom Up
Residential	Water Heating	Res HPWH Switch - Summer	DLC	Summer	Bottom Up
Residential	Water Heating	Res HPWH Grid-Ready - Winter	DLC	Winter	Bottom Up
Residential	Water Heating	Res HPWH Grid-Ready - Summer	DLC	Summer	Bottom Up
Residential	Space Heating	Res Space Heat Switch - West	DLC	Winter	Bottom Up
Residential	Space Cooling	Res Space Cooling Switch - West	DLC	Summer	Bottom Up
Residential	Space Heating	Res Space Heat Thermostat - West	DLC	Winter	Bottom Up
Residential	Space Cooling	Res Space Cooling Thermostat - West	DLC	Summer	Bottom Up
Commercial	Space Heating	Com Space Heating Switch - Small/West	DLC	Winter	Bottom Up
Commercial	Space Cooling	Com Space Cooling Switch - Small/West	DLC	Summer	Bottom Up
Commercial	Space Heating	Com Space Heating Thermostat - West	DLC	Winter	Bottom Up
Commercial	Space Cooling	Com Space Cooling Thermostat - West	DLC	Summer	Bottom Up
Commercial	Space Heating	Com Space Heating Switch - Medium/West	DLC	Winter	Bottom Up
Commercial	Space Cooling	Com Space Cooling Switch - Medium/West	DLC	Summer	Bottom Up
Commercial	All	Com Demand Curtailment - Winter	Demand Curtailment	Winter	Top Down
Commercial	All	Com Demand Curtailment - Summer	Demand Curtailment	Summer	Top Down
Industrial	All	Ind Demand Curtailment - Winter	Demand Curtailment	Winter	Top Down
Industrial	All	Ind Demand Curtailment - Summer	Demand Curtailment	Summer	Top Down
Residential	All	Res TOU Pricing - Winter	Pricing	Winter	Top Down
Residential	All	Res TOU Pricing - Summer	Pricing	Summer	Top Down
Residential	All	Res Critical Peak Pricing - Winter	Pricing	Winter	Top Down
Residential	All	Res Critical Peak Pricing - Summer	Pricing	Summer	Top Down
Commercial	All	Com Critical Peak Pricing - Winter	Pricing	Winter	Top Down
Commercial	All	Com Critical Peak Pricing - Summer	Pricing	Summer	Top Down
Industrial	All	Ind Critical Peak Pricing - Winter	Pricing	Winter	Top Down
Industrial	All	Ind Critical Peak Pricing - Summer	Pricing	Summer	Top Down
Industrial	All	Ind Real Time Pricing - Winter	Pricing	Winter	Top Down
Industrial	All	Ind Real Time Pricing - Summer	Pricing	Summer	Top Down

Appendix C – Resource Adequacy Metrics Determination

Resource Adequacy Metrics Determination

January 13, 2020

Current Status

Section 14(1)(f) of CETA requires each utility to determine metrics for resource adequacy (RA) for the resource plan consistent with the forecasts. The CETA does not define resource adequacy and to-date no state or federal agency provides any definition beyond broad sweeping terms. NERC defines the reliability of the interconnected BPS in terms of two basic and functional aspects, Adequacy and Operating Reliability. NERC differentiates these further:

> **Adequacy:** is the ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and reasonably expected unscheduled outages of system components.
>
> **Operating Reliability:** is the ability of the electric system to withstand sudden disturbances, such as electric short circuits or unanticipated loss of system components

In Pacific Northwest, it has been in the purview of the either the Balancing Area, or the Load Serving Entity to determine what, if any, RA standards it may strive to meet.

Currently, Clark Public Utilities as an LSE uses a 12% planning margin as the metric for RA. CPU calculates a deterministic load/resource balance for each month of the year using 112% of a one-hour peak load as its obligation. Normal weather drives the peak load forecast. Subtracting expected resources from the 112% of load calculation determines CPU's resource adequacy.

Regional Focus

Aside from the newfound interest at the state level in resource adequacy, the Pacific Northwest utility community is also shining a bright light on resource adequacy through several different efforts.

Pacific Northwest Power Supply Annual Adequacy Assessment

The first effort is really a continuing effort that began in the late 1990s timeframe. The Northwest Power and Conservation Council (Council) publishes an annual Adequacy Assessment for the region as a whole. For the past 15 or so years, most members of the utility community ignored the outcomes. Results indicated plenty of surplus resources as loads held steady or shrank due to conservation and resource levels held steady or even increased. This state of adequacy provided no reason for concern by any individual utility regardless of its own position.

Recently the Adequacy Assessment has signaled some concern about the region's position. If an individual were to apply the Council's own standard, the region appears to be resource inadequate starting next year (2021) with a small departure from its own established metric and by 2026, the region is very resource inadequate.

The Council is exploring many RA metrics and standards that more clearly delineate and comprehensively define RA. The Council's Resource Adequacy Advisory Committee (https://www.nwcouncil.org/energy/energy-advisory-committees/resource-adequacy-advisory-committee) is the forum for these efforts and discussions.

Northwest Power Pool Resource Adequacy Program

The Northwest Power Pool (NWPP) is a voluntary organization of primarily major generating utilities serving the Pacific Northwest of the United States and the Pacific Southwest of Canada. The NWPP primarily focuses on utility operations, planning, and operating reserve sharing. From these common interests, RA has emerged as a topic of great interest to the NWPP membership. The NWPP began a journey in October 2019 toward developing an RA program for its members. (https://www.nwpp.org/resources/?name=&workgroup=12)

As this effort has just started, no definitive answers or requirements of the program are available. However, given the history of the NWPP and its abilities to bring the utilities together to form arrangements for the betterment of the region and its member utilities, it is highly likely that standards or standard approaches will materialize from these efforts.

Conclusion

Clark Public Utilities believes it has always met the CETA requirement that each IRP include RA metrics. The use of the 12% planning margin serves that purpose. CPU will stay involved with both the Council's efforts and the developments of the NWPP's RA program. CPU will update or change its approach toward RA metrics and standards as conditions require.

For Further Reading/Viewing

https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2019.pdf

https://www.nwcouncil.org/sites/default/files/2024%20RA%20Assessment%20Final-2019-10-31.pdf

https://www.nwpp.org/private-media/documents/2019.11.12_NWPP_RA_Assessment_Review_Final_10-23.2019.pdf

Appendix D – Distributed Energy and Resources

Distributed Energy Resources & Generation

January 2020

Distributed Generation Growth Analysis

Clark Public Utilities anticipates substantial growth in customer owned distributed generation over the next twenty years. As of January 2020, Clark Public Utilities facilitates, integrates and provides the Net Metering benefit to 10.414 MW of installed distributed generation capacity. Our customers have installed 1,489 individual generating systems, primarily rooftop solar. In recent years, distributed generation have exceeded 15% year-over-year annual growth rates.

State incentive programs drive higher adoption rates. Currently, the WA State renewable incentive programs have closed to new participants, and beginning in 2020, the federal tax credit starts decreasing. Because of this, Clark Public Utilities performed a distributed generation growth analysis that examined three different future scenarios. The conservative scenario assumes 10% annual growth, the moderate scenario assumes 15% annual growth and the aggressive scenario assumes 20% annual growth. The overwhelming majority of installed capacity is within Clark Public Utilities' residential customer sector. Clark Public Utilities anticipates this trend to continue into the next two decades.

Clark Public Utilities forecasts 1.25 aMW of energy generation from the 10.414 MW of existing distributed generation in 2020. The growth analysis shows by 2039 the utility could realize between 7.64 aMW and 39.92 aMW of annual distributed energy generation. The moderate growth scenario shows 17.79 aMW of annual electricity generation from distributed generation resources in 2039.

**Analysis includes a 12% capacity factor for solar generation sited in Clark County, WA.*

Distributed Generation: Growth Analysis	2020	2025	2030	2035	2039
Conservative Scenario					
10% Annual Growth Rate					
Customers	1,489	2,398	3,862	6,220	9,107
Installed Capacity (MW)	10.414	16.772	27.011	43.502	63.691
Generation (aMW)	1.25	2.01	3.24	5.22	7.64
Percent of Total Load	0.2349%	0.3738%	0.5869%	0.9168%	1.3047%
Moderate Scenario					
15% Annual Growth					
Customers	1,489	2,995	6,024	12,116	21,191
Installed Capacity (MW)	10.414	20.946	42.130	84.739	148.210
Generation (aMW)	1.25	2.51	5.06	10.17	17.79
Percent of Total Load	0.2349%	0.4668%	0.9153%	1.7859%	3.0360%
Aggressive Scenario					
20% Annual Growth					
Customers	1,489	3,705	9,219	22,941	47,571
Installed Capacity (MW)	10.414	25.913	64.481	160.449	332.706
Generation (aMW)	1.25	3.11	7.74	19.25	39.92
Percent of Total Load	0.2349%	0.5775%	1.4009%	3.3815%	6.8153%

Net Metering Analysis

The state mandated net metering threshold is set at 4.0% of taxable power sales in 1996. For Clark Public Utilities this calculates to ~40 MW

Using the distributed generation growth analysis, the utility estimates the different years of meeting the threshold. Under a conservative adoption rate, the analysis shows Clark Public Utilities hitting the net metering threshold in 2035, while under a moderate adoption the year is 2030. The aggressive adoption scenario shows the utility hitting the net metering threshold during 2028. Once Clark Public Utilities hits the threshold, a reassessment of the compensate rate for distributed generation is required.

Distributed Generation: Growth Analysis

Year	Conservative Scenario (10% Growth YoY)			Moderate Scenario (15% Growth YoY)			Aggressive Scenario (20% Growth YoY)		
	Customers	DG Capacity (MW)	aMW Gen	Customers	DG Capacity (MW)	aMW Gen	Customers	DG Capacity (MW)	aMW Gen
2020	1,489	10.414	1.25	1,489	10.414	1.25	1,489	10.414	1.25
2021	1,638	11.455	1.37	1,712	11.976	1.44	1,787	12.497	1.50
2022	1,802	12.601	1.51	1,969	13.773	1.65	2,144	14.996	1.80
2023	1,982	13.861	1.66	2,265	15.838	1.90	2,573	17.995	2.16
2024	2,180	15.247	1.83	2,604	18.214	2.19	3,088	21.594	2.59
2025	2,398	16.772	2.01	2,995	20.946	2.51	3,705	25.913	3.11
2026	2,638	18.449	2.21	3,444	24.088	2.89	4,446	31.096	3.73
2027	2,902	20.294	2.44	3,961	27.701	3.32	5,335	37.315	4.48
2028	3,192	22.323	2.68	4,555	31.857	3.82	6,402	44.778	5.37
2029	3,511	24.556	2.95	5,238	36.635	4.40	7,683	53.734	6.45
2030	3,862	27.011	3.24	6,024	42.130	5.06	9,219	64.481	7.74
2031	4,248	29.712	3.57	6,927	48.450	5.81	11,063	77.377	9.29
2032	4,673	32.684	3.92	7,967	55.718	6.69	13,276	92.852	11.14
2033	5,140	35.952	4.31	9,162	64.075	7.69	15,931	111.423	13.37
2034	5,654	39.547	4.75	10,536	73.686	8.84	19,118	133.707	16.04
2035	6,220	43.502	5.22	12,116	84.739	10.17	22,941	160.449	19.25
2036	6,842	47.852	5.74	13,933	97.450	11.69	27,529	192.538	23.10
2037	7,526	52.637	6.32	16,024	112.068	13.45	33,035	231.046	27.73
2038	8,279	57.901	6.95	18,427	128.878	15.47	39,642	277.255	33.27
2039	9,107	63.691	7.64	21,191	148.210	17.79	47,571	332.706	39.92

Community Solar & Low Income Customers

Clark Public Utilities operates 319 kW of installed community solar sited within Clark County, WA. In 2019, the Clark Public Utilities Board of Commissioners allocated 5%, approximately 15 kW, of the community solar array to the utility low-income program, Operation Warm Heart. This design change allows for many members of our most vulnerable populations to realize the benefit of local, renewable energy resources. Clark Public Utilities will continue to look for additional opportunities that will allow for limited and low-income customers to participate in renewable energy programs and projects.

Appendix E – Electric Vehicle Saturation

Electric Vehicle Saturation

January 2020

Background

Clark Public Utilities anticipates customer adoption of electric vehicles (EVs), combined with broader transportation electrification efforts will create a new transportation load sector. Clark Public Utilities believes this emerging sector of personal use EVs, corporate and public fleet electrification, plus the potential electrification of mass transit, will drive new incremental load growth in Clark Public Utilities' territory over the coming decades.

Fleet, commercial and mass transit electrification opportunities certainly hold noteworthy potential. However, Clark Public Utilities believes the primary increase in electric load related to EVs will materialize via personal and passenger use electric vehicle adoption.

On average, one passenger EV will consume 3.6 megawatt-hours (MWh) of electricity in one calendar year. This represents a 25% increase in annual consumption for the typical Clark County household. Clark Public Utilities begins 2020 with 2,841 EV's registered within its service territory that represent 10,228 MWh of load, or 1.17 average megawatts (aMW) or ~ 0.2% of the utility's 2020 system load requirements.

Future possibilities

Clark Public Utilities staff ran four different 20-year growth scenarios in an effort to estimate future EV loads the utility may realize. The analysis included a conservative scenario with a 10% annual growth rate, two moderate growth scenarios, and an aggressive scenario with a 25% annual growth rate. On the conservative end, the analysis showed up to 17,375 registered EV's, consuming 7.14 aMW of electricity annually in Clark County, WA by 2039. On the aggressive end, the analysis showed up to 62,389 registered EV's, consuming 25.64 aMW annually in Clark County, WA by 2040. A very aggressive analysis showed, while unlikely, there is potential to see nearly 200,000 EV's in Clark County by 2039; which would add over 80 aMW of transportation sector load to the Clark Public Utilities system.

Transportation Electrification: Growth Analysis					
	2020	**2025**	**2030**	**2035**	**2039**
Conservative Scenario					
10% Annual Growth					
EV Volume	2,841	4,575	7,369	11,868	17,375
Annual EV Load (MW)	10,228	16,472	26,528	42,723	62,551
Annual EV Load (aMW)	1.17	1.88	3.03	4.88	7.14
Moderate Scenario					
15% Annual Growth					
EV Volume	2,841	5,714	11,493	23,117	40,432
Annual EV Load (MW)	10,228	20,571	41,376	83,223	145,557
Annual EV Load (aMW)	1.17	2.35	4.72	9.50	16.62
Aggressive Scenario					
20% Annual Growth					
EV Volume	2,841	8,670	26,459	80,746	197,134
Annual EV Load (MW)	10,228	31,212	95,252	290,686	709,682
Annual EV Load (aMW)	1.17	3.56	10.87	33.18	81.01

While the forecasted increases to the overall Clark County electric load are manageable they are also potentially quite large. If not properly managed through effective incentive and smart software solutions, the transportation sector has the potential to add significant strain to the Clark Public Utilities distribution grid during peak consumption times. The utility anticipates developing a Transportation Electrification Plan that will address these issues to be presented to the Board of Commissioners for adoption. Attention to potential distribution system upgrades, time of use, and transmission constraints will be among other topics addressed within the plan.

Clark Public Utilities' Action Plan for Future EV adoption

Clark Public Utilities believes opportunities to collaborate with EV customers abound. Maximizing the benefit for both the EV customers and the non-participating ratepayers is the goal. Over the next several years, the utility aims to test and pilot a variety of tools and programs to encourage smart EV solutions. Additionally, opportunities for new charging infrastructure, customer education, EV promotion and local partnerships will be assertively pursued.