Agenda
Utility Advisory Committee Meeting
Tuesday, July 14, 2020
Via Zoom
(833) 548-0282 (Toll Free) or (877) 853-5247 (Toll Free)
Meeting ID 953 0702 6963

Note: Governor Inslee's Proclamation 20-28 prohibits meetings from being conducted in person. For this meeting, the Utility Advisory Committee will meet remotely. The public may attend this meeting through telephonic access by calling the phone number provided.

Committee Members: Chair Sanders, Vice-Chair Parker and Committee Members Larkin, Porter, LoPresti, Anderson, and Gregoire

Liaisons: Council Liaison Lemley
Staff Liaison Energy Services Director Whitney

Regular Meeting – 3:00 p.m.

Call to Order / Attendance:

Approval of Agenda: (Approved by Motion)

Approval of Minutes: (Approved by Motion)

Approval of March 10, 2020 Meeting Minutes

Public Comments:

Items of Business:

1. Status - Each City Utility (20 Minutes)
   - Clint Whitney, Energy Services Director
     Pete Rogalsky, Public Works Director
     Tom Huntington, Fire & Emergency Services Director

2. Optimum Resource Mix by Energy Northwest - E3 Study (25 Minutes)
   - Clint Whitney, Energy Services Director

3. Richland Energy Services Integrated Resource Plan (25 Minutes)
   - Clint Whitney, Energy Services Director

4. RMC Title 14 - Addition of Small Cell and Revised Rate Schedule 90 (5 Minutes)
   - Clint Whitney, Energy Services Director

Unfinished Business:

Other Informational Items:

1. Bonneville Power Administration's Financial Reserve Policy Surcharge Suspension
   - Clint Whitney, Energy Services Director

2. Energy Services Monthly Capital Work Plan
   - Clint Whitney, Energy Services Director

3. Energy Services Reliability Analysis
   - Clint Whitney, Energy Services Director

4. Energy Services Financial Status Update
   - Clint Whitney, Energy Services Director

5. Forward Planning Agenda
   - Clint Whitney, Energy Services Director

Adjournment

The next Utility Advisory Committee Meeting is September 8, 2020.

Richland Public Library is ADA accessible with special parking and access available at the entrance facing Northgate Drive. Requests for sign interpreters, audio equipment, and/or other special services must be received 48 hours prior to the Utility Advisory Committee Meeting by calling the City Clerk's Office at 942-7389.

UTILITY ADVISORY COMMITTEE AGENDA ITEM COVERSHEET

Meeting Date: 7/14/2020

Agenda Category: Approval of Minutes

Prepared By: Clint Whitney, Energy Services Director

Subject:
Approval of March 10, 2020 Meeting Minutes

Department:
Energy Services

Recommended Motion:
Approve minutes of the March 10, 2020 Utility Advisory Committee meeting.

Summary:

Fiscal Impact:

Attachments:

1. 031020 UAC Minutes - FOR APPROVAL

MINUTES DRAFT

UTILITY ADVISORY COMMITTEE REGULAR MEETING

Public Library Gallery Room ~ 955 Northgate Drive
March 10, 2020 ~ 3:00 p.m.

CALL TO ORDER:

Chair Sanders called the meeting to order at 3:00 p.m.

ATTENDANCE:

Chair James Sanders, Vice-Chair Graham Parker, Committee Members Dave Larkin, Charles LoPresti, Dan Porter, Amy Anderson, and Don Gregoire were present. Also present were Council Liaison Lemley, Staff Liaison and Energy Services Director Whitney, Public Works Director Rogalsky, Fire & Emergency Services Director Huntington, Business Services Manager Edgemon, Power Analyst Manzo and Administrative Assistant II Grimes.

APPROVAL OF THE AGENDA:

MEMBER PORTER MOVED AND MEMBER LOPRESTI SECONDED THE <u>MOTION TO APPROVE THE AGENDA AS PUBLISHED.</u> THE MOTION CARRIED 7-0.

APPROVAL OF MINUTES:

MEMBER LOPRESTI MOVED AND MEMBER LARKIN SECONDED THE <u>MOTION TO APPROVE THE JANUARY 14, 2020 MEETING MINUTES AS AMENDED</u>. THE MOTION CARRIED 7-0.

PUBLIC COMMENTS:

Mr. Larkin commented on a conversation he had with fellow jurors on a recent trial that he was a juror on. They expressed to him their belief the utilities do rate increases because they wanted more money and wish that the increases were not so large every other year, but maybe smaller each year. Mr. Larkin let the UAC members know he explained to the citizens that rate increases are tied to costs the utility incurs and not because they are trying to make a profit. Mr. Porter mentioned a resident told him their power had been shut off on a recent home they purchased due to communications going to the seller. The UAC members discussed each situation’s probable miscommunication and possible remedies.

ITEMS OF BUSINESS:

1. Status – Each City Utility

Staff Report: Directors from Fire & Emergency Services, Public Works, and Energy Services Presented.

Director Huntington updated UAC on the hiring development for Station's 73 and 75. He intends to present a draft review of the department's newly developed Strategic Plan and possible rate review at the July meeting. Equipment and vehicles are in the process of being procured for the new station and DGR Grant Construction, Inc. was awarded the contract for the design-build of both station locations.

The UAC Members had several clarifying questions and stated their views on the topic. Discussion included: where the EMS academies are located and trends in public safety jobs, and what altered processes Fire & EMS personnel are taking during the COVID-19 response.

Director Rogalsky stated the non-potable water is starting to come online in the next few weeks for irrigating purposes. Discussions have stalled with the WA Department of Ecology over the water rights in the Horn Rapids area and the amount water the City should have a right to. The City is waiting for Ecology to make a final determination on the proof of appropriation, as there is disagreement between the two on the amount of water that should be provided. For the wastewater utility, they continue to make capital improvements needed for operating the treatment plant and will continue for the next few years. The solid waste utility will be undergoing a rate review this year and he plans to be back at the May meeting to give a preliminary evaluation. The Stormwater utility continues to make water quality improvements with adding water treatments on pipes where the run-off goes to the river.

The UAC Members had several clarifying questions and stated their views on the topic. Discussion included: what type of technology improvements need to be made to the wastewater treatment plant and whether the hazardous waste collection operations will be taken over by the City.

Director Whitney informed UAC that due to the winter conditions being mild, overall revenue for the electric utility was down, but the snow pack in the mountains was normal so the run-off should be satisfactory to Bonneville Power Administration (BPA). The Capital Improvement Plan (CIP) projects for 2020 have started to ramp up including replacing over 600 rental lights with LED bulbs to help conserve energy and the human resources it was taking to constantly repair the lights prior to be changed out. The planned 2020 CIP projects include a new substation design, boring and cable replacement projects, construction of Horn Rapids Solar, Storage and Training project, and Advanced Meter Infrastructure installation. Mr. Whitney informed the committee there will be future conversations around small modular reactors as the clean energy legislation starts to be comprehended in order to balance resource inadequacy.

The UAC Members had several clarifying questions and stated their views on the topic. Discussion included: when streetlights will be changed over to LED in mass and what that process would look like.

2. Horn Rapids Solar, Storage and Training Project Update

Staff Report: Director Whitney discussed the construction timeline for the project and probable delays due to the COVID-19 response and materials being delayed for the solar panels and battery. The expectation is the site will be operational by October 2020. Mr. Whitney stated a tour of the facility by UAC is planned for the September meeting and it can coincide with a tour of the landfill at the same time.

The UAC Members had several clarifying questions and stated their views on the topic. Discussion included: how BPA will shape the load with this additional non-federal power purchase and how Pacific Northwest National Laboratory will be doing analytics from data that is collected from HRSST.

3. Energy Services Financial Update

Staff Report: Director Whitney presented an updated financial picture of the electric utility. Due to the City implementing a new financial enterprise system in October of last year, the financial reports are delayed. Mr. Whitney went over the updated cost of service analysis (COSA) and its projections for when rate increases are needed. Also presented was the utility's customer count. The utility will reach 25,000 customers in 2020 and will be prompted to have 3% of the retail load be renewable energy within four years. The current hydropower resources in BPA's fuel mix do not count as renewable in this legislation. HRSST is expected to bring 1% of that retail load in renewable resources.

The UAC Members had several clarifying questions and stated their views on the topic. Discussion included: how the bond rating for the utility and BPA are tied to financials, rate pressures BPA has to contend with and how that affects RES rates, and the difference between a customer count and a meter count.

4. Columbia River System Operations Draft Environmental Impact Statement (CRSO DEIS)

Staff Report: Director Whitney summarized the recently released draft EIS and the multiple objective alternatives (MO) examined in the study. Each MO examined gave certain outcomes for the individual objectives or statements of need. The preferred alternative was a variation of multiple objectives and did not recommend dam breaching. The City is currently discussing how to respond to the DEIS by public comment.

The UAC Members had several clarifying questions and stated their views on the topic. Discussion included: the various effects of dam breaching the study outlined and what it would do to local electric reliability, what the community attitude is on the issue, financial impacts of dam breaching, and how long the issue of dam breaching has been in the public sphere.

OTHER INFORMATION:

1. **Energy Services 2019 Capital Work Plan Year End**
2. **Bonneville Power Administration's Bond Rating**
3. **NWPPA Annual Meeting**
4. **Forward Planning Agenda**

The UAC Members discussed: the date and location of NWPPA's Annual Meeting and to contact Director Whitney if interested in attending, sending the forward planning agenda items on the request for business items to UAC members, and agenda items requested to be added to the forward planning agenda.

ADJOURNMENT

Chair Sanders adjourned the meeting at 5:04 p.m.

Respectfully submitted: ______________________________
Kylie Grimes, Administrative Assistant II

Reviewed by: ______________________________
Clinton R. Whitney, Energy Services Director

Date Approved:

Date Published:

UTILITY ADVISORY COMMITTEE AGENDA ITEM COVERSHEET

Meeting Date: 7/14/2020

Agenda Category: Items of Business

Prepared By: Clint Whitney, Energy Services Director
Pete Rogalsky, Public Works Director
Tom Huntington, Fire & Emergency Services Director

Subject:
Status - Each City Utility (20 Minutes)

Department:
Energy Services

Recommended Motion:

Summary:
Per request from UAC members, a representative for each of the five City utilities will present a policy summary.

Fiscal Impact:

Attachments:

UTILITY ADVISORY COMMITTEE AGENDA ITEM COVERSHEET

Meeting Date: 7/14/2020

Agenda Category: Items of Business

Prepared By: Clint Whitney, Energy Services Director

Subject:
Optimum Resource Mix by Energy Northwest - E3 Study (25 Minutes)

Department:
Energy Services

Recommended Motion:

Summary:

Energy Northwest contracted with Energy Environmental & Economics (E3) for an analysis of resource adequacy given the renewable trends and carbon legislation. Attached are the results of the E3 study and executive summary. Greg Cullen from Energy Northwest will provide an overview presentation of the findings from the study. The key take away is that renewable energy generation projects will continue in the northwest. However, the number of overbuilding necessary for renewable energy projects makes it less feasible as an optimized resource. The adequacy of generation resources is exacerbated by carbon legislation and the closure of baseload coal generation. The combination of carbon legislation, resource optimization and need for baseload resources indicates small modular reactors (SMR) should be part of our industry future.

Fiscal Impact:

Attachments:

1. E3 Study - Executive Summary
2. Energy Northwest E3 Presentation

Pacific Northwest Zero-Emitting Resources Study

Executive Summary

January 29, 2020

Energy+Environmental Economics

1.1 Study purpose

The Northwest energy system is undergoing a transition. In 2019, Washington state adopted the Clean Energy Transformation Act, which sets the state on a path to serve 100 percent of retail electric loads with carbon-free electricity. In that context, Energy Northwest retained E3 to investigate the role of zero-emitting resources in meeting the region's future energy needs in a carbon constrained future.

Energy Northwest is a public power joint operating agency created by the Washington state legislature in 1957 and its membership includes 27 public utility districts and municipalities. Energy Northwest's portfolio is comprised solely of carbon-free generating resources, including wind, solar, hydropower and nuclear. The agency owns and operates the Columbia Generating Station (CGS), the only nuclear generator in the Northwest and third largest generating resource in the state of Washington. CGS is licensed to operate through 2043, with the potential for a second 20-year license extension through 2063. Energy Northwest, leveraging its expertise in the nuclear industry, is also exploring a potential role developing small modular nuclear reactors (SMRs) in the region. SMRs are an emerging, technology – with domestic commercial operation planned for the mid-to-late 2020s – that offer potential cost, performance and safety advantages over conventional nuclear generation.

This research focuses on two key questions of interest to Energy Northwest:

+ What are optimal electricity resource portfolios to achieve deep carbon emissions reductions in the Pacific Northwest?

+ How does the availability of firm zero-emitting generation, including both CGS and SMRs, affect the cost of achieving carbon reduction goals while maintaining a reliable electric system?

The study builds on previous analyses done by E3 in the Northwest, including:

+ *Pacific Northwest Low Carbon Scenario Analysis (2017):* This study found that a portfolio of hydro, renewables and natural gas is the least cost strategy to achieve an 80% reduction in electricity sector emissions in the Northwest and that policies that directly target GHG reductions are lower cost than those that rely on renewable-only mandates or bans on gas generation.
+ *Pacific Northwest Low Carbon Scenario Analysis: 2018 Scenarios and Sensitivities (2018)*: This study found that the cost of achieving 100% decarbonized electricity in the Northwest is greatly reduced if firm-zero GHG resources like SMRs or biomethane powered gas generators are available.
+ *Resource Adequacy in the Pacific Northwest (2019):* This study found that firm generation is required to ensure a reliable system under deep decarbonization. That generation is needed because the marginal capacity contributions of wind, solar and storage decline as their penetrations increase. The study also found that gas is the least cost option to provide firm capacity given existing technologies.

1.2 Approach

This study uses E3's RESOLVE model to optimize the portfolio of resources serving loads in the "Core NW" region (Figure 1). RESOLVE co-optimizes investments and operations to minimize total NPV of electric system costs over the study time horizon.

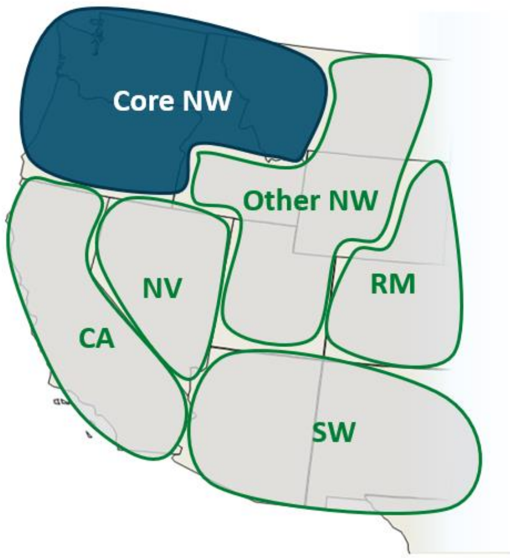


Figure 1: The Core NW Region. RESOLVE simulates electric sector operations across the west and optimizes investments in the Core NW region.

Scenarios in this study are designed to evaluate the implications of resource options for the cost and infrastructure requirements of achieving deep electricity emissions reductions in the Northwest. These resources include energy limited, variable and "firm" zero-emitting resources (Figure 2). Past work by E3 suggests that deep electric sector emissions reductions are possible using largely energy limited or variable resources, provided those resources are backed by firm capacity.

Key resource option scenarios include:

+ Renewables and Gas Available
+ Renewables, CGS Relicensing and Gas Available
+ Renewables, CGS, Gas and Zero-Emitting Firm Available
+ Renewables, CGS and Zero-Emitting Firm Available (No New Gas)

Energy Limited or Variable Zero-Emitting Resources	"Firm" Zero-Emitting Resources
Hydro Flexible resource that can help balance wind and solar	**Columbia Generating Station (CGS)** Existing zero-GHG firm capacity
Wind Inexpensive energy, high quality resource, but variable	**Small Modular Reactors (SMRs)** Firm, dispatchable zero-GHG generation
Solar Inexpensive energy, high quality resource in the West, but variable	**Biomethane** Zero-GHG fuel for existing infrastructure, not yet widely commercial, competing uses
Storage Rapidly decreasing costs, but energy and duration limited	**Carbon Capture and Sequestration** Low- to zero-GHG, not commercialized

Figure 2: Zero-Emitting Resources in available RESOLVE. RESOLVE also has the option to select fossil generation.

Resource option scenarios are compared against different electric sector emissions reduction scenarios, including 80%, 90%, 95% and 100% below 1990 levels (Figure 3). These scenarios represent different levels of GHG emissions policy ambition for the NW electricity system.

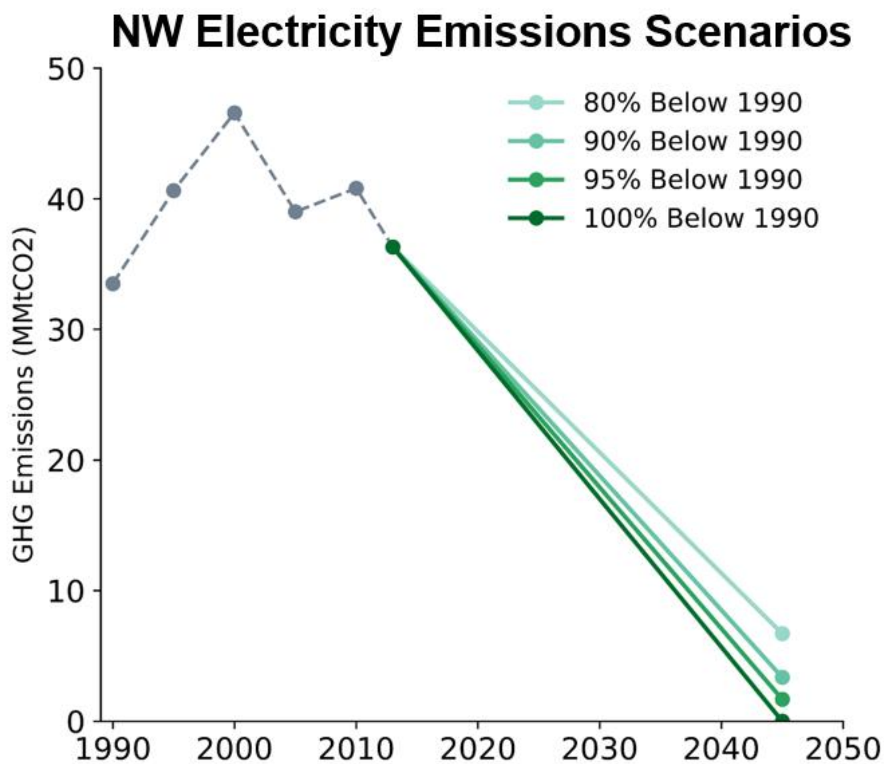


Figure 3: Electric GHG Emissions Scenarios. Past work by E3 suggests that a GHG cap of between 3 and 5 MMtCO2 is needed to achieve an 80% economy-wide emission reduction in Washington and Oregon.

1.3 Key Assumptions

This study updates several resource cost assumptions incorporated in past NW RESOLVE analyses.

1.3.1 RENEWABLES AND STORAGE COSTS

Wind and solar resource costs have been updated to NREL 2019 ATB Mid case assumptions. Battery storage costs are derived from the Lazard LCOS 4.0 report[1].

1.3.2 NUCLEAR COSTS

E3 worked with Energy Northwest to develop resource costs for both the cost of relicensing CGS and building SMRs. E3 used two sources for SMR costs, the NREL ATB Nuclear resource and "nth of a kind" estimates from NuScale, a vendor that designs and markets SMR technologies.

E3 also considered the cost of SMRs after receiving a production tax credit (PTC) as an additional cost sensitivity. Today, an $18/MWh PTC is available for up to 6,000 MW of new nuclear capacity. After accounting for nuclear projects that are under construction or announced, E3 assumed that 3,000 MW of PTC capacity is available to the Northwest region.

1.4 Findings

A key finding of this analysis is that very deep electric emissions reductions in the region can be achieved at manageable costs, provided firm capacity is available. However, the costs of achieving 100% GHG reductions exhibit a marked increase when new firm capacity cannot be built in the region (Figure 4).

[1] The bulk of the analysis done in this report was completed before LCOS 5.0 was released.

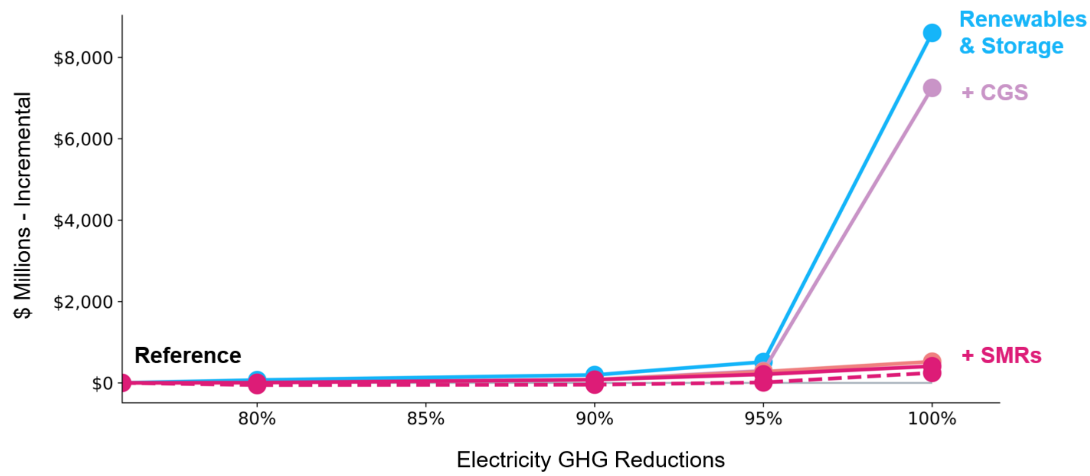


Figure 4: GHG abatement costs. The y-axis represents the incremental cost of each scenario compared to a Reference case that does not apply an emissions constraint.

1.4.1 COLUMBIA GENERATING STATION

CGS is relicensed in all the resource and emissions target scenarios in which it is available. The value of CGS stems from its ability to provide both energy and firm capacity without emitting carbon. The value of CGS ranges from $75 million per year in the 80% GHG reduction scenario to $1.35 billion in the 100% GHG reduction scenario.

1.4.2 SMALL MODULAR REACTORS

The role of SMRs in the Northwest's future electricity system depends on their cost, the stringency of regional emissions limits and the availability of gas generators to provide firm capacity.

- **Base Costs:** At NREL ATB and NuScale costs, SMRs are selected in the 95% and 100% emissions reduction scenarios. In all but one case, the first

SMRs are built in 2045. By 2045, the amount of SMR generation selected by the model under the NuScale cost scenario is about twice that of the amount selected under the NREL cost scenario due to the lower costs projected by NuScale.

+ **Production Tax Credit:** When a nuclear production tax credit is available, SMRs are selected in all emissions reduction scenarios and are built earlier, with the first units coming online in 2040.
+ **No New Gas**: SMRs have their largest build out in cases where gas generators—powered by either natural gas or biomethane—cannot be built. In these cases, the first SMRs are built by 2030, with at least 6.3 GW of SMRs built by 2045.
+ **100% GHG Reduction:** At NuScale costs, SMRs reduce the cost of achieving a 100% electric sector GHG reduction by nearly $8 billion per year). That value stems from those resources' ability to provide firm capacity, thereby avoiding a large overbuild of renewables.

1.5 Scenario Cost Comparison

Scenario costs are summarized in terms of average retail rates in Figure 5. The cost of the scenarios considered in this analysis are similar when natural gas generation capacity can be built. Those scenarios exhibit similar portfolio builds, largely relying on renewables that are backed by rarely used gas generation. If new gas capacity is not available, the costs of decarbonizing the Northwest electricity system increase markedly when only renewables, hydro and storage are available. If zero-GHG firm resources—including CGS, SMRs and biomethane—are available then the services provided by gas generators can be replaced at reasonable cost. That same finding holds in cases where zero-GHG emissions are allowed in the Northwest electricity system.

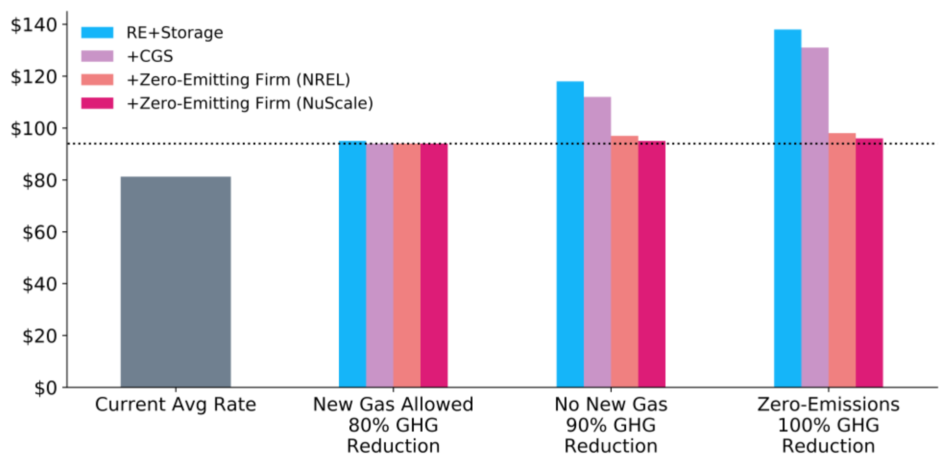


Figure 5: 2045 electricity rates under different scenarios. The y-axis shows the average retail rates for different resource and emissions scenarios. The x-axis shows the current average retail rate in the Northwest and the future rates under scenarios where new gas is allowed, where no new gas is allowed, and where the region achieves 0 GHG emissions.

1.6 Conclusions

Achieving deep decarbonization of the Northwest electricity system can be accomplished at reasonable cost if firm capacity can be built in the region. Columbia Generating Station is relicensed in all scenarios while zero-emitting firm resources like SMRs are most valuable under very tight emissions reductions regimes. In those cases, zero-emitting firm resources provide important reliability services that reduce the cost of achieving deep emissions reductions relative to scenarios that only rely on renewables and storage. SMRs have their largest role when new gas generators cannot be built or when they are able to receive a nuclear production tax credit. In those cases, SMRs are built in all emissions reduction scenarios.

Optimum Resource Mix – E3 Study

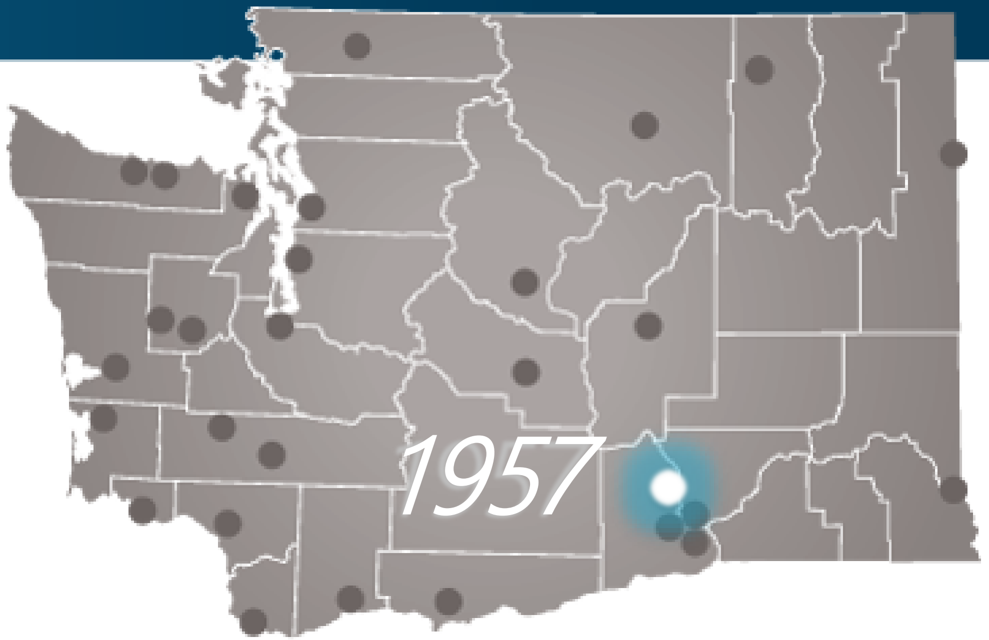
Greg Cullen, Energy Services and Development General Manager

Richland Utility Advisory Committee Meeting

July 14, 2020

Energy Northwest

A not-for-profit Municipal Corporation



Asotin County PUD	Clark Public Utilities	Klickitat County PUD	Seattle City Light
Benton County PUD	Ferry County PUD	Lewis County PUD	Skamania County PUD
Chelan County PUD	Franklin County PUD	Mason County PUD 1	Snohomish County PUD
City of Port Angeles	Grant County PUD	Mason County PUD 3	Tacoma Public Utilities
City of Richland	Grays Harbor County PUD	Okanogan County PUD	Wahkiakum County PUD
City of Centralia	Jefferson County PUD	Pacific County PUD	Whatcom County PUD
Clallam County PUD 1	Kittitas County PUD	Pend Oreille County PUD	

ENERGY NORTHWEST

Transition in the Northwest Power Industry

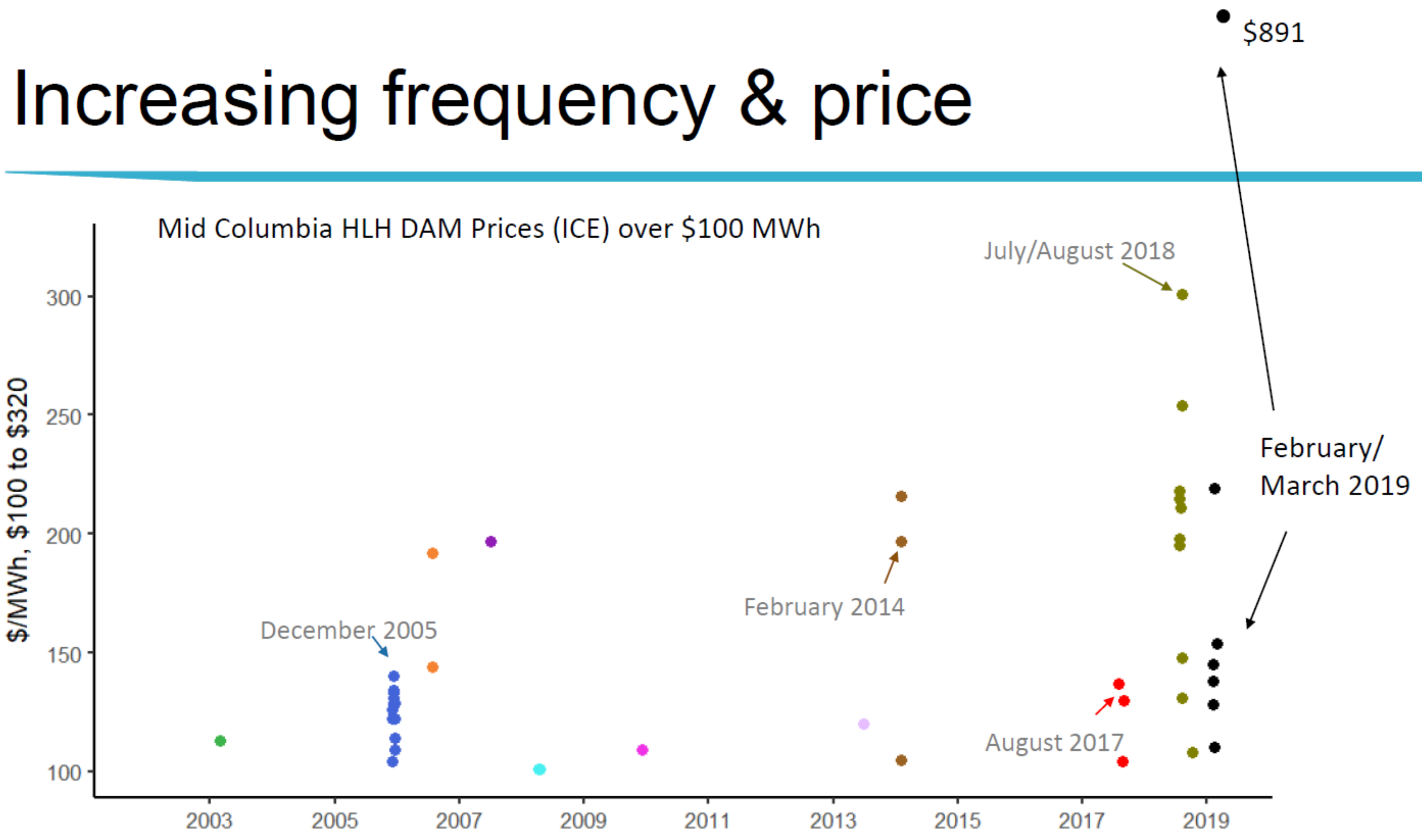
- Focus on carbon reduction
- Increasing capacity challenges
- Bonneville Power Administration contracts - 2028

Focus on Carbon Reduction - CETA

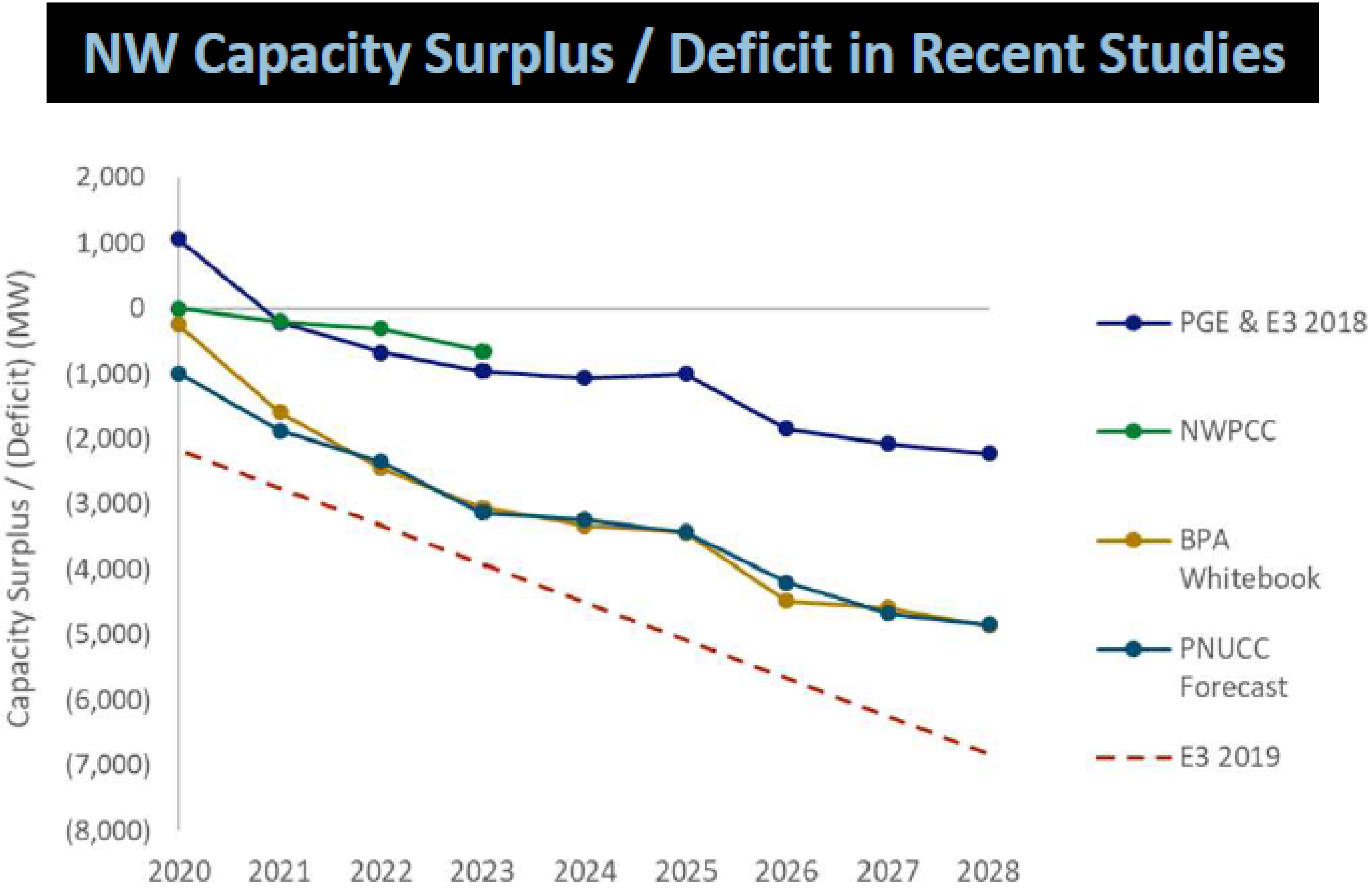
- Zero Coal by 2025
- 100% Carbon Neutral by 2030
  - 80% of power must come from "nonemitting electric generation and electricity from renewable resources."
  - The other 20 percent of the obligation can be satisfied in one of three ways:
    - Renewable energy credits (RECs), i.e., vouchers certifying that someone else generated clean energy
    - An administrative penalty based on tons remaining uncovered (which effectively amounts to a $100 per ton carbon tax)
    - Energy Transformation Projects (ETPs)
      - includes such things as electric car infrastructure, weatherization, or renewable natural gas projects
- 100% Clean Energy by 2045

Increasing Capacity Challenges

Increasing frequency & price



The Importance of Capacity



Resource Adequacy in the Pacific Northwest

Serving Load Reliably under a Changing Resource Mix

(Energy & Environmental Economics Study)

2018 Load and Resource Balance

Load (GW)	2018
Peak Load	43
PRM (%)	*12%*
PRM	5
Total Load Requirement	48

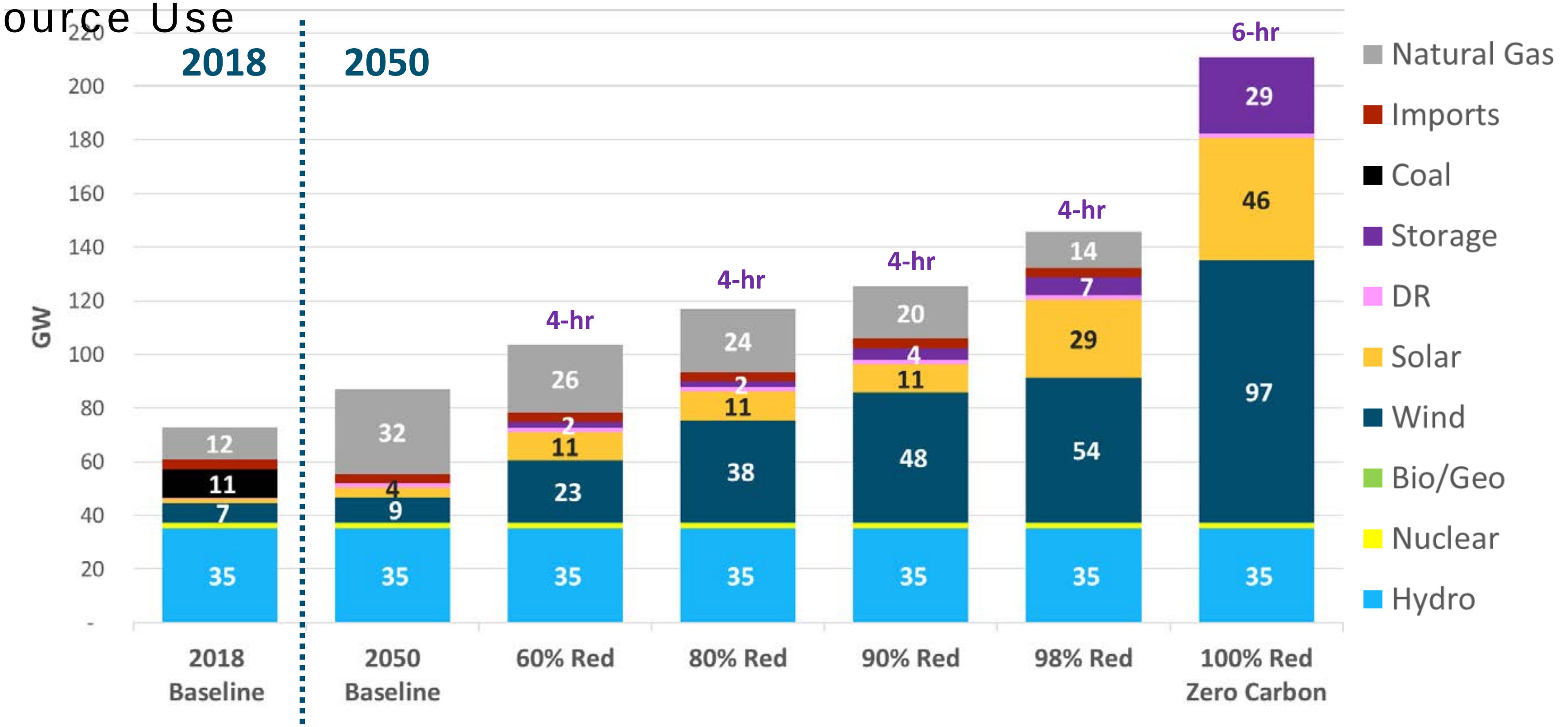
Resources / Effective Capacity (GW)	2018	Nameplate Capacity (GW)	ELCC* (%)	Capacity Factor (%)
Coal	11			
Gas	12			
Bio/Geo	1			
Imports	3			
Nuclear	1			
DR	0.3			
Hydro	18	*35*	*53%*	*44%*
Wind	0.5	*7.1*	*7%*	*26%*
Solar	0.2	*1.6*	*12%*	*27%*
Storage	0			
Total Supply	47			

Wind and solar contribute little effective capacity with ELCC* of 7% and 12%

**ELCC = Effective Load Carrying Capability = firm contribution to system peak load*

Scenario Summary

2050 Resource Use

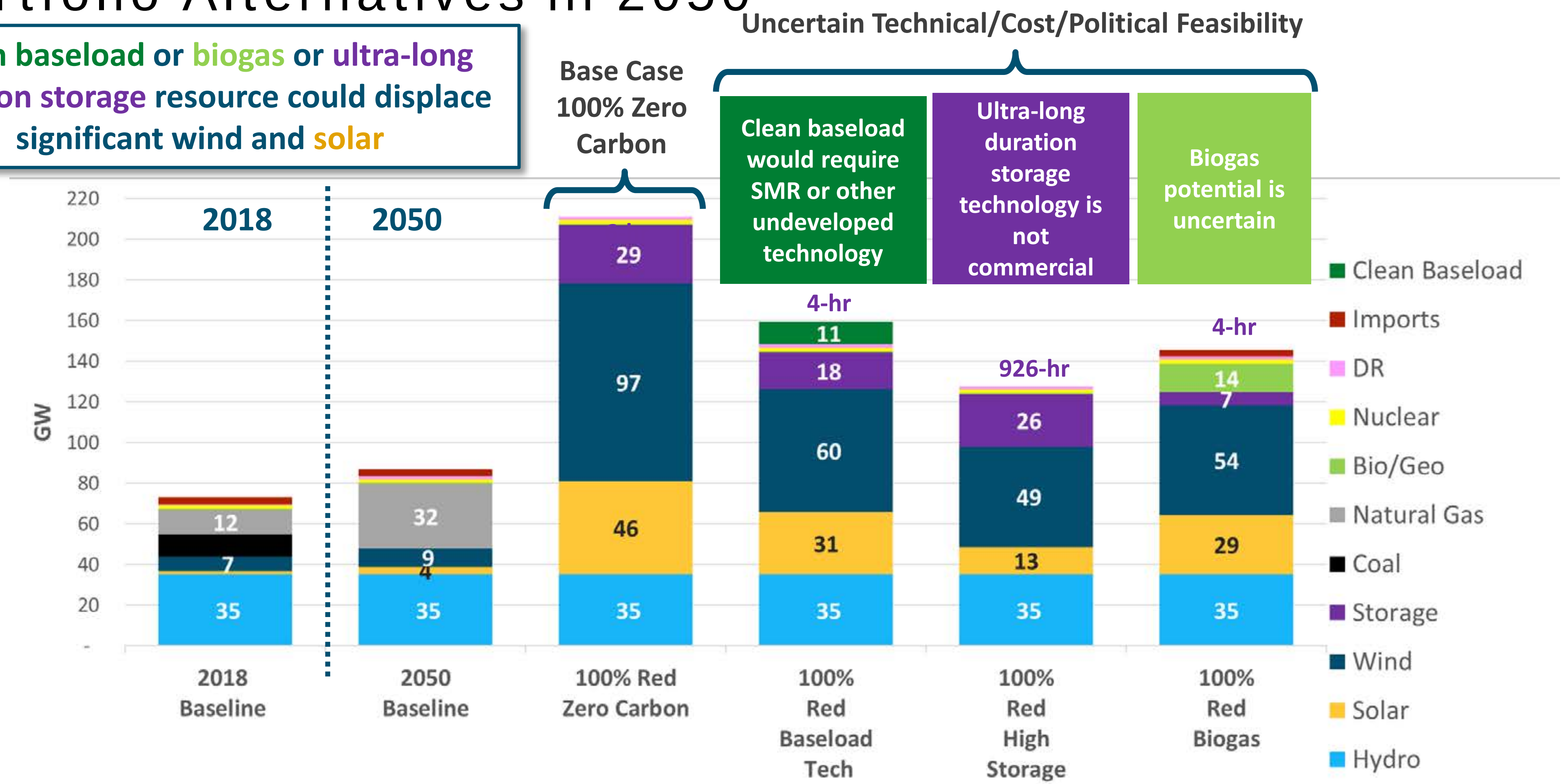


Renewable Capacity (GW)	13	34	49	59	83	143
Annual Renewable Curtailment (%)	Low	Low	4%	10%	21%	47%
Gas Capacity (GW)	32	26	24	20	14	0
Gas Capacity Factor (%)	46%	27%	16%	9%	3%	0%

[1]CPS+ % = renewable/hydro/nuclear generation divided by retail electricity sales
[2]GHG-Free Generation % = renewable/hydro/nuclear generation, minus exports, divided by total wholesale load

100% Reduction Portfolio Alternatives in 2050

Clean baseload or biogas or ultra-long duration storage resource could displace significant wind and solar



Carbon (MMT CO2)	50	0	0	0	0
Annual Cost Delta ($B)	Base	$16- $28	$14-$21	$550-$990	$4 - $9
Additional Cost ($/MWh)	Base	$52-$89	$46-$69	$1,800-$3,200	$14 - $30

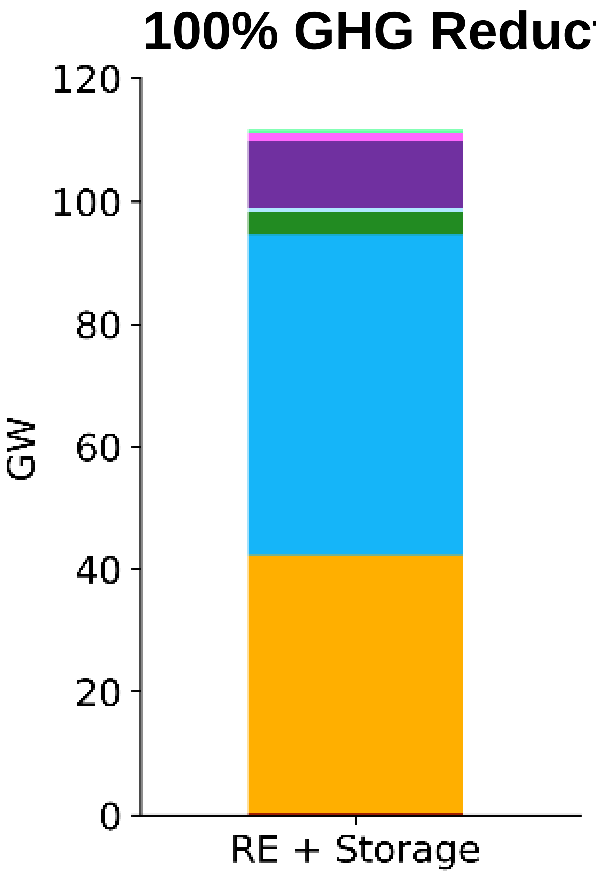
Energy+

Energy+Environmental Economics

Pacific Northwest Zero-Emitting Resources Study

Dan Aas, Managing Consultant
Oluwafemi Sawyerr, Consultant
Clea Kolster, Consultant
Patrick O'Neill, Consultant
Arne Olson, Senior Partner

Benefits of zero-emitting firm capacity at 100% GHG reductions – (1 of 4)



Key Resource Additions

10.5 GW Storage

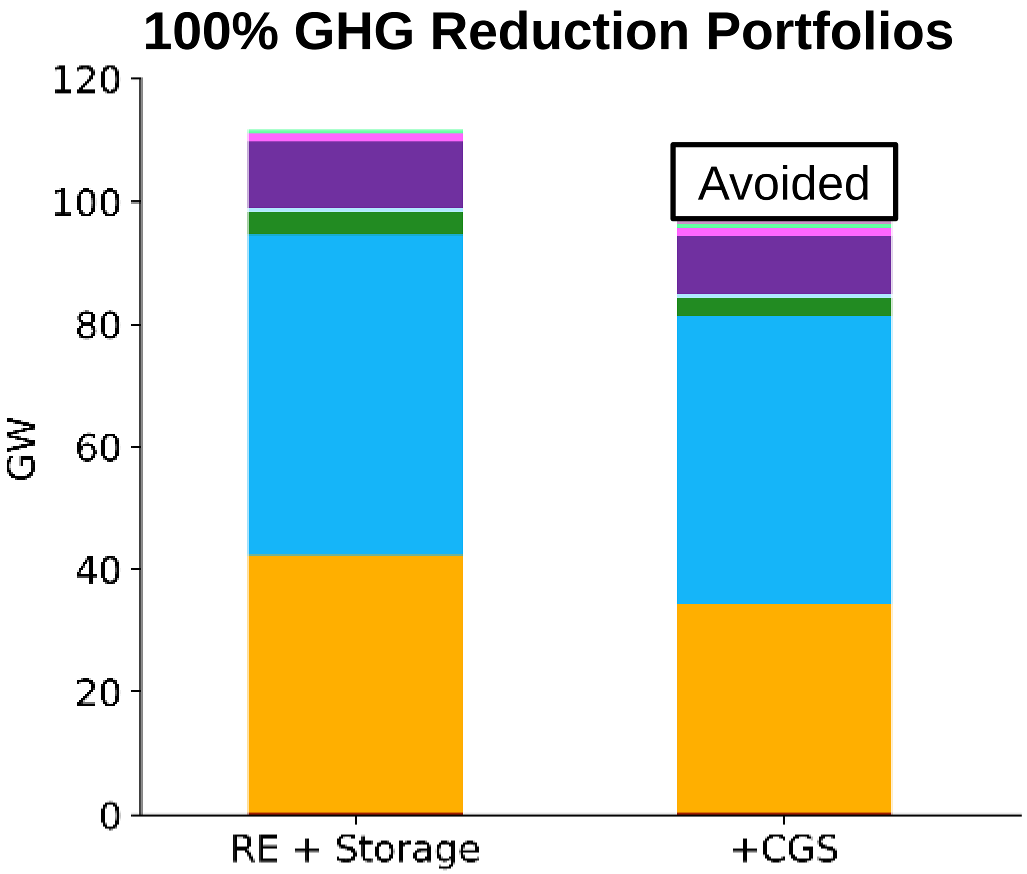
52 GW Wind

42 GW Solar

A system that largely relies on wind, water, solar and battery storage (RE + Storage) requires over 100 GW of new capacity additions in 2045 to maintain reliability

This system costs more than $8B per year over the Reference Scenario

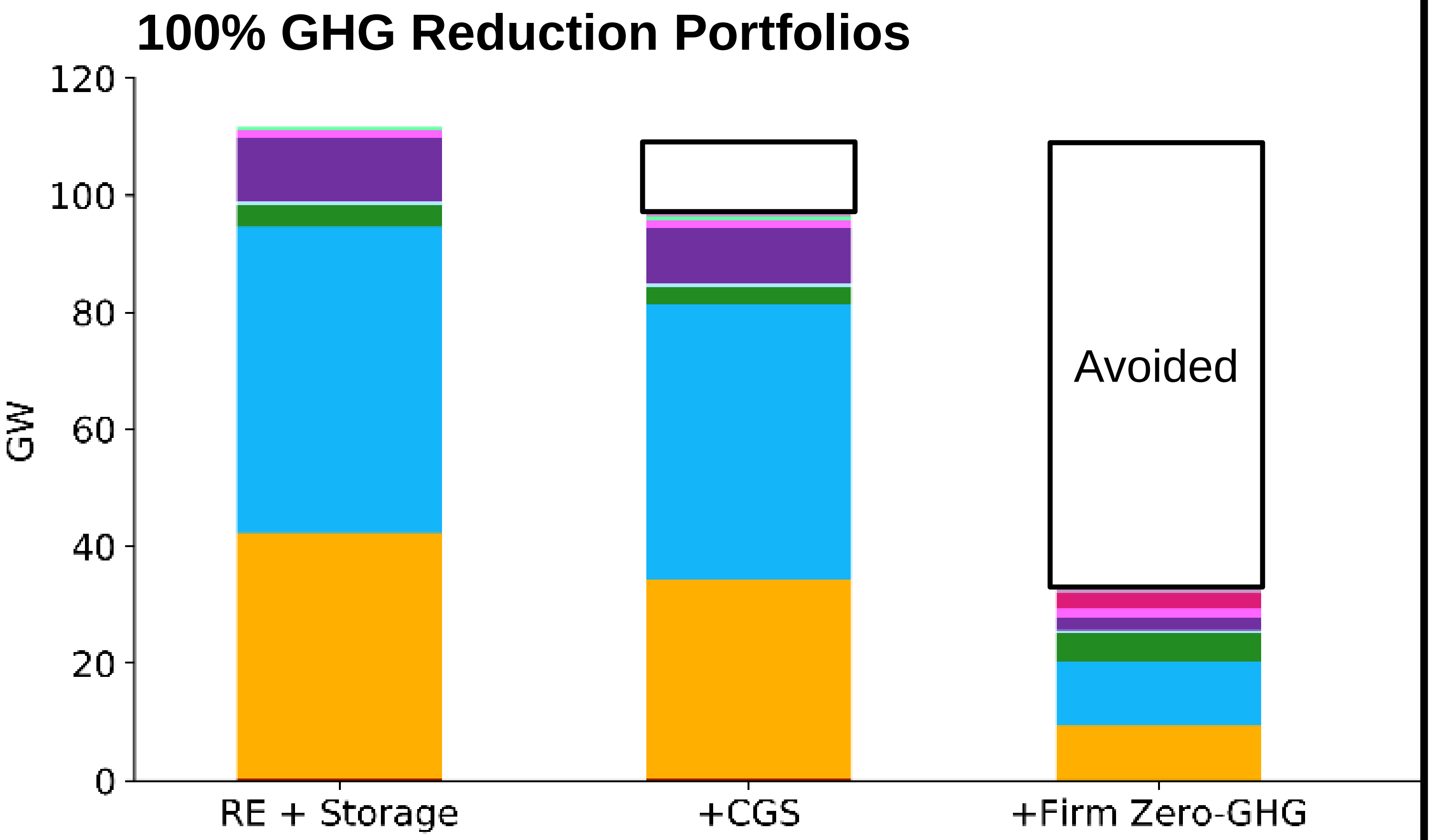
Benefits of zero-emitting firm capacity at 100% GHG reductions – (2 of 4)



Adding	Avoids
+1.2 GW CGS	-1.2 GW Storage
	-5.2 GW Wind
	-8 GW Solar
+1.2 GW Firm	-14.4 GW Non-firm

Relicensing CGS reduces the total cost of the NW electricity system by $1.4 billion per year in 2045

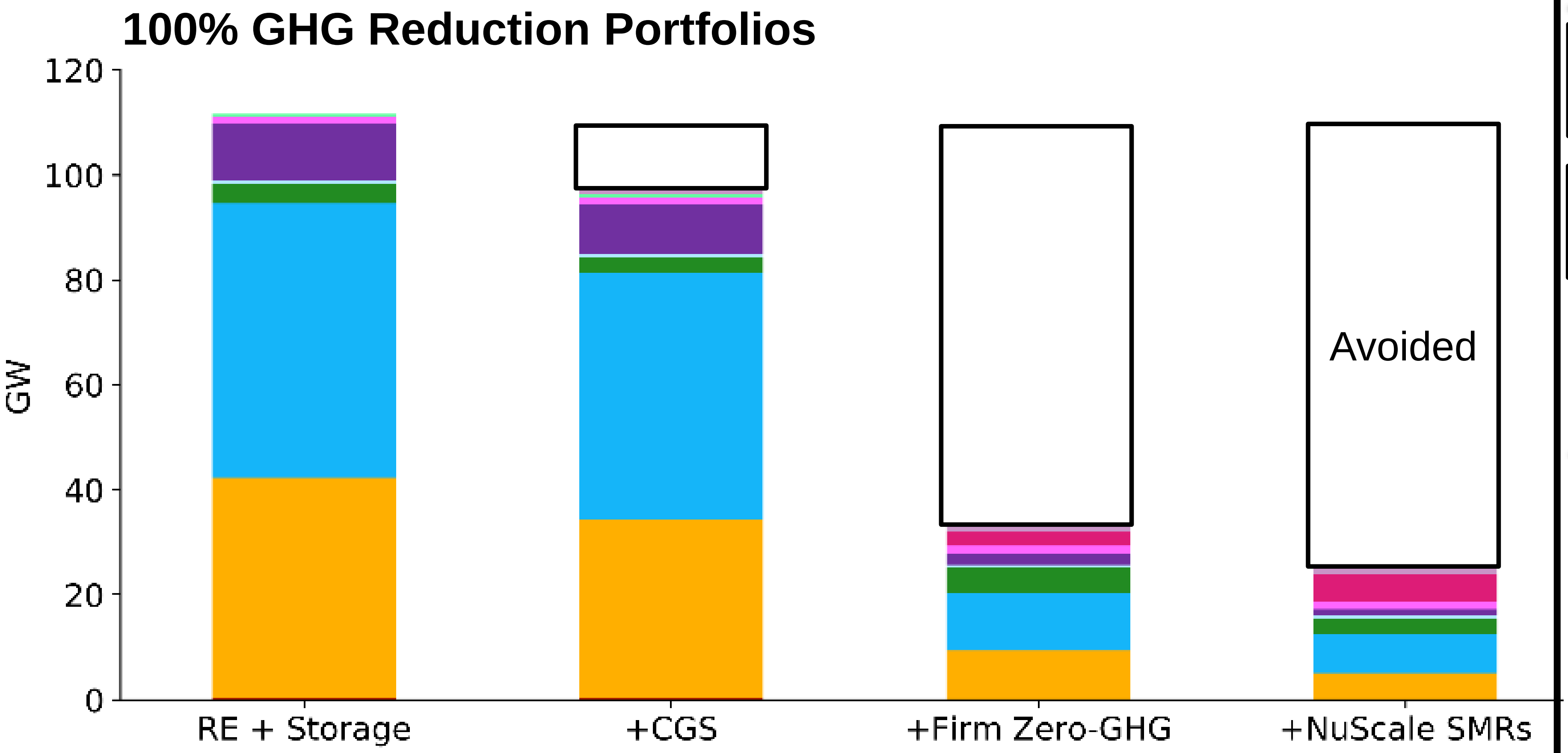
Benefits of zero-emitting firm capacity at 100% GHG reductions – (3 of 4)



Adding	Avoids
+1.2 GW CGS	-8.5 GW Storage
+2 GW Biomethane	-41 GW Wind
+2.6 GW SMRs	-32 GW Solar
+5.8 GW Firm	-81.5 GW Non-firm

CGS + additional firm, zero-GHG generation reduces electric system costs by almost $8 billion per year relative to RE+Storage

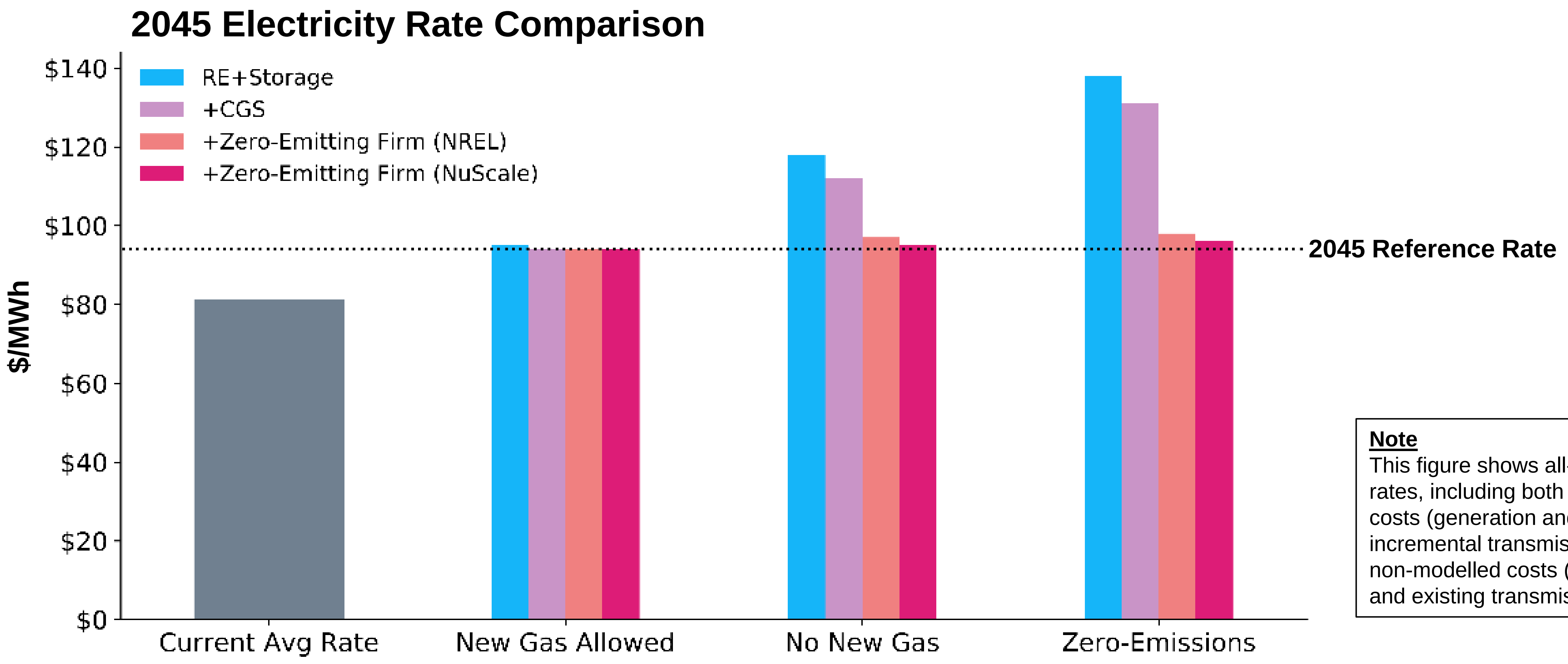
Benefits of zero-emitting firm capacity at 100% GHG reductions – (4 of 4)



Adding	Avoids
+1.2 GW CGS	-9.5 GW Storage
+5.3 GW SMRs	-44.8 GW Wind
	-37 GW Solar
+6.5 GW Firm	-91 GW Non-firm

CGS + NuScale SMRs reduce system costs by almost $8B per year relative to RE + Storage

Zero-emitting firm resources reduce electricity rates, particularly in scenarios with gas resource limitations



Note
This figure shows all-in retail rates, including both modelled costs (generation and incremental transmission) and non-modelled costs (distribution and existing transmission)

Nuclear – A Carbon Free Energy Source

- Columbia Generating Station
  - Maintain reliability, predictability, and cost-effectiveness
  - Subsequent License Renewal (SLR)
    - Extend operation from 2043 to 2063
  - Extended Power Uprate (EPU)
    - Increase output by ~150MW
- Small Modular Reactors
  - Performing feasibility evaluation

Small Modular Reactors

- **Feasibility evaluation focus:**
  - **Costs**
    - **Estimates**
    - **Funding sources**
    - **Estimate refinement**
  - **Schedule**
  - **Public Support**
  - **Risk Management**
  - **Develop funding plan from interested partners**


Questions?

UTILITY ADVISORY COMMITTEE AGENDA ITEM COVERSHEET

Meeting Date: 7/14/2020

Agenda Category: Items of Business

Prepared By: Clint Whitney, Energy Services Director

Subject:
Richland Energy Services Integrated Resource Plan (25 Minutes)

Department:
Energy Services

Recommended Motion:
Motion to endorse the IRP and recommend that City Council adopt the 2020 Integrated Resource Plan.

Summary:

An integrated resource plan (IRP) is an important tool for effective utility management and planning for future load, conservation, power supply, and renewable and carbon-free energy integration. Richland Energy Services' (RES') IRP will serve as the basis for near- and long-term planning and policy development. Near-term challenges include integrating an increasing amount of distributed generation and demand side resources into its system. Long-term challenges include transitioning initially to a 100% carbon-neutral electricity supply and later to a 100% carbon-free electricity supply and achieving all cost-effective conservation. RES must meet these challenges while providing reliable service at the lowest reasonable cost.

RES has reached the 25,000 customer threshold and is no longer a Bonneville Power Administration full requirements customer. As such, RES needs to satisfy the requirements of Chapter 19.280 RCW, Electric Utility Resource Plans and submit to the Washington State Department of Commerce an IRP.

RES contracted with EES Consulting to consult with staff and develop its 2020 IRP, 2019 conservation potential assessment (CPA), and renewable energy acquisition assessment, which also meet the requirements of Chapter 19.285 RCW, Energy Independence Act and Chapter 194-37 WAC Energy Independence. In addition, the IRP will guide staff in preparing to comply with Chapter 19.405 RCW Washington Clean Energy Transformation Act (CETA) and Chapter 194-40 WAC Clean Energy Transformation Act.

At the July UAC meeting, EES Consulting will present the IRP results and recommendations. The City Council must conduct a public hearing and adopt the IRP before RES staff submits it to Commerce. Staff requests that UAC endorse the IRP and recommend that City Council adopt it.

Fiscal Impact:
The recommended average 20-year resource portfolio cost is estimated at $187,000,000, which will be funded through electric rates and included in future budgets.

Attachments:

1. EES Consulting Presentation - Integrated Resource Plan
2. RES Draft Integrated Resource Plan
3. 2019 CPA Final Report

City of Richland
Utility Advisory Committee
2020 Integrated Resource Plan

EES Consulting
a GDS Associates Company

July 14, 2020

What is an Integrated Resource Plan?

- The process of optimizing resource options and minimizing the total consumer cost, including environmental costs, that may be attributed to the resource mix
- Process used to determine a long-term resource strategy
- Used to plan how a utility will meet its retail customers future loads by examining both demand-side and supply-side resources on an equal basis
- IRPs are generally filed every 2 to 5 years
- Plans are useless but planning is essential

Why Develop an Integrated Resource Plan?

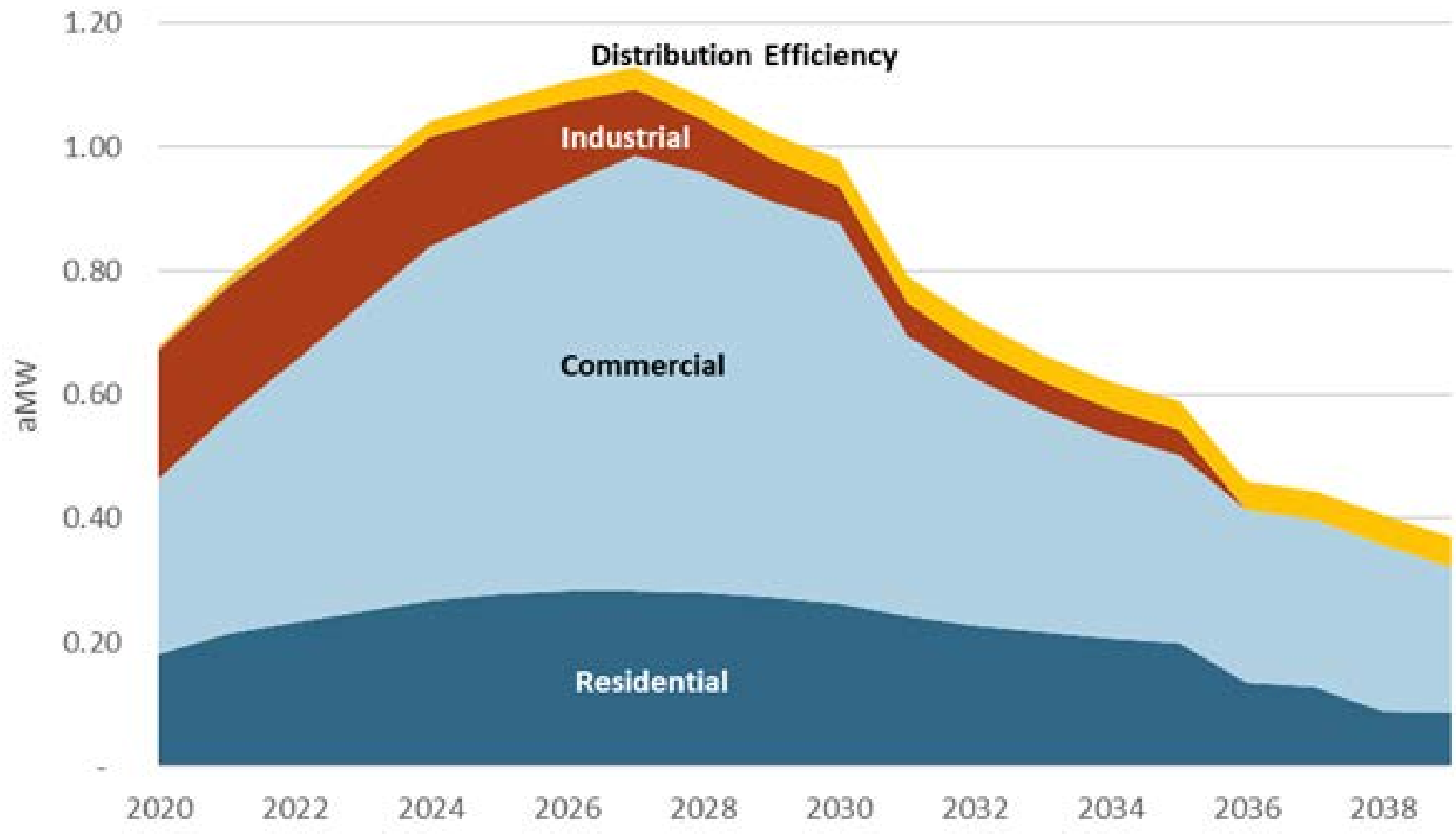
- **Renewable portfolio standards and carbon policies impact resource choices**
- **Energy Independence Act: Utilities in Washington with more than 25,000 customers required to do an IRP at least every four years with updates every two years**
- **Clean Energy Transformation Act: Washington Utilities required to be carbon neutral by 2030 and carbon-free by 2045**
- **BPA no longer serves all RES load requirements**
  - BPA allocated Tier 1 power based on historic loads (high water mark)
  - Above-HWM load served by BPA Tier 2 products, non-federal resources or market purchases
  - Flat blocks of market power currently lower in cost than BPA Tier 1 rates

Load Forecast

- **Load forecast defines how much power supply is required**
- **Understand data**
  - Go back 5 – 10 years on monthly number of customers, usage per customer, hourly system loads
  - Weather normalize loads (Heating Degree Days, Cooling Degree Days)
  - Economic Data (Consumer Price Index, Income, unemployment)
  - Conservation spending/savings
  - Appliance saturations (e.g. HVAC)
  - Projection of population growth
- **Understand customers**
  - Which customers' loads are increasing/decreasing?
  - Which customers can make a big impact on resource choice and risk?
  - What happens if they leave?
  - What happens if a new large load comes to town?
  - How are customers consumption patterns going to change?

Base Case Cost-Effective Energy Efficiency

- Conservation Potential Assessment (CPA) completed by EES Consulting in February 2020
- Projected cumulative conservation acquisitions are 15.8 aMW over the 20-year study period

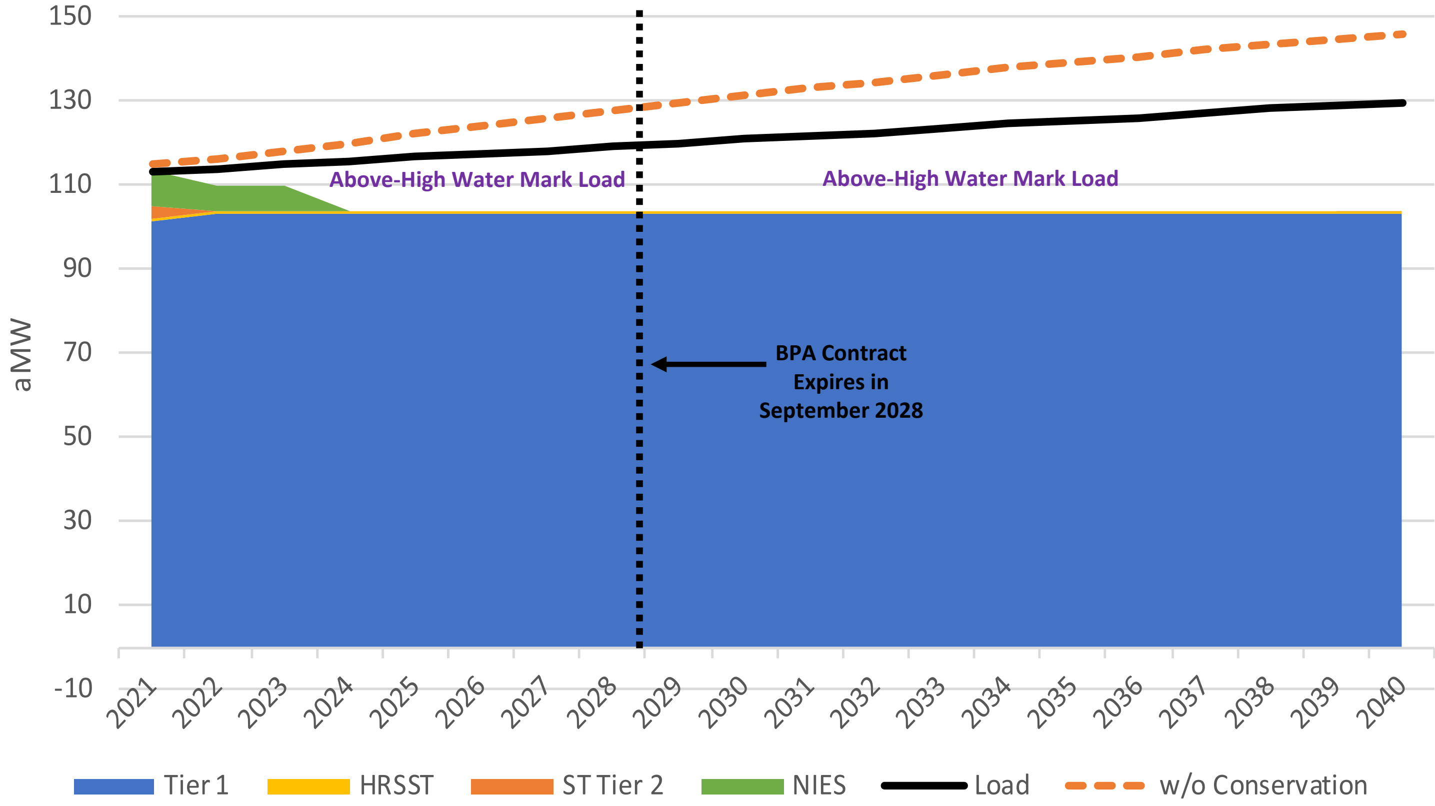


Commercial = greatest potential

Industrial = large energy efficiency projects can be very valuable

* Average annual conservation acquisition = 0.77 aMW

Projected RES Load/Resource Balance



Horn Rapids Solar, Storage and Training Project (HRSST) = 0.8 aMW
Northwest Intergovernmental Energy Supply (NIES) purchase = 6-8 aMW (expires end of CY23)

Load forecast includes 0.7% load growth - 17 aMW over 20 years

Above-High Water Market load can be served by market purchases, contract resources, BPA Tier 2 and/or energy efficiency

Lowest cost resource for serving load growth is energy efficiency

<u>BPA Tier 1 purchase construct will likely change in post-2028 contract</u>
Contract HWM based on actual 2010 loads under current contract
Rate Period HWMs based on projected loads and capability of dedicated resources (re-set every two years)

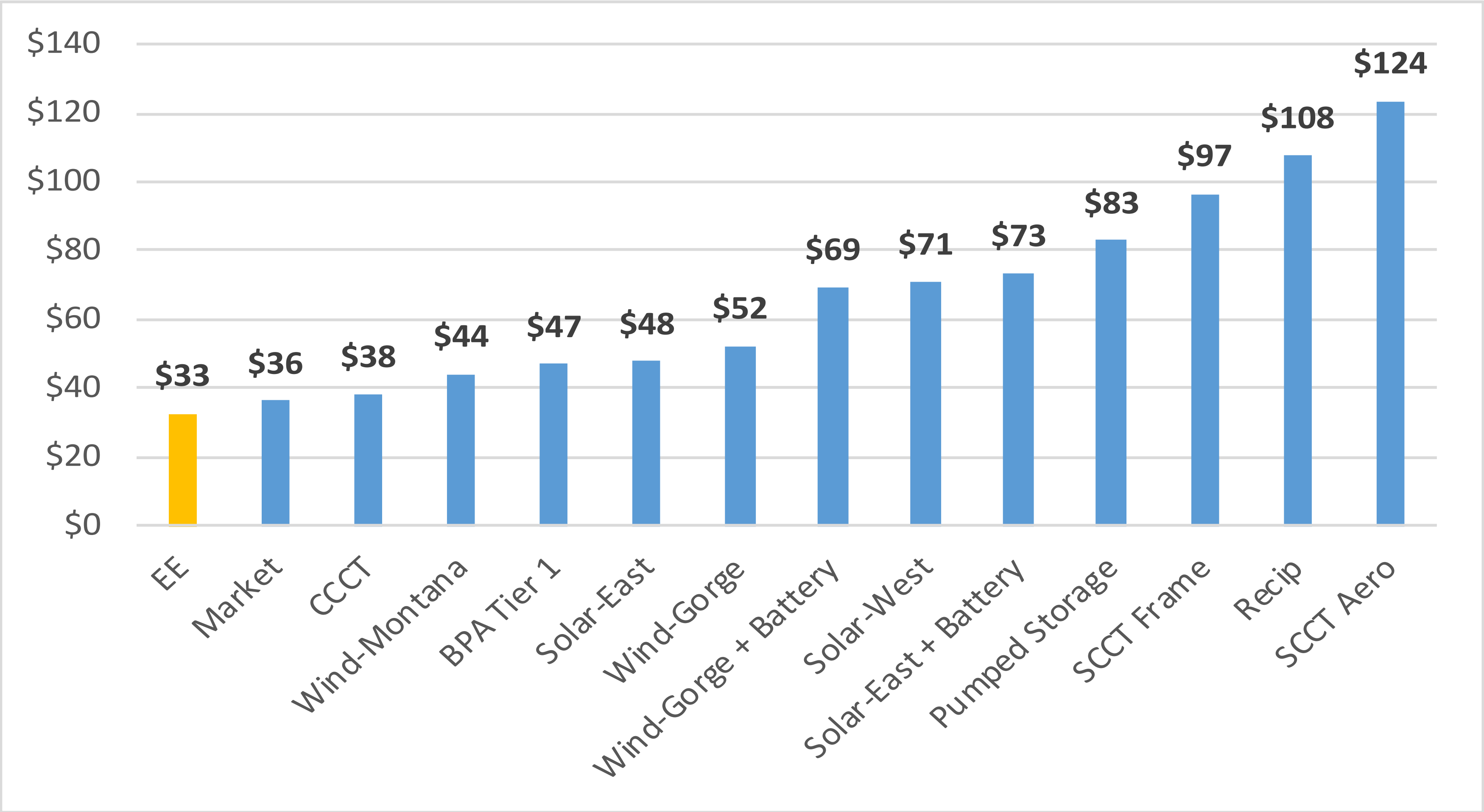
IRP Modeling Overview

- **IRP Evaluates Demand- and Supply-Side Resources on an Equal Basis**
- **General Framework is the Following**
  - **Step 1: Screening analysis**
    - Conservation Potential Assessment
    - Supply side resources
      - Renewable resources
      - Local resources (cogeneration, solar, micro-hydro, biomass, etc.)
  - **Step 2: Portfolio development and analysis**
    - Portfolios explore different combinations of resources that allow utility to meet projected loads and renewable energy requirements
  - **Step 3: Risk analysis**
    - Evaluates the risk of each portfolio
  - **Step 4: Action Plan**
    - Develop a Plan for 3 to 5 Years

Step 1: Screening Analysis

- **Compares resources 20-year levelized costs**
- **Results a selection of the best fit resources**
  - Supply side resources
  - Demand side resources
- **Supply side resources**
  - Fuel costs
  - Capital costs
  - O&M costs
  - Capacity factors
- **Demand side resources – Conservation Potential Assessment**
  - Incentives
  - Installation costs
  - Avoided energy costs

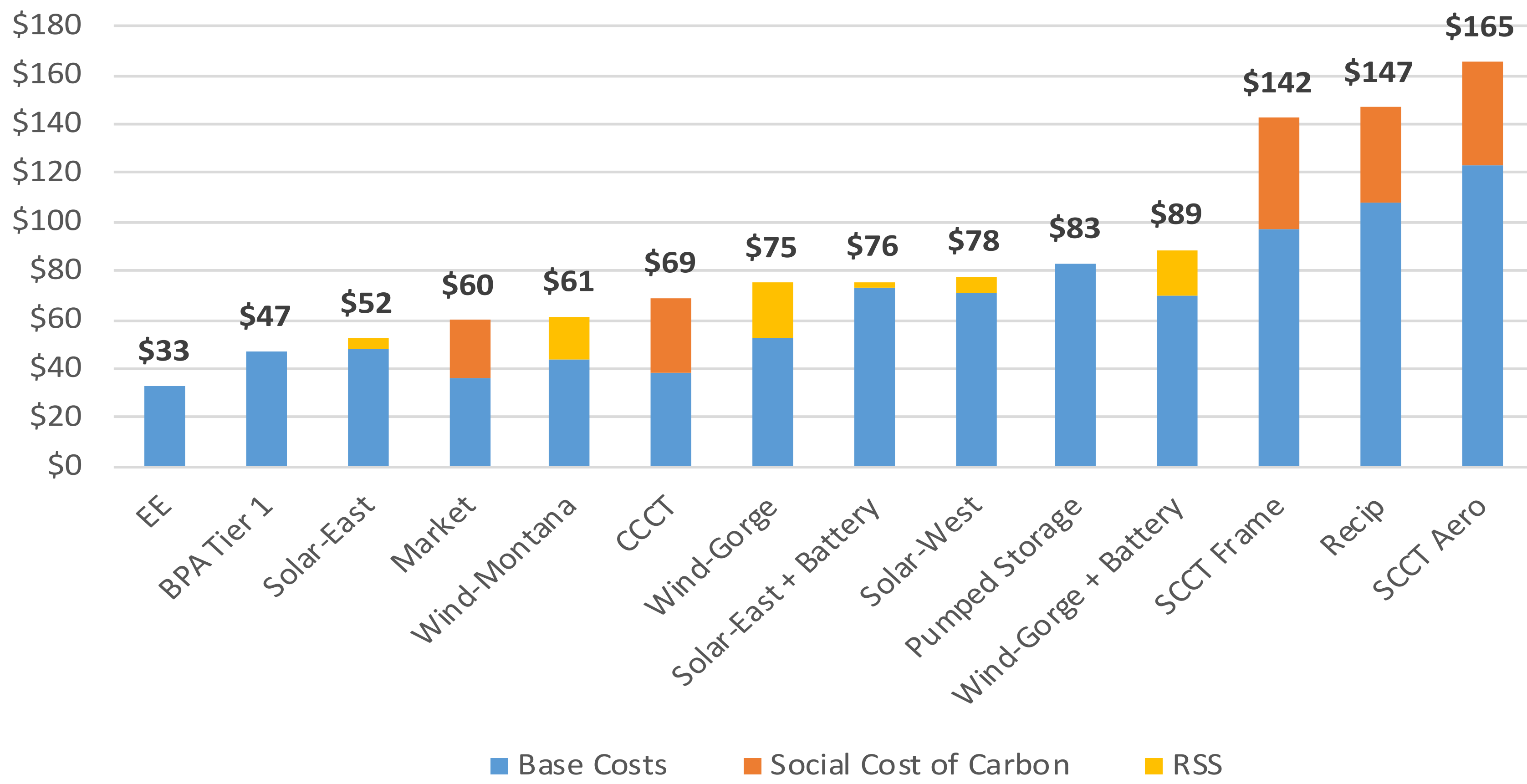
20-year Levelized Cost Comparison ($/MWh)



Social Cost of Carbon

- **CETA requires utilities to include the social cost of greenhouse gas emissions in resource evaluation, planning and acquisition [RCW 19.280.030(3)]**
- **Department of Commerce has determined that customer-owned utilities should use the same cost values that the legislature has enacted for investor-owned utilities**
- **Establishes a specific set of cost values developed by a federal interagency working group in 2016 and inflation factor used to escalate costs to base year used in IRPs**
- **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, assuming 53 kg of CO_2 per MMBtu
- **Including projected social cost of carbon adds**
  - Market: $23/MWh
    - Assuming: heat rate = 7,195 Btu/kWh in August- March when gas-fired resources are the marginal resource; 0 Btu/kWh during spring/summer runoff season when hydro or wind serve as marginal resource
  - CCCT: $32/MWh [heat rate = 6,550 Btu/kWh]
  - Reciprocating Engine: $39/MWh [heat rate = 8,350 Btu/kWh]
  - SCCT Aero: $42/MWh [heat rate = 8,930 Btu/kWh]
  - SCCT Frame: $46/MWh [heat rate = 9,773 Btu/kWh]

20-year Levelized Cost Comparison including Social Cost of Carbon ($/MWh)



- Under the current BPA power contract, above-HWM load must be served with flat resources.
- BPA's Resource Support Services (RSS) products flatten intermittent renewable generation across hours, days and seasons, resulting in flat blocks of power

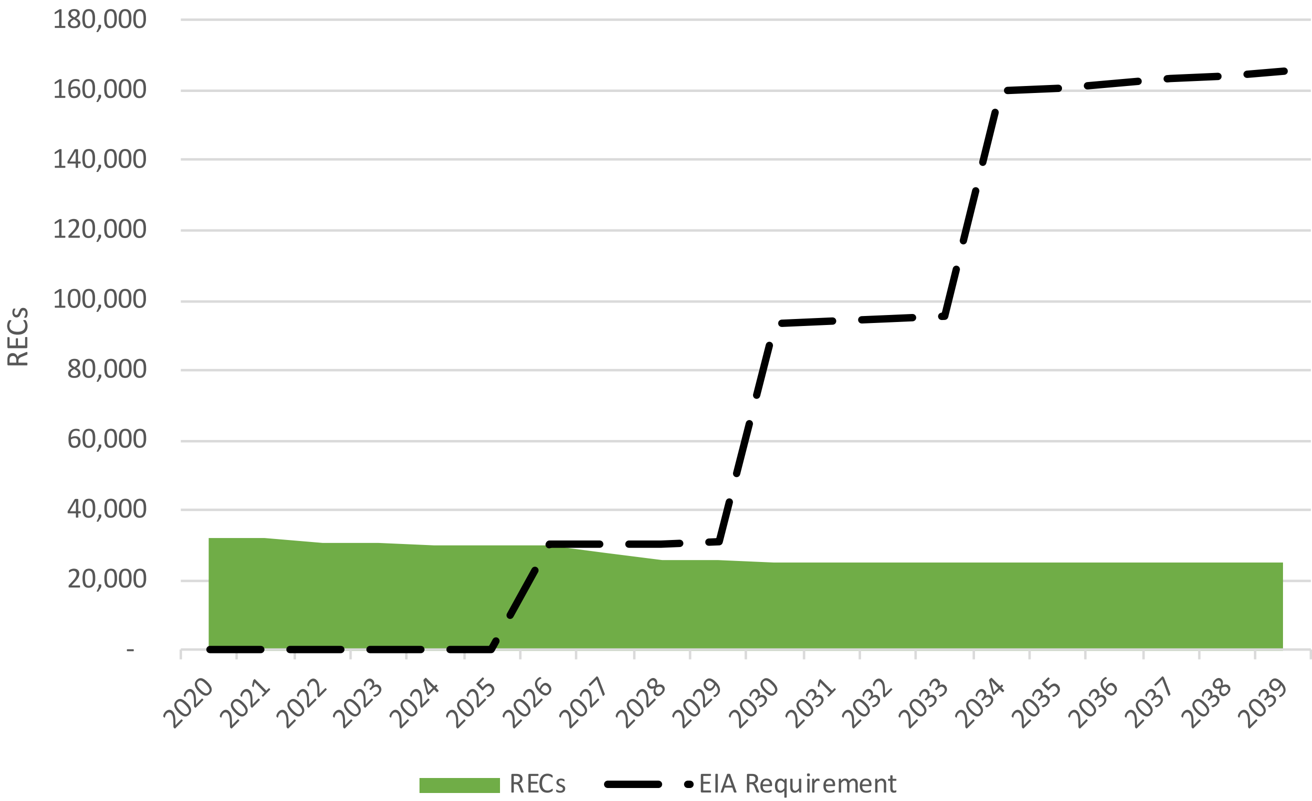
Qualitative Review of Other Resources

- **The IRP screening (previous slide) only includes resources that are currently commercially available**
- **There is good data available for those resources – from IOU IRPs and the Council's 2021 Plan**
- **There are other resources that are addressed qualitatively – given the lack availability in market and lack of resource cost and characteristics data**
- **The following resources are addressed qualitatively in the IRP:**
  - Geothermal
  - Small Modular Nuclear
  - Wave Power
  - Tidal Power
  - Landfill Gas
  - Anaerobic Digesters - Farm Manure
  - Wastewater Treatment Plants
  - Biomass - Woody Debris
  - Micro-hydro (municipal water systems, fish ladders at hydro facilities)

Step 2: Portfolio Analysis

- **Objective—least costly mix of resources that meets all requirements**
- **Portfolio options**
  - Large utilities – run many, many portfolios
  - Smaller utilities – find scenarios that match resources to load growth and legislative mandates (Energy Independence Act (EIA), Clean Energy Transformation Act)
- **Maximize BPA Tier 1 purchase**
- **Maximize conservation/energy efficiency**
- **Meet renewable energy requirements**
- **Financial Parameters to Evaluate**
  - Minimize rate impacts
  - Minimize utility's risks
  - Compare Portfolio's Net Present Values and/or Levelized Costs

Projected EIA Requirements



RES is required to comply with the EIA's renewable energy targets as follows:

- 3 percent of retail load must be served by renewables in 2026-29
- 9 percent of retail load must be served by renewables in 2030-33
- 15 percent of retail load must be served by renewables beginning in 2034

- RECs shown above (green area) are a combination of RECs associated with RES's purchase of the renewable resources (wind and incremental hydro) included in BPA's Tier 1 resource pool and HRSST
- HRSST RECs count as double under the EIA because HRSST is a distributed resource (2.2 multiplier)

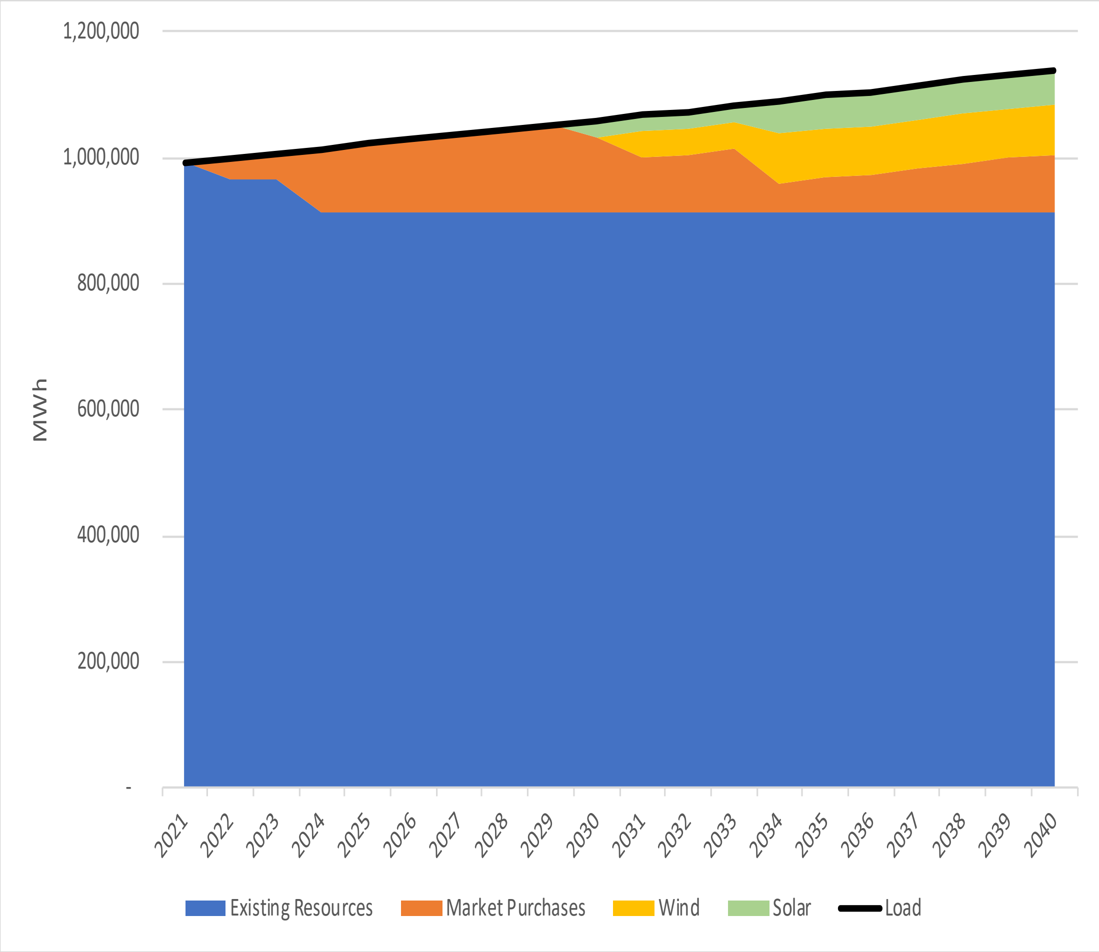
Portfolios

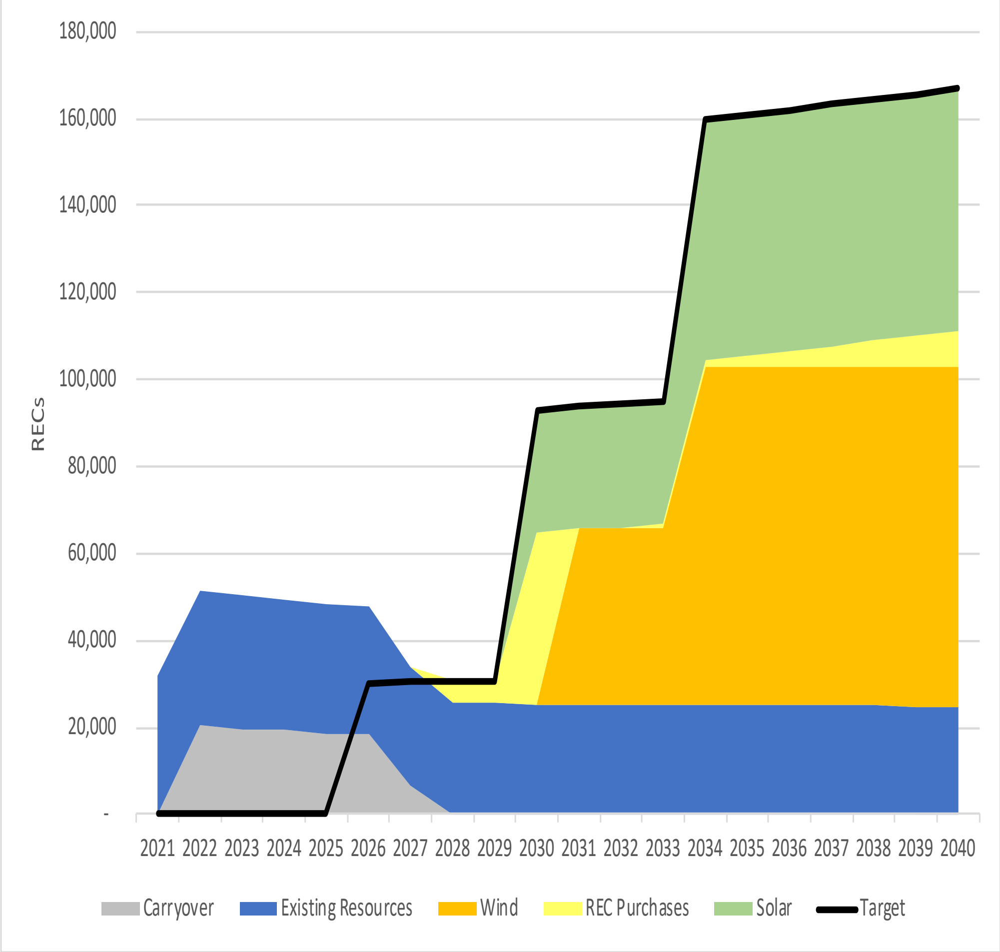
- **Portfolio #1: Market Purchases Serve Above-HWM Load and REC Purchases Meet EIA Requirements**

- **Portfolio #2: Serve Above-HWM Load with Market and Wind Purchases and Use RECs from Wind Purchase to Meet EIA Requirements**

- **Portfolio #3: Serve Above-HWM Loads with Market, Wind and Solar and Use RECs from Wind and Solar Purchases to Meet EIA Requirements**

Portfolio #3: Serve Above-HWM Loads with Market, Wind and Solar and Use RECs from Wind and Solar Purchases to Meet EIA Requirements

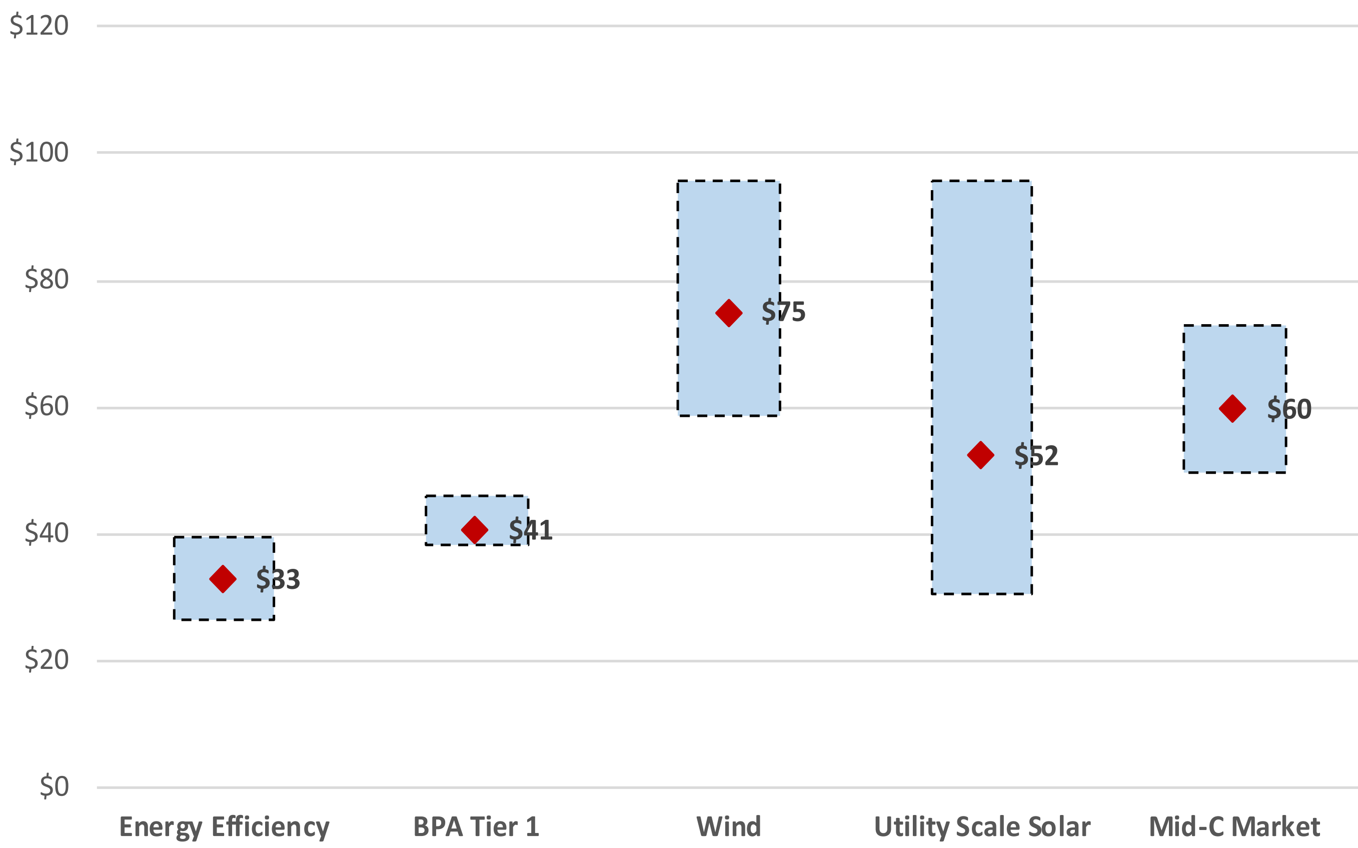




* Wind project capacity factor = 37%; solar capacity factor = 33%

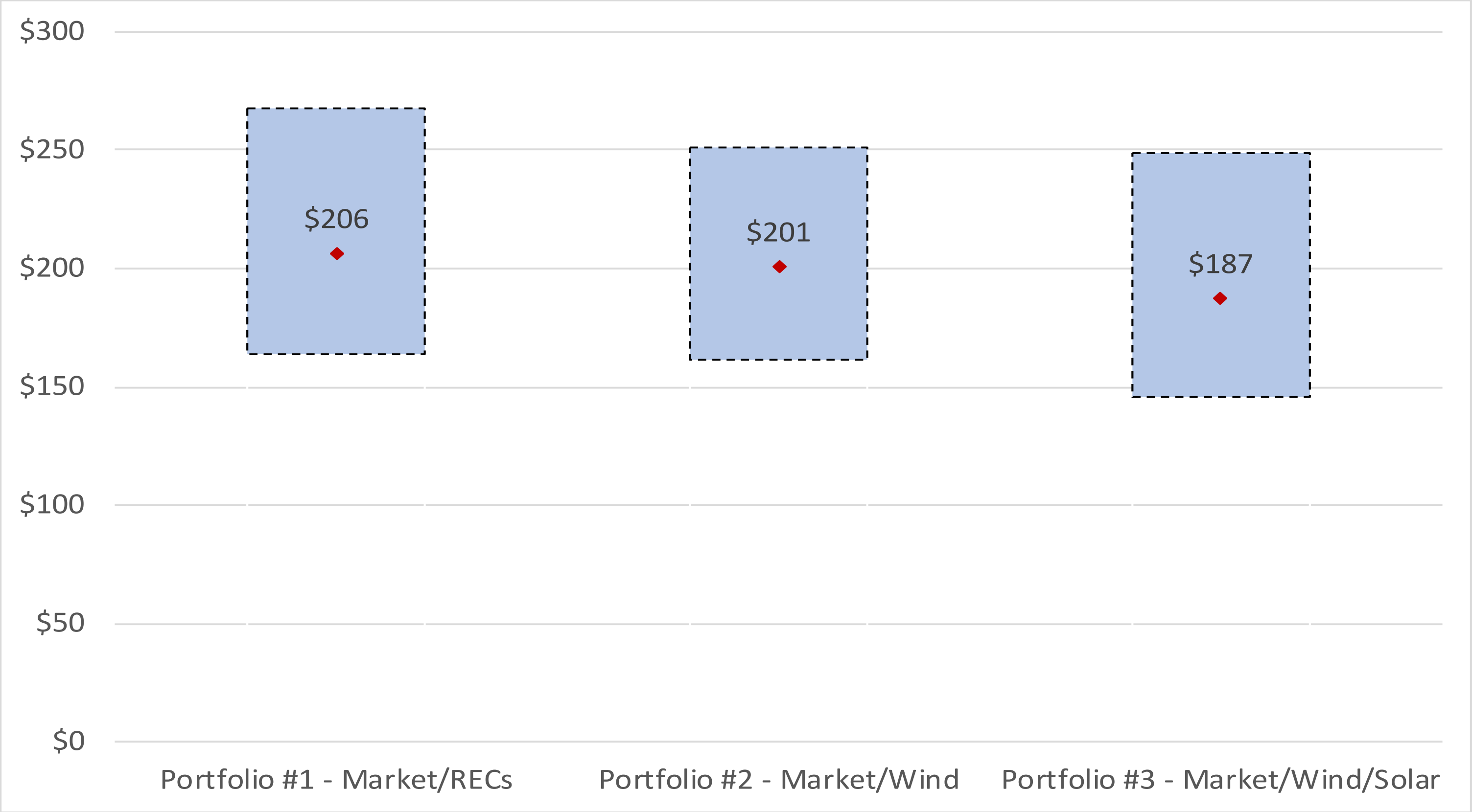
Step 3: Risk Analysis (cont'd)

Range of 20-year Levelized Resource Costs ($/MWh)



Step 3: Risk Analysis (cont'd)

Range of 2021-40 Portfolio Costs (millions)

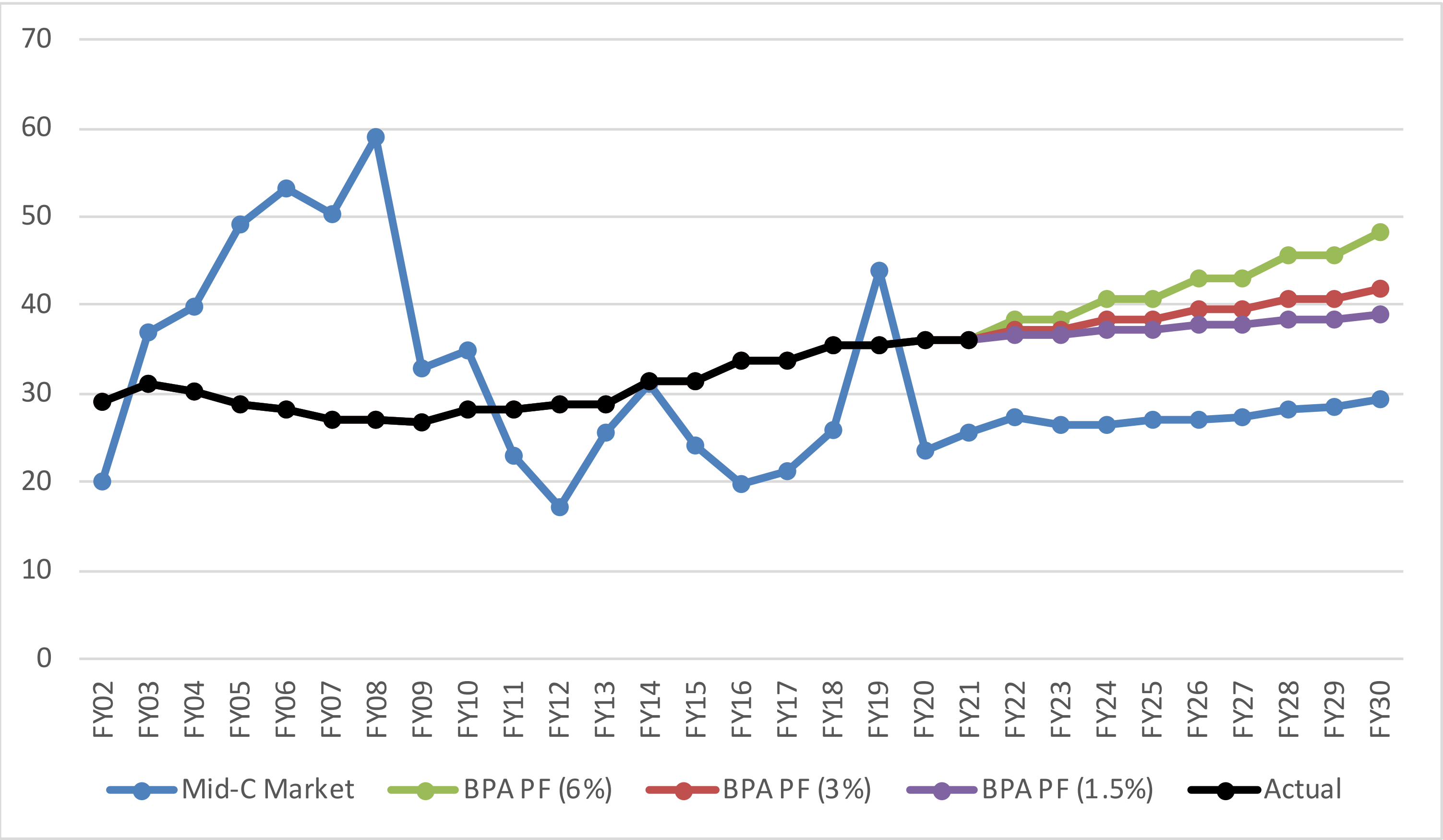


- **Portfolio #3 has the lowest costs under base case assumptions**
- **The range of potential outcomes is based on variations in projected wholesale market prices, REC prices, solar project costs and wind project costs**

Value of BPA Tier 1 Power

- **Market prices are for flat blocks of power – not load following**
  - Not an "apples-to-apples" comparison
- **BPA power is carbon-free**
- **Loads can be followed using monthly, daily, hourly and real-time markets**
  - Requires 24 x 7 scheduling desk & additional costs
- **BPA PF Load Following contracts provide the following –> costs included in PF power rates**
  - Real-time load fluctuations
  - Daily load fluctuations
  - Seasonal load fluctuations
  - Peak demands (guaranteed supply at demand rates)
- **What is the value of load following?**
- **EES base case estimate: $6/MWh – based on BPA demand rate, cost of capacity in California and scheduling fees**

Historic and Projected BPA Rates vs. Mid-C Market Prices



* Forward market prices shown above are as of February 14, 2020. Market prices are dynamic.

Add estimated $5 to 7/MWh value of BPA load following service to market prices

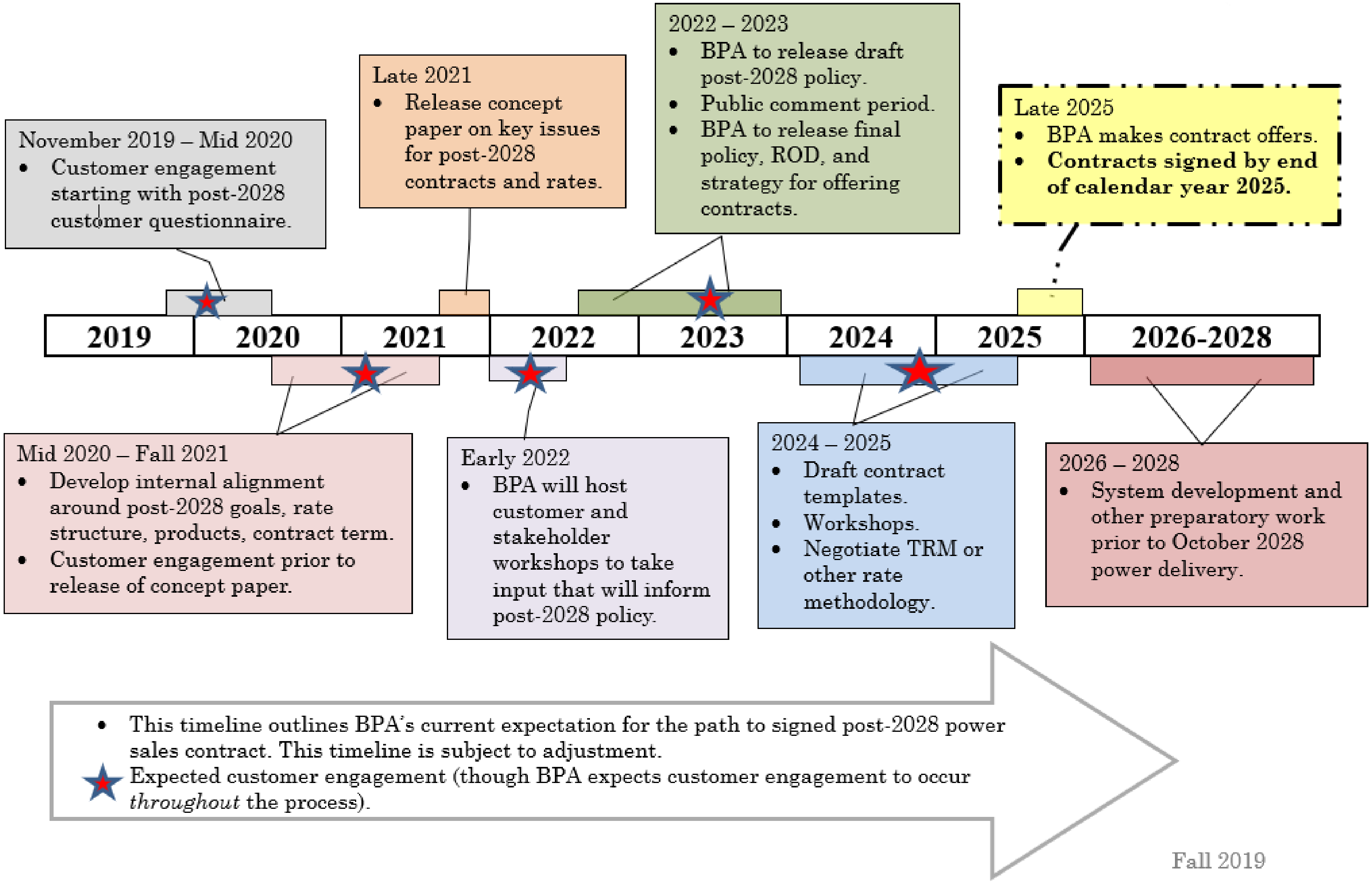
Add estimated value of $5 to 7/MWh value of carbon-free power to market prices

BPA rates are competitive with wholesale market when all attributes included in price comparison

BPA Power Contract Take-aways

- **Projected BPA rates are competitive with current forward market prices, but critical issues include:**
  - Timing of BPA contract commitment – what will forward market prices be in 2025?
  - Term of next BPA contract?
  - Products included in next BPA contract?
  - Rate design of next BPA contract?
  - Amount of power BPA will make available to utilities: new high-water marks or other criteria?
  - If utilities diversify (i.e. serve part of load with market purchases) will BPA allow full load to come back to BPA under subsequent contract?
  - Losing access to carbon-free power could be costly in the long run
  - What is the value of load following?
  - BPA Tier 1 rates more competitive when load following costs and value of carbon-free power are added to projected market purchase prices

Timeline for Post-2028 Power Policy, Rates and Contracts



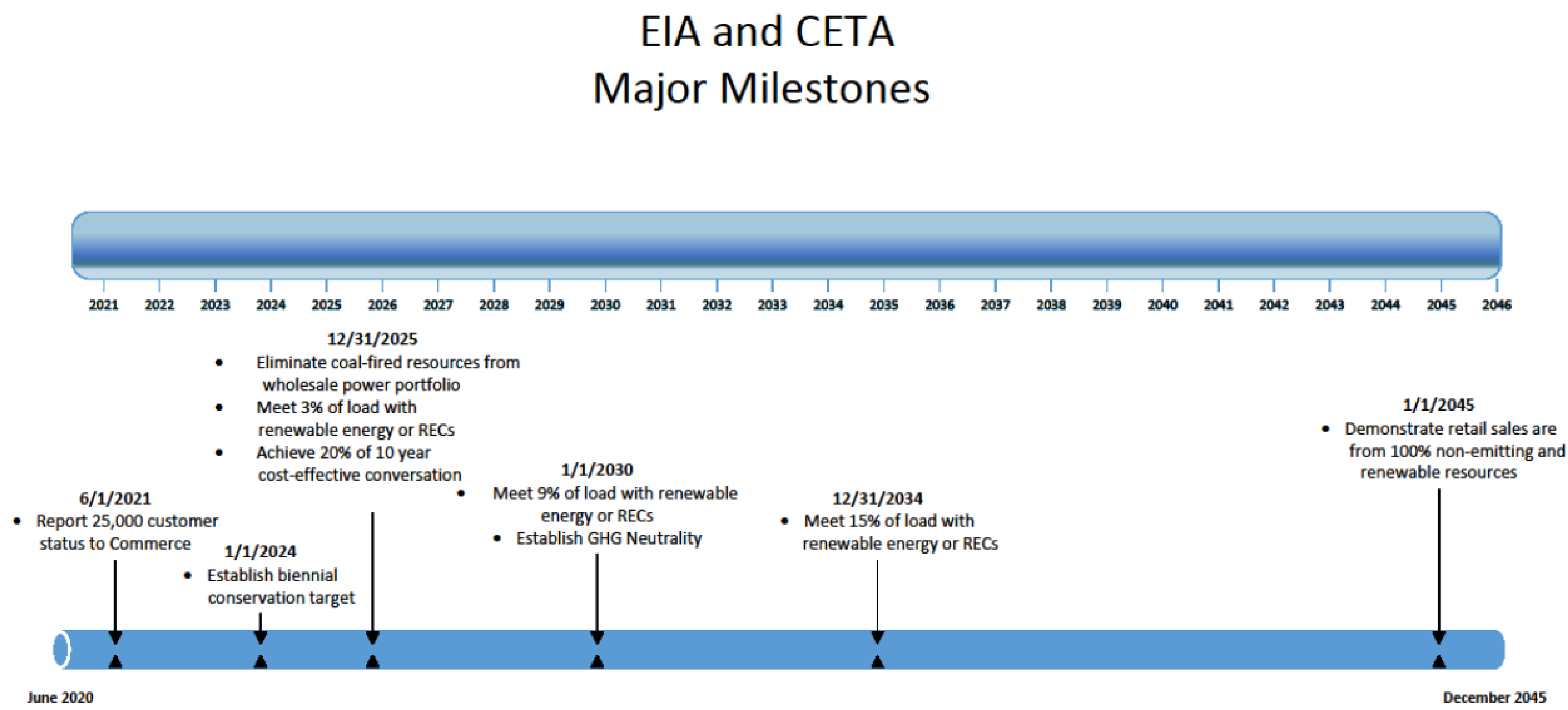
Step 4: Action Plan

- ***BPA Tier 1 Power:* RES should not take any actions that would result in decreases to the Tier 1 allocation rights in its current and future BPA power contracts**
  - Value of load following service must be considered when comparing BPA rates to market
  - BPA's Tier 2 power is carbon-free and, under CETA, RES will need to be carbon neutral by 2030 and carbon-free by 2045
- ***Energy Efficiency:* Cost-effective energy efficiency measures identified in RES's 2019 CPA, are the least expensive resources available to RES**
  - Implementing these measures will reduce RES's above-HWM load which will reduce RES's market price risk exposure since above-HWM load is served by market purchases
- ***Above-HWM Power Purchases:* Lowest cost and lowest risk portfolio includes**
  - Combination of market, solar and wind purchases to serve above-HWM load (Portfolio #3)
  - RECs associated with solar and wind purchases in addition to REC purchases to meet renewable energy requirements
    - EIA compliance begins 2026
    - Begin purchasing RECs in 2027, solar in 2028, and wind in 2029

Next Steps

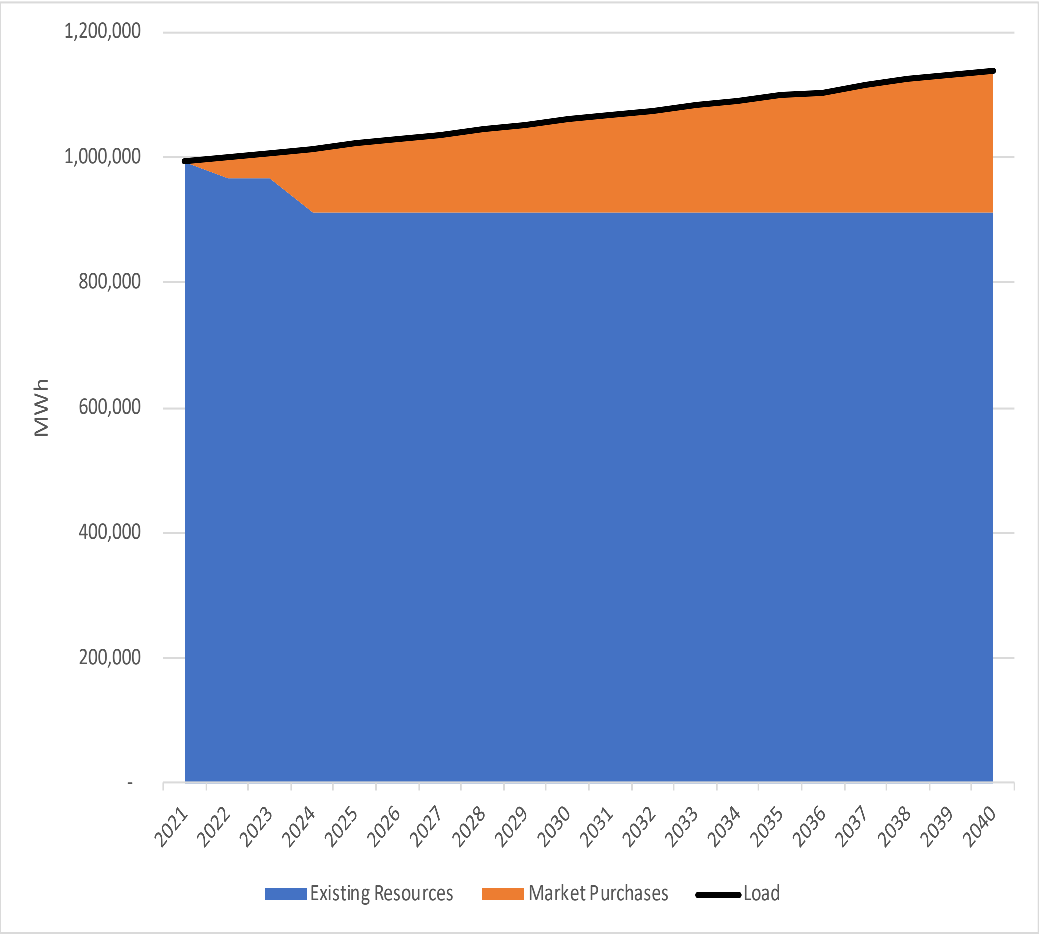
- July 14 – Request UAC motion recommending City Council adopt the IRP
- July 21 – Public hearing on IRP
- August 4 – Request Council adopt the IRP
- September 1 – Submit IRP to Commerce
- Continue to participate in CETA rulemaking
- 2021 – Update 2022 IRP and Clean Energy Implementation Plan (CEIP) and Clean Energy Action Plan (CEAP)

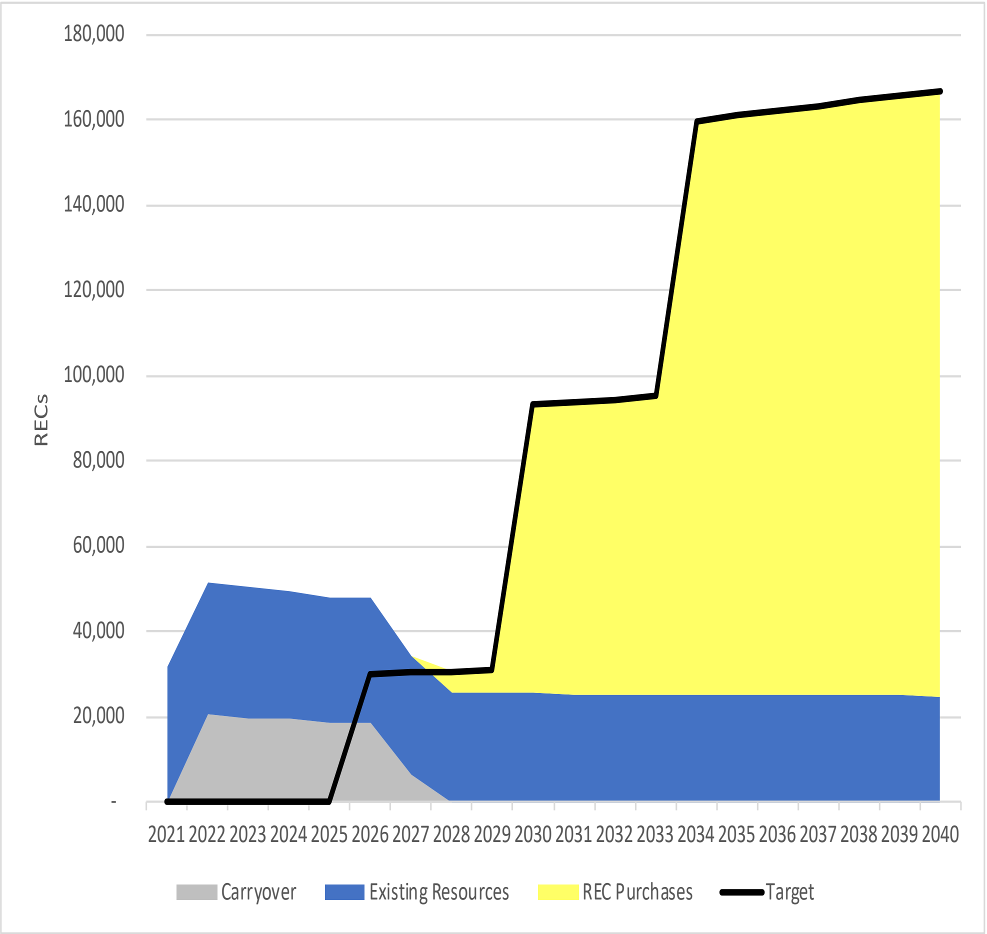
EIA and CETA Compliance Milestones



Appendix

Portfolio #1: Market Purchases Serve Above-HWM Load and REC Purchases Meet EIA Requirements

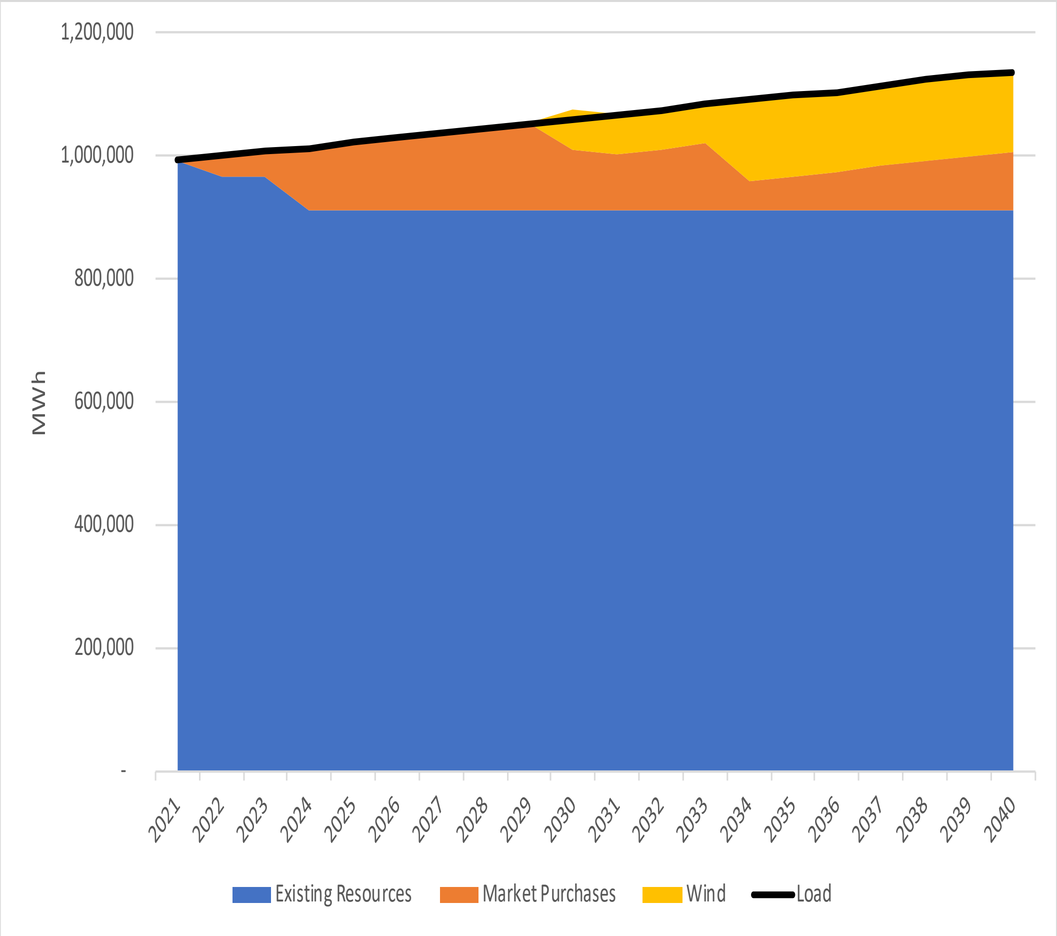


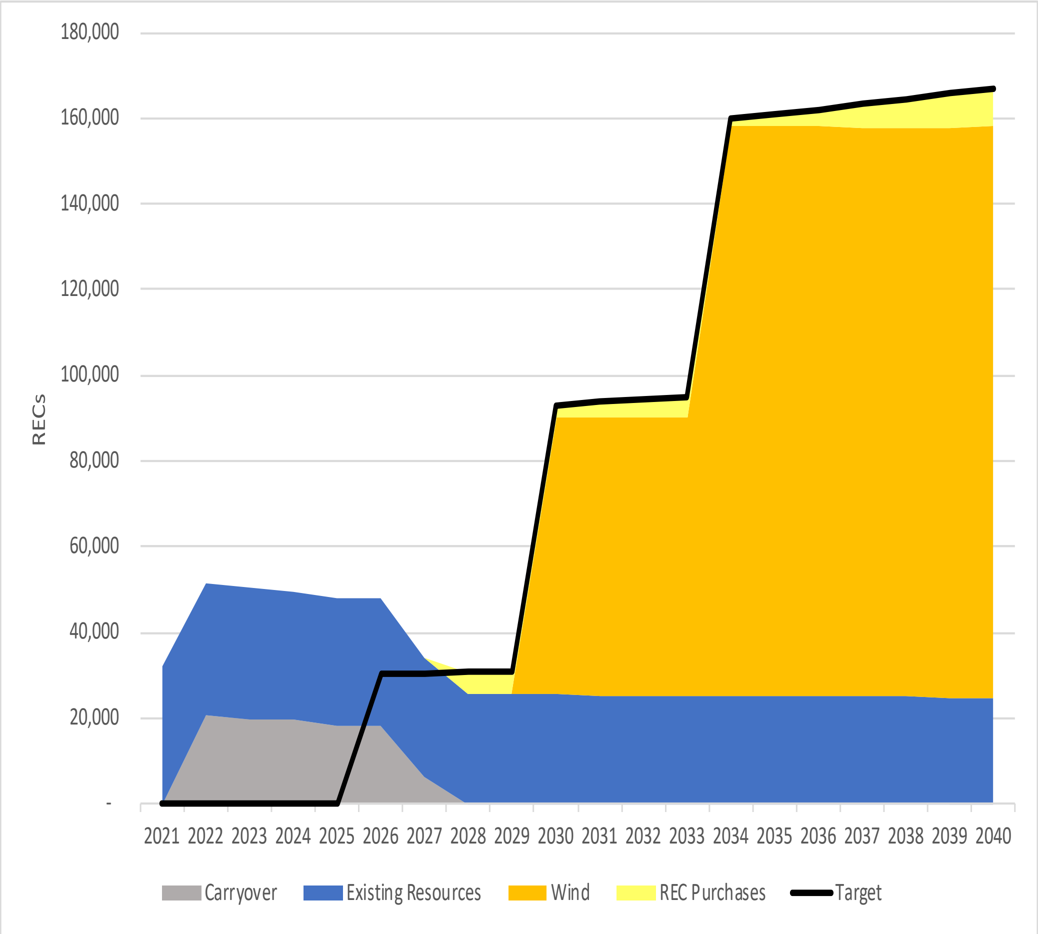


* Blue area includes BPA Tier 1 power, NIES purchases and HRSST

* Blue area includes BPA's Tier 1 RECs and HRSST

Portfolio #2: Serve Above-HWM Load with Market and Wind Purchases and Use RECs from Wind Purchase to Meet EIA Requirements





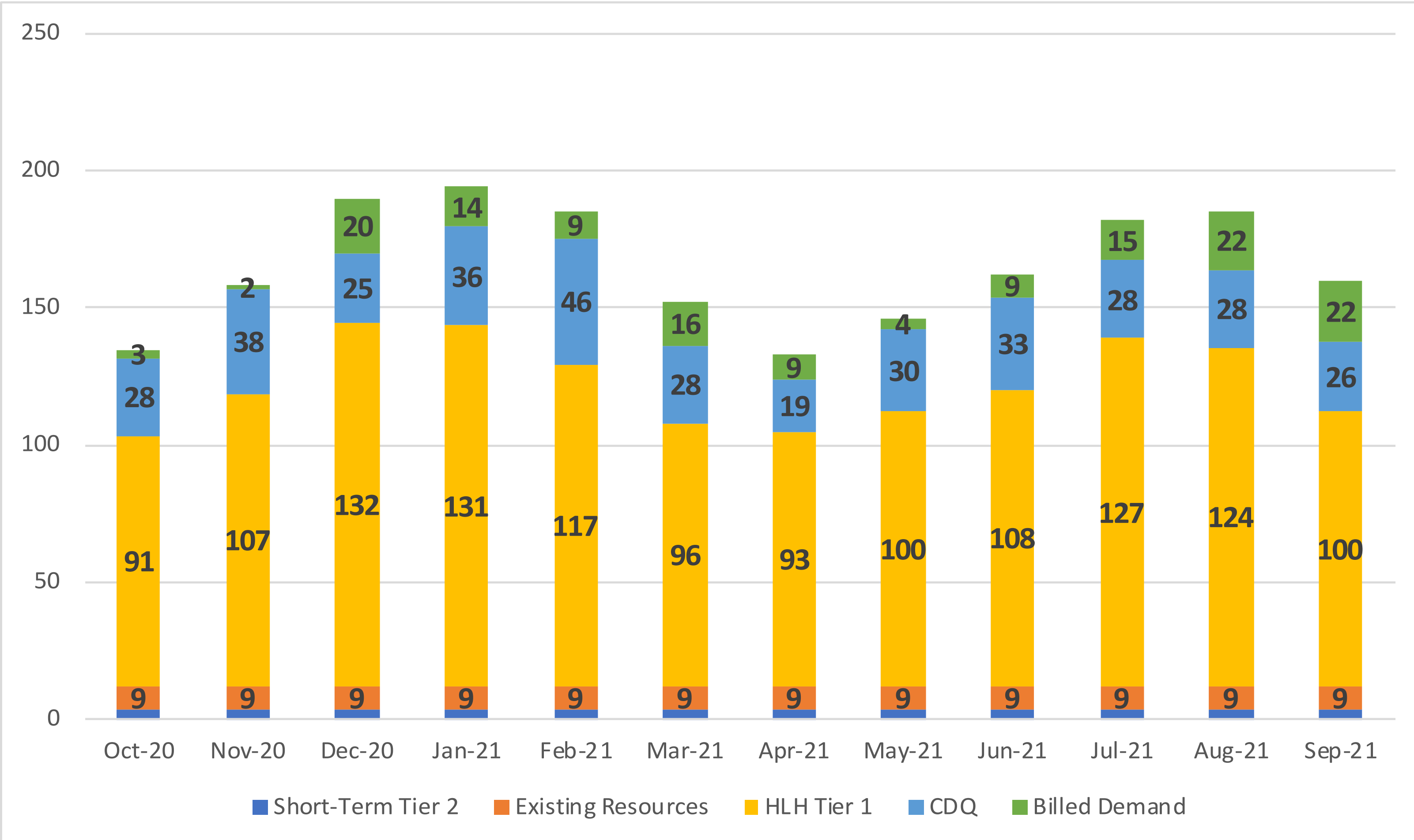
* Wind project capacity factor = 37%

Step 3: Risk Analysis

- **How Do the Portfolios Perform Under Different Assumptions?**
  - Market prices
  - REC prices
  - Capacity factors of wind and solar resources
  - Capital costs
  - Operation and maintenance costs
  - Resource support services costs

	Low Case	Base Case	High Case
Market Purchase (1)	CY21 = $23/MWh Escalation = 1.7%	CY21 = $29/MWh Escalation = 2.9%	CY21 = $38/MWh Escalation = 3.3%
RECs	CY21 = $3.3/REC CY30 = $6.2/REC CY40 = $10.0/REC	CY21 = $5.0/REC CY30 = $9.5/REC CY40 = $20.0/REC	CY21 = $8.5/REC CY30 = $20.0/REC CY40 = $35.0/REC
Wind Purchase	Capacity Factor = 41% Capital Cost = $1,450/kW Fixed O&M = $37/kW-yr RSS = $15/MWh	Capacity Factor = 37% Capital Cost = $1,700/kW Fixed O&M = $40/kW-yr RSS = $20/MWh	Capacity Factor = 32% Capital Cost = $1,939/kW Fixed O&M = $49/kW-yr RSS = $22/MWh
Solar Purchase	Capacity Factor = 37.5% Capital Cost = $1,165/kW Fixed O&M = $14.55/kW-yr RSS = $2/MWh	Capacity Factor = 32.5% Capital Cost = $1,527/kW Fixed O&M = $31/kW-yr RSS = $4/MWh	Capacity Factor = 28% Capital Cost = $2,600kW Fixed O&M = $40/kW-yr RSS = $6/MWh

How Does BPA Serve RES Peak Demands?



"Existing Resources" include NIES purchase purchase and HRSST
CDQ = Contract Demand Quantity

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

* Including dispatchable load

Base Case Supply Side Resource Characteristics

	Capital Cost ($/kW)	Fixed O&M ($/kW)	Variable O&M ($/MWh	Capacity (MW)	Capacity Factor	Heat Rate (Btu/kWh)
Natural Gas Baseload - CCCT	$1,140	$11.38	$2.11	383	75%	6,550
Natural Gas Peaker – SCCT	$657	$3.06	$5.15	235	10%	9,793
Natural Gas Peaker – Recip	$1,247	$6.98	$4.25	77	15%	8,350
Natural Gas Peaker – Aero	$1,154	$6.57	$2.67	96	12%	8,930
Wind - Gorge	$1,699	$39.85	$0.00	100	37%	NA
Wind - Montana	$1,648	$39.85	$0.00	150	43%	NA
Wind + Battery	$1,994	$69.16	$0.00	25	37%	NA
Solar – Westside	$1,527	$31.00	$0.00	50	22%	NA
Solar - Eastside	$1,527	$31.00	$0.00	50	33%	NA
Solar – Eastside + Battery	$2,431	$42.50	$0.00	17.5	33%	NA
Pumped Storage	2480	11.31	0.37	400	27%	NA

* Based on survey of assumptions used in by IOUs in recent IRPs and reference cases to be used in NWPCC's 2021 plan

Richland Energy Services

2020 Integrated Resource Plan
Draft

April 23, 2020

Prepared by:

EES Consulting
a GDS Associates Company

570 Kirkland Way, Suite 100
Kirkland, Washington 98033

A registered professional engineering corporation with
offices in Kirkland, WA and Portland, OR

Telephone: (425) 889-2700 Facsimile: (425) 889-2725

DRAFT

EES Consulting
a GDS Associates Company

Steve Andersen, Manager
steve.andersen@gdsassociates.com
503-223-5900

April 23, 2020

Ms. Sandi Edgemon
Richland Energy Services
840 Northgate
Richland, Washington 99352

Dear Ms. Edgemon:

It is with pleasure that EES Consulting (EES) submits this draft of the 2020 Integrated Resource Plan for Richland Energy Services (RES).

We appreciate all of the assistance you and your staff have provided in conjunction with this study. Please feel free to contact me directly with any questions or comments.

Very truly yours,

Steve Andersen
Manager

Table of Contents

Executive Summary

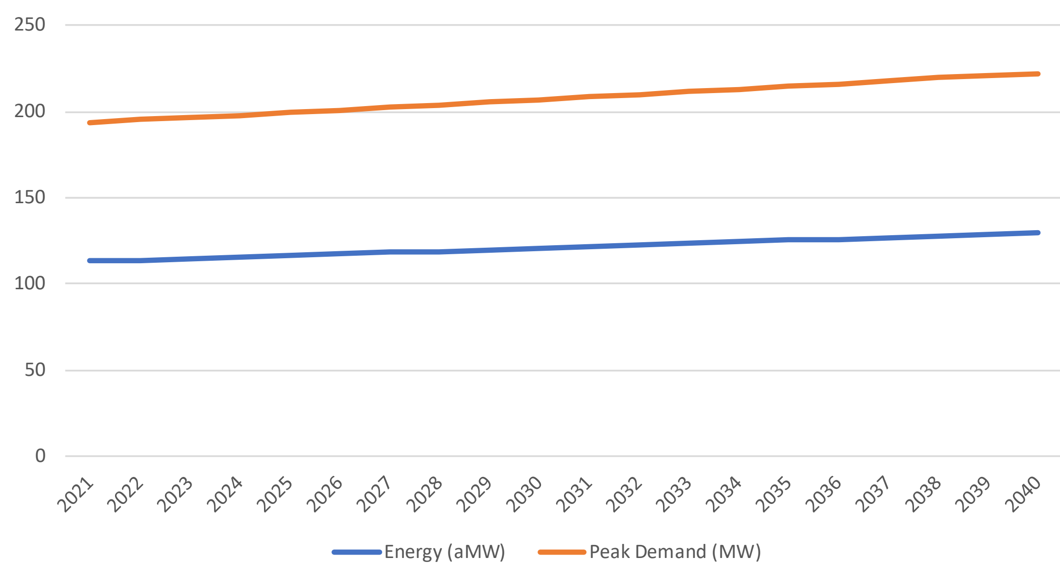
In 2006, Washington State enacted House Bill 1010, requiring public utilities that are not full requirements customers of the Bonneville Power Administration (BPA) and that serve more than 25,000 customers to complete an Integrated Resource Plan (IRP) in accordance with RCW 19.280. Richland Energy Services' (RES) total customer count eclipsed the 25,000-customer threshold in January 2020. Given that RES is now over the 25,000-customer threshold, this IRP has been completed in response to the state mandate. Under the law RES is required to submit a full report every four years with accompanying updates every two years. RES voluntarily completed a full IRP in 2016. RES is submitting second full IRP in 2020. The 20-year study period for the 2020 IRP is 2021 through 2040.

IRPs evaluate potential future resources in areas of reliability, cost, risk and environmental impact. IRPs consider demand-side resources on an equal basis with supply-side resources by comparing 20-year levelized costs. This report lays out the updated analysis performed by EES with respect to its forecast loads, existing resources, and future resource strategies. In addition, this report provides updates on the regulatory considerations and constraints that impact RES's resource planning.

Projected Loads and Existing Resources

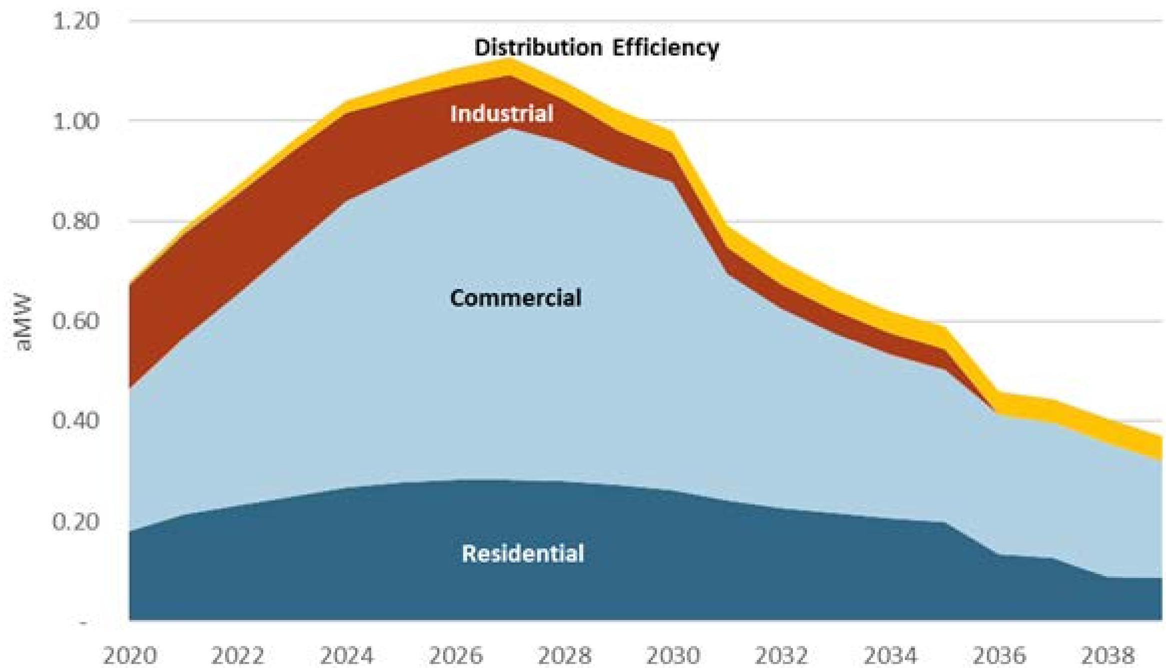
Exhibit ES-1 shows total system annual energy (power purchase requirements) and peak demands for the 20-year study period 2021-40.

Exhibit ES-1
Projected Annual Loads – Peak Demand and Energy



As shown above, loads are projected to be escalate steadily in CY21 through CY40. The average annual growth rate is 0.7 percent for energy and peak demand. The load forecast shown above includes anticipated conservation achievements. According to the Conservation Potential Assessment (CPA) completed by EES Consulting in February 2020, projected cumulative conservation acquisitions are approximately 138,320 MWh or 15.8 aMW over the 20-year study period. Exhibit ES-2 below shows the base case annual cost-effective energy efficiency potential identified in the CPA by sector.

Exhibit ES-2
Base Case Annual Cost-Effective Energy Efficiency Potential (aMW)



Source: RES's 2020 Conservation Potential Assessment

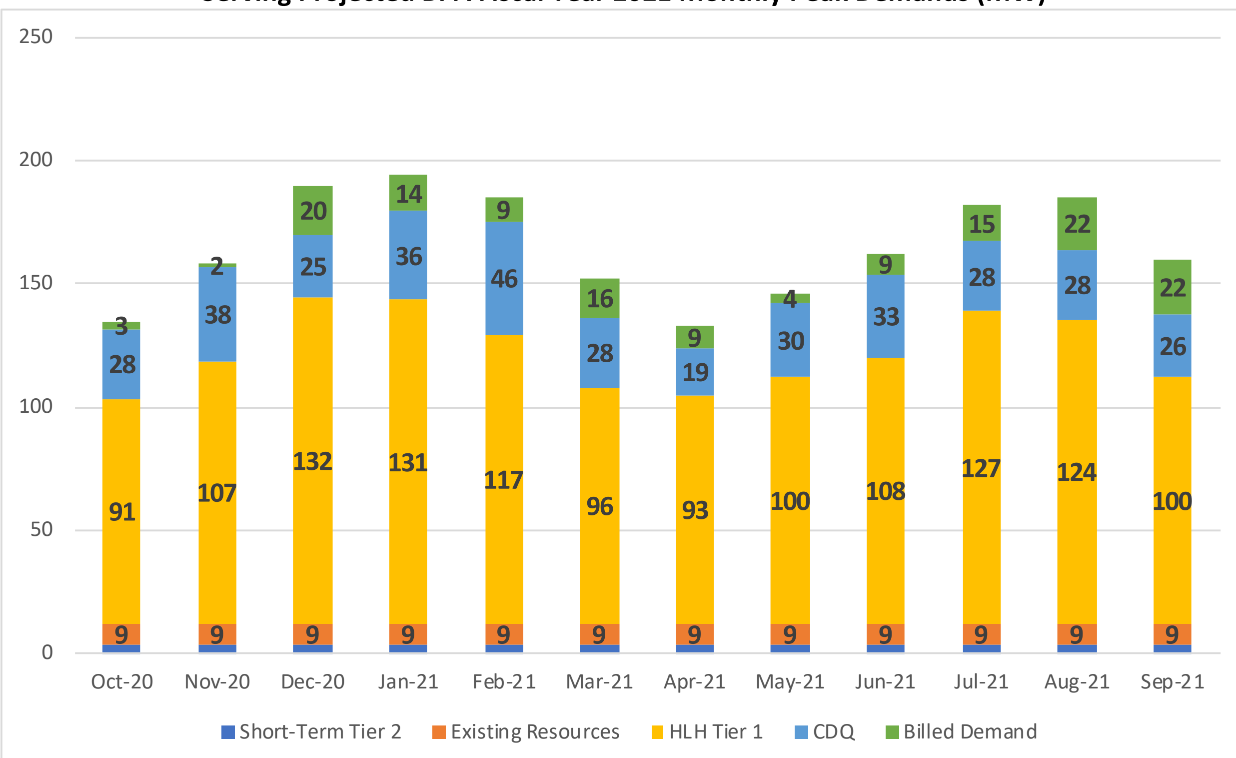
RES currently purchases 90 percent of its power requirements from BPA under a 20-year contract that expires in September 2028, 3 percent from BPA through a short-term Tier 2 product purchase that expires in September 2021, 7 percent from NIES through contracts that expire in September 2023 and 0.5 percent from the Horn Rapids Solar and Storage Training Project.

Power requirements above BPA Tier 1 allocations may be purchased from BPA at Tier 2 rates or from alternative suppliers including market purchases and owned generation. Above-HWM load must be served by flat blocks of power. BPA offers utilities several alternatives for Tier 2 power products and associated pricing. BPA's Tier 2 rates are designed to recover the full costs of the generating resources or market purchases used to serve Tier 2 loads.

As a load following customer, RES currently purchases all of its peak demand requirements from BPA. The monthly billing determinants for BPA's demand product are calculated by taking RES's monthly system peak demand less RES's average on-peak energy consumption less RES's above HWM purchases and RES's Contract Demand Quantity (CDQ). The monthly CDQs are set for the contract period (through September 2028) and are based on historic load factors. RES's CDQs vary between a high of 46 megawatts and low of 19 megawatts. The average monthly demand billing determinant is projected to be near 12 megawatts in CY21.

Figure ES-3 shows an example of the calculation of BPA's demand billing determinant. The monthly peak demands shown below are based on BPA's total retail load and customer system peak forecasts for RES.

Figure ES-3
Serving Projected BPA Fiscal Year 2021 Monthly Peak Demands (MW)

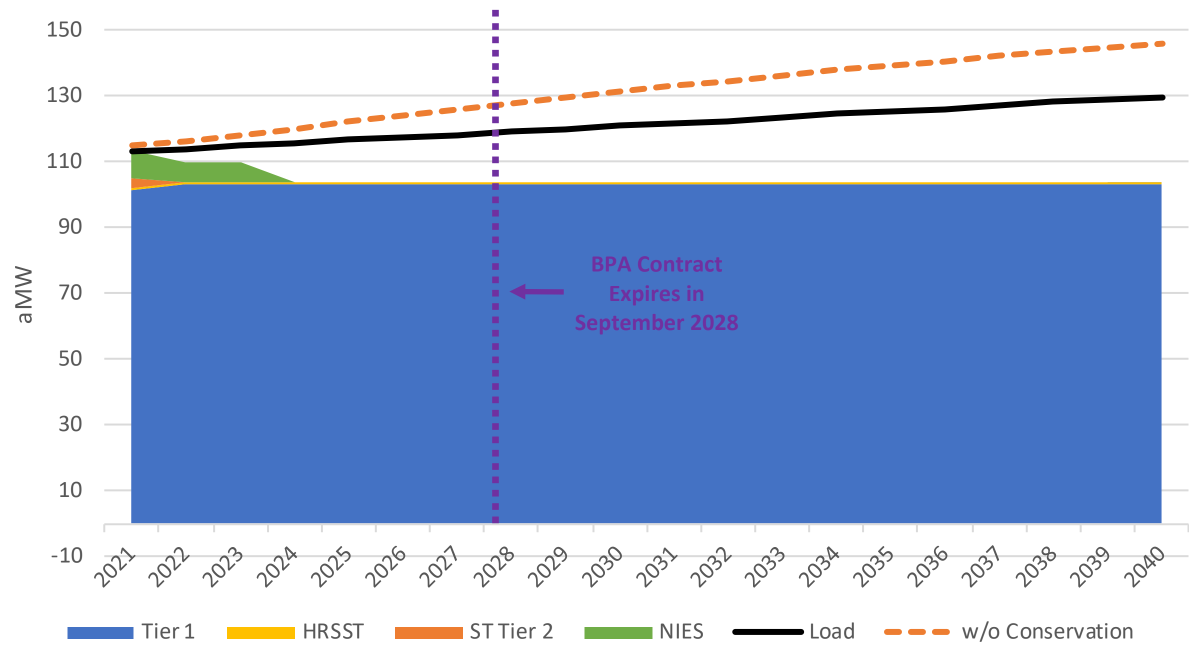


Note: Existing Resources include NIES purchase and HRSST.

BPA's monthly demand rates vary between a high of $12.10 per kilowatt and a low of $5.04 per kilowatt. Given the relatively high BPA demand rates reducing peak demands can result in fairly significant savings. If the demand billing determinant could be reduced by 1 megawatt in each month, RES's annual purchased power costs could be reduced by $120,000. As such, it is important to consider resources such as demand response units that can reduce RES's monthly peak demands.

RES's existing resource portfolio also includes the Horned Rapids Solar, Storage and Training Project (HRSST) and a market purchase through Northwest Intergovernmental Energy Supply (NIES). Exhibit ES-4 below shows RES's load/resource balance including non-federal resources.

Exhibit ES-4
RES Load/Resource Balance

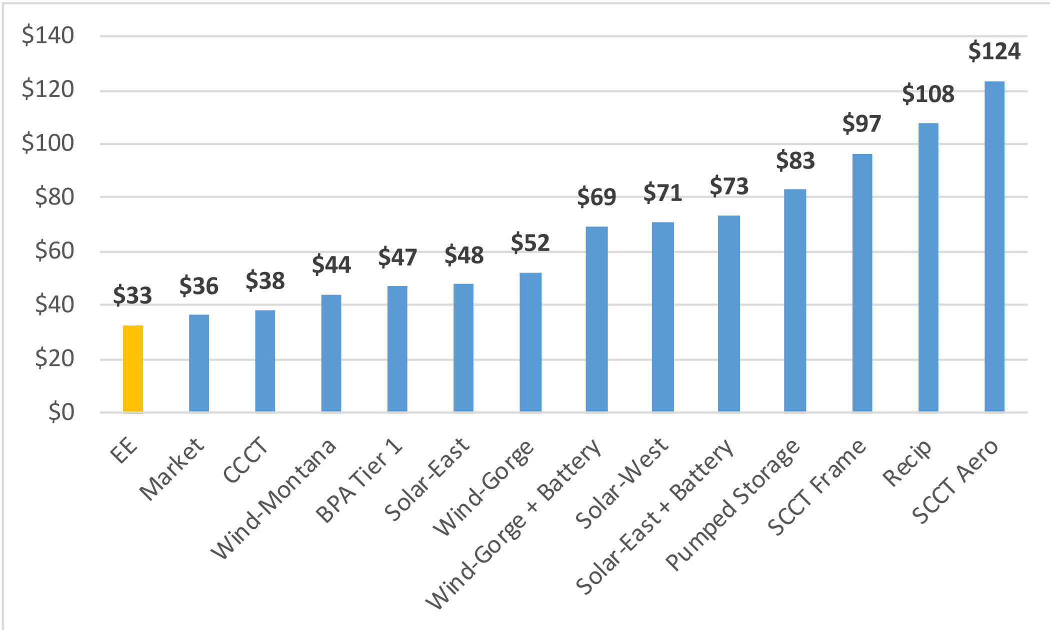


Note: Tier 1 purchases are set for the current rate period (through September 2028). Tier 1 purchases shown after 2028 assume RES's allocation of BPA Tier 1 power does not change in the next contract period. Projected conservation achievements align with the annual achievements shown in Exhibit ES-2.

As shown above in Exhibit ES-4, RES is short on resources through 2040. On a short-term basis, RES can serve above-HWM load with market purchases through NIES or another entity.

Exhibit ES-5 below shows the nominal levelized costs of the supply-side resources discussed in the body of this report. The 20-year levelized cost of energy efficiency is per RES's 2019 CPA. The BPA Tier 1 rate assume 3 percent BPA rate increases every other year (every rate case).

Exhibit ES-5
Projected 20-year (2021-40) Levelized Costs ($/MWh)



Source: Utility IRPs, NW Power Council Data and RES Conservation Potential Assessment.

Exhibit ES-5 shows that energy efficiency and the wholesale market are the lowest cost resources followed by utility scale wind located in Montana, a combined cycle combustion turbine, utility scale solar located on the east side of the Cascade Mountains and BPA Tier 1 rates. The Production Tax Credit (PTC), which is applicable to wind projects at a reduced credit of 60 percent, expires at the end of 2020. Wind project costs are shown above without the PTC. The Investment Tax Credit (ITC), which is applicable to solar projects, is 30 percent in 2019, but steps down to 26 percent in 2020, 22 percent in 2021 and 10 percent in 2022 where it will remain. Solar project costs are shown above include a 10 percent ITC.

The Clean Energy Transformation Act (CETA) requires electric utilities in Washington State to include the social cost of greenhouse gas emissions in resource evaluation, planning and acquisition [RCW 19.280.030(3)]. The Washington State Department of Commerce has determined that customer-owned utilities should use the same cost values that the legislature has enacted for investor-owned utilities which establishes a specific set of cost values developed by a federal interagency working group in 2016. Inflation factors will escalate costs to the base years used in IRPs. Based on the methodology established by the working group, the projected social cost of carbon used in this analysis includes the following assumptions:

- 2021 cost of carbon (per metric tons): $76.5/metric ton
- 2021 cost of carbon (per MMBtu): $4.06/MMBtu, assuming 53 kilograms of CO_2 per MMBtu

The projected social cost of carbon impacts the resources shown above in Exhibit ES-5 differently, based on the resources' carbon content, which is determined by their heat rate in Btu/kWh. Including the social cost of carbon increases the 20-year levelized costs of the following resources included in Exhibit ES-5:

Market: $23/MWh based on an assumed market heat rate of 7,195 Btu/kWh in August- March when gas-fired resources are the marginal resource; 0 Btu/kWh during spring/summer runoff season when hydro or wind serve as marginal resource

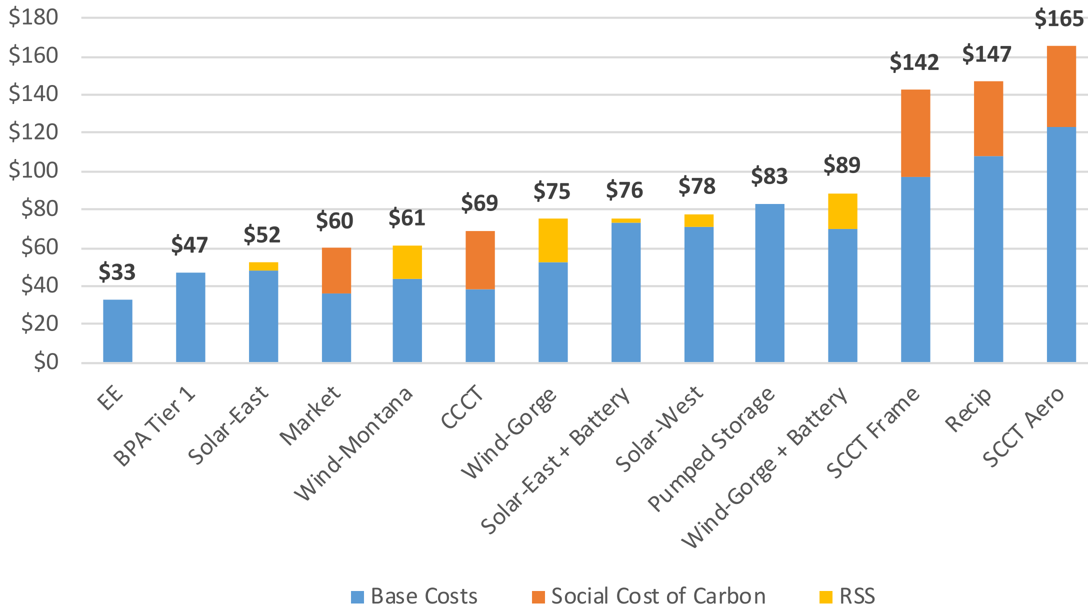
- CCCT: $32/MWh based on an assumed heat rate of 6,550 Btu/kWh
- Reciprocating Engine: $39/MWh based on an assumed heat rate of 8,350 Btu/kWh
- SCCT Aero: $42/MWh based on an assumed heat rate of 8,930 Btu/kWh
- SCCT Frame: $46/MWh based on an assumed heat rate of 9,773 Btu/kWh

Due to the intermittency of wind and the unpredictability of the output, the amount of hourly generation is uncertain. 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. BPA uses the capacity and flexibility of its resource pool to provide wind integration services to its customer utilities through a product known as Resource Support Services (RSS).

Under the current BPA power contract, above-HWM load must be served with flat resources. BPA's RSS products flatten intermittent renewable generation across hours, days and seasons, resulting in flat blocks of power. Since solar generation is also not flat across all hours RSS products are also used to flatten utilities' solar power purchases. RSS prices are resource specific since wind and solar resources have different capabilities primarily based on their capacity factors. Based on RSS prices currently offered by BPA an RSS of $20/MWh is assumed for wind projects located in the Gorge, $15/MWh for Montana wind, $5/MWh for solar projects located on the west-side of the Cascades and $3.5/MWh for solar project on the east side.

Exhibit ES-6 below shows the nominal levelized costs of the supply-side resources including the projected social cost of carbon and RSS.

Exhibit ES-6
Projected 20-year (2021-40) Levelized Costs including Social Cost of Carbon and RSS ($/MWh)

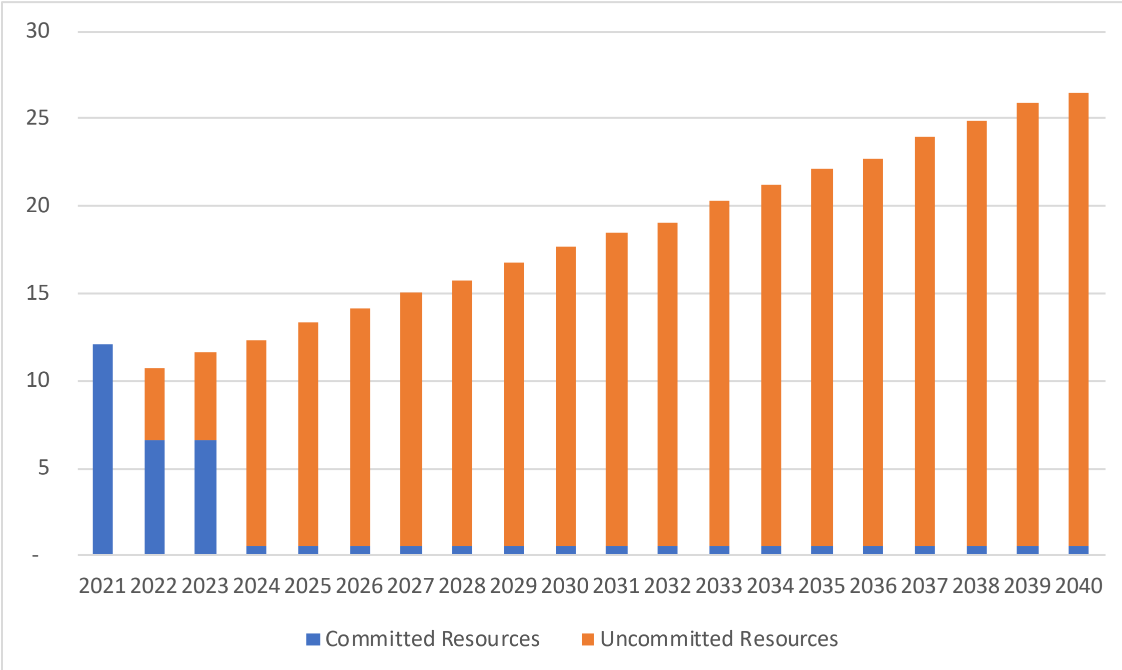


As shown above when the social cost of carbon is included in the analysis the cost of a CCCT falls from being the 3rd lowest cost resource to the 6th lowest cost resource and the market falls from 2nd to 4th.

Portfolios

Projected above-HWM loads are shown below in Figure ES-7. Committed resources include the NIES purchase in 2021 through 2023 and HRSST in all years.

Exhibit ES-7
Projected above-High Water Mark Load (aMW)

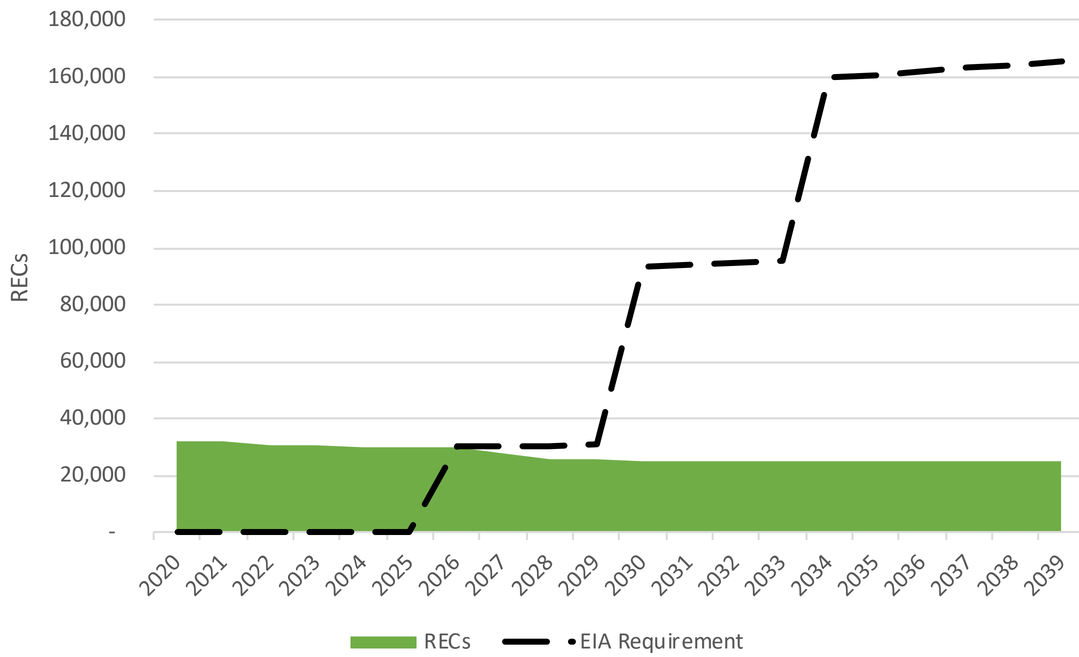


As shown above, RES is short on committed above-HWM serving resources in 2020 through 2040. In addition to be being short on load-serving resources RES is also short on RECs required to meet the renewable energy requirements under the Energy Independence Act. RES exceeded the 25,000-customer threshold in January 2020. As such, RES is required to comply with the EIA's renewable energy targets as follows:

- 3 percent of retail load must be served by renewables in 2026-29
- 9 percent of retail load must be served by renewables in 2030-33
- 15 percent of retail load must be served by renewables beginning in 2034

Figure ES-8 shows RES's REC position compared to its requirements under the EIA.

Exhibit ES-8
RES Projected RECs vs. EIA Requirements



The RECs shown above (green area) are a combination of RECs associated with RES's purchase of the renewable resources (wind and incremental hydro) included in BPA's Tier 1 resource pool and HRSST. HRSST accounts for approximately 55 percent of the RECs currently under contract. HRSST RECs count as double because HRSST is a distributed resource. Distributed resources are eligible to use a 2.0 REC multiplier under the EIA.

The costs of serving RES's above-HWM loads while meeting the EIA's renewable energy requirements were calculated for three scenarios or portfolios.

As shown above, RES needs to acquire additional RECs, either from eligible renewable resources or from the REC market, beginning in 2027. Vintage 2016 HRSST and BPA Tier 1 RECs are sufficient to meet the first year of EIA requirements. Three portfolios were developed for meeting RES's above-HWM and renewable energy purchase requirements:

- Portfolio #1: Wholesale market purchases serve above-HWM load and REC purchases used to meet EIA requirements.
- Portfolio #2: Wholesale market and wind purchases serve above-HWM load and RECs from wind purchase meet EIA Requirements.
- Portfolio #3: Wholesale market, wind and solar purchases serve above-HWM load and RECs from wind and solar purchases meet EIA Requirements.

A sensitivity analysis is included to determine a range of costs associated with each portfolio. The sensitivity analysis is a deterministic analysis to show a best case, worst case, and expected case of the costs associated with each portfolio.

The three portfolios included in the analysis are discussed below.

Portfolio #1: Market Purchases Serve Above-HWM Load and REC Purchases Meet EIA Requirements

Figure ES-9 below shows a resource stack in which RES purchases enough power from the wholesale market to meet its load requirements. The blue area in Exhibit ES-9 includes BPA Tier 1 power, NIES purchases and HRSST.

Exhibit ES-9
Serve Above-HWM Loads Market Purchases

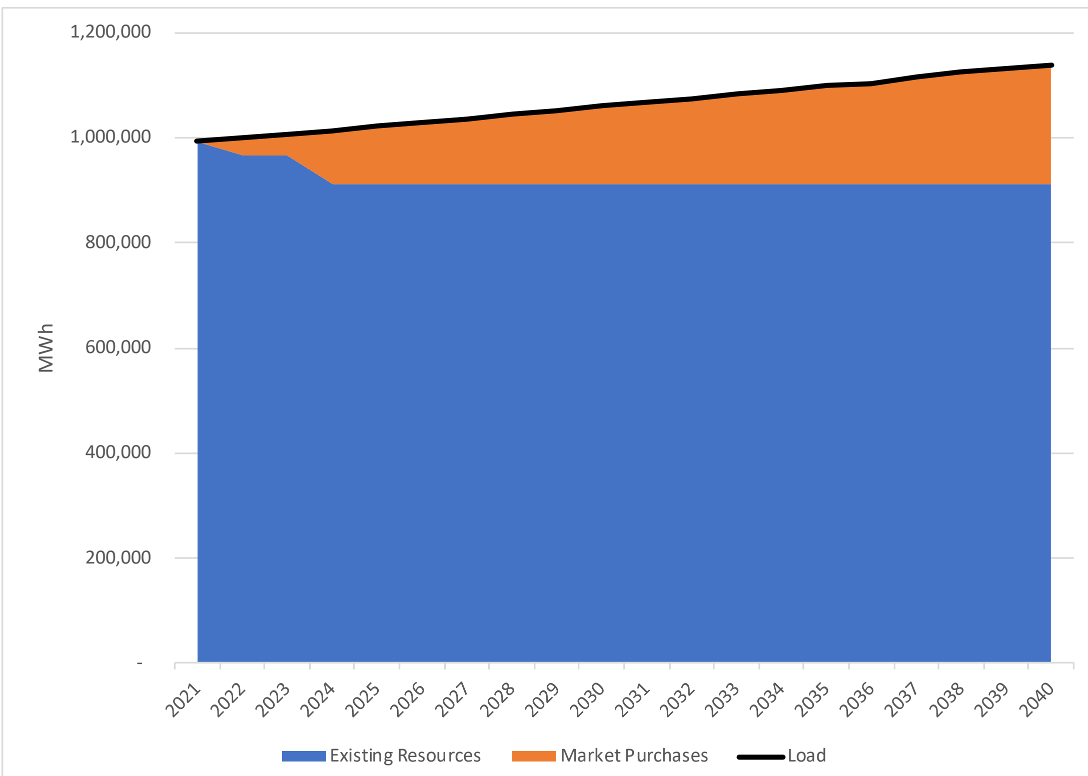
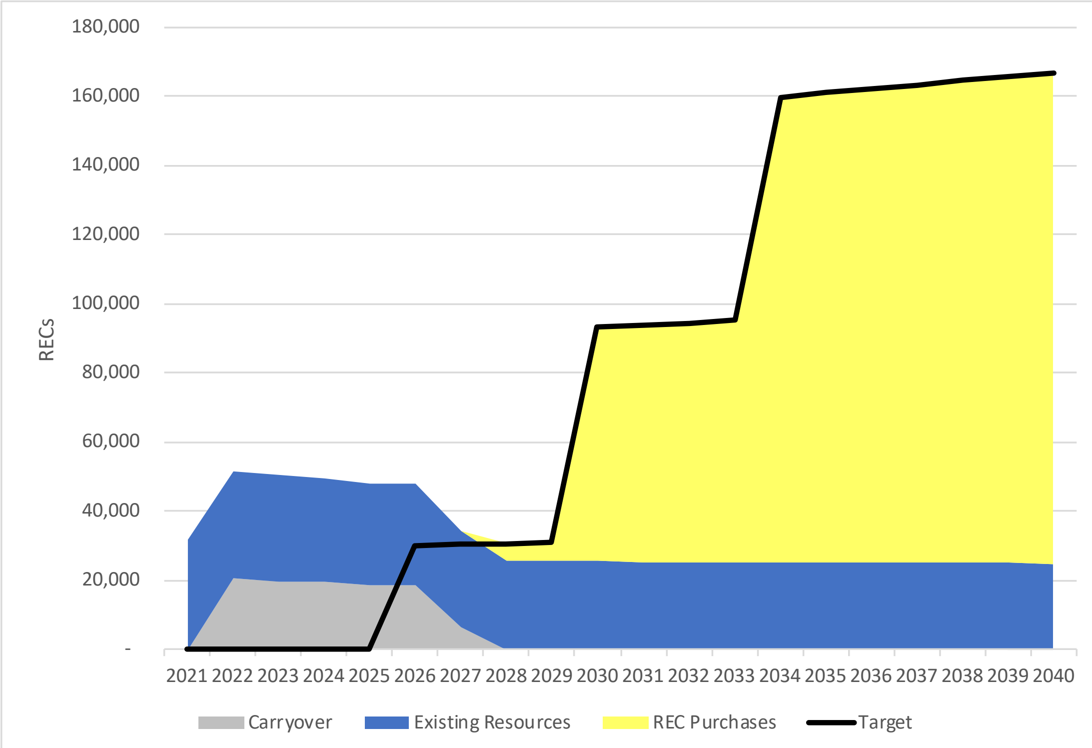


Exhibit ES-10 below shows RES's REC portfolio compared to its renewable energy requirement/target under the EIA. In this portfolio the REC short positions shown above in Exhibit ES-8 are met entirely through REC purchases.

Exhibit ES-10
REC Purchases Used to Meet EIA's Renewable Energy Purchases

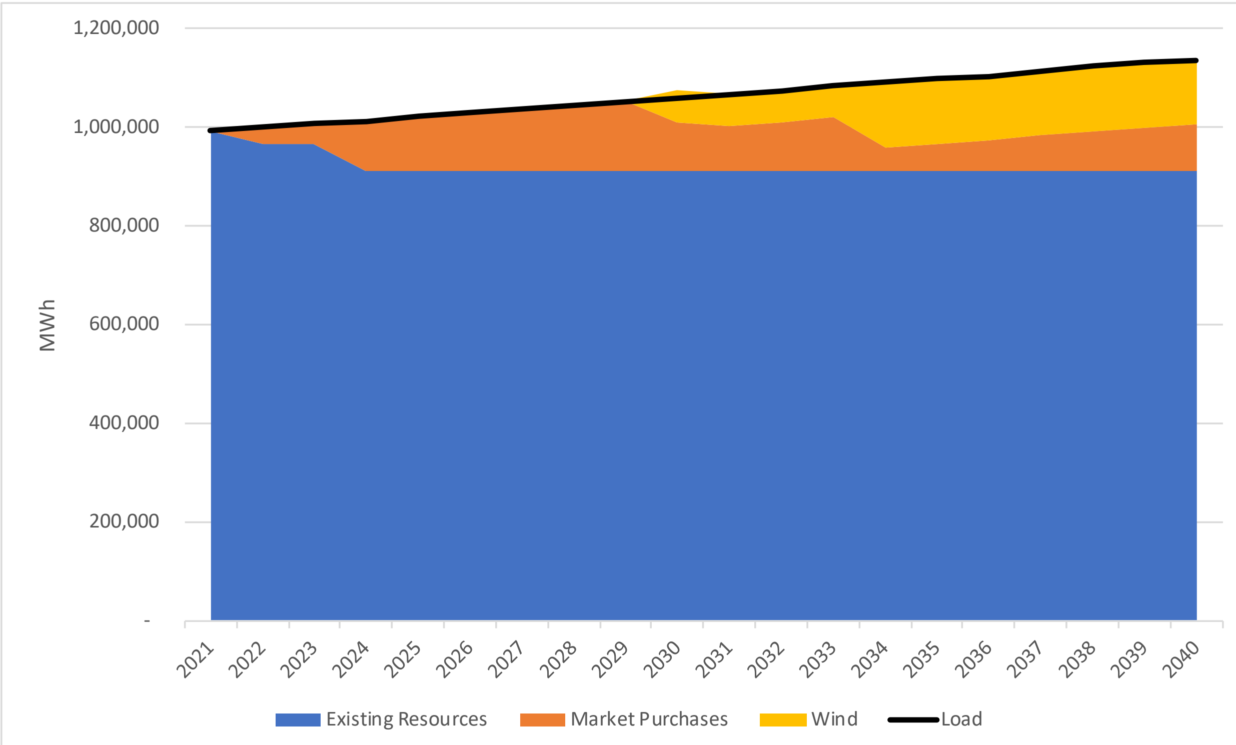


Under the EIA utilities can use RECs from the previous year, the current year and the subsequent year to satisfy renewable energy requirements. For example, during the first year of compliance (CY26), RES can use vintage 2025, vintage 2026 and vintage 2027 RECs to meet the CY26 renewable target of 3 percent. The carryover amounts shown in gray in Exhibit ES-10 represent HRSST and BPA Tier 1 RECs from the prior year.

Portfolio #2: Serve Above-HWM Load with Market and Wind Purchases and Use RECs from Wind Purchase to Meet EIA Requirements

Exhibit ES-11 below shows a resource stack in which RES serves nearly half of its above-HWM load with output from a wind project and the other half from wholesale market purchases. The blue area in Exhibit ES-11 includes BPA Tier 1 power, NIES purchases and HRSST.

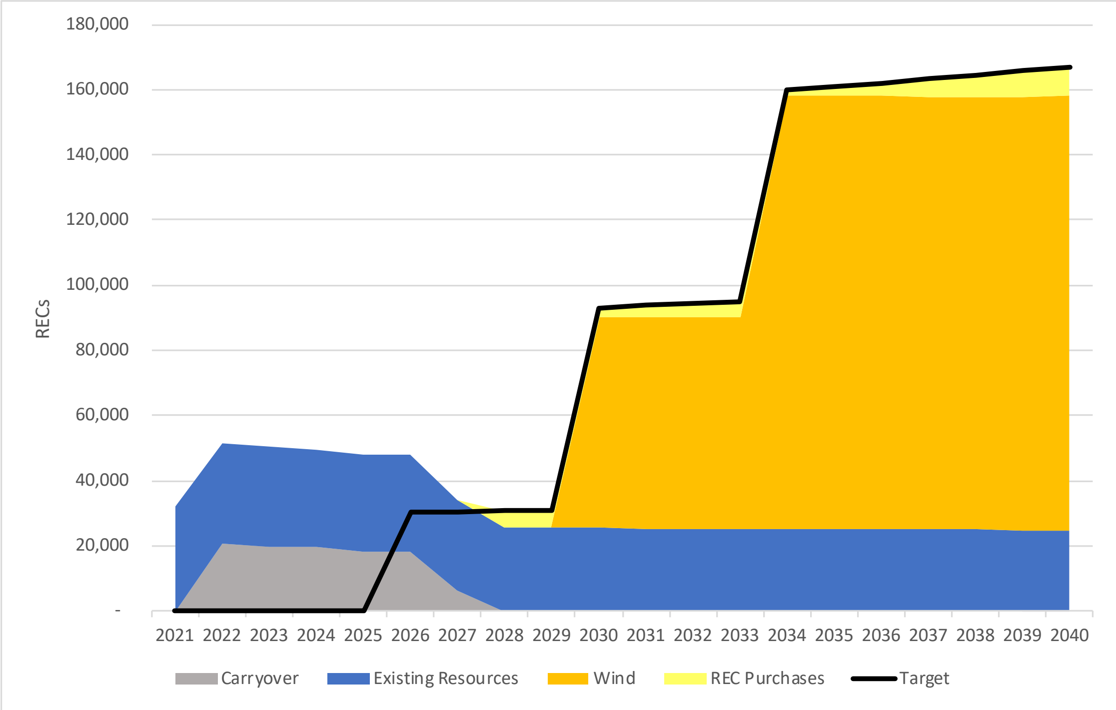
Exhibit ES-11
Serve Above-HWM Loads with Combination of Wind and Market Purchases



As shown in Exhibit ES-11, above-HWM loads are served by wholesale market purchases (orange area) in the earlier years with wind power serving increasing amounts of load through 2040. The amount of wind purchases layered into the portfolio is dictated based on the EIA renewable energy requirements. Wind purchases increase from 3.5 MW in 2028-2030 to 23 MW in 2031-33 and 43 MW in 2034-2040. A capacity factor of 37 percent is assumed for the wind project which is assumed to be located in the Columbia River Gorge.

Exhibit ES-12 below shows that wind RECs fill in the short REC positions identified in Exhibit ES-8.

Exhibit ES-12
Wind Purchase Used to Meet EIA's Renewable Energy Purchase Requirements

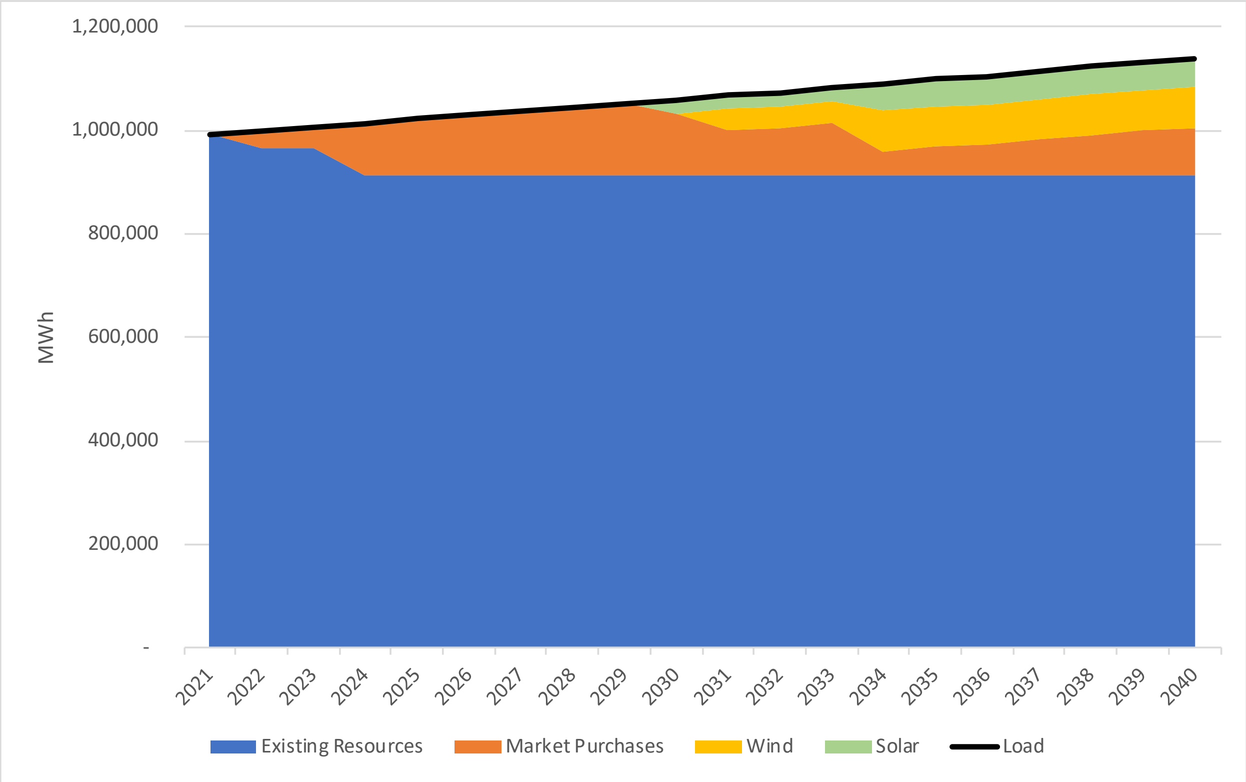


As shown above REC purchases (yellow area) are used to meet small REC deficits in Portfolio #2.

Portfolio #3: Serve Above-HWM Loads with Market, Wind and Solar Purchases and Use RECs from Wind and Solar Purchases to Meet EIA Requirements

Exhibit ES-13 below shows a resource stack in which RES serves nearly half of its above-HWM load with output from wind and solar projects and the other half from wholesale market purchases. The blue area in Exhibit ES-11 includes BPA Tier 1 power, NIES purchases and HRSST.

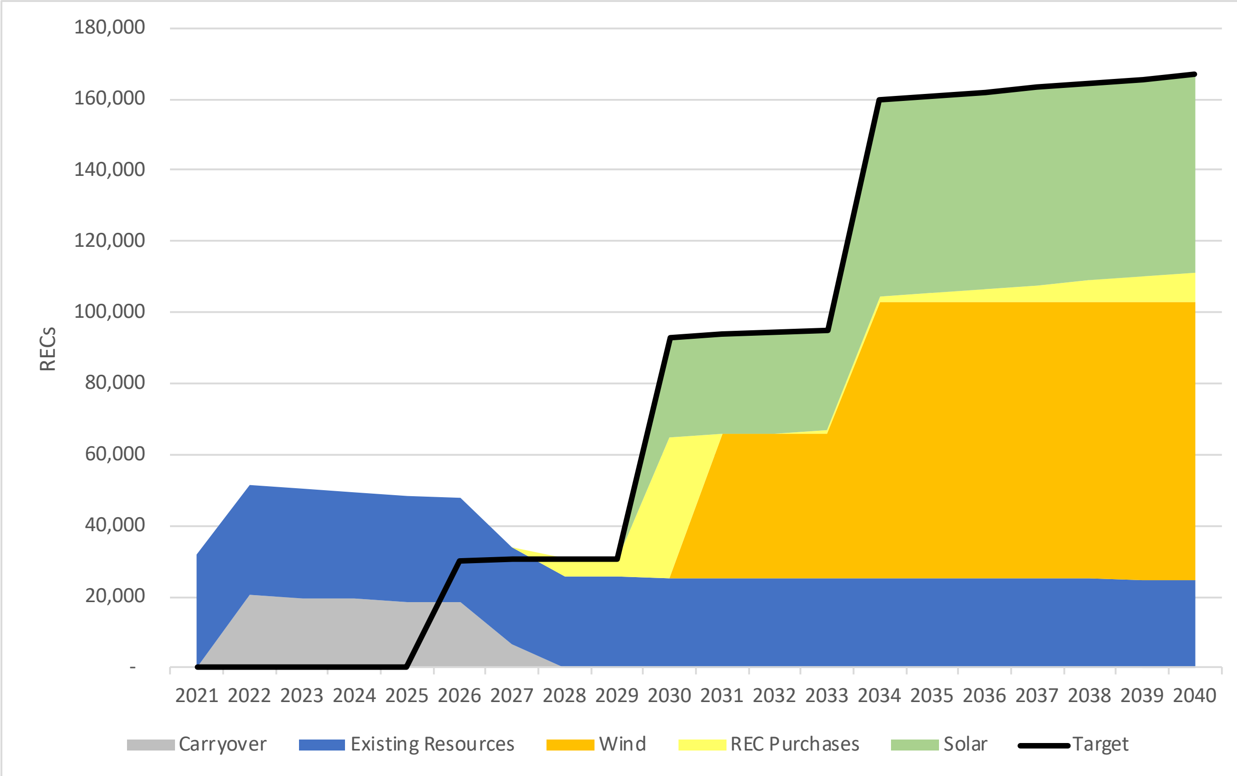
Figure ES-13
Serve Above-HWM Loads with Combination of Wind, Solar and Market Purchases



As shown in Exhibit ES-13, above-HWM loads are served by wholesale market purchases (orange area) in the earlier years with solar and wind power serving increasing amounts of load through 2040. The amount of solar and wind purchases layered into the portfolio is dictated based on the EIA renewable energy requirements. Solar purchases increase from 4 MW in 2028-2030 to 12 MW in 2031-33 and 19.5 MW in 2034-2040. A capacity factor of 32.5 percent is assumed for the solar project which assumed to be located on the east side of the Cascades. Wind purchases increase from 12.5 MW in 2031-2034 to 26.25 MW in 2034-40. A capacity factor of 37 percent is assumed for the wind project (same as Portfolio #2).

Exhibit ES-14 below shows that solar and wind RECs fill in the short REC positions identified in Exhibit ES-8.

Exhibit ES-14
Wind and Solar Purchases Used to Meet EIA's Renewable Energy Purchase Requirements

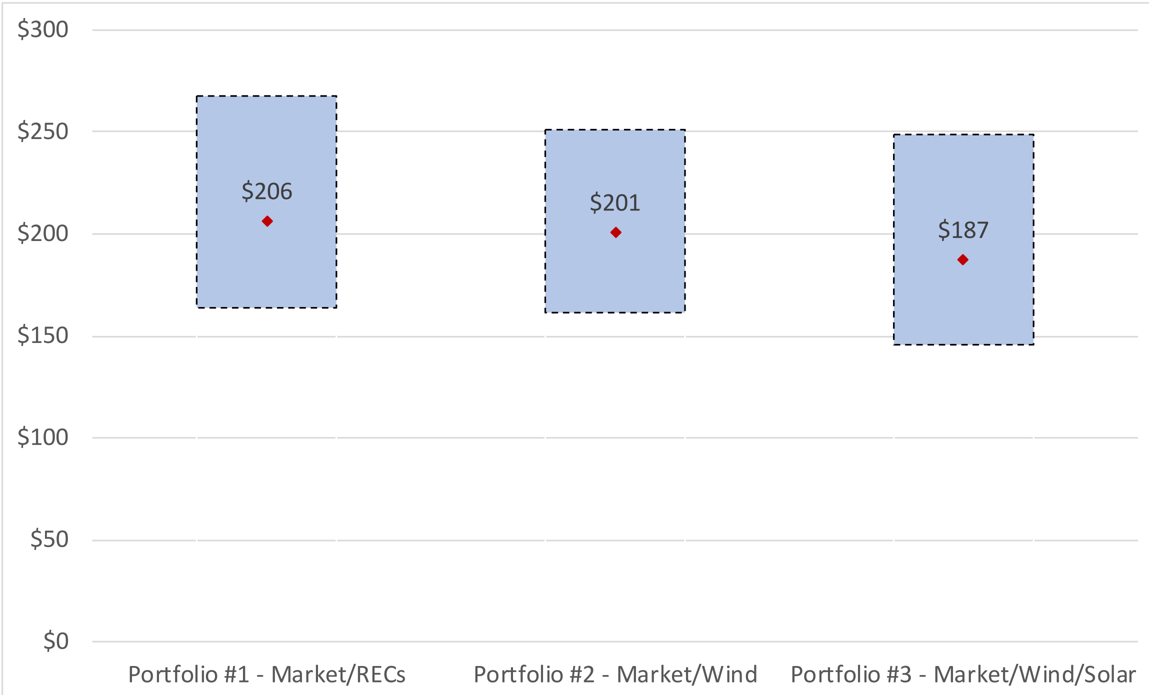


As shown above REC purchases (yellow area) are used to meet small REC deficits in Portfolio #3.

The cost of serving above-HWM load and meeting EIA renewable energy requirements was calculated for the three portfolios for the 20-year test period 2021-40. A sensitivity analysis was included to determine a range of costs associated with each portfolio.

For each portfolio, ES-15 shows the range of potential costs associated with new wholesale market, solar, wind and REC purchases required to serve above-HWM load and meet the EIA's renewable energy requirements.

Exhibit ES-15
2021-40 Market, Wind, Solar and REC Costs (millions)



Total costs under base case pricing assumptions are depicted by the red diamonds in Exhibit ES-15. As shown above, Portfolio #3 has the lowest costs. Portfolio #3 has the lowest costs because it includes east-side solar and, as shown above in Exhibit ES-6, the 20-year levelized east-side solar cost of $52/MWh is less expensive than the market ($60/MWh) and wind located in the Gorge ($75/MWh).

The bottom of the blue box shows costs using low cost assumptions while the top of the blue box shows costs using high cost assumptions. The Portfolio #2 and #3 low cost cases include higher capacity factors and lower capital, fixed O&M and RSS costs for wind and solar purchases. The Portfolio #2 and #3 high cost cases include lower capacity factors and higher capital, fixed O&M and RSS costs for wind and solar purchases The Portfolio #1 and #2 low and high cost cases include low and high wholesale market and REC prices, respectively, and the social cost of carbon. Low market prices are approximately 25 percent lower than base case market prices. High market prices are approximately 35 percent greater than base case market prices.

Recommendations

Below are specific recommendations based on observations made throughout this report.

BPA Tier 1 Power: RES should not take any actions that would result in decreases to the Tier 1 allocation rights in its current and future BPA power contracts. Although wholesale market prices are currently less than BPA Tier 1 rates, market prices are exposed to supply and price risks to which BPA power purchases, are not exposed. In addition, market prices are for flat blocks of power with no load shaping capability while BPA's load following product serves RES's hourly loads. As such, in order to properly compare market prices to BPA's rates the cost of load following would need to be added to the market price of power. In addition, BPA's resources are carbon-free and, under CETA, RES will need to be carbon neutral by 2030 and carbon-free by 2045.

Energy Efficiency: The cost-effective energy efficiency measures identified in RES's 2019 CPA, are the least expensive resources available to RES. Implementing these measures will reduce RES's above-HWM load which will reduce RES's market price risk exposure since above-HWM load is served by market purchases (renewable and non-renewable).

Renewable Energy Purchase Requirements: RES will be required to comply with renewable energy purchase requirements under the EIA beginning in 2026. RES is short renewable energy beginning in 2027. The lowest cost and lowest risk portfolio that complies with renewable energy purchase requirements is to purchase a combination of market, solar and wind power to serve above-HWM load and meet renewable energy requirements using the RECs associated with the solar and wind purchases. RES should work with NIES to identify a blend of market, solar and wind power purchases that can serve load and meet EIA requirements. Purchasing through NIES, rather than going it alone, should reduce costs due to economies of scale and administrative burden. The cost of renewable resources, RECs, and market prices should be monitored going forward to ensure that this remains the best strategy.

Local Resources: In order to diversify its resource portfolio, increase its self-sustainability and decrease its dependence on BPA transmission to serve load and reduce its wholesale transmission costs, RES should continue to promote local resource development, such as the HRSST, and consider pursuing state and federal grant money that would allow RES to accelerate local resource development. Potential local resources include small scale solar, cogeneration at wastewater treatment plants, and battery storage systems that complement small scale solar systems and provide backup in the event of a transmission contingency.

Demand Response: RES should gauge its customers' interest in participating in Demand Response programs. If enough customers are interested, RES should pursue the installation of Demand Response Units (DRUs) to help RES reduce its peak demands and, thus, its demand costs under the current BPA power contract.

Rooftop Solar: RES currently has over 200 customers with rooftop solar installations, with more than half of those installed over the past two years. Despite recent tariffs on imported solar panels, the cost of solar power is expected to continue to decrease. As an east-side utility, rooftop solar installations have relatively high capacity factors (compared to west-side utilities). The relatively high capacity factors and downward trajectory of solar costs will likely continue to make rooftop solar an attractive to RES customers. RES should consider taking steps to prepare itself for continued growth in rooftop solar installations so that RES can be in a better position to operate a truly “smart” and efficient grid. This would ultimately result in lower distribution system and power supply costs.

CETA Compliance: Beginning in 2022 as RES prepares to ramp up to carbon neutrality in 2030, RES should consider, offsetting the small amount of carbon included in its BPA purchases and a percentage of the carbon included in its non-federal purchases with REC purchases. RES should consider sourcing all of its non-federal purchases that are used to serve above-HWM load to carbon-free resources, such as hydro, by 2030.

Projected Load/Resource Balance

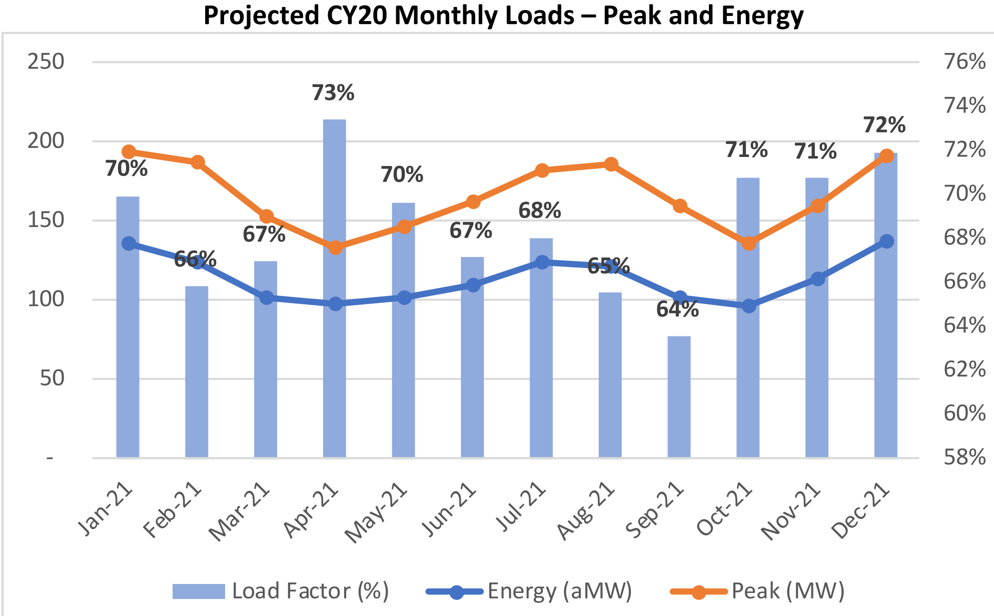
The objective of this study is to evaluate RES's existing resources to determine future net energy and capacity requirements. In addition, this analysis evaluates the costs and benefits associated with a variety of alternative resources that could be deployed to serve RES's projected above-High Water Mark (HWM) loads over the 20-year planning period 2021 to 2040.

EES Consulting has reviewed RES's projected loads and, based on RES's projected load/resource balance, assessed RES's future resource needs over the 20-year study period 2021-40. Projected loads provided by RES, as described below, will be used to assess RES's above-HWM loads and future resource needs.

Projected Load

Exhibit 1 below shows RES's projected total system monthly energy (power purchase requirements), peak demands (MW) and load factors for test first year of the 20-year test period (CY21). Projected purchased power requirements are based on the sum of forecast retail sales and distribution system losses. Projected monthly energy loads vary from lows of 96 and 97 aMW in September and April, respectively, to highs of 136 and 137 aMW in January and December, respectively. The projected load for the year is 113 aMW. Projected monthly peak demands vary from a low of 133 MW in April to a high of 194 MW in January.

Exhibit 1
Projected CY20 Monthly Loads – Peak and Energy

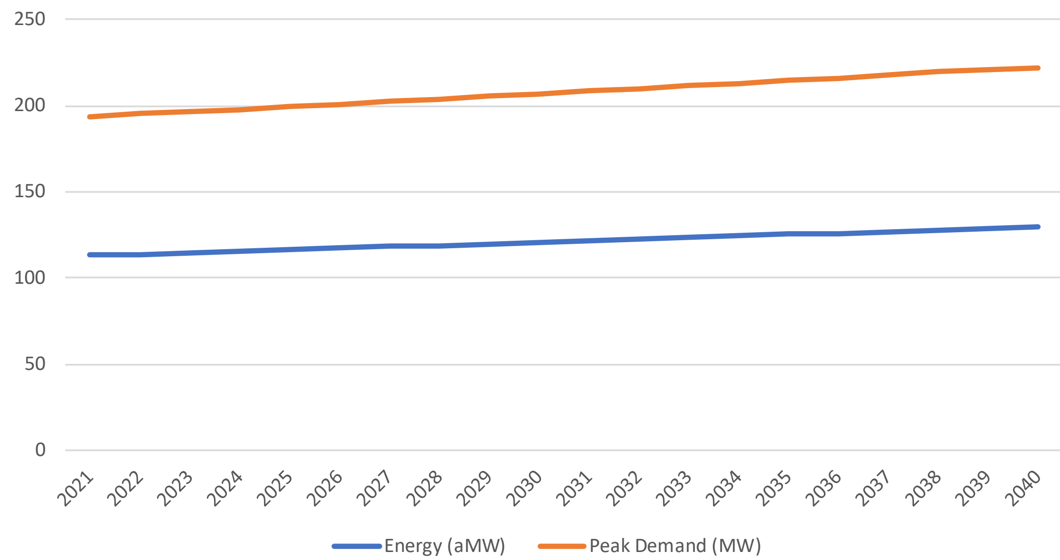


The load forecast provided by RES, which was prepared by BPA, only goes out through 2029. The average annual growth rate included in the load forecast is 0.7 percent. This growth rate was assumed to continue in 2030 through 2040. Some of the key assumptions for the base case forecast are provided below.

- No significant large customer additions
- Continue conservation acquisitions
- 0.7 percent load growth

Exhibit 2 shows total system annual energy (power purchase requirements) and peak demands for the 20-year study period 2021-40.

Exhibit 2
Projected Annual Loads – Peak Demand and Energy



As shown above, the study assumes that projected loads escalate at a steady rate through 2040.

Existing Resources

RES currently purchases 90 percent of its power requirements from BPA under a 20-year contract that expires in September 2028, 3 percent from BPA through a short-term Tier 2 product purchase that expires in September 2021, 7 percent from NIES through contracts that expire in September 2023 and 0.5 percent from the Horn Rapids Solar and Storage Training Project.

BPA markets electric energy from 29 federal hydroelectric projects in the Pacific Northwest, certain nuclear projects, and contractual purchases and exchanges to meet approximately 50 percent of the Pacific Northwest's energy requirement.

The rate structure included in BPA's current power contracts was developed through a formal proceeding known as the Tiered Rate Methodology (TRM). BPA's rates are tiered with market-based rates serving load growth above 2010 actual loads (the high-water mark or HWM). Under TRM, the sum of the Tier 1 allocations of all of BPA's customer utilities is roughly equal the capability of the Federal Based System (FBS) under critical water conditions. With this approach, each BPA customer effectively receives a share of output from the FBS for a 20-year contract period (expires September 30, 2028).

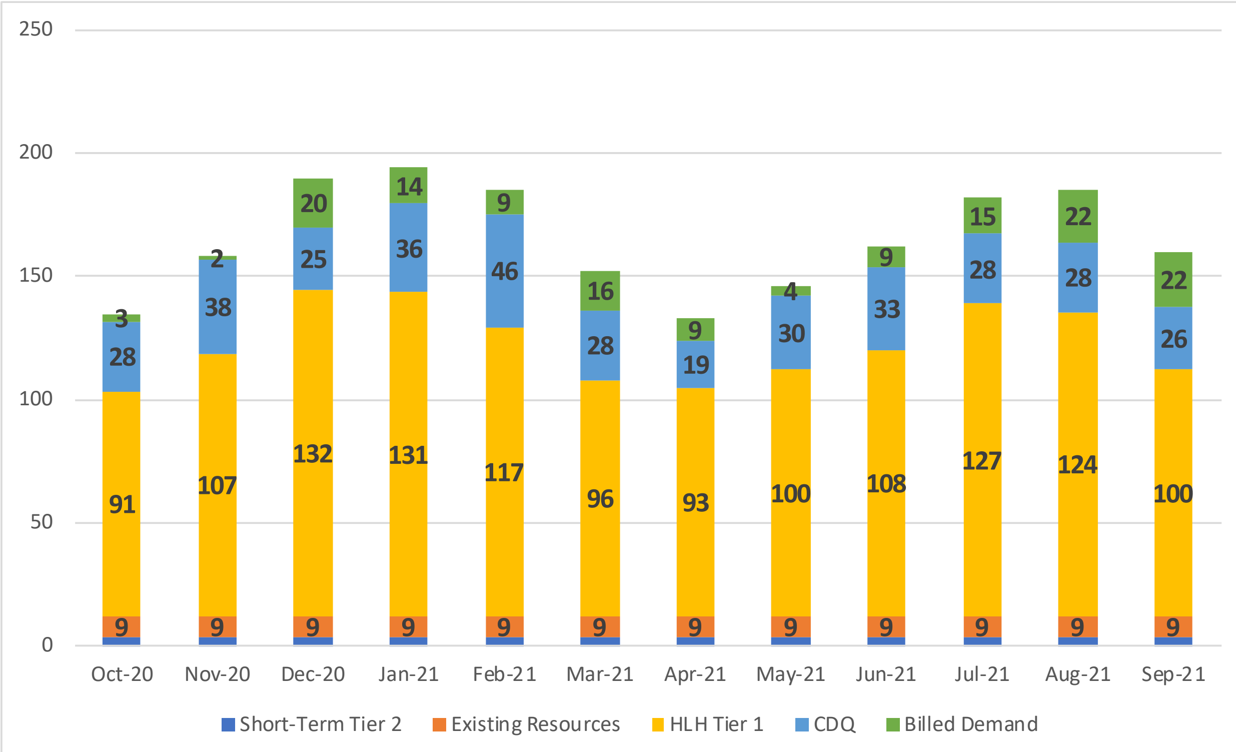
Under the current BPA power contract, RES's contract HWM (CHWM) is 105.4 aMW. RES's CHWM was established based on RES's historic loads and represents RES's maximum allocation of BPA Tier 1 system power. RES's rate period HWM (RHWM) for the current rate period (October 2019 through September 2021) is 103.3 aMW. RHWMs are established for each two-year rate period based on projected RES loads and projected BPA Tier 1 system capability. RES's BPA fiscal year loads are projected to be near 113 aMW, or 10 aMW greater than its RHWM during the current rate period. Under the current BPA contract, load growth above a utility's RHWM is served at market-based prices by either one of BPA's Tier 2 products or by a non-federal (i.e. non-BPA) resource. RES has committed to supplying any above-HWM load that may materialize prior to FY25 with non-federal purchases.

BPA's load following customers, including RES, are subject to BPA's load shaping rates. These rates apply when a utility's monthly load shape is different than the utility's monthly share of energy available from the FBS. Load shaping charges apply during months in which a utility's share of the FBS is less than a utility's power requirements. Load shaping credits apply during months in which a utility's power requirements are less than the utility's share of the FBS. Load shaping rates are based on BPA's projection of market prices at the time of the rate case. RES's projected CY21 power supply costs include net load shaping credits of approximately $790,000.

As a load following customer, RES currently purchases all of its peak demand requirements from BPA. The monthly billing determinants for BPA's demand product are calculated by taking RES's monthly system peak demand less RES's average on-peak energy consumption less RES's above HWM purchases and RES's Contract Demand Quantity (CDQ). The monthly CDQs are set for the contract period (through September 2028) and are based on historic load factors. RES's CDQs vary between a high of 46 megawatts and low of 19 megawatts. The average monthly demand billing determinant is projected to be near 12 megawatts in CY21.

Exhibit 3 shows an example of the calculation of BPA's demand billing determinant. The monthly peak demands shown below are based on the monthly demand forecast provided by EES and monthly load factors based on BPA's total retail load and customer system peak forecasts for RES.

Exhibit 3
Serving Projected BPA Fiscal Year 2021 Monthly Peak Demands (MW)



Note: Existing Resources include NIES purchase and HRSST.

BPA's monthly demand rates vary between a high of $12.10 per kilowatt and a low of $5.04 per kilowatt. Given the relatively high BPA demand rates reducing peak demands can result in fairly significant savings. If the demand billing determinant could be reduced by 1 megawatt in each month, RES's annual purchased power costs could be reduced by $120,000. As such, it is important to consider resources such as demand response units that can reduce RES's monthly peak demands.

BPA also owns and operates approximately 75 percent of the Pacific Northwest's high-voltage transmission system. BPA's transmission facilities interconnect with utilities in the Canadian province of British Columbia and with utilities in California. RES also purchases transmission and ancillary services from BPA under a Network or "NT" contract. BPA sets rates for transmission and ancillary services every other year through its rate case process. BPA's rates for each service are based on forecast sales and forecast costs associated with providing services.

As discussed below, RES's existing resource portfolio includes the Horn Rapids Solar, Storage and Training Project (HRSST) and a market purchase through Northwest Intergovernmental Energy Supply (NIES).

Northwest Intergovernmental Energy Supply

Northwest Intergovernmental Energy Supply (NIES) is a subsidiary of Northwest Requirements Utilities (NRU) which is a trade association that serves 53 member utilities. NRU's primary function is to participate in BPA rate cases and other BPA rate related activities including Integrated Program Review, Quarterly Business Review, Capital Planning and other arenas.

Through NIES, NRU, NRU facilitates members' purchases of non-federal resources to serve above-HWM loads. NIES members include 12 BPA customer utilities. The utilities include public utility districts and municipal utilities. NIES members decide, based on their above-HWM resource needs, whether or not they want to participate in market power purchases. The value of NIES is that it can purchase large quantities of power to be used to serve the loads of several utilities and does not have to purchase odd lots of power (generally defined as quantities less than 25 megawatts). This typically results in lower purchase prices compared to the purchase prices associated with purchasing smaller quantities of power to serve individual utilities relatively small above-HWM loads.

RES is currently purchasing an 8 MW flat block of power through NIES. The NIES purchase steps down to 6 MW in October 2021 and expires in October 2023.

Horn Rapids Solar, Storage and Training Project

The Horn Rapids Solar, Storage & Training Project (HRSST), located with RES's service territory, is a utility-scale solar and storage facility. The facility combines solar generation with battery storage and technician training. Construction began in February 2020 and is expected to be complete by the end of 2020. The project will include a 4 MW generating array of photovoltaic panels and a 1 MW battery storage system. The project will be interconnected to RES's distribution system and will provide enough energy to power 600 RES residential customers. Average annual generation from the project is projected to be 0.582 aMW. The capacity factor is expected to be 21 percent.

Potelco, a utility construction company based in Sumner, Washington is building the system. The solar portion of the project will be owned by Tucci Energy Services. Energy Northwest will own and operate the battery storage system. The battery system will smooth out the output from the solar, shift off-peak generation to times when the energy is needed, and help reduce peak energy demand. The battery system has the capability to store up to 4 hours or 4 MWh of energy. The project will serve as a training ground for solar and battery technicians throughout the nation.

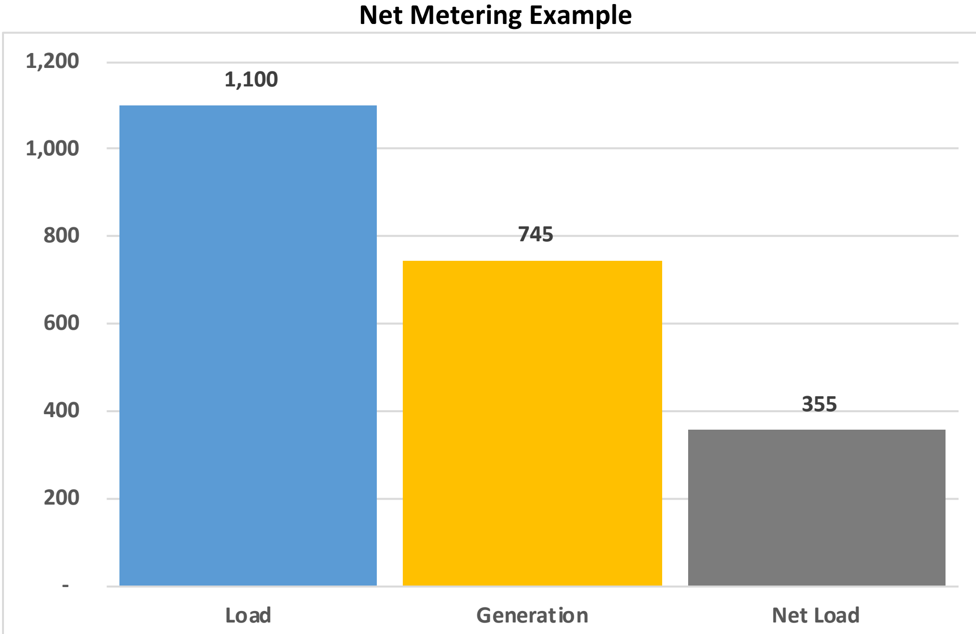
Distributed Generation

Distributed generation like the HRSST has several advantages over central-station generation, including enhanced localized reliability; improved efficiency due to avoided transmission losses;

and a partial hedge against changing future power costs. Most DG technologies are relatively new to the electric industry and rapid deployment of distributed generation can stress distribution system reliability. For example, the rapid growth of rooftop solar in some service territories has increased the total solar generation on some circuits to a level where the utility had to put a moratorium on the installation of additional rooftop solar installations until reliability issues could be addressed.

In net metering, the meter simply "runs backwards" when a homeowner's solar panel or other generation equipment is producing more electricity than the property is using, sending the excess energy back through the utility's distribution system lines to other energy consumers. An example of a typical net metering customer's monthly load (1,100 kWh/month), generation and net metered load is shown below in Exhibit 4. The example assumes a rooftop solar installation with a capacity of 6.8 kW and capacity factor of 15 percent at a residential home with 1,100 kWh of load.

Exhibit 4
Net Metering Example



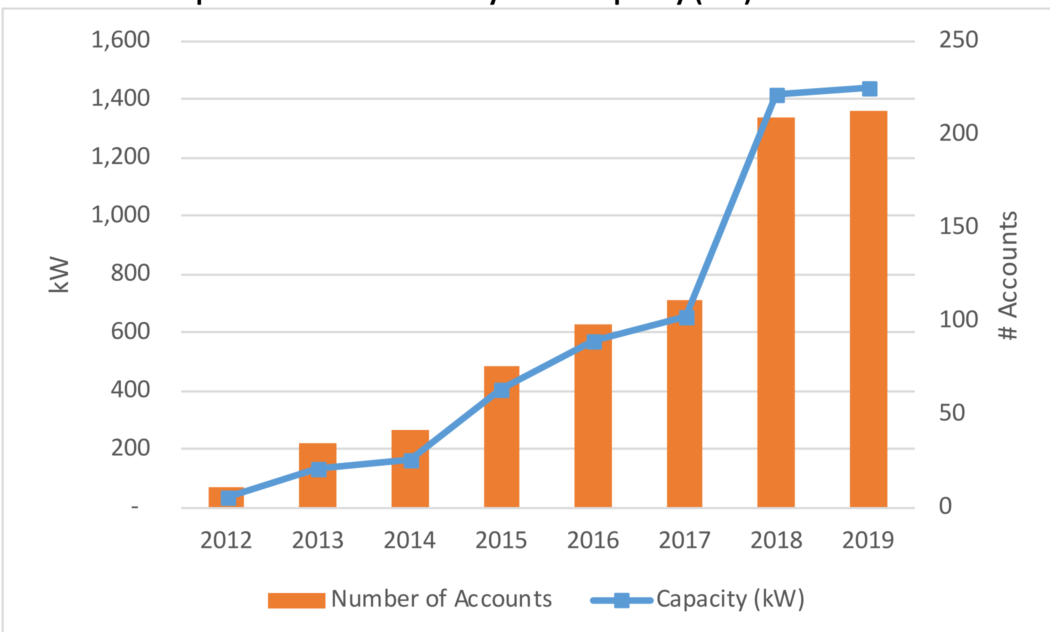
Net-metering rules vary by state. Some states limit the amount of surplus energy that can be rolled over from year to year, while others do not. Washington's net-metering law applies to systems up to 100 kilowatts of capacity that generate electricity using solar, wind, hydro, biogas from animal waste, or combined heat and power technologies (including fuel cells). All customer classes are eligible, and all utilities, including municipal utilities and electric cooperatives, must offer net metering. Under Washington State law, net metering is available on a first-come, first-served basis until the cumulative generating capacity of net-metered systems equals 4 percent of a utility's 1996 peak demand. Based on RES's 1996 peak demand, the cap on net metering for RES is 8,191 kW.

Net excess generation (NEG) is credited to the customer's next bill at the utility's retail rate. On April 30 of each calendar year, any remaining NEG is surrendered to the utility without compensation to the customer.

Exhibit 5 below shows cumulative installed solar capacity and customer counts for net-metering customers in RES's service territory. The biggest increases occurred in 2018 when 98 customers installed rooftop solar and added 763 kW of capacity to the system. As of August 2019, RES had 212 net metered customers with 1,440 kW of installed solar capacity.

Exhibit 5

Installed Rooftop in RES Service Territory: Solar Capacity (kW) and Number of Accounts

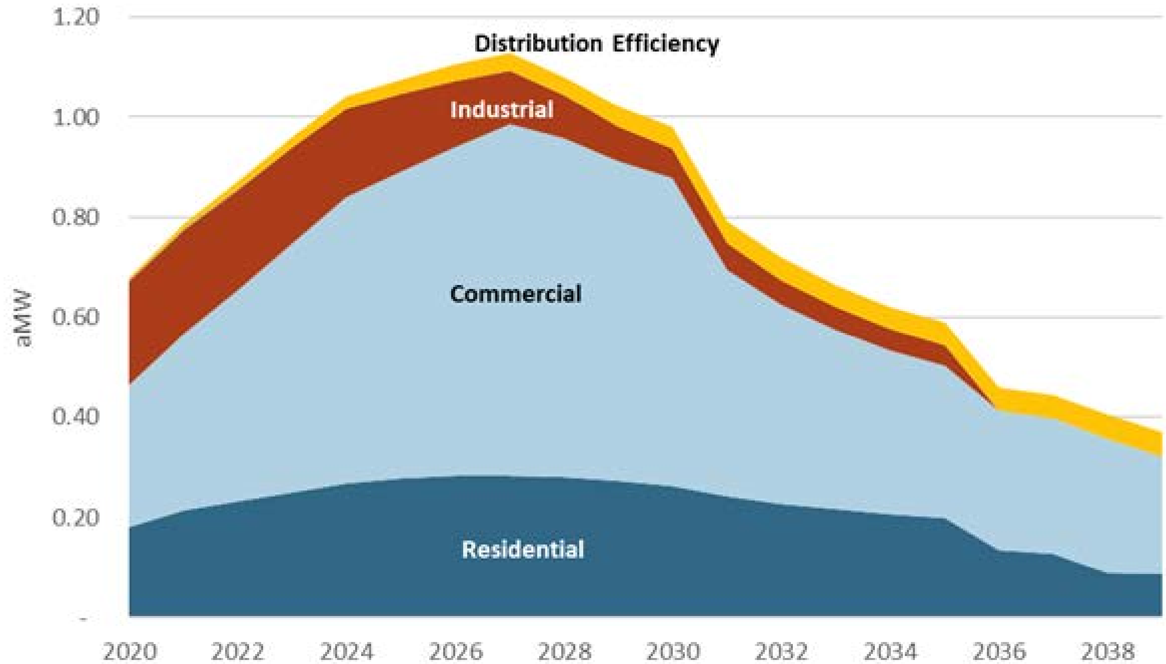


Source: RES

Load/Resource Balance

As discussed above, the load forecast includes a 0.7 percent annual load growth rate over the 20-year study period. The load forecast includes anticipated conservation achievements. According to the 2019 Conservation Potential Assessment (CPA) completed by EES Consulting, projected cumulative conservation acquisitions are approximately 138,320 MWh or 15.8 aMW over the 20-year study period. The CPA base case shows annual conservation acquisitions averaging near 6,800 MWh or 0.8 aMW across all sectors including residential, commercial, industrial, distribution efficiency and agriculture. Exhibit 6 below shows the base case annual cost-effective energy efficiency potential identified in the CPA by sector.

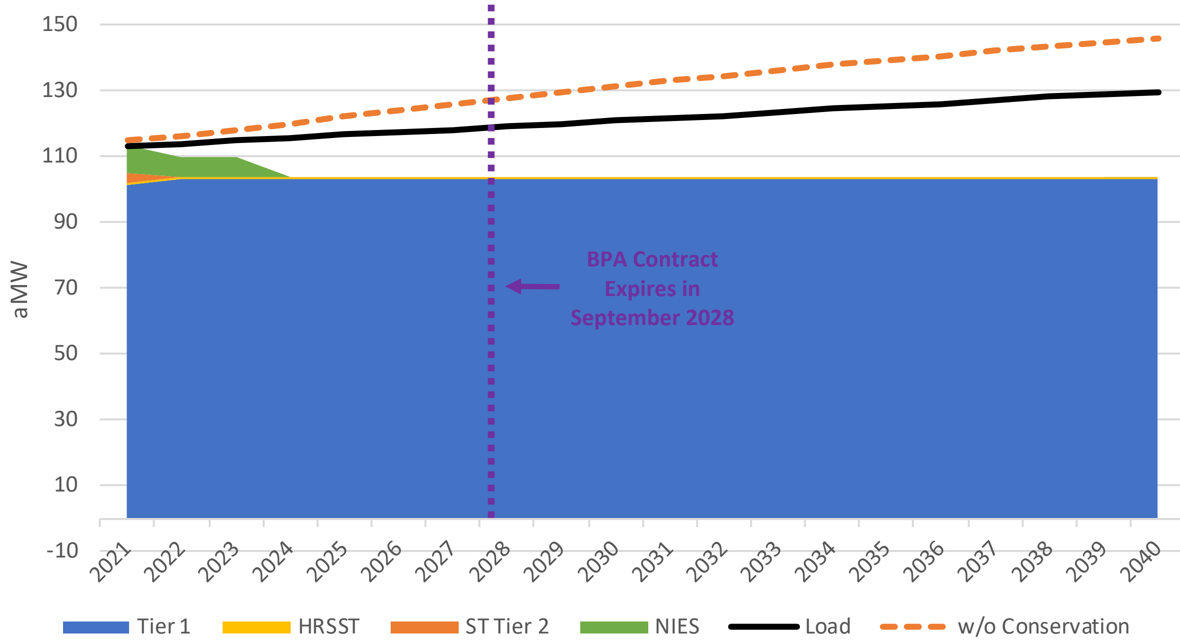
Exhibit 6
Base Case Annual Cost-Effective Energy Efficiency Potential (aMW)



Source: RES's 2019 Conservation Potential Assessment

Exhibit 7 below shows RES's load/resource balance including non-federal resources.

Exhibit 7
RES Load/Resource Balance



Note: Tier 1 purchases are set for the current rate period (through September 2028). Tier 1 purchases shown after 2028 assume RES's allocation of BPA Tier 1 power does not change in the next contract period. Projecte conservation achievements align with the annual achievements shown in Exhibit ES-2.

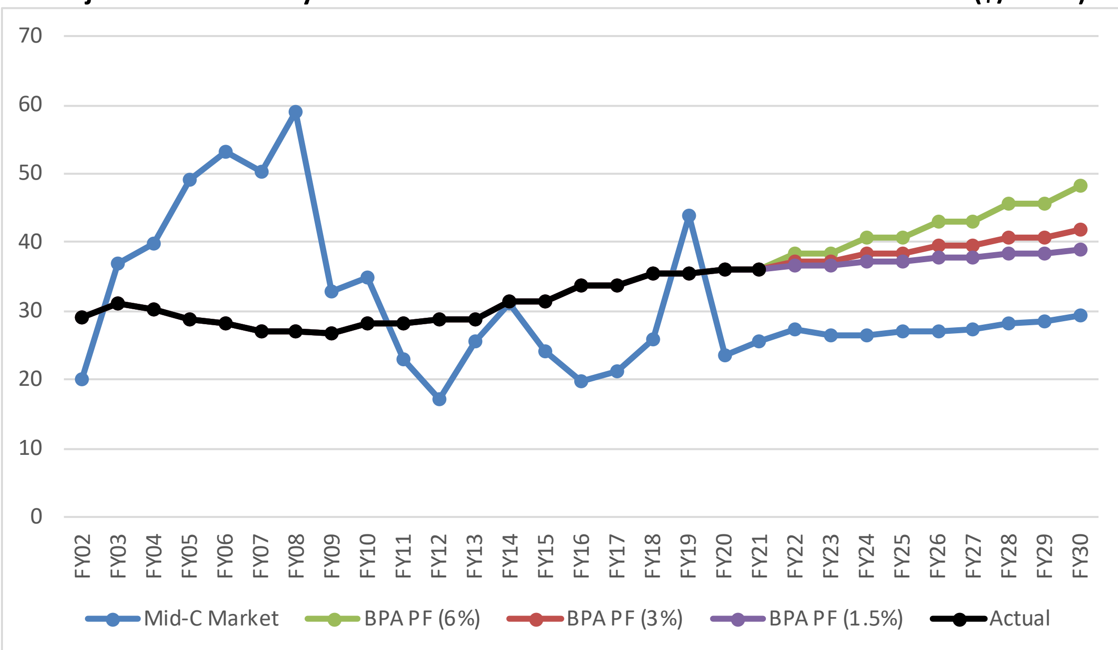
As shown above in Exhibit 7, RES is short on resources through 2040. On a short-term basis, RES can serve above-HWM load with market purchases through NIES or another entity.

Exhibit 7 shows that, absent RES's projected conservation achievements, which are per the 2019 CPA base case, RES's loads would increase at a much faster rate. Without conservation, RES's projected loads would increase by 31 aMW between 2021 and 2040 with an average annual load growth rate of 1.3 percent.

It is unknown whether the quantity of power and transmission currently provided by BPA under existing contracts will be available under new contracts that begin in October 2028. There is also uncertainty with respect to BPA's future power rates. BPA's rates continue to increase with each two-year rate period. Thanks to low natural gas prices and depressed loads, BPA's power rates are currently greater than wholesale market prices. Whether or not this trend will continue is unknown. Based on current projections of wholesale market and natural gas market prices it could be argued that BPA's rates will be above market for an extended period of time.

Exhibit 8 below shows projected wholesale market prices by BPA fiscal year compared to projected BPA rates with varying BPA rate increases. The average BPA rate increase under the current contract is near 5 percent. The rate increase in the most recent rate case was only 1.5 percent. BPA fiscal years run from October through September.

Exhibit 8
Projected BPA Priority Firm Rates and Forward Mid-Columbia Market Prices ($/MWh)



Forward market prices shown above are as of February 14, 2020. Market prices are dynamic.

Exhibit 8 extends out through BPA fiscal year 2030, which is three years after the current power contracts expire in 2028. Forward market prices change every hour and, as such, the forward prices shown above are simply a snapshot in time. Forward market prices have, for the most part, been lower than BPA's rates for more than a decade due, primarily, to the low cost of natural gas. As discussed above, forward wholesale market prices are for flat blocks of power across all hours, days and months of a year. BPA's load following product follows RES's loads across all hours, days and months. As such, Exhibit 8 does not show an apples to apples comparison. The estimated value of load following service is estimated to be between $5 to 7/MWh. In addition, BPA's power is almost entirely carbon-free. Carbon-free power will continue to have greater value in the wholesale market as states' carbon policies come into play.

Generating Resources

This section provides background information on the current status of a range of supply-side resource options. This includes some history as well as the latest information on commercially operational projects and demonstration projects in place, as well as research currently underway. The research surveyed available sources in the Western Electrical Coordinating Council (WECC) to determine potential future options available to RES.

As noted above RES currently purchases power from BPA as a load following customer under a 17-year contract that expires at the end of September 2028. Under the current BPA power contracts, total Tier 1 allocations are roughly equal to the capability of the FBS under critical water conditions. Power required to serve above-HWM load may be provided by owned resources or purchased from BPA through a Tier 2 product purchase or from alternative/non-federal suppliers.

BPA's Tier 2 products are priced at Tier 2 rates. BPA's Tier 2 rates are designed to recover the full costs of the generating resources and/or market purchases that will be used to serve Tier 2 loads. BPA offers utilities several Tier 2 power products and associated pricing. Tier 2 product choices include:

Short-Term Tier 2: Utilities commit to purchase power for two-year rate period. Rates are determined each rate period and reflect the cost of market purchases to serve short-term Tier 2 purchases.

Vintage Tier 2: Utilities make a long-term commitment to purchase the output from a specific generating resource. Rates are based on the projected costs of the resources.

Since BPA's Tier 2 short-term rates are based on market purchases made at market prices, Tier 2 short-term-rates should, on a planning basis, be considered to be equal to forecast market prices.

Supply-Side Resource Development Overview

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 the 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. As discussed above, 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.

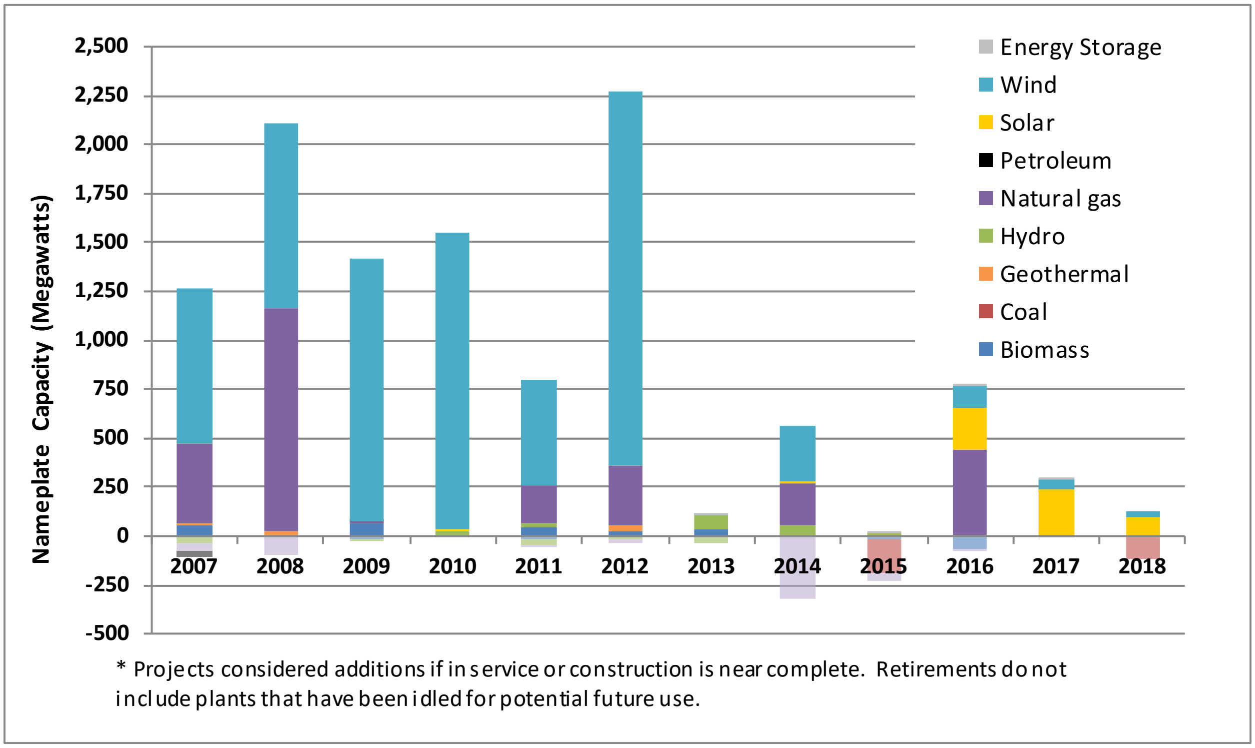
RES exceeded the 25,000-customer threshold in January 2020. As such, RES is required to comply with the EIA's renewable energy targets as follows:

- 3 percent of retail load must be served by renewables in 2026-29
- 9 percent of retail load must be served by renewables in 2030-33
- 15 percent of retail load must be served by renewables beginning in 2034

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 Exhibit 9, recent supply side resource development in the Northwest has primarily been limited to wind projects required to meet RPS requirements and natural gas plants. Exhibit 9 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.

Exhibit 9
Pacific Northwest Generation Additions and Retirements (MW)



Source: Northwest Power and Conservation Council (August 2018)

Supply-side resources can be divided into two categories – dispatchable and not dispatchable. 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. Exhibit 10 below shows a summary of supply-side resource characteristics.

Exhibit 10
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

*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 dispatch-ability 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.

Ownership versus Partnering

The costs associated with the various supply side resource alternatives included in this report are the same regardless of whether a utility chooses to purchase shares of the output of a generating resource via a power purchase agreement or to own the resource outright. There are advantages to both options. 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.
- 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 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:

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

There are opportunities for RES to participate in the acquisition of above-HWM load serving resources as it has done with power purchases made through NIES. The benefits of acquiring resources within a pool of utilities includes reduced costs due to economies of scale, diversified pool of alternative resources technologies that may not otherwise be available to an individual utility and access to information regarding potential new resource opportunities that may not otherwise be available. In addition, scheduling and purchasing power in increments of at least 25 megawatts can result in savings via economies of scale. Buying and selling power on the open market in relatively small pieces can be administratively burdensome and result in paying premiums for purchases and related services.

Generating Resource Costs and Characteristics

Estimated cost information for both fossil fuel-fired and renewable resources included in this report 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 are provided with and without the projected social cost of carbon.

Transmission costs are not included in the generating resource cost calculations included in this report. As a BPA network transmission customer, the cost of delivering resources to RES's points of delivery with BPA does not vary by location, with the exception of generation projects that are located within 75 circuit miles of a utilities' point of delivery. These resources qualify for BPA's Short Distance Discount (SDD). RES could potentially reduce its BPA transmission costs if it were to purchase a share of the output of a generating project that qualifies for the SDD. Wind projects such as the proposed Horse Heaven Hills wind project and the Nine Canyon wind project, phase 1 of which has been in commercial operation since 2002, both of which are within 75 miles of an RES point of delivery would qualify for the SDD. There is also the potential for more wind and solar projects as well as small scale modular reactors that would qualify for the SDD. The discount is based on average heavy load hour generation and, as such, base load resources, such as small-scale modular reactors, and resources that peak during heavy load hours, such as solar, would receive a larger credit than wind projects under BPA's current rate schedules.

Clean Energy Transformation Act

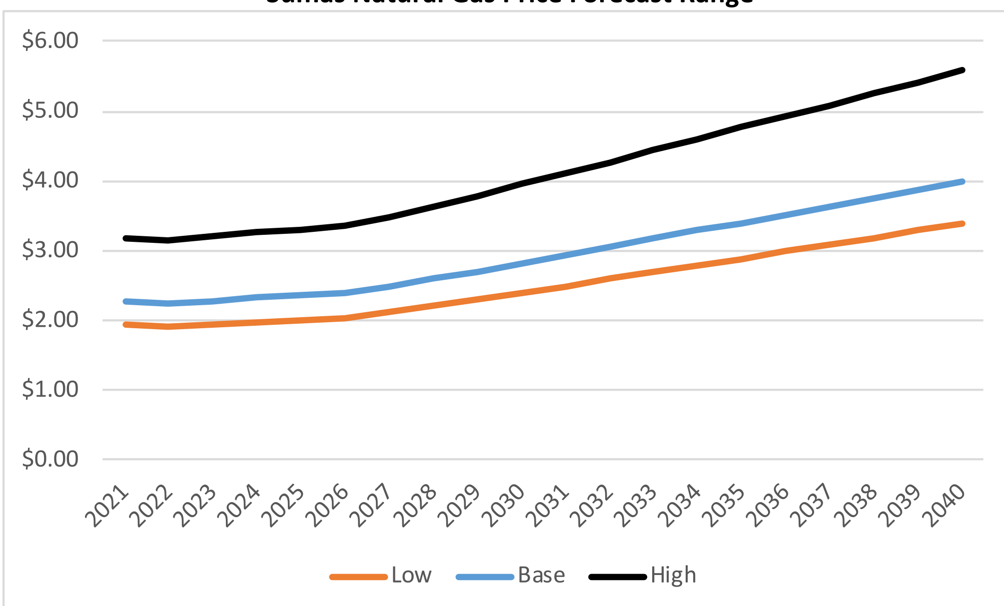
Washington passed the Clean Energy Transformation Act (CETA) in May 2019. CETA rulemaking is currently in progress and is scheduled to conclude at the end of calendar year 2020. Under the CETA all load in the state of Washington must be served by carbon-free resources by 2045. The CETA applies to all electric utilities serving retail customers in Washington and sets specific milestones to reach the required 100 percent carbon-free energy supply. The first milestone is in 2022, when each utility must prepare and publish a clean energy implementation plan with its own targets for energy efficiency and renewable energy.

Under the CETA, utilities must eliminate coal-fired electricity from their resource portfolios by 2025. RES's resource portfolio already meets this requirement. In 2030, all retail sales must be greenhouse gas neutral, although up to 20 percent can come from alternate compliance options such as purchasing RECs. As a BPA load following customer, RES's path to complying with the 2030 requirement is fairly straightforward. There is a small amount of market purchases included in RES's power purchases from BPA. If necessary, the small amount of carbon included in RES's BPA purchases can be offset with a small amount of REC purchases. In order to comply with CETA, beginning in 2030, RES will need to serve above-HWM load with market purchases sourced to carbon-free resources, such as hydro, or purchase RECs to complement market purchases from unspecified sources.

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. Exhibit 11 below shows the range of natural gas price forecasts for the Sumas delivery point.

Exhibit 11
Sumas Natural Gas Price Forecast Range



Source: S&P Global

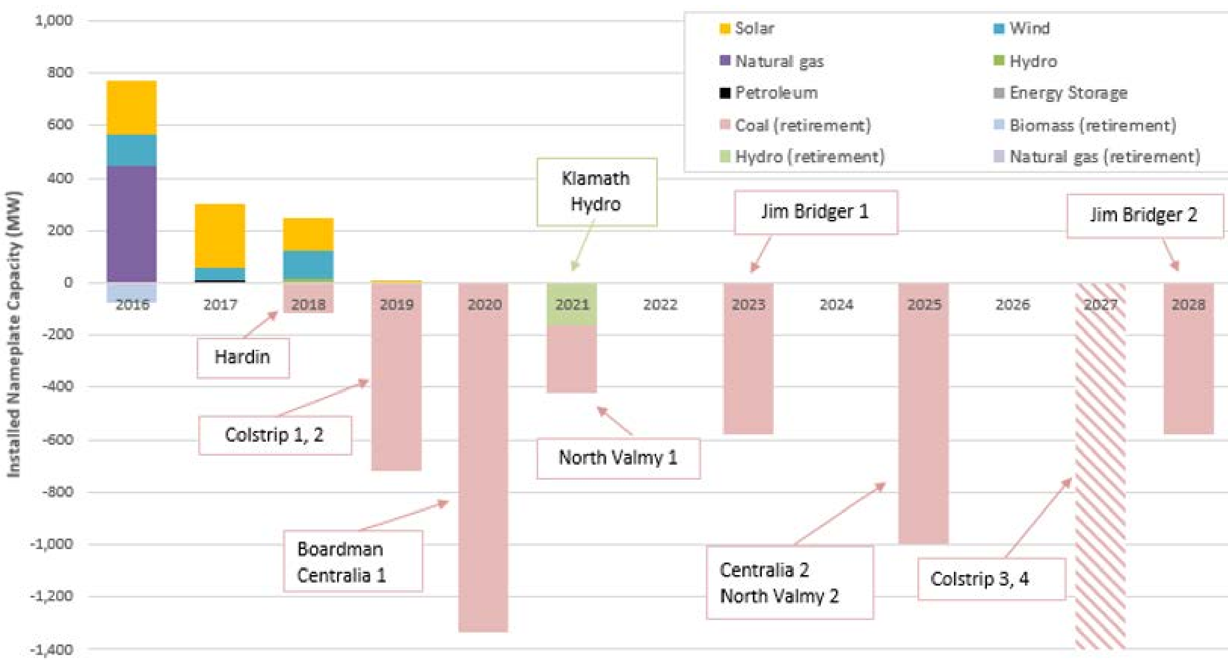
The high natural gas price forecast recognizes the possibility that demand may outstrip supply in the future due to limited supplies. The supply of natural gas could become limited if global economic growth accelerates and/or if the use of gas-fired resources as a 'bridge resources', used to provide 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 Exhibit 12.

Exhibit 12
Planned Resource Retirements



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 in which 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 600 megawatts. 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 to for commercial operation 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 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 $65/MWh.

Renewable Energy 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 competition for wind projects during the period 2006 through 2012. However, as shown in Exhibit 1 above, wind project development has slowed since 2012. 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 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 Exhibit 1. Currently there is 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 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 be 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 total generation and total load. 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 Exhibit 19.

Utility-Scale Solar

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.

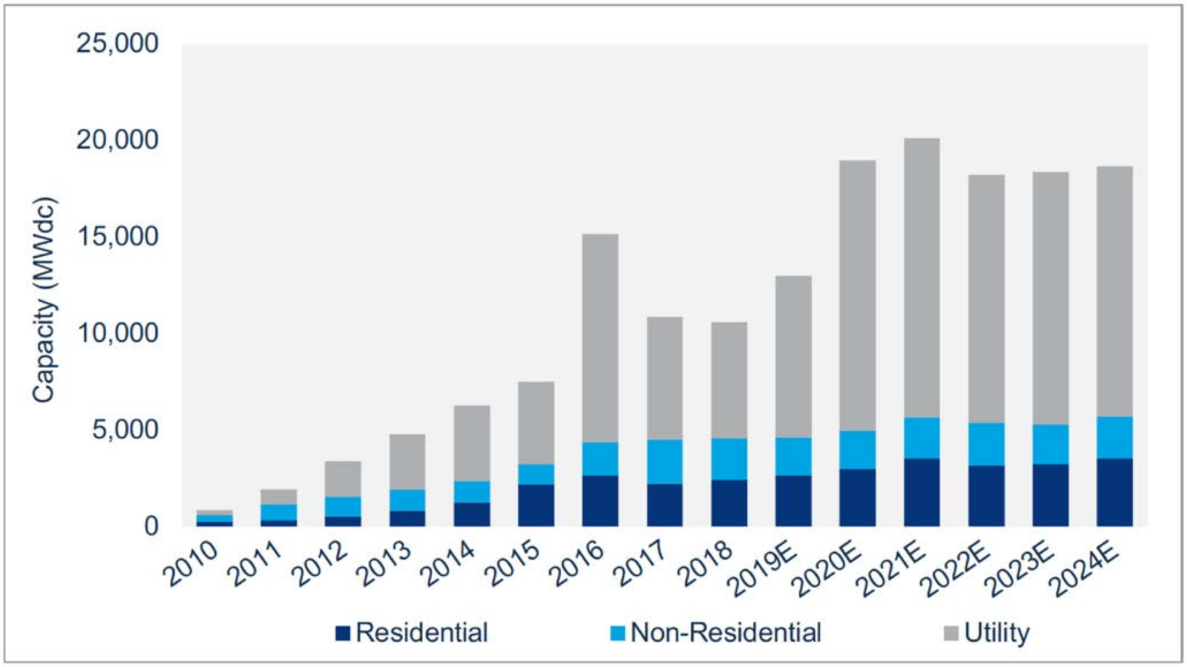
CSP technologies use reflective materials such as mirrors to concentrate the sun's energy and convert it to electricity. CSP technologies are more efficient (approximately 30 percent capacity factor) than PV and have the potential to be more cost-effective and practical than PV for centralized plants. 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. Exhibit 13 shows actual solar PV capacity installations in 2010 through 2018 and expected installations in 2019 through 2024.

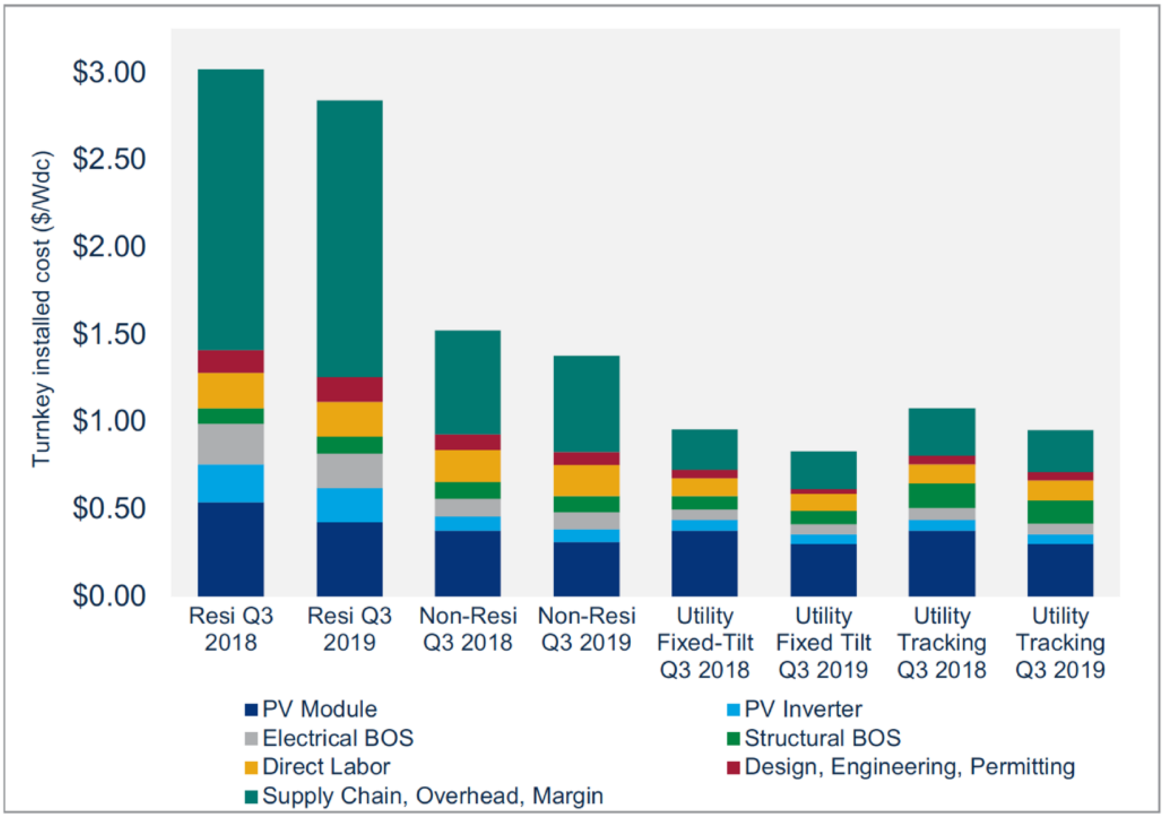
Exhibit 13
U.S. PV Installation Forecast (2010-2024)



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 Exhibit 14, the current cost of utility-scale solar PV is less than $1/watt.

Exhibit 14
U.S. Solar PV Average System Costs by Market Segment

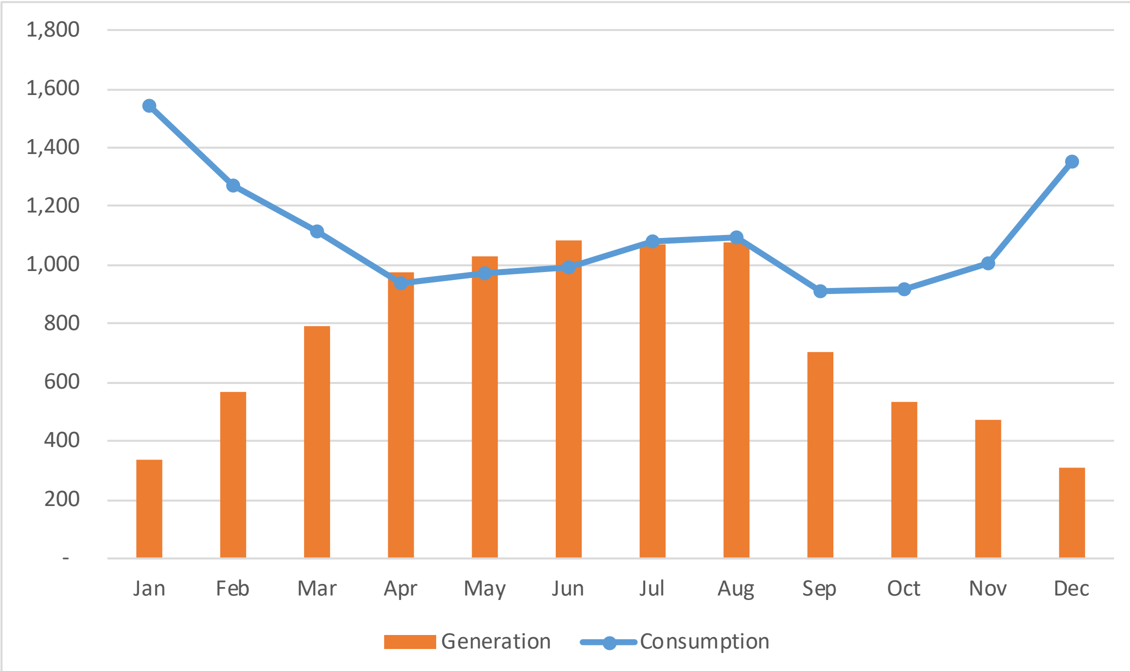


Source: Wood Mackenzie Power & Renewables

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. Exhibit 15 below demonstrates that solar generation is not an ideal match for RES's residential loads.

Exhibit 15
Typical Monthly Residential Rooftop Solar Generation and Load (kWh)



Note: Assumes average monthly residential load of 1,100 kWh, rooftop solar capacity of 6.8 kW and an average monthly capacity factor of 15 percent.

The blue line in Exhibit 15 above shows the typical seasonal load of a residential customer in RES's service territory compared to the typical output expected from a 6.8-kilowatt rooftop solar installation. As shown above, loads exceed solar generation during 7 months of the year and solar generation matches up well with loads during the other 5 months. Generally speaking, the seasonal shape of RES's residential load is the opposite of the seasonal shape of solar generation with peak loads in the winter and low solar generating potential in the winter. The same mismatch of load and generation shapes would apply to a utility scale solar (greater than 1 MW) located in RES's 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 Exhibit 19.

Geothermal

Geothermal projects, like wind and solar, have little or no carbon dioxide emissions. Unlike solar and wind projects, geothermal projects have relatively high capacity factors and can be used as base-load resources. The three types of geothermal power plants are:

- *Dry Steam Plants:* Steam directly from a geothermal reservoir is used to turn generator turbines.
- *Flash Steam Plants:* High pressure hot water is converted to steam to turn generator turbines. After cooling, the steam condenses to water and is injected back into the ground. Most geothermal plants are flash steam plants.
- *Binary Cycle Plants:* Heat from geothermal hot water is transferred to another liquid. Upon heating the second liquid is turned into steam that turns the generator turbines.

Current U.S. geothermal electric power production totals approximately 3,600 megawatts of installed capacity. The largest group of geothermal plants in the world is located in The Geysers, a geothermal field in California. The Geysers includes 22 geothermal power plants with a total capacity of 1,517 megawatts of installed capacity. The 13-megawatt Raft River project in southern Idaho became the first commercially operational geothermal project in the Northwest when it began operations in January 2008. The 28.5-megawatt Neal Hot Springs project in southeastern Oregon is the largest geothermal plant operating in the Northwest.

Potential geothermal resources in the Northwest include deep vertical faults in the Basin and Range geological province in southeastern Oregon and Southern Idaho and shallow magmatic intrusions associated with the volcanoes of the Cascade mountain range. Geothermal development in the Northwest has historically been constrained by high-risk, low-success exploration and well field confirmation. In addition, most of these locations are remote and would require significant transmission investments to facilitate transmitting the power to load centers.

The NWPCC considers geothermal to be an “emerging” technology and will not include geothermal in the 2021 Plan’s resource portfolios.

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.

Micro-Hydro

Micro hydro is a type of hydroelectric power that typically produces from 5 to 100 kilowatts of electricity using the flow of water. The amount of generation at a particular project depends on the projected hydraulic head and flow of the project. The higher each of these are, the greater the potential capacity. Hydraulic head is the pressure measurement of water falling in a pipe expressed as a function of the vertical distance the water descends. A drop in elevation of at least two feet is typically required. Flow is the projected amount of water that falls in the project and is usually measured in gallons per minute, cubic feet per second, or liters per second.

The majority of micro-hydro projects are simply smaller versions of hydro projects that include intake structures, penstocks and powerhouses. A few examples of micro-hydro projects are discussed below:

- *Fish Ladders:* Small generators that use the attraction water from fish ladders to turn small turbines are another example of micro-hydro projects. Permitting a micro-hydro project could be a lengthy process due to the potential environmental impacts. Utilizing the existing infrastructure of the fish ladders of an existing dam or pipe-fed water systems would allow utilities to significantly simplify the permitting process and, in many cases, increase the capacity factor of the generation.
- *Municipal Water Systems Technology #1:* There are a lot of aging municipal water system pipes that will need to be replaced in the near future. It makes sense to consider replacing some of the pipes with pipes that include micro turbines, especially for cities and utilities that have clean energy requirements. The two biggest benefits of utilizing existing water systems are that there is no environmental impact and the projects would have high capacity factors since they will be generating energy 24 hours a day. The water systems need to have a sufficient amount of gravity flow for these technologies to work. Conduit projects use a turbine to perform the function of a Pressure Reducing Valve (PRV). As with a PRV, a hydropower turbine reduces pressure. Instead of dissipating excess energy like a PRV, however, the turbine converts the energy to usable power. Canyon Power has developed a project in Logan, Utah that uses this technology.
- *Municipal Water Systems Technology #2:* Lucid Energy has designed a hydroelectric system in which energy is generated as water flows through turbines integrated into municipal water pipes. Lucid Energy's system puts four small turbines in a section of pipe upstream from the PRV. The PRV still operates downstream from the turbines. The lifespan of the PRV is extended because the turbines remove quite a bit of the pressure. The city of Riverside, CA uses this technology to power water system operations during the day and streetlights at night. In Portland, Oregon, the power generated by the project is sold under a 20-year contract to Portland General Electric. The Portland Water Bureau will own the system after

20 years. The system generates 900 MWh per year or enough to power 100 homes. Lucid Energy's website says the cost of power is between 5 and 12 cents/kWh.

If RES and the City of Richland are interested in examining the potential for siting distributed generation using the municipal water system the first step would be to do an analysis of the gravity flow (aka head pressure) to determine if this technology is an option.

Biomass Energy Overview

Biomass is made up mainly of the elements carbon and hydrogen. Several technologies can be employed to free the energy bound up in these chemical compounds. Biomass fuels include the following:

- Forest residue: log slash and forest thinning
- Paper mill residue: wood chips, shavings, sander dust and other wood waste
- Pulp chemical recovery: spent pulping liquor used in chemical pulping of wood
- Agricultural crop residues: obtained after harvesting cycle of commodity crops
- Energy crops: grown specifically for use as feedstocks in energy generation processes including hybrid poplar, hybrid willow and switchgrass
- Animal waste: combustible gas obtained by anaerobic decomposition of animal manure
- Municipal solid waste: organic component of municipal solid waste
- Landfill gas/wastewater treatment: combustible gas obtained by anaerobic decomposition of organic matter in landfills and wastewater treatment plants

Four biomass energy technologies are discussed in detail below.

Landfill Gas Projects

Landfill gas consists mainly of methane and carbon dioxide and is produced when organic wastes in landfill sites decay. Landfill gas must be burned or flared in order to reduce the hazards associated with a large buildup of gas. Instead of being released directly into the atmosphere where it is a potent GHG, the methane can be used as fuel to power a turbine. For this reason, landfill gas generation is hailed for its potential reductions to GHG. It is estimated that methane has 21 times the greenhouse warming potential of carbon dioxide. Landfill gas generation is also popular for reducing regional and local pollution. RES should consider whether there is any potential for participating in a landfill gas project in the Tri-Cities area.

Anaerobic Digesters (Farm Manure)

Animal waste management is a critical factor in protecting water quality. Anaerobic digestion is one method of handling manure that is likely to become more prevalent due to standards that require large (700 cows or more) dairy operations to obtain discharge permits. The permits require that an approved method of managing manure be included in dairies' practices. The Environmental Protection Agency favors anaerobic digestion for managing manure. Manure is fed into a tank in which methanogen bacteria breakdown volatile solids into methane gas and carbon dioxide. The gas can be used by reciprocating engines to produce electricity. This method of generating power falls under the “biomass” categorization and qualifies as an eligible renewable resource under Washington’s RPS rules. The on-going costs and logistical challenges associated with acquiring, transporting and handling biomass fuels are relatively high.

Animal wastes contain large quantities of nitrogen, phosphorous, potassium, and bacteria. If not properly managed, these wastes can enter surface water and cause eutrophication (excessive richness of nutrients in a lake or other body of water, frequently due to runoff from the land, which causes a dense growth of plant life and death of animal life from lack of oxygen).

The Department of Ecology assumes the primary enforcement role to ensure that agricultural operations do not degrade water quality. Farm owners are encouraged to work with the Natural Resources Conservation Service and the local Conservation District to develop and implement farm plans and Best Management Practices (BMPs) to protect water quality. Collecting and transporting manure to a generating facility would help farmers adhere to BMPs and reduce their risk of being fined by the Department of Ecology. This could ultimately reduce farmers’ overall compliance costs. A project would also protect water quality and provide local renewable generation.

<u>Wastewater Treatment Plants</u>

Water resource recovery facilities, traditionally known as wastewater treatment plants, are uniquely positioned to be leaders in on-site renewable energy generation and energy conservation. Treatment facilities are very energy intensive. On-site cogeneration engines can be fueled by two fuels: biogas produced from the anaerobic digestion of wastewater sludge and biogas produced from the co-digestion of fats, oils and grease (“FOG”). The cogeneration also provides heat to the treatment plant.

An initial investment in a FOG receiving and processing facility must be made in order to access a second source of biogas. However, a FOG station can also have profound operation and maintenance benefits. Diverting fats, oils and grease at their source (e.g. restaurants and food processors) before they get flushed into the wastewater collection system avoids significant collection system cleanout costs. The tipping fees FOG haulers pay to the county could result in a new revenue stream.

When combined with energy efficiency investments and on-site solar generation, the facilities can be managed to achieve net-zero energy demand. Net-zero energy consumption is the goal of a wastewater treatment plant in Gresham, Oregon. The Gresham facility is generating power using two 395-kilowatt co-generation engines fueled by biogas, including biogas from a FOG facility, and a 420-kilowatt solar system. The generation systems combined with energy efficiency investments will result in net-zero energy consumption for the facility. The facility is also generating RECs that are sold to the local utility which will use them to comply with state RPS requirements. The Energy Trust of Oregon provided assistance and funds to lower the facility's energy efficiency and reduce generation costs.

The potential for installing biogas-fueled generation at any of the wastewater treatment facilities located in RES's service territory should be explored.

Biomass-Woody Debris

Direct combustion (the burning of material by direct heat) is the simplest method of capturing the stored chemical energy in biomass. Biomass generating projects fueled by woody debris typically burn forest waste. Cogeneration, sometimes referred to as combined heat and power, is the joint production of electricity and useful thermal or mechanical energy. The heat generated by burning woody debris is typically sold to a manufacturing process, a greenhouse or another industrial application that has a use for thermal energy. The electricity generated by a biomass-woody debris project is typically sold to the local utility.

Generating projects can be relatively small (e.g. 1 to 2 megawatts). RES's current BPA power contract allows "behind the meter" resources of up to 1 megawatt. "Behind-the-meter" resources essentially reduce utilities' net loads on BPA.

Biomass generation fueled by woody-debris is dispatch-able and can be ramped up and down to follow daily load fluctuations. The ability to dispatch generation could allow RES to reduce its peak loads and its wholesale power costs.

There are some concerns that woody biomass generation can result in increased greenhouse gas emissions. However, the EPA has stated that the impact is likely that there are minimal to no net atmospheric contributions of biogenic CO_2 emissions. Biomass generation could even reduce impacts compared to an alternate fate of disposal.

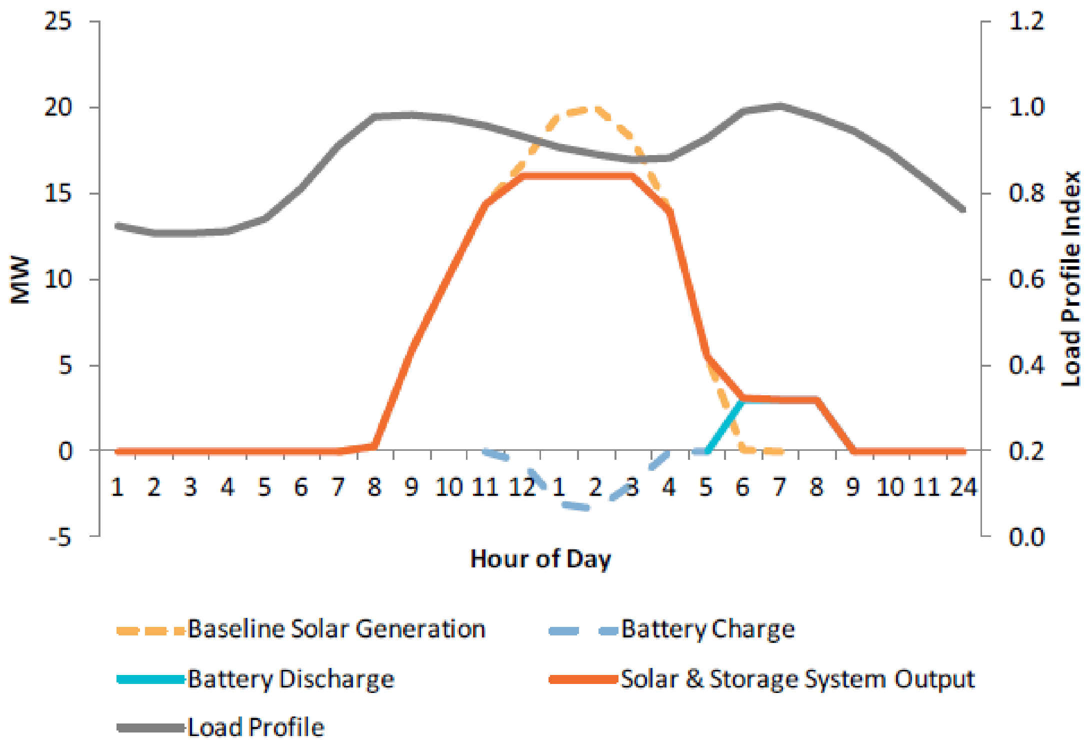
Battery Storage Systems

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. Exhibit 16 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.

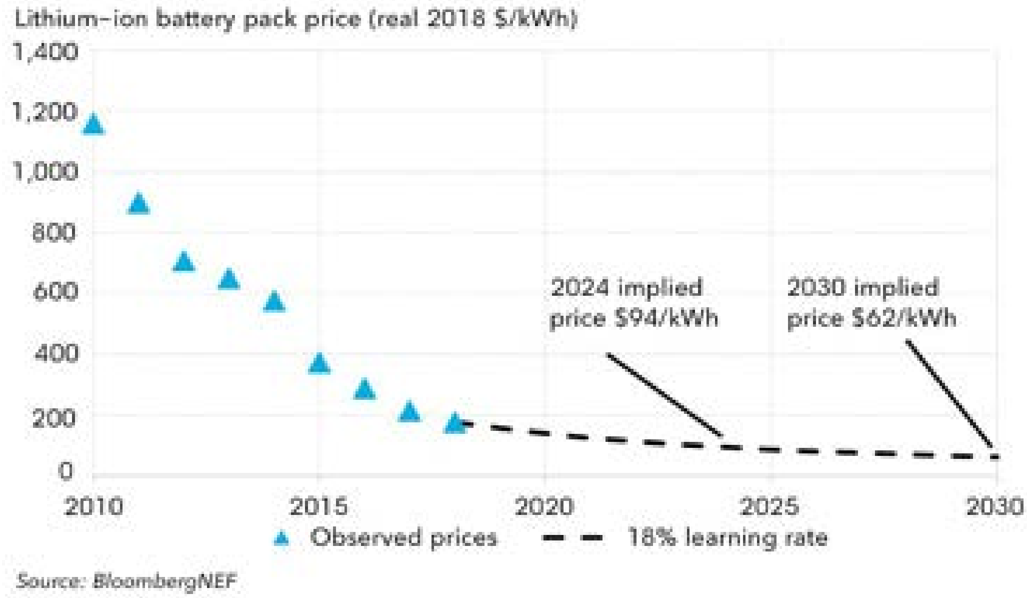
Exhibit 16
Example of Utility Scale Solar PV and Battery Storage System



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

Exhibit 17 shows the decrease in lithium-ion battery prices since 2010 and the expected decrease in costs down to $62/MWh in 2030.

Exhibit 17
Lithium-ion Battery Price Outlook (Utility Scale Projects)



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 Exhibit 17, 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 Council includes reference cases for both a 100

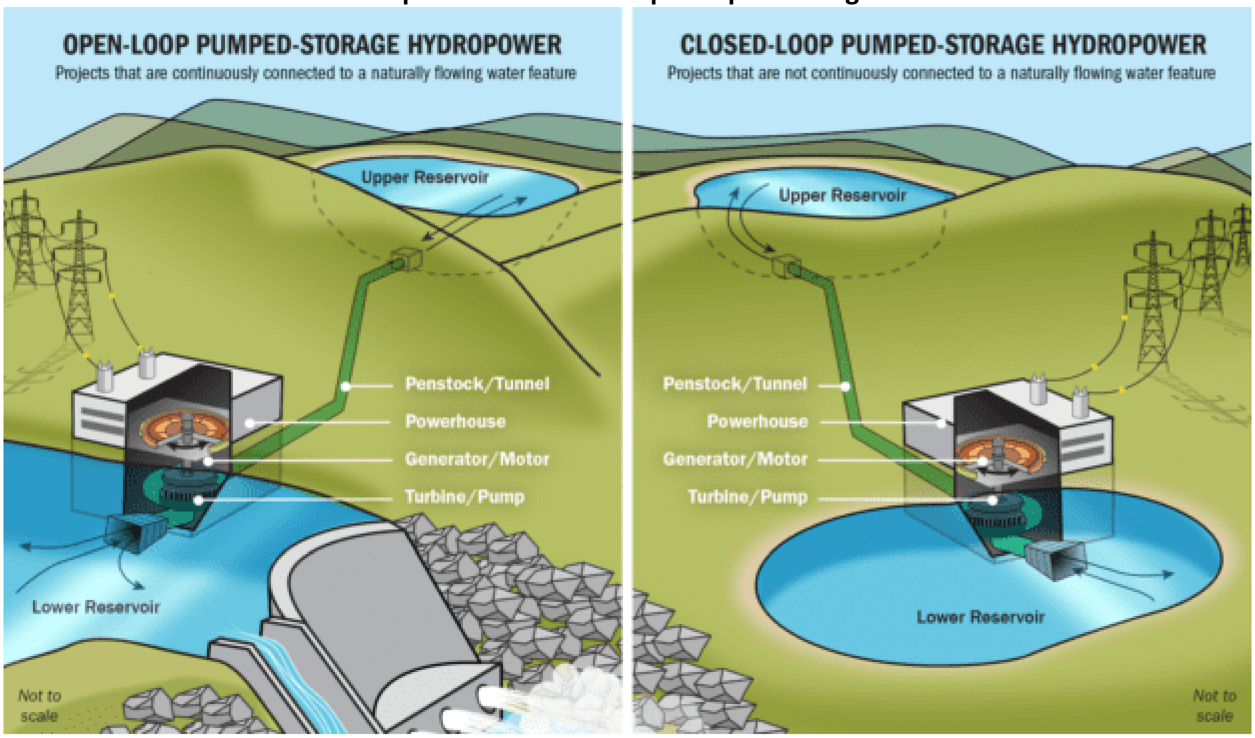
MW solar project and 100 MW solar with a battery with 4-hour discharge capability of 400 MWh. The capital costs are 90 percent greater in the solar plus battery case ($1,350/kW compared to $2,568/kW) while the fixed O&M costs are more than double ($14.55/kW-year compared to $31/kW-year).

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. Generally, however, 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. Exhibit 18 below shows a depiction of closed- and open-looped pumped storage power plants.

Exhibit 18
Mechanics of Open- and Closed-Loop Pumped Storage Power Plants



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 million or $2,880/kW million. 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 council'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

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

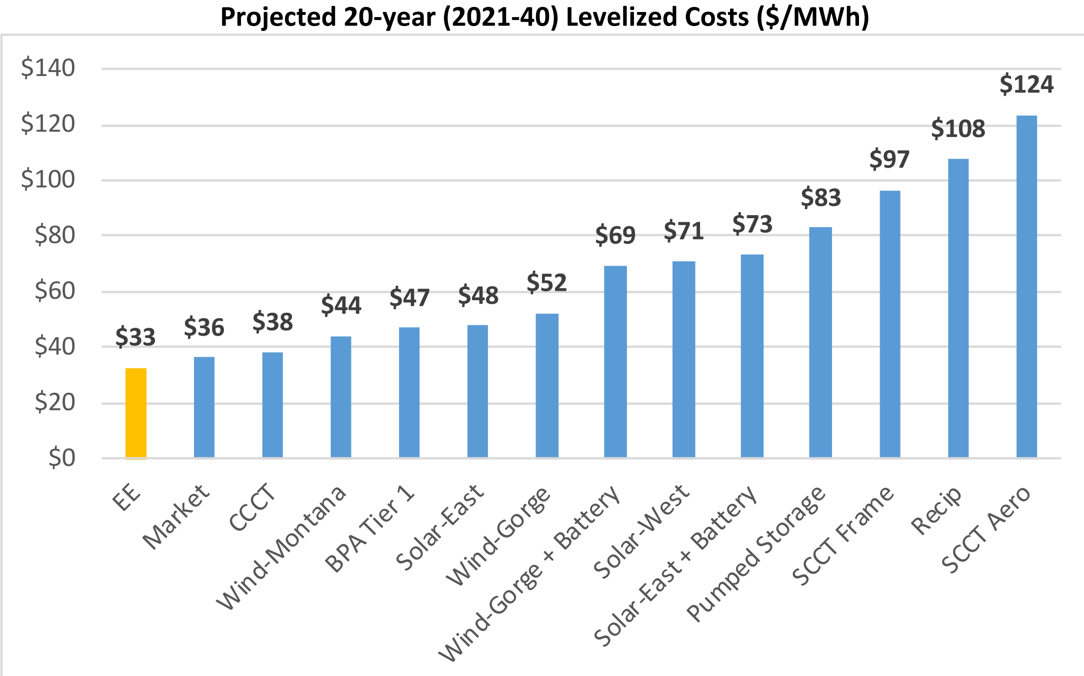
20-Year (2017-36) Levelized Costs

Exhibit 19 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.

Exhibit 19 Supply-Side Resource Characteristics							
	Capital Cost ($/kW)	Fixed O&M ($/kW)	Variable O&M ($/MWh	Capacity (MW)	Capacity Factor	Heat Rate (Btu/kWh)	Heat Rate (Btu/kWh)
Natural Gas – CCCT	$1,140	$11.38	$2.11	383.30	75%	6,550	6,550
Natural Gas Peaker – SCCT	$657	$3.06	$5.15	235.05	10%	9,793	9,793
Natural Gas Peaker – Recip	$1,247	$6.98	$4.25	77.25	15%	8,350	8,350
Natural Gas Peaker – Aero	$1,154	$6.57	$2.67	96.00	12%	8,930	8,930
Wind - Gorge	$1,699	$39.85	$0.00	100.00	37%	NA	NA
Wind - Montana	$1,648	$39.85	$0.00	150.00	43%	NA	NA
Wind + Battery	$1,994	$69.16	$0.00	25.00	37%	NA	NA
Solar – Westside	$1,527	$31.00	$0.00	50.00	22%	NA	NA
Solar - Eastside	$1,527	$31.00	$0.00	50.00	33%	NA	NA
Solar – Eastside + Battery	$2,431	$42.50	$0.00	17.50	33%	NA	NA
Pumped Storage	$2,480	$11.31	$0.37	400.00	27%	NA	NA

Exhibit 20 below shows the nominal levelized costs of the resources discussed above. The 20-year levelized cost of energy efficiency is per RES's 2019 CPA. The BPA Tier 1 rate assume 3 percent BPA rate increases every other year (every rate case).

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



Source: Utility IRPs, NW Power Council Data and RES Conservation Potential Assessment.

Exhibit 20 shows that energy efficiency and the wholesale market are the lowest cost resources followed by utility scale wind located in Montana, a combined cycle combustion turbine, utility scale solar located on the east side of the Cascade Mountains and BPA Tier 1 rates. The Production Tax Credit (PTC), which is applicable to wind projects at a reduced credit of 60 percent, expires at the end of 2020. Wind project costs are shown above without the PTC. The Investment Tax Credit (ITC), which is applicable to solar projects, is 30 percent in 2019, but steps down to 26 percent in 2020, 22 percent in 2021 and 10 percent in 2022 where it will remain. Solar project costs are shown above include a 10 percent ITC.

<u>Social Cost of Carbon</u>

The Clean Energy Transformation Act requires utilities to include the social cost of greenhouse gas emissions in resource evaluation, planning and acquisition [RCW 19.280.030(3)]. The Washington State Department of Commerce has determined that customer-owned utilities should use the same cost values that the legislature has enacted for investor-owned utilities which establishes a specific set of cost values developed by a federal interagency working group in 2016. Inflation factors will escalate costs to the base years used in IRPs. Based on the methodology established by the working group, the projected social cost of carbon used in this analysis includes the following assumptions:

- 2021 cost of carbon (per metric tons): $76.5/metric ton
- 2021 cost of carbon (per MMBtu): $4.06/MMBtu, assuming 53 kilograms of CO_2 per MMBtu

The projected social cost of carbon impacts the resources shown above in Exhibit ES-5 differently, based on the resources' carbon content, which is determined by their heat rate in Btu/kWh. Including the social cost of carbon increases the 20-year levelized costs of the following resources included in Exhibit ES-5:

- Market: $23/MWh based on an assumed market heat rate of 7,195 Btu/kWh in August-March when gas-fired resources are the marginal resource; 0 Btu/kWh during spring/summer runoff season when hydro or wind serve as marginal resource
- CCCT: $32/MWh based on an assumed heat rate of 6,550 Btu/kWh
- Reciprocating Engine: $39/MWh based on an assumed heat rate of 8,350 Btu/kWh
- SCCT Aero: $42/MWh based on an assumed heat rate of 8,930 Btu/kWh
- SCCT Frame: $46/MWh based on an assumed heat rate of 9,773 Btu/kWh

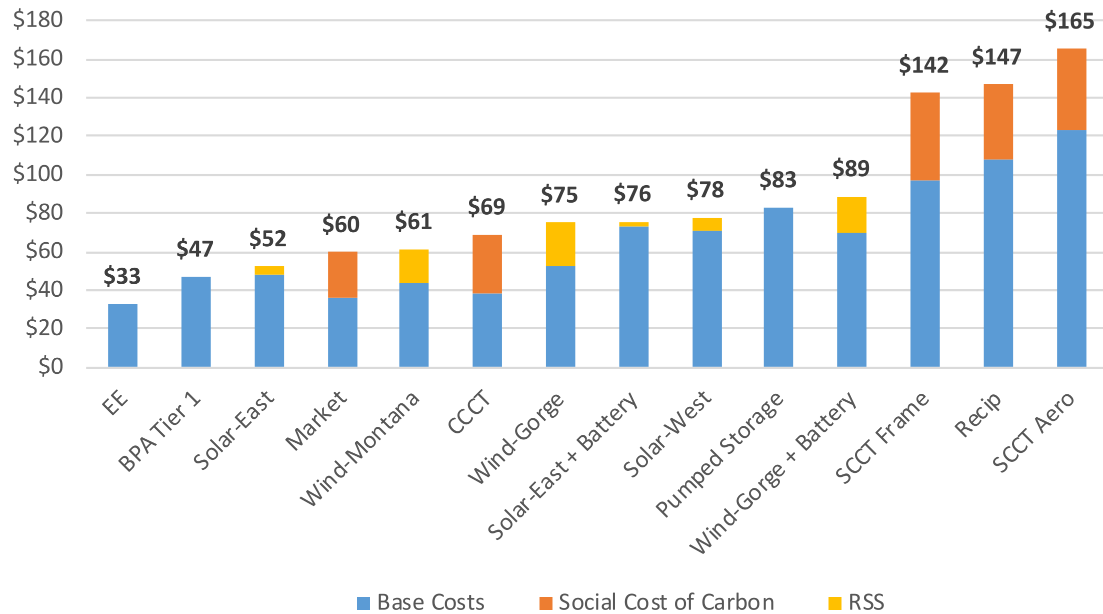
<u>Resource Support Services</u>

Due to the intermittency of wind and the unpredictability of the output, the amount of hourly generation is uncertain. 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. BPA uses the capacity and flexibility of its resource pool to provide wind integration services to its customer utilities through a product known as Resource Support Services (RSS).

Under the current BPA power contract, above-HWM load must be served with flat resources. BPA's RSS products flatten intermittent renewable generation across hours, days and seasons, resulting in flat blocks of power. Since solar generation is also not flat across all hours RSS products are also used to flatten utilities' solar power purchases. RSS prices are resource specific since wind and solar resources have different capabilities primarily based on their capacity factors. Based on RSS prices currently offered by BPA an RSS of $20/MWh is assumed for wind projects located in the Gorge, $15/MWh for Montana wind, $5/MWh for solar projects located on the west-side of the Cascades and $3.5/MWh for solar project on the east side.

Exhibit 21 below shows the nominal levelized costs of the supply-side resources including the projected social cost of carbon and RSS.

Exhibit 21
Projected 20-year (2021-40) Levelized Costs including Social Cost of Carbon and RSS ($/MWh)



As shown above when the social cost of carbon is included in the analysis the cost of a CCCT falls from being the 3rd lowest cost resource to the 6th lowest cost resource and the market falls from 2nd to 4th.

Resource Portfolios

Resource plans evaluate potential future resources in areas of reliability, cost, risk and environmental impact. The preferred resource strategy is one that provides the best combination of cost and risk while meeting reliability and environmental needs. Resource planning considers demand-side resources on an equal basis with supply-side resources by comparing 20-year levelized costs.

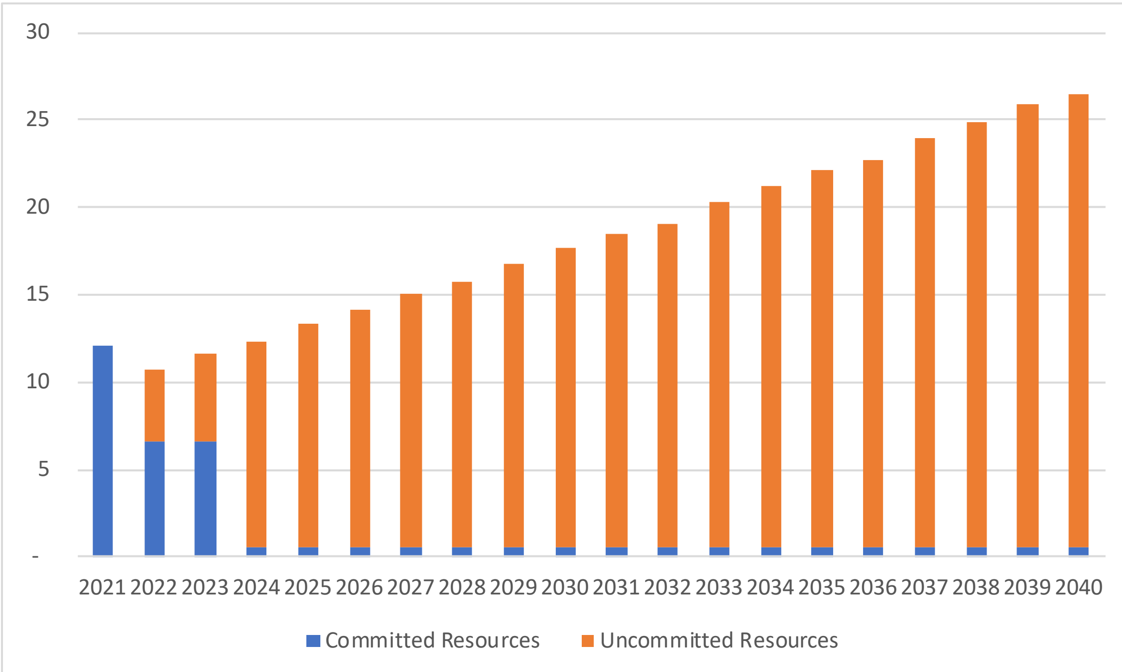
RES wants to continue to encourage the use of energy efficiency/conservation in its service territory. In addition, RES will continue to provide good customer service by assisting customers that are interested in producing renewable energy through net metered projects. Both energy efficiency and net metering reduce RES's future loads. As such, energy efficiency and net metering are the first resources deployed in that they reduce the need for other resources. In developing resource strategies, it is also important to consider the following:

- RES purchases the majority of its power from BPA's Tier 1 resources which are relatively low cost and low carbon emitting
- RES does not want to decrease its allocation of BPA Tier 1 power
- RES does not want to decrease its reliability
- RES must meet the EIA's conservation and renewable energy requirements

This section focuses on the resource options that, based on current availability and projected costs, are the most likely candidates to serve RES's future loads and ensure EIA compliance. The resources included in the resource portfolios include energy efficiency, wholesale market purchases, BPA Tier 1 power, solar and wind. Base case 20-year levelized costs of these resources are shown above in Exhibits 20 and 21. However, the costs of all of the resources are based on assumptions regarding operating characteristics and cost components that, if altered, could result in higher or lower resource costs. As such, sensitivity analysis with respect to resource costs is included.

Projected above-HWM loads are shown below in Exhibit 22. Committed resources include the NIES purchase in 2021 through 2023 and HRSST in all years.

Exhibit 22
Projected above-High Water Mark Load (aMW)

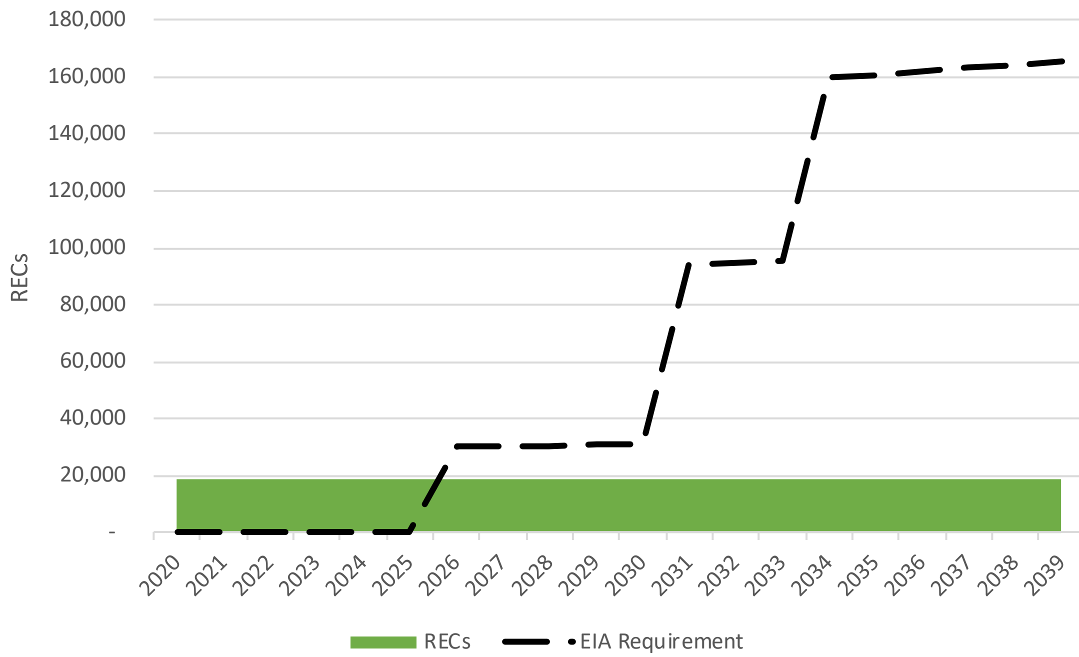


As shown above, RES is short on committed above-HWM serving resources in 2020 through 2040. In addition, to be being short on load-serving resources RES is also short on RECs required to meet the renewable energy requirements under the EIA. RES exceeded the 25,000-customer threshold in January 2020. As such, RES is required to comply with the EIA's renewable energy targets as follows:

- 3 percent of retail load must be served by renewables in 2026-29
- 9 percent of retail load must be served by renewables in 2030-33
- 15 percent of retail load must be served by renewables beginning in 2034

Exhibit 23 shows RES's REC position compared to its requirements under the EIA.

Exhibit 23
RES Projected RECs vs. EIA Requirements



The RECs shown above (green area) are a combination of RECs associated with RES's purchase of the renewable resources (wind) included in BPA's Tier 1 resource pool and HRSST. The eligible BPA Tier 1 resources include power purchase agreements BPA entered into for a portion of the output of the Condon, Klondike and Stateline wind projects. The contracts with the three wind projects expire between now and July 2027. BPA's Tier 1 resources also include incremental hydro generation at six hydroelectric projects. The RECs associated these projects are eligible renewable resources due to a provision included in CETA. The provision includes a stipulation that the RECs need to be retired for compliance during the same year they were generated (e.g., vintage 2026 RECs are only eligible for compliance in 2026). Exhibit 23 assumes that RES has the same access to BPA Tier 1 RECs under a new BPA power contract (effective in October 1, 2028) that is has under its existing BPA power contract (expires September 30, 2028) and that BPA replaces expiring wind contracts with like purchases. HRSST accounts for approximately 55 percent of the RECs currently under contract. HRSST RECs count as double because HRSST is a distributed resource. Distributed resources are eligible to use a 2.0 REC multiplier under the EIA.

The costs of serving RES's above-HWM loads while meeting the EIA's renewable energy requirements were calculated for three scenarios or portfolios.

As shown above, RES needs to acquire additional RECs, either from eligible renewable resources or from the REC market, beginning in 2027. Vintage 2016 HRSST and BPA Tier 1 RECs are sufficient to meet the first year of EIA requirements. Three portfolios were developed for meeting RES's above-HWM and renewable energy purchase requirements:

- *Portfolio #1:* Wholesale market purchases serve above-HWM load and REC purchases used to meet EIA requirements.
- *Portfolio #2:* Wholesale market and wind purchases serve above-HWM load and RECs from wind purchase meet EIA Requirements.
- *Portfolio #3:* Wholesale market, wind and solar purchases serve above-HWM load and RECs from wind and solar purchases meet EIA Requirements.

A sensitivity analysis is included to determine a range of costs associated with each portfolio. The sensitivity analysis is a deterministic analysis to show a best case, worst case, and expected case of the costs associated with each portfolio.

The three portfolios included in the analysis are discussed below.

Portfolio #1: Market Purchases Serve Above-HWM Load and REC Purchases Meet EIA Requirements

Exhibit 24 below shows a resource stack in which RES purchases enough power from the wholesale market to meet its load requirements. The blue area in Exhibit ES-9 includes BPA Tier 1 power, NIES purchases and HRSST.

Exhibit 24
Serve Above-HWM Loads Market Purchases

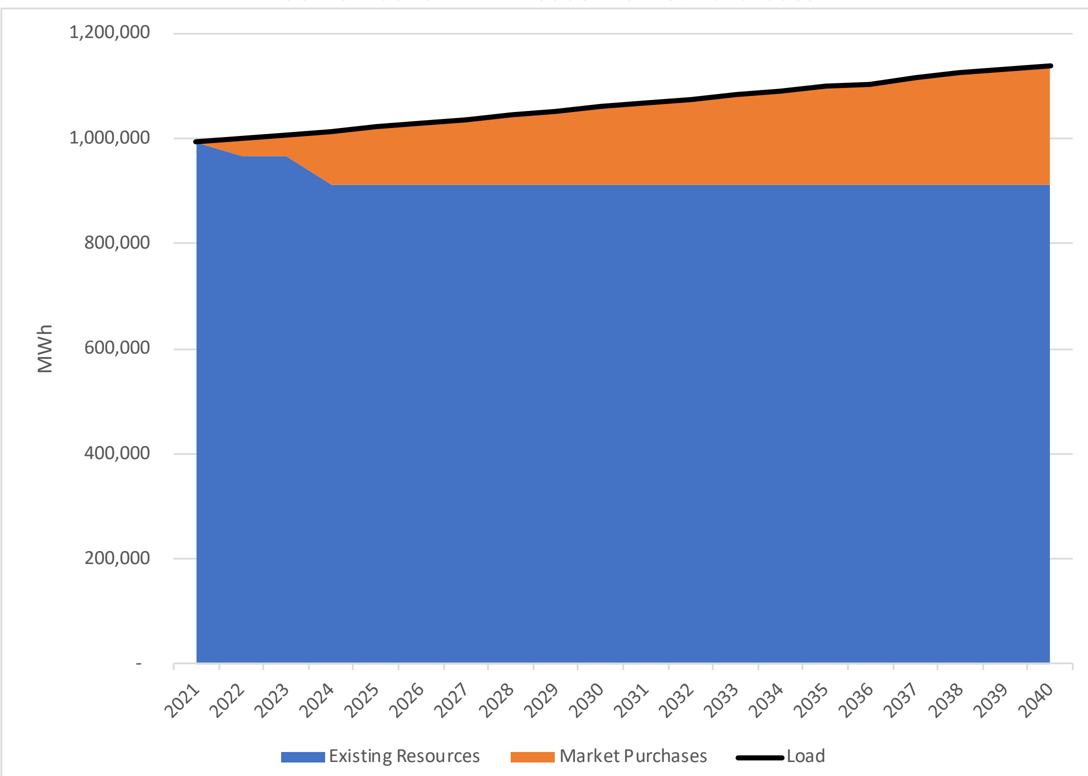
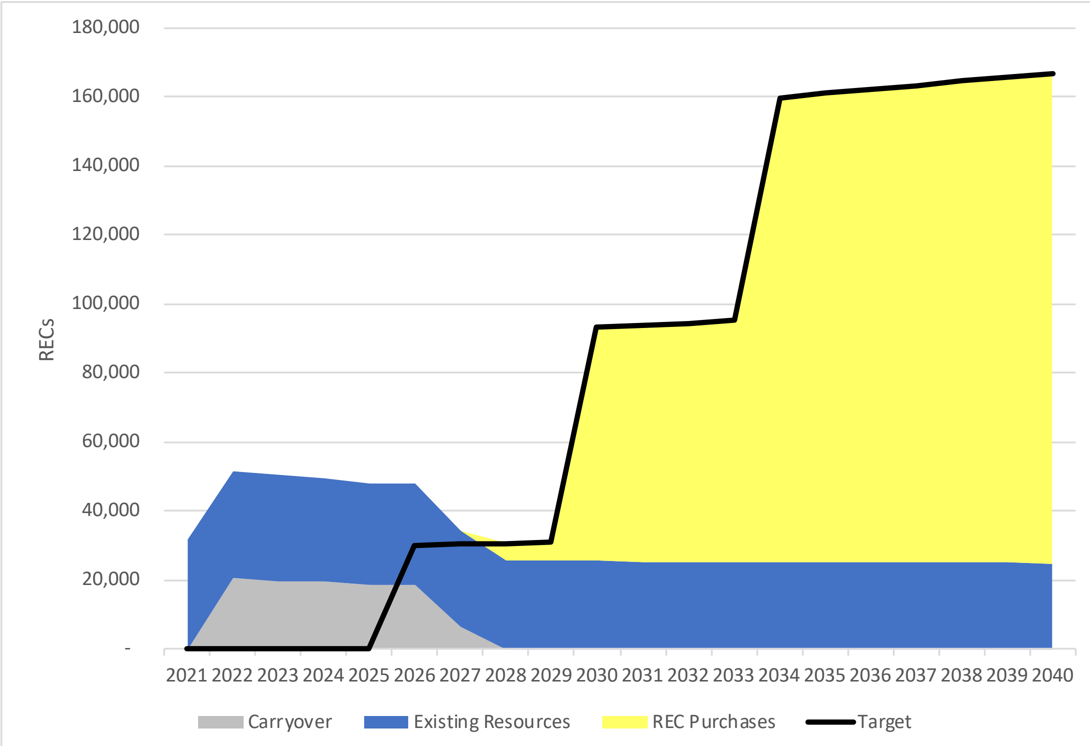


Exhibit 25 below shows RES's REC portfolio compared to its renewable energy requirement/target under the EIA. In this portfolio the REC short positions shown above in Exhibit 23 are met entirely through REC purchases.

Exhibit 25
REC Purchases Used to Meet EIA's Renewable Energy Purchases

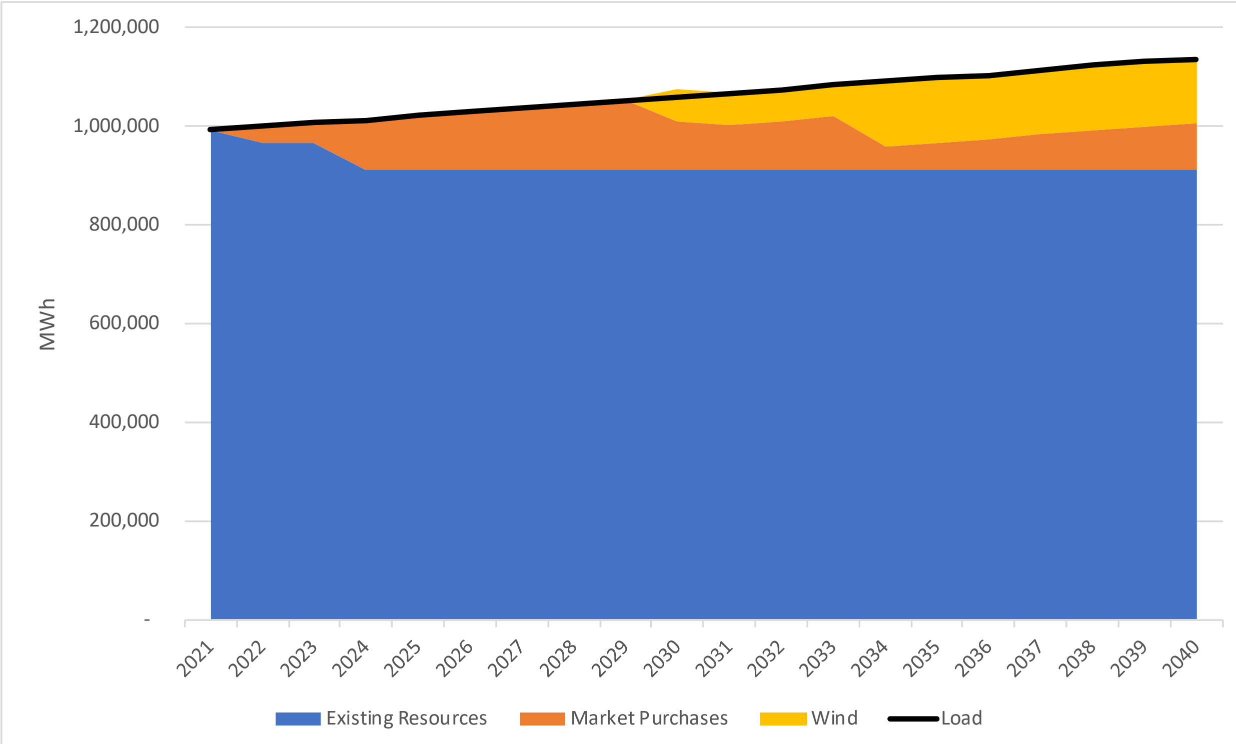


Under the EIA utilities can use RECs from the previous year, the current year and the subsequent year to satisfy renewable energy requirements. For example, during the first year of compliance (CY26), RES can use vintage 2025, vintage 2026 and vintage 2027 RECs to meet the CY26 renewable target of 3 percent. The carryover amounts shown in gray in Exhibit 25 represent HRSST and BPA Tier 1 RECs from the prior year.

Portfolio #2: Serve Above-HWM Load with Market and Wind Purchases and Use RECs from Wind Purchase to Meet EIA Requirements

Exhibit 26 below shows a resource stack in which RES serves nearly half of its above-HWM load with output from a wind project and the other half from wholesale market purchases. The blue area in Exhibit 26 includes BPA Tier 1 power, NIES purchases and HRSST.

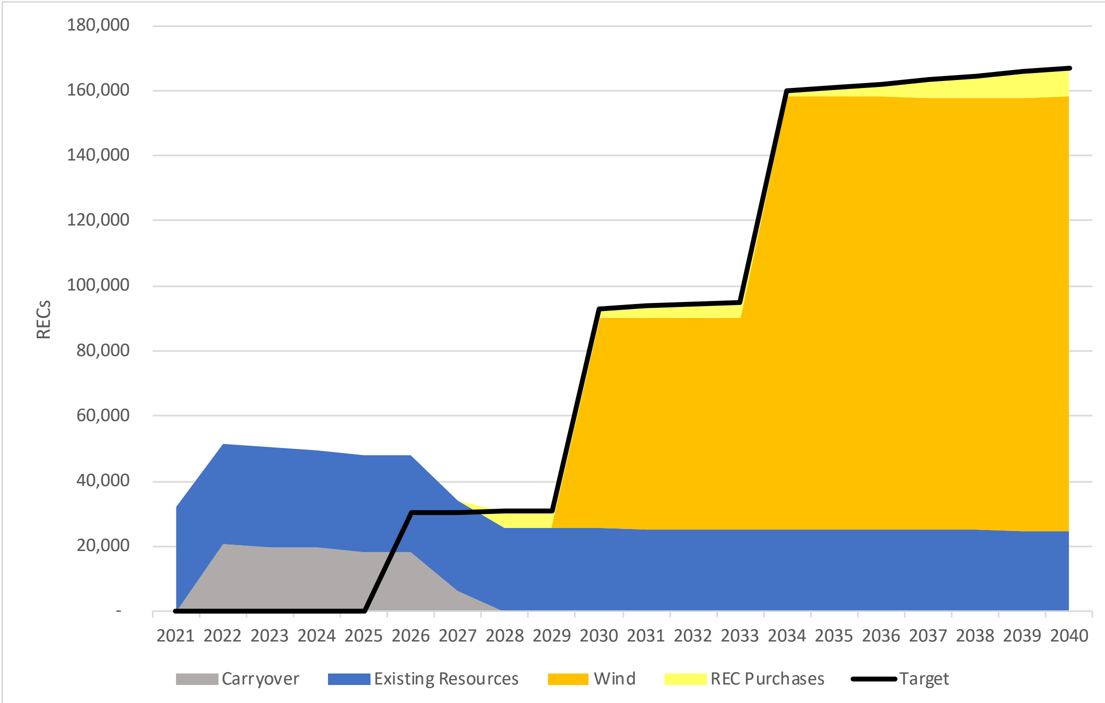
Exhibit 26
Serve Above-HWM Loads with Combination of Wind and Market Purchases



As shown in Exhibit 26, above-HWM loads are served by wholesale market purchases (orange area) in the earlier years with wind power serving increasing amounts of load through 2040. The amount of wind purchases layered into the portfolio is dictated based on the EIA renewable energy requirements. Wind purchases increase from 3.5 MW in 2028-2030 to 23 MW in 2031-33 and 43 MW in 2034-2040. A capacity factor of 37 percent is assumed for the wind project which is assumed to be located in the Columbia River Gorge.

Exhibit 27 below shows that wind RECs fill in the short REC positions identified in Exhibit 23.

Exhibit 27
Wind Purchase Used to Meet EIA's Renewable Energy Purchase Requirements

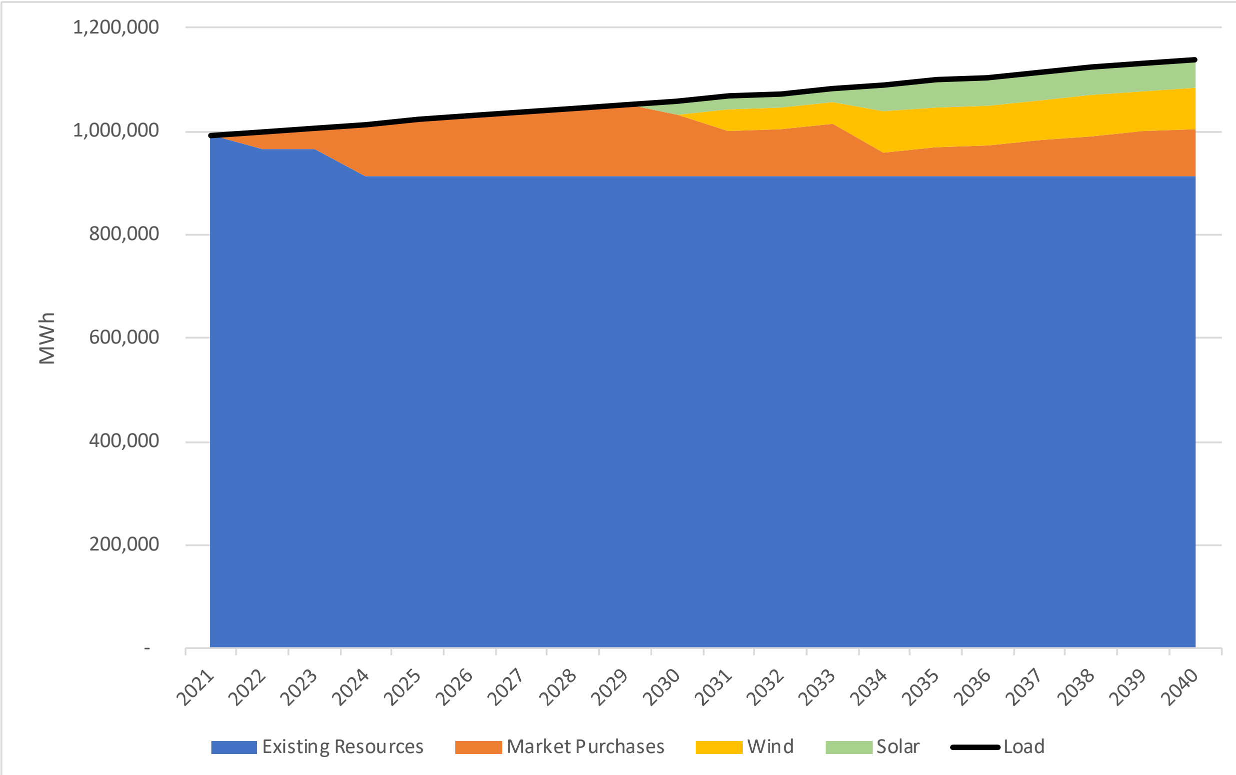


As shown above REC purchases (yellow area) are used to meet small REC deficits in Portfolio #2.

Portfolio #3: Serve Above-HWM Loads with Market, Wind and Solar Purchases and Use RECs from Wind and Solar Purchases to Meet EIA Requirements

Exhibit 28 below shows a resource stack in which RES serves nearly half of its above-HWM load with output from wind and solar projects and the other half from wholesale market purchases. The blue area in Exhibit 28 includes BPA Tier 1 power, NIES purchases and HRSST.

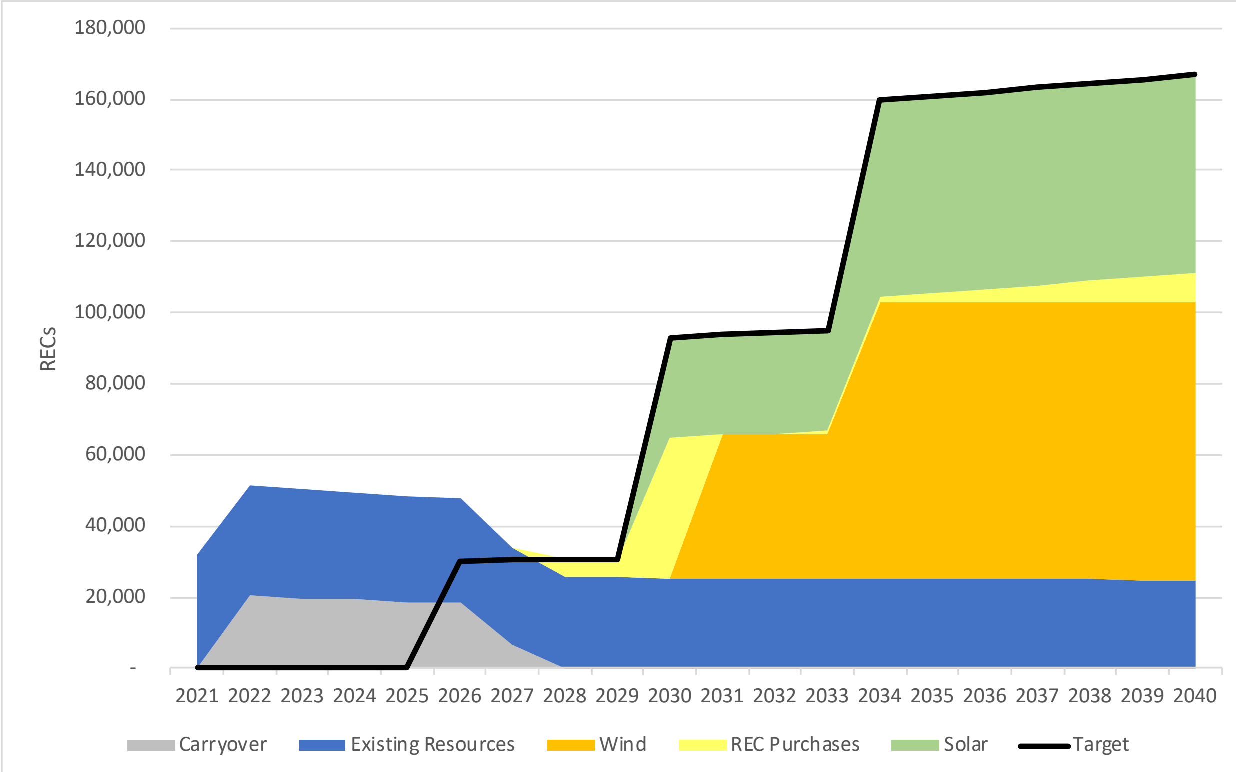
Exhibit 28
Serve Above-HWM Loads with Combination of Wind, Solar and Market Purchases



As shown in Exhibit 28, above-HWM loads are served by wholesale market purchases (orange area) in the earlier years with solar and wind power serving increasing amounts of load through 2040. The amount of solar and wind purchases layered into the portfolio is dictated based on the EIA renewable energy requirements. Solar purchases increase from 4 MW in 2028-2030 to 12 MW in 2031-33 and 19.5 MW in 2034-2040. A capacity factor of 32.5 percent is assumed for the solar project which assumed to be located on the east side of the Cascades. Wind purchases increase from 12.5 MW in 2031-2034 to 26.25 MW in 2034-40. A capacity factor of 37 percent is assumed for the wind project (same as Portfolio #2).

Exhibit 29 below shows that solar and wind RECs fill in the short REC positions identified in Exhibit 23.

Exhibit 29
Wind and Solar Purchases Used to Meet EIA's Renewable Energy Purchase Requirements



As shown above REC purchases (yellow area) are used to meet small REC deficits in Portfolio #3.

Resource Portfolio Costs

The cost of serving above-HWM load and meeting EIA renewable energy requirements was calculated for the three portfolios for the 20-year test period 2021-40. A sensitivity analysis was included to determine a range of costs associated with each portfolio. The sensitivity analysis includes the following low, base and high cases for each resource that is used to meet above-HWM load and RES's renewable energy requirements under the EIA.

Exhibit 30 Resource Operating Characteristics and Cost Assumptions			
	Low Case	**Base Case**	**High Case**
Market Purchase (1)	CY21 = $23/MWh Escalation = 1.7%	CY21 = $29/MWh Escalation = 2.9%	CY21 = $38/MWh Escalation = 3.3%
RECs	CY21 = $3.3/REC CY30 = $6.2/REC CY40 = $10.0/REC	CY21 = $5.0/REC CY30 = $9.5/REC CY40 = $20.0/REC	CY21 = $8.5/REC CY30 = $20.0/REC CY40 = $35.0/REC
Wind Purchase	Capacity Factor = 41% Capital Cost = $1,450/kW Fixed O&M = $37/kW-yr RSS = $15/MWh	Capacity Factor = 37% Capital Cost = $1,700/kW Fixed O&M = $40/kW-yr RSS = $20/MWh	Capacity Factor = 32% Capital Cost = $1,939/kW Fixed O&M = $49/kW-yr RSS = $22/MWh
Solar Purchase	Capacity Factor = 37.5% Capital Cost = $1,165/kW Fixed O&M = $14.55/kW-yr RSS = $2/MWh	Capacity Factor = 32.5% Capital Cost = $1,527/kW Fixed O&M = $31/kW-yr RSS = $4/MWh	Capacity Factor = 28% Capital Cost = $2,600kW Fixed O&M = $40/kW-yr RSS = $6/MWh

(1) CY21 prices do not include social cost of carbon.

Exhibit 31 shows the base case and range of projected Mid-C market prices. Actual Mid-C prices are shown in 2003 through 2019.

Exhibit 31
Range of Projected Mid-C Market Prices

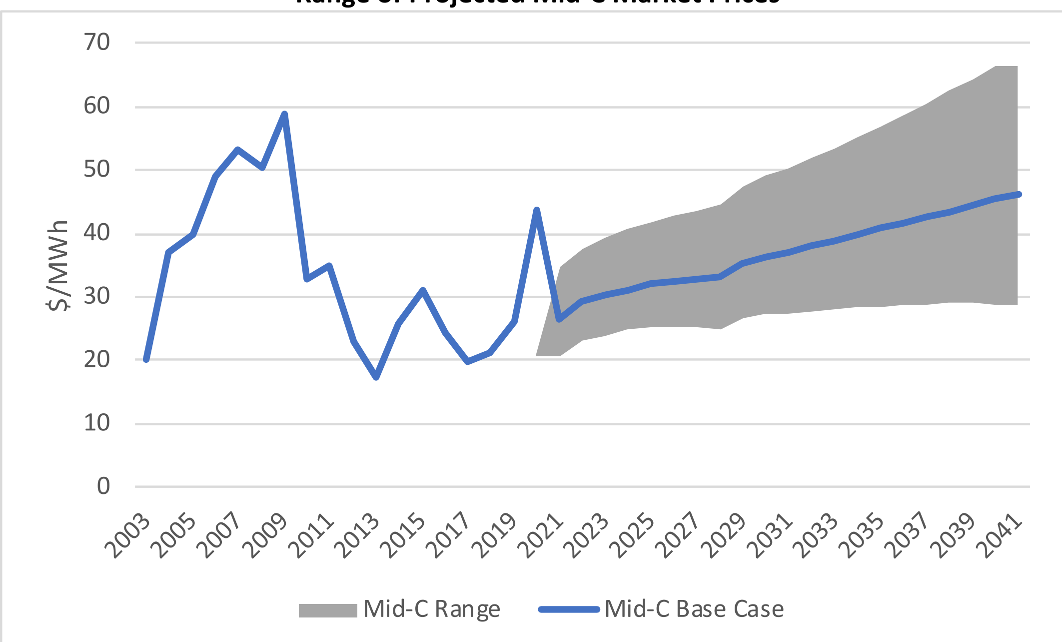


Exhibit 32 shows the range of 20-year levelized costs for BPA Tier 1, energy efficiency, Mid-C market plus the social cost of carbon, wind and solar purchases. The wind and solar purchases in RSS. Consistent with Exhibit 8 above, the range of BPA Tier 1 rates assume low, base and high escalation rates of 1.5, 3 and 6 percent. The red diamonds show the base case 20-year levelized costs.

Exhibit 32
Range of 20-year Levelized Resource Costs ($/MWh)

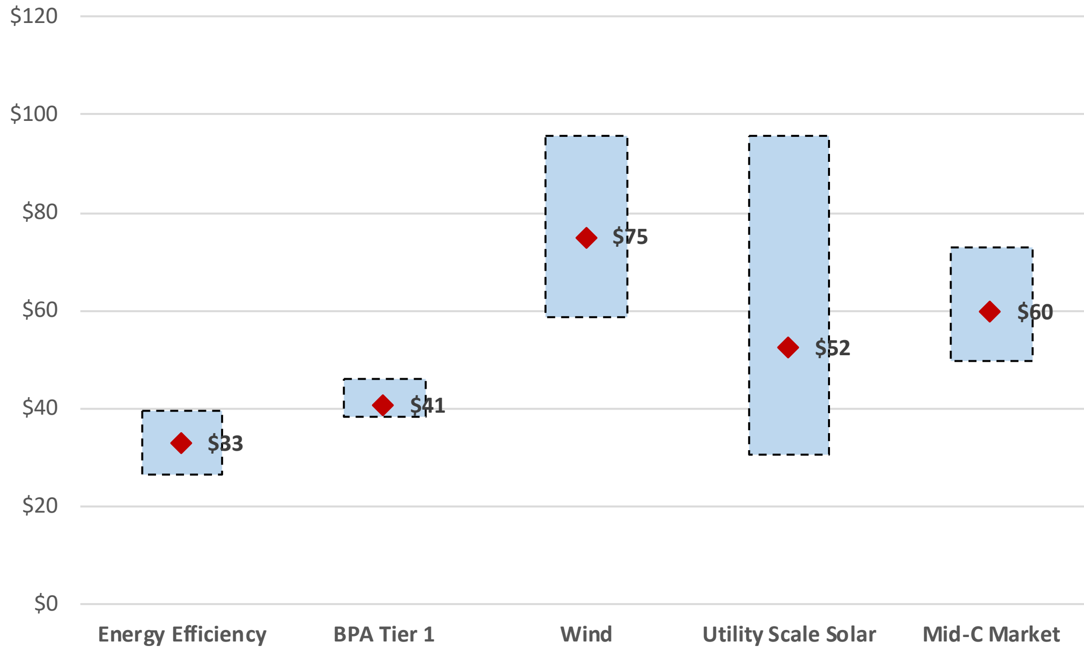
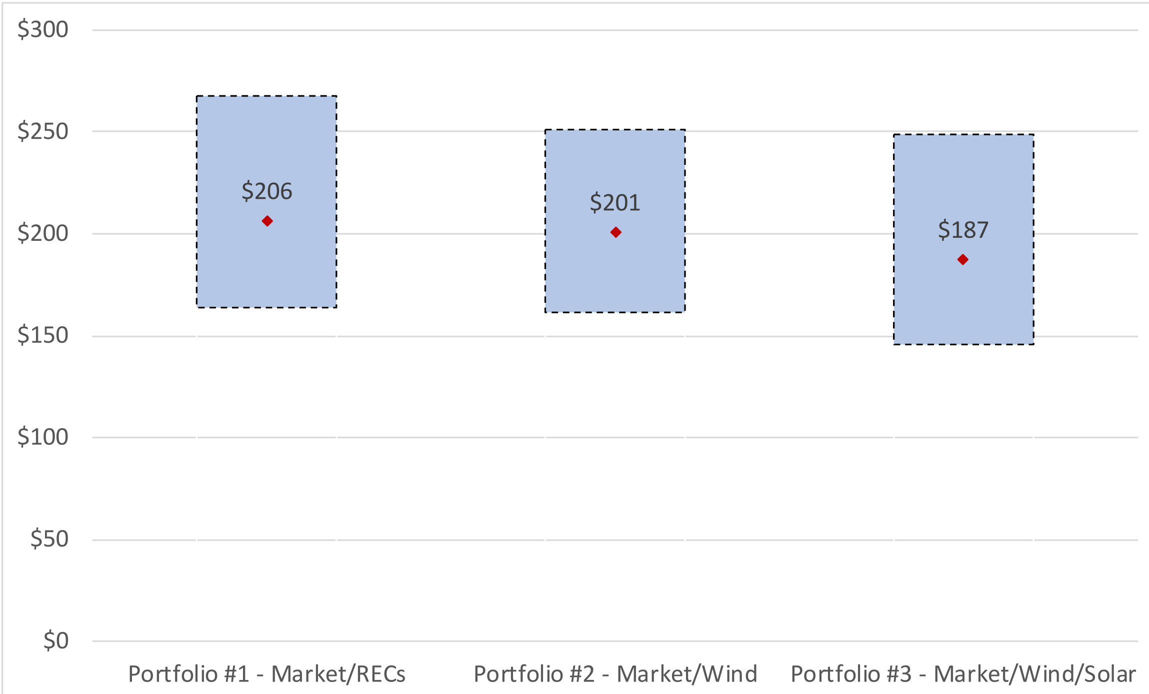


Exhibit 33 shows the range of costs for each of the portfolios described above assuming the range of Mid-C market (including the social cost of carbon), solar, wind and REC purchases costs discussed above. The solar and wind purchase costs include RSS.

Exhibit 33
Range of 2021-40 Portfolio Costs (millions)



Total costs under base case pricing assumptions are depicted by the red diamonds in Exhibit 33. As shown above, Portfolio #3 has the lowest costs. Portfolio #3 has the lowest costs because it includes east-side solar and, as shown above in Exhibit 32, the base case 20-year levelized east-side solar cost of $52/MWh is less expensive than the market ($60/MWh) and wind located in the Gorge ($75/MWh).

The bottom of the blue box shows costs using low cost assumptions while the top of the blue box shows costs using high cost assumptions. The Portfolio #2 and #3 low cost cases include higher capacity factors and lower capital, fixed O&M and RSS costs for wind and solar purchases. The Portfolio #2 and #3 high cost cases include lower capacity factors and higher capital, fixed O&M and RSS costs for wind and solar purchases. The Portfolio #1 and #2 low and high cost cases include low and high wholesale market and REC prices, respectively, and the social cost of carbon. Low market prices are approximately 25 percent lower than base case market prices. High market prices are approximately 35 percent greater than base case market prices.

Recommendations

The reference cases that have been developed for the NWPCC's 2021 Power Plan as well as the IRPs of several IOUs conclude that conservation and demand response programs are the most cost-effective future resources and can be relied on to meet future load growth and energy and capacity requirements. This is consistent with the recommendations of this study.

It is unknown whether the quantity of power and transmission currently provided by BPA under existing contracts will be available under new contracts that begin in October 2028. Primarily due to low natural gas prices wholesale market prices are currently less than BPA's power rates. Whether or not this trend will continue is unknown. Based on current projections of wholesale market and natural gas market prices it could be argued that BPA's rates will be above market for an extended period of time.

Factors that could put upward pressure on future wholesale market prices include carbon costs and natural gas price spikes due to shifts in the current supply and demand paradigm for the natural gas industry. BPA Tier 1 rates are immune to potential cost adders associated with carbon emission restrictions. In addition, the impact of fluctuations in natural gas prices on BPA Tier 1 rates is muted by BPA's ability to draw down reserves during periods of low surplus energy sales revenue. If additional cap and trade, carbon tax or other carbon policies are implemented on a state or federal level the value of BPA Tier 1 power will increase due to the fact that it has no carbon emissions. Displacing Tier 1 power purchases with alternative resources due to current market conditions is not advised as it could have a long-term effect on RES's ability to obtain its maximum allocation of Tier 1 power during the next contract period.

In addition, forward wholesale market prices are for flat blocks of power across all hours, days and months of a year. BPA's load following product follows RES's loads across all hours, days and months. As such, comparing BPA's Tier 1 rates and wholesale market prices is not an apples-to-apples comparison. The estimated value of load following service is estimated to be between $5 to 7/MWh.

Many of the resources discussed in the "Supply-Side Resources" section of this report, such as pumped hydro, micro-hydro, batteries, grid management and tidal power, are many years away from implementation due to significant technological, permitting and cost hurdles. Some of the resources discussed above, such as solar, conservation, and demand-side management can be addressed in the near term.

Below are specific recommendations based on observations made throughout this report.

BPA Tier 1 Power

RES should not take any actions that would result in decreases to the Tier 1 allocation rights in its current and future BPA power contracts. Although wholesale market prices are currently less than BPA Tier 1 rates, market prices are exposed to supply and price risks to which BPA power purchases, are not exposed. In addition, market prices are for flat blocks of power with no load shaping capability while BPA's load following product serves RES's hourly loads. As such, in order to properly compare market prices to BPA's rates the cost of load following would need to be added to the market price of power. In addition, BPA's resources are carbon-free and, under CETA, RES will need to be carbon neutral by 2030 and carbon-free by 2045.

Energy Efficiency

The cost-effective energy efficiency measures identified in RES's 2019 CPA are the least expensive resources available to RES. Implementing these measures will reduce RES's above-HWM load which will reduce RES's market price risk exposure since above-HWM load is served by market purchases (renewable and non-renewable).

Renewable Energy Purchase Requirements

RES will be required to comply with renewable energy purchase requirements under the EIA beginning in 2026. RES is short renewable energy beginning in 2027. The lowest cost and lowest risk portfolio that complies with renewable energy purchase requirements is to purchase a combination of market, solar and wind power to serve above-HWM load and meet renewable energy requirements using the RECs associated with the solar and wind purchases. RES should work with NIES to identify a blend of market, solar and wind power purchases that can serve load and meet EIA requirements. Purchasing through NIES, rather than going it alone, should reduce costs due to economies of scale and administrative burden. The cost of renewable resources, RECs, and market prices should be monitored going forward to ensure that this remains the best strategy.

Local Resources

In order to diversify its resource portfolio, increase its self-sustainability and decrease its dependence on BPA transmission to serve load and potentially reduce its wholesale transmission costs, RES should continue to promote local resource development, such as the HRSST, and consider pursuing state and federal grant money that would allow RES to accelerate local resource development. Potential local resources include small scale solar, micro-hydro projects, cogeneration at wastewater treatment plants, landfill gas projects, wind projects and battery storage systems that complement solar and wind projects and provide backup in the event of a transmission contingency.

Rooftop Solar

RES currently has over 200 customers with rooftop solar installations, with more than half of those installed over the past two years. Despite recent tariffs on imported solar panels, the cost of solar power is expected to continue to decrease. As an east-side utility, rooftop solar installations have relatively high capacity factors (compared to west-side utilities). The relatively low capacity factors and downward trajectory of solar costs will likely continue to make rooftop solar an attractive to RES customers. RES should consider taking steps to prepare itself for continued growth in rooftop solar installations so that RES can be in a better position to operate a truly "smart" and efficient grid. This would ultimately result in lower distribution system and power supply costs.

Demand Response

RES should gauge its customers' interest in participating in Demand Response programs. If enough customers are interested, RES should pursue the installation of Demand Response Units to help RES reduce its peak demands and, thus, its demand costs under the current BPA power contract.

CETA Compliance

Beginning in 2022 as RES prepares to ramp up to carbon neutrality in 2030, RES should consider, offsetting the small amount of carbon included in its BPA purchases and a percentage of the carbon included in its non-federal purchases with REC purchases. RES should consider sourcing all of its non-federal purchases that are used to serve above-HWM load to carbon-free resources, such as hydro, by 2030.

Richland Energy Services

2019 Conservation Potential Assessment
Final Report

March 20, 2020

Prepared by:

EES Consulting
a GDS Associates Company

1455 NW Irving Street, Suite 200
Portland, Oregon 97209

A registered professional engineering and management consulting firm with offices throughout the United States

Telephone: (425) 889-2700 Facsimile: (425) 889-2725

March 20, 2020

Ms. Sandi Edgemon
Richland Energy Services
625 Swift Boulevard, MS-23
Richland, Washington 99352

SUBJECT: 2019 Conservation Potential Assessment

Dear Ms. Edgemon:

Please find attached the final report summarizing the 2019 Richland Energy Services Conservation Potential Assessment (CPA). This report covers the time period from 2020 through 2039. The measures and information used to develop Richland's preliminary conservation potential incorporate the most current information available for Energy Independence Act (EIA) reporting.

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

Best Regards,

Steve Andersen

Steve Andersen
Manager of Project Evaluations

1455 NW Irving Street ▪ Suite 200 ▪ Portland, OR 97209
503 223-5900 ▪ Fax 866-611-3791 ▪ www.eesconsulting.com

Marietta, GA; Austin, TX; Auburn, AL; Manchester, NH; Madison, WI; Orlando, FL; Augusta, ME; Seattle, WA and Portland, OR

Contents

Executive Summary

This report describes the methodology and results of the 2019 Conservation Potential Assessment (CPA) for Richland Energy Services (Richland). This assessment provides estimates of energy savings by sector for the period 2020 to 2039. The assessment considers a wide range of conservation resources that are reliable, available and cost-effective within the 20-year planning period.

Background

Richland provides electricity service to over 24,500 customers in Benton County, Washington, excluding Benton PUD 1's service territory.

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. Although Richland is currently below the customer requirement, the utility is expected to exceed the 25,000-customer threshold in 2020.

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 Richland's compliance with EIA requirements.

This assessment was built on the same model used in the 2017 CPA cycle, which was based on the completed Seventh Power Plan. The model was subsequently 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
  - 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 current data and forecasts. 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 and evaluate risk.

Results

Table ES-1 shows 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 energy efficiency potential is 15.79 aMW. The most important numbers per the EIA are the 10-year potential of 9.75 aMW, and the two-year potential of 1.47 aMW.

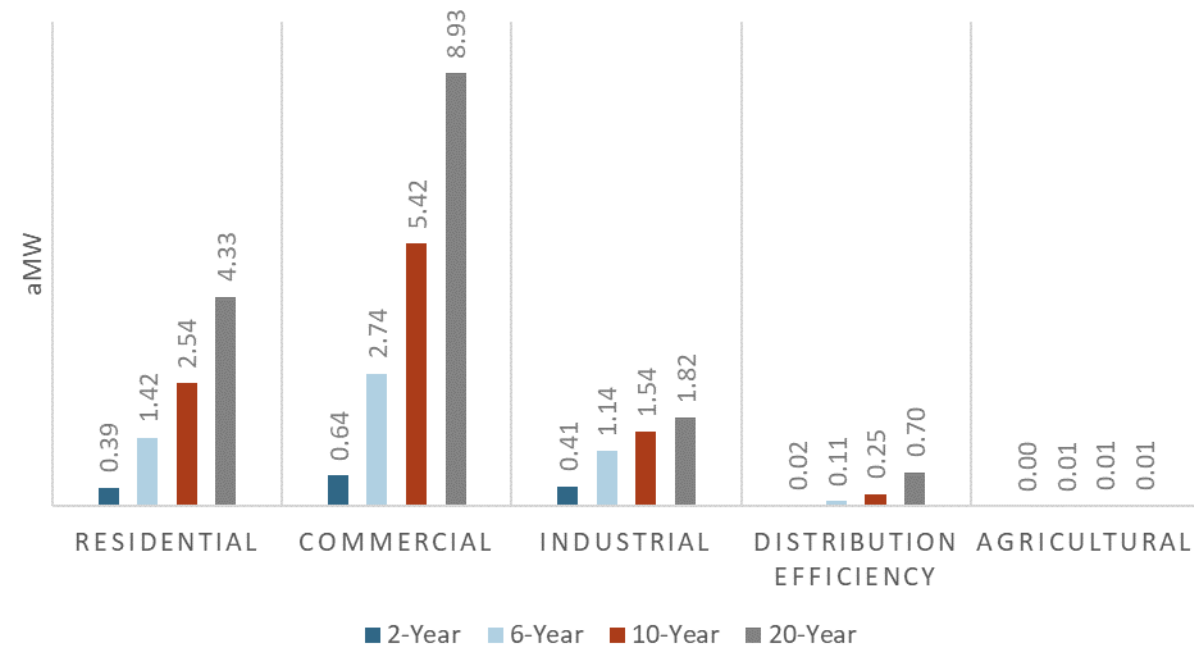
These estimates include energy efficiency that could be achieved through Richland's utility programs and also through Richland's share of the Northwest Energy Efficiency Alliance (NEEA) accomplishments. Some code and standard changes may also account for part of the potential, especially in the later years. In some cases, the savings from those changes will be quantified by NEEA or through BPA's Momentum Savings work. While not quantified at a utility-specific level, the Momentum Savings quantified by BPA could be further savings claimed against the Seventh Plan conservation targets.

Table ES-1
Cost Effective Potential (aMW)

	2-Year*	6-Year	10-Year	20-Year
Residential	0.39	1.42	2.54	4.33
Commercial	0.64	2.74	5.42	8.93
Industrial	0.41	1.14	1.54	1.82
Distribution Efficiency	0.02	0.11	0.25	0.70
Agricultural	0.00	0.01	0.01	0.01
Total	**1.47**	**5.41**	**9.75**	**15.79**

**2020 and 2021*
Note: Numbers in this table and others throughout the report may not add to total due to rounding.

Figure ES-1
Cost-Effective Potential



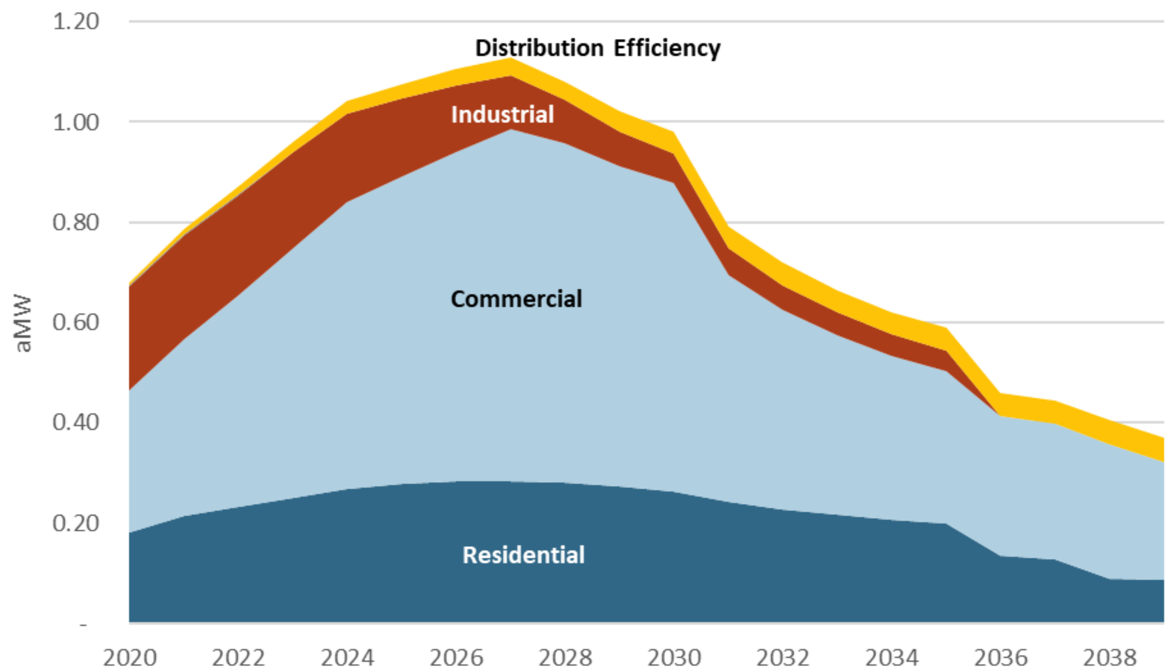
Energy efficiency also has the potential to reduce peak demands. Based upon hourly load profiles developed for the Seventh Power Plan and load data provided by Richland, the reductions in peak demand provided by energy efficiency are summarized in Table ES-2 below. Richland's annual peak occurs in the winter evenings. In addition to these peak demand savings, demand savings would occur throughout the year.

Table ES-2
Cost Effective Demand Savings - Base Case (MW)

	2-Year	6-Year	10-Year	20-Year
Residential	1.24	4.15	7.04	11.62
Commercial	0.98	4.13	8.06	13.18
Industrial	0.48	1.30	1.76	2.08
Distribution Efficiency	0.02	0.13	0.31	0.87
Agricultural	0.00	0.01	0.01	0.01
Total	**2.72**	**9.73**	**17.17**	**27.76**

The 20-year energy efficiency potential is shown on an annual basis in Figure ES-2. This assessment shows annual potential starting at 0.68 aMW in 2020 and ramping up to 1.13 aMW in 2027. Ramp rates from the Northwest Power and Conservation Council's (Council) Seventh Power Plan technical documentation were used to develop the annual savings potential estimates over the 20-year study. In some instances, alternate ramp rates were assigned to measures to better fit Richland's recent potential.

Figure ES-2
Annual Cost-Effective Energy Efficiency Potential Estimates



Relative to the 2017 CPA cycle, the amount of cost-effective potential in the residential sector has decreased. Much of the change is due to federal lighting 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 for residential lighting. While there is some uncertainty about whether the federal standard will be implemented, Washington state recently enacted identical standards, also scheduled to take effect in 2020. Accordingly, residential lighting measures have not been included in this CPA. The remaining conservation potential in the residential sector is among the HVAC and water heating end uses. Notable areas for achievement include:

- HVAC-related measures, including weatherization and duct sealing
- Water heating measures like heat pump water heaters and clothes washers

Significant conservation is also available in Richland's commercial sector. Notable areas for commercial sector savings potential include:

- Lighting – including exterior and lighting power density measures
- Commercial HVAC measures like rooftop unit controllers and ductless heat pumps

Comparison to Previous Assessment

Table ES-3 shows a comparison of 2, 10, and 20-year Base Case conservation potential by customer sector for this assessment and the results of Richland's 2010 and 2017 CPA.

Table ES-3 Comparison of 2010 and 2017 CPA to 2019 CPA Cost-Effective Potential								
	10-Year				20-Year			
	2010	2017	2019	% Change	2010	2017	2019	% Change
Residential	7.12	2.01	2.54	-44%	14.20	3.60	4.33	-51%
Commercial	7.38	1.01	5.42	29%	15.36	2.09	8.93	2%
Industrial	1.02	0.68	1.54	81%	2.18	0.89	1.82	19%
Distribution Efficiency	1.16	0.24	0.25	-64%	2.13	0.69	0.70	-50%
Agricultural	0.00	0.00	0.01	-	0.00	0.00	0.01	-
Total	**16.68**	**3.94**	**9.75**	**-5%**	**33.87**	**7.26**	**15.79**	**-23%**

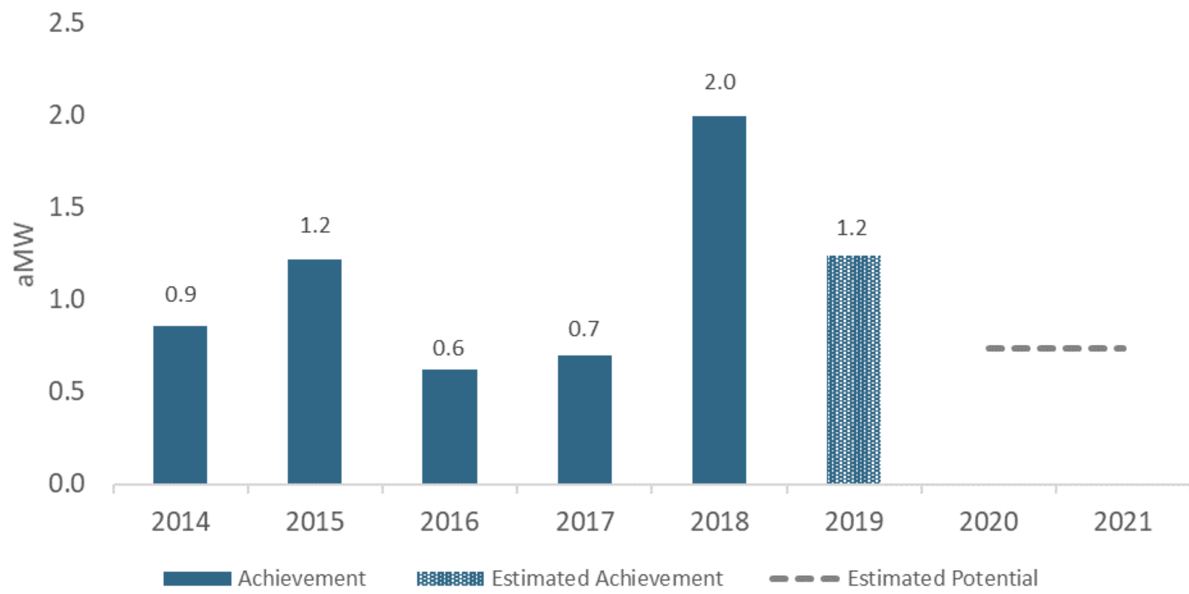
**Note that the 2010 columns refer to the CPA completed in 2009 for the time period of 2010 through 2029, the 2017 columns refer to the CPA completed in 2016 for the time period of 2017 through 2036. The % Change is calculated as the 2019 change from the average of 2010 and 2017 cost-effective potential.*

The results of this 2019 assessment are lower than the 2010 results and higher than 2017 for a variety of reasons. The CPA model has been updated in accordance to the Seventh Plan, avoided cost assumptions have changed, as well as the above-mentioned changes to lighting standards. On top of these changes Richland has experienced growth in population, load and other economic inputs to the CPA model which increases the pool from which cost-effective potential is estimated. Some of the change in potential between the commercial and industrial sectors is the result of more accurate industrial classification which has moved some load from the commercial to the industrial sector. Additionally, the Council updated its assumptions on the value of deferred transmission and distribution capital expenditures, 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 compares Richland's historic conservation achievement with its targets. The biennium potential for this assessment shows a decrease from historic achievement given the likely changes to residential lighting programs, however the potential remains realistic as these savings were not considered when aligning potential with recent program history. The figure shows that Richland has consistently met its projected energy efficiency target, and that the potential estimates presented in this report are achievable through Richland's utility conservation programs and the utility's share of NEEA savings.

Figure ES-3
Historic Achievement and Targets



Conclusion

This report summarizes the CPA conducted for Richland for the 2020 to 2039 timeframe. Based on the results of the Base Case scenario, the total 10-year cost effective potential is 9.75 aMW and the 2-year potential is 1.47 aMW. This assessment results in lower potential than the previous assessments, largely due to the exclusion of many residential lighting measures as well as the change in the valuation of transmission and distribution capacity costs. The avoided cost assumptions are discussed further in Appendix IV.

Introduction

Objectives

The objective of this report is to describe the results of the Richland Energy Services (Richland) 2019 Electric Conservation Potential Assessment (CPA). This assessment provides estimates of energy savings by sector for the period 2020 to 2039, with the primary focus on 2020 to 2029 (10 years). 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 Richland's compliance documentation. The results and guidance presented in this report will also assist Richland in strategic planning for its conservation programs in the near future.

The conservation measures used in this analysis are based on the measures included in the Council's Seventh Power Plan and updated where appropriate with subsequent changes 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

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. Richland expects to exceed the 25,000-customer threshold in 2020 and, as such, is developing an IRP and CPA. The legislation mandates that these resource plans include assessments of commercially available conservation and efficiency measures. This CPA is designed to assist in meeting these requirements for conservation analyses. More background information is provided below.

Energy Independence Act

Chapter 19.285 RCW, the Energy Independence Act, 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.
- 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.

City of Richland I-937 Compliance Summary Steps: 2020 Qualification

Year	Conservation/ Renewable Target	January 1 - Compliance Actions	June 1 – Reporting Requirements
2021	NA		Report 25,000 customer status to State
2022	NA		
2023	NA	Complete/update 10-year CPA and expand EE programs. Augment staff.	
2024	10% of CPA	Acquire 1/10th of CPA within one year.	Report CPA and 2024 conservation savings (optional)
2025	Additional 10% of CPA (or 20% at end of 2 years)	Complete/update 10-year CPA. Acquire 2/10th of CPA within two years.	Report previous year's conservation savings and renewables. (optional)
2026	10% of CPA 3% Renewables		Report CPA and previous two years' conservation savings and renewables.
2027	Additional 10% of CPA (or 20% at end of 2 years) 3% of Renewables	Complete/update 10-year CPA. Acquire 2/10th of CPA within two years.	Report previous year's conservation savings and renewables.
2028	10% of CPA 3% Renewables		Report CPA and previous two years' conservation savings and renewables.
2029	Additional 10% of CPA (or 20% at end of 2 years) 3% of Renewables	Complete/update 10-year CPA. Acquire 2/10th of CPA within two years.	Report previous year's conservation savings and renewables.
2030	10% of CPA 9% Renewables		Report CPA and previous two years' conservation savings and renewables.
2031	Additional 10% of CPA (or 20% at end of 2 years) 9% of Renewables	Complete/update 10-year CPA. Acquire 2/10th of CPA within two years.	Report previous year's conservation savings and renewables.
2032	10% of CPA 9% Renewables		Report CPA and previous two years' conservation savings and renewables.
2033	Additional 10% of CPA (or 20% at end of 2 years) 9% of Renewables	Complete/update 10-year CPA. Acquire 2/10th of CPA within two years.	Report previous year's conservation savings and renewables.
2034	10% of CPA 15% Renewables		Report CPA and previous two years' conservation savings and renewables.
2035	Additional 10% of CPA (or 20% at end of 2 years) 15% of Renewables	Complete/update 10-year CPA. Acquire 2/10th of CPA within two years.	Report previous year's conservation savings and renewables.

Other Legislative Considerations

Washington State recently enacted several laws that impact conservation planning. Washington's Clean Energy Transformation Act (CETA), ESSB 5116, has several components that impact conservation planning. First it requires the use of a specific social cost of carbon in utility planning. It also sets several requirements for the retail sales of electricity to be from greenhouse gas free or renewable sources. This CPA has accounted for these changes to avoided cost assumptions associated with this legislation in the 2021 CPA.

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.

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

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 Richland's service area is similar to that of the region, or that the regional survey data represents 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, risk credits are included in the analysis to mitigate the market price risk 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.

- Discount rate –This CPA uses a discount rate that is specific to Richland. The rate 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 timing of 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 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 – Richland'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
- Summary
- References & Appendices

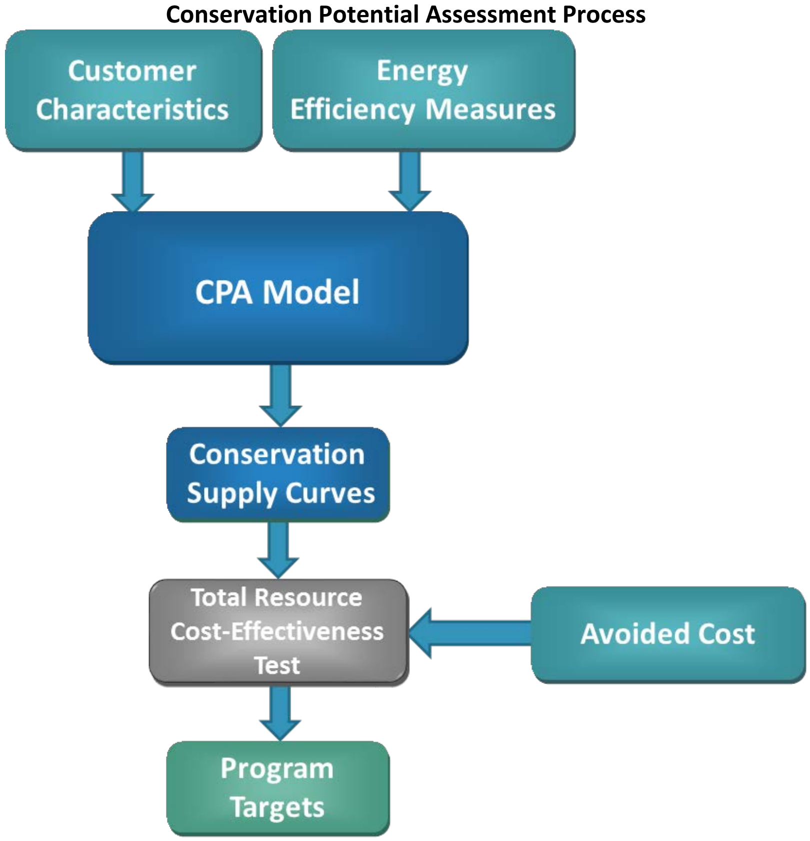
Methodology

This study is a comprehensive assessment of the energy efficiency potential in Richland'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 Richland'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 Richland'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 Richland's historic conservation achievement data, where applicable. Richland's historic achievement is discussed in detail in the next section.

Energy Efficiency Measure Data

The characterization of efficiency measures includes measure savings, demand savings, measure costs, and measure life. 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.

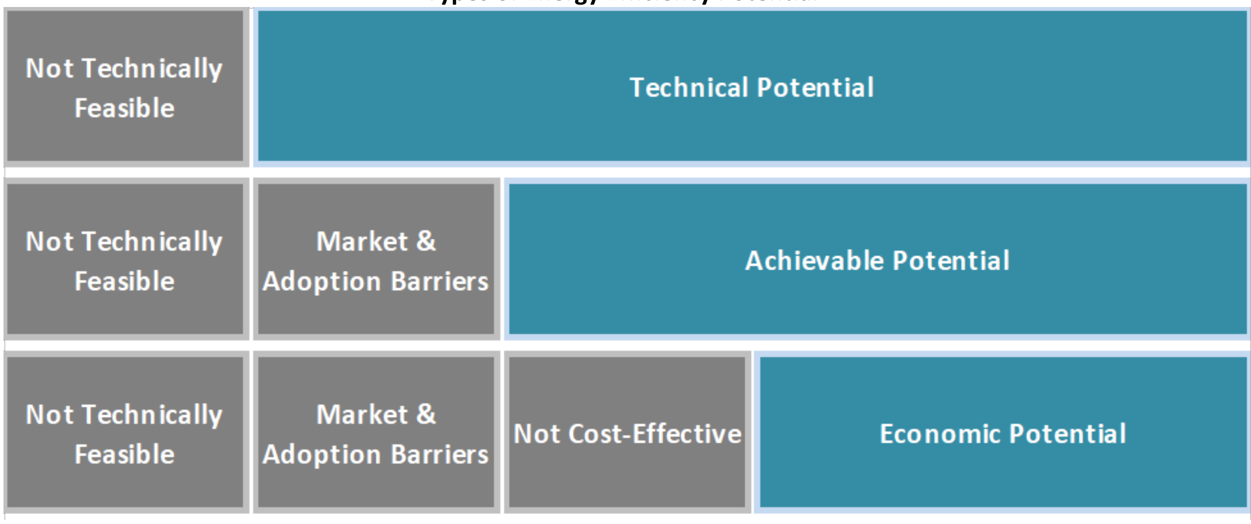
Other financial-related data needed for defining measure costs and benefits include: discount rate, avoided costs, line losses, and deferred capacity-expansion benefits.

A list of measures by end-use used in this CPA is included 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 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 three 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 be installed the measure. 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] Reproduced 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 unaffected 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. Achievable potential considers 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 a maximum achievability of 85% for all measures 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 the 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 includes 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.

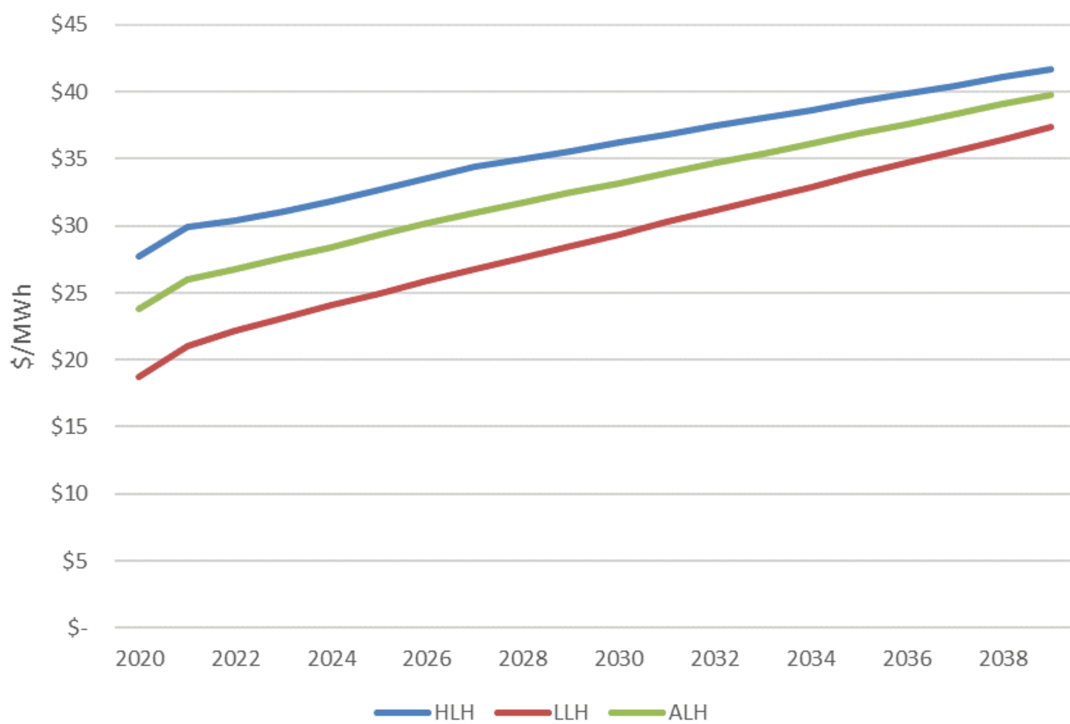
Avoided Cost

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 ($/aMW) and values associated with the demand savings ($/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.

Figure 3 shows the 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 (Mid-Columbia)



The EIA requires that utilities "…set avoided costs equal to a forecast of market prices." As discussed in Appendix IV, Richland currently meets the majority of its peak demands through purchases of Tier 1 power from BPA. Since Richland's loads exceed its rate period high water mark, as defined in the current BPA power contract, a relatively small amount of Richland's capacity needs are met through non-federal market purchases. As such, Richland's marginal purchases are currently market-based power purchase contracts. This matches up well with EIA rules that require the use of market prices in the calculation of avoided costs.

Social Cost of Carbon & Renewable Energy Credits

In addition to the avoided cost of energy, energy efficiency provides the benefit of reducing carbon emissions. The EIA rules require the inclusion of the social cost of carbon, and Washington's recently enacted Clean Energy Transformation Act seeks specifies which values should be used. These values were used in the development of the results discussed in this report. Additional scenarios considered other values. While rulemaking is still ongoing, state staff have proposed adopting the social cost of carbon developed by the federal Interagency Workgroup using the 2.5 percent discount rate, the same values that the CETA requires investor-owned utilities to use.

These carbon costs were included in all avoided cost scenarios.

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, utilities are required to source 15% of all electricity sold to retail customers from renewable energy resources and in 2030 the requirement effectively goes to 100%, while allowing 20% of the requirement to be met through RECs or other means. Conservation can reduce the cost of this requirement by reducing Richland'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, Council staff developed a distribution system credit value of $6.33/kW-year and a transmission system credit of $2.85/kW-year applied to peak savings from conservation measures, at the time of the regional transmission and local distribution system peaks. These values were developed in preparation for the 2021 Power Plan.

Generation Capacity

Currently, Richland is a load-following customer of BPA and pays a demand charge to BPA, based on its peak demand every month. The demand charge is set in each rate case based on the marginal capacity resource. Currently, the demand charges are approximately $10/kw-month and are based on an LMS100 combustion turbine. These demand charges effectively serve as the marginal cost of generation capacity for Richland.

By assuming a monthly shape to conservation's demand savings, the charges were converted into a value of $81/kW-year. For the base case, it was assumed BPA's demand charges will increase in real terms by 3% annually. Over twenty years, the resulting cost of avoided capacity is $89/kW-year (2012$) in levelized terms. In the low scenario, no cost escalation was assumed, resulting in a 20-year levelized cost of $69/kW-yr.

In the Council's Seventh Power Plan, a generation capacity value of $115/kW-year was explicitly calculated ($2012). This value was used in the high scenario.

Risk Analysis

In the past, 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 $18/MWh and $26/kW-year were included in the avoided cost. For reference, in the past, 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.

Pacific Northwest Electric Power Planning and Conservation Act Credit

Finally, a 10% benefit was added to all 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 most recent real discount rate assumption developed by the Council is 4%, which was used in the Seventh Plan. For Richland, a discount rate of 3.75% was used to model conservation potential for this assessment. This discount rate is used by Richland in other financial modelling. 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.

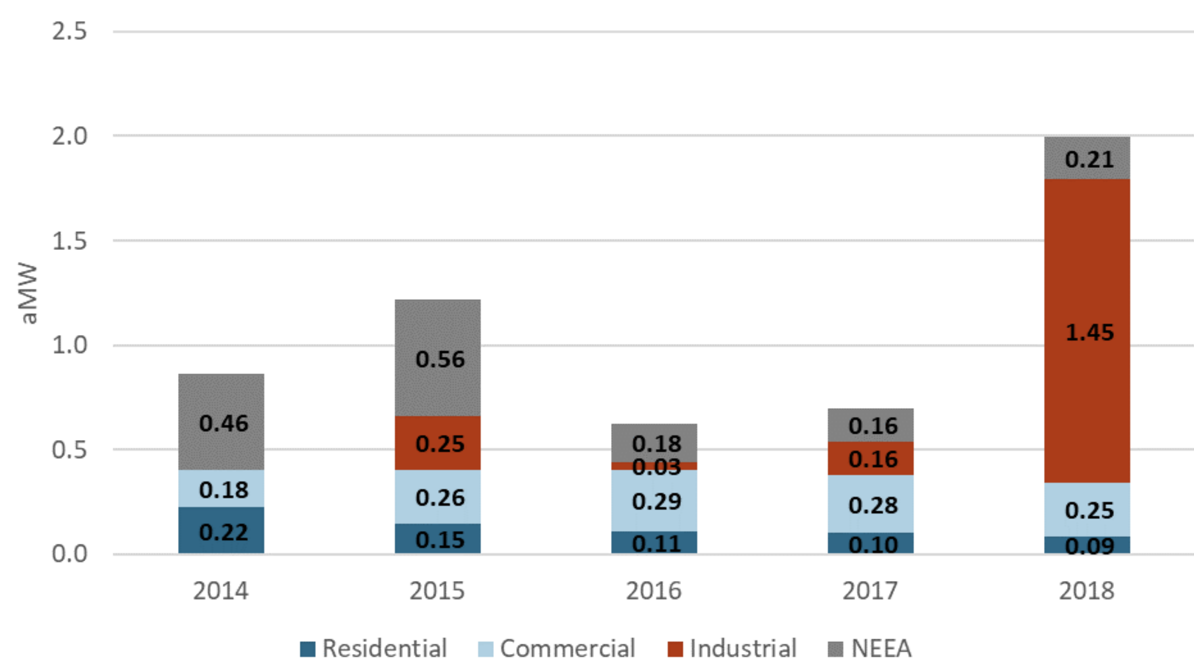
Recent Conservation Achievement

Richland has pursued conservation and energy efficiency resources. Currently, the utility offers several rebate programs for both residential and non-residential customers. These include residential heating and weatherization and programs for non-residential lighting and custom projects for non-residential customers.

Figure 4 details the distribution of conservation among the utility's customer sectors and through Northwest Energy Efficiency Alliance (NEEA) efforts over the past five years. Richland's conservation achievement has averaged 1.08 aMW per year since 2014. More detail for these savings is provided below for each sector.

Savings from NEEA declined 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. NEEA's work helps bring energy efficient emerging technologies, like ductless heat pumps and heat pump water heaters to the Northwest markets.

Figure 4
Richland's Recent Conservation History by Sector



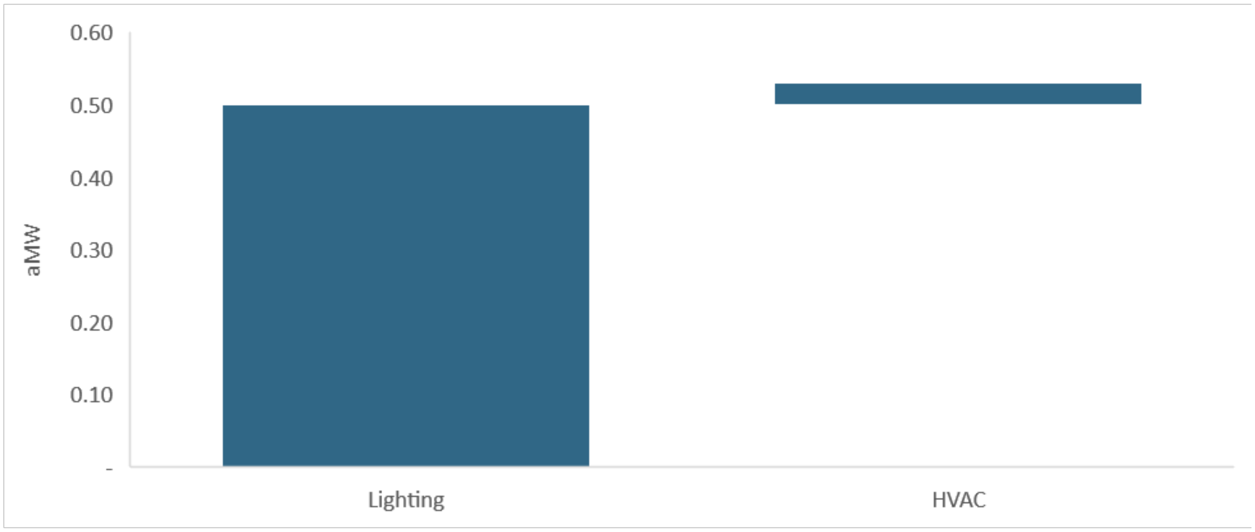
Residential

Richland achieved 0.19 aMW of residential conservation in 2017 and 2018. All of these savings occurred in the HVAC end-use.

Commercial

Historic achievement in the commercial sector is due to lighting and HVAC. Figure 5 shows the breakdown of 2017 and 2018 savings.

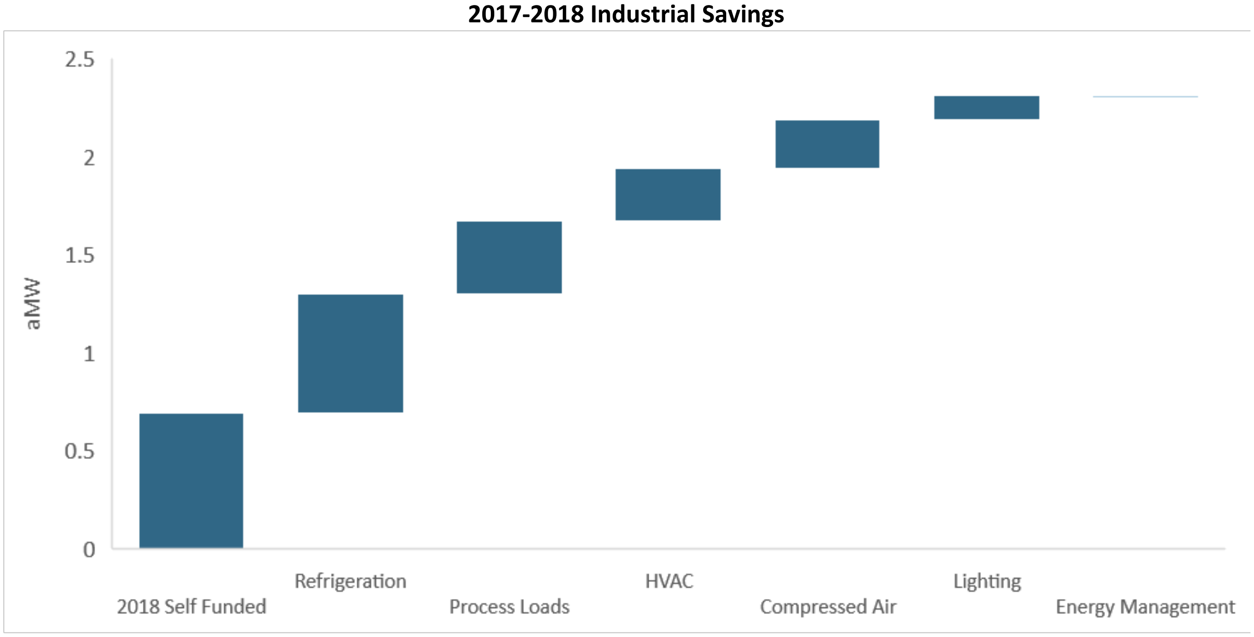
Figure 5
2017-2018 Commercial Savings



Industrial

Historic achievement in the industrial sector is primarily due to custom projects, refrigeration and process loads.

Figure 6
2017-2018 Industrial Savings



Current Conservation Programs

Richland offers a wide range of conservation programs to its customers. These programs include rebates and low-interest loans to qualified customers for energy efficient HVAC equipment and conservation measures including insulation, windows, and doors. Customers can select only a rebate or apply for a low-interest loan with a rebate. For commercial and industrial customers rebates are available for lighting and custom projects.

Summary

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

Customer Characteristics Data

Richland serves more than 24,500 electric customers in Benton County, Washington, with a service area population of nearly 57,500. A key component of an energy efficiency assessment is to understand the characteristics of these customers – primarily the building and end-use characteristics. These characteristics are described below for each customer sector.

Residential

For the residential sector, the key characteristics include house type, heat fuel type, and water heating. Table 1 shows relevant residential data for single family, multi-family and manufactured homes in Richland'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. The data shown in Table 1 provides estimates of the current residential characteristics in Richland's service territory and are utilized as the baseline in this study.

This assessment assumes an average annual residential growth rate of 1.0 percent.

Table 1
Residential Building Characteristics

Heating Zone	Cooling Zone	Solar Zone	Residential Households	Total Population
1	3	3	24,196	57,426

	Single Family	Multifamily Low Rise	Multifamily High Rise	Manufactured
Heating / Cooling System Saturations				
Electric Forced Air Furnace (FAF)	6%	16%	16%	56%
Heat Pump (HP)	61%	0%	0%	19%
Ductless HP (DHP)	3%	0%	0%	0%
Electric Zonal (Baseboard)	6%	67%	67%	0%
Central AC	20%	12%	12%	44%
Room AC	12%	63%	63%	13%
Appliance Saturations				
Electric WH	79%	77%	77%	94%
Refrigerator	136%	105%	105%	119%
Freezer	45%	16%	16%	50%
Clothes Washer	96%	53%	53%	100%
Clothes Dryer	91%	49%	49%	100%
Dishwasher	87%	67%	67%	88%
Electric Oven	96%	100%	100%	100%
Desktop	49%	40%	40%	56%
Laptop	53%	35%	35%	38%
Monitor	51%	44%	44%	56%

Commercial

Building square footage 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 (kWh per square foot). The 2020 commercial square footage was estimated with 2018 load data provided by Richland. Load data was converted to floor area by applying energy use intensity values from the Commercial Building Stock Assessment (CBSA).

Table 2 shows 2020 commercial square footage and growth rates in each of the 18 building categories. The growth rates presented in Table 2 do not include commercial building demolition assumptions for Richland's service territory. Demolition rates are based on Council assumptions and vary by year and building segment. The average growth rate for commercial buildings is 1.2%.

Table 2
Commercial Building Square Footage by Segment

Segment	Area (Square Feet)	Growth Rate
Large Office	6,625,296	
Medium Office	9,449,283	
Small Office	503,552	
Extra Large Retail	1,912,331	
Large Retail	690,311	
Medium Retail	478,259	
Small Retail	20,882	
School (K-12)	1,643,867	
University	413,762	
Warehouse	5,564,246	
Supermarket	17,243	
Mini Mart	49,832	
Restaurant	232,200	
Lodging	572,093	
Hospital	1,063,551	
Residential Care	341,531	
Assembly	506,939	
Other Commercial	1,395,817	
Total	**31,480,994**	**1.2%**

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.

Richland provided 2018 energy use for its industrial customers. Individual industrial customer usage and projected growth is shown by industrial segment in Table 3.

Table 3
Industrial Sector Load by Segment

Segment	Annual Base Load (2018 MWh)	Annual Growth Rate
Foundries	25,355	1.0%
Frozen Food	57,487	1.7%
Other Food	9,328	1.0%
Metal Fabrication	37,715	0.5%
Cold Storage	3,311	4.1%
Chemical	189	1.0%
Miscellaneous Manufacturing	15,601	1.2%
Total	**148,986**	**1.2%**

Distribution Efficiency (DEI)

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 aMW, depending on the measure.

Richland 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.

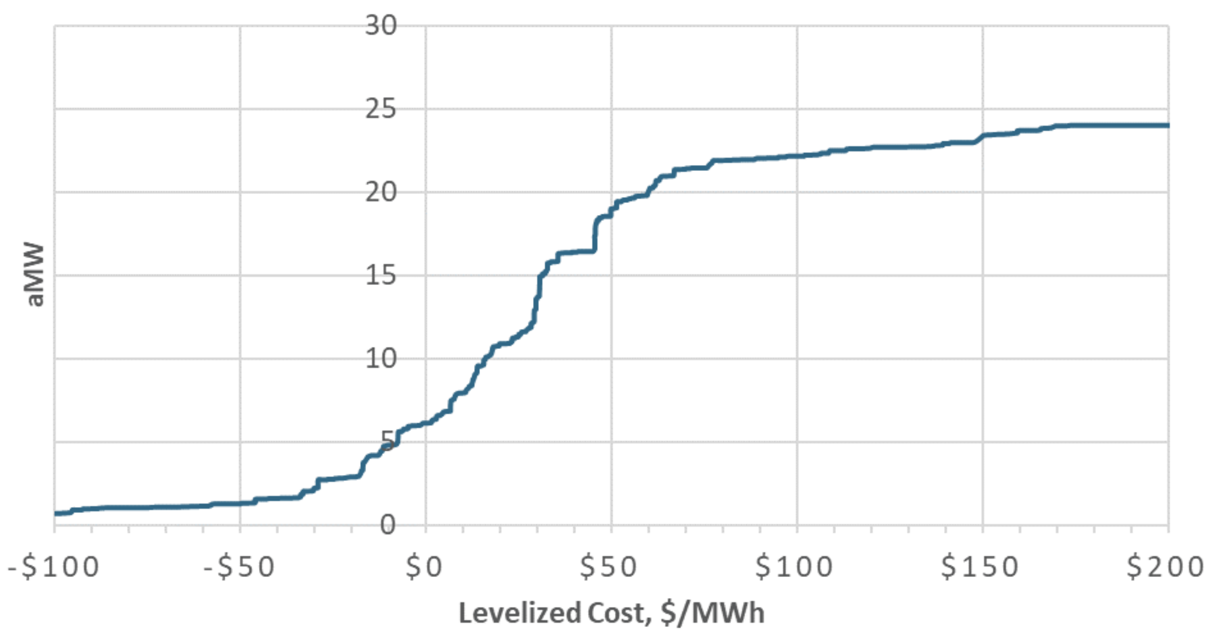
Results – Energy Savings and Costs

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.

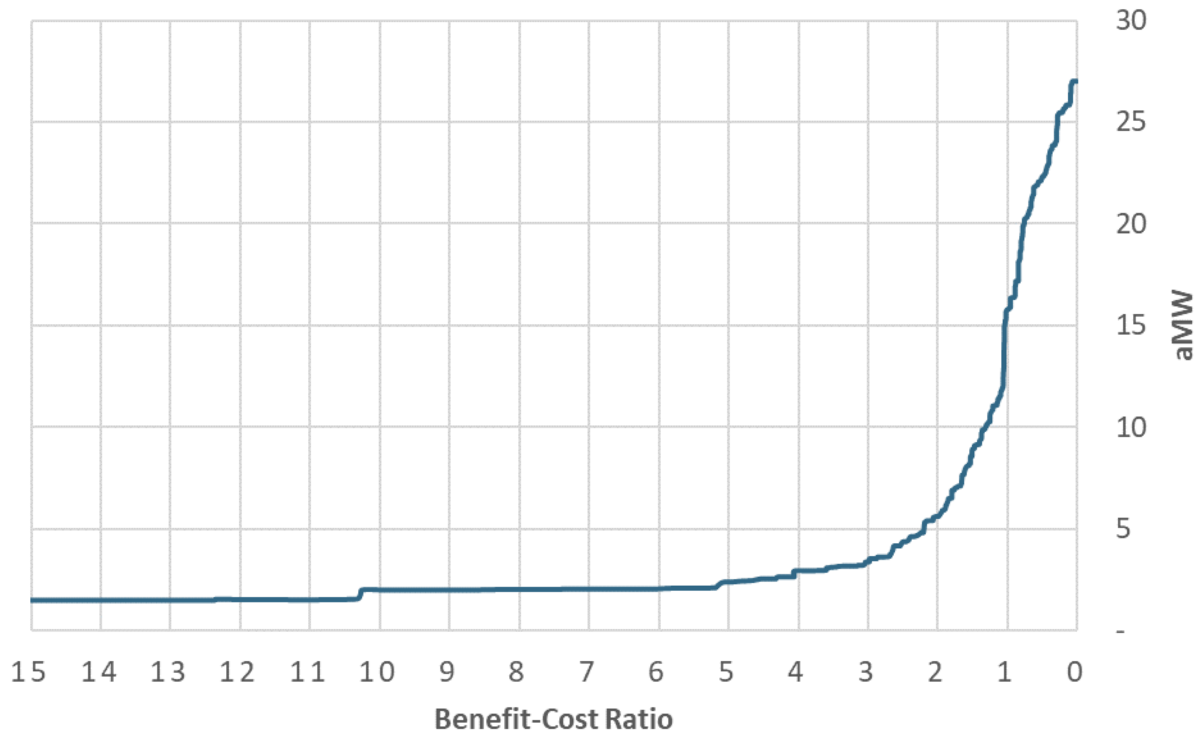
Figure 7, below, shows a supply curve of 20-year achievable potential. A supply curve is developed by plotting energy efficiency savings potential (aMW) against the levelized cost ($/MWh) of the conservation. The technical potential has not been screened for cost effectiveness. Costs are standardized (levelized), allowing for the comparison of measures with different lives. The supply curve facilitates comparison of demand-side resources to supply-side resources and is often used in conjunction with resource plans. Figure 7 shows that 13.2 aMW of saving potential are available for less than $30/MWh and over 22 aMW are available for under $80/aMW. Total achievable potential for Richland is approximately 27 aMW over the 20-year study period.

Figure 7
20-Year Technical-Achievable Potential 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 8 below. This figure repeats the overall finding that 15.79 aMW of potential is cost-effective with a benefit-cost ratio greater than or equal to 1.0. The line is steep near the point where the benefit-cost ratio is 1.0, suggesting significant changes in economic potential if avoided cost parameters are changed.

Figure 8
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 4 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 achievable potential, it shows that 15.79 aMW of the total 27.03 aMW is cost-effective for Richland. The last section of this report discusses how these values could be used for setting targets.

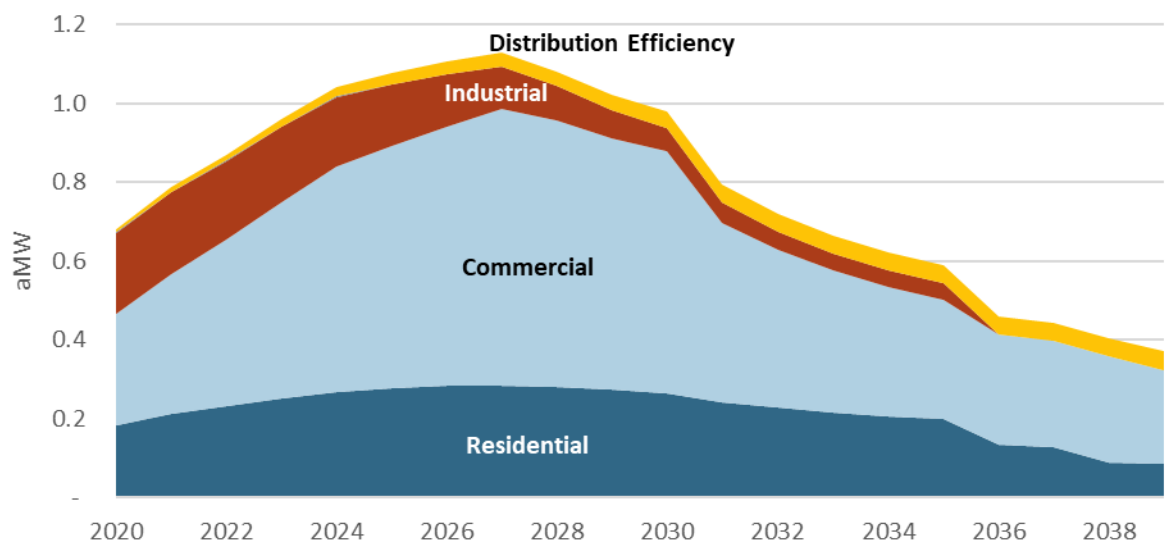
Table 4
Cost-Effective Achievable Potential - Base Case (aMW)

	2-Year	6-Year	10-Year	20-Year
Residential	0.39	1.42	2.54	4.33
Commercial	0.64	2.74	5.42	8.93
Industrial	0.41	1.14	1.54	1.82
Distribution Efficiency	0.02	0.11	0.25	0.70
Agricultural	0.00	0.01	0.01	0.01
Total	**1.47**	**5.41**	**9.75**	**15.79**

Sector Summary

Figure 9 shows economic achievable potential by sector on an annual basis.

Figure 9
Annual Achievable Potential by Sector



The largest share of the potential is in the commercial sector followed by substantial savings potential in the residential sector. Ramp rates are used to establish reasonable 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 Richland's current rate of program achievement. These changes decelerated the acquisition of potential in all sectors except distribution efficiency and agricultural. 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 7 below shows how recent program history compares to the near-term program potential. Residential savings exclude lighting savings, as these measures were excluded from the program potential. Savings from NEEA have been allocated to the appropriate sectors.

Table 7
Comparison of Program Achievement and Potential

	Program History				Potential		
	2017	2018	2019	Average	2020	2021	2022
Residential	0.229	0.249	0.220	0.233	0.181	0.213	0.232
Commercial	0.307	0.295	0.507	0.370	0.284	0.354	0.420
Industrial	0.165	1.453	0.514	0.711	0.206	0.207	0.201
Distribution Efficiency	-	-	-	-	0.001	0.001	0.001
Agricultural	-	-	-	-	0.007	0.011	0.015
Total	**0.701**	**1.997**	**1.241**	**1.313**	**0.680**	**0.786**	**0.870**

Residential

Residential 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 10 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 primarily comprised of measures in the HVAC and water heating end uses. Measures in other end uses, such as refrigeration, did not pass the economic screening.

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. Other measures included in the water heating end use include aerators, behavior programs, clothes washers, and thermostatic shutoff valves.

Electronics contribute slightly to Richland's potential with both computer and monitor measures. Food preparation also contributes somewhat with electric oven and microwave measures.

Figure 10
Annual Residential Potential by End Use

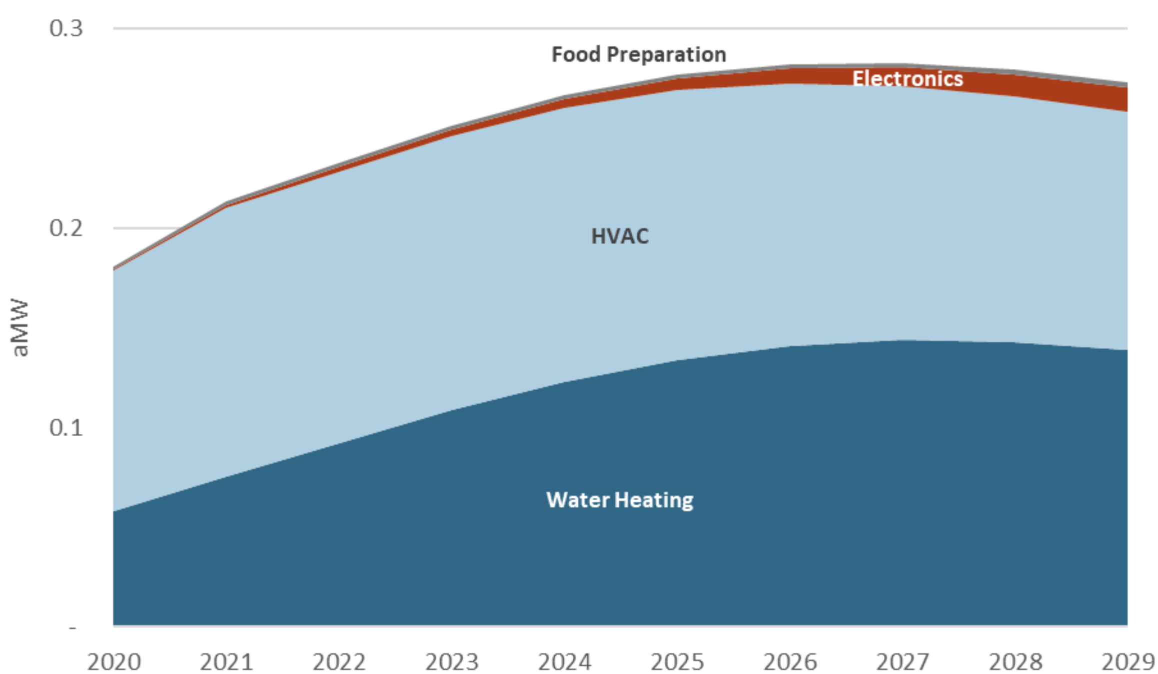
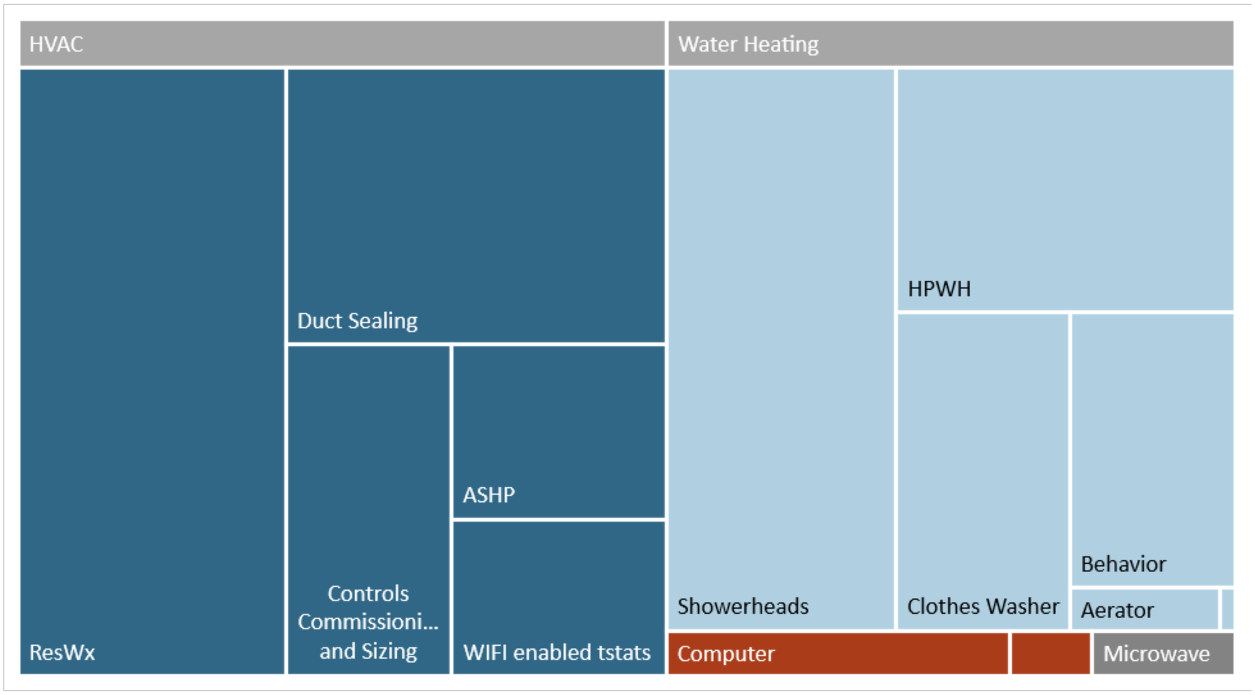


Figure 11 shows how the 10-year residential potential breaks down into end uses and key measure categories. The area of each block represents its share of the total 10-year residential potential.

Figure 11
Annual Residential Potential by End-Use



Commercial

Commercial lighting measures are the largest share of commercial conservation potential for the 2019 CPA planning period (Figure 12). Lighting savings are lower in this assessment after accounting for the federal EISA standard, which impacts several commercial measures.

HVAC control measures continue make up a substantial part of the balance of commercial conservation potential for this assessment period. Significant measures in this category include advanced rooftop controls, ductless heat pumps and variable refrigerant flow technology.

Commercial HVAC measures are often more complicated and disruptive to install compared to lighting measures and are, therefore, more slowly acquired.

Figure 12
Annual Commercial Potential by End Use

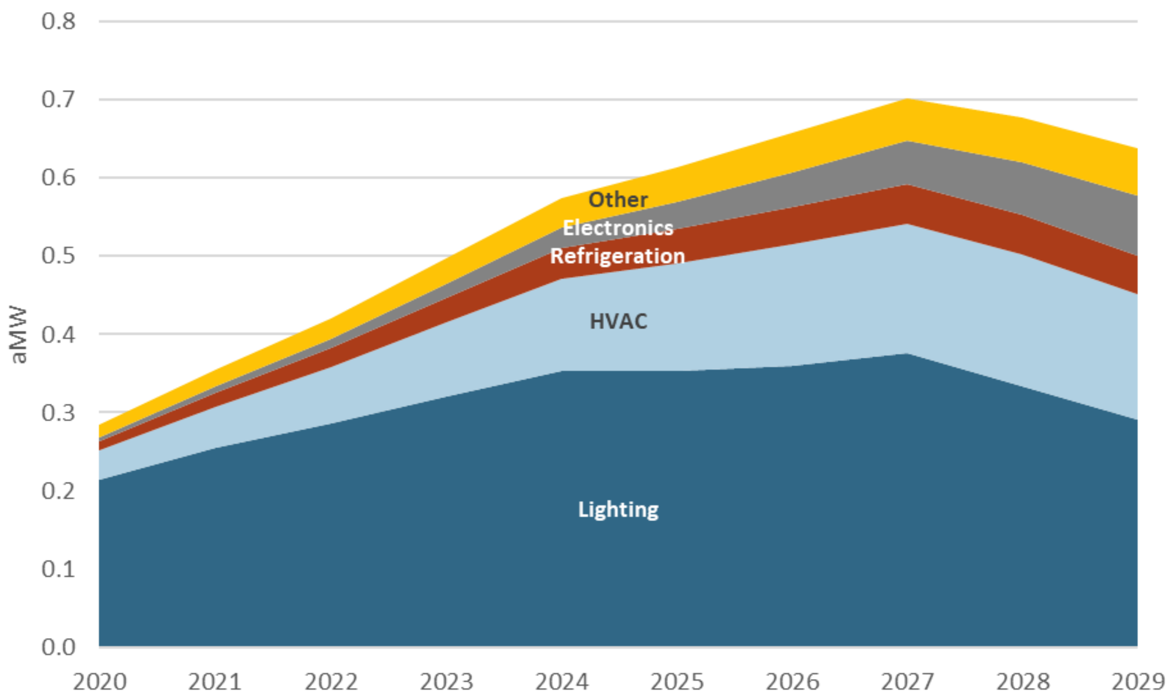
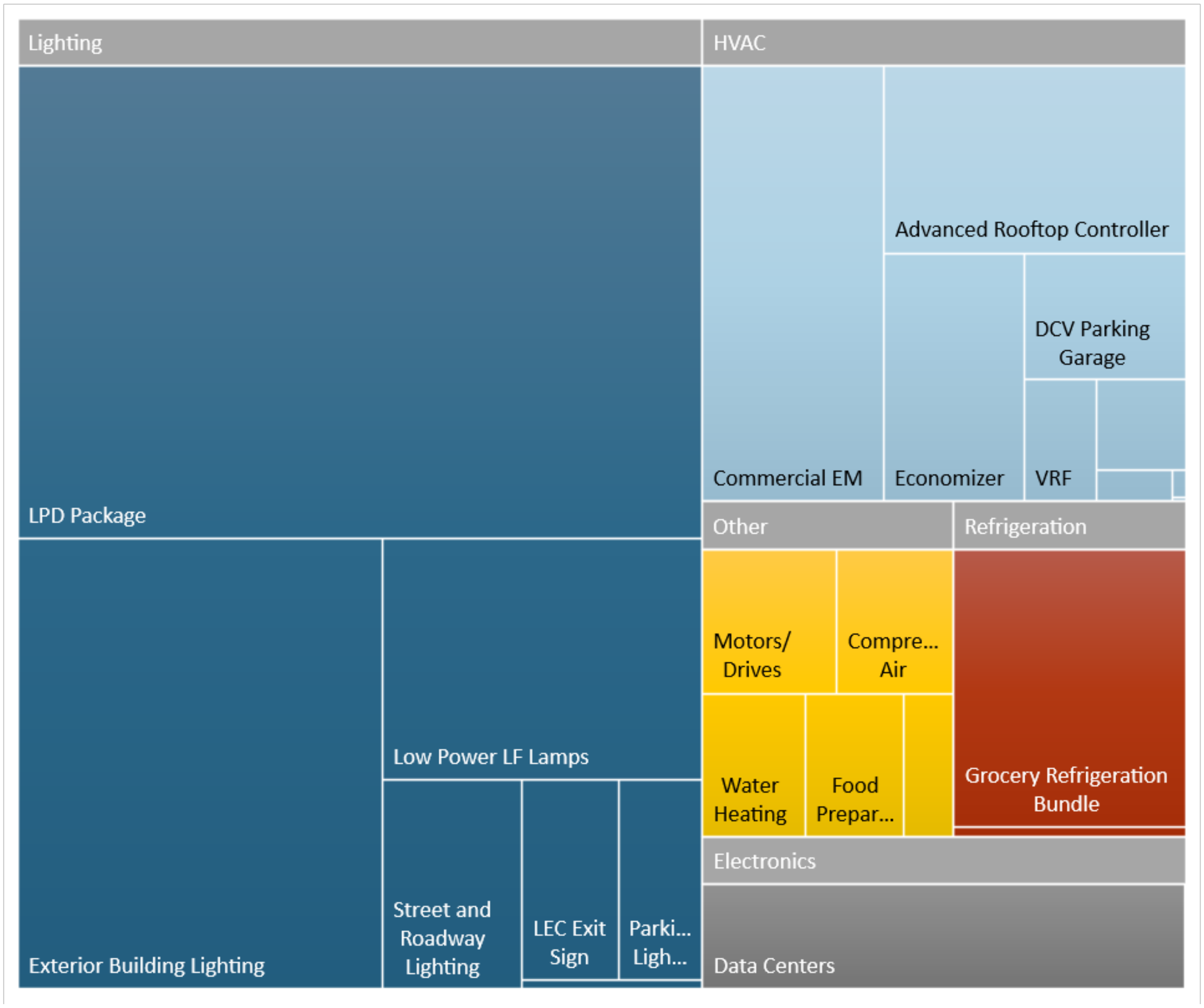


Figure 12 shows that, unlike residential potential, the commercial potential is characterized by a diverse set of measures and end uses due to the more varied nature of commercial buildings. The Other category is made up of measures in the compressed air, motors/drives, process loads, food preparation and water heating end uses. 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 13. The area of each block represents its share of the 10-year commercial potential.

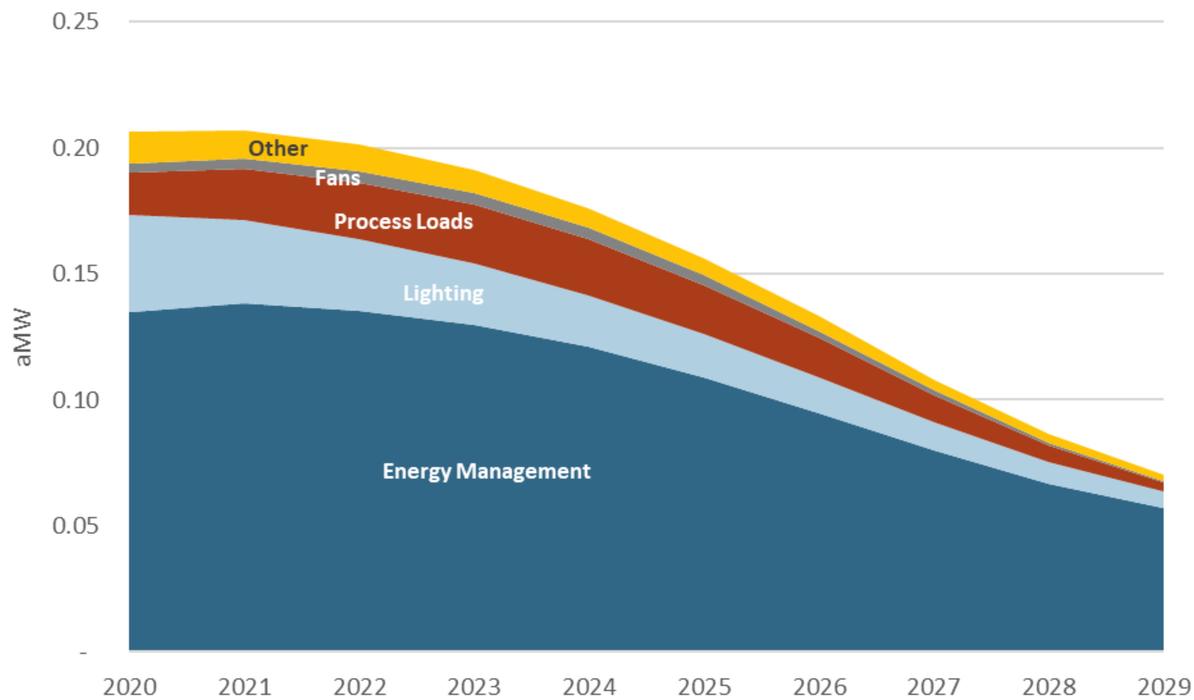
Figure 13
Commercial Potential by End Use and Measure Category



Industrial

Industrial sector potential by end-use category is shown in Figure 14. The majority of industrial potential is made up of energy management. Other measures also contribute savings to this sector, such as lighting and process load measures. The 2, 6, 10 and 20-year industrial sector potential estimates by measure end-use category are provided in Appendix VI.

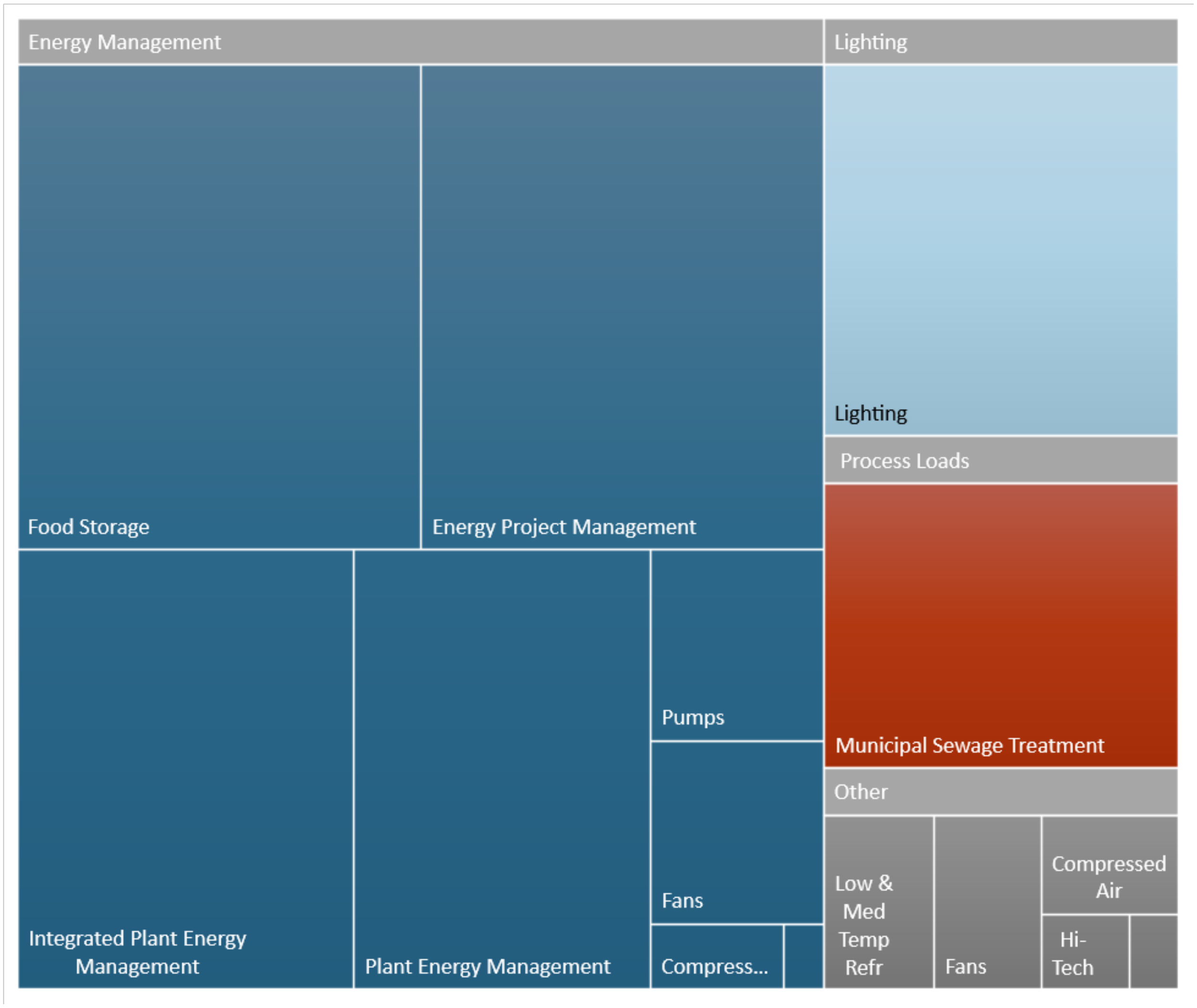
Figure 14
Annual Industrial Potential by End Use



In Figure 14, the Other category is comprised of measures in the high-tech, compressed air, low and medium temperature refrigeration, and metals end uses.

Figure 15 shows how the 10-year industrial potential breaks down by end use and measure categories. Energy management is a suite of behavioral measures targeted towards specific end uses or generally at industrial sites (such as energy project management, integrated plant energy management and plant energy management).

Figure 15
Industrial Potential by End Use and Measure Category

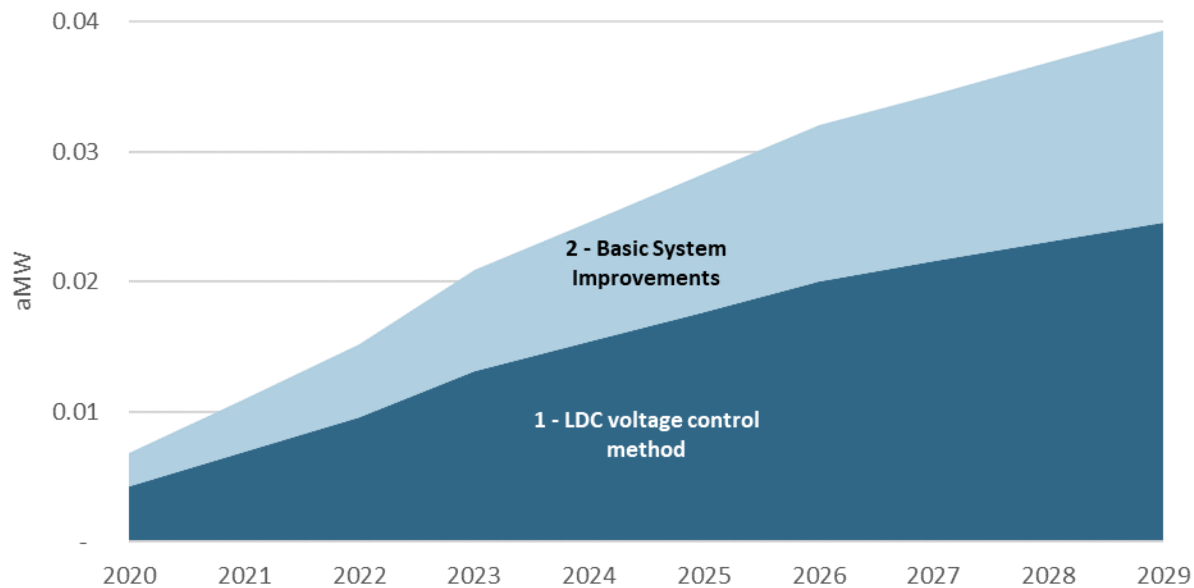


Distribution Efficiency

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 16. 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 previous section are also based on the end-system sales method.

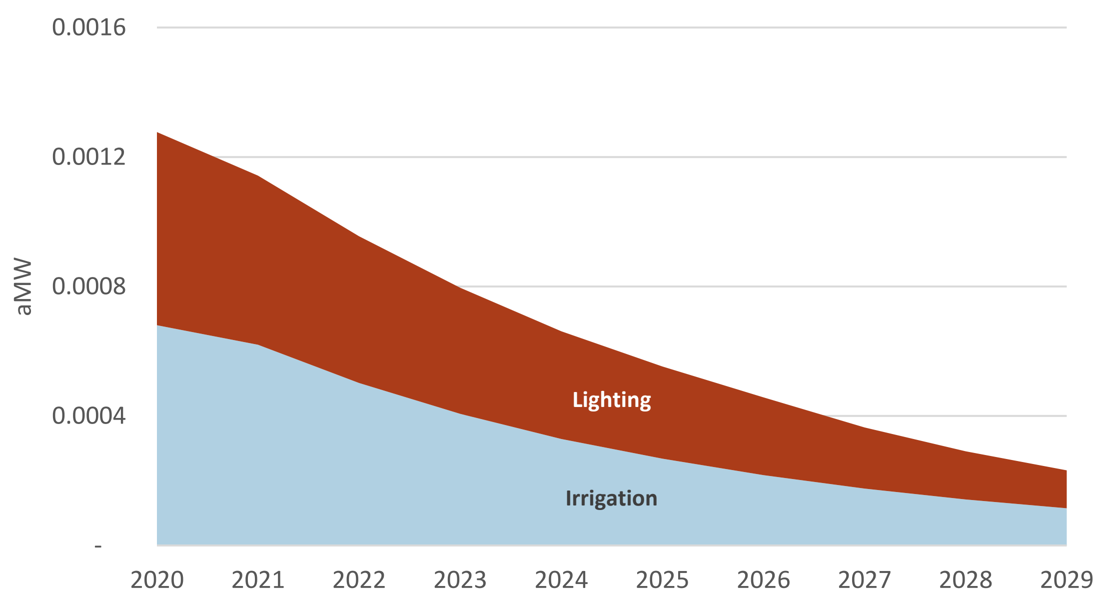
Figure 16
Annual Distribution System Potential by End Use



Agricultural

Figure 17 below show agricultural potential by end-use through 2029. Potential is made up of irrigation and lighting measures.

Figure 17
Annual Agricultural Potential by End Use



Cost

Budget costs can be estimated at a high level based on the incremental cost of the measures (Table 8). The assumptions in this estimate include: 20 percent of measure cost for administrative costs and 40 percent for incentive costs. These costs for administrative expenses and incentives are standard assumptions and are used in the Seventh Power Plan.

This table shows that Richland can expect to spend $3.5 million to realize estimated savings over the next two years including program administration costs. The bottom row of Table 8 shows the cost per MWh of first-year savings. Annual utility program costs can be found in Appendix VIII.

Table 8
Utility Program Costs (2019$)

	2-Year	6-Year	10-Year	20-Year
Residential	$1,587,000	$5,124,000	$8,426,000	$13,934,000
Commercial	$1,241,000	$5,415,000	$10,945,000	$20,245,000
Industrial	$517,000	$1,413,000	$1,908,000	$2,268,000
Distribution Efficiency	$6,000	$37,000	$85,000	$240,000
Agricultural	$4,000	$8,000	$11,000	$12,000
Total	**$3,355,000**	**$11,997,000**	**$21,375,000**	**$36,699,000**
$/First Year MWh	$261	$253	$250	$265

The cost estimates above are conservative estimates for costs going forward since they are based on historic values. Future conservation achievement may be more costly/difficult since the lowest cost, easiest programs are usually implemented first. In addition, as energy efficiency markets become more saturated, it may require more effort from Richland to acquire conservation through its programs. This additional effort may increase administrative costs.

Besides looking at the utility cost, Richland 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 ratepayer will together pay for conservation, similar to how the costs of other power resources are considered (such as in an IRP) and ultimately paid. The TRC costs are shown below (Table 9), levelized over the measure life of each measure. TRC costs by sector and end use are presented in Appendix VIII. Based on costs from the Seventh Power Plan, distribution efficiency measures are by far the lowest cost resource.

Table 9 TRC Levelized Cost (2019$/kWh)				
	2-Year	**6-Year**	**10-Year**	**20-Year**
Residential	$0.063	$0.060	$0.058	$0.060
Commercial	$0.047	$0.048	$0.048	$0.052
Industrial	$0.036	$0.037	$0.037	$0.036
Distribution Efficiency	$0.007	$0.007	$0.007	$0.007
Agricultural	$0.042	$0.042	$0.042	$0.042
Total	**$0.049**	**$0.049**	**$0.049**	**$0.051**

Scenario Results

The costs and savings discussed in the results section describe the Base Case scenario. Under this scenario, annual potential for the planning period was estimated by applying assumptions that reflect Richland'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 more closely reflect Richland'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 avoided cost 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 10 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 10 Avoided Cost Assumptions by Scenario, $2012			
	Base	**Low**	**High**
Energy	Market Forecast	-50%-85% Confidence Interval*	+50%-85% Confidence Interval*
Social Cost of Carbon	Federal 2.5% Discount Rate Values	Federal 2.5% Discount Rate Values	Federal 2.5% Discount Rate Values
Value of REC Compliance	Existing RPS + CETA	Existing RPS + CETA	Existing RPS + CETA
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	$89	$69	$115
Implied Risk Adder: $/aMW $/kW-year	N/A	Up to -$18/aMW -$20/kW-year Average of -$11/aMW -$20/kW-year	Up to $18/aMW $26/kW-year Average of $11/aMW $26/kW-year

Table 11 summarizes results across each avoided input scenario, using Base Case load forecasts and measure acquisition rates.

Table 11 Cost-Effective Potential - Scenario Comparison (aMW)				
	2-Year	**6-Year**	**10-Year**	**20-Year**
Base Case	1.47	5.41	9.75	15.79
Low Scenario	1.05	3.85	6.77	10.29
High Scenario	1.82	6.46	11.58	19.07

In the table above, the change in cost-effective potential when going from the base to the low case is greater than the change in potential when going from the base to the high case. This suggests that there is less risk in pursuing energy efficiency that would end up costing more than the avoided costs, but more risk in undervaluing energy efficiency. This suggests that there is real risk of doing too little energy efficiency, as there could be additional energy efficiency that would be cost effective if some of the avoided costs assumed in the base case were too low.

This result is somewhat evident from the Benefit-Cost Ratio supply curve presented earlier in the report. The supply curve has a steep slope to the right of the threshold of cost-effectiveness, where the BCR equals 1.0, suggesting a high degree of sensitivity to upward changes in avoided cost parameters. The fact that the cost-effective potential increased more in the high avoided cost scenario than in the low scenario indicates the nature of the risk: there is more risk to undervaluing energy efficiency than overvaluing it. Richland should consider this outcome when selecting their goals.

In addition to analyzing the sensitivity of the 20-year cost-effective potential to variation in avoided costs, this analysis considered the sensitivity of results to the avoided cost scenarios described above in combination with different sector growth rates. These scenarios are described below.

Low Scenario

The Low Conservation scenario evaluates the cost-effective energy efficiency potential under a low market price forecast. The Base Case market price forecast and other avoided cost assumptions were adjusted downward as outlined in Table 10 above.

Under the Low scenario sector growth assumptions were not changed. Results of the Low scenario analysis are shown in Table 12.

Key parameters for the Low scenario include:

- Low avoided cost assumptions

Table 12
Cost-Effective Potential - Low Case (aMW)

	2-Year	6-Year	10-Year	20-Year
Residential	0.21	0.83	1.46	2.43
Commercial	0.51	2.07	3.91	5.86
Industrial	0.31	0.84	1.12	1.29
Distribution Efficiency	0.02	0.11	0.25	0.70
Agricultural	0.00	0.00	0.01	0.01
Total	**1.05**	**3.85**	**6.77**	**10.29**

High Scenario

Richland's High Conservation scenario makes use of the high avoided cost assumptions described above in Table 10.

Key parameters for the High scenario include:

- High avoided cost assumptions

Table 13 Cost Effective Achievable Potential - High Case (aMW)				
	2-Year	**6-Year**	**10-Year**	**20-Year**
Residential	0.44	1.68	3.16	5.93
Commercial	0.74	3.07	6.01	9.78
Industrial	0.61	1.56	2.05	2.36
Distribution Efficiency	0.03	0.15	0.35	0.99
Agricultural	0.00	0.01	0.01	0.01
Total	**1.82**	**6.46**	**11.58**	**19.07**

Summary

This report summarizes the results of the 2019 CPA conducted for Richland Energy Services. 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 per EIA requirements. 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 cycle. 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 Richland 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."[2] 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.[3]

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 ten-year assessments. This document serves as support for the target selected by Richland and approved by its City Council.

Summary

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.

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

[3] 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

aMW –Average Megawatt

BPA – Bonneville Power Administration

CFL – Compact Fluorescent Light Bulb

EIA – Energy Independence Act

EES – EES Consulting

HLH – Heavy load hour energy

HVAC – Heating, ventilation and air-conditioning

kW – kilowatt

kWh – kilowatt-hour

LED – Light-emitting diode

LLH – Light load hour energy

MF –Multi-Family

MH –Manufactured House

MW –Megawatt

aMW –Megawatt-hour

NEEA – Northwest Energy Efficiency Alliance

NPV – Net Present Value

O&M – Operation and Maintenance

RPS – Renewable Portfolio Standard

RTF – Regional Technical Forum

SB 5116 – Washington Senate Bill 5116

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 considers 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 – "Richland 2019 Conservation Potential Assessment." Final Report – March 20, 2020.
2) Model – "EES CPA Model-v3.3_base.xlsm" and supporting files
   a. MC_AND_LOADSHAPE-Richland-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 Richland 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 $ 72/kW-year in the base case cost effectiveness analysis. This is based upon Richland's 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 Richland'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 Federal 2.5% discount rate values.	Report – See avoided cost appendix
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 (EES) has conducted a Conservation Potential Assessment (CPA) for the City of Richland Energy Services Department (RES) for the period 2020 through 2039, following the requirements of RCW 19.285 and WAC 194.37. According to WAC 197.37.070, the cost-effectiveness of conservation must be evaluated 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 considers 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 (Mid-C) trading hub. This section summarizes the methodology used to develop the forecast, benchmarks it against other forecasts, and compares the forecast to the market forecast used in RES's 2015 CPA.

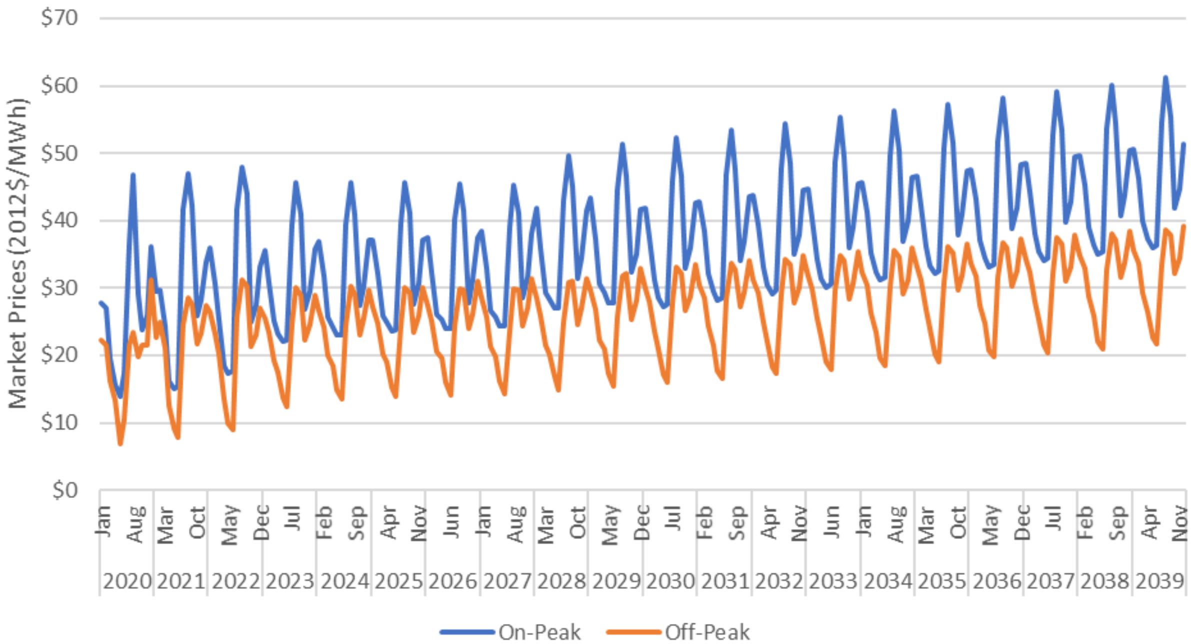
Methodology

For the period January 2020 to October 2029, projected monthly on- and off-peak market prices were provided through a subscription service. These market prices were sourced on November 1, 2019. EES extended the sourced market prices through the remainder of the CPA period by applying a simple linear model controlling for seasonal variation in prices. The resulting price forecast for the period January 2020 to December 2039 has an annual growth rate of 2.9%.

Results

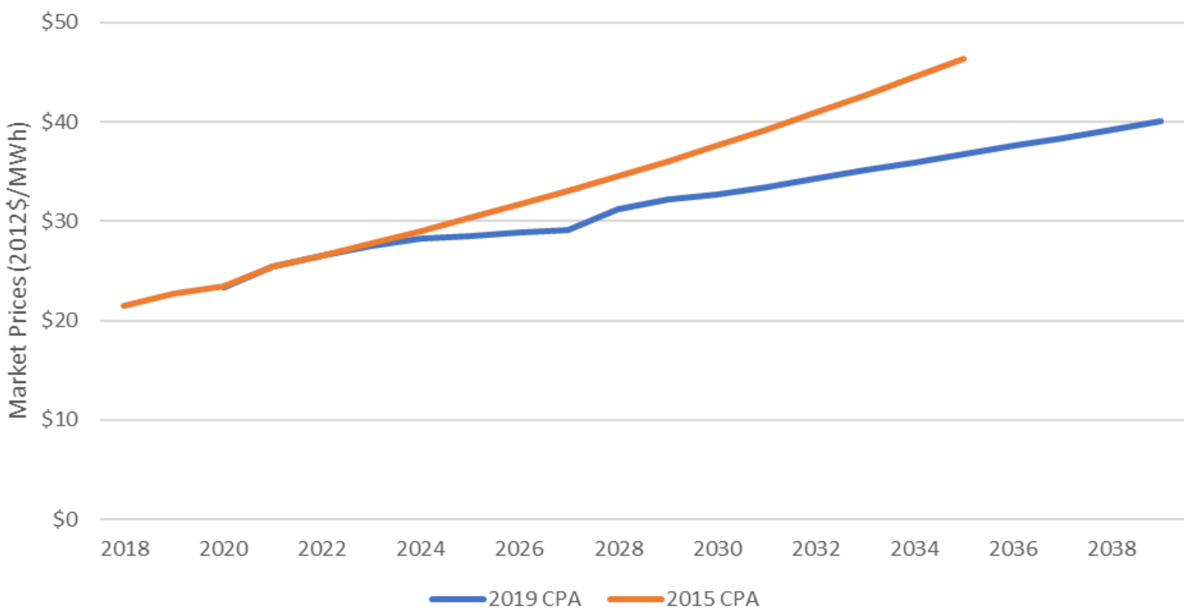
Figure IV-1 illustrates the resulting monthly, diurnal market price forecast. The levelized value of around-the-clock forecast market prices over the study period is $31.22/MWh in 2012 dollars, assuming a 3.75 percent real discount rate.

Figure IV-1
Forecast Mid-C Market Prices



This market price forecast is slightly lower than the market price forecast used in RES's previous CPA, conducted in 2015. Figure IV-2 compares the average annual price of the two forecasts. The 2019 CPA's 20-year market price forecast begins at approximately the same values as the 2015 CPA, however lower prices in 2024 through 2029 result in a divergence in the later forecast period of roughly nine dollars.

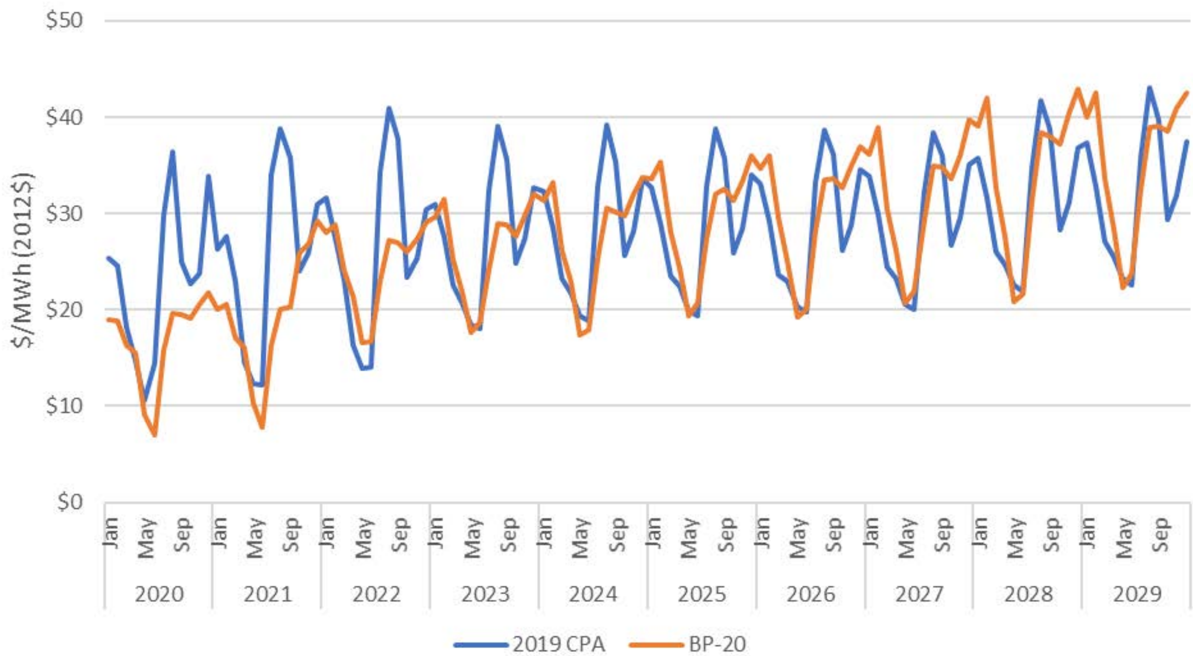
Figure IV-2
Forecast Mid-C Market Prices in 2019 CPA and 2015 CPA



Benchmarking

Figure IV-4 compares the EES market forecast with the 2020-29 market price forecast included in BPA's rate models used in the calculation of BPA's initial proposal for FY 2020-21 power rates. The monthly shapes differ in the short term as the BPA market price forecast is lower through the first few years, likely due to lower market power prices at the time it was prepared, in the second quarter of 2019. The forecasts are similar from summer 2021 forward, noting the CPA forecast peaks higher in summer months.

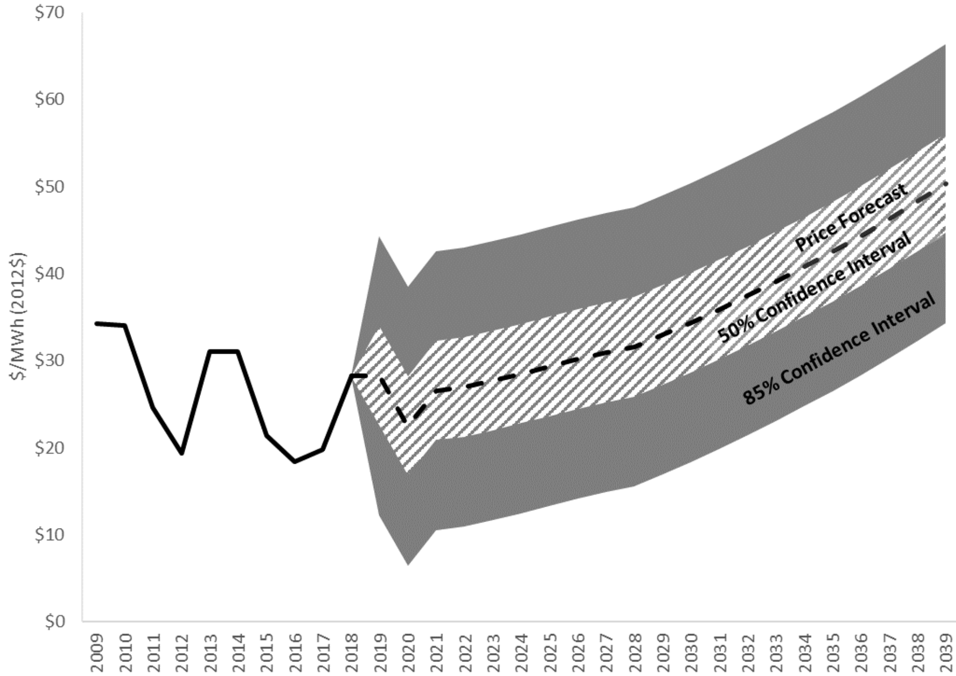
Figure IV-4
Forecast Mid-C Market Prices compared to BPA's Market Price Forecast



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-C 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 an 85% confidence interval over time to estimate the high and low market price forecasts. Figure IV-5 illustrates how the historic and forecast prices were used to develop the confidence intervals used to develop the high and low forecasts.

Figure IV-5
Mid-C Market Price History and Forecast with Confidence Intervals



Figures IV-6 and IV-7 compare the resulting price forecasts, for on-peak and off-peak load hours, respectively.

Figure IV-6
On-Peak Mid-C Market Price Forecast

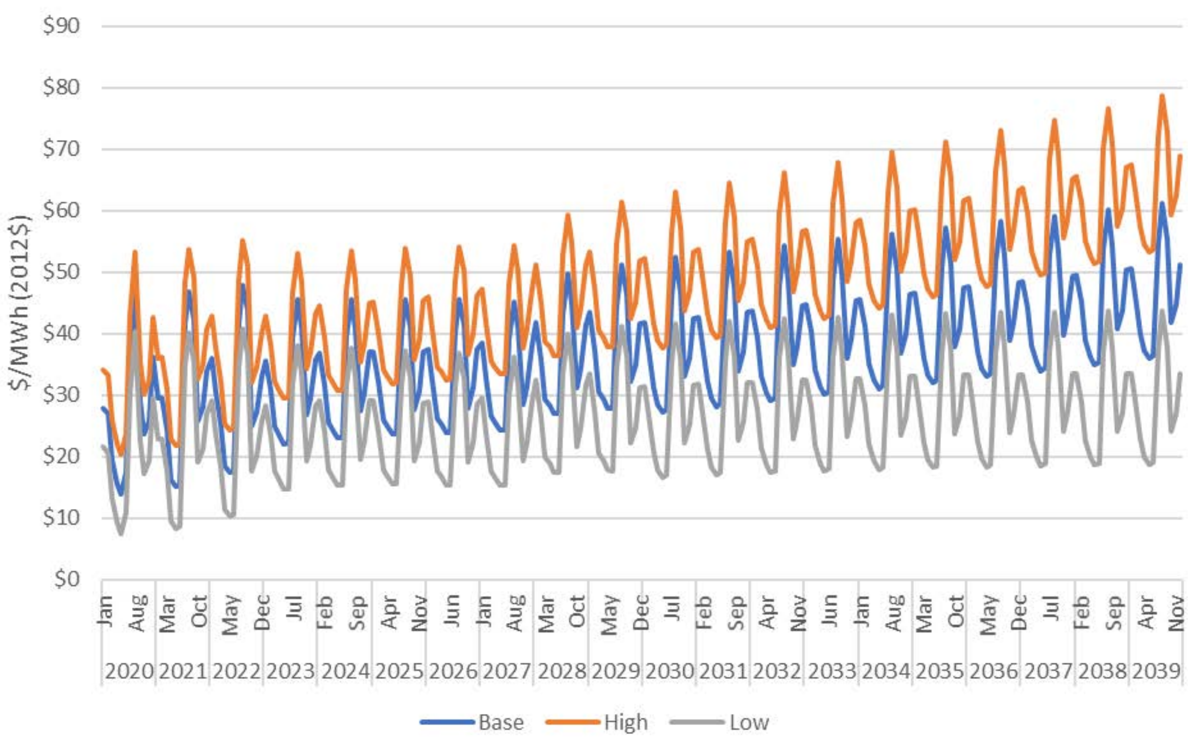
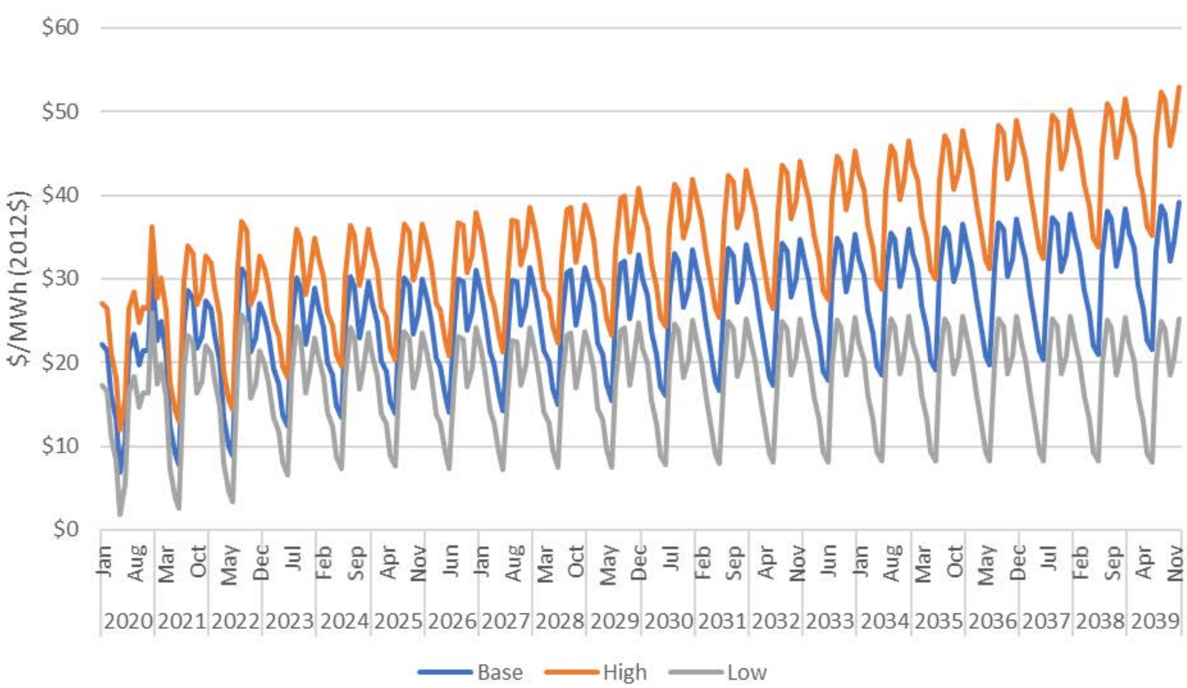


Figure IV-7
Off-Peak Mid-C Market Price Forecast



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 and energy savings, 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 cost that society incurs when fossil fuels are burned to generate electricity. EIA rules require that CPAs include the social cost of carbon when evaluating cost effectiveness using the total resource cost test (TRC). Further, Washington state's Clean Energy Transformation Act (CETA) seeks to specify what values utilities use. While rulemaking is still ongoing, state staff have proposed adopting the social cost of carbon developed by the federal Interagency Workgroup using the 2.5 percent discount rate, the same values that the CETA requires investor-owned utilities to use.

These carbon costs were included in all avoided cost scenarios.

In addition to these carbon costs, the variation of the marginal generation resource over time also needs to be considered. In the spring runoff season, hydropower and wind are the likely marginal resources, while gas turbines likely 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 all other months.

Beginning in 2030, CETA requires that all energy be greenhouse gas neutral, although there are provisions for alternate compliance paths until 2045. As such, the CPA assumes that all energy will be carbon-free from 2030 through the end of the study period.

Value of Renewable Portfolio Standard Compliance

Washington's Energy Independence Act established a Renewable Portfolio Standard (RPS) for utilities with 25,000 or more customers. RES will be required to source 3% of all electricity sold to retail customers from renewable energy resources beginning in 2026. In 2030, the requirement increases to 9%.

Washington's CETA requires that 100% of sales be greenhouse gas neutral in 2030, although 20% can be achieved through alternate compliance options such as the purchase of Renewable Energy Credits (RECs). Due to these requirements, energy efficiency's value in reducing RPS compliance costs changes over time.

From 2025 to 2029, energy efficiency can reduce the cost of compliance associated with the existing RPS requirements by reducing RES's overall load. Under a 3% RPS requirement, for every 100 units of energy efficiency acquired, RES's RPS spending requirement is reduced by 3 units. In effect, this adds 3 percent of the costs of RECs to the avoided costs of energy efficiency. EES has used a blend of several forecasts of REC prices and incorporated them into the avoided costs of energy efficiency accordingly.

Beginning in 2030, all energy sales must be greenhouse gas neutral, allowing for 20% of the compliance to be achieved through purchases of RECs or other means. Accordingly, the CPA assumes that the marginal cost of power in 2030 would be the market price of power plus the full cost of a REC.

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 economic conditions 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 develops a risk adder ($/MWh) for 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 the risk adder was determined to be $0/MWh after the addition of the generation capacity deferral credit. While the Council uses stochastic portfolio modeling to value the risk credit, utilities conduct scenario and uncertainty analysis. The scenarios modeled in RES's CPA include an inherent value for the risk credit.

For RES's 2019 CPA, the avoided cost parameters have been estimated explicitly and a scenario analysis is performed. Therefore, no risk adder was used 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 RES's biennial target based on the range modeled effectively selects the utility's preferred risk strategy and associated risk credit.

Deferred Transmission and Distribution System Investment

Energy efficiency measure savings reduce capacity requirements on both the transmission and distribution systems. The Council recently updated its estimates for these capacity savings, which were $31/kW-year and $26/kW-year for distribution and transmission systems, respectively (2012$). These values were used in the Seventh Plan. The new values, $2.85/kW-year and $6.33/kW-year (2012$) for transmission and distribution systems, respectively, will be used in the next Power Plan. These assumptions are used in all scenarios in the CPA.

Deferred Investment in Generation Capacity

Currently, RES is a load-following customer of BPA and pays a demand charge to BPA, based on its peak demand every month. The demand charge is set in each rate case based on the marginal capacity resource. Currently, the demand charges are approximately \$10/kw-month and are based on an LMS100 combustion turbine. These demand charges effectively serve as the marginal cost of generation capacity for RES.

By assuming a monthly shape to conservation's demand savings, the charges were converted into a value of \$81/kW-year. For the base case, it was assumed BPA's demand charges will increase in real terms by 3% annually. Over twenty years, the resulting cost of avoided capacity is \$89/kW-year (2012\$) in levelized terms. In the low scenario, no cost escalation was assumed, resulting in a 20-year levelized cost of \$69/kW-yr.

In the Council's Seventh Power Plan[4], a generation capacity value of \$115/kW-year was explicitly calculated (\$2012). This value was used in the high scenario.

Summary of Scenario Assumptions

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

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

Table IV-1 Avoided Cost Assumptions by Scenario			
	Base	**Low**	**High**
Energy	Market Forecast	-50%-85% Confidence Interval*	+50%-85% Confidence Interval*
Social Cost of Carbon	Federal 2.5% Discount Rate Values	Federal 2.5% Discount Rate Values	Federal 2.5% Discount Rate Values
Value of RPS Compliance	Existing RPS + CETA	Existing RPS + CETA	Existing RPS + CETA
Distribution System Credit, $/kW-year (2012$)	$6.33	$6.33	$6.33
Transmission System Credit, $/kW-year (2012$)	$2.85	$2.85	$2.85
Deferred Generation Capacity Credit, $/kW-year (2012$)	$89	$69	$115
Implied Risk Adder	N/A	Up to -$18/MWh -$20/kW-year Average of -$11/MWh -$20/kW-year	Up to $18/MWh $26/kW-year Average of $11/MWh $26/kW-year

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

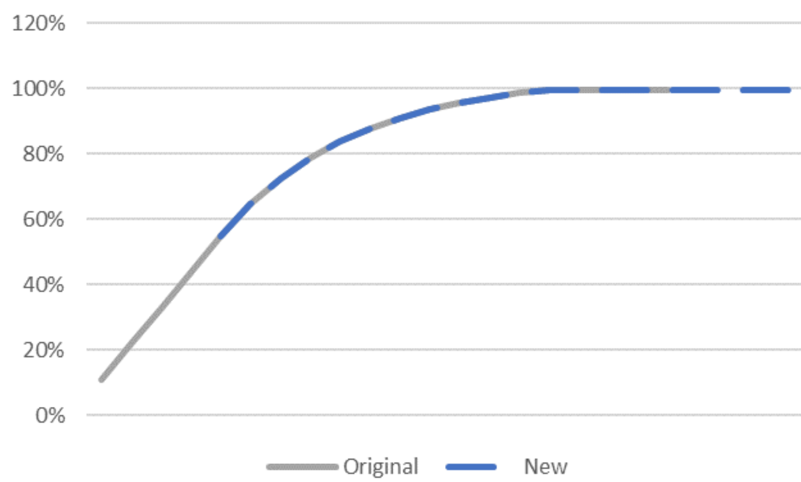
Appendix V – Ramp Rate Documentation

This section is intended to document how measure-level ramp rates were adjusted to align near term potential with recent achievements of Richland 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.

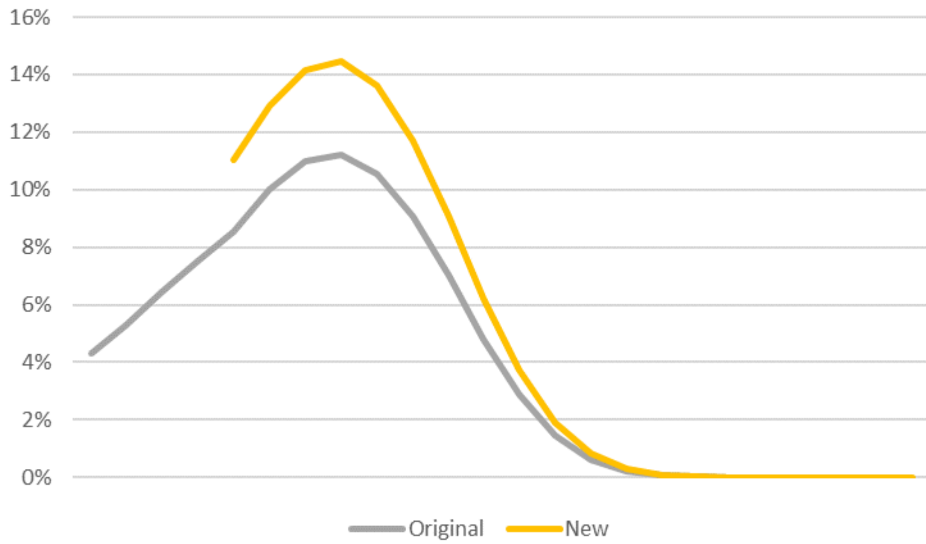
For lost opportunity measures, the ramp rates represent the share of equipment turning over in a given year that is achieved by efficiency programs. For these ramp rates, the only modification necessary was to extrapolate the final years to cover the time period relevant to the 2019 CPA. An example of 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 in figure V-2.

Figure V-2
Example Retrofit Ramp Rate Modification



With these modified ramp rates, Richland'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 do not include savings from Richland's residential lighting program.

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

	Program History				Potential		
	2017	2018	2019	Average	2020	2021	2022
Residential	0.229	0.249	0.220	0.233	0.181	0.213	0.232
Commercial	0.307	0.295	0.507	0.370	0.284	0.354	0.497
Industrial	0.165	1.453	0.514	0.711	0.206	0.207	0.201
Agricultural	-	-	-	-	0.001	0.001	0.001
Distribution Efficiency	-	-	-	-	0.007	0.011	0.015
Total	**0.701**	**1.997**	**1.241**	**1.313**	**0.680**	**0.786**	**0.870**

Measure detail for each sector was acquired from BPA reporting, 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	-	-	-	-	0.001	0.002	0.002
Food Preparation	-	-	-	-	0.001	0.002	0.002
HVAC	0.102	0.086	-	0.094	0.121	0.135	0.136
Lighting	-	-	-	-	-	-	-
Refrigeration	-	-	-	-	-	-	-
Water Heating	-	-	-	-	0.058	0.075	0.092
Whole Bldg/Meter Level	-	-	-	-	-	-	-
NEEA	0.127	0.163	0.171	0.154	-	-	-
Total	**0.229**	**0.249**	**0.220**	**0.233**	**.181**	**0.213**	**0.232**

Electronics – Savings in this category were delayed and spread out as Richland has not achieved savings in this category in recent years. Savings from NEEA's consumer electronics initiative may apply here.

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

Water Heating – Savings in this category were delayed and spread out as Richland has not achieved savings in this category in recent years. Savings from NEEA's consumer electronics initiative may apply here.

The commercial sector achievements and estimated potential 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	-	-	-	-	0.004	0.005	0.007
Electronics	-	-	-	-	0.005	0.008	0.013
Food Preparation	-	-	-	-	0.004	0.005	0.006
HVAC	0.030	0.001	-	0.015	0.037	0.053	0.072
Lighting	0.245	0.254	-	0.250	0.214	0.254	0.285
Motors/Drives	-	-	-	-	0.003	0.004	0.006
Process Loads	-	-	-	-	0.001	0.002	0.002
Refrigeration	-	-	-	-	0.012	0.018	0.024
Water Heating	-	-	-	-	0.003	0.004	0.005
NEEA	0.032	0.041	0.043	0.038	-	-	-
Total	**0.307**	**0.295**	**0.51**	**0.370**	**0.284**	**0.354**	**0.420**

HVAC – Commercial HVAC ramp rates were decreased from Seventh Plan rates to more accurately reflect Richland's historical savings.

Lighting - Commercial lighting ramp rates were decreased from Seventh Plan rates to more accurately reflect Richland's historical savings.

Richland did not report savings in other end uses and ramp rates were decreased from Seventh Plan rates where cost-effective potential was identified.

The majority of savings in the Industrial sector are achieved by large custom projects and therefore are not directly mappable to individual end uses. Therefore, EES slowed down ramp rates in the Industrial sector to more closely align with recent levels of program achievement at the sector level and accounting for large custom projects completed in 2018 and 2019. The resulting conservation potential is shown above in Table V-1.

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 IV-4 Agriculture End Uses and Measures		
End Use	**Measures/Categories**	**Data Source**
Dairy Efficiency	Efficient Lighting	7th Plan
	Milk Pre-Cooler	7th Plan
	Vacuum Pump	7th Plan
Irrigation	Low Energy Sprinkler Application	7th Plan
	Irrigation Hardware	7th Plan, RTF
	Scientific Irrigation Scheduling	7th Plan, BPA
Lighting	Agricultural Lighting	7th Plan
Motors/Drives	Motor Rewinds	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 – Energy Efficiency 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	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Food Preparation	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	0.00	0.00	0.00	0.00
HVAC	0.12	0.13	0.14	0.14	0.14	0.14	0.13	0.13	0.12	0.12	0.12	0.11	0.11	0.11	0.11	0.10	0.06	0.06	0.06	0.06
Lighting	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Refrigeration	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Water Heating	0.06	0.08	0.09	0.11	0.12	0.13	0.14	0.14	0.14	0.14	0.13	0.12	0.11	0.11	0.10	0.09	0.07	0.06	0.03	0.02
Whole Bldg/Meter Le	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**0.18**	**0.21**	**0.23**	**0.25**	**0.27**	**0.28**	**0.28**	**0.28**	**0.28**	**0.27**	**0.26**	**0.24**	**0.23**	**0.22**	**0.21**	**0.20**	**0.13**	**0.13**	**0.09**	**0.09**

Residential - Detail	aMW																			
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Dryer																				
Clothes Dryer	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Electronics																				
Advanced Power Strips	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Computer	0.001	0.001	0.002	0.003	0.004	0.005	0.006	0.007	0.009	0.010	0.010	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
Monitor	0.000	0.000	0.000	0.001	0.001	0.001	0.001	0.002	0.002	0.002	0.003	0.003	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Food Preparation																				
Electric Oven	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Microwave	0.001	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
HVAC																				
ASHP	0.003	0.004	0.006	0.009	0.011	0.014	0.016	0.018	0.020	0.021	0.022	0.023	0.023	0.024	0.024	0.024	0.024	0.024	0.024	0.024
Controls Commissioning and Sizing	0.004	0.006	0.009	0.013	0.017	0.020	0.024	0.027	0.029	0.031	0.033	0.034	0.034	0.035	0.035	0.035	0.035	0.035	0.035	0.035
DHP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DHP Ducted	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Duct Sealing	0.040	0.044	0.042	0.040	0.038	0.035	0.032	0.029	0.026	0.023	0.022	0.020	0.019	0.018	0.017	0.016	-	-	-	-
GSHP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Heat Recovery Ventilation	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
ResWx	0.062	0.068	0.066	0.064	0.060	0.055	0.049	0.043	0.038	0.034	0.031	0.028	0.026	0.025	0.023	0.022	-	-	-	-
WIFI enabled tstats	0.012	0.013	0.012	0.012	0.011	0.011	0.011	0.010	0.010	0.009	0.009	0.009	0.008	0.008	0.008	0.007	0.002	0.002	0.002	0.002
Lighting																				
LF Lighting	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Lighting	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Lighting PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Refrigeration																				
Freezer	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Refrigerator	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Water Heating																				
Aerator	0.001	0.002	0.002	0.003	0.003	0.003	0.003	0.002	0.002	0.002	0.001	0.001	0.001	0.001	0.001	0.000	0.000	0.000	0.000	0.000
Behavior	0.016	0.019	0.021	0.021	0.020	0.018	0.014	0.010	0.007	0.005	0.003	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
Clothes Washer	0.012	0.014	0.016	0.018	0.019	0.020	0.020	0.021	0.021	0.022	0.022	0.022	0.022	0.022	0.022	0.022	0.007	0.004	0.004	0.004
Dishwasher	0.001	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
HPWH	0.006	0.010	0.014	0.020	0.025	0.031	0.036	0.041	0.045	0.048	0.050	0.052	0.053	0.054	0.054	0.054	0.054	0.049	0.012	0.009
Showerheads	0.016	0.022	0.029	0.036	0.044	0.051	0.056	0.060	0.060	0.057	0.051	0.043	0.034	0.026	0.019	0.014	0.009	0.009	0.009	0.009
Solar Water Heater	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Thermostatic Valve	0.005	0.007	0.009	0.011	0.012	0.012	0.011	0.009	0.008	0.006	0.004	0.003	0.002	0.001	0.001	0.000	-	-	-	-
WasteWater Heat Recovery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Whole Bldg/Meter Level																				
EV Supply Equip	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**0.181**	**0.213**	**0.232**	**0.251**	**0.267**	**0.277**	**0.282**	**0.283**	**0.279**	**0.273**	**0.263**	**0.241**	**0.227**	**0.216**	**0.206**	**0.198**	**0.134**	**0.126**	**0.089**	**0.086**

Commercial	aMW																			
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Compressed Air	0.00	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	0.00	0.00	-	-	-
Electronics	0.01	0.01	0.01	0.02	0.03	0.03	0.04	0.06	0.07	0.08	0.09	0.02	-	-	-	-	-	-	-	-
Food Preparation	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	-	-	-	-
HVAC	0.04	0.05	0.07	0.09	0.12	0.14	0.16	0.17	0.17	0.16	0.14	0.12	0.09	0.07	0.05	0.03	0.02	0.02	0.02	0.02
Lighting	0.21	0.25	0.29	0.32	0.35	0.35	0.36	0.38	0.33	0.29	0.28	0.22	0.22	0.23	0.23	0.23	0.23	0.22	0.22	0.19
Motors/Drives	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Process Loads	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	-	-	-	-
Refrigeration	0.01	0.02	0.02	0.03	0.04	0.04	0.05	0.05	0.05	0.05	0.04	0.03	0.03	0.02	0.01	0.01	-	-	-	-
Water Heating	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Total	**0.28**	**0.35**	**0.42**	**0.50**	**0.57**	**0.61**	**0.66**	**0.70**	**0.68**	**0.64**	**0.62**	**0.45**	**0.40**	**0.36**	**0.33**	**0.30**	**0.28**	**0.27**	**0.27**	**0.24**

Commercial - Detail	**aMW**																			
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**
Compressed Air	0.004	0.005	0.007	0.008	0.009	0.011	0.012	0.012	0.012	0.012	0.011	0.009	0.008	0.006	0.005	0.004	0.000	-	-	-
Electronics																				
Data Centers	0.005	0.008	0.013	0.018	0.025	0.034	0.045	0.055	0.067	0.078	0.090	0.017	-	-	-	-	-	-	-	-
Desktop	0.000	0.000	0.000	0.000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Laptop	0.000	0.000	0.000	0.000	0.000	0.000	0.000	-	-	-	-	-	-	-	-	-	-	-	-	-
Monitor	0.000	0.000	0.000	0.000	0.000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Smart Plug Power Strips	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Food Preparation																				
Cooking Equipment	0.003	0.004	0.005	0.006	0.007	0.008	0.009	0.009	0.010	0.010	0.011	0.011	0.011	0.004	-	-	-	-	-	-
Pre-Rinse Spray Valve	0.001	0.001	0.001	0.001	0.001	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	-	-	-	-
HVAC																				
Advanced Rooftop Controller	0.010	0.014	0.019	0.025	0.030	0.036	0.040	0.042	0.042	0.039	0.034	0.028	0.021	0.014	0.009	0.004	-	-	-	-
Commercial EM	0.013	0.019	0.026	0.034	0.042	0.050	0.055	0.059	0.059	0.055	0.049	0.039	0.029	0.020	0.012	0.006	-	-	-	-
DCV Parking Garage	0.004	0.005	0.007	0.009	0.011	0.013	0.014	0.015	0.015	0.014	0.012	0.010	0.008	0.005	0.003	0.001	-	-	-	-
DCV Restaurant Hood	0.001	0.002	0.002	0.003	0.004	0.005	0.006	0.006	0.006	0.006	0.006	0.005	0.003	0.002	0.002	0.001	-	-	-	-
Demand Control Ventilation	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	-	-	-	-
DHP	0.002	0.003	0.004	0.005	0.006	0.007	0.008	0.008	0.009	0.008	0.008	0.006	0.005	0.004	0.003	0.002	0.001	0.001	0.001	0.001
Economizer	0.006	0.009	0.012	0.015	0.019	0.022	0.025	0.026	0.026	0.024	0.021	0.017	0.013	0.009	0.005	0.003	-	-	-	-
Premium Fume Hood	0.000	0.000	0.000	0.001	0.001	0.001	0.002	0.002	0.002	0.003	0.003	0.004	0.004	0.004	0.004	0.004	0.005	0.005	0.005	0.005
Secondary Glazing Systems	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
VRF	0.001	0.001	0.002	0.003	0.004	0.005	0.006	0.007	0.008	0.009	0.010	0.011	0.011	0.011	0.012	0.012	0.012	0.012	0.012	0.012
WEPT	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	-	-	-	-
Lighting																				
Bi-Level Stairwell Lighting	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Exterior Building Lighting	0.040	0.050	0.057	0.071	0.085	0.099	0.111	0.121	0.100	0.084	0.070	0.013	0.013	0.013	0.013	0.014	0.014	0.014	0.014	0.014
LEC Exit Sign	0.007	0.008	0.009	0.009	0.010	0.010	0.010	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.012	0.012	0.004	0.003	0.003
Lighting Controls Interior	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.000
Low Power LF Lamps	0.032	0.037	0.041	0.045	0.048	0.050	0.051	0.053	0.028	-	-	-	-	-	-	-	-	-	-	-
LPD Package	0.102	0.123	0.138	0.152	0.165	0.175	0.182	0.187	0.190	0.192	0.193	0.195	0.194	0.195	0.196	0.196	0.197	0.197	0.197	0.164
Parking Lighting	0.008	0.011	0.014	0.017	0.020	0.013	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Street and Roadway Lighting	0.024	0.025	0.025	0.026	0.026	0.005	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.005	0.005	0.005
Motors/Drives																				
ECM-VAV	0.002	0.004	0.006	0.007	0.009	0.011	0.013	0.015	0.016	0.017	0.018	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019
MotorsRewind	0.000	0.000	0.000	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Process Loads																				
Municipal Water Supply	0.001	0.002	0.002	0.003	0.004	0.005	0.005	0.006	0.006	0.006	0.005	0.004	0.003	0.002	0.001	0.001	-	-	-	-
Refrigeration																				
Grocery Refrigeration Bundle	0.012	0.017	0.022	0.029	0.036	0.042	0.048	0.051	0.051	0.048	0.042	0.034	0.026	0.017	0.011	0.005	-	-	-	-
Water Cooler Controls	0.001	0.001	0.002	0.003	0.004	0.002	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Water Heating																				
Commercial Clothes Washer	0.001	0.001	0.001	0.001	0.001	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.000	-	-	-	-	-	-	-
Showerheads	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	-	-	-	-
WHTanks	0.001	0.001	0.002	0.003	0.004	0.005	0.006	0.007	0.009	0.010	0.011	0.012	0.012	0.013	0.013	0.013	0.013	0.013	0.013	0.013
Total	**0.284**	**0.354**	**0.420**	**0.497**	**0.574**	**0.613**	**0.657**	**0.702**	**0.677**	**0.638**	**0.615**	**0.454**	**0.400**	**0.359**	**0.327**	**0.304**	**0.278**	**0.271**	**0.269**	**0.236**

Industrial	aMW																			
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Compressed Air	0.00	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	-	-	-	-
Energy Management	0.13	0.14	0.14	0.13	0.12	0.11	0.09	0.08	0.07	0.06	0.05	0.05	0.04	0.04	0.04	0.04	-	-	-	-
Fans	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	-	-	-	-
Hi-Tech	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	-	-	-	-
Lighting	0.04	0.03	0.03	0.02	0.02	0.02	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	-	-	-	-
Low & Med Temp Ref	0.01	0.01	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	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
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	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Process Loads	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	-	-	-	-
Pulp	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Pumps	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Transformers	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Wood	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**0.21**	**0.21**	**0.20**	**0.19**	**0.18**	**0.16**	**0.13**	**0.11**	**0.09**	**0.07**	**0.06**	**0.05**	**0.05**	**0.04**	**0.04**	**0.04**	**-**	**-**	**-**	**-**

Industrial - Detail	aMW																			
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Compressed Air	0.004	0.004	0.003	0.003	0.002	0.002	0.002	0.001	0.001	0.001	0.001	0.000	0.000	0.000	0.000	0.000	-	-	-	-
Energy Management																				
Compressed Air	0.002	0.002	0.002	0.001	0.001	0.001	0.001	0.001	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.000	-	-	-	-
Energy Project Management	0.032	0.034	0.032	0.030	0.029	0.027	0.026	0.024	0.023	0.021	0.020	0.019	0.018	0.017	0.016	0.015	-	-	-	-
Fans	0.005	0.006	0.007	0.007	0.006	0.005	0.004	0.003	0.002	0.001	0.000	0.000	0.000	0.000	0.000	0.000	-	-	-	-
Food Storage	0.033	0.037	0.040	0.040	0.038	0.032	0.025	0.017	0.011	0.006	0.003	0.001	0.001	0.000	0.000	0.000	-	-	-	-
Hi-Tech	0.000	0.000	0.001	0.001	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	-	-	-	-
Integrated Plant Energy Manageme	0.021	0.021	0.021	0.021	0.021	0.021	0.021	0.021	0.021	0.021	0.021	0.021	0.021	0.021	0.021	0.021	-	-	-	-
Plant Energy Management	0.036	0.031	0.026	0.022	0.019	0.016	0.013	0.010	0.008	0.006	0.005	0.004	0.003	0.002	0.002	0.001	-	-	-	-
Pumps	0.005	0.006	0.007	0.007	0.007	0.006	0.004	0.003	0.002	0.001	0.000	0.000	0.000	0.000	0.000	0.000	-	-	-	-
Fans	0.004	0.004	0.005	0.005	0.004	0.004	0.003	0.002	0.001	0.001	0.000	0.000	0.000	0.000	0.000	0.000	-	-	-	-
Hi-Tech	0.001	0.001	0.002	0.002	0.002	0.001	0.001	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	-	-	-	-
Lighting	0.038	0.033	0.028	0.024	0.020	0.017	0.014	0.011	0.009	0.007	0.005	0.004	0.003	0.002	0.002	0.002	-	-	-	-
Low & Med Temp Refr																				
Food Processing	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Food Storage	0.006	0.005	0.005	0.004	0.003	0.003	0.002	0.002	0.001	0.001	0.001	0.001	0.001	0.000	0.000	0.000	-	-	-	-
Material Handling	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Metals	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	-	-	-	-
Misc																				
Belts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Food Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Motors	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Paper	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Process Loads																				
Municipal Sewage Treatment	0.017	0.020	0.022	0.023	0.022	0.019	0.015	0.011	0.006	0.003	0.001	0.001	0.000	0.000	0.000	0.000	-	-	-	-
Pulp	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Pumps	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Transformers	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Wood	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**0.206**	**0.207**	**0.201**	**0.191**	**0.176**	**0.156**	**0.133**	**0.108**	**0.087**	**0.070**	**0.059**	**0.052**	**0.048**	**0.045**	**0.043**	**0.041**	**-**	**-**	**-**	**-**

Agricultural	aMW																			
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Dairy Efficiency	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Irrigation	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	-	-	-	-
Lighting	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	-	-	-	-
Motors/Drives	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**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**	**-**	**-**	**-**	**-**

Distribution Efficiency **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	0.00	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
2 - Light system improve	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
3 - Major system improv	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4 - EOL voltage control n	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
A - SCL implement EOL w	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**0.01**	**0.01**	**0.02**	**0.02**	**0.02**	**0.03**	**0.03**	**0.03**	**0.04**	**0.04**	**0.04**	**0.04**	**0.04**	**0.04**	**0.05**	**0.05**	**0.05**	**0.05**	**0.05**	**0.05**

Appendix VIII – Cost Estimates by End-Use

	Utility Program Costs (2019$)																			
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Residential	$744,000	$843,000	$865,000	$887,000	$896,000	$889,000	$870,000	$841,000	$810,000	$781,000	$753,000	$712,000	$686,000	$666,000	$648,000	$632,000	$359,000	$353,000	$351,000	$349,000
Commercial	$548,000	$693,000	$828,000	$982,000	$1,136,000	$1,228,000	$1,325,000	$1,416,000	$1,411,000	$1,378,000	$1,337,000	$1,103,000	$1,020,000	$959,000	$910,000	$874,000	$833,000	$785,000	$779,000	$701,000
Industrial	$260,000	$257,000	$249,000	$236,000	$217,000	$193,000	$165,000	$134,000	$108,000	$88,000	$74,000	$65,000	$60,000	$56,000	$53,000	$51,000	$0	$0	$0	$0
Distribution Efficiency	$2,000	$4,000	$5,000	$7,000	$8,000	$10,000	$11,000	$12,000	$13,000	$13,000	$14,000	$15,000	$15,000	$15,000	$16,000	$16,000	$16,000	$16,000	$16,000	$16,000
Agricultural	$2,000	$2,000	$2,000	$1,000	$1,000	$1,000	$1,000	$1,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total	**$1,556,000**	**$1,799,000**	**$1,949,000**	**$2,113,000**	**$2,258,000**	**$2,321,000**	**$2,372,000**	**$2,404,000**	**$2,342,000**	**$2,260,000**	**$2,178,000**	**$1,895,000**	**$1,781,000**	**$1,696,000**	**$1,627,000**	**$1,573,000**	**$1,208,000**	**$1,154,000**	**$1,146,000**	**$1,066,000**
$/First Year MWh	$261	$261	$256	$251	$248	$246	$245	$243	$247	$253	$254	$273	$283	$291	$299	$305	$301	$297	$323	$329

TRC Levelized Cost (2019$/kWh)				
	2-Year	6-Year	10-Year	20-Year
Residential	**$ 0.063**	**0.059949**	**0.058323**	**0.059527**
Dryer				
Electronics	$ 0.070	$ 0.070	$ 0.070	$ 0.070
Food Preparation	$ 0.083	$ 0.083	$ 0.083	$ 0.083
HVAC	$ 0.072	$ 0.074	$ 0.076	$ 0.082
Lighting				
Refrigeration				
Water Heating	$ 0.042	$ 0.034	$ 0.029	$ 0.023
Whole Bldg/Meter Level				
Commercial	**$ 0.047**	**$ 0.048**	**$ 0.048**	**$ 0.052**
Compressed Air	$ 0.008	$ 0.008	$ 0.008	$ 0.008
Electronics	$ 0.041	$ 0.041	$ 0.041	$ 0.041
Food Preparation	$ 0.034	$ 0.022	$ 0.018	$ 0.016
HVAC	$ 0.048	$ 0.049	$ 0.049	$ 0.051
Lighting	$ 0.049	$ 0.050	$ 0.052	$ 0.056
Motors/Drives	$ 0.035	$ 0.035	$ 0.035	$ 0.035
Process Loads	$ 0.039	$ 0.039	$ 0.039	$ 0.039
Refrigeration	$ 0.038	$ 0.038	$ 0.038	$ 0.038
Water Heating	$ 0.052	$ 0.058	$ 0.062	$ 0.064
Industrial	**$ 0.036**	**$ 0.037**	**$ 0.037**	**$ 0.036**
Compressed Air	$ 0.015	$ 0.015	$ 0.015	$ 0.015
Energy Management	$ 0.022	$ 0.023	$ 0.024	$ 0.026
Fans	$ 0.017	$ 0.017	$ 0.017	$ 0.017
Hi-Tech	$ 0.015	$ 0.015	$ 0.015	$ 0.015
Lighting	$ 0.059	$ 0.059	$ 0.059	$ 0.059
Low & Med Temp Refr	$ 0.054	$ 0.054	$ 0.054	$ 0.054
Material Handling				
Metals	$ 0.017	$ 0.017	$ 0.017	$ 0.017
Misc				
Motors				
Paper				
Process Loads	$ 0.075	$ 0.075	$ 0.075	$ 0.075
Pulp				
Pumps				
Transformers				
Wood				
Distribution Efficiency	**$ 0.007**	**$ 0.007**	**$ 0.007**	**$ 0.007**
Agricultural	**$ 0.042**	**$ 0.042**	**$ 0.042**	**$ 0.042**
Dairy Efficiency				
Irrigation	$ 0.051	$ 0.051	$ 0.051	$ 0.051
Lighting	$ 0.040	$ 0.040	$ 0.040	$ 0.040
Motors/Drives				
Total	**$0.049**	**$0.049**	**$0.049**	**$0.051**

UTILITY ADVISORY COMMITTEE AGENDA ITEM COVERSHEET

Meeting Date: 7/14/2020

Agenda Category: Items of Business

Prepared By: Clint Whitney, Energy Services Director

Subject:

RMC Title 14 - Addition of Small Cell and Revised Rate Schedule 90 (5 Minutes)

Department:

Energy Services

Recommended Motion:

Summary:

The City revised Richland Municipal Code (RMC) Title 23 to address zoning of small cell communication facilities and Title 28 for franchise provisions of small cell facilities.

The purpose of this ordinance is to facilitate a quick review and installation of using unmetered electrical services similar to those provided to cable television amplifiers. Ordinance No. 15-20 recommends adding small cell electrical service to existing Schedule 90 for Cable Television Amplifiers and aligning the energy rate to be the same as Schedule 20 for Small General Service.

Fiscal Impact:

Total revenue for Schedule 90: Cable Television Amplifier in 2019 was approximately $43,200 compared to a total electrical rate revenue of $66M. The addition of small cell services to Schedule 90 and aligning the energy rate to the same as Small General Service is not going to generate significant revenue after accounting for wholesale power costs.

Attachments:

1. Ordinance No. 15-20

ORDINANCE NO. 15-20

AN ORDINANCE of the City of Richland amending Richland Municipal Code Section 14.24.060 related to retail electric rates.

WHEREAS, Richland Municipal Code (RMC) Title 14 provides for electrical service procedures applicable to the installation of electrical services in the City; and

WHEREAS, City Council previously enacted amendments to address zoning in Title 23 and franchise provisions located in Title 28 of the Richland Municipal Code in order to provide for the deployment of small cell facilities; and

WHEREAS, City Council acknowledges the growing use of smart phones, personal wireless devices, internet data services, and therefore deem it in the public interest to ensure for the electrical services to small cell installations using processes established in Chapter 14 RMC; and

WHEREAS, Staff recommends adding small cell installations to existing Schedule 90 for Cable Television Amplifiers and aligning the energy rate to the same as Schedule 20 for Small General Service.

NOW, THEREFORE, BE IT ORDAINED by the City of Richland as follows:

Section 1. Richland Municipal Code Section 14.24.060, entitled Retail electric rates, as first enacted by Ordinance No. 90, and last amended by Ordinance No. 19-19, is hereby amended to read as follows:

RMC 14.24.060 Retail electric rates.
Rates for electricity are summarized by class of service as listed below. Rates are effective with the first bill received in June 2019 and apply to all usage during the billing period.

SCHEDULE 10: General Residential

A. Availability: In all territory serviced by the city’s electrical utility.
B. Applicability: To domestic uses of electric energy by all residential customers not eligible under other rate schedules.
C. Character of Service: Sixty hertz alternating current of such phase and voltage as the electric utility may have available.
D. Delivery Point: The following rates are based upon the supply of service to the entire premises through a single delivery and metering point. Separate supply for the same customer at other points of consumption shall be separately metered and billed.
E. Rates:

Daily Service Charge:

Single-phase service:	$0.69/day
Multiphase service:	$0.98/day
Monthly Energy Charge:	$0.0741/kWh

F. For electrical service supplied to residential customers qualifying as low income senior or low income disabled citizens, the service charge shall be waived and the energy charge shall be discounted 15 percent of Schedule 10. Qualifications and other information regarding low income senior or low income disabled citizens can be found in Chapter 3.29 RMC (finance).

SCHEDULE 20: Small General Service

A. Availability: In all territory served by the city's electric utility.

B. Applicability: To all nonresidential uses supplied through a single meter where anticipated monthly maximum demand does not exceed 50 kilowatts and the load is not eligible under other rate schedules.

C. Character of Service: Sixty hertz alternating current of such phase and voltage as the electric utility may have available.

D. Rates:

Daily Service Charge:

Single-phase service:	$0.86/day
Multiphase service:	$1.16/day
Monthly Energy Charge:	$0.0667/kWh
Monthly Demand Charge:	No Charge

SCHEDULE 22: Medium General Service

A. Availability: In all territory served by the city's electric utility.

B. Applicability: To all nonresidential uses supplied through a single meter, where anticipated monthly maximum demand is greater than 50 kilowatts, but less than or equal to 300 kilowatts, and the load is not eligible under other rate schedules.

C. Character of Service: Sixty hertz alternating current of such phase and voltage as the electric utility may have available.

D. Rates:

Daily Service Charge:

Single-phase service:	$1.38/day
Multiphase service:	$1.66/day

Monthly Energy Charge:	$0.0428/kWh
Monthly Demand Charge:	$5.17/kW

SCHEDULE 24: Large General Service

A. Availability: In all territory served by the city's electric utility.

B. Applicability: To all nonresidential uses supplied through a single meter, where anticipated monthly maximum demand is greater than 300 kilowatts, but less than or equal to 1,000 kilowatts, and the load is not eligible under other rate schedules.

C. Character of Service: Sixty hertz alternating current of such phase and voltage as the electric utility may have available.

D. Rates:

Daily Service Charge:	
Multiphase service:	$2.01/day
Monthly Energy Charge:	$0.0428/kWh
Monthly Demand Charge:	$5.58/kW

SCHEDULE 30: Small Industrial

A. Availability: In all territory served by the city's electric utility.

B. Applicability: To all nonresidential uses supplied through a single meter where anticipated monthly maximum demand is greater than 1,000 kilowatts but less than or equal to 5,000 kilowatts and the load is not eligible under other rate schedules.

C. Character of Service: Sixty hertz alternating current of such phase and voltage as the electric utility may have available.

D. Rates:

Daily Service Charge:	
Multiphase service:	$8.34/day
Monthly Energy Charge:	$0.0428/kWh
Monthly Demand Charge:	$5.92/kW

SCHEDULE 31: Large Industrial

A. Availability: In all territory served by the city's electric utility.

B. Applicability: To all nonresidential uses supplied through a single meter where anticipated monthly maximum demand is greater than 5,000 kilowatts and the load is not eligible for service under other rate schedules.

C. Character of Service: Sixty hertz alternating current of such phase and voltage as the electric utility may have available.

D. Rates:

Daily Service Charge:	$8.34/day
Monthly Energy Charge:	$0.0423/kWh
Monthly Demand Charge:	$5.52/kW

SCHEDULE 33: Economic Development Rate

A. Terms and conditions of negotiated rate will be by contract.

B. Will be based upon the benefits derived from the new load and/or employment opportunities that expand the local economy.

C. Will utilize marginal costing concept.

SCHEDULE 40: Small Irrigation 0 – 60 Horsepower

A. Availability: In all territory served by the city's electric utility.

B. Applicability: To uses of electrical power on a continuous basis for seasonal agricultural irrigation pumping or agricultural drainage pumping.

C. Character of Service: Sixty hertz alternating current of such phase and voltage as the electric utility may have available.

D. Rates:

Monthly Energy Charge:	$0.0650/kWh
Monthly Demand Charge:	No Charge

Annual Service Charge:

To be billed at beginning of irrigation season.

(1) $194.10 single-phase service.

(2) $258.80 multiphase service.

SCHEDULE 45: Large Irrigation Over 60 Horsepower

A. Availability: In all territory served by the city's electric utility.

B. Applicability: To uses of electrical power on a continuous basis for seasonal agricultural irrigation pumping or agricultural drainage pumping.

C. Character of Service: Sixty hertz alternating current of such phase and voltage as the electric utility may have available.

D. Rates:

Monthly Energy Charge:	$0.0428/kWh
Monthly Demand Charge:	$7.30/kW

Annual Service Charge:

To be billed at beginning of irrigation season.

$0.57/horsepower all horsepower greater than 60, plus:

(1) $194.10 single-phase service.

(2) $258.80 multiphase service.

SCHEDULE 60: Traffic Lighting

A. Availability: In all territory served by the city's electric utility.

B. Applicability: To municipally owned traffic-regulating signal systems on public streets and highways.

C. Character of Service: Sixty hertz alternating current of such phase and voltage as the electric utility may have available.

D. Rates:

Daily Service Charge:	$0.69/day
Monthly Energy Charge:	$0.0653/kWh

SCHEDULE 90: Cable Television Amplifier/Small Cell

A. Availability: In all territory served by the city's electric utility.

B. Applicability: To owners of cable television amplifiers or small cell installed on facilities owned by the city's electric utility.

C. Character of Service: Sixty hertz alternating current of such phase and voltage as the electric utility may have available.

D. Rates:

Monthly Energy Charge:	~~$0.0553~~ $0.0667/kWh

SCHEDULE 100: New Large Single Load

A. Availability: In all territory served by the city's electric utility.

B. Applicability: To new large single load customers defined in Public Law 96-501 and as such constitute electrical loads greater than or equal to 10 average megawatts during any consecutive 12-month period and which cause the utility to incur wholesale power costs in excess of normal rates.

C. Character of Service: Sixty hertz alternating current of such phase and voltage as the electric utility may have available.

D. Rates: Terms and conditions of negotiated rate will be by contract.

Section 2. This ordinance shall take effect the day following its publication in the official newspaper of the City of Richland.

Section 3. Should any section or provision of this ordinance be declared by a court of competent jurisdiction to be invalid, that decision shall not affect the validity of the ordinance as a whole or any part thereof, other than the part so declared to be invalid.

Section 4. The City Clerk and the codifiers of this ordinance are authorized to make necessary corrections to this ordinance, including but not limited to the correction of scrivener's errors/clerical errors, section numbering, references, or similar mistakes of form.

PASSED by the City Council of the City of Richland, Washington, at a regular meeting on the ____ day of ___________, 2020.

____
Ryan Lukson, Mayor

Attested by:

____
Jennifer Rogers, City Clerk

Approved as to form:

____
Heather Kintzley, City Attorney

Date Published: ___________

UTILITY ADVISORY COMMITTEE AGENDA ITEM COVERSHEET

Meeting Date: 7/14/2020 Agenda Category: Other Informational Items

Prepared By: Clint Whitney, Energy Services Director

Subject:
Bonneville Power Administration's Financial Reserve Policy Surcharge Suspension

Department:
Energy Services

Recommended Motion:
This is an informational item only.

Summary:

In response to the COVID-19 pandemic and the economic challenges it has placed on utility customers, Bonneville Power Administration (BPA) assessed rate relief options from utility requests. BPA's Administrator, Elliott Mainzer, provided a letter (attached) to utilities proposing to suspend its Financial Reserves Policy Surcharge (FRP Surcharge) for the remainder of the current rate period.

The FRP Surcharge triggered when BPA failed to maintain a liquidity metric of 60 days cash on hand for the transmission and power business units. Other FRP elements include a leverage metric using a debt-to asset ratio of 75-85% within 10 years. Failing to meet liquidity metric resulted in a FRP Surcharge to recover $30M in total from BPA customers of over the federal fiscal year 2020-2021 period. For the City, this amounts to approximately $50,000 per month ($600k per year) which began October 2019 and was expected through September 2021. BPA is recommending the FRP Surcharge be suspended beginning July 2020 and through September 2021. The total cost deferment for the City is expected to be approximately $750,000.

The suspension of the BPA FRP Surcharge, along with controlling capital and M&O expenditures, is expected to defer an electrical rate increase to later in 2021 or after. More financial analysis will take place in early 2021 for projections on timing.

Fiscal Impact:

Attachments:

1. Financial Reserve Policy Surcharge Suspension Letter

Department of Energy

Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208-3621

EXECUTIVE OFFICE

May 29, 2020

Dear BPA customers:

The COVID-19 pandemic has created significant challenges and uncertainties for utilities across the Pacific Northwest. In recent months, daily life has changed significantly to combat the spread of the virus, and communities are facing unprecedented economic impacts. Since the outbreak of COVID-19, the Bonneville Power Administration has been assessing the flexibilities it can extend to customers to help alleviate the economic challenges. After discussing these challenges with customers and considering our options for providing rate relief, Bonneville is proposing to suspend its Financial Reserves Policy Surcharge (FRP Surcharge) for the remainder of the current rate period.

To do so, we are initiating an expedited rate proceeding in June, conducted under Section 7(i) of the Northwest Power Act. In addition, if the FRP Surcharge is suspended in the final decision, we would also seek expedited approval from the Federal Energy Regulatory Commission. The effective date of the suspension would depend on several factors, including the timing of the Commission's approval. The suspension of the surcharge would provide power customers rate relief of about $3 million per month for the remainder of FY 2020 and $30 million for all of FY 2021.

We can also take immediate advantage of contractual flexibilities and provide support through extended payment agreements, which are available to power and transmission customers on a case-by-case basis. In addition, Regional Dialogue customers have access to the Flexible Priority Firm program to shape FY 2020 power charges into FY 2021. Bonneville believes that the proposal to suspend the FRP Surcharge, coupled with extended payment options, will provide meaningful relief to our customers.

I am grateful for the partnership with our customers and their recognition of the importance of Bonneville's long-term financial standing. But we can also all agree that this extraordinary situation requires extraordinary measures. The proposal Bonneville intends to make in the expedited section 7(i) proceeding, if accepted in the record of decision, would provide the region's utilities some much needed financial relief. Bonneville will host a customer workshop on Friday, June 5, to discuss the proposed changes to the FRP Surcharge along with a proposed schedule for the expedited rate proceeding.

While it is going to take some time to understand the full impact of the COVID-19 pandemic on the region's utilities and Bonneville, I am confident that we can work together to find a path forward through these unprecedented events.

Sincerely,

Elliot Mainzer
Administrator and CEO

UTILITY ADVISORY COMMITTEE AGENDA ITEM COVERSHEET

Meeting Date: 7/14/2020

Agenda Category: Other Informational Items

Prepared By: Clint Whitney, Energy Services Director

Subject:
Energy Services Monthly Capital Work Plan

Department:
Energy Services

Recommended Motion:
This is an informational item only.

Summary:
The attached is Energy Services Capital Working Plan (CWP) monthly report includes data from up to May 2020.

Fiscal Impact:

Attachments:

1. RES Capital Working Plan Status Report

Richland Energy Services

Capital Work Plan

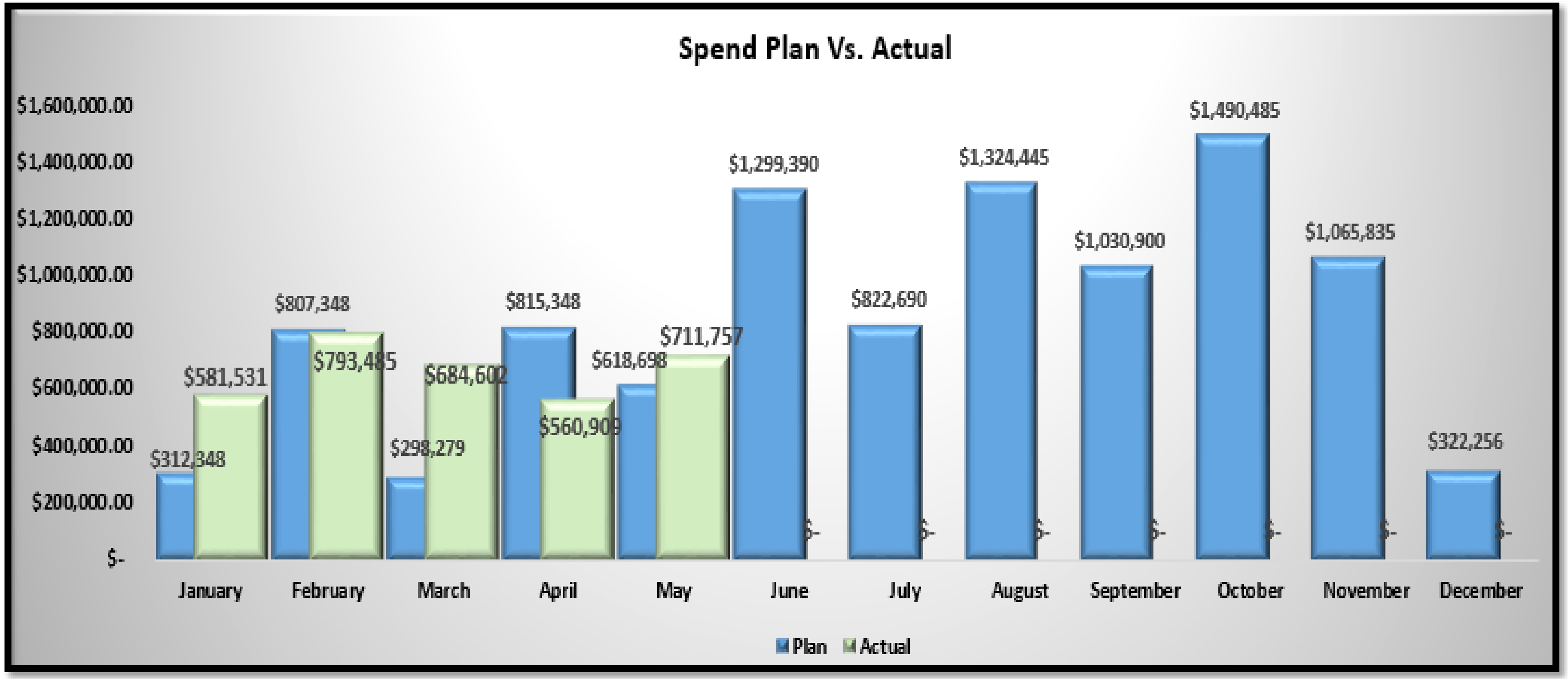
May 2020

CWP Costs for May

	Approved 2020 Budget	Total Project Costs	Actual	Sum of Remaining	May
⊞ Leslie Rd. Substation	$ 1,421,900	$ -	$ -	$ -	$0.00
⊞ Line Extensions	$ 1,288,000	$ 1,288,000	$ 456,269	$ 831,731	$19,582.02
⊞ Smart Grid - Advanced Metering Infrastructure	$ 3,771,000	$ 1,176,312	$ 144,339	$ 1,031,973	$32,531.41
⊞ System Improvements	$ 4,384,000	$ 3,730,352	$ 1,420,081	$ 2,310,271	$117,444.80
⊞ Renewal and Replacement	$ 1,934,200	$ 3,091,658	$ 1,245,305	$ 1,846,353	$541,042.49
⊞ Gateway Substation	$ 1,112,000	$ 562,700	$ 66,291	$ 496,409	$1,156.73
⊞ Purchase Southwest Service Area Infrastructure	$ 359,000	$ 359,000	$ -	$ 359,000	$0.00
Grand Total	$ 14,270,100	$ 10,208,022	$ 3,332,285	$ 6,875,737	$711,757.45

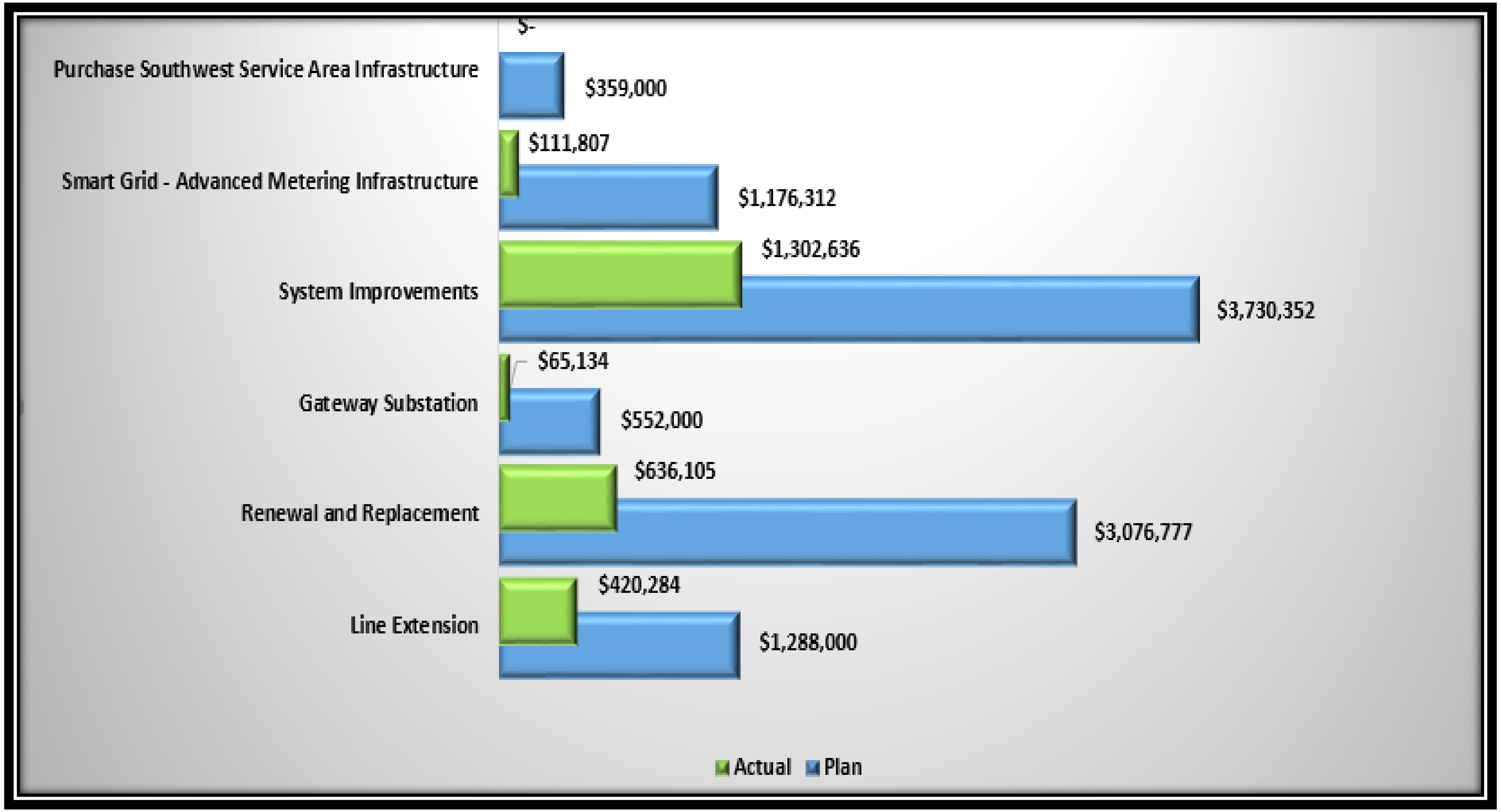
Cost Performance YTD:	$3,332,285
Cost Performance remaining:	$6,875,737
YTD % Complete	33%

CWP Monthly Spend Actuals

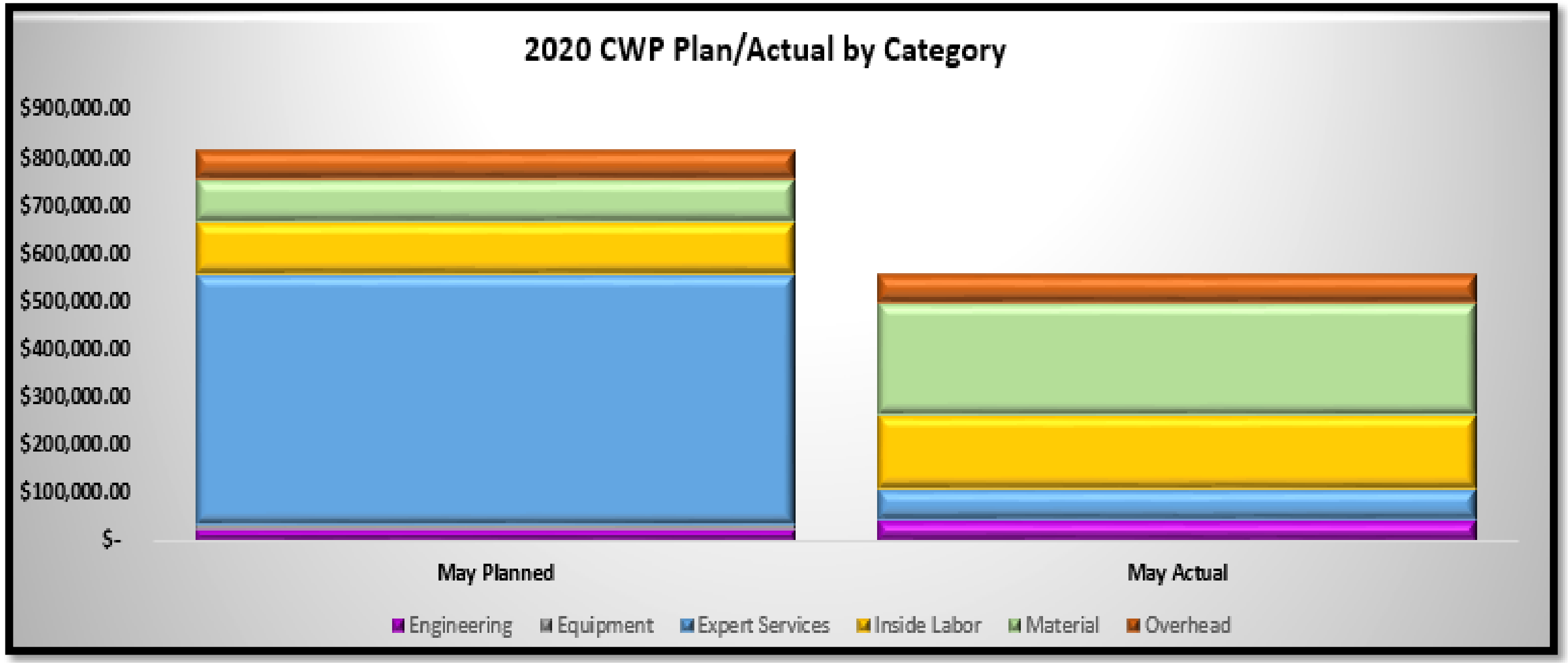


% Complete of Overall Spend Plan		
To-Date Projected	$ 2,852,021.00	14%
To-Date Actual	$3,332,285	117%
Variance	$480,264	103%

Costs by Category



CWP Cost Types



Cost Type	May Planned	May Actual
Engineering	$ 23,242.13	$ 27,264.65
Equipment	$ 9,569.42	$ -
Expert Services	$ 314,684.34	$ 493,774.03
Inside Labor	$ 76,451.76	$ 92,603.09
Material	$ 142,245.70	$ 55,553.67
Overhead	$ 52,504.64	$ 42,562.01
Total	$ 618,698.00	$ 711,757.45

CWP Project Costs for May

	Approved 2020 Budget	Total Project Costs	Actual	Sum of Remaining	May
Line Extensions	$ 1,288,000	$ 1,288,000	$ 456,269	$ 831,731	$19,582.02
Smart Grid - Advanced Metering Infrastructure	$ 3,771,000	$ 1,176,312	$ 144,339	$ 1,031,973	$32,531.41
System Improvements	$ 4,384,000	$ 3,730,352	$ 1,420,081	$ 2,310,271	$117,444.80
M&O Horn Rapids Solar Storage and Training proj	$ 3,500,000	$ 2,500,000	$ 423,257	$ 2,076,743	$2,812.99
METER INSTALLATION MATERIALS	$ 74,000	$ 74,000	$ 93,674	$ (19,674)	$10,750.41
NEW & ALT SVCS - UNDERGROUND	$ 405,000	$ 405,000	$ 208,906	$ 196,094	$38,344.49
Relocation of electrical facilities for the Duportai	$ 112,000	$ 311,352	$ 271,933	$ 39,419	$7,717.55
250 Skyline: Ext 3P 1/0J ~1100' set 2 V11's, replace 3	$ -	$ -	$ 53,355	$ (53,355)	$0.00
THAYER FEEDER X-25 UG R&R	$ -	$ -	$ 248,031	$ (248,031)	$43,442.95
Relay Replacement					
2700 Duportail-Replace Sub Fdr REF550 Relay Pane	$ 293,000	$ 293,000	$ -	$ 293,000	$0.00
DISTRIBUTION FEEDER RELAY REPLACEMENT	$ -	$ -	$ 2,344	$ (2,344)	$1,082.52
First Street Sub Bank 1: Relay Replacement	$ -	$ -	$ 24,965	$ (24,965)	$594.10
First Street Sub Bank 3: Relay Replacement	$ -	$ -	$ 23,372	$ (23,372)	$0.00
City Shops Remodel	$ -	$ -	$ -	$ -	$0.00
Renewal and Replacement	$ 1,934,200	$ 3,091,658	$ 1,245,305	$ 1,846,353	$541,042.49
Renewal and Replacement	$ 859,200	$ 635,090	$ 519,980	$ 115,110	$19,940.40
Pole Replacement Program	$ 864,000	$ 257,000	$ -	$ 257,000	$0.00
2020 Boring					
GARDEN PARK; NEW UG PRIMARY	$ -	$ -	$ -	$ -	$0.00
Quailwood Apartment Complex-R&R~750	$ -	$ 196,604	$ 113,955	$ 82,649	$98,093.85
MAPLE RIDGE/WINDSONG UG R&R	$ -	$ 709,573	$ 26,467	$ 683,106	$26,116.90
GARDEN PARK #3-UG R&R (Deffered)	$ 211,000	$ 472,139	$ 276,334	$ 195,805	$276,054.65
Dock Crew					
RIVERCREST UG R&R	$ -	$ 261,248	$ 73,085	$ 188,163	$13,070.52
WASHINGTON PARK 2&3 UG R&R	$ -	$ 216,350	$ 167,190	$ 49,160	$107,766.17
LYNNWOOD TERRACE - UG R&R	$ -	$ 297,640	$ 68,157	$ 229,483	$0.00
THAYER/MC MURRY, UG R&R	$ -	$ 46,014	$ 138	$ 45,876	$0.00
Gateway Substation	$ 1,112,000	$ 562,700	$ 66,291	$ 496,409	$1,156.73
Purchase Southwest Service Area Infrastructure	$ 359,000	$ 359,000	$ -	$ 359,000	$0.00
Grand Total	$ 14,270,100	$ 10,208,022	$ 3,332,285	$ 6,875,737	$711,757.45

UTILITY ADVISORY COMMITTEE AGENDA ITEM COVERSHEET

Meeting Date: 7/14/2020

Agenda Category: Other Informational Items

Prepared By: Clint Whitney, Energy Services Director

Subject:
Energy Services Reliability Analysis

Department:
Energy Services

Recommended Motion:
This is an informational item only.

Summary:

Attached is an update on the reliability indices for Energy Services through June 2020. Overall, electrical outages continue to decrease while compared to previous years. The Institute for Electrical and Electronics Engineers (IEEE) publishes methodologies for electric utility reliability indices. Similarly, American Public Power Association (APPA) provides data to compare against other public/private utilities by geographically and size.

The three year trend for the City of Richland continues to have a lower frequency of outages, as shown by the System Average Interruption Frequency Indices (SAIFI), than even the top quartile of comparable utilities. However, when an outage occurs, it takes longer than most utilities to restore. This is shown by the Customer Average Interruption Duration Indices (CAIDI). Both of these are consistent with higher reliability from underground infrastructure which also takes longer to dig and repair. The City of Richland has approximately 70% of electrical infrastructure underground.

The overall continuing decrease in outages indicates the capital improvement investments are targeted in the correct areas. The last two slides are heat maps of the frequency of outages on underground and overhead electrical infrastructure along with planned capital improvements.

Fiscal Impact:

Attachments:

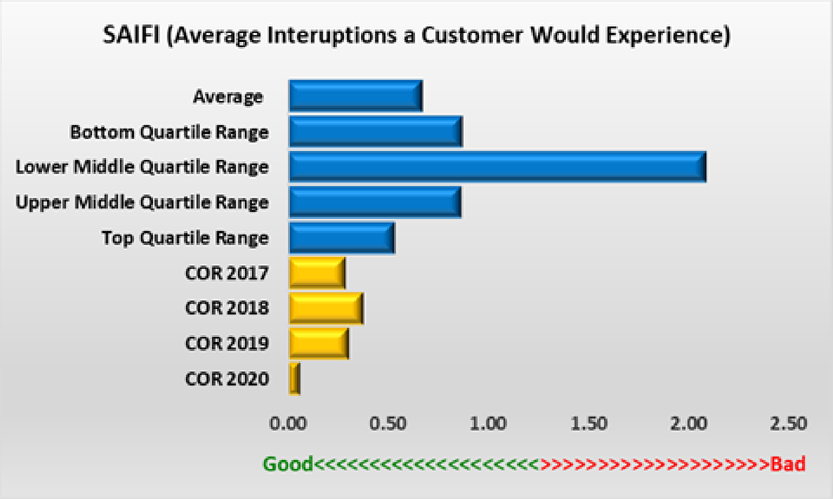
1. RES 2020 Reliability

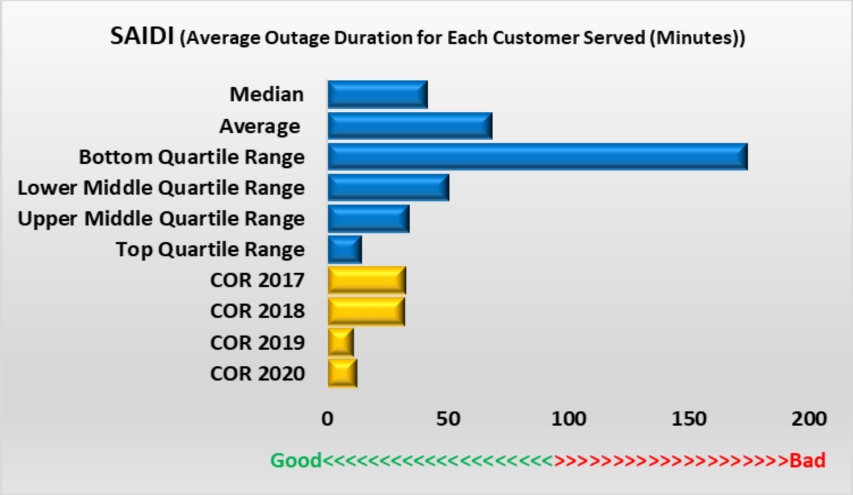
CITY OF RICHLAND
WASHINGTON

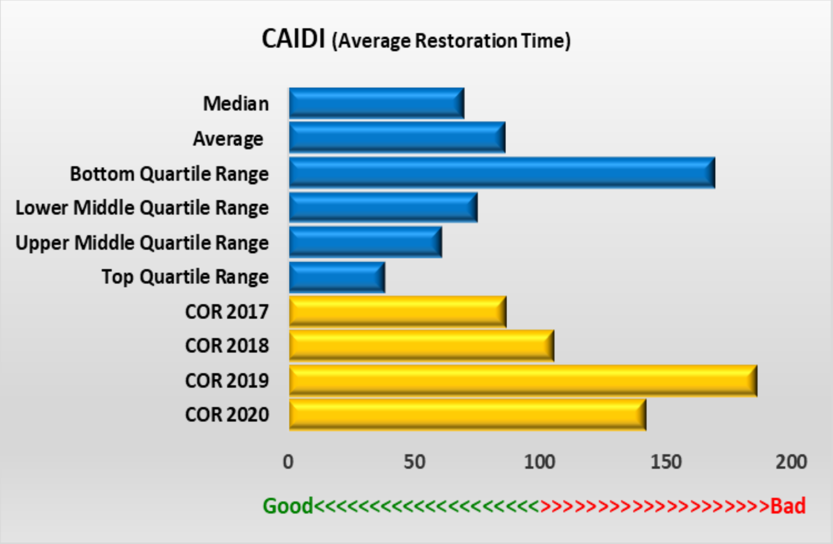
Energy Services Reliability and Capital Improvement Plan

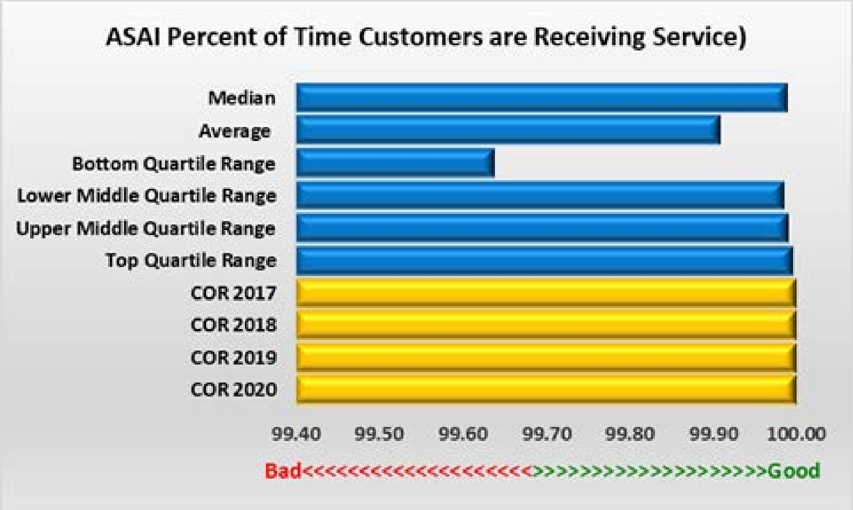
Clint Whitney
Trevor Wilkerson
July 14, 2020

Reliability Trends

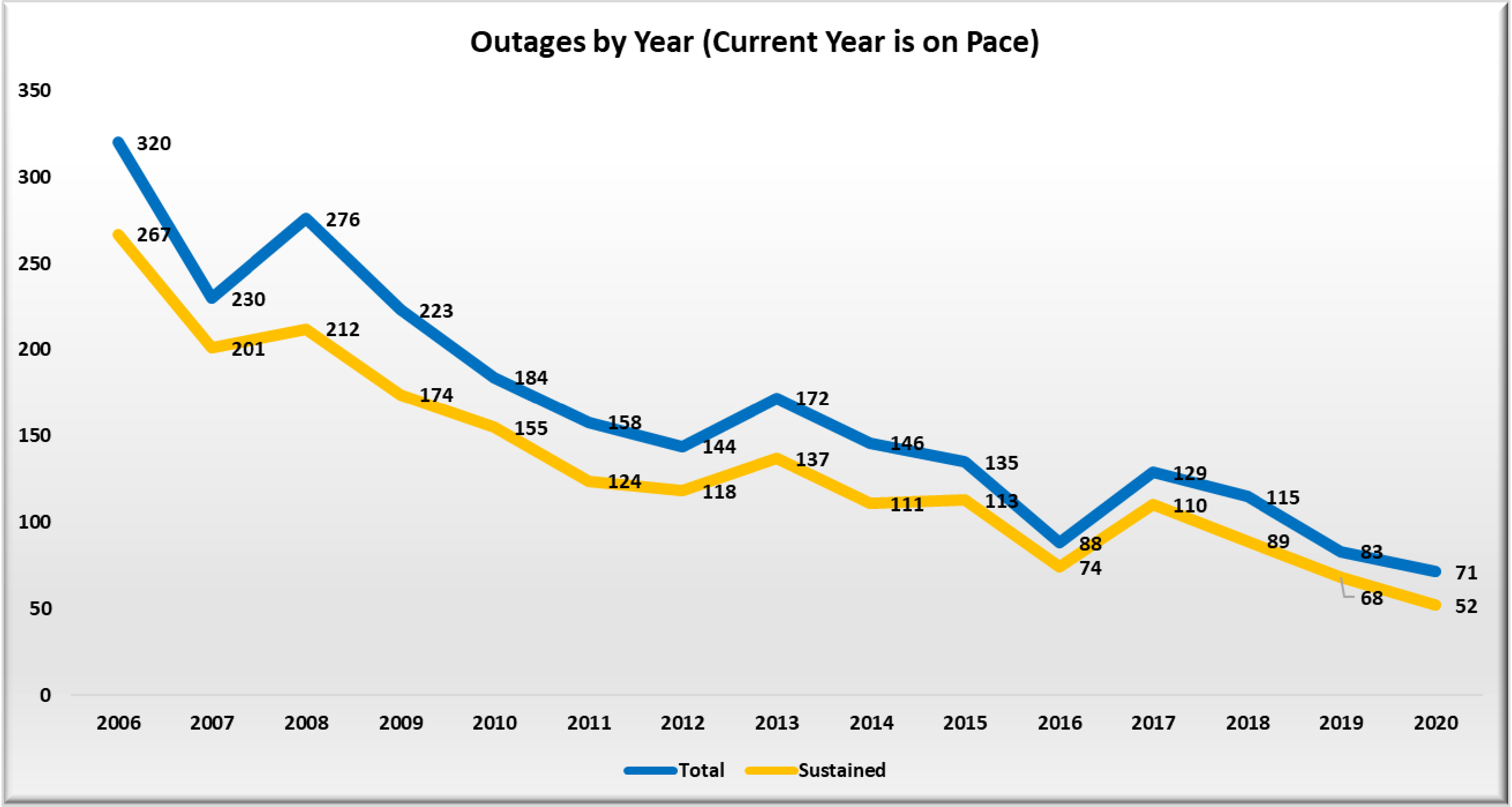




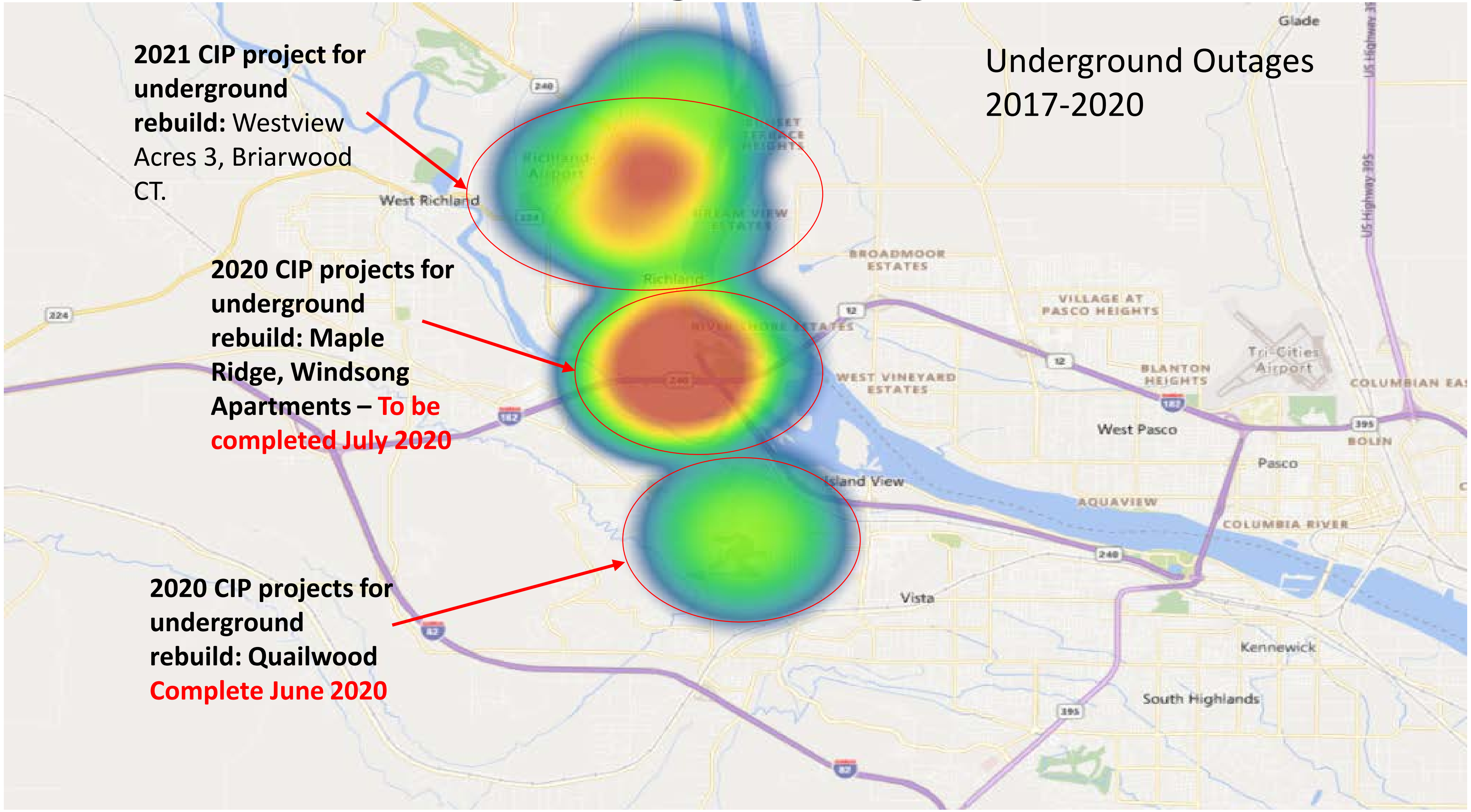




Reliability Trends



Reliability Analytics



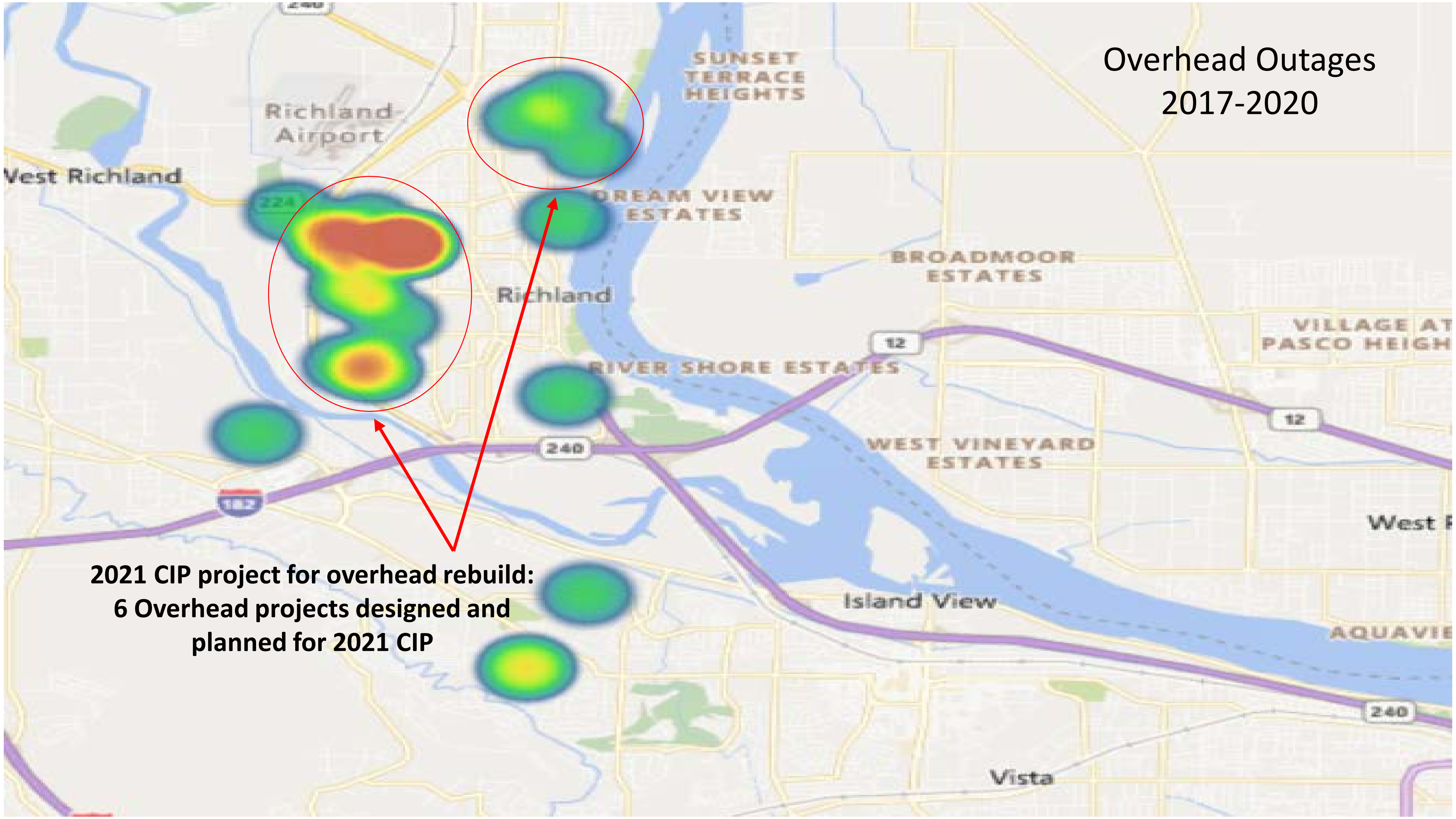
Underground Outages 2017-2020

2021 CIP project for underground rebuild: Westview Acres 3, Briarwood CT.

2020 CIP projects for underground rebuild: Maple Ridge, Windsong Apartments – **To be completed July 2020**

2020 CIP projects for underground rebuild: Qualwood
Complete June 2020

Reliability Analytics



UTILITY ADVISORY COMMITTEE AGENDA ITEM COVERSHEET

Meeting Date: 7/14/2020

Agenda Category: Other Informational Items

Prepared By: Clint Whitney, Energy Services Director

Subject:

Energy Services Financial Status Update

Department:

Energy Services

Recommended Motion:

This is an informational item only.

Summary:

See attached memo for information on this agenda item.

Fiscal Impact:

Attachments:

1. Memo - RES Financial Status Update

ENERGY SERVICES DEPARTMENT

MEMORANDUM

TO: Utility Advisory Committee

FROM: Clint Whitney, Energy Services Director

DATE: July 14, 2020

SUBJECT: RES Financial Status Update

Last year brought the City of Richland Energy Services (RES) many challenges with a conversion of the City's financial software system to a new vendor. The Energy Services department is still recreating financial reports similar to the previous system while the City's Finance department finishes end of year financial reports. Some of these efforts have been delayed from the COVID-19 effects in early 2020 while many employees continue working remotely.

Until quarterly financial reports are posted for 2020, RES continues to monitor projections versus actuals for revenues and expenses using a combination of internal reports. With $42.6M wholesale power expenses representing approximately 60% of RES total expenses, it is a primary focus area using a gross margin graph (attached).

The gross margin has data through May, with June expenses and revenues still pending for this year. The higher revenue than projected is largely temporary effects from COVID-19. The effects from COVID-19 have caused revenues from residential energy consumption to be about 10% higher than projected from the Cost of Service Analysis (COSA). This is a result of many customers working remotely from home with increased HVAC, plug and lighting loads. However, revenues from commercial energy usage is down about 10% with many small, medium and large commercial loads reduced from COVID-19 closures. Industrial loads in the City have been up about 10% which is largely from recent expansions in the food processing and cold storage areas. Overall, energy consumption is mixed or flat with higher revenue from the different rate class margins.

2020 RES financials are expected to see various COVID-19 effects including: higher operating expenses from overtime and alternating shifts, increased risk from aging accounts receivables, and increased long term risk to commercial revenues from business closures. One positive outcome is the temporary suspension of BPA's Financial Reserve Policy (FRP) beginning July 2020 through September 2021 as presented in a separate agenda item.

With the COVID-19 slow down and stoppages in developer driven line extensions, RES was able to divert operational employees to focus on completing other capital projects. Capital expenses represent approximately 15% of RES total expenses and are presented in a separate agenda item.

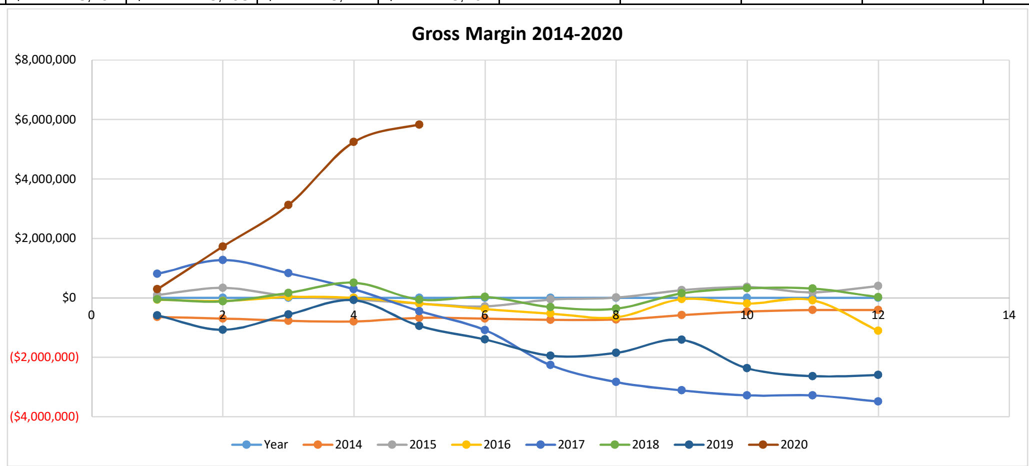
Last Updated **COSA Model Update 2020.02.27 Draft**
7/9/2020

RES 2020 Gross Margin COSA vs. Actuals

	January	February	March	April	May	June	July	August	September	October	November	December	Total
COSA Revenue	$ 5,801,520	$ 4,677,897	$ 4,241,073	$ 3,747,881	$ 4,018,831	$ 4,176,781	$ 4,959,715	$ 4,909,573	$ 3,867,311	$ 3,686,403	$ 4,272,616	$ 5,695,343	$ 54,054,945
COSA Power Cost	$ (3,909,521)	$ (3,537,321)	$ (3,369,040)	$ (3,335,057)	$ (3,348,443)	$ (3,328,950)	$ (3,915,076)	$ (3,685,949)	$ (3,204,384)	$ (3,135,957)	$ (3,327,202)	$ (4,492,267)	$ (42,589,167)
COSA Gross Margin	$ 1,891,999	$ 1,140,576	$ 872,033	$ 412,824	$ 670,388	$ 847,831	$ 1,044,639	$ 1,223,623	$ 662,927	$ 550,446	$ 945,414	$ 1,203,077	$ 11,465,778
COSA Gross Margin	33%	24%	21%	11%	17%	20%	21%	25%	17%	15%	22%	21%	21%
Actual Revenue	$ 6,143,809	$ 5,975,434	$ 5,546,515	$ 5,716,783	$ 4,382,202	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 27,764,743
Actual Power Cost	$ (3,965,033)	$ (3,396,639)	$ (3,273,549)	$ (3,181,552)	$ (3,128,177)								$ (16,944,950)
Actual Gross Margin	$ 2,178,776	$ 2,578,795	$ 2,272,966	$ 2,535,231	$ 1,254,025	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 10,819,793
Actual Gross Margin %	35%	43%	41%	44%	29%								$ 0
Gross Margin Difference	**$ 286,777**	**$ 1,438,219**	**$ 1,400,934**	**$ 2,122,407**	**$ 583,637**								**$ (645,985)**
Cumulative Gross Margin	$ 286,777	$ 1,724,996	$ 3,125,930	$ 5,248,336	$ 5,831,973								
Revenue Variance	$ 342,289	$ 1,297,537	$ 1,305,442	$ 1,968,902	$ 363,371								
Revenue Variance %	6%	22%	24%	34%	8%								
YTD Power Cost	$ (3,965,033)	$ (7,361,672)	$ (10,635,221)	$ (13,816,773)	$ (16,944,950)								
YTD Power Cost %	9%	17%	25%	32%	40%								
YTD Power Contribution Margin	$ 2,178,776	$ 4,757,571	$ 886,728	$ (2,553,475)	$ (6,845,966)								
YTD Margin %	35%	43%	41%	44%	29%								
Current Debt Service Ratio	2.48	2.48	2.48	2.48	2.48	2.48	2.48	2.48	2.48	2.48	2.48	2.48	

2020 Actual Revenue by Rate Class

Residential	$ 3,430,364	$ 2,937,380	$ 2,890,379	$ 2,895,011	$ 1,932,574								$ 14,085,709
SGS	$ 609,306	$ 596,507	$ 525,053	$ 500,706	$ 391,243								$ 2,622,815
MGS	$ 693,532	$ 863,164	$ 720,437	$ 707,694	$ 615,552								$ 3,600,379
LGS	$ 620,665	$ 728,307	$ 626,638	$ 659,880	$ 629,591								$ 3,265,081
S. Industrial	$ 228,599	$ 259,975	$ 251,170	$ 322,926	$ 241,770								$ 1,304,440
L. Industrial	$ 508,741	$ 541,246	$ 482,276	$ 513,203	$ 408,380								$ 2,453,846
S. Irrigation	$ 1,680	$ 975	$ 652	$ 13,975	$ 11,378								$ 28,660
L. Irrigation	$ 1,280	$ 1,265	$ 1,410	$ 52,479	$ 102,446								$ 158,879
Cable	$ 3,602	$ 3,602	$ 3,602	$ 3,602	$ 3,602								$ 18,008
Street	$ 30,446	$ 28,482	$ 30,521	$ 32,633	$ 32,543								$ 154,626
Security Lighting	$ 12,179	$ 10,737	$ 10,884	$ 11,451	$ 9,858								$ 55,109
Traffic Lights	$ 3,417	$ 3,794	$ 3,493	$ 3,224	$ 3,264								$ 17,193



UTILITY ADVISORY COMMITTEE AGENDA ITEM COVERSHEET

Meeting Date: 7/14/2020

Agenda Category: Other Informational Items

Prepared By: Clint Whitney, Energy Services Director

Subject:
Forward Planning Agenda

Department:
Energy Services

Recommended Motion:
This is an informational item only.

Summary:
Proposed future Utility Advisory Committee agenda items:

September 2020 -
Draft Strategic Plan Review (EMS)
Solid Waste Capital Program & Financing (PW)
Landfill Rate Review (PW)
HRSST & Landfill Field Tours (RES & PW)

November 2020 -
Wastewater Capital Program and Financing (PW)
Energy Efficiency Status (RES)

January 2021 -
Water Capital Program and Financing (PW)
Advanced Metering Infrastructure Policies (RES)

March 2021 - Review and Recommendations for Rates (RES)

May 2021 - Review and Recommendations for Bonds (RES)

July 2021 - Reliability Analysis (RES)

Fiscal Impact:

Attachments: