2019 Integrated resource plan

VOLUME II – APPENDICES M-R
OCTOBER 18, 2019

This 2019 Integrated Resource Plan Report is based upon the best available information at the time of preparation. The IRP action plan will be implemented as described herein, but is subject to change as new information becomes available or as circumstances change. It is PacifiCorp's intention to revisit and refresh the IRP action plan no less frequently than annually. Any refreshed IRP action plan will be submitted to the State Commissions for their information.

For more information, contact:
PacifiCorp
IRP Resource Planning
825 N.E. Multnomah, Suite 600
Portland, Oregon 97232
(503) 813-5245
irp@pacificorp.com
www.pacificorp.com

Cover Photos (Top to Bottom):
Marengo Wind Project
Transmission Line
Electric Meter
Pavant III Solar Plant

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APPENDIX M – CASE STUDY FACT SHEETS

Case Fact Sheets Overview

This appendix documents the 2019 Integrated Resource Plan modeling assumptions used for the preferred portfolio, initial portfolio-development cases, C-Cases, CP-Cases, No Gas and Energy Gateway Cases, and Sensitivity Cases.

Case Fact Sheets - Overview

Preferred Portfolio Fact Sheet

The Preferred Portfolio Fact Sheet summarizes key assumptions and portfolio results for the Preferred Portfolio developed for the 2019 Integrated Resource Plan (IRP).

Quick Reference Guide

Case	Description	Parent Case	SO PVRR ($m)	Load	Private Gen	CO_2 Policy	FOTs	Gateway	1st Year of New Thermal
P-45 CNW	No Dave Johnston Wind Option	P-45CP	21,480	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026

Initial Portfolio-Development Fact Sheets

The following Initial Portfolio-Development Fact Sheets summarize key assumptions and portfolio results for each portfolio initially developed for the 2019 IRP.

Quick Reference Guide

Case	Description	Parent Case	SO PVRR ($m)	Load	Private Gen	CO_2 Policy	FOTs	Gateway	1st Year of New Thermal
P-01	Coal Study Benchmark	-	24,407	Base	Base	Med Gas, Med CO_2	Base	Segment F	2033
P-02	Regional Haze Reference	-	23,191	Base	Base	Med Gas, Med CO_2	Base	Segment F	2031
P-03	Regional Haze Intertemporal	-	21,951	Base	Base	Med Gas, Med CO_2	Base	Segment F	2030
P-04	Coal Study C-42	-	21,720	Base	Base	Med Gas, Med CO_2	Base	Segment F	2028
P-06	Gadsby Alternative Case	-	21,980	Base	Base	Med Gas, Med CO_2	Base	Segment F	2030
P-07	Gadsby Alternative Case	P-06	21,905	Base	Base	Med Gas, Med CO_2	Base	Segment F	2029
P-08	Naughton 3 Small Gas Conversion	P-03	21,979	Base	Base	Med Gas, Med CO_2	Base	Segment F	2030
P-09	Naughton 3 Large Gas Conversion	P-03	21,885	Base	Base	Med Gas, Med CO_2	Base	Segment F	2030
P-10	Naughton 3 Large Gas Conversion	P-04	21,723	Base	Base	Med Gas, Med CO_2	Base	Segment F	2029
P-11	Cholla 4 Retirement 2020	P-09	21,873	Base	Base	Med Gas, Med CO_2	Base	Segment F	2030
P-12	Cholla 4 Retirement 2025	P-06	21,854	Base	Base	Med Gas, Med CO_2	Base	Segment F	2029
P-13	Jim Bridger 1&2 SCRs	P-11	22,346	Base	Base	Med Gas, Med CO_2	Base	Segment F	2032
P-14	Naughton 1&2 and Jim Bridger 1-4 Retirement 2022	P-09	21,696	Base	Base	Med Gas, Med CO_2	Base	Segment F	2028
P-15	Retire All Coal by 2030	P28	22,132	Base	Base	Med Gas, Med CO_2	Base	Segment F	2027
P-16	Jim Bridger 1&2 Retirement 2022, No CO_2	P04	18,634	Base	Base	Med Gas, No CO_2	Base	None	2028
P-17	High CO_2	P-15	22,070	Base	Base	Med Gas, High CO_2	Base	Segment F	2028
P-18	Social Cost of Carbon	P-15	30,022	Base	Base	Low Gas, SCC CO_2	Base	Segment F	2028
P-19	Low Gas	P-04	20,882	Base	Base	Low Gas, Med CO_2	Base	Segment F	2023
P-20	High Gas	P-07	22,746	Base	Base	High Gas, Med CO_2	Base	Segment F	2029
P-28	Colstrip 3&4 Retirement 2025	P-11	21,805	Base	Base	Med Gas, Med CO_2	Base	Segment F	2030
P-30	Naughton 1&2 Retirement 2022	P-11	21,708	Base	Base	Med Gas, Med CO_2	Base	Segment F	2029

Case Fact Sheets - Overview

P-31	Naughton 1&2 Retirement 2025	P-11	21,652	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026
P-32	Naughton 1&2 Retirement 2025 with Gadsby 1-3 Retirement 2032	P-07	21,763	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026
P-33	Jim Bridger 1&2 Retirement 2022	P-11	21,895	Base	Base	Med Gas, Med CO_2	Base	Segment F	2030
P-34	Jim Bridger 1&2 Retirement 2022, with Gadsby 1-3 Retirement 2020)	P-11	21,949	Base	Base	Med Gas, Med CO_2	Base	Segment F	2028
P-35	Jim Bridger 3&4 Retirement 2022	P-11	21,732	Base	Base	Med Gas, Med CO_2	Base	Segment F	2029
P-45	Jim Bridger 1 Retirement 2023 and Jim Bridger 2 Retirement 2038	P-31	21,593	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026
P-46	Jim Bridger 3&4 Retirement 2025	P-31	21,419	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026
P-53	Jim Bridger 1&2 Retirement 2025, Jim Bridger 3 Retirement 2028, and Jim Bridger 4 Retirement 2032	P-31	21,438	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026
P-54	Jim Bridger 2 Retirement 2024	P-31	21,708	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026

C-Cases Portfolio-Development Fact Sheets

The following C-Cases Portfolio-Development Fact Sheets summarize key assumptions and portfolio results for each C-Case developed for the 2019 IRP.

Quick Reference Guide

Case	Description	Parent Case	SO PVRR ($m)	Load	Private Gen	CO_2 Policy	FOTs	Gateway	1st Year of New Thermal
P-31C	Naughton 1 & 2 Retirement 2025	P-11	21,639	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026
P-36C	Jim Bridger 1-2 and Naughton 1&2 Retirement 2025	P-46	21,544	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026
P-45C	Jim Bridger 1 & 2 Retirement 2023 and 2038	P-31	21,537	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026
P-46C	Jim Bridger 3 & 4 Retirement 2025	P-31	21,431	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026
P-46 J23C	Jim Bridger 3 & 4 Retirement 2023	P-46	21,385	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026
P-47C	Jim Bridger 3 & 4 Retirement 2035	P-45	21,467	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026
P-48C	Jim Bridger 3 & 4 Retirement 2033	P-45	21,482	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026
P-53C	Jim Bridger 1 & 2 Retirement 2025, Jim Bridger 3 Retirement 2028, and Jim Bridger 4 Retirement 2032	P-31	21,450	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026
P-53 J23C	Jim Bridger 1 & 2 Retirement 2023	P-53	21,394	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026
P-54C	Jim Bridger 2 Retirement 2024	P-54	21,591	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026

Case Fact Sheets - Overview

CP-Cases Portfolio-Development Fact Sheets

The following CP-Cases Portfolio-Development Fact Sheets summarize key assumptions and portfolio results for each CP-Case developed for the 2019 IRP.

Quick Reference Guide

Case	Description	Parent Case	SO PVRR ($m)	Load	Private Gen	CO_2 Policy	FOTs	Gateway	1st Year of New Thermal
P-36CP	Jim Bridger 1-2 and Naughton 1-2 Retirement 2025	P-46	21,553	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026
P-45CP	Jim Bridger 1-2 Retirement 2023 and 2038	P-31	21,480	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026
P-46CP	Jim Bridger 3 & 4 Retirement 2025	P-31	21,460	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026
P-46CP J23C	Jim Bridger 3 & 4 Retirement 2023	P-46	21,402	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026
P-47CP	Jim Bridger 3 & 4 Retirement 2035	P-45	21,469	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026
P-48CP	Jim Bridger 3 & 4 Retirement 2033	P-45	21,457	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026
P-53CP	Jim Bridger 1 & 2 Retirement 2025, Jim Bridger 3 Retirement 2028, and Jim Bridger 4 Retirement 2032	P-31	21,479	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026

No Gas & Energy Gateway Fact Sheets

The following Fact Sheets summarize key assumptions and portfolio results for each No Gas and Energy Gateway Case developed for the 2019 IRP.

Quick Reference Guide

Case	Description	Parent Case	SO PVRR ($m)	Load	Private Gen	CO_2 Policy	FOTs	Gateway	1st Year of New Thermal
P-29	P-45CNW, No New Gas Option	P-45CNW	21,798	Base	Base	Med Gas, Med CO_2	Base	Segment F	-
P-29 PS	P-45CNW, No New Gas Option with pumped hydro storage	P-45CNW	21,970	Base	Base	Med Gas, Med CO_2	Base	Segment F	-

Case	Description	Parent Case	SO PVRR ($m)	Load	Private Gen	CO_2 Policy	FOTs	Gateway	1st Year of New Thermal
P-22	Energy Gateway Segment D.3	P-45CNW	21,886	Base	Base	Med Gas, Med CO_2	Base	Add Segment D.3	2030
P-23	Energy Gateway Segment D.1 and F	P-45CNW	22,151	Base	Base	Med Gas, Med CO_2	Base	Add Segments F and D.1	2026
P-25	Energy Gateway Segment D.3, E & H	P-45CNW	22,273	Base	Base	Med Gas, Med CO_2	Base	Add Segments D.3, Segment E, and H	2030
P-26	Energy Gateway Segment H	P-45CNW	21,579	Base	Base	Med Gas, Med CO_2	Base	Add Segment H	2028

Case Fact Sheets - Overview

Sensitivity Fact Sheets

The following Sensitivity Fact Sheets summarize key assumptions and portfolio results for each sensitivity being developed for the 2019 IRP.

Quick Reference Guide

Case	Description	Parent Case	SO PVRR ($m)	Load	Private Gen	CO_2 Policy	FOTs	Gateway	1st Year of New Thermal
S-01	Low Load	P-45CNW	20,617	Low	Base	Base	Base	Base	2030
S-02	High Load	P-45CNW	22,602	High	Base	Base	Base	Base	2026
S-03	1 in 20 Load Growth	P-45CNW	21,634	1 in 20	Base	Base	Base	Base	2026
S-04	Low Private Generation	P-45CNW	21,758	Base	Low	Base	Base	Base	2029
S-05	High Private Generation	P-45CNW	21,371	Base	High	Base	Base	Base	2030
S-06	Business Plan	P-45CNW	21,695	Base	Base	Base	Base	Base	2028
S-07	No Customer Preference	P-45CNW	21,609	Base	Base	Base	Base	Base	2030
S-08	High Customer Preference	P-45CNW	21,636	Base	Base	Base	Base	Base	2030

Portfolio: Preferred Portfolio (P-45CNW)

Preferred Portfolio Fact Sheet

PORTFOLIO ASSUMPTIONS

Description
The preferred portfolio, P-45CNW, is a variant of P-45CP with all of the same assumptions and Planning and Risk Deterministic methodology applied except 620 MW Dave Johnston Wind in 2029 is removed.

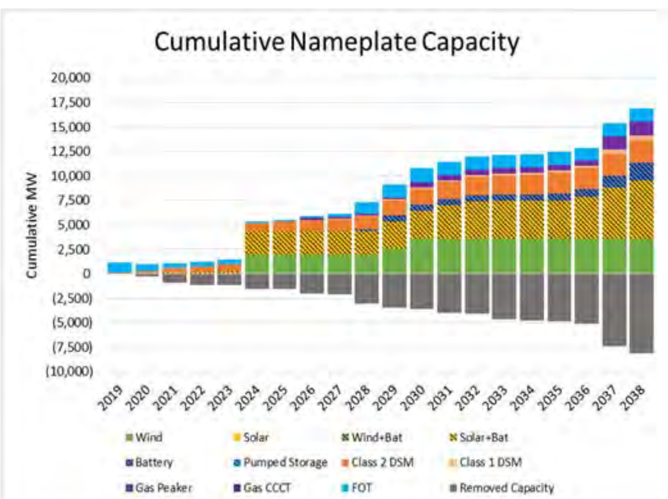
PORTFOLIO SUMMARY

System Optimizer PVRR ($m) $21,480

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus Wyoming – to – Utah S	*2024*	*1,700*
Goshen – to – Utah N	*2030*	*800*
Yakima- to – S. Oregon/California	*2036*	*450*

Resource Portfolio
Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as cumulative nameplate capacity, are summarized in the figure below.

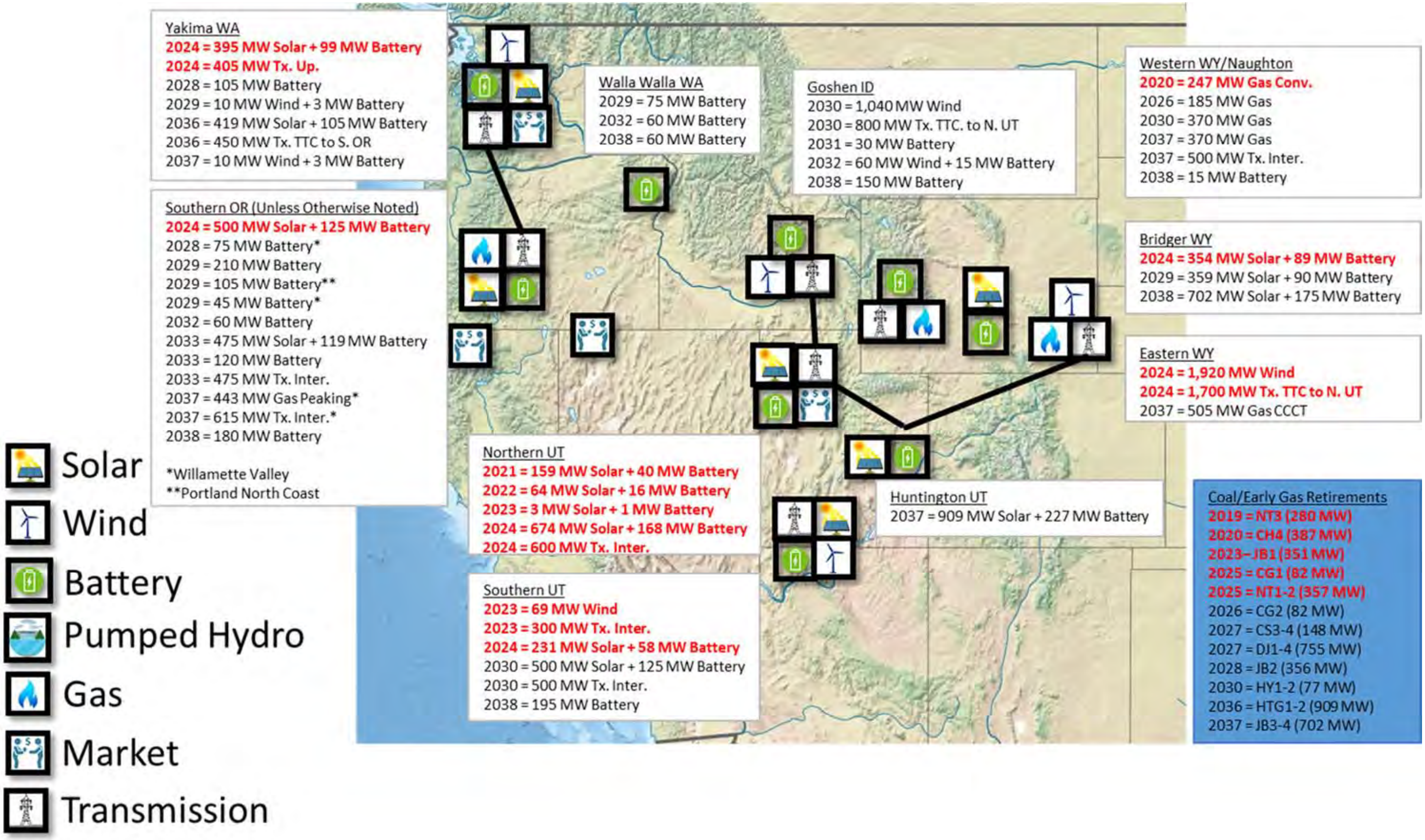


Retirement Assumptions
P-45CNW is the Preferred Portfolio case, and the retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2026
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2023
Jim Bridger 2	Retire 2028
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3	Retire 2019
Wyodak	Retire 2039

Portfolio: Preferred Portfolio (P-45CNW)

Case - P-45CNW (Preferred Portfolio)



Portfolio: Coal Study Benchmark (P-01)

Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

P-01 serves as the benchmark portfolio to which the other Initial Portfolio-Development cases can be compared to determine their relative benefits or costs. It assumes scrubbers are added to Jim Bridger Unit 1 in 2022 & Unit 2 in 2021.

PORTFOLIO SUMMARY

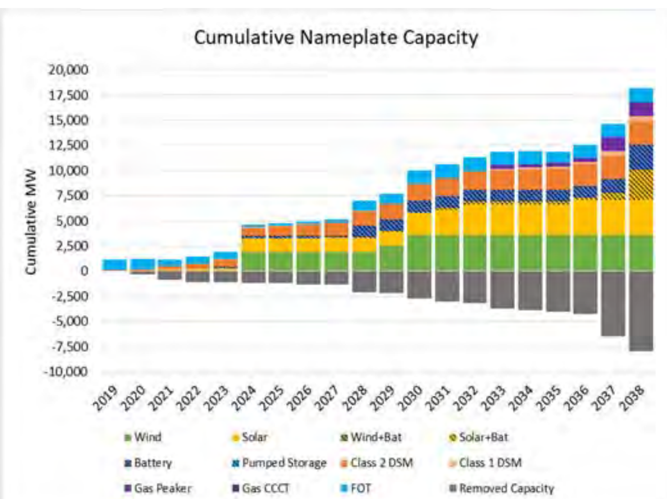
System Optimizer PVRR ($m) ***$23,191***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus Wyoming – to – Utah S	*2024*	*1,700*
Goshen – to – Utah N	*2030*	*800*
Walla Walla- to – Yakima	*2032*	*200*
Yakima- to – S. Oregon/California	*2037*	*450*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as cumulative nameplate capacity, are summarized in the figure below.



Retirement Assumptions

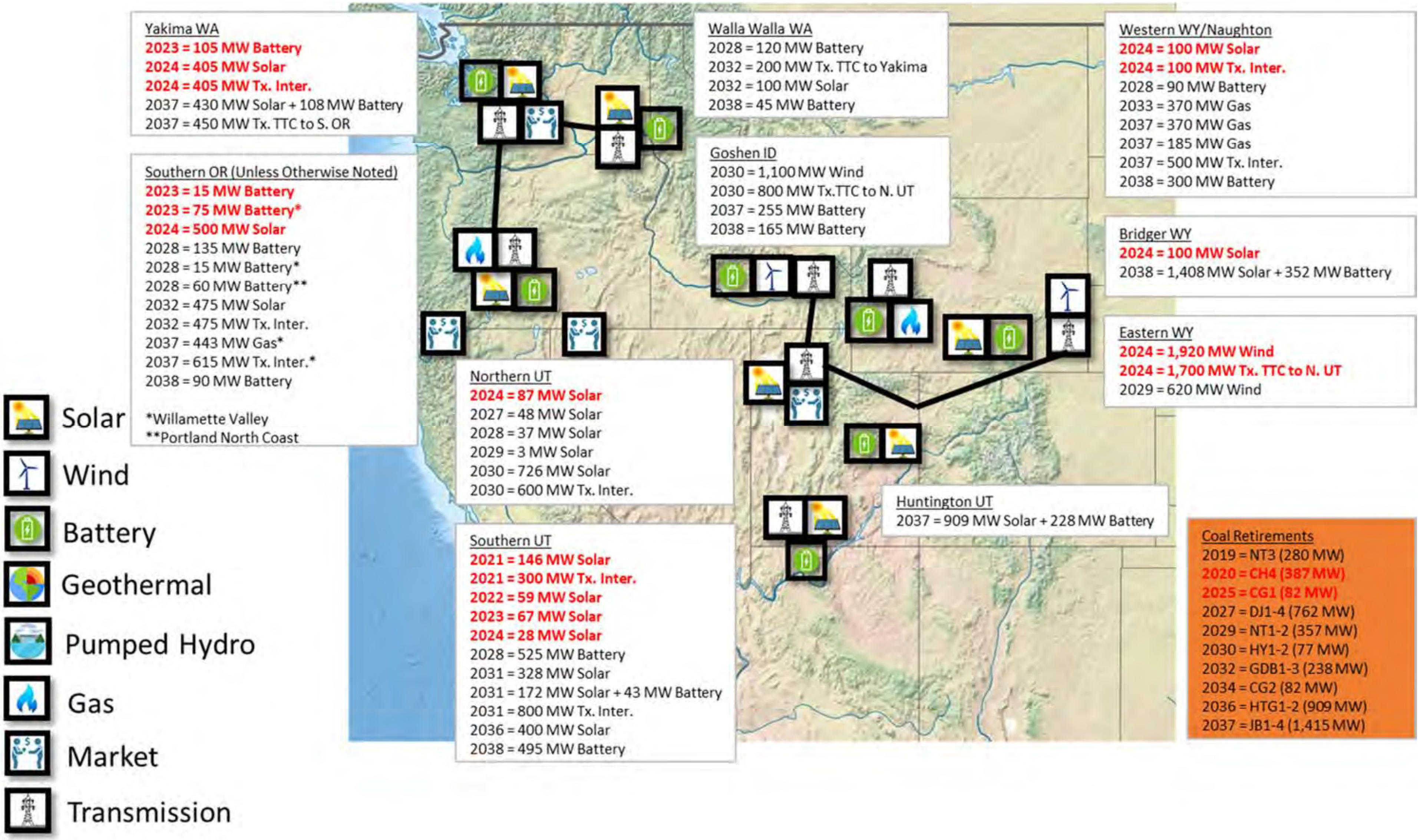
Initial portfolio-development case P-01 is the coal study case, and the retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2046
Colstrip 4	Retire 2046
Craig 1	Retire 2025
Craig 2	Retire 2034
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	SCR 2022 & Retire 2037
Jim Bridger 2	SCR 2021 & Retire 2037
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2029
Naughton 2	Retire 2029
Naughton 3	Retire 2019
Wyodak	Retire 2039

SCR = selective catalytic reduction

Portfolio: Coal Study Benchmark (P-01)

Case - P-01 (Coal Study Benchmark)



Portfolio: Regional Haze Reference (P-02)

Initial Portfolio-Development Fact Sheets

Portfolio Assumptions

Description

Case P-02 is the Regional Haze Reference case which adds scrubbers between 2021 and 2023 to Hunter Units 1 & 2 and Huntington Units 1 & 2, in addition to the scrubbers in the base case for Jim Bridger Units 1 & 2, followed by each unit's expected retirement date. In addition, it retires Cholla Unit 4 in 2025 instead of 2020 in the base case, Colstrip Units 3 & 4 in 2027 instead of 2046 and Craig Unit 2 in 2026 instead of 2034.

Portfolio Summary

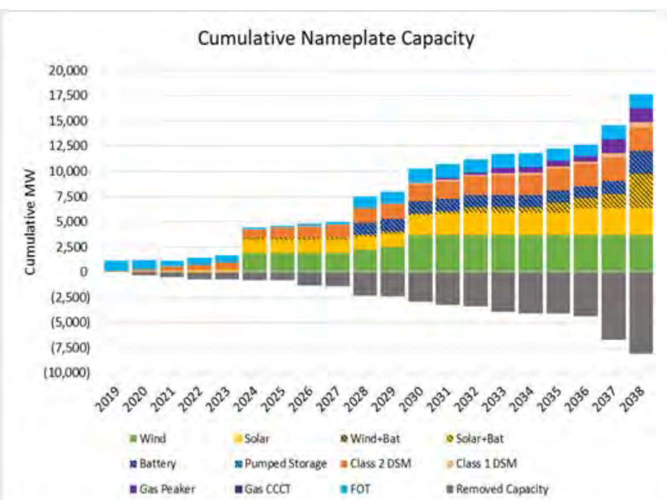
System Optimizer PVRR ($m) $23,191

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Walla Walla – to Yakima, Expansion	*2032*	*200*
Yakima – to – S. Oregon/California	*2037*	*450*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

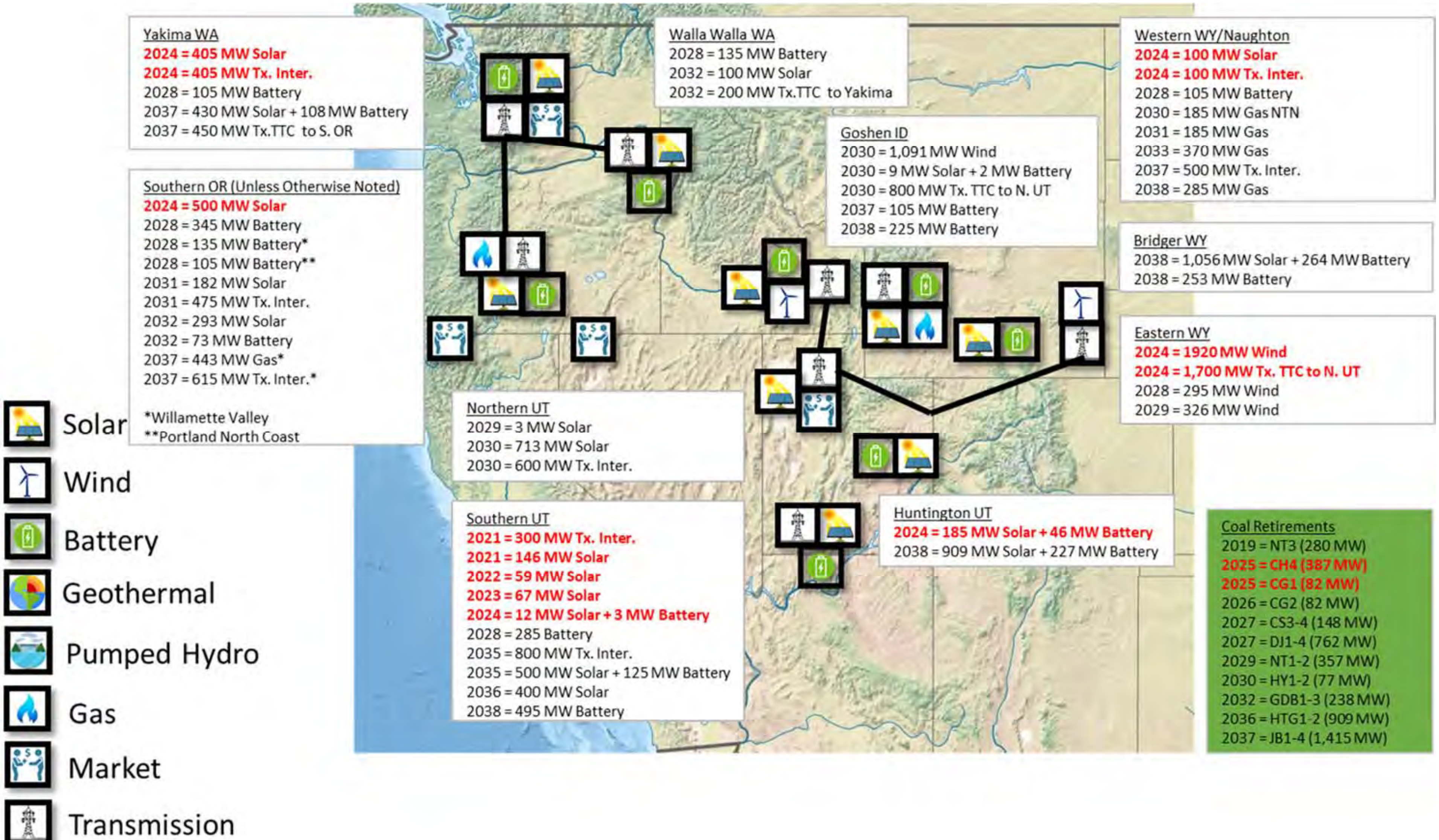
Initial portfolio-development case P-02 is the regional haze references case, and the retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2025
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2026
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	SCR 2022 Retire 2042
Hunter 2	SCR 2022 Retire 2042
Hunter 3	Retire 2042
Huntington 1	SCR 2022 Retire 2036
Huntington 2	SCR 2023 Retire 2036
Jim Bridger 1	SCR 2022 Retire 2037
Jim Bridger 2	SCR 2021 Retire 2037
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2029
Naughton 2	Retire 2029
Naughton 3	Retire 2019
Wyodak	SCR 2024 Retire 2039

SCR = selective catalytic reduction

Portfolio: Regional Haze Reference (P-02)

Case - P-02 (Regional Haze Reference)



Portfolio: Regional Haze Intertemporal (P-03)

Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

Similar to P-02, P-03 has all of the same retirement dates without the addition of the scrubbers on Hunter Units 1 & 2, Huntington Units 1 & 2 and Jim Bridger Units 1 & 2.

PORTFOLIO SUMMARY

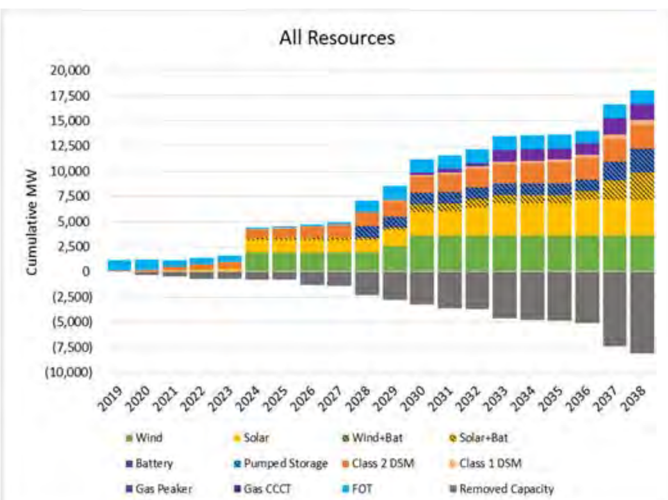
System Optimizer PVRR ($m) ***$21,951***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Walla Walla – to Yakima, Expansion	*2031*	*200*
Yakima – to – S. Oregon/California	*2037*	*450*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



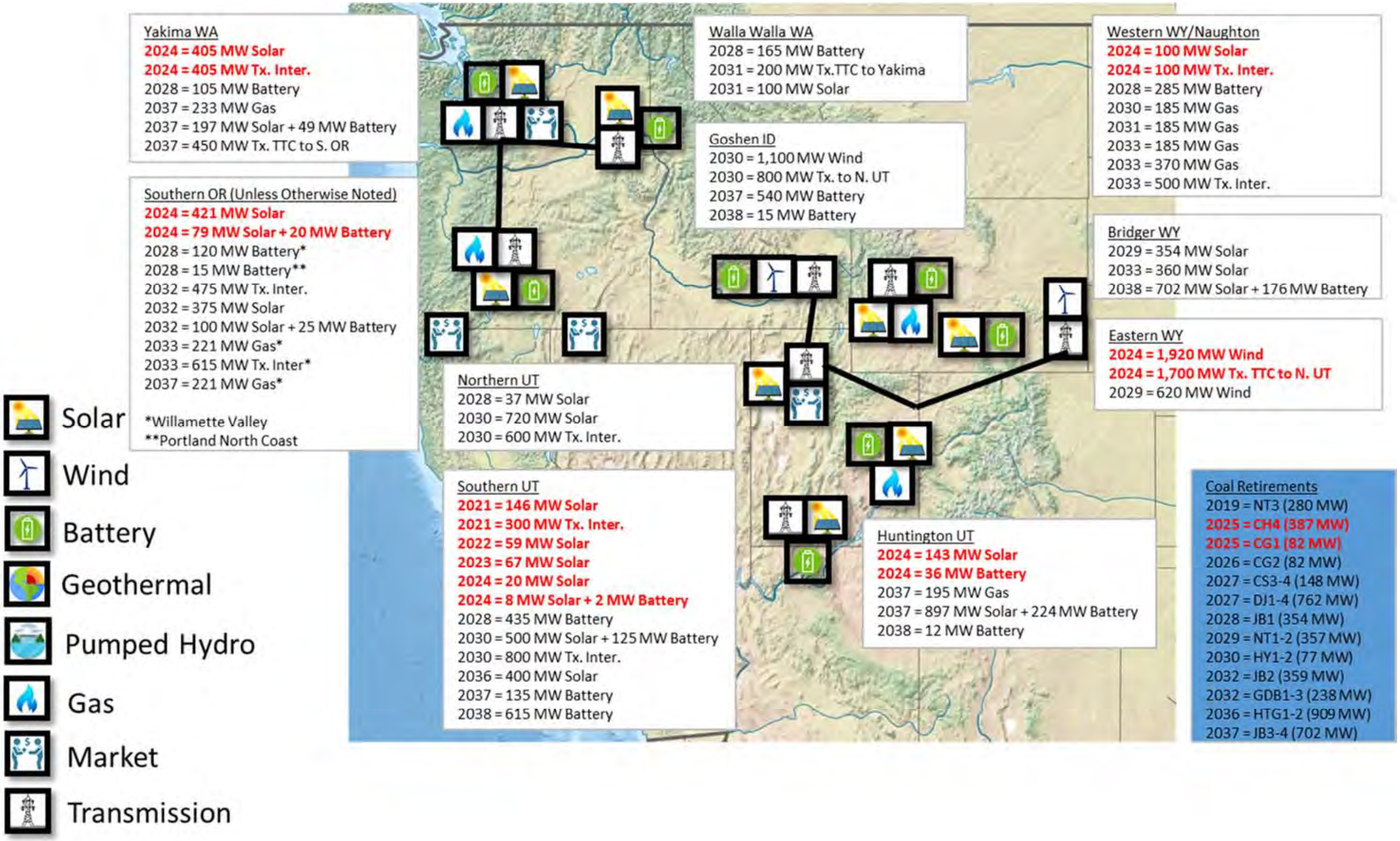
Retirement Assumptions

Initial portfolio-development case P-03 is the regional haze intertemporal case, and the retirement assumptions are summarized in the following table.

Unit	**Description**
Cholla 4	Retire 2025
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2026
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2028
Jim Bridger 2	Retire 2032
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2029
Naughton 2	Retire 2029
Naughton 3	Retire 2019
Wyodak	Retire 2039

Portfolio: Regional Haze Intertemporal (P-03)

Case - P-03 (Regional Haze Intertemporal)



Portfolio: Coal Study C-42 (P-04)

Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

Similar to the P-01 benchmark, P-04 has the same retirement assumptions except Jim Bridger Units 1 & 2 retire in 2022 instead of 2037 and Naughton Units 1 & 2 also retire in 2022 instead of 2029. In addition, no units have scrubbers added.

PORTFOLIO SUMMARY

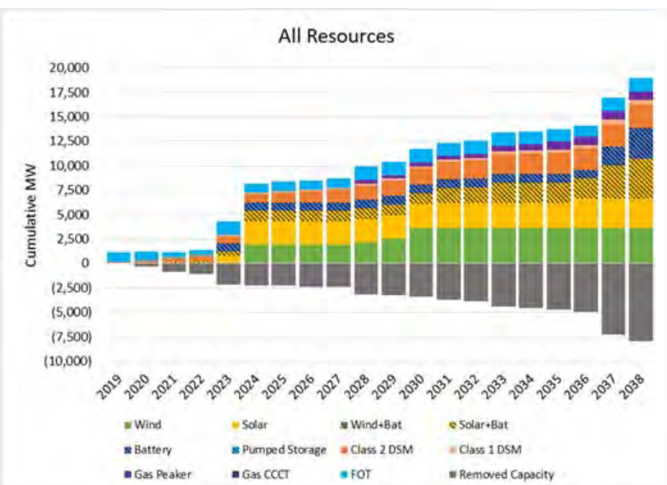
System Optimizer PVRR ($m) ***$21,720***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Walla Walla – to Yakima, Expansion	*2031*	*200*
Yakima – to – S. Oregon/California	*2037*	*450*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



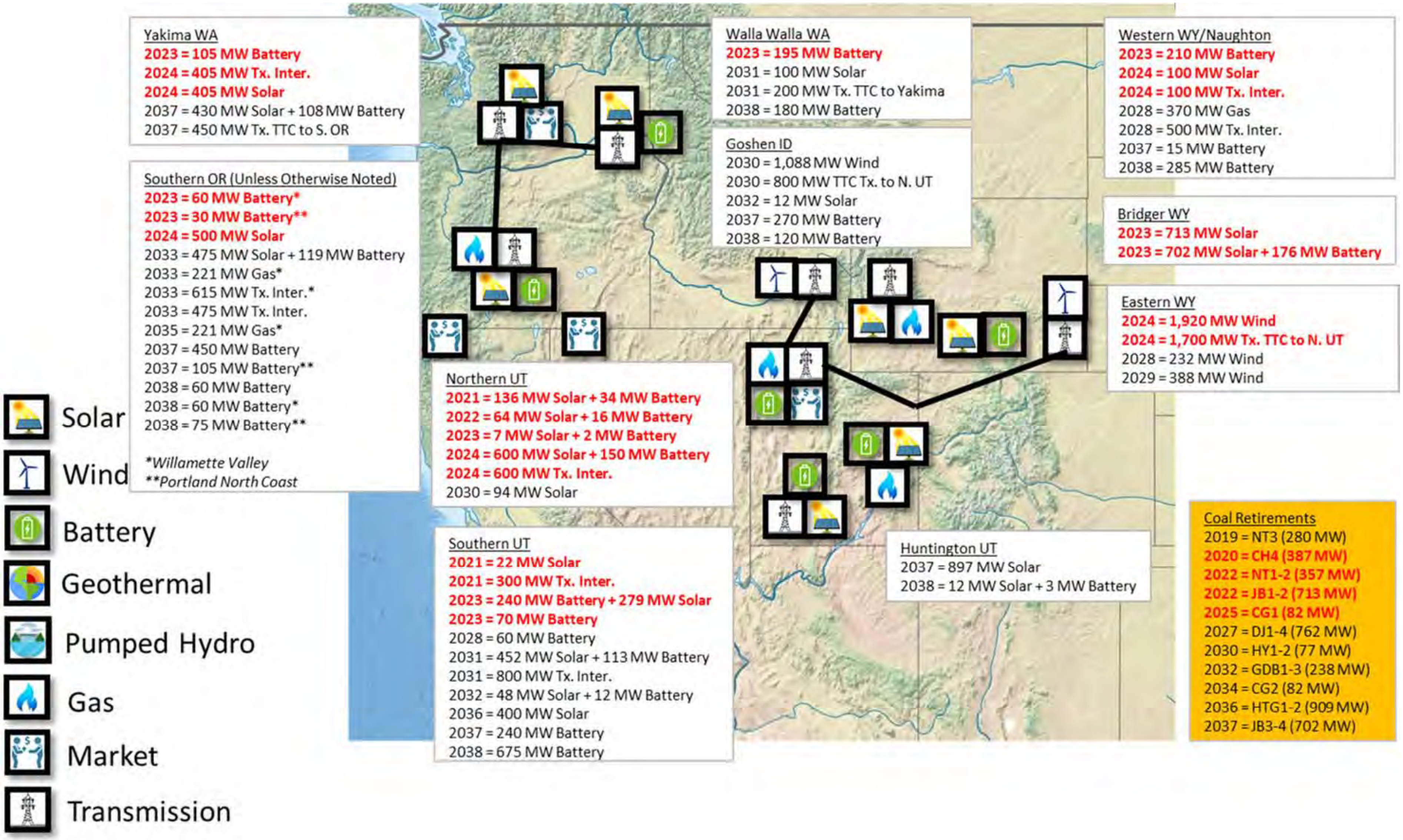
Retirement Assumptions

Initial portfolio-development case P-04 is P-01 with Jim Bridger Units 1 & 2 and Naughton Units 1 & 2 retiring in 2022. Full retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2046
Colstrip 4	Retire 2046
Craig 1	Retire 2025
Craig 2	Retire 2034
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2022
Jim Bridger 2	Retire 2022
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2022
Naughton 2	Retire 2022
Naughton 3	Retire 2019
Wyodak	Retire 2039

Portfolio: Coal Study C-42 (P-04)

Case - P-04 (Coal Study C-42)



Portfolio: Gadsby Alternative Case (P-06)

Initial Portfolio-Development Fact Sheets

Portfolio Assumptions

Description

Similar to P-04, P-06 has the same retirement assumptions except Colstrip Units 3 & 4 retire earlier in 2027 instead of 2047, Craig Unit 2 retires in 2025 instead of 2034, and Gadsby Units 1-3 retire in 2020 instead of 2032. In addition, Jim Bridger Unit 2 retires later, in 2032 instead of 2022 and Naughton Units 1 & 2 retire in 2029 instead of 2022. Meanwhile, Naughton 3 undergoes a larger gas conversion in 2020 followed by retirement in 2029.

Portfolio Summary

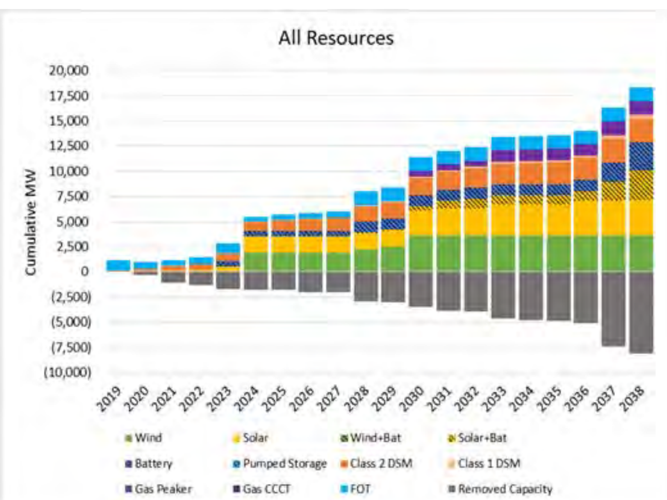
System Optimizer PVRR ($m) $21,980

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Walla Walla – to Yakima, Expansion	*2031*	*200*
Yakima – to – S. Oregon/California	*2038*	*450*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

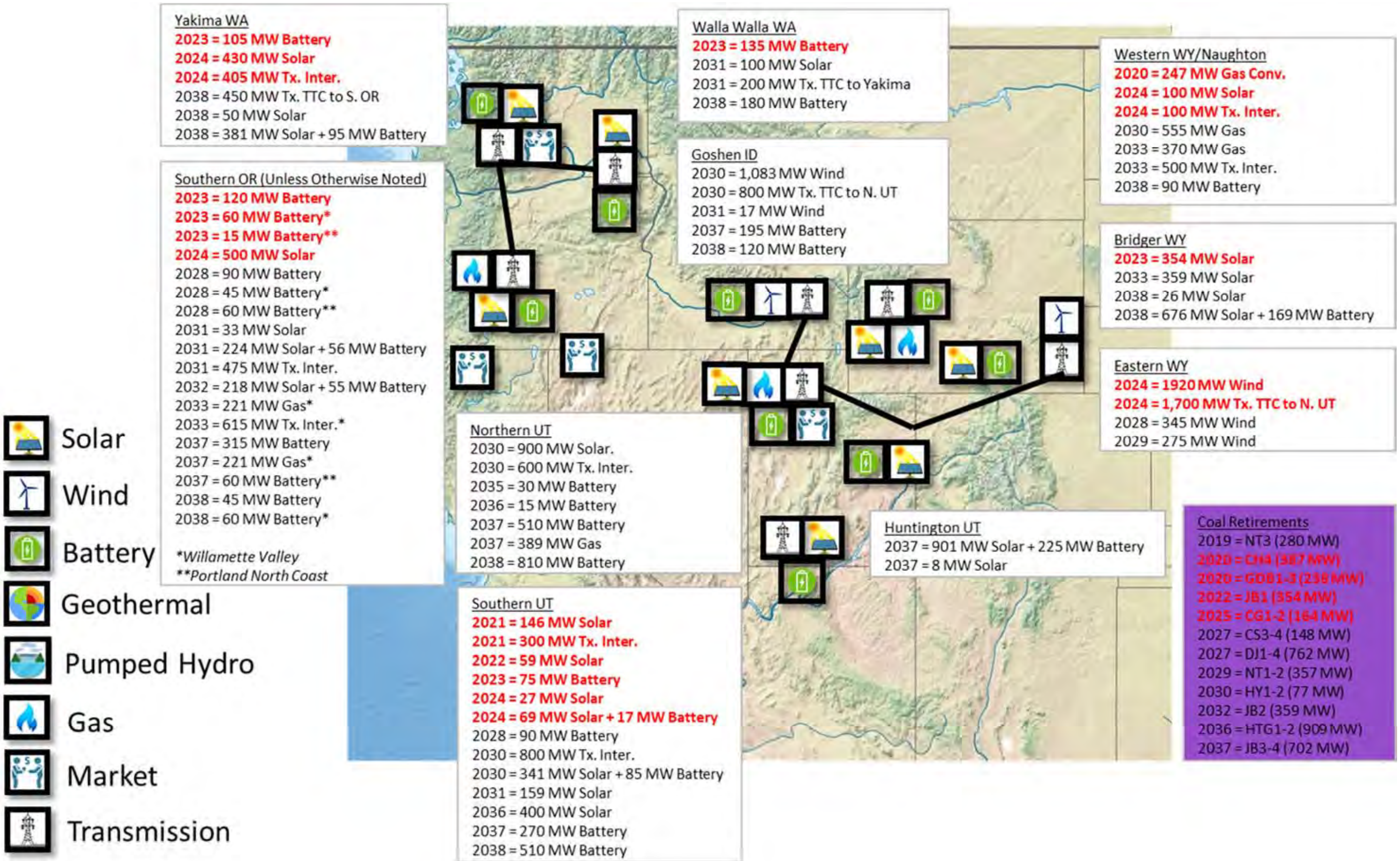
Initial portfolio-development case P-06 is Gadsby Units 1-3 alternative retirements. Full retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2025
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2020
Gadsby 2	Retire 2020
Gadsby 3	Retire 2020
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2022
Jim Bridger 2	Retire 2032
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2029
Naughton 2	Retire 2029
Naughton 3	Lg. GC 2020 Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Gadsby Alternative Case (P-06)

Case - P-06 (Gadsby Alternative Case)



Portfolio: Gadsby Alternative Case (P-07)

Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

A variant of case P-06, P-07 has all of the same retirement assumptions as well as gas conversion plans but tests retirement of Jim Bridger Unit 2 in 2028.

PORTFOLIO SUMMARY

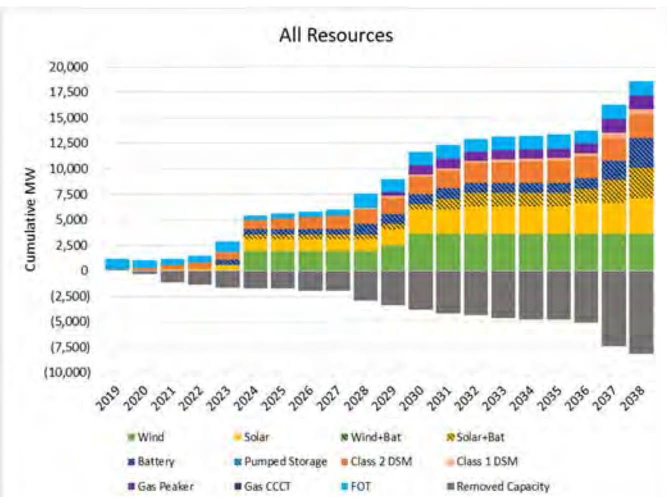
System Optimizer PVRR ($m) $21,905

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Walla Walla – to Yakima, Expansion	*2032*	*200*
Yakima – to – S. Oregon/California	*2038*	*450*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

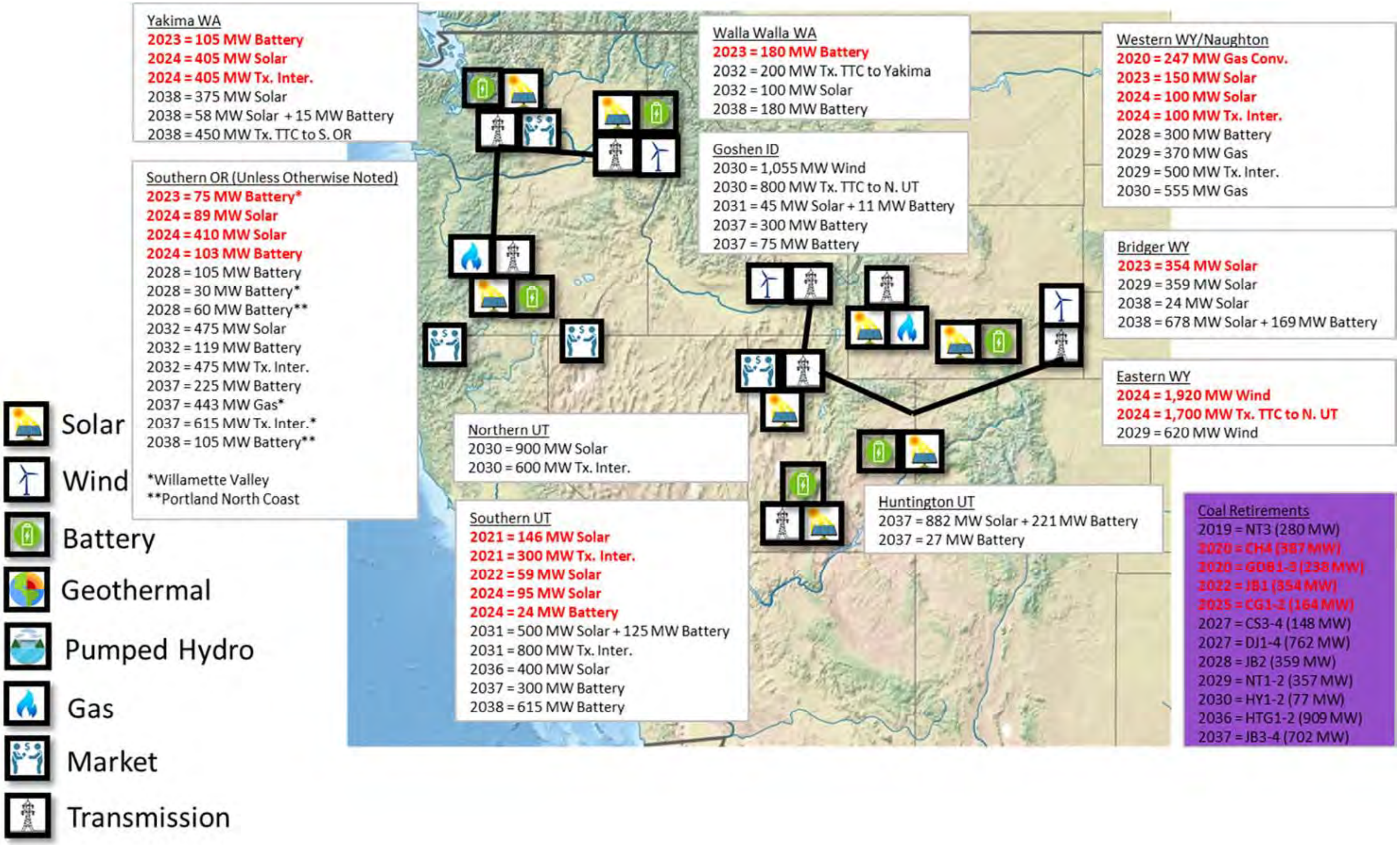
Initial portfolio-development case P-07 is P-06 with Jim Bridger Unit 2 retiring in 2028. Full retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2025
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2020
Gadsby 2	Retire 2020
Gadsby 3	Retire 2020
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2022
Jim Bridger 2	Retire 2028
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2029
Naughton 2	Retire 2029
Naughton 3	Lg. GC 2020 Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Gadsby Alternative Case (P-07)

Case - P-07 (Gadsby Alternative Case)



Portfolio: Naughton 3 Small Gas Conversion (P-08)

Initial Portfolio-Development Fact Sheets

Portfolio Assumptions

Description

A variant of case P-03, P-08 has all of the same retirement assumptions except tests a small gas conversion on Naughton Unit 3 in 2022 with retirement still followed in 2029.

Portfolio Summary

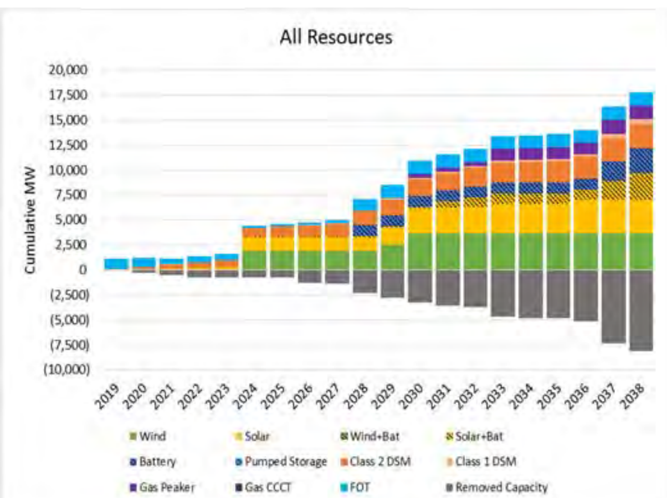
System Optimizer PVRR ($m) $21,979

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Walla Walla – to Yakima, Expansion	*2032*	*200*
Yakima – to – S. Oregon/California	*2038*	*450*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

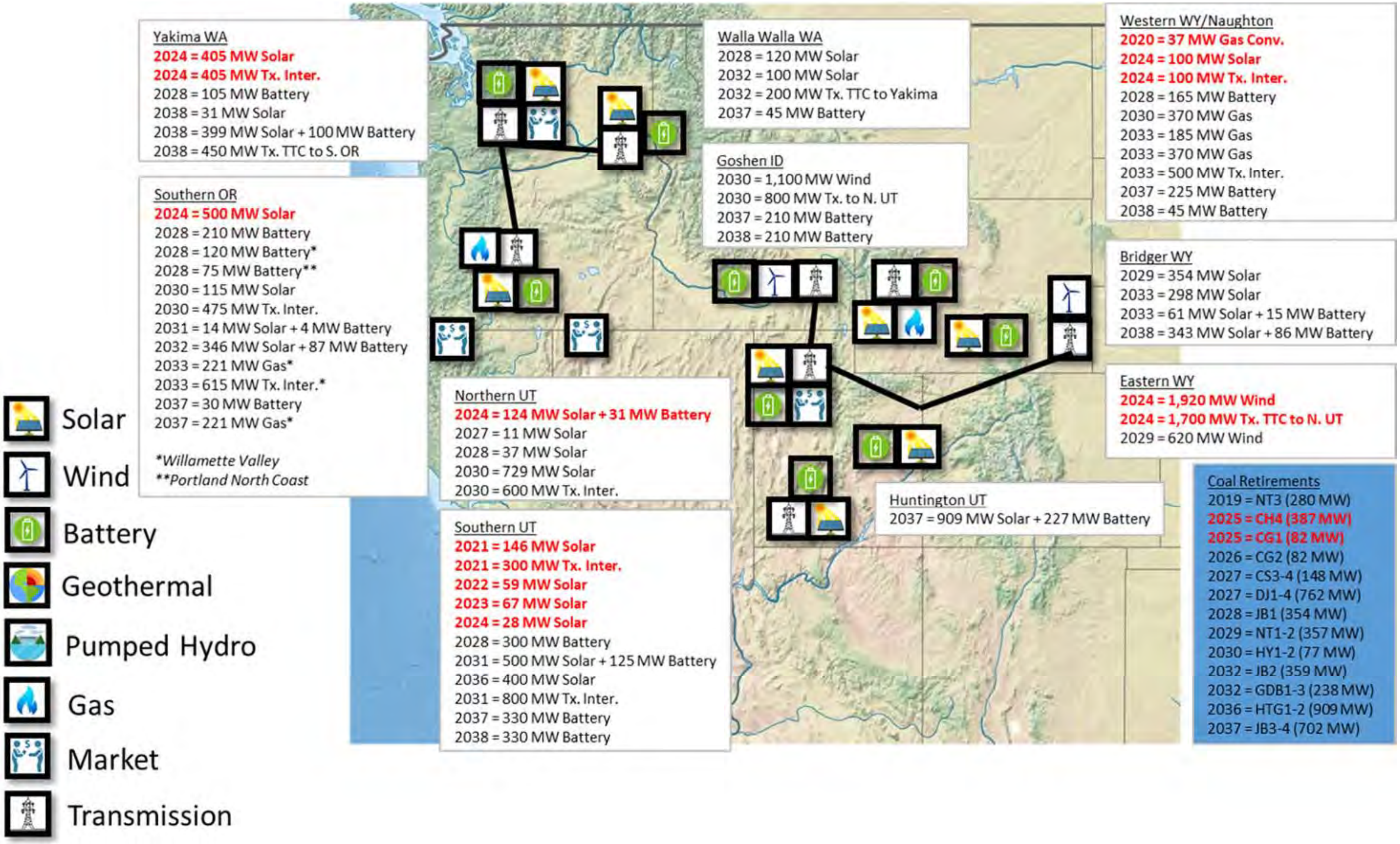
Initial portfolio-development case P-08 is P-03 with Naughton Unit 3 undergoing small gas conversion in 2020. Full retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2025
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2026
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2028
Jim Bridger 2	Retire 2032
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2029
Naughton 2	Retire 2029
Naughton 3	Sm. GC 2020 Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Naughton 3 Small Gas Conversion (P-08)

Case - P-08 (Naughton 3 Small Gas Conversion)



Portfolio: Naughton 3 Large Gas Conversion (P-09)

Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

A variant of case P-03, P-09 has all of the same retirement assumptions except tests a large gas conversion on Naughton Unit 3 in 2022 with retirement still followed in 2029.

PORTFOLIO SUMMARY

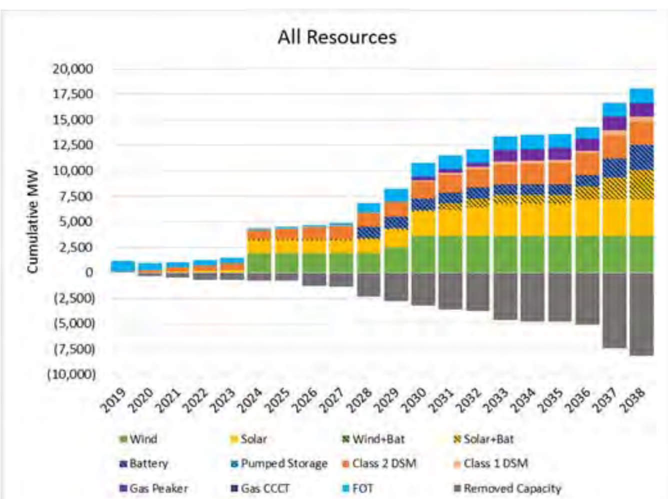
System Optimizer PVRR ($m) ***$21,885***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Walla Walla – to Yakima, Expansion	*2031*	*200*
Yakima – to – S. Oregon/California	*2036*	*450*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

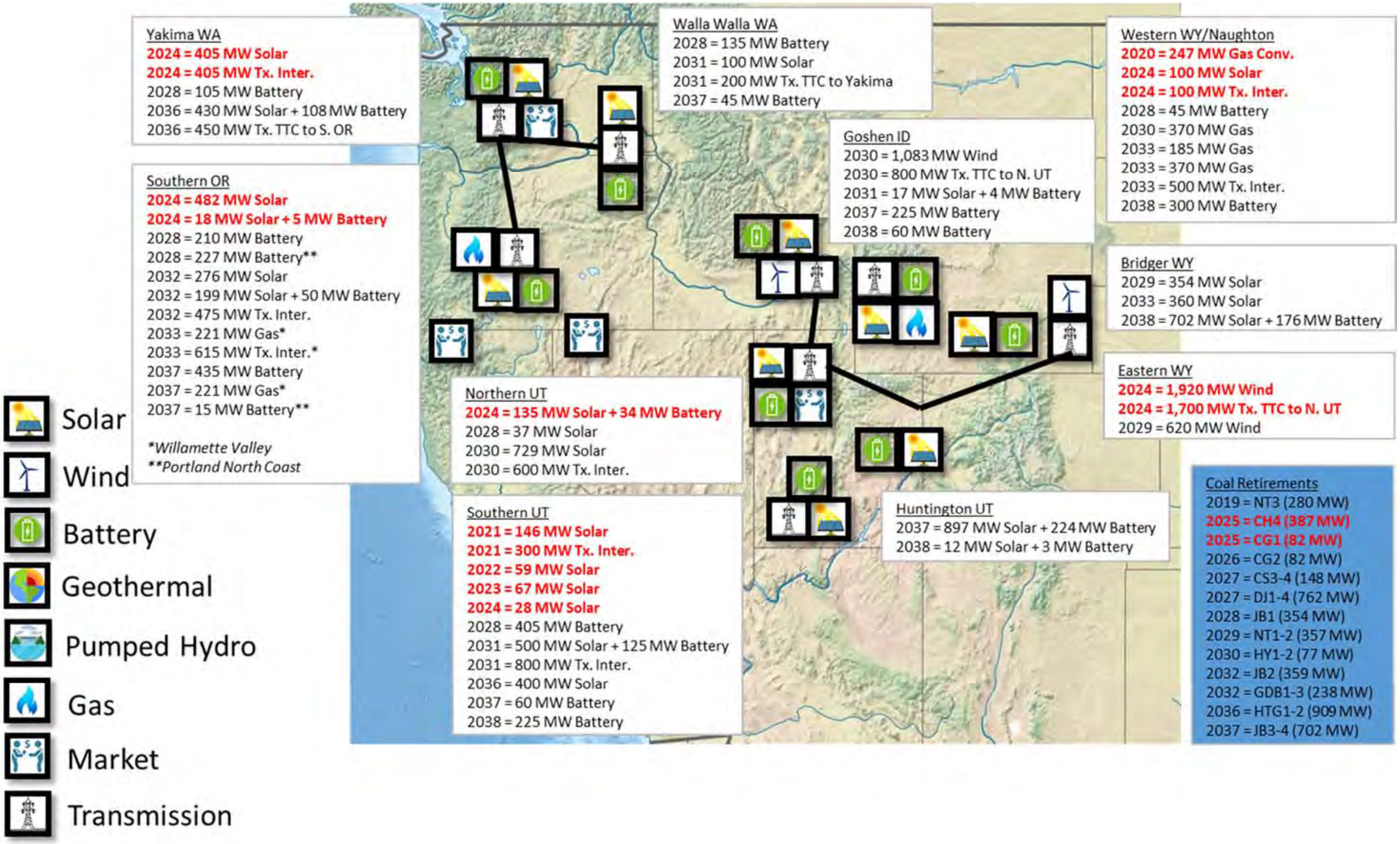
Initial portfolio-development case P-09 is P-03 with Naughton Unit 3 undergoing large gas conversion in 2020. Full retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2025
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2026
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2028
Jim Bridger 2	Retire 2032
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2029
Naughton 2	Retire 2029
Naughton 3	Lg. GC 2020 Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Naughton 3 Large Gas Conversion (P-09)

Case - P-09 (Naughton 3 Large Gas Conversion)



Portfolio: Naughton 3 Large Gas Conversion (P-10)

Initial Portfolio-Development Fact Sheets

Portfolio Assumptions

Description

A variant of case P-04, P-10 has all of the same retirement assumptions except tests a large gas conversion on Naughton Unit 3 in 2020 with retirement still followed in 2029.

Portfolio Summary

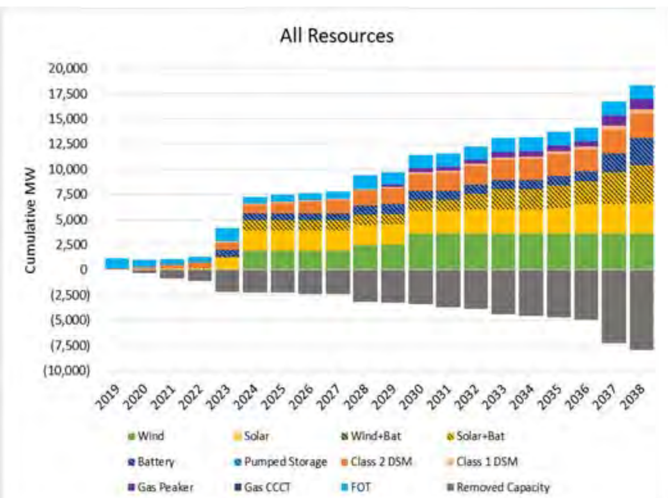
System Optimizer PVRR ($m) $21,723

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Walla Walla – to Yakima, Expansion	*2032*	*200*
Yakima – to – S. Oregon/California	*2035*	*450*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

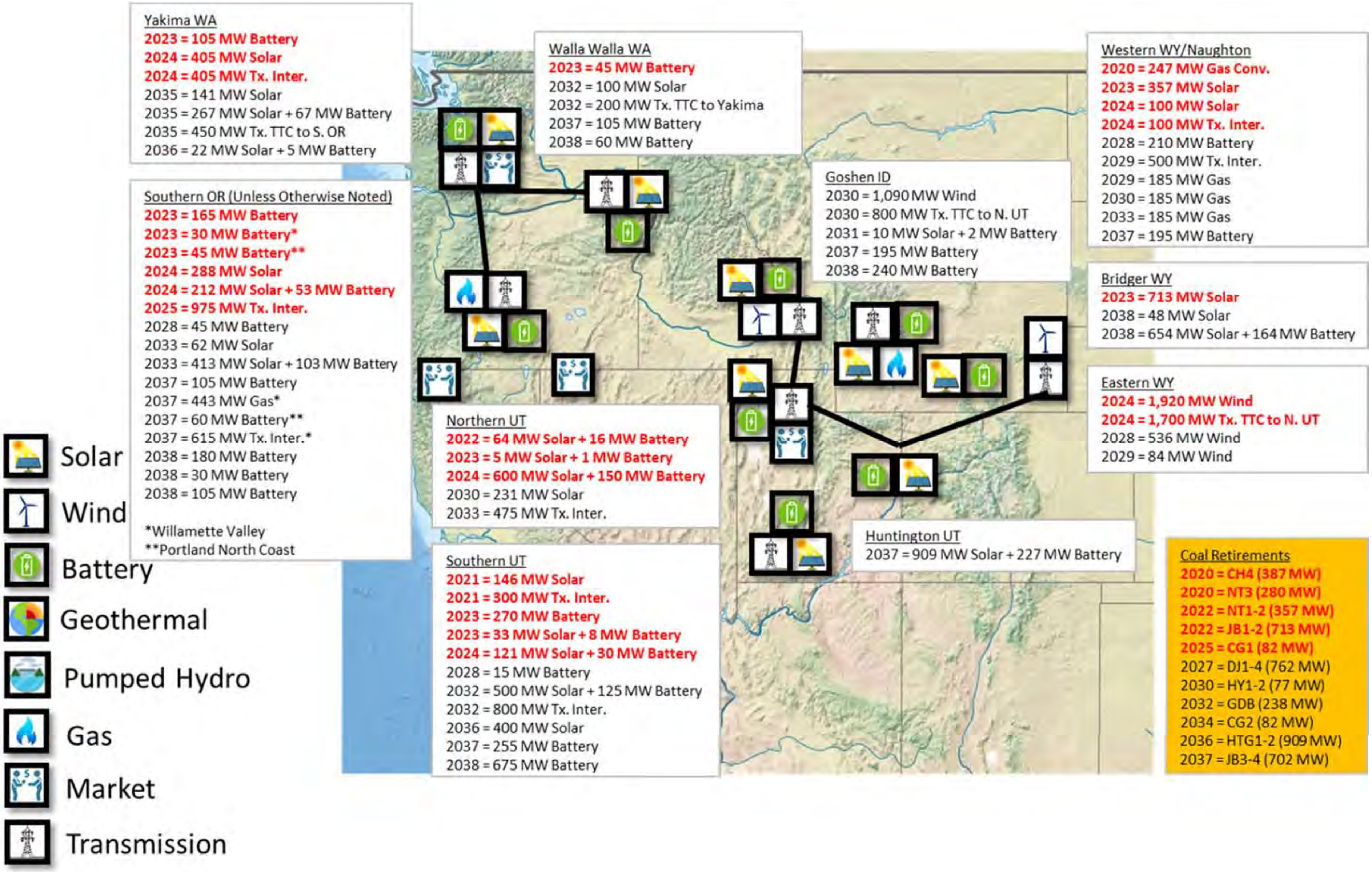
Initial portfolio-development case P-10 is P-04 with Naughton Unit 3 undergoing large gas conversion in 2020. Full retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2046
Colstrip 4	Retire 2046
Craig 1	Retire 2025
Craig 2	Retire 2034
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2022
Jim Bridger 2	Retire 2022
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2022
Naughton 2	Retire 2022
Naughton 3	Lg. GC 2020 Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Naughton 3 Large Gas Conversion (P-10)

Case - P-10 (Naughton 3 Large Gas Conversion)



Portfolio: Cholla 4 Retirement 2020 (P-11)

Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

A variant of case P-09, P-11 has all of the same retirement assumptions except tests retirement of Cholla Unit 4 in 2020 instead of 2025.

PORTFOLIO SUMMARY

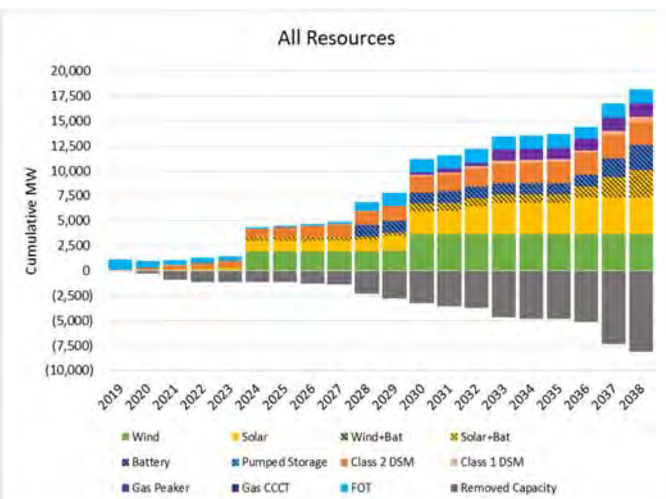
System Optimizer PVRR ($m) ***$21,873***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Walla Walla – to Yakima, Expansion	*2031*	*200*
Yakima – to – S. Oregon/California	*2036*	*450*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

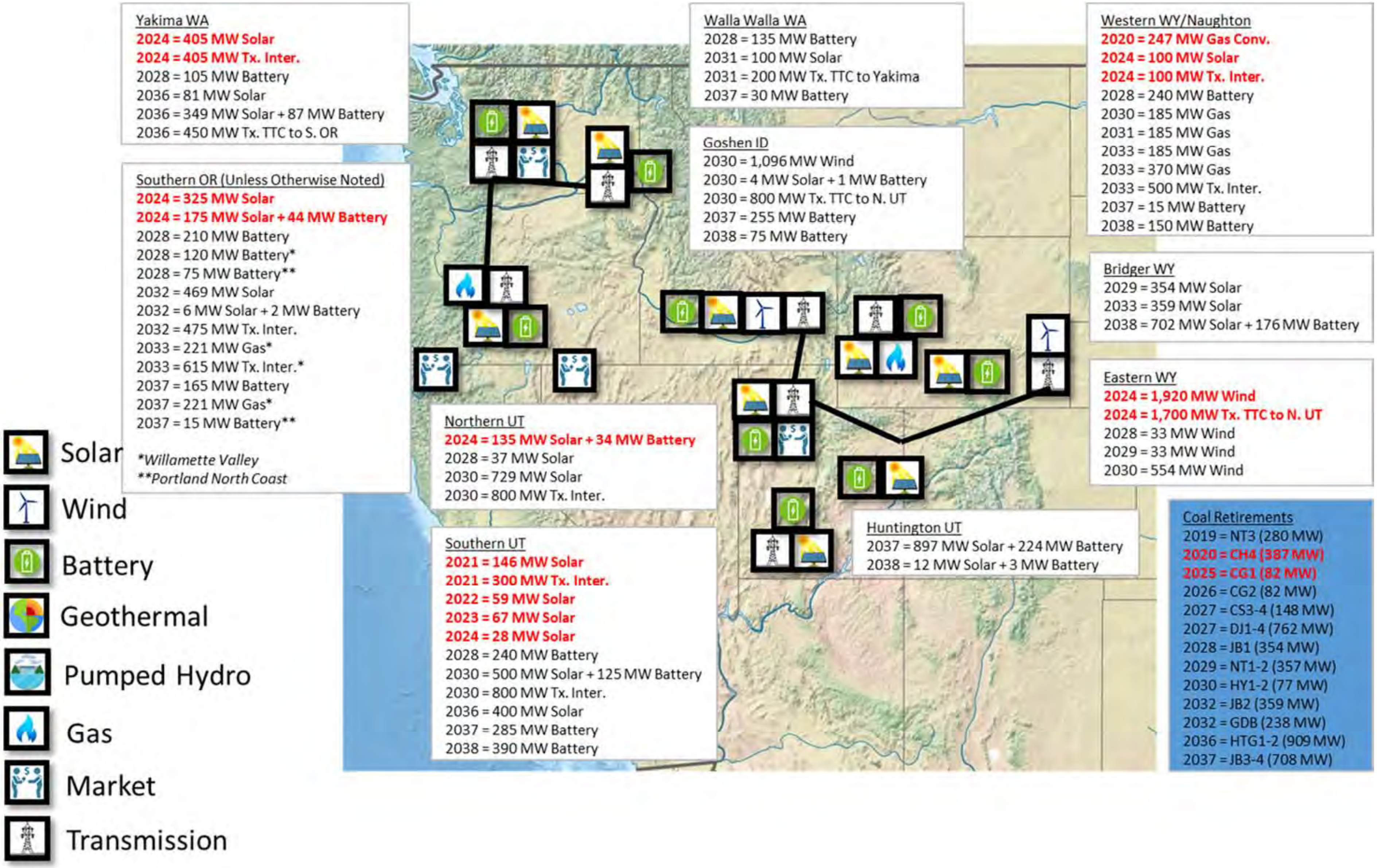
Initial portfolio-development case P-11 is P-09 with Cholla Unit 4 retirement accelerated to 2020. Full retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2026
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2028
Jim Bridger 2	Retire 2032
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2029
Naughton 2	Retire 2029
Naughton 3	Lg. GC 2020 Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Cholla 4 Retirement 2020 (P-11)

Case - P-11 (Cholla 4 Retirement 2020)



Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

A variant of case P-06, P-12 has all of the same retirement assumptions except tests a Cholla Unit 4 retirement in 2025 instead of 2020.

PORTFOLIO SUMMARY

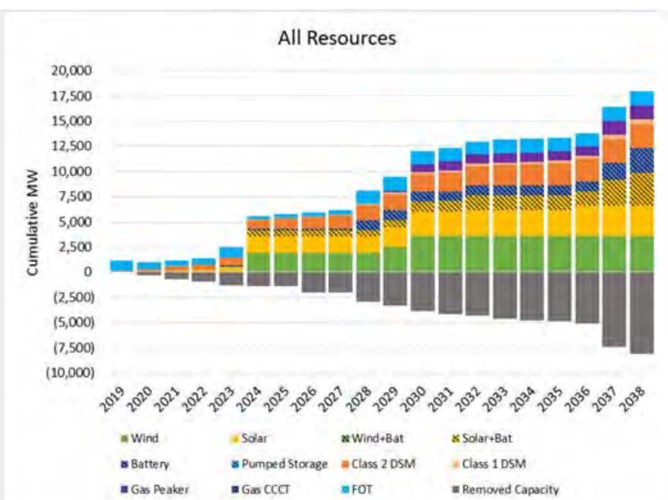
System Optimizer PVRR ($m) $21,854

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Walla Walla – to Yakima, Expansion	*2032*	*200*
Yakima – to – S. Oregon/California	*2037*	*450*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

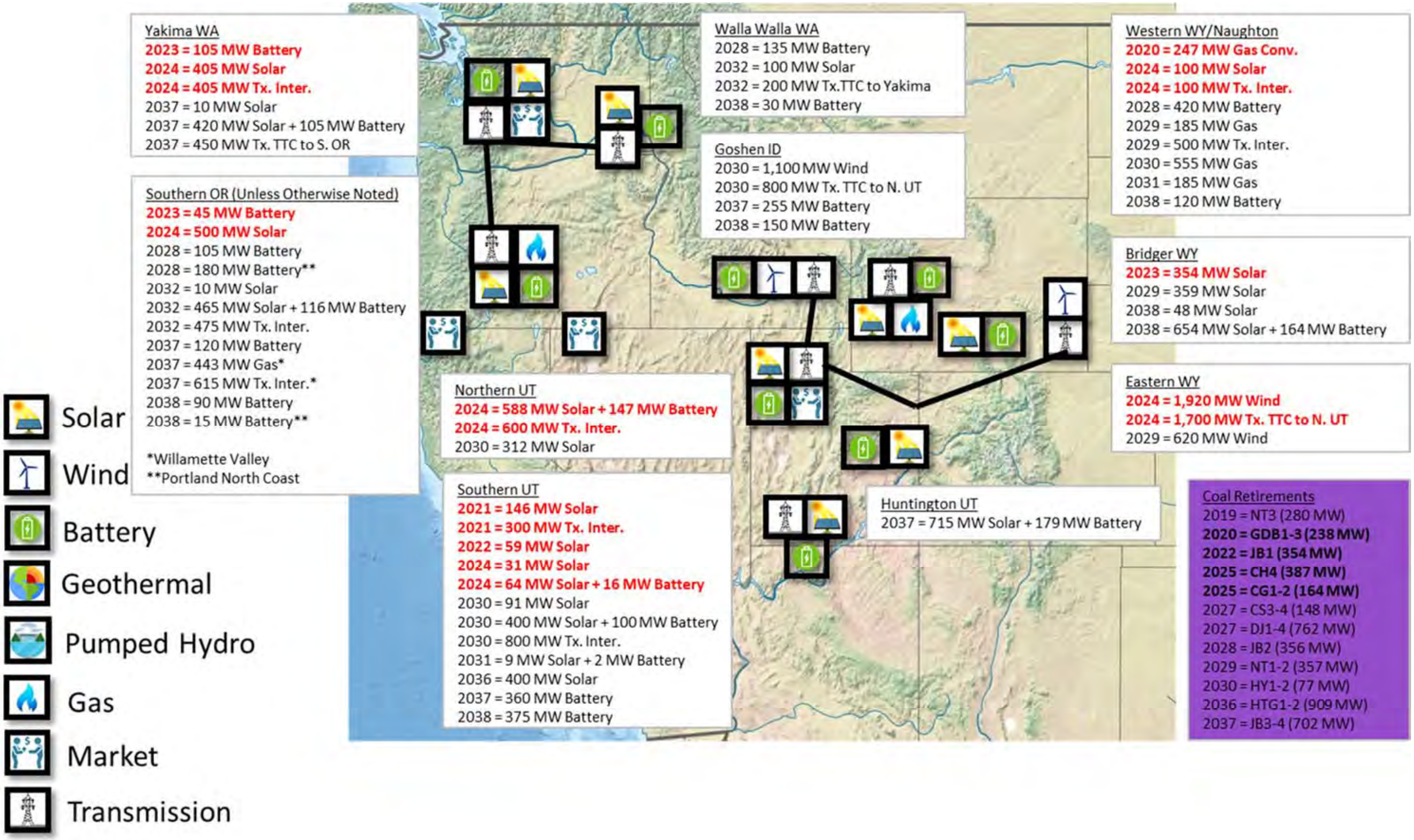
Initial portfolio-development case P-12 is P-06 with Cholla Unit 4 retiring in 2025. Full retirement assumptions are summarized in the following table.

Unit	**Description**
Cholla 4	Retire 2025
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2025
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2020
Gadsby 2	Retire 2020
Gadsby 3	Retire 2020
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2022
Jim Bridger 2	Retire 2032
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2029
Naughton 2	Retire 2029
Naughton 3	Lg. GC 2020 Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Cholla 4 Retirement 2025 (P-12)

Case - P-12 (Cholla 4 Retirement 2025)



Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

A variant of case P-11, P-13 has all of the same retirement assumptions except tests the addition of scrubbers to Jim Bridger Unit 1 in 2022 followed by retirement in 2037 instead of 2028, and Jim Bridger Unit 2 in 2022 followed by retirement in 2037 instead of 2032.

PORTFOLIO SUMMARY

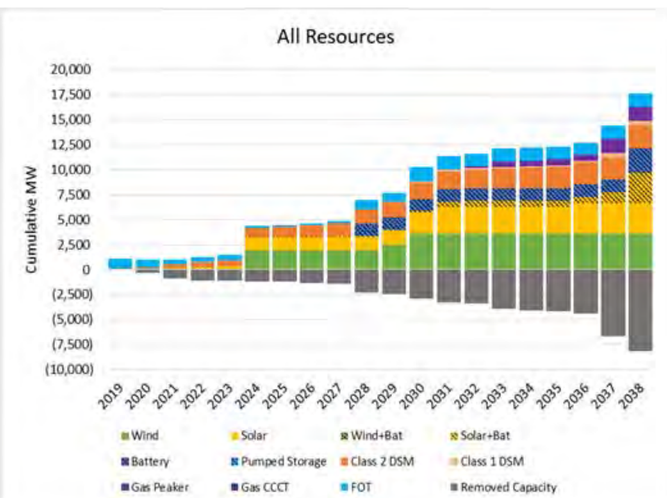
System Optimizer PVRR ($m) $22,346

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Walla Walla – to Yakima, Expansion	*2031*	*200*
Yakima – to – S. Oregon/California	*2037*	*450*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

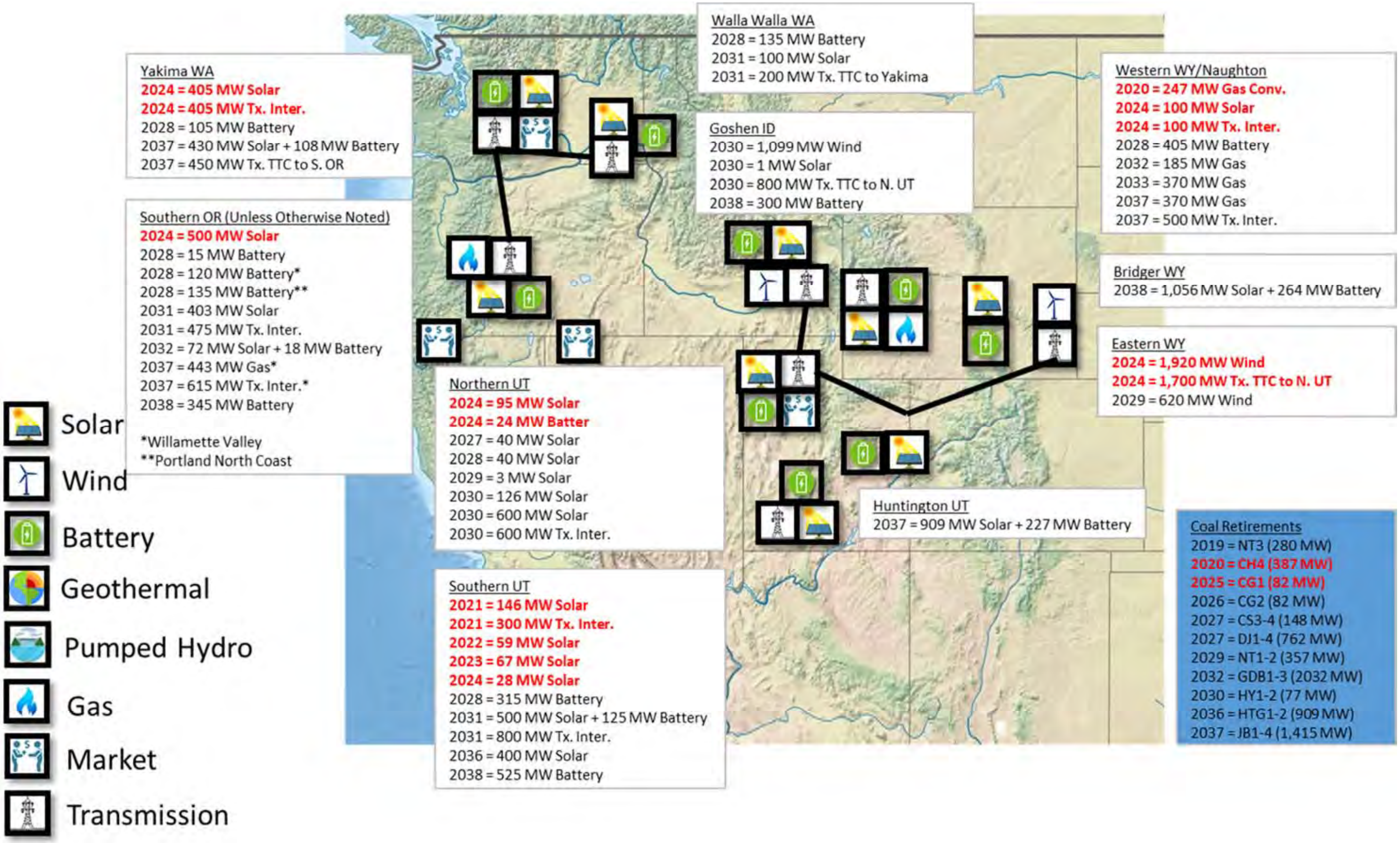
Initial portfolio-development case P-13 is P-11 with Jim Bridger Units 1 & 2 converting to SCRs. Full retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2026
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2037
Jim Bridger 2	Retire 2037
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2029
Naughton 2	Retire 2029
Naughton 3	Lg. GC 2020 Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Jim Bridger 1 & 2 SCRs (P-13)

Case - P-13 (Jim Bridger 1 & 2 SCRs)



Portfolio: Naughton 1 & 2 and Jim Bridger 1-4 Retirement 2022 (P-14)

Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

A variant of case P-09, P-14 has all of the same retirement assumptions except retires Cholla in 2020 instead of 2025, all Jim Bridger Units in 2022 instead of Unit 1 in 2028, Unit 2 in 2032 and Units 3 & 4 in 2037. In addition, it retires Naughton Units 1 & 2 in 2022 instead of 2029.

PORTFOLIO SUMMARY

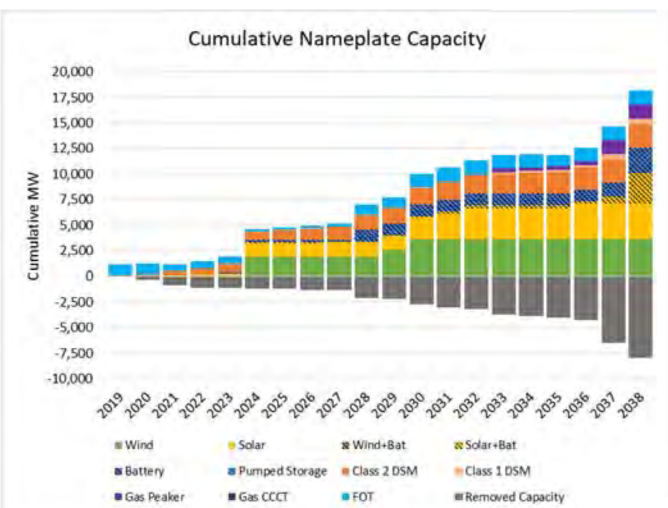
System Optimizer PVRR ($m) ***$21,696***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Walla Walla – to Yakima, Expansion	*2032*	*200*
Yakima – to – S. Oregon/California	*2038*	*450*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

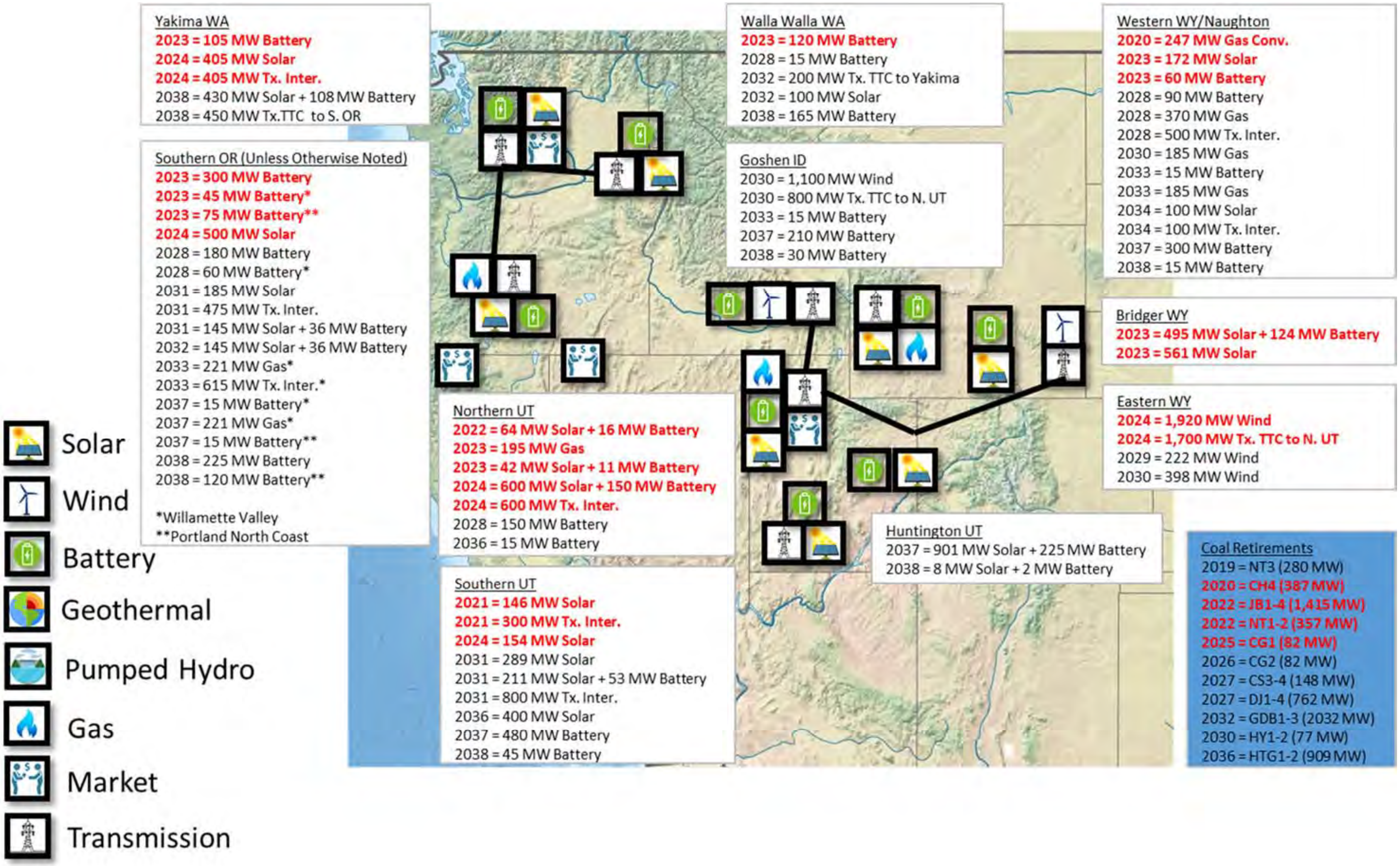
Initial portfolio-development case P-14 is P-11 with Naughton Units 1 & 2 and Jim Bridger Units 1-4 retiring in 2022. Full retirement assumptions are summarized in the following table.

Unit	**Description**
Cholla 4	Retire 2020
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2026
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2022
Jim Bridger 2	Retire 2022
Jim Bridger 3	Retire 2022
Jim Bridger 4	Retire 2022
Naughton 1	Retire 2022
Naughton 2	Retire 2022
Naughton 3	Lg. GC 2020 Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Naughton 1 & 2 and Jim Bridger 1-4 Retirement 2022 (P-14)

Case - P-14 (Naughton 1-2 and Jim Bridger 1-4 Retired 2022)



Portfolio: Retire All Coal by 2030 (P-15)

Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

At stakeholder request, a variant of case P-28, P-15 was designed to economically retire all coal by 2030.

PORTFOLIO SUMMARY

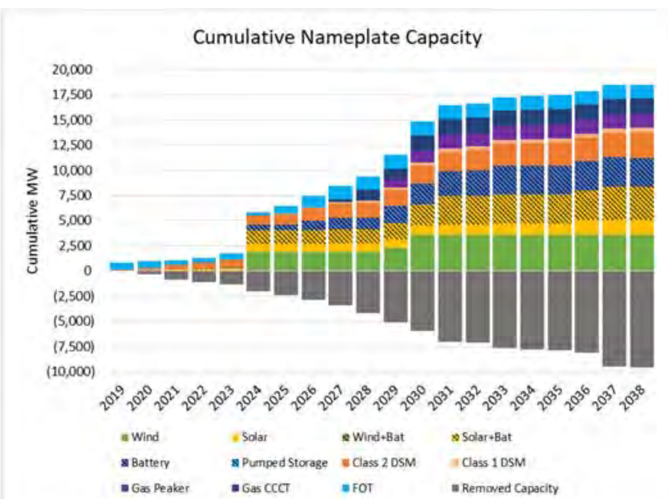
System Optimizer PVRR ($m) $22,132

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Goshen – to – Utah N, Expansion	*2030*	*800*
Yakima – to – S. Oregon/California	*2037*	*450*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

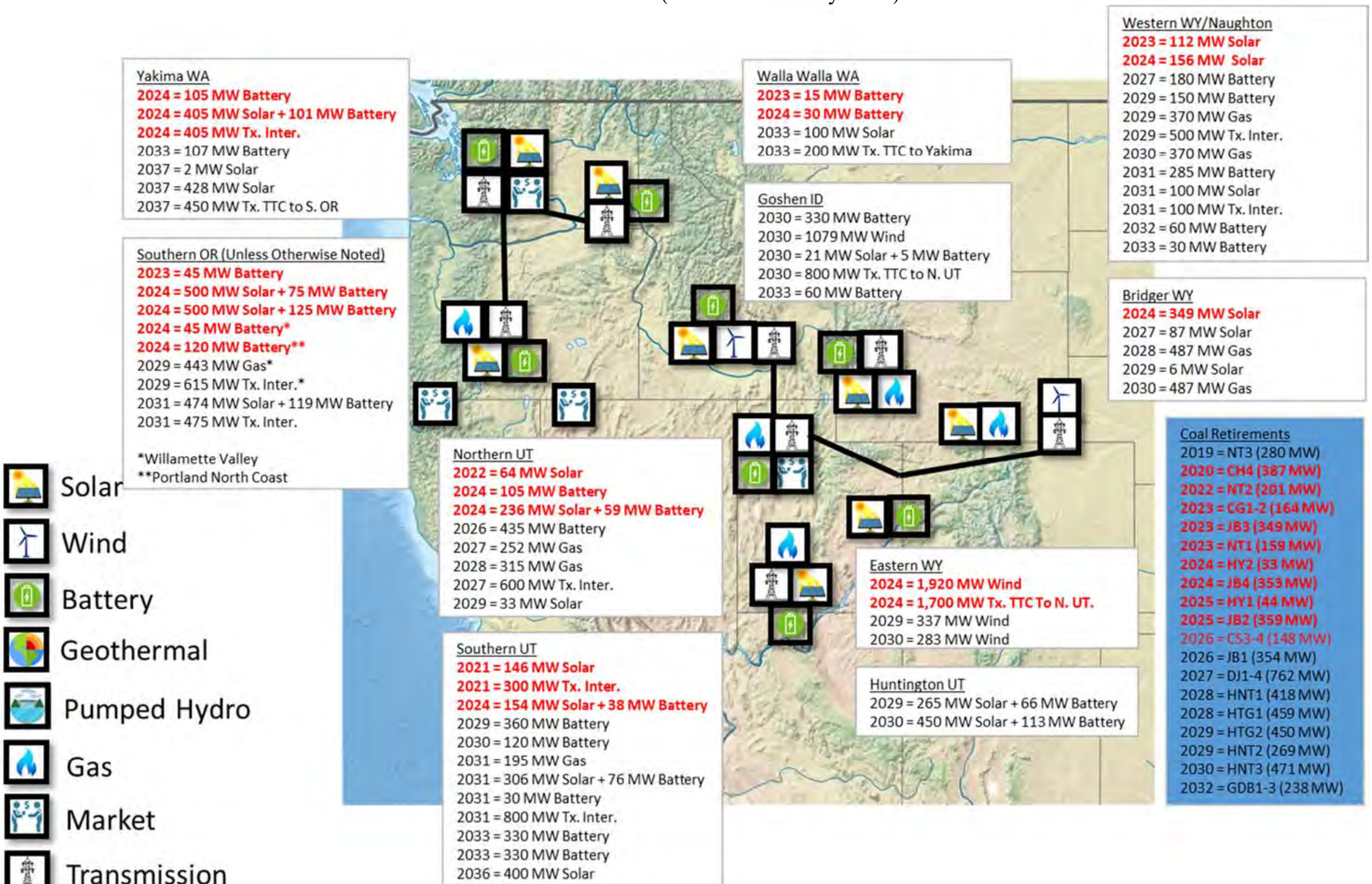
Initial portfolio-development case P-15a is P-28 with all coal retired by 2030. Full retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2026
Colstrip 4	Retire 2026
Craig 1	Retire 2023
Craig 2	Retire 2023
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2025
Hayden 2	Retire 2024
Hunter 1	Retire 2028
Hunter 2	Retire 2029
Hunter 3	Retire 2030
Huntington 1	Retire 2028
Huntington 2	Retire 2029
Jim Bridger 1	Retire 2026
Jim Bridger 2	Retire 2025
Jim Bridger 3	Retire 2023
Jim Bridger 4	Retire 2024
Naughton 1	Retire 2023
Naughton 2	Retire 2022
Naughton 3	Lg. GC 2020 Retire 2029
Wyodak	Retire 2030

GC = gas conversion

Portfolio: Retire All Coal by 2030 (P-15)

Case - P-15 (Retire All Coal by 2030)



Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

A variant of case P-04, P-16 has all of the same retirement assumptions except was run with a low gas – no CO_2 price policy scenario through the System Optimizer and Planning and Risk.

PORTFOLIO SUMMARY

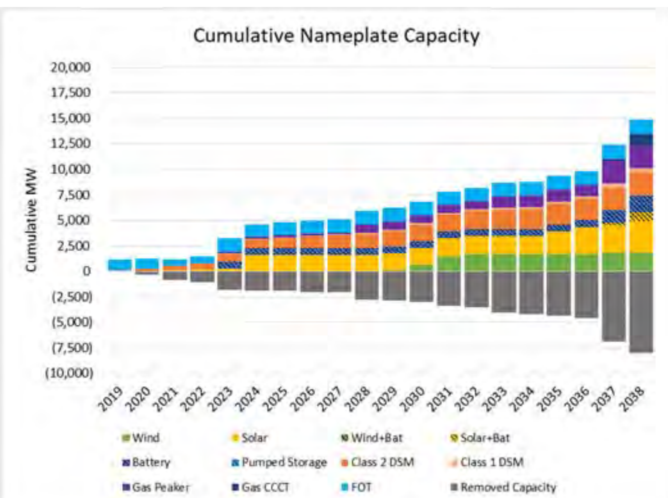
System Optimizer PVRR ($m) $18,634

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Goshen – to – Utah N, Expansion	*2032*	*800*
Yakima – to – S. Oregon, Expansion	*2037*	*450*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



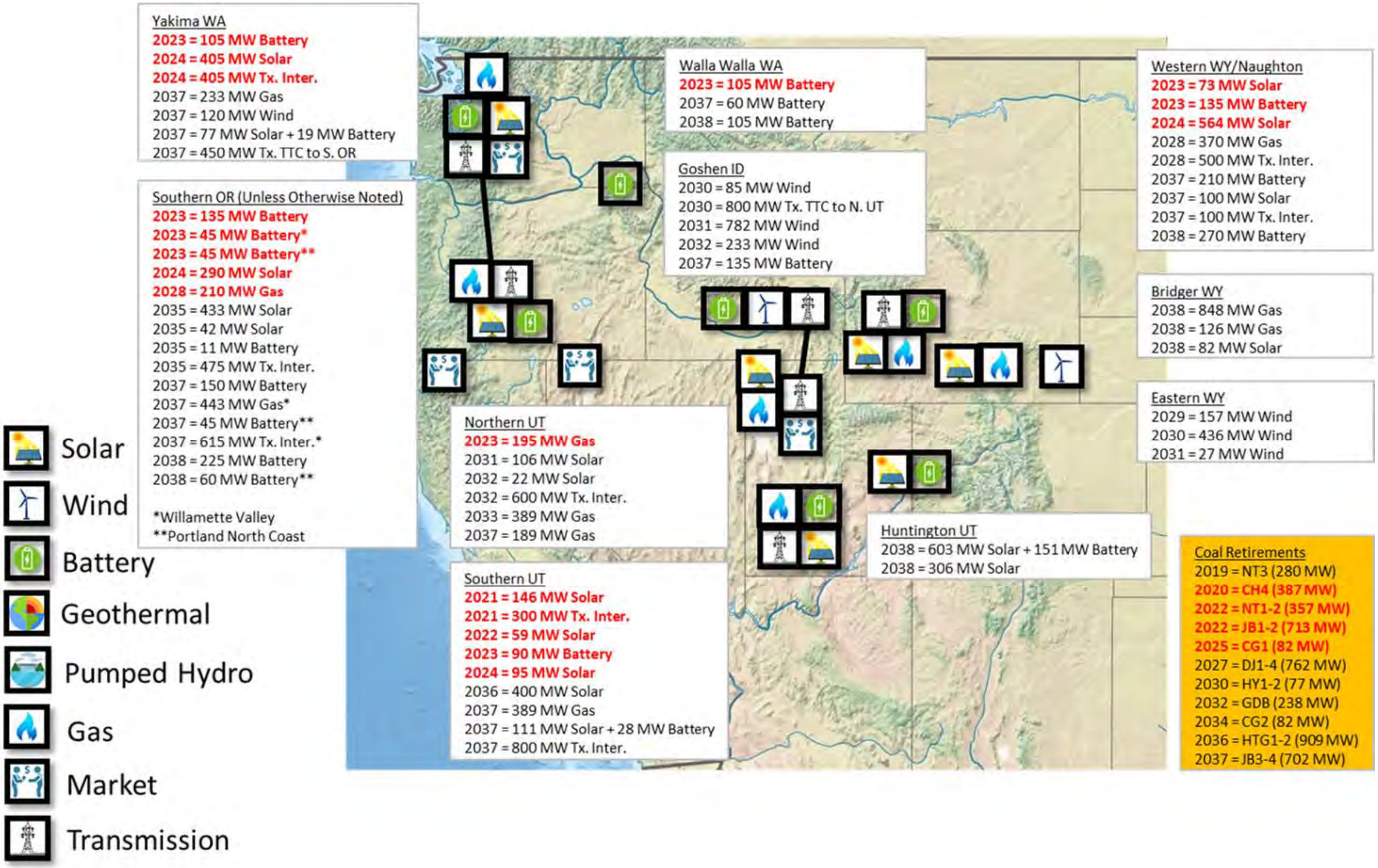
Retirement Assumptions

Initial portfolio-development case P-16 is P-04 with Jim Bridger Unit 1 & 2 Retired in 2022, with no CO_2. Full retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2046
Colstrip 4	Retire 2046
Craig 1	Retire 2025
Craig 2	Retire 2034
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2022
Jim Bridger 2	Retire 2022
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2022
Naughton 2	Retire 2022
Naughton 3	Retire 2019
Wyodak	Retire 2039

Portfolio: Jim Bridger 1 & 2 Retirement 2022, No CO_2 (P-16)

Case - P-16 (Jim Bridger 1 & 2 Retired 2022, No CO_2)



Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description
A variant of case P-15, P-17 has all of the same retirement assumptions except was run with a medium gas – high CO_2 price policy scenario through the System Optimizer and Planning and Risk.

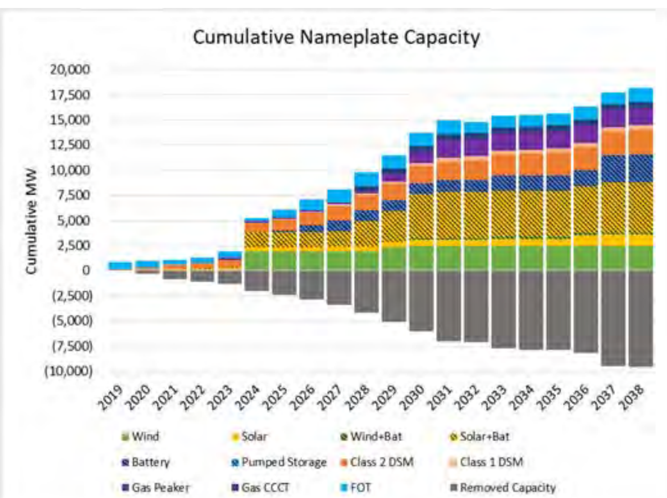
PORTFOLIO SUMMARY

System Optimizer PVRR ($m) $22,070

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Walla Walla – to Yakima, Expansion	*2033*	*200*
Yakima – to – S. Oregon/California	*2037*	*450*

Resource Portfolio
Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



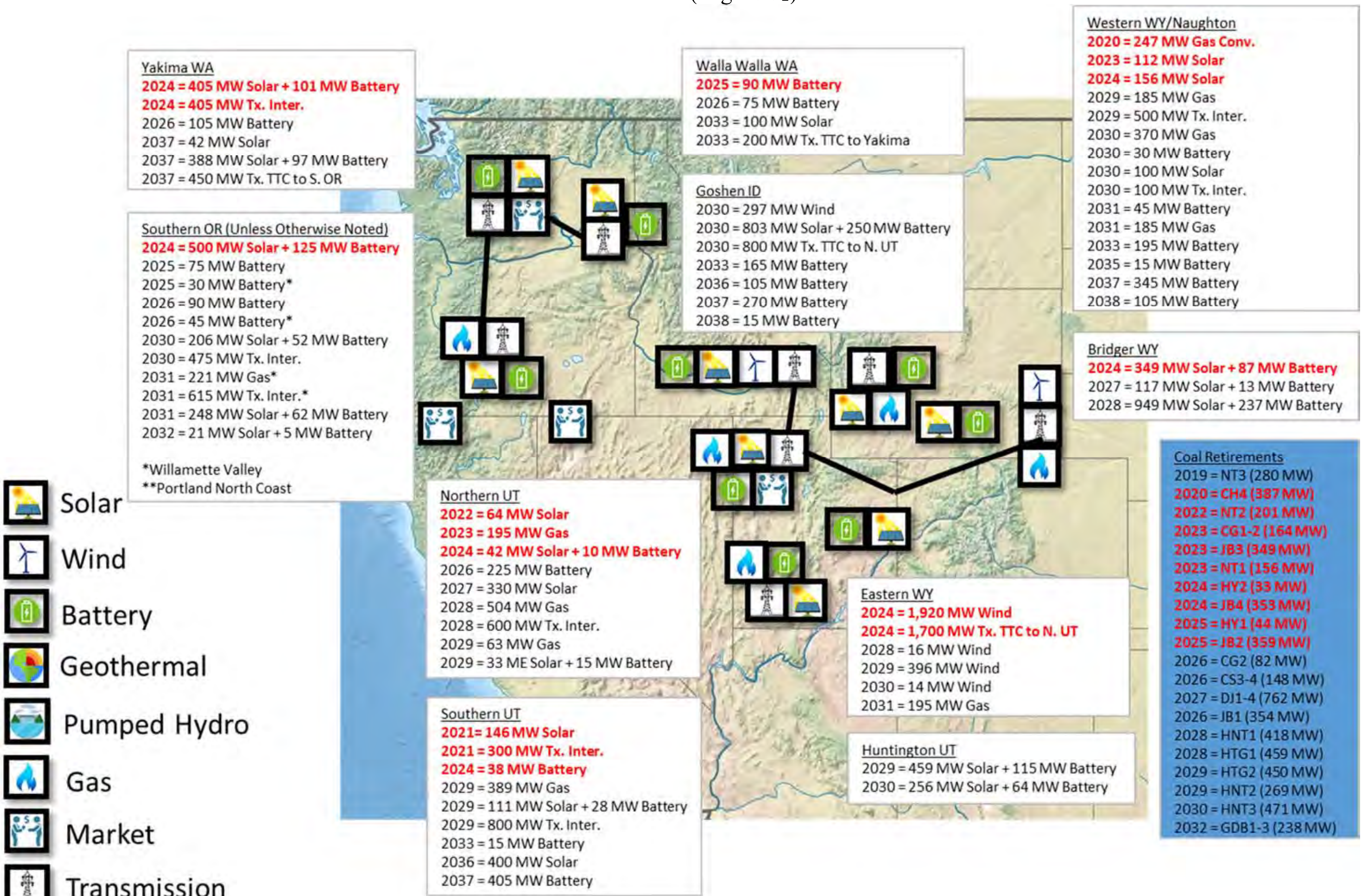
Retirement Assumptions
Initial portfolio-development case P-17 is P-15 with high CO_2, and the retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2026
Colstrip 4	Retire 2026
Craig 1	Retire 2023
Craig 2	Retire 2023
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2025
Hayden 2	Retire 2024
Hunter 1	Retire 2028
Hunter 2	Retire 2029
Hunter 3	Retire 2030
Huntington 1	Retire 2028
Huntington 2	Retire 2029
Jim Bridger 1	Retire 2026
Jim Bridger 2	Retire 2025
Jim Bridger 3	Retire 2023
Jim Bridger 4	Retire 2024
Naughton 1	Retire 2023
Naughton 2	Retire 2022
Naughton 3	Lg. GC 2020 Retire 2029
Wyodak	Retire 2030

GC = gas conversion

Portfolio: High CO_2 (P-17)

P-17 (High CO_2)



Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

A variant of case P-15, P-18 has all of the same retirement assumptions except was run with a medium gas – social cost of carbon price policy scenario through the System Optimizer and Planning and Risk.

PORTFOLIO SUMMARY

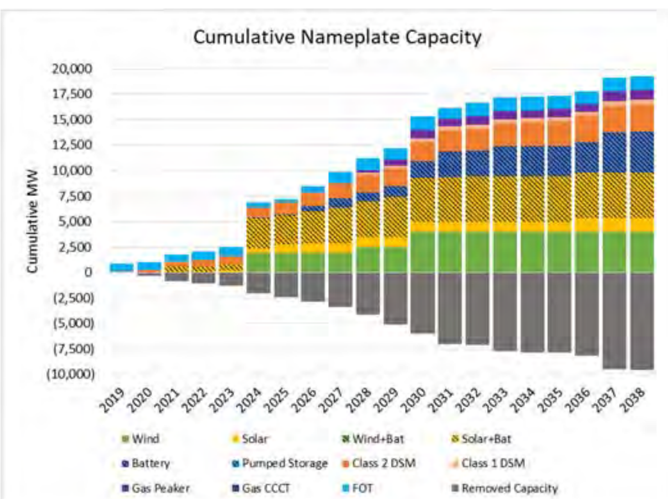
System Optimizer PVRR ($m) $30,022

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Yakima – to – S. Oregon/California	*2030*	*450*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

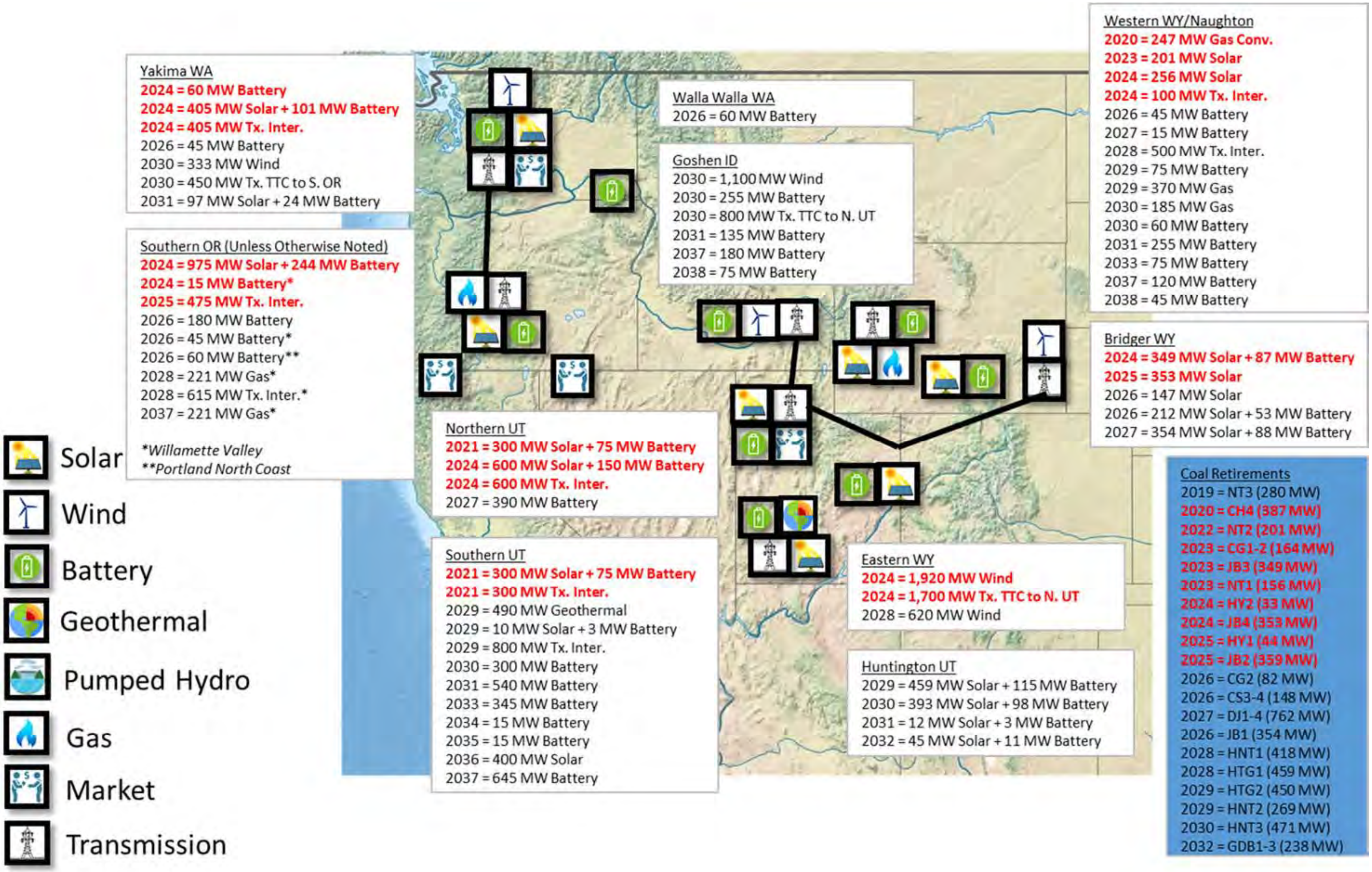
Initial portfolio-development case P-18 is P-15, social cost of carbon, and the retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2026
Colstrip 4	Retire 2026
Craig 1	Retire 2023
Craig 2	Retire 2023
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2025
Hayden 2	Retire 2024
Hunter 1	Retire 2028
Hunter 2	Retire 2029
Hunter 3	Retire 2030
Huntington 1	Retire 2028
Huntington 2	Retire 2029
Jim Bridger 1	Retire 2026
Jim Bridger 2	Retire 2025
Jim Bridger 3	Retire 2023
Jim Bridger 4	Retire 2024
Naughton 1	Retire 2023
Naughton 2	Retire 2022
Naughton 3	Lg. GC 2020 Retire 2029
Wyodak	Retire 2030

GC = gas conversion

Portfolio: Social Cost of Carbon (P-18)

P-18 (Social Cost of Carbon)



Initial Portfolio-Development Fact Sheets

Portfolio Assumptions

Description

A variant of case P-04, P-19 has all of the same retirement assumptions except was run with a low gas – medium CO_2 price policy scenario through the System Optimizer and Planning and Risk.

Portfolio Summary

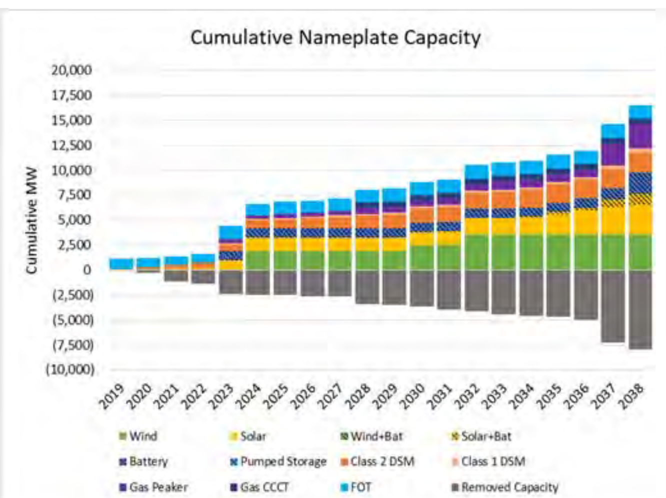
System Optimizer PVRR ($m) ***$20,882***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



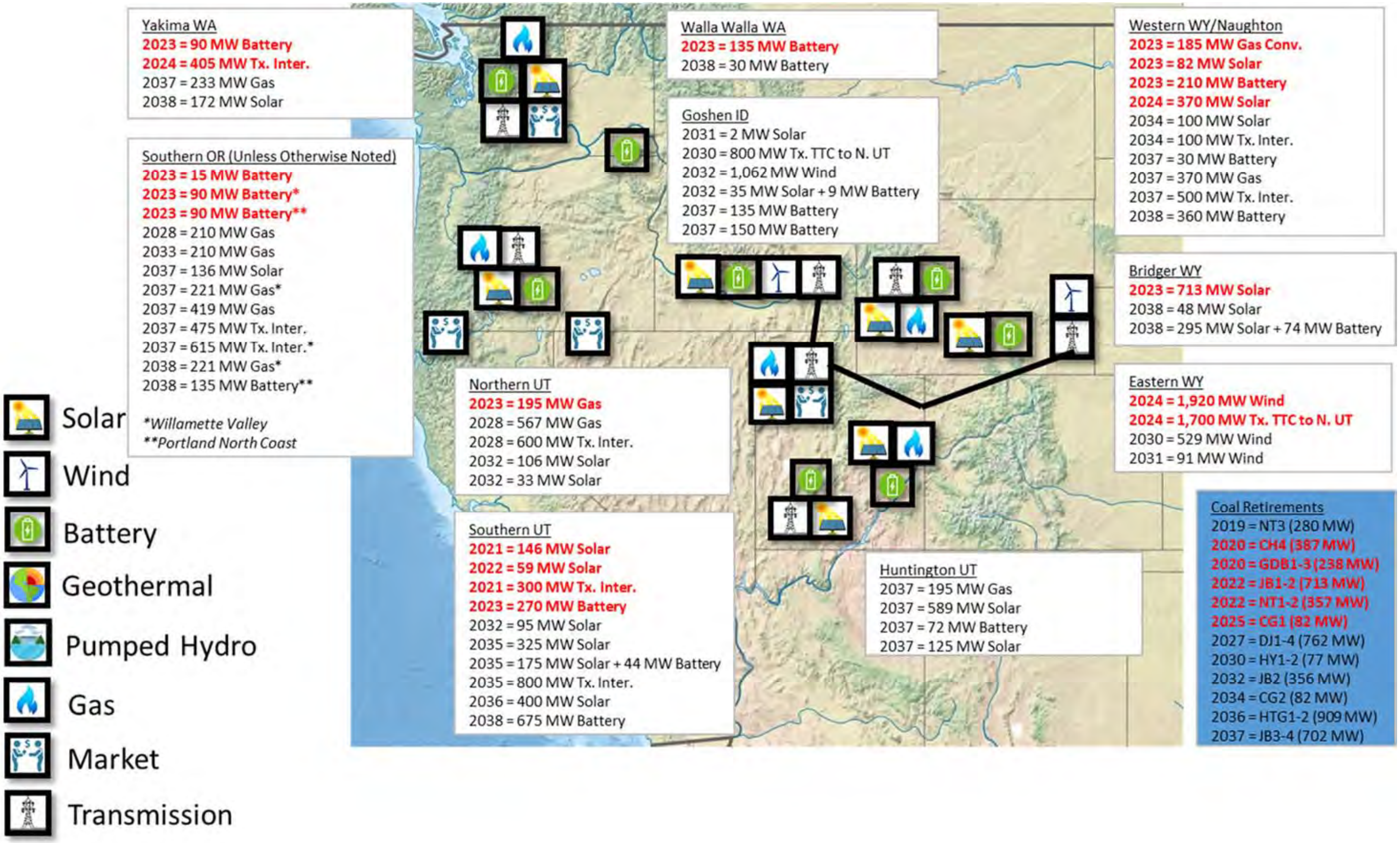
Retirement Assumptions

Initial portfolio-development case P-19 is P-04 with low gas. Full retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2046
Colstrip 4	Retire 2046
Craig 1	Retire 2025
Craig 2	Retire 2034
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2020
Gadsby 2	Retire 2020
Gadsby 3	Retire 2020
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2022
Jim Bridger 2	Retire 2022
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2022
Naughton 2	Retire 2022
Naughton 3	Retire 2019
Wyodak	Retire 2039

Portfolio: Low Gas (P-19)

P-19 (Low Gas)



Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description
A variant of case P-07, P-20 has all of the same retirement assumptions except was run with a high gas – medium CO_2 price policy scenario through the System Optimizer and Planning and Risk.

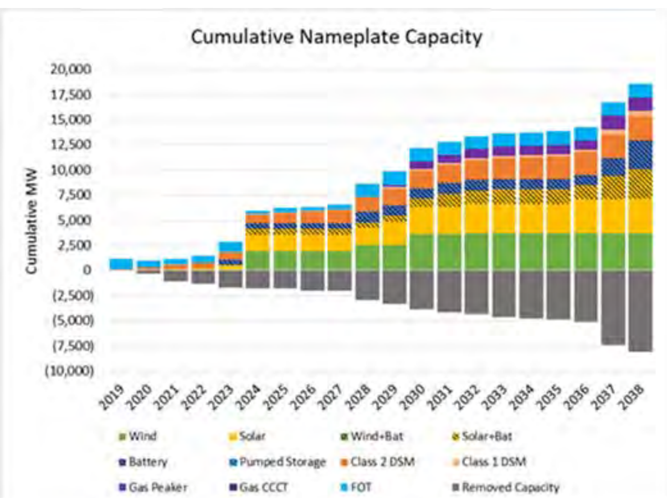
PORTFOLIO SUMMARY

System Optimizer PVRR ($m) $22,746

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Walla Walla – to Yakima, Expansion	*2030*	*200*
Yakima – to – S. Oregon/California	*2032*	*450*

Resource Portfolio
Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



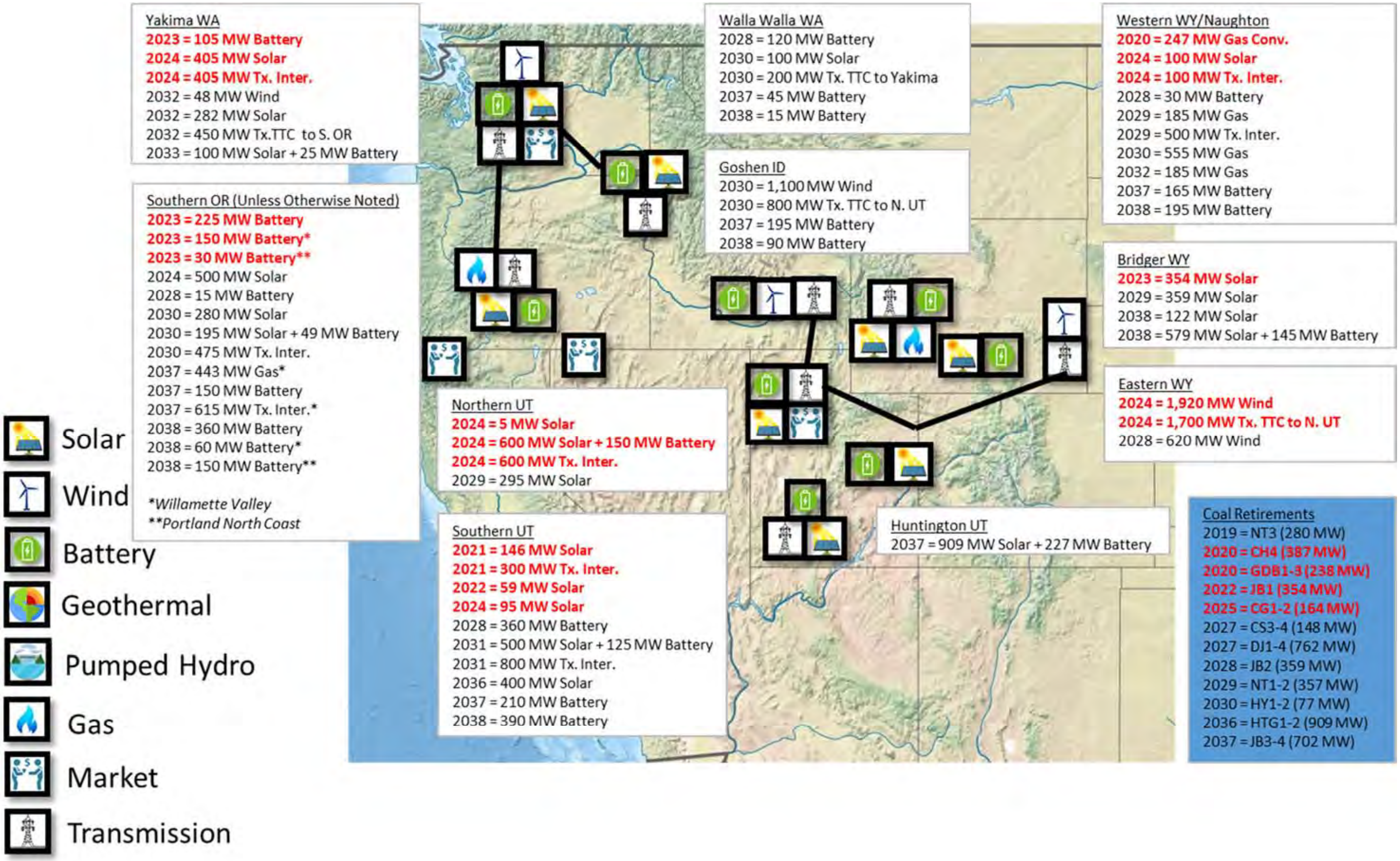
Retirement Assumptions
Initial portfolio-development case P-20 is P-07 with high gas. Full retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2025
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2020
Gadsby 2	Retire 2020
Gadsby 3	Retire 2020
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2022
Jim Bridger 2	Retire 2028
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2029
Naughton 2	Retire 2029
Naughton 3	Lg. GC 2020 Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: High Gas (P-20)

P-20 (High Gas)



Portfolio: Colstrip 3 & 4 Retirement 2025 (P-28)

Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description
A variant of case P-11, P-28 has the same retirement assumptions except accelerates retirement of Colstrip Unis 3 & 4 to 2025 instead of 2027.

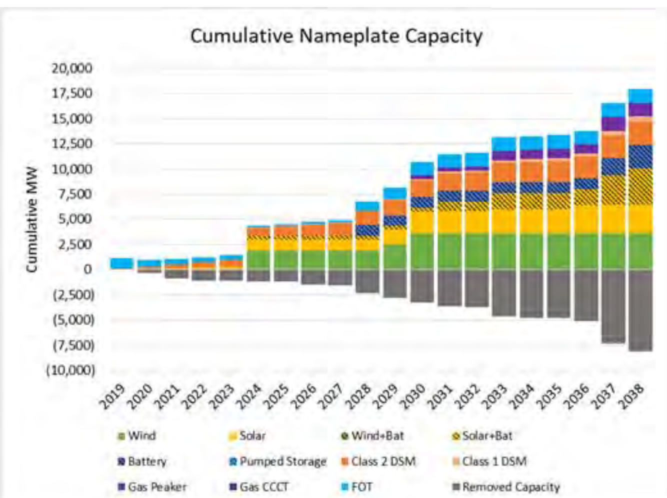
PORTFOLIO SUMMARY

System Optimizer PVRR ($m) $21,805

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Walla Walla – to Yakima, Expansion	*2031*	*200*
Yakima – to – S. Oregon/California	*2037*	*450*

Resource Portfolio
Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



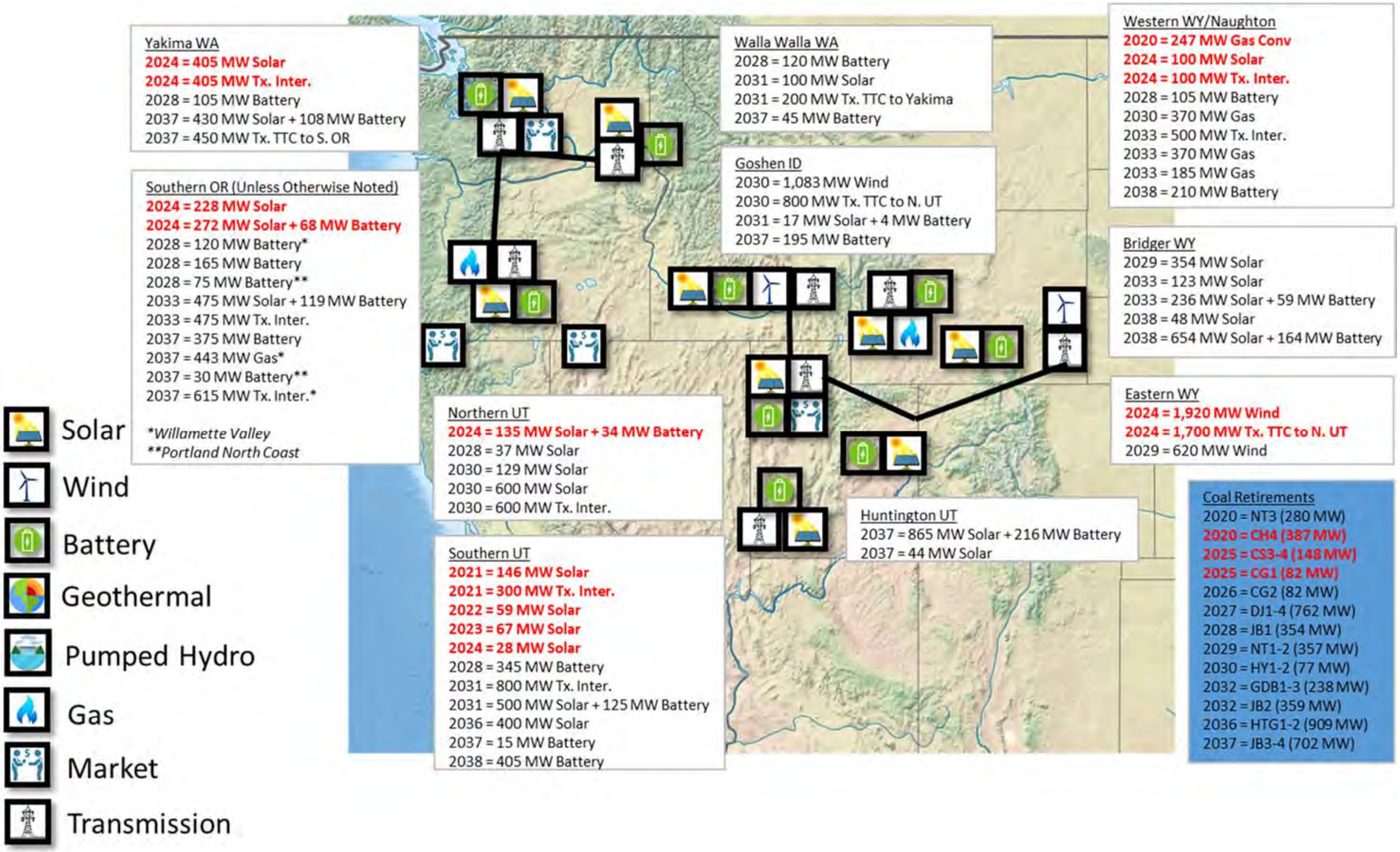
Retirement Assumptions
Initial portfolio-development case P-28 is P-11 with Colstrip Units 3 & 4 retirement accelerated to 2025. Full retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2025
Colstrip 4	Retire 2025
Craig 1	Retire 2025
Craig 2	Retire 2026
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2028
Jim Bridger 2	Retire 2032
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2029
Naughton 2	Retire 2029
Naughton 3	Lg. GC 2020 Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Colstrip 3 & 4 Retirement 2025 (P-28)

P-28 (Colstrip 3-4 Retirement 2025)



Portfolio: Naughton 1 & 2 Retirement 2022 (P-30)

Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description
A variant of case P-11, P-30 has all of the same retirement assumptions except accelerates retirement of Naughton Units 1 & 2 from 2029 to 2022.

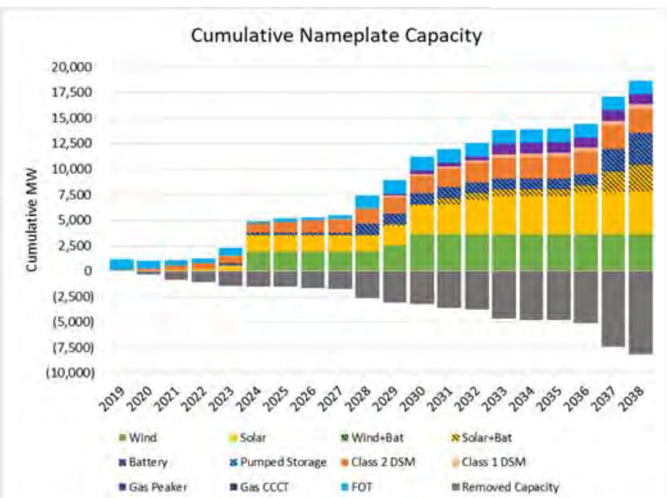
PORTFOLIO SUMMARY

System Optimizer PVRR ($m) ***$21,708***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Walla Walla – to Yakima, Expansion	*2031*	*200*
Yakima – to – S. Oregon/California	*2037*	*450*

Resource Portfolio
Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



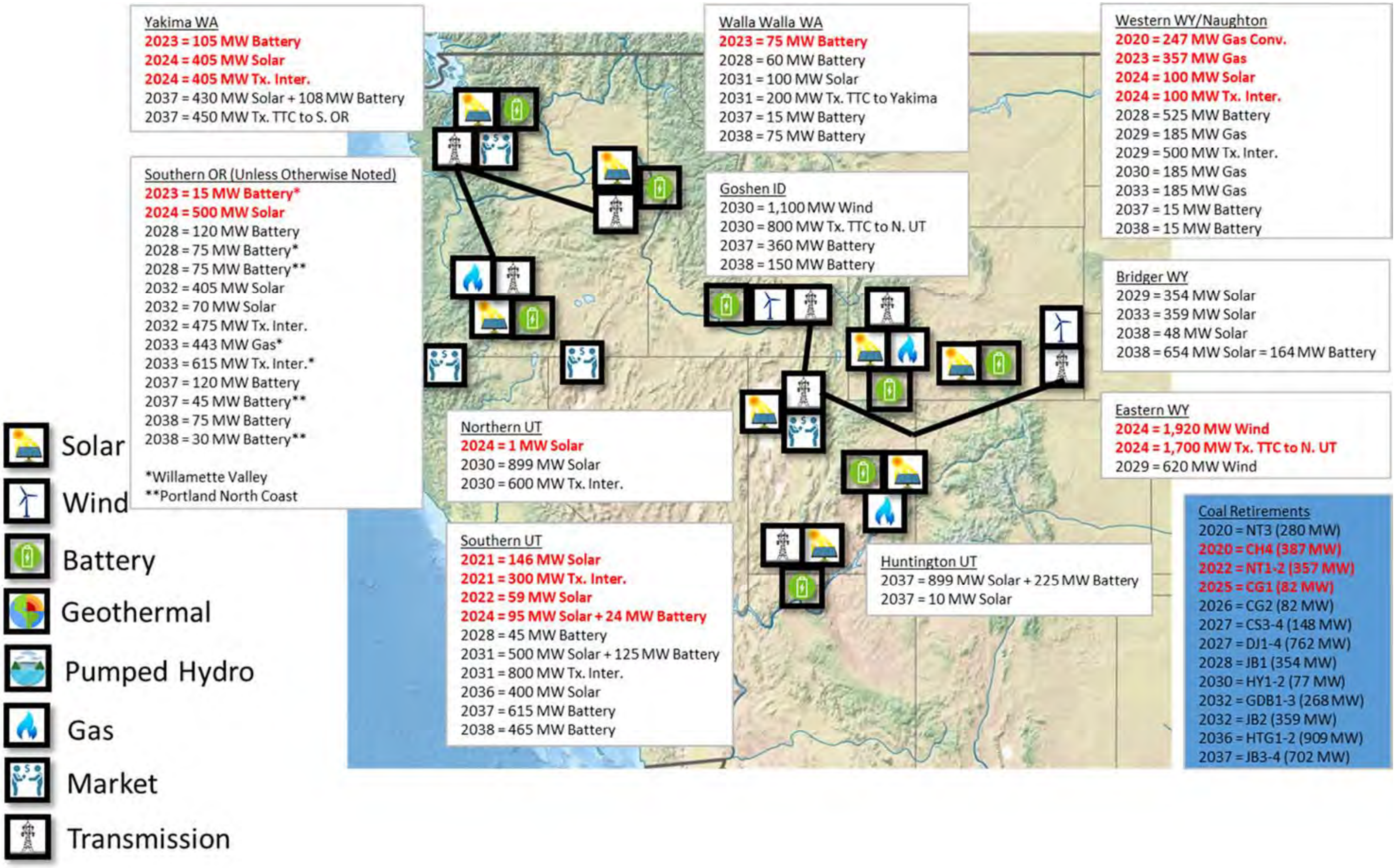
Retirement Assumptions
Initial portfolio-development case P-30 is P-11 with Naughton 1 & 2 Units retirement accelerated to 2022. Full retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2026
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2028
Jim Bridger 2	Retire 2032
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2022
Naughton 2	Retire 2022
Naughton 3	Lg. GC 2020 Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Naughton 1 & 2 Retirement 2022 (P-30)

P-30 (Naughton 1 & 2 Retirement 2022)



Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

A variant of case P-11, P-31 has all of the same retirement assumptions except accelerates retirement of Naughton Units 1 & 2 from 2029 to 2025.

PORTFOLIO SUMMARY

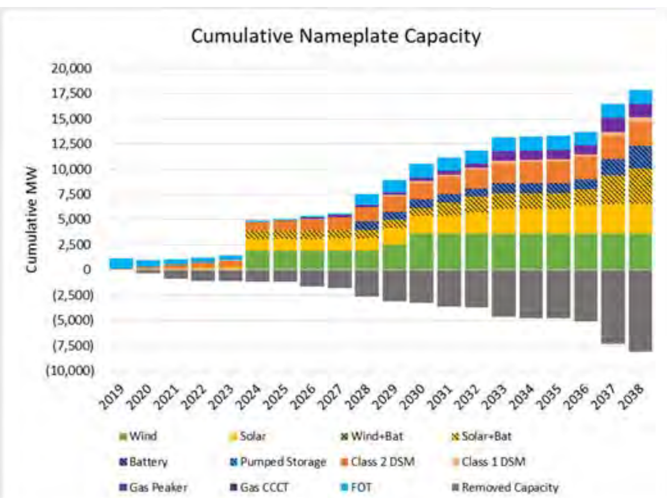
System Optimizer PVRR ($m) $23,484

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Walla Walla – to Yakima, Expansion	*2032*	*200*
Yakima – to – S. Oregon/California	*2037*	*450*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



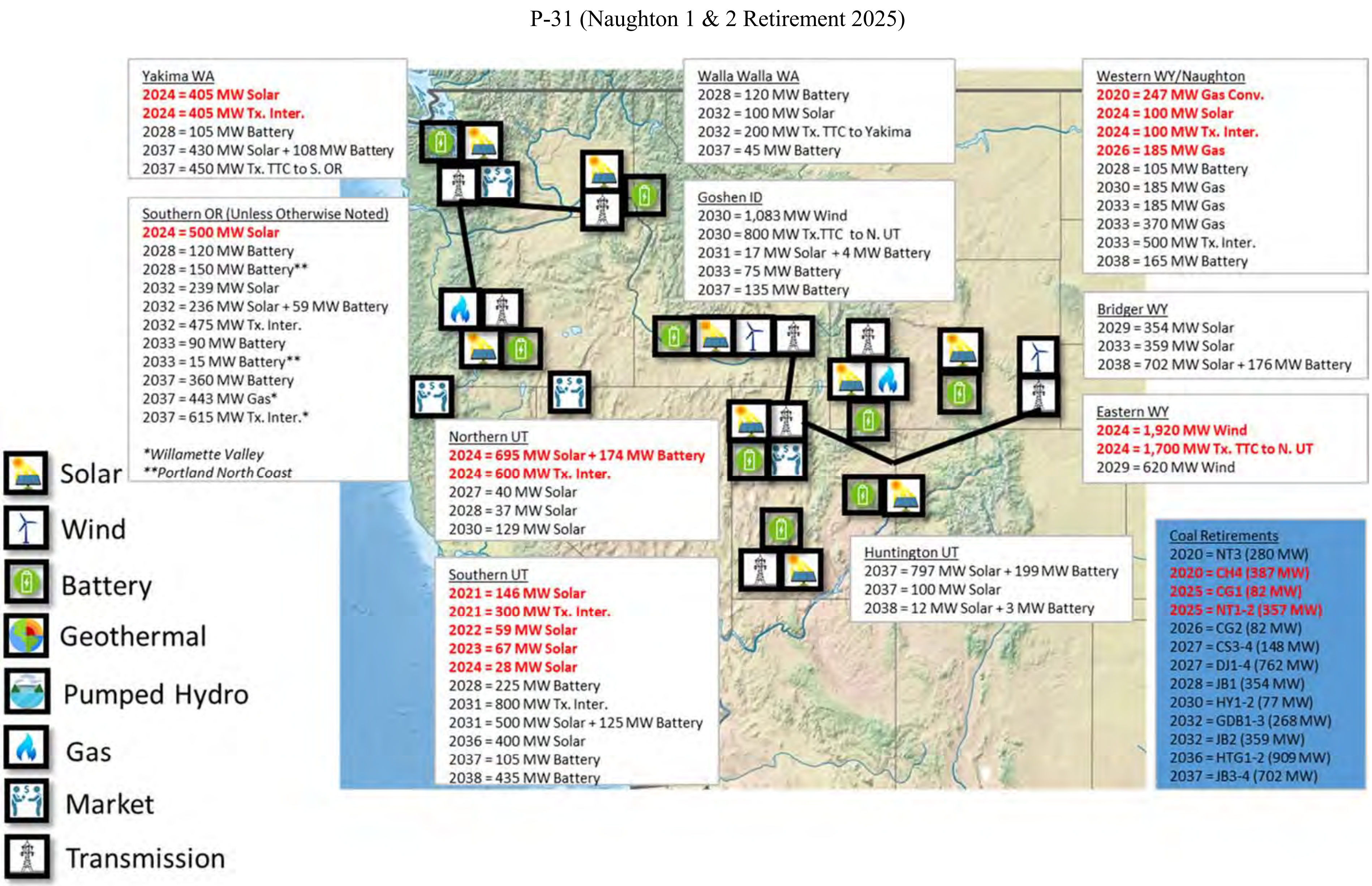
Retirement Assumptions

Initial portfolio-development case P-31 is P-11 with Naughton 1-2 Unit retirements accelerated to 2025. Full retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2026
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2028
Jim Bridger 2	Retire 2032
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3	Lg. GC 2020 Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Naughton 1 & 2 Retirement 2025 (P-31)



Portfolio: Naughton 1 & 2 Retirement 2025 with Gadsby 1-3 Retirement 2032 (P-32)

Initial Portfolio-Development Fact Sheets

Portfolio Assumptions

Description
A variant of case P-07, P-32 has all of the same retirement assumptions except accelerates retirement of Naughton Units 1 & 2 from 2029 to 2022, and slows retirements of Gadsby Units 1- 3 to 2032 from 2020.

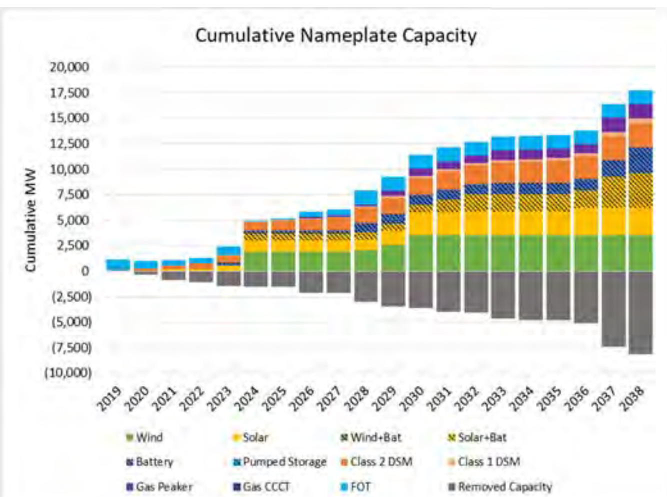
Portfolio Summary

System Optimizer PVRR ($m) ***$21,763***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Yakima – to – S. Oregon/California	*2037*	*450*

Resource Portfolio
Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



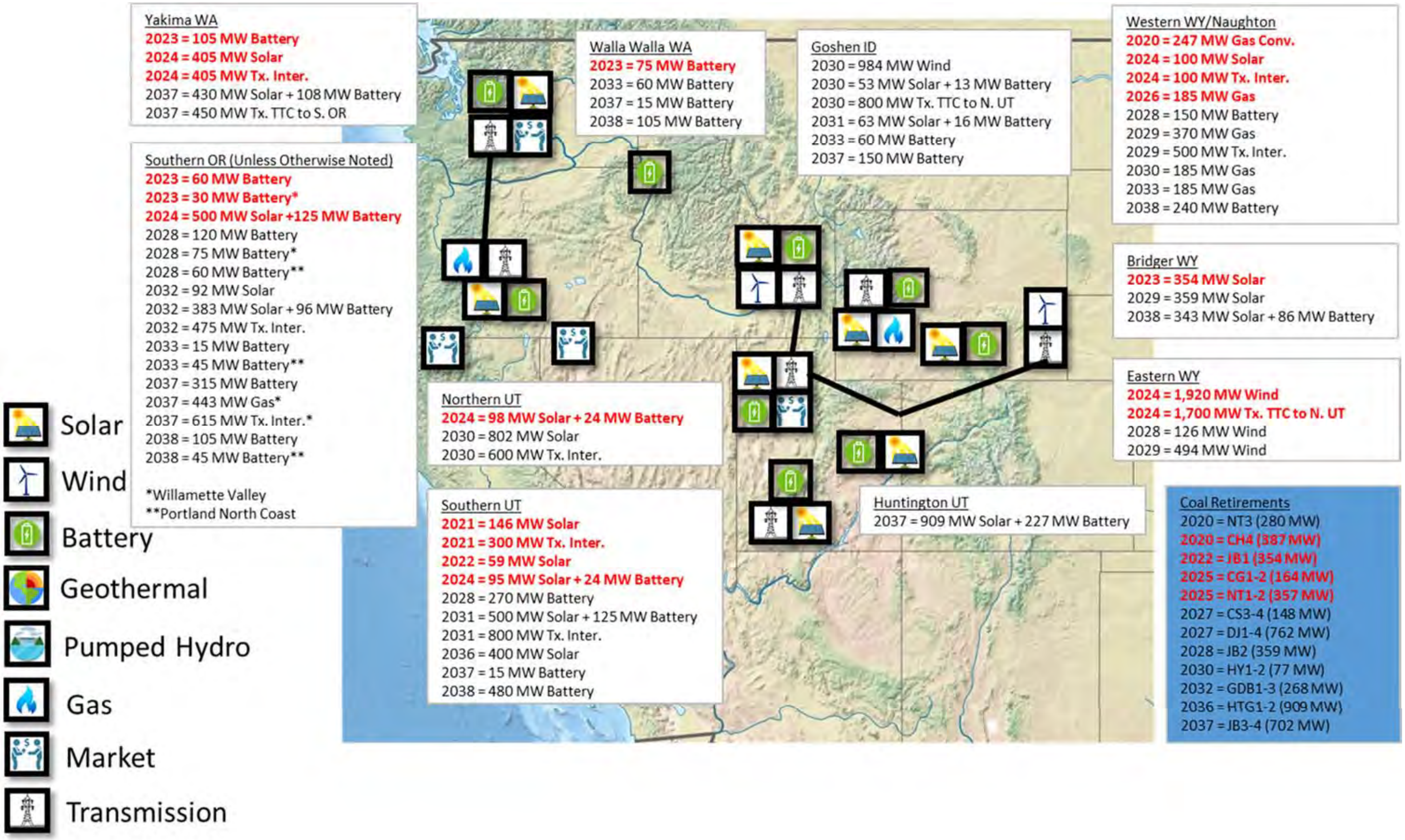
Retirement Assumptions
Initial portfolio-development case P-32 is P-07 with Naughton Units 1 & 2 retirement accelerated to 2025 and Gadsby 1-3 retiring in 2032. Full retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2025
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2022
Jim Bridger 2	Retire 2028
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3	Lg. GC 2020 Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Naughton 1 & 2 Retirement 2025 with Gadsby 1-3 Retirement 2032 (P-32)

P-32 (Naughton 1 & 2 Retirement 2025 with Gadsby 1-3 Retirement 2032)



Portfolio: Jim Bridger 1 & 2 Retirement 2022 (P-33)

Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

A variant of case P-11, P-33 has all of the same retirement assumptions except accelerates retirement of Jim Bridger Unit 1 from 2028 to 2022 and Unit 2 from 2032 to 2022.

PORTFOLIO SUMMARY

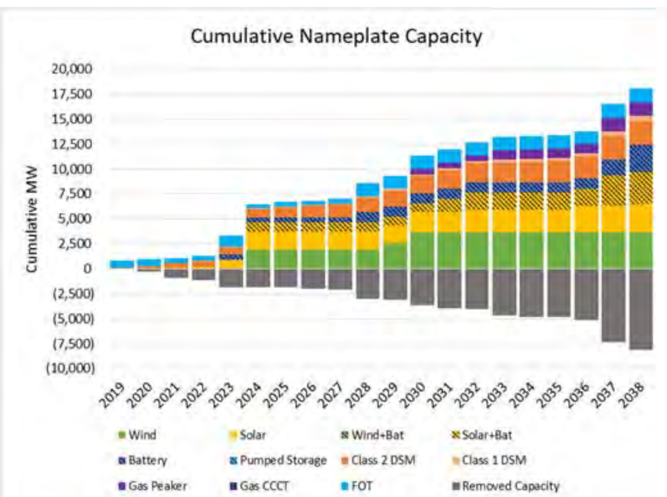
System Optimizer PVRR ($m) $21,895

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Walla Walla – to Yakima, Expansion	*2032*	*200*
Yakima – to – S. Oregon/California	*2037*	*450*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

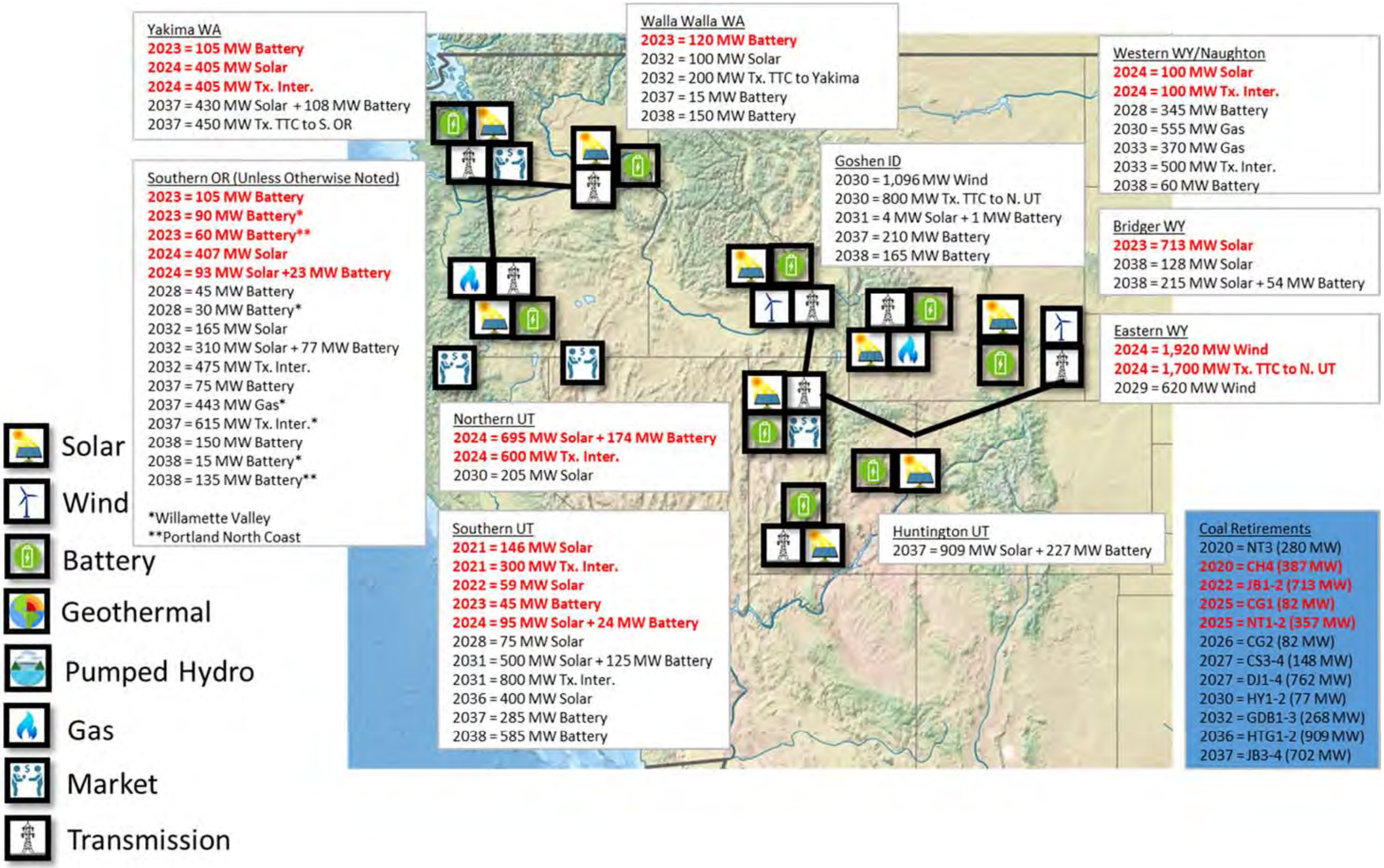
Initial portfolio-development case P-33 is P-11 with Jim Bridger Units 1-2 retirement accelerated to 2022. Full retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2026
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2022
Jim Bridger 2	Retire 2022
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2029
Naughton 2	Retire 2029
Naughton 3	Lg. GC 2020 Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Jim Bridger 1 & 2 Retirement 2022 (P-33)

P-33 (Jim Bridger 1 & 2 Retirement 2022)



Portfolio: Jim Bridger 1 & 2 Retirement 2022 with Gadsby 1-3 Retirement 2020 (P-34)

Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

A variant of case P-11, and a sibling of P-33, P-34 has all of the same retirement assumptions except accelerates retirement of Jim Bridger Unit from 2028 to 2022 and Unit 2 from 2032 to 2022. In addition, P-34 accelerates retirement of Gadsby Units 1- 3 from 2032 to 2022.

PORTFOLIO SUMMARY

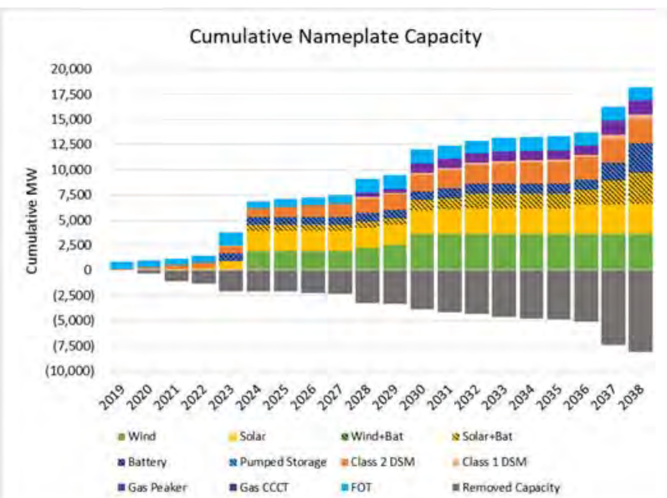
System Optimizer PVRR ($m) ***$21,949***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Walla Walla – to Yakima, Expansion	*2031*	*200*
Yakima – to – S. Oregon/California	*2038*	*450*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

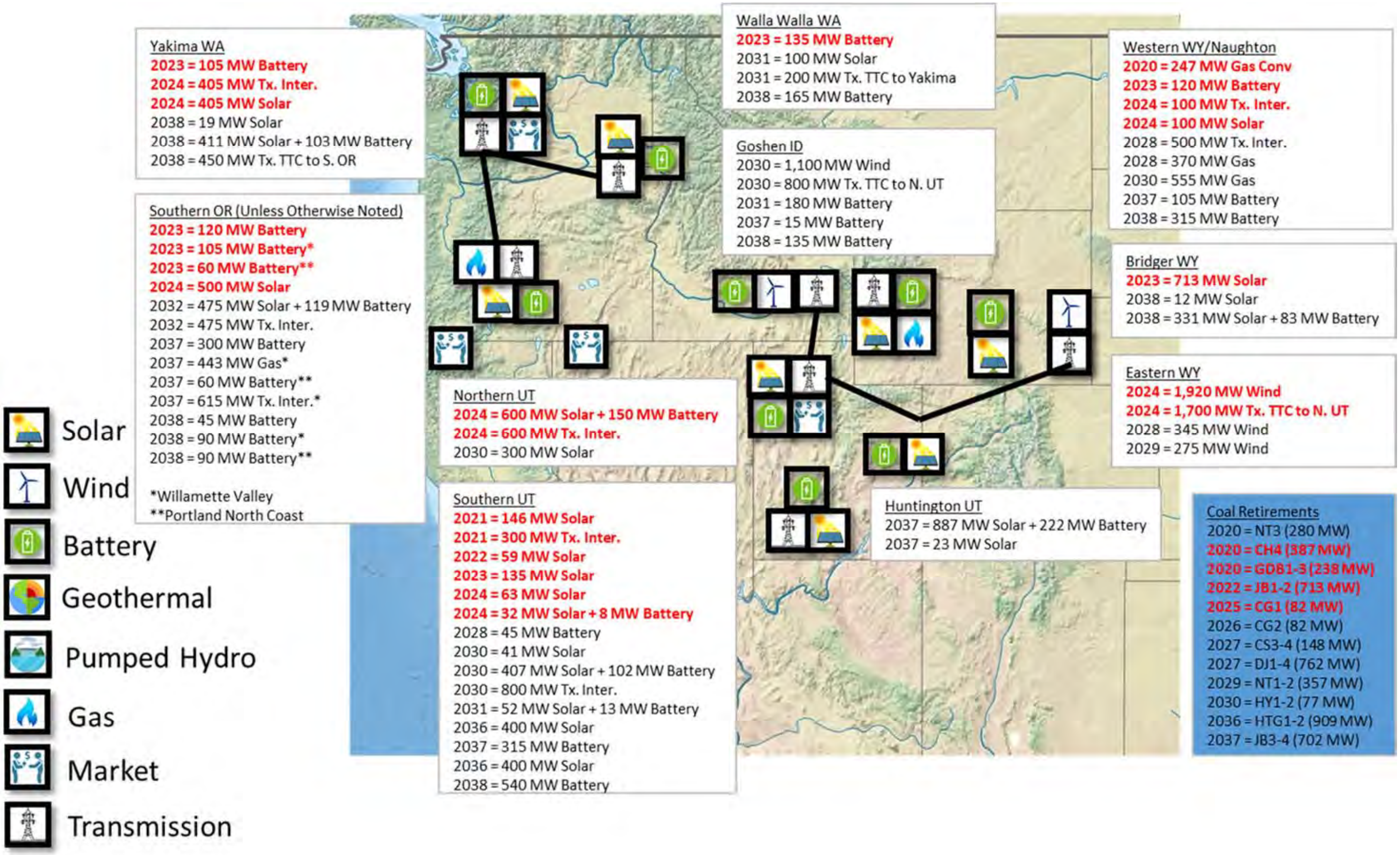
Initial portfolio-development case P-34 is P-11 with Gadsby Units 1-3 retirement accelerated to 2020 and Jim Bridger Units 1 & 2 retirements accelerated to 2022. Full retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2026
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2020
Gadsby 2	Retire 2020
Gadsby 3	Retire 2020
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2022
Jim Bridger 2	Retire 2022
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2029
Naughton 2	Retire 2029
Naughton 3	Lg. GC 2020 Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Jim Bridger 1 & 2 Retirement 2022 with Gadsby 1-3 Retirement 2020 (P-34)

P-34 (Jim Bridger 1 & 2 Retirement 2022 with Gadsby 1-3 Retirement 2020)



Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

A variant of case P-11, and a sibling of P-33 & P-34, P-35 has all of the same retirement assumptions except accelerates retirement of Jim Bridger Units 3 & 4 from 2037 to 2022.

PORTFOLIO SUMMARY

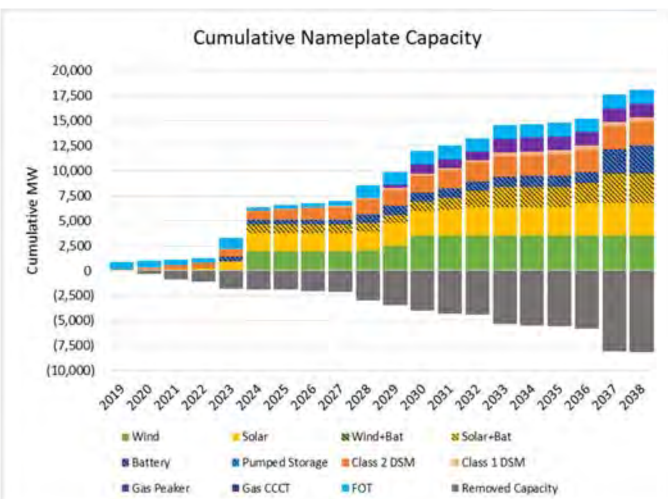
System Optimizer PVRR ($m) ***$21,732***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Walla Walla – to Yakima, Expansion	*2031*	*200*
Yakima – to – S. Oregon/California	*2033*	*450*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

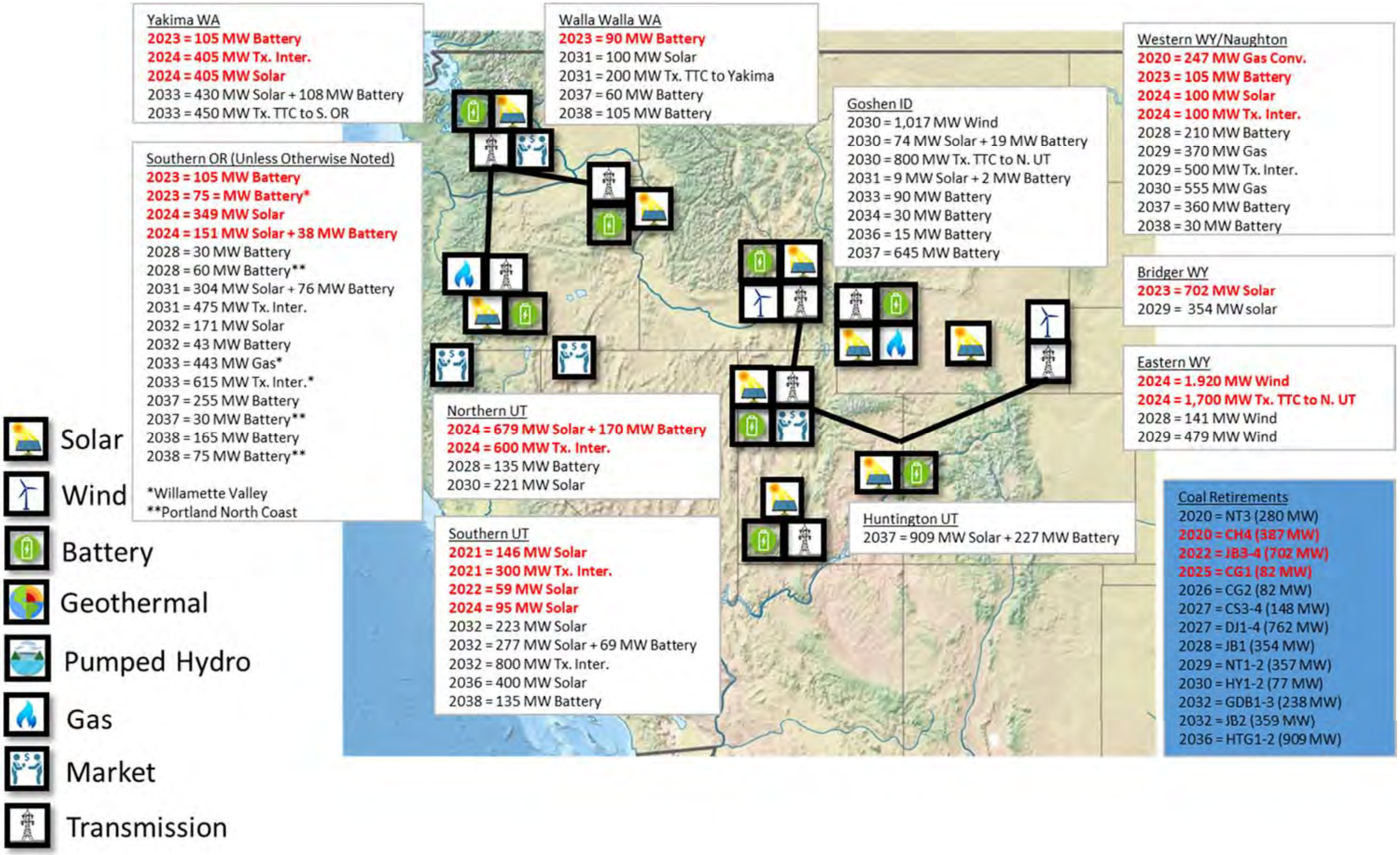
Initial portfolio-development case P-35 is P-11 with Jim Bridger Units 3 & 4 retirement accelerated to 2022. Full retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2026
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2028
Jim Bridger 2	Retire 2032
Jim Bridger 3	Retire 2022
Jim Bridger 4	Retire 2022
Naughton 1	Retire 2029
Naughton 2	Retire 2029
Naughton 3	Lg. GC 2020 Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Jim Bridger 3-4 Retirement 2022 (P-35)

P-35 (Jim Bridger 3 & 4 Retirement 2022)



Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

A variant of case P-31, P-45 has all of the same retirement assumptions except accelerates retirement of Jim Bridger Unit 1 from 2028 to 2023 and Jim Bridger Unit 2 from 2032 to 2028.

PORTFOLIO SUMMARY

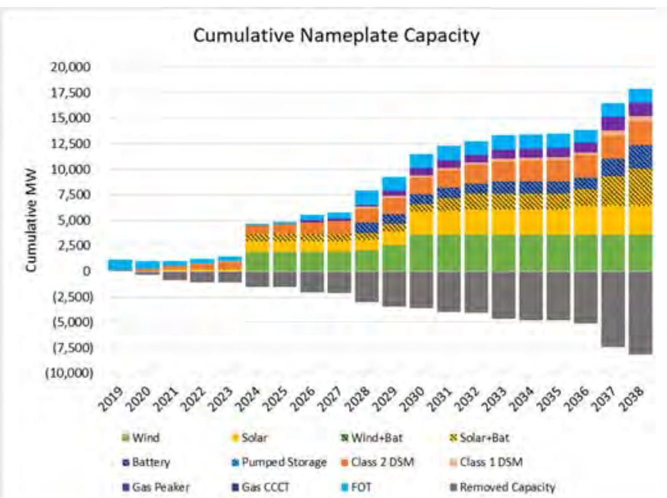
System Optimizer PVRR ($m) $21,593

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Walla Walla – to Yakima, Expansion	*2032*	*200*
Yakima – to – S. Oregon/California	*2037*	*450*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

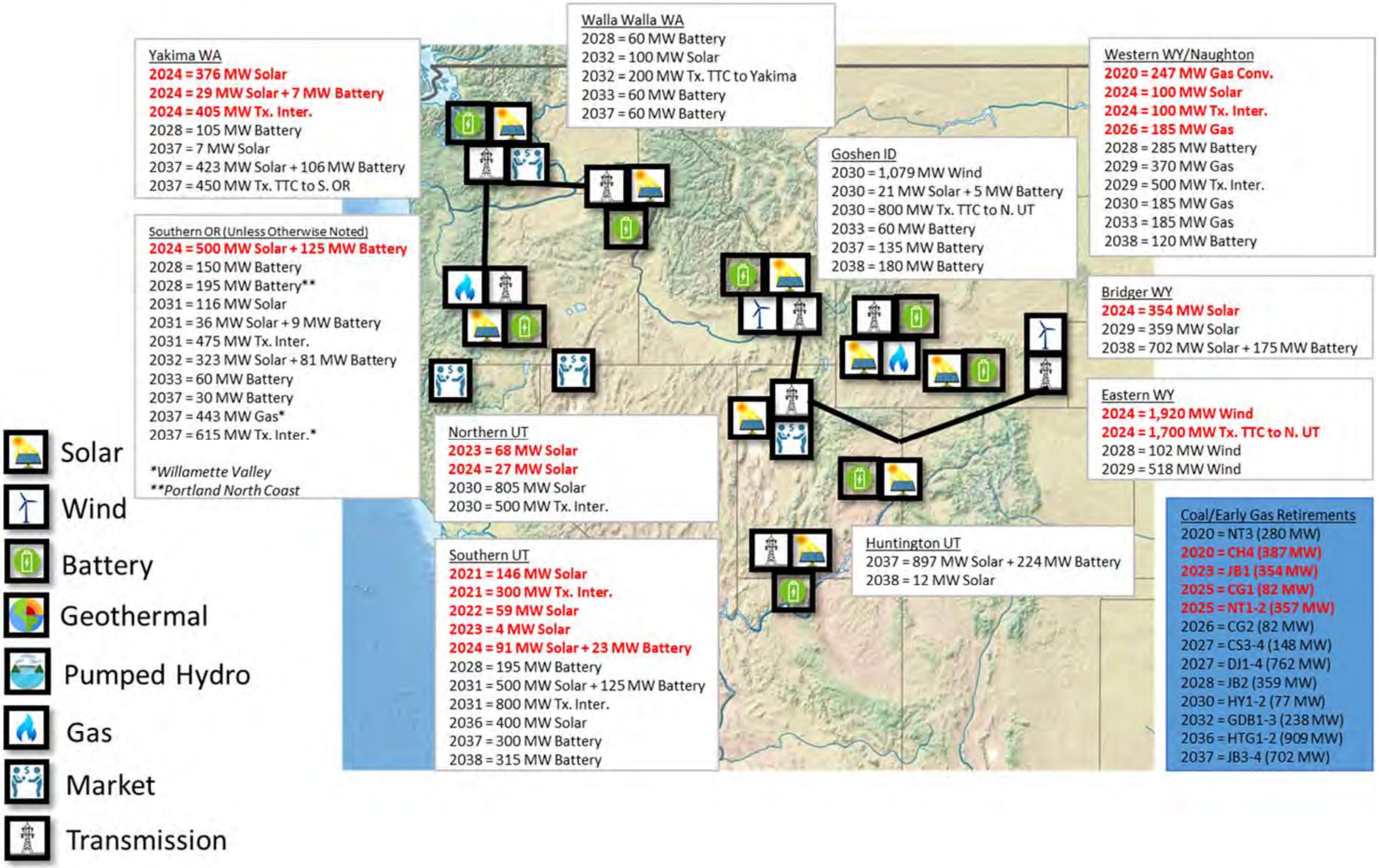
Initial portfolio-development case P-45 is P-31 with Jim Bridger Unit 1 retiring in 2023, Jim Bridger Unit 2 retiring in 2028. Full retirement assumptions are summarized in the following table.

Unit	**Description**
Cholla 4	Retire 2020
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2026
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2023
Jim Bridger 2	Retire 2028
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3	Lg. GC 2020 Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Jim Bridger 1 Retirement 2023, Jim Bridger 2 Retirement 2028 (P-45)

P-45 (Jim Bridger 1 Retirement 2023, Jim Bridger 2 Retirement 2028)



Portfolio: Jim Bridger 3 & 4 Retirement 2025 (P-46)

Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

A variant of case P-31, and a sibling of P-45, P-46 has all of the same retirement assumptions except accelerates retirement of Jim Bridger Units 3 & 4 from 2037 to 2025.

PORTFOLIO SUMMARY

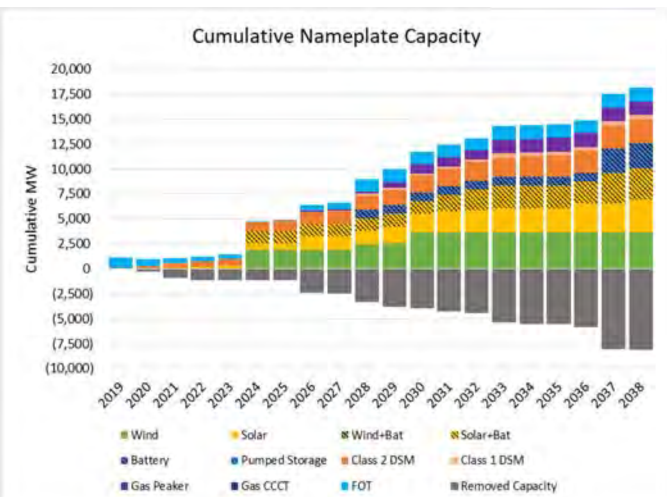
System Optimizer PVRR ($m) ***$21,419***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Walla Walla – to Yakima, Expansion	*2032*	*200*
Yakima – to – S. Oregon/California	*2038*	*450*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

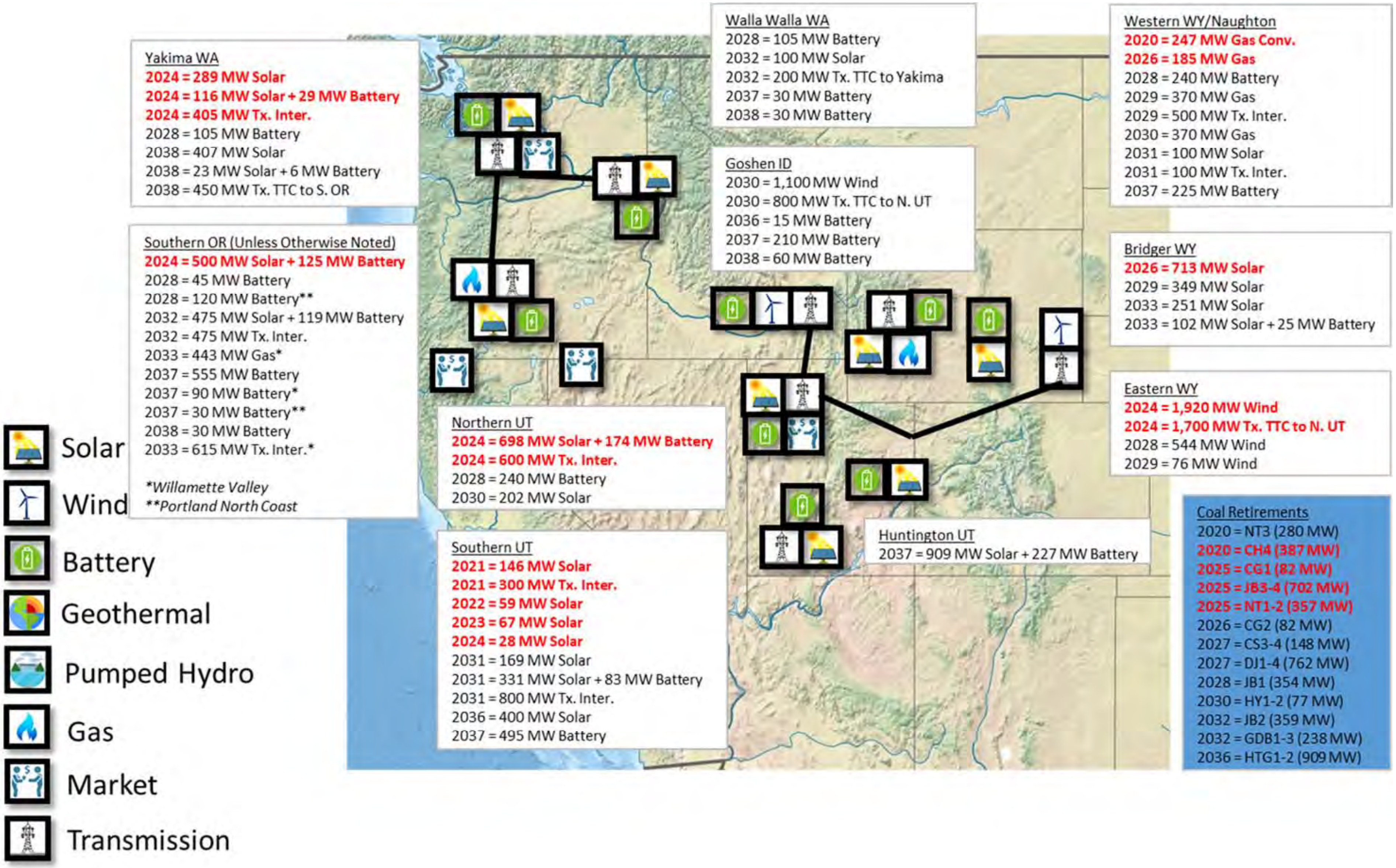
Initial portfolio-development case P-46 is P-31 with Jim Bridger Units 3 & 4 retiring in 2025. Full retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2026
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2028
Jim Bridger 2	Retire 2032
Jim Bridger 3	Retire 2025
Jim Bridger 4	Retire 2025
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3	Lg. GC 2020 Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Jim Bridger 3 & 4 Retirement 2025 (P-46)

P-46 (Jim Bridger 3 & 4 Retirement 2025)



Portfolio: Jim Bridger 1 & 2 Retirement 2025, Jim Bridger 3 Retirement 2028, and Jim Bridger 4 Retirement 2032 (P-53)

Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

A variant of case P-31, and a sibling of P-46, P-53 has all of the same retirement assumptions except accelerates retirement of Jim Bridger Unit 1 from 2028 to 2025, Jim Bridger Unit 2 from 2032 to 2025, Jim Bridger Unit 3 from 2037 to 2028, and Jim Bridger Unit 4 from 2037 to 2032.

PORTFOLIO SUMMARY

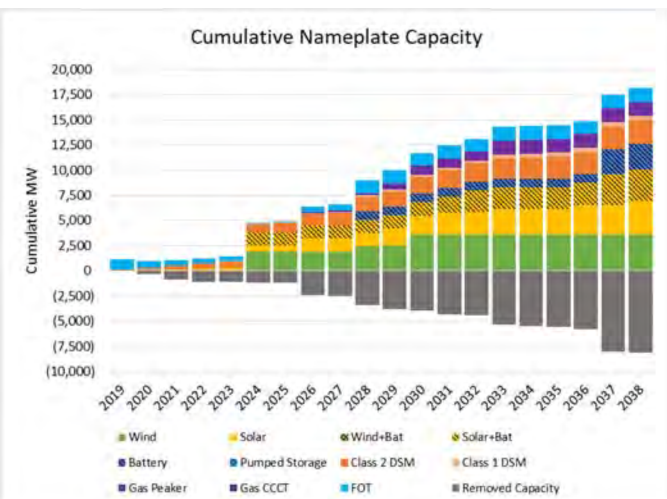
System Optimizer PVRR ($m) ***$21,438***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Walla Walla – to Yakima, Expansion	*2032*	*200*
Yakima – to – S. Oregon/California	*2038*	*450*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

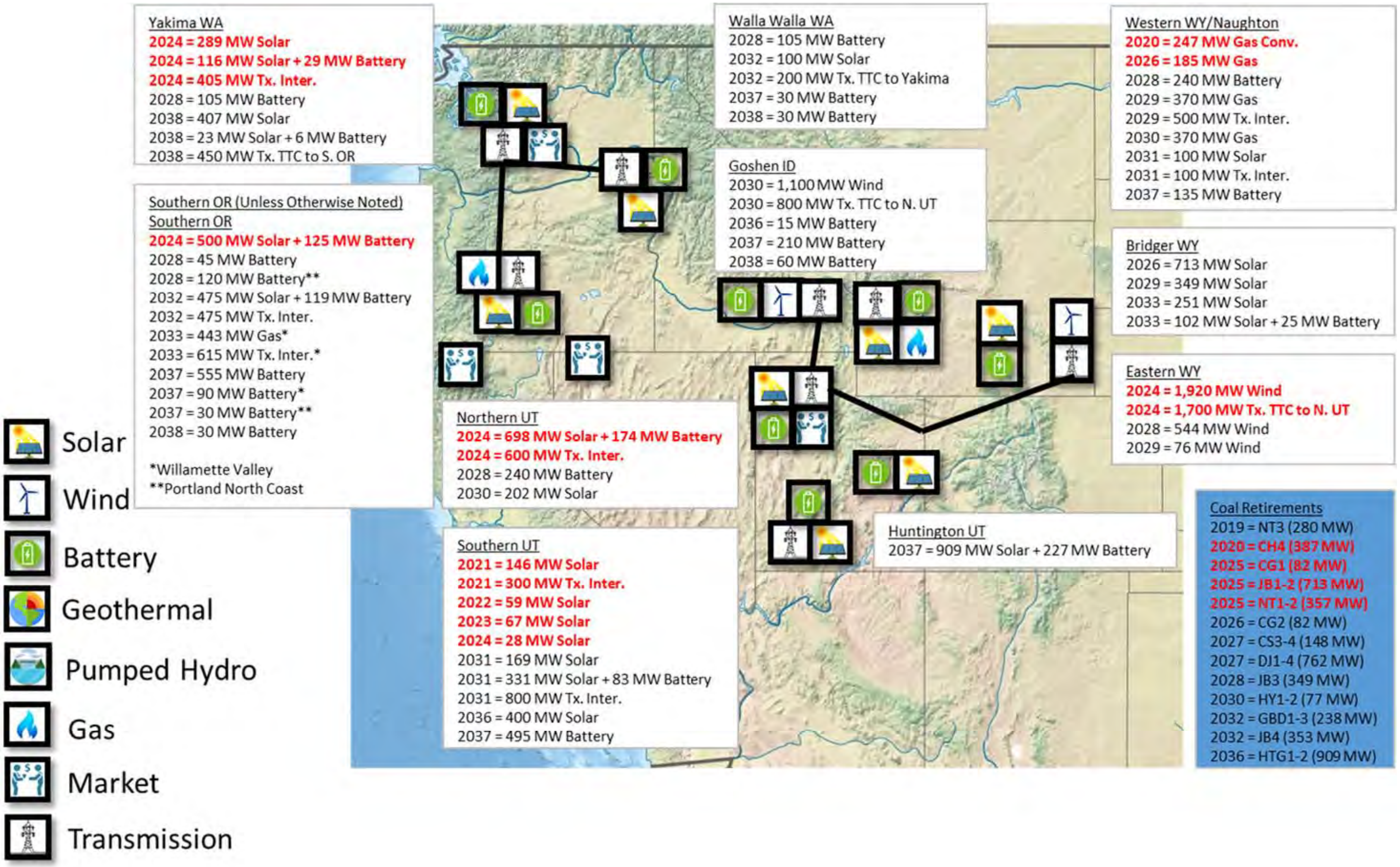
Initial portfolio-development case P-53 is P-31 with Jim Bridger Units 1 & 2 retiring in 2025, Jim Bridger Unit 3 retiring in 2028, and Jim Bridger Unit 4 retiring in 2032. Full retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2026
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2025
Jim Bridger 2	Retire 2025
Jim Bridger 3	Retire 2028
Jim Bridger 4	Retire 2032
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3	Lg. GC 2020 Retire 2029
Wyodak	Retire 2039

GC = Gas Conversion

Portfolio: Jim Bridger 1 & 2 Retirement 2025, Jim Bridger 3 Retirement 2028, and Jim Bridger 4 Retirement 2032 (P-53)

P-53 (Jim Bridger 1 & 2 Retirement 2025, Jim Bridger 3 Retirement 2028, and Jim Bridger 4 Retirement 2032)



Portfolio: Jim Bridger 2 Retirement 2024 (P-54)

Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

A variant of case P-31, P-54 has all of the same retirement assumptions except accelerates retirement of Jim Bridger Unit 2 from 2032 to 2024.

PORTFOLIO SUMMARY

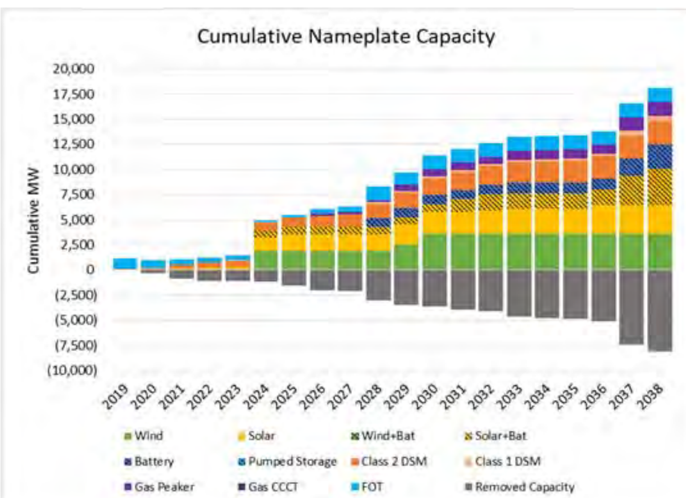
System Optimizer PVRR ($m) $23,708

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2025*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Walla Walla – to Yakima, Expansion	*2033*	*200*
Yakima – to – S. Oregon/California	*2037*	*450*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

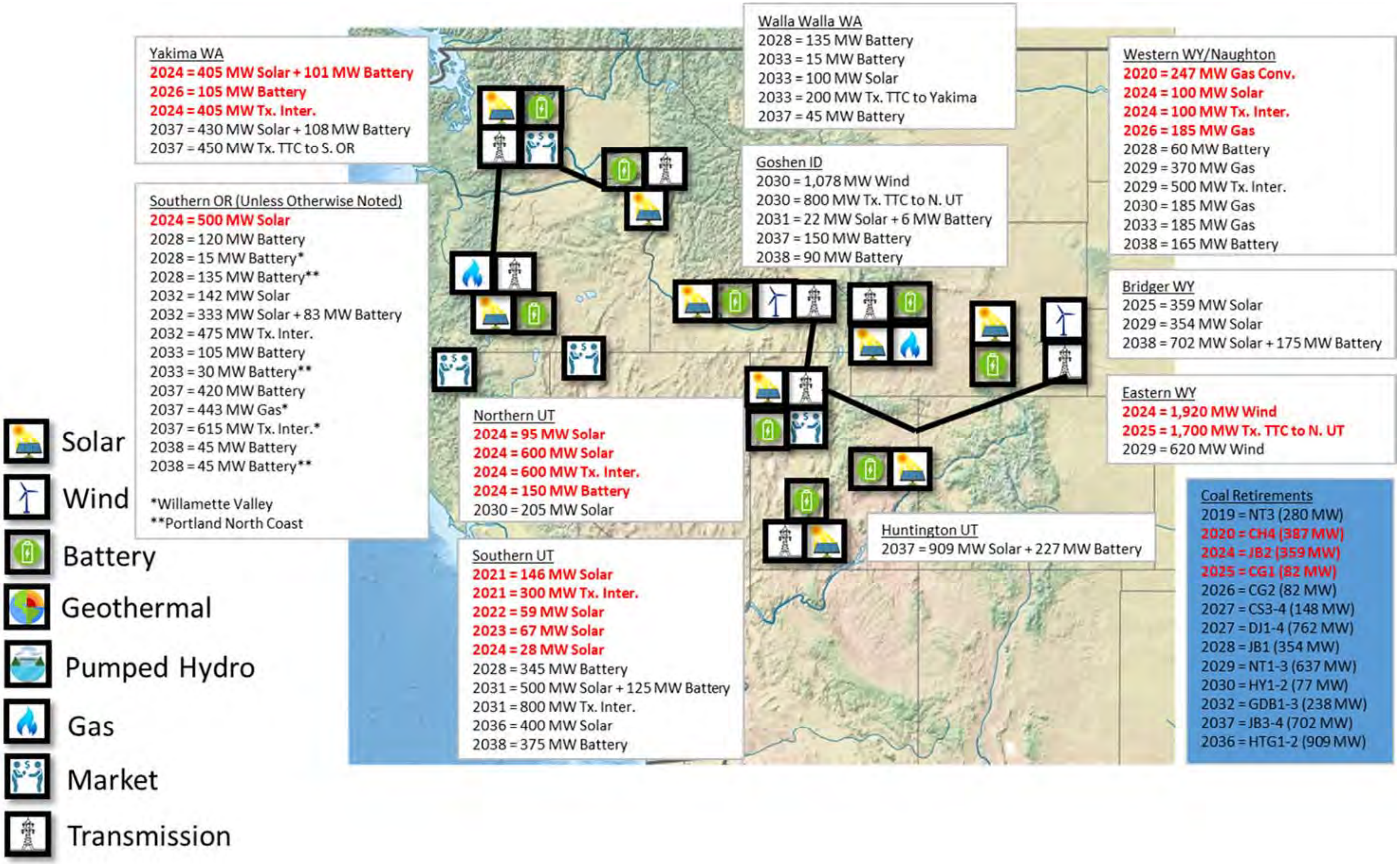
Initial portfolio-development case P-54 is P-31 with Jim Bridger 2 retiring in 2024. Full retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2026
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2028
Jim Bridger 2	Retire 2024
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2029
Naughton 2	Retire 2029
Naughton 3	Lg. GC 2020 Retire 2029
Wyodak	Retire 2039

GC = Gas Conversion

Portfolio: Jim Bridger 2 Retirement 2024 (P-54)

P-54 (Jim Bridger 2 Retirement 2024)



Portfolio: Naughton 1 & 2 Retirement 2025 (P-31C)

C-Cases Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description
A variant of P-11, P-31C has all of the same retirement assumptions except was processed through Planning and Risk Deterministic runs for reliability beyond the initial 2023, 2030 and 2038 to include 2024 through 2029.

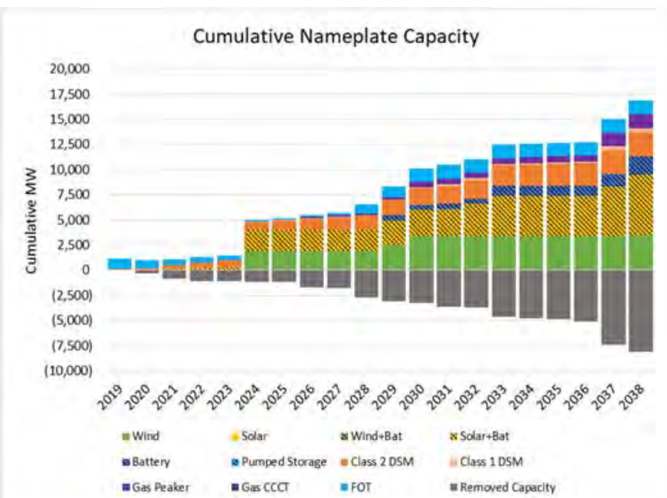
PORTFOLIO SUMMARY

System Optimizer PVRR ($m) ***$21,639***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Yakima – to – S. Oregon/California	*2038*	*450*

Resource Portfolio
Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



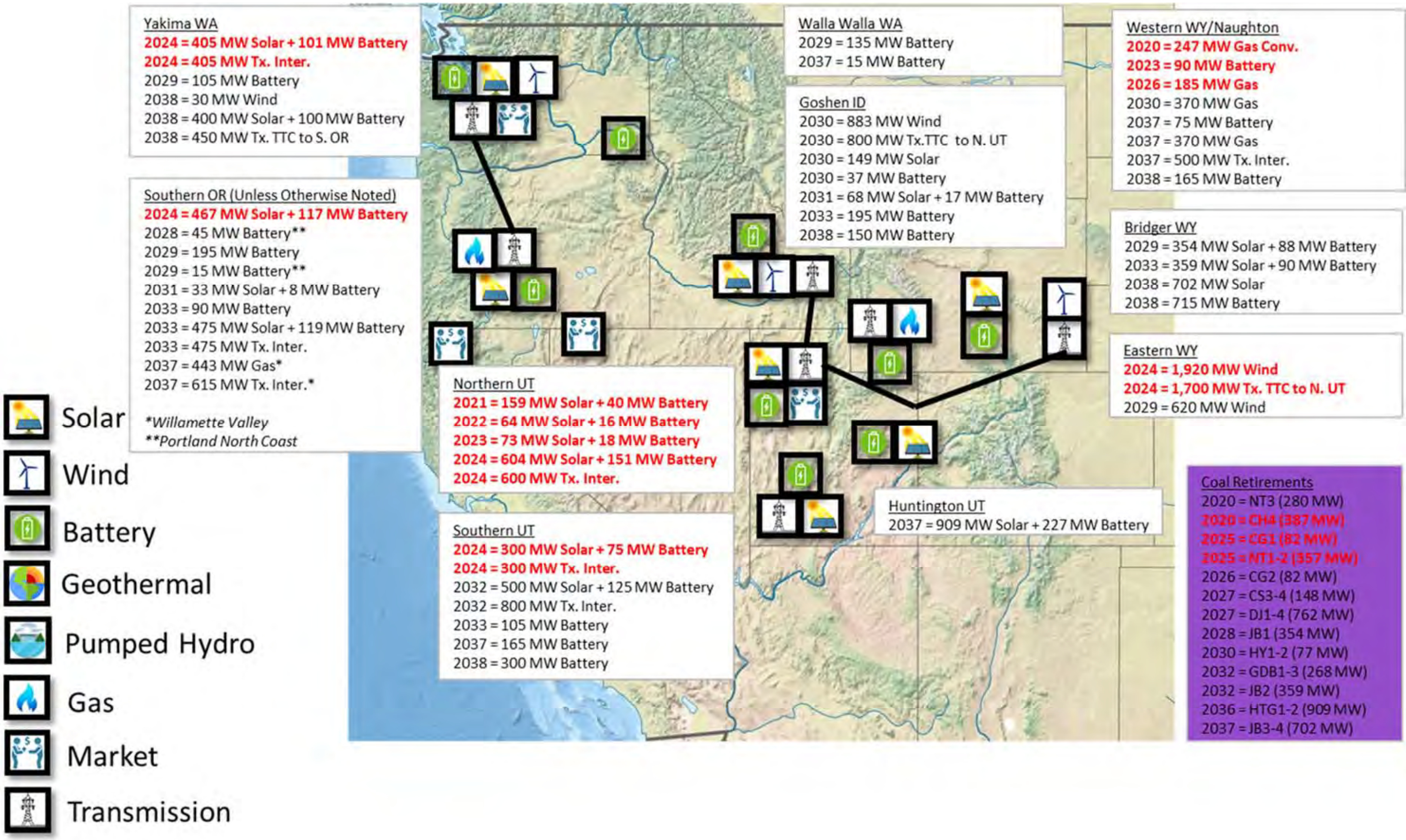
Retirement Assumptions
A variant of case P-11, P-31C has all of the same retirement assumptions except accelerates retirement of Naughton Units 1 & 2 from 2029 to 2025. Full retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2026
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2028
Jim Bridger 2	Retire 2032
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3	Lg. GC 2020 Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Naughton 1 & 2 Retirement 2025 (P-31C)

P-31C (Naughton 1 & 2 Retirement 2025)



Portfolio: Jim Bridger 1 & 2 & Naughton 1&2 Retiring 2025 (P-36C)

C-Cases Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

A variant of case P-46, P-36C has all of the same retirement assumptions except was processed through Planning and Risk Deterministic runs for reliability beyond the initial 2023, 2030 and 2038, to include 2024 through 2029.

PORTFOLIO SUMMARY

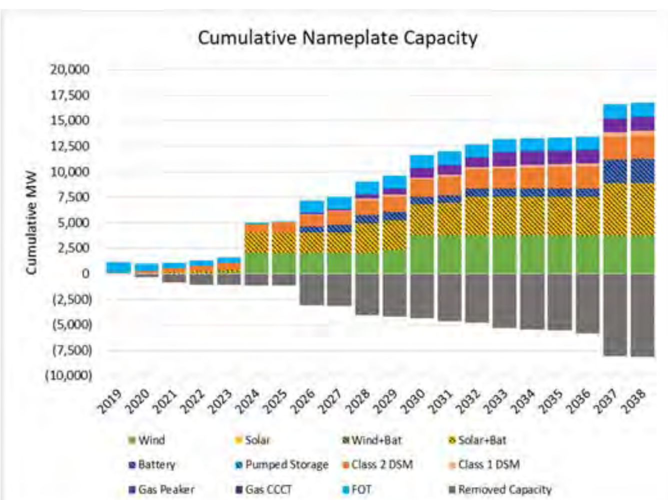
System Optimizer PVRR ($m) ***$21,544***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Yakima – to – S. Oregon/California	*2037*	*450*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

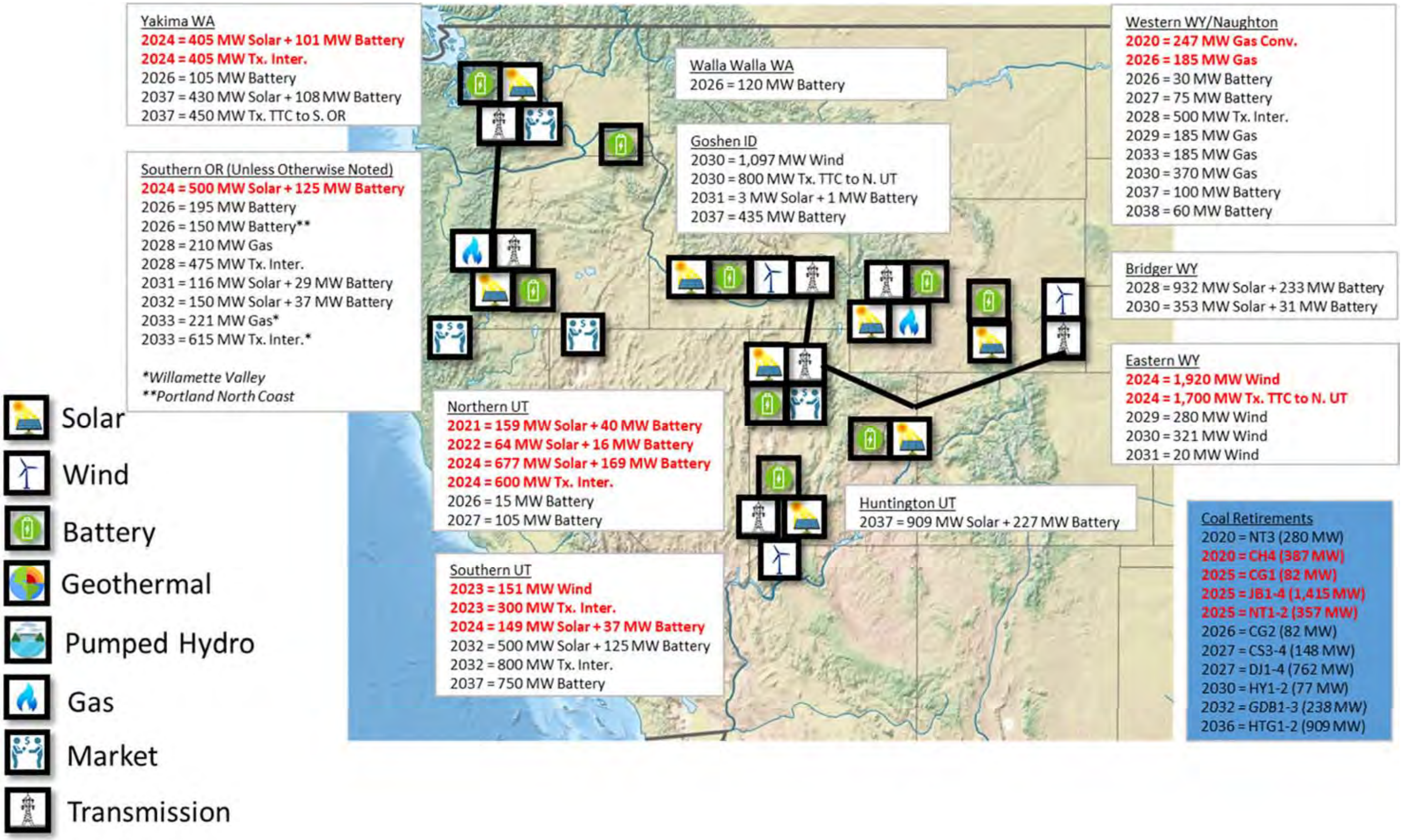
A variant of case P-14, P-36C has all of the same retirement assumptions except slows retirement of Jim Bridger Units 1-4 and Naughton Units 1 & 2 from 2022 to 2025. Full retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2026
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2025
Jim Bridger 2	Retire 2025
Jim Bridger 3	Retire 2025
Jim Bridger 4	Retire 2025
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3	Lg. GC 2020 Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Jim Bridger 1 & 2 & Naughton 1&2 Retiring 2025 (P-36C)

P-36C (Jim Bridger 1 & 2 and Naughton 1 & 2 Retiring 2025)



Portfolio: Jim Bridger 1 Retirement 2023 and Jim Bridger 2 Retirement 2038 (P-45C)

C-Cases Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

A variant of case P-31, P-45C has all of the same retirement assumptions except was processed through Planning and Risk Deterministic runs for reliability beyond the initial 2023, 2030 and 2038, to include 2024 through 2029.

PORTFOLIO SUMMARY

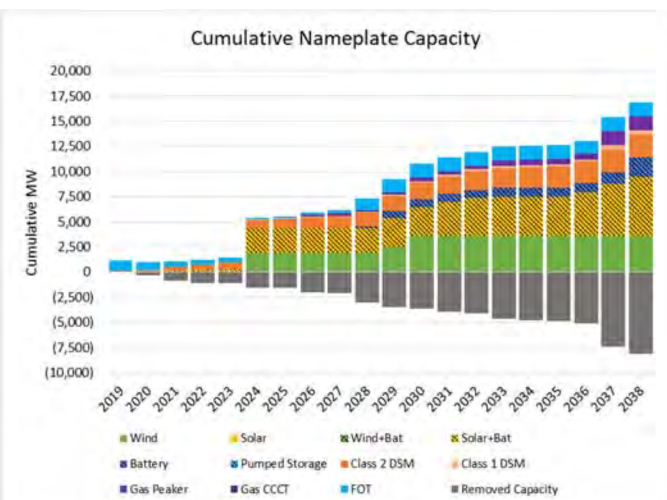
System Optimizer PVRR ($m) ***$21,537***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Yakima – to – S. Oregon/California	*2036*	*450*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

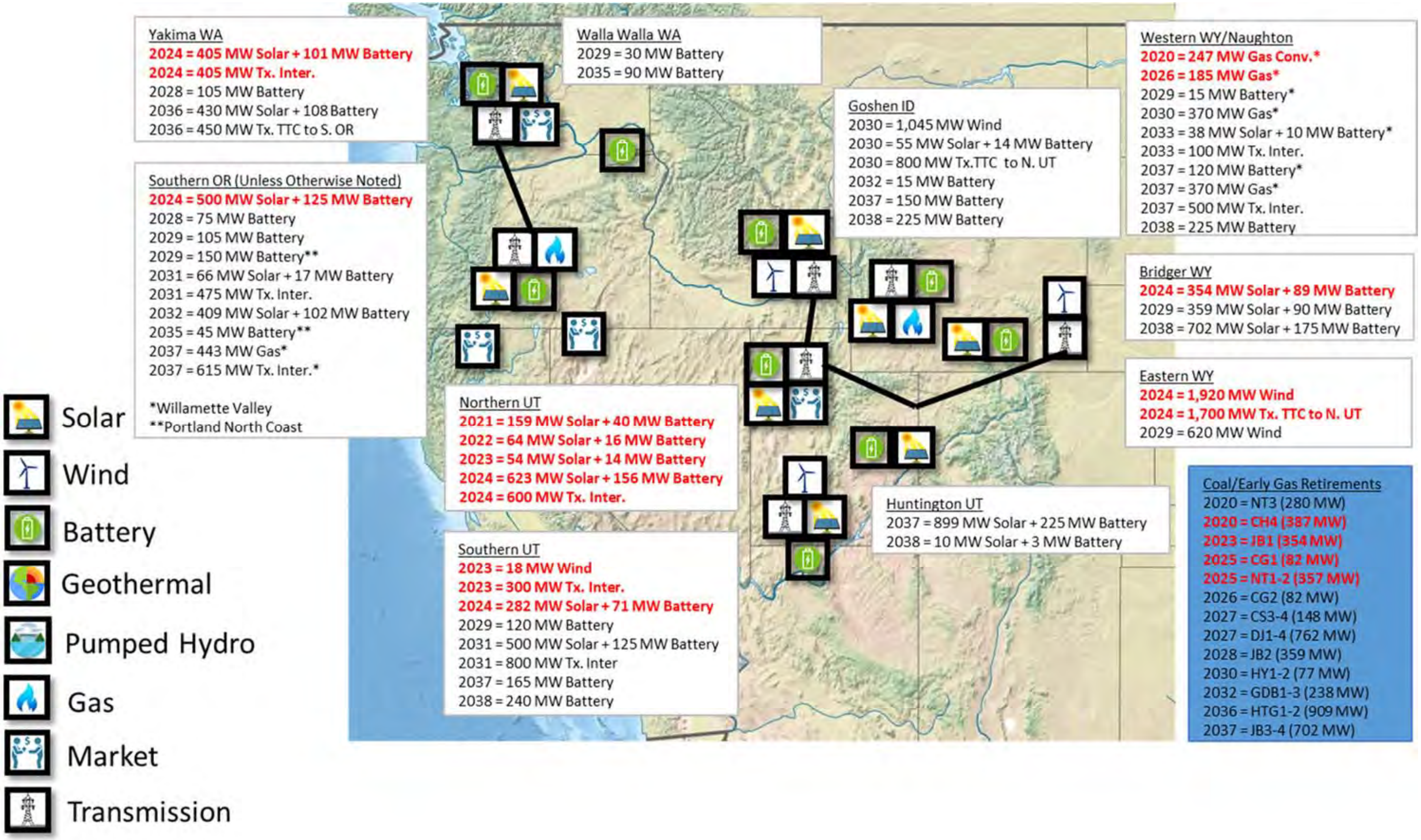
A variant of case P-31, P-45C has all of the same retirement assumptions except accelerates retirement of Jim Bridger Unit 1 from 2028 to 2023 and Unit 2 from 2032 to 2028. Full retirement assumptions are summarized in the following table.

Unit	**Description**
Cholla 4	Retire 2020
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2026
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2023
Jim Bridger 2	Retire 2028
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3	Lg. GC 2020 Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Jim Bridger 1 Retirement 2023 and Jim Bridger 2 Retirement 2038 (P-45C)

P-45C (Jim Bridger 1 Retirement 2023 & Jim Bridger 2 Retirement 2038)



Portfolio: Jim Bridger 3 & 4 Retirement 2025 (P-46C)

C-Cases Portfolio-Development Fact Sheets

Portfolio Assumptions

Description
A variant of case P-31, P-46C has all of the same retirement assumptions except was processed through Planning and Risk Deterministic runs for reliability beyond the initial 2023, 2030 and 2038, to include 2024 through 2029.

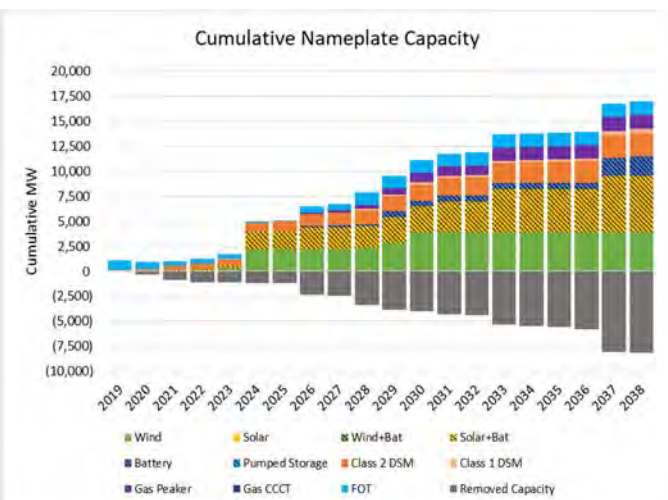
Portfolio Summary

System Optimizer PVRR ($m) ***$21,431***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Yakima – to – S. Oregon/California	*2037*	*450*

Resource Portfolio
Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



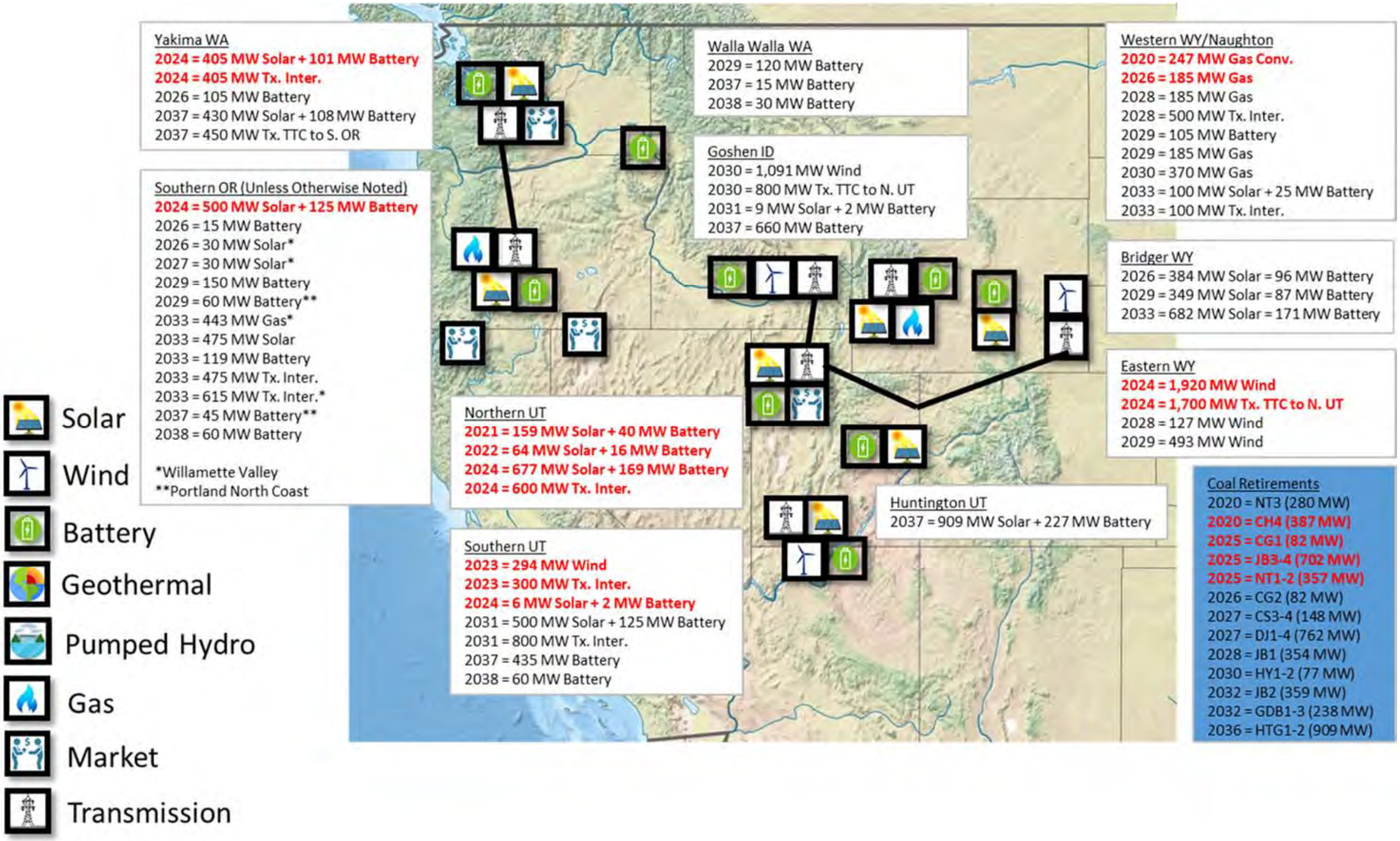
Retirement Assumptions
A variant of case P-31C, and a sibling of P-45C, P-46C has all of the same retirement assumptions except accelerates retirement of Jim Bridger Units 3 & 4 from 2037 to 2025. Full retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2026
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2028
Jim Bridger 2	Retire 2032
Jim Bridger 3	Retire 2025
Jim Bridger 4	Retire 2025
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3	Lg. GC 2020 Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Jim Bridger 3 & 4 Retirement 2025 (P-46C)

P-46C (Jim Bridger 3 & 4 Retirement 2025)



Portfolio: Jim Bridger 3 & 4 Retirement 2023 (P-46J23C)

C-Cases Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description
A variant of sibling case P-46C, P-46J23C has all of the same retirement assumptions except accelerates retirement of Jim Bridger Units 3 & 4 from 2025 to 2023. In addition, it was processed through Planning and Risk Deterministic runs for reliability beyond the initial 2023, 2030 and 2038, to include 2024 through 2029.

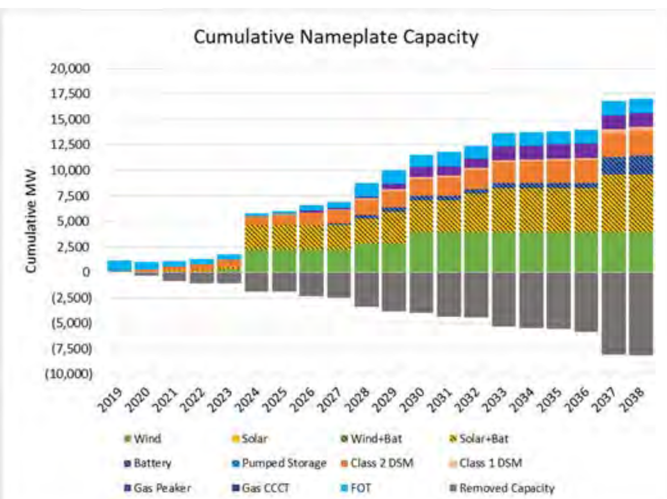
PORTFOLIO SUMMARY

System Optimizer PVRR ($m) ***$21,385***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Yakima – to – S. Oregon/California	*2037*	*450*

Resource Portfolio
Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.

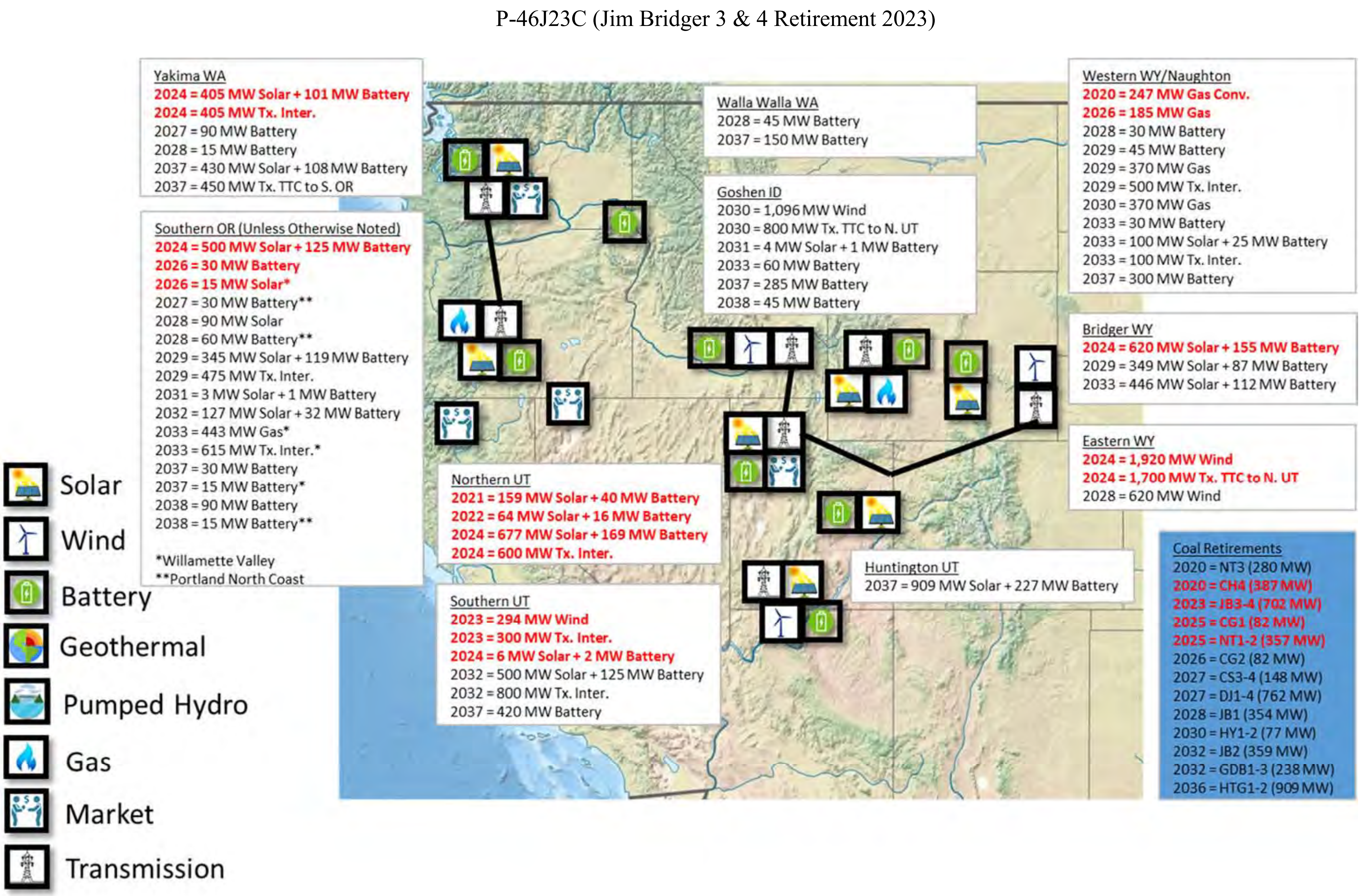


Retirement Assumptions
C-Case portfolio-development case P-46J23C is P-46C with Jim Bridger Units 3-4 retiring in 2023. Full retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2026
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2028
Jim Bridger 2	Retire 2032
Jim Bridger 3	Retire 2023
Jim Bridger 4	Retire 2023
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3	Lg. GC 2020 Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Jim Bridger 3 & 4 Retirement 2023 (P-46J23C)



Portfolio: Jim Bridger 3 & 4 Retirement 2035 (P-47C)

C-Cases Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description
A variant of case P-45C, P-47C has all of the same retirement assumptions except accelerates retirement of Jim Bridger Units 3 & 4 from 2037 to 2035. In addition, it was processed through Planning and Risk Deterministic runs for reliability beyond the initial 2023, 2030 and 2038, to include 2024 through 2029.

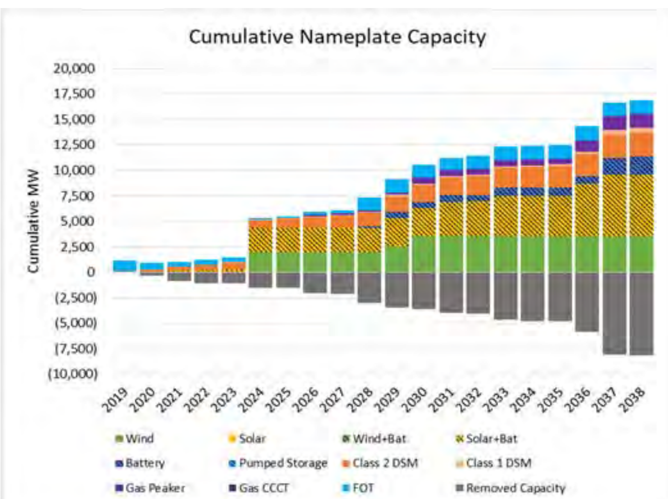
PORTFOLIO SUMMARY

System Optimizer PVRR ($m) $21,467

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Yakima – to – S. Oregon/California	*2036*	*450*

Resource Portfolio
Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



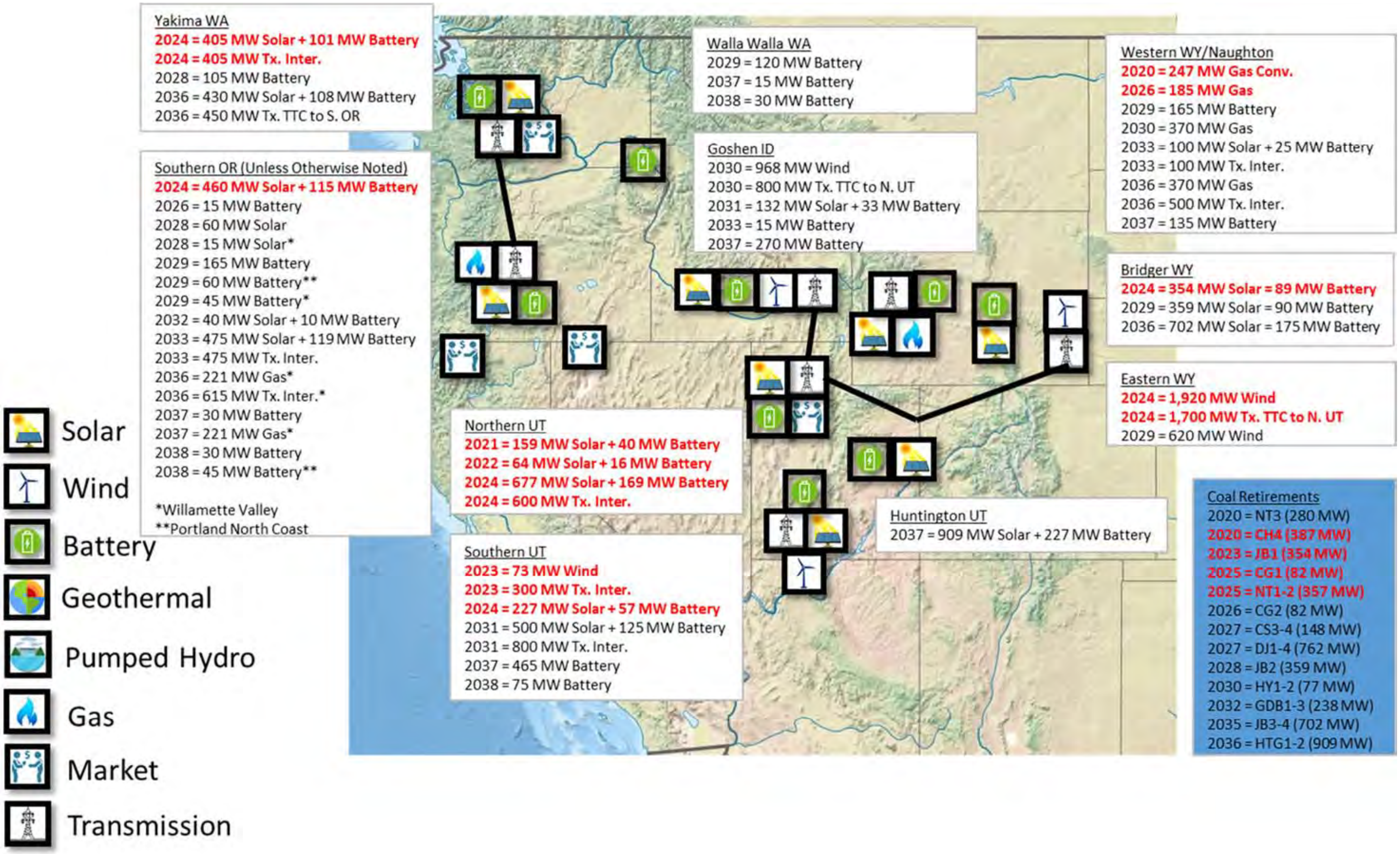
Retirement Assumptions
C-Case portfolio-development case P-47C is P-45C with Jim Bridger Units 3-4 retiring in 2035. Full retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2026
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2023
Jim Bridger 2	Retire 2028
Jim Bridger 3	Retire 2035
Jim Bridger 4	Retire 2035
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3	Lg. GC 2020 Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Jim Bridger 3 & 4 Retirement 2035 (P-47C)

P-47C (Jim Bridger 3 & 4 Retirement 2035)



Portfolio: Jim Bridger 3 & 4 Retirement 2033 (P-48C)

C-Cases Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description
A variant of case P-45C, and a sibling to P-47C, P-48C has all of the same retirement assumptions except accelerates retirement of Jim Bridger Units 3 & 4 from 2037 to 2033. In addition, it was processed through Planning and Risk Deterministic runs for reliability beyond the initial 2023, 2030 and 2038, to include 2024 through 2029.

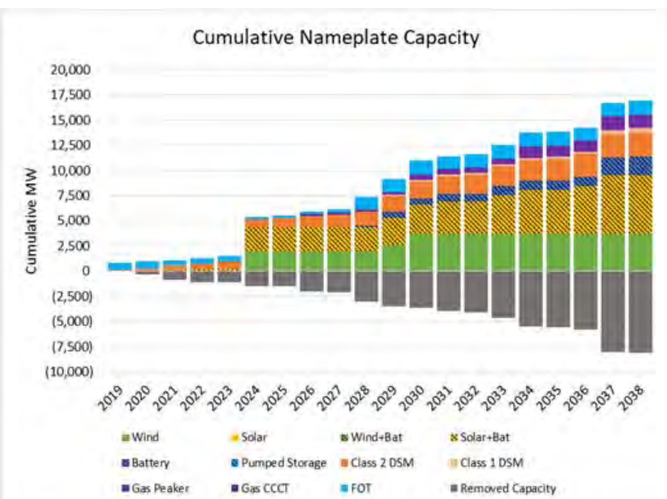
PORTFOLIO SUMMARY

System Optimizer PVRR ($m) ***$21,482***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Yakima – to – S. Oregon/California	*2036*	*450*

Resource Portfolio
Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



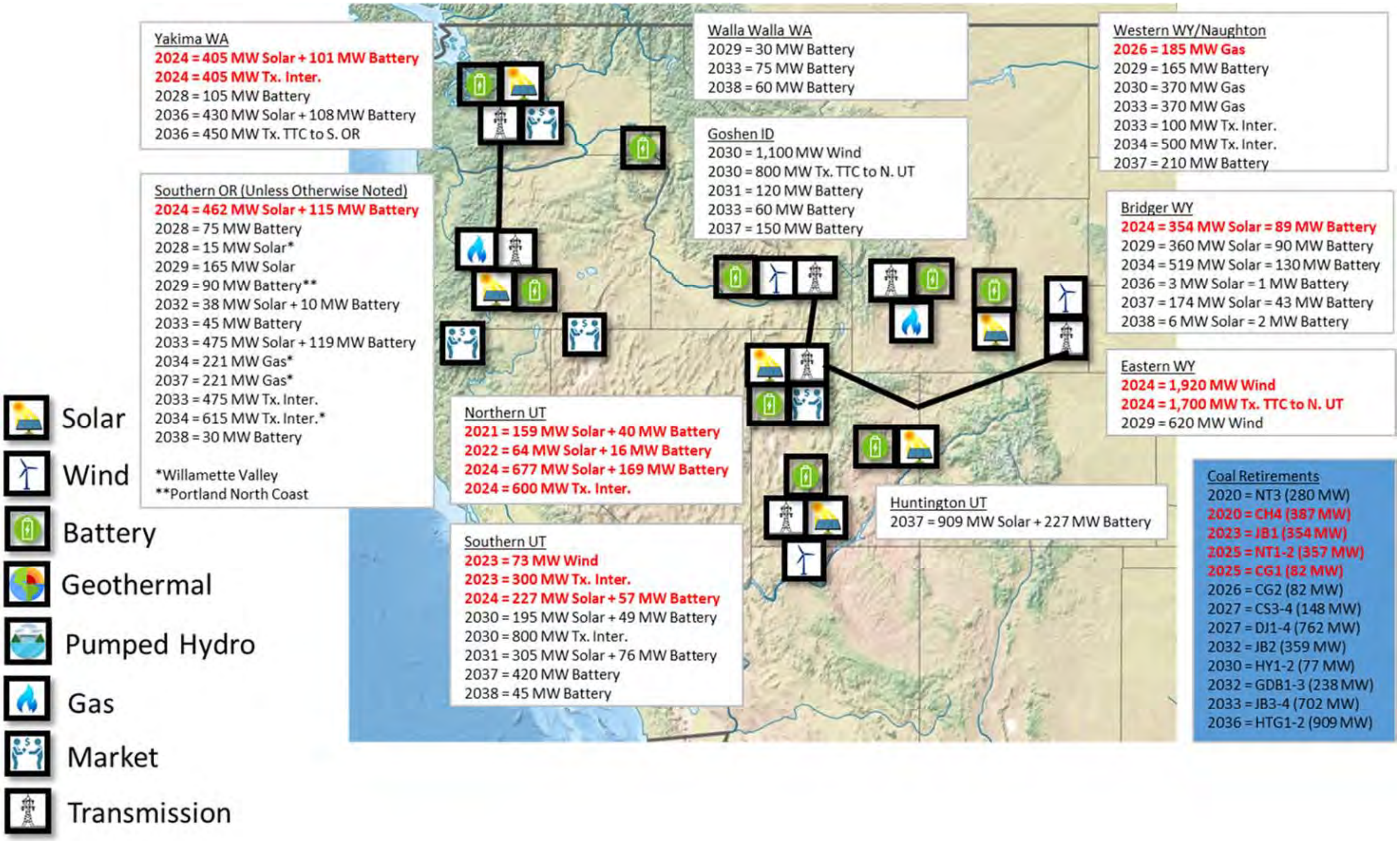
Retirement Assumptions
C-Case portfolio-development case P-48C is P-45C with Jim Bridger Units 3-4 retiring in 2033. Full retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2026
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2023
Jim Bridger 2	Retire 2032
Jim Bridger 3	Retire 2033
Jim Bridger 4	Retire 2033
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3	Lg. GC 2020 Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Jim Bridger 3 & 4 Retirement 2033 (P-48C)

P-48C (Jim Bridger 3 & 4 Retirement 2033)



Portfolio: Jim Bridger 1 &2 Retirement 2025, Jim Bridger 3 Retirement 2028, and Jim Bridger 4 Retirement 2032 (P-53C)

C-Cases Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

A variant of P-53, P-53C has all of the same retirement assumptions except was processed through Planning and Risk Deterministic runs for reliability beyond the initial 2023, 2030 and 2038, to include 2024 through 2029.

PORTFOLIO SUMMARY

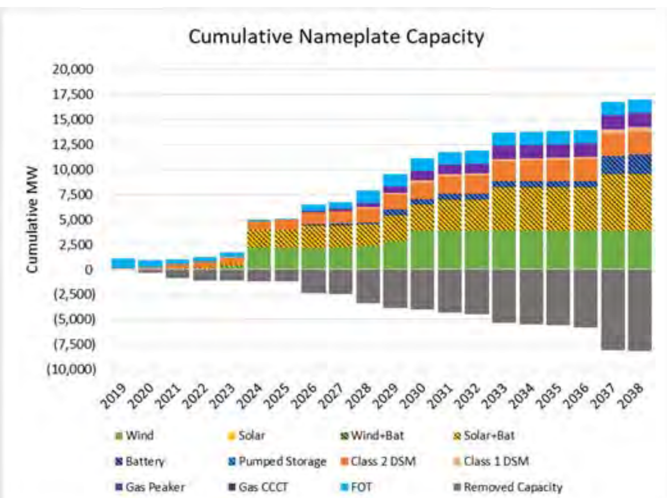
System Optimizer PVRR ($m) ***$21,450***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Yakima – to – S. Oregon/California	*2037*	*450*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

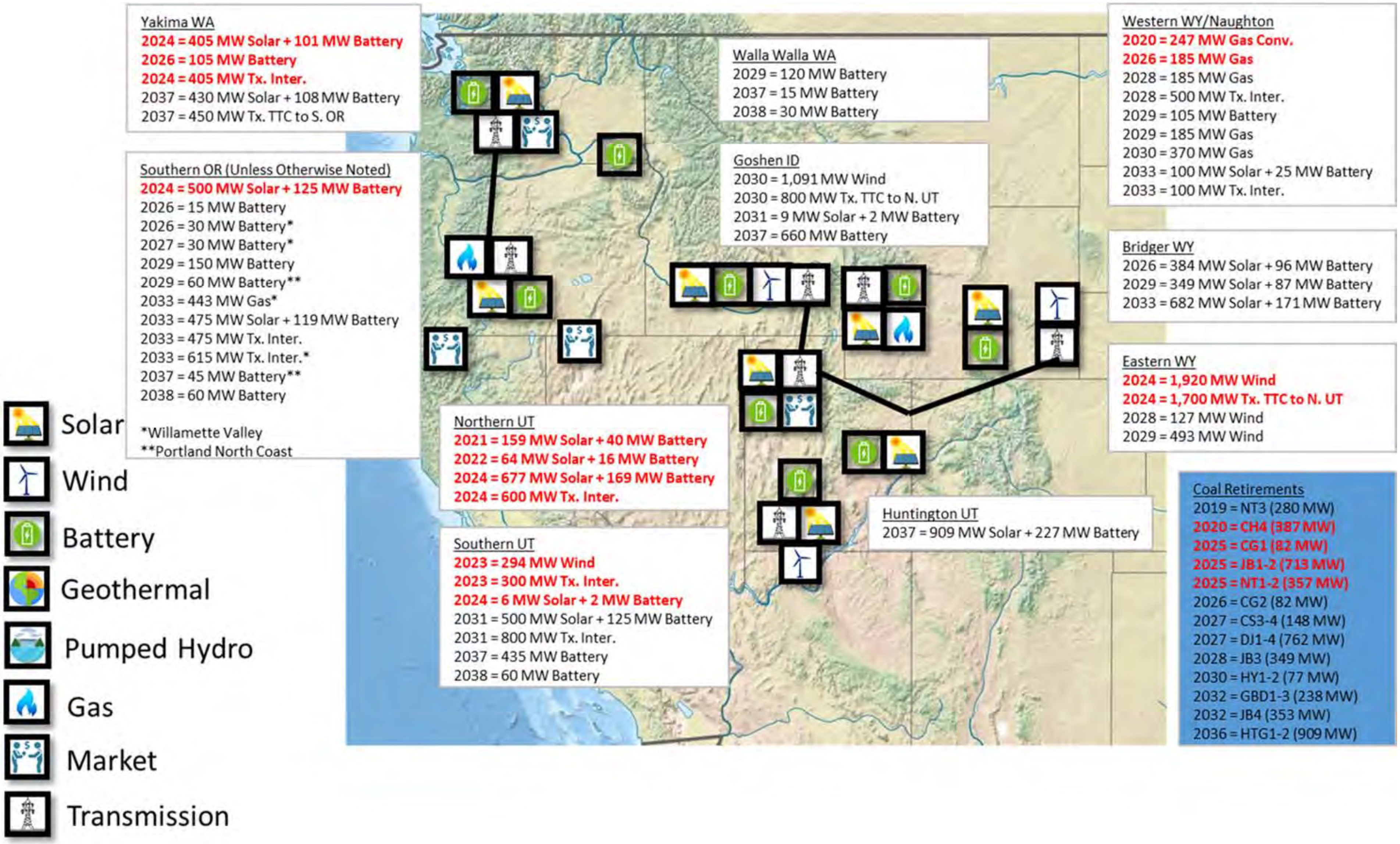
C-Case portfolio-development case P-53C is P-31C with Jim Bridger Units 1-2 retiring in 2025, Jim Bridger Unit 3 retiring in 2028, and Jim Bridger Unit 4 retiring in 2032. Full retirement assumptions are summarized in the following table.

Unit	**Description**
Cholla 4	Retire 2020
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2026
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2025
Jim Bridger 2	Retire 2025
Jim Bridger 3	Retire 2028
Jim Bridger 4	Retire 2032
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3	Lg. GC 2019 Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Jim Bridger 1 &2 Retirement 2025, Jim Bridger 3 Retirement 2028, and Jim Bridger 4 Retirement 2032 (P-53C)

P-53C (P-31 with JB1-2 Retiring 2025, JB3 Retiring 2028, and JB4 Retiring 2032)



Portfolio: Jim Bridger 1 & 2 Retirement 2023 (P-53J23C)

C-Cases Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description
A variant of sibling case P-53, P-53J23C has all of the same retirement assumptions except accelerates retirement of Jim Bridger Units 1 & 2 from 2025 to 2023. In addition, it was processed through Planning and Risk Deterministic runs for reliability beyond the initial 2023, 2030 and 2038, to include 2024 through 2029.

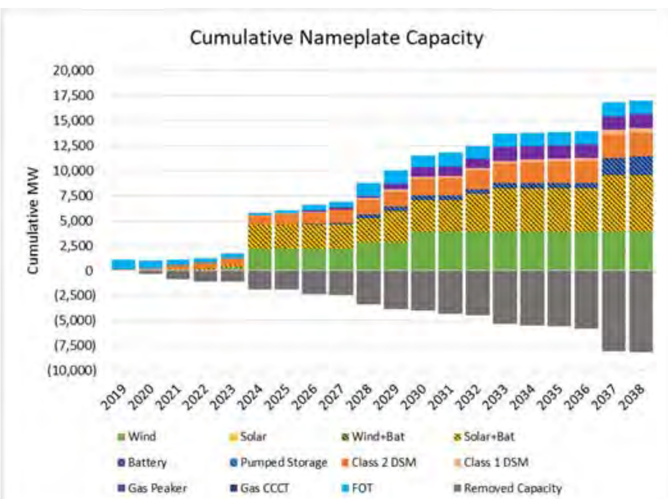
PORTFOLIO SUMMARY

System Optimizer PVRR ($m) ***$21,394***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Yakima – to – S. Oregon/California	*2037*	*450*

Resource Portfolio
Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.

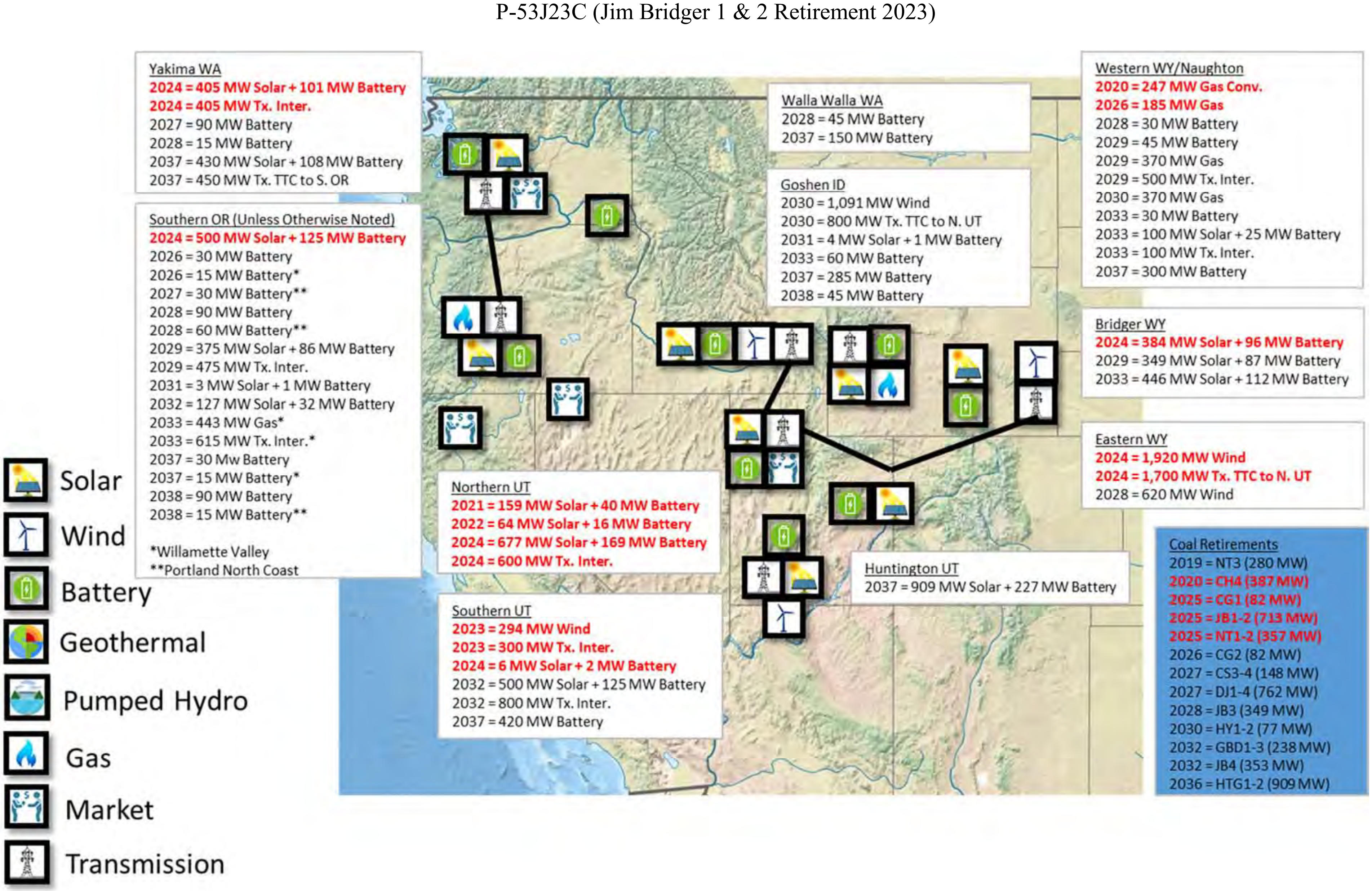


Retirement Assumptions
C-Case portfolio-development P-53J23C is P-53 with Jim Bridger Units 1 & 2 retiring in 2023. Full retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2026
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2023
Jim Bridger 2	Retire 2023
Jim Bridger 3	Retire 2028
Jim Bridger 4	Retire 2032
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3	Lg. GC 2019 Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Jim Bridger 1 & 2 Retirement 2023 (P-53J23C)



Portfolio: Jim Bridger 2 Retirement 2024 (P-54C)

C-Cases Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description
A variant of P-54, P-54C has all of the same retirement assumptions except was processed through Planning and Risk Deterministic runs for reliability beyond the initial 2023, 2030 and 2038, to include 2024 through 2029.

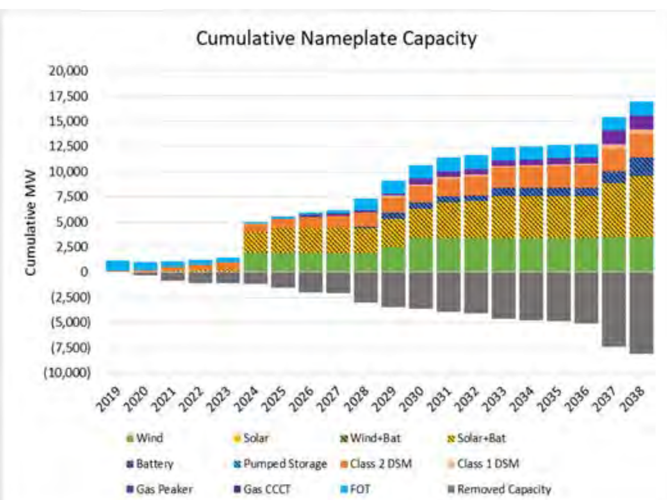
PORTFOLIO SUMMARY

System Optimizer PVRR ($m) ***$21,450***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Yakima – to – S. Oregon/California	*2037*	*450*

Resource Portfolio
Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



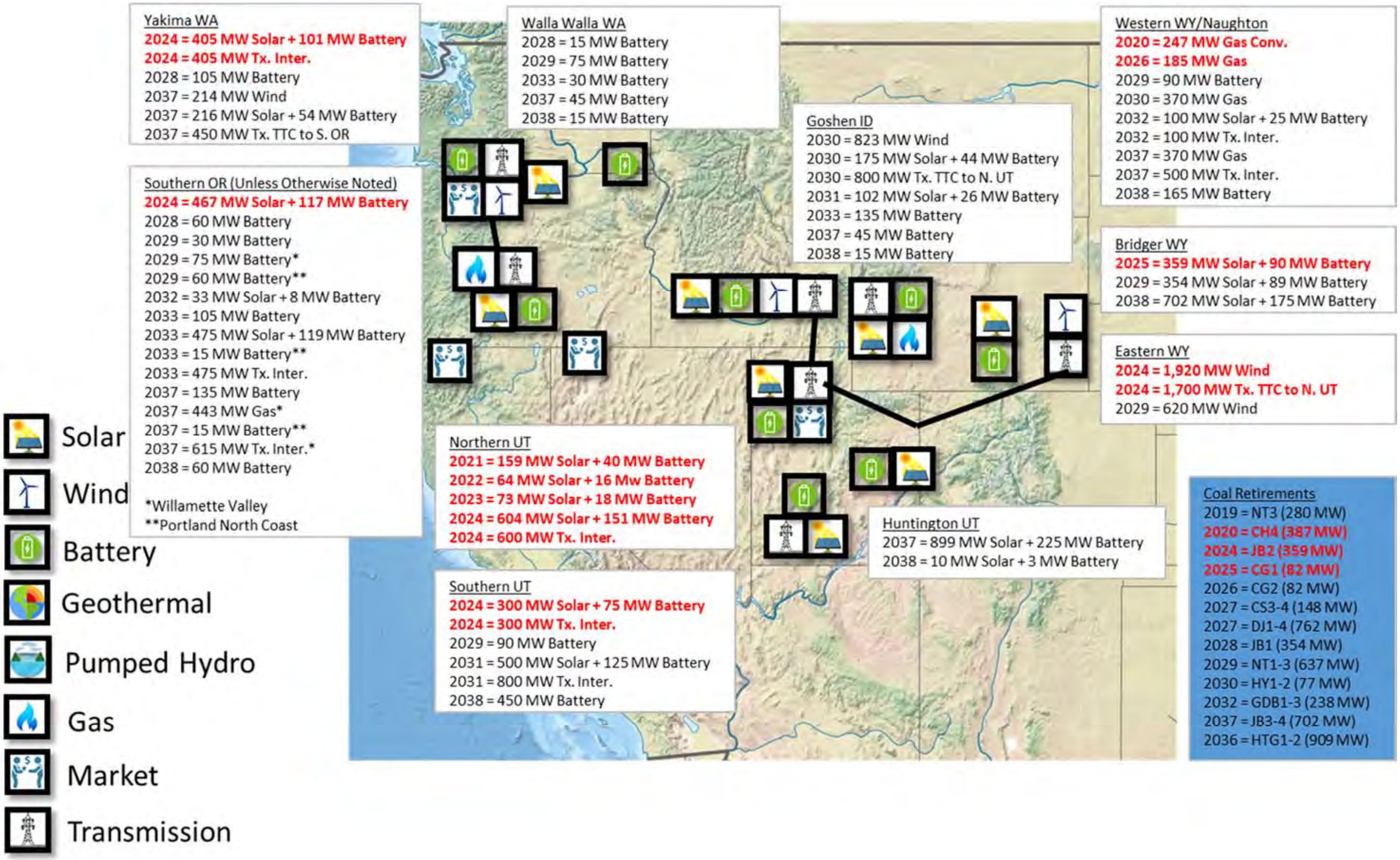
Retirement Assumptions
C-Case portfolio-development case P-54C is P-31 with Jim Bridger Unit 2 retiring in 2024. Full retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2026
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2028
Jim Bridger 2	Retire 2024
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2029
Naughton 2	Retire 2029
Naughton 3	Lg. GC 2019 Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Jim Bridger 2 Retirement 2024 (P-54C)

P-54C (Jim Bridger 2 Retirement 2024)



Portfolio: Jim Bridger & Naughton 1&2 Retiring 2025 (P-36CP)

CP-Cases Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description
A variant of case P-36, P-36CP has all of the same retirement assumptions except was processed through Planning and Risk Deterministic runs for reliability beyond the C-Cases' 2023 through 2030 and 2038, to include 2031 through 2037.

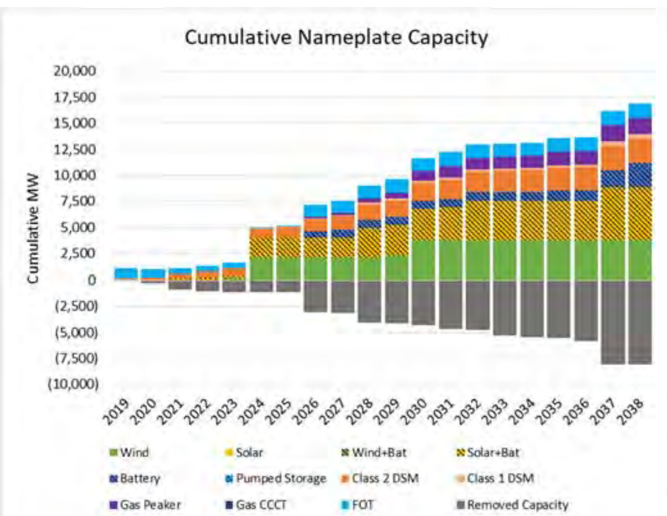
PORTFOLIO SUMMARY

System Optimizer PVRR ($m) $21,553

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Yakima – to – S. Oregon/California	*2037*	*450*

Resource Portfolio
Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



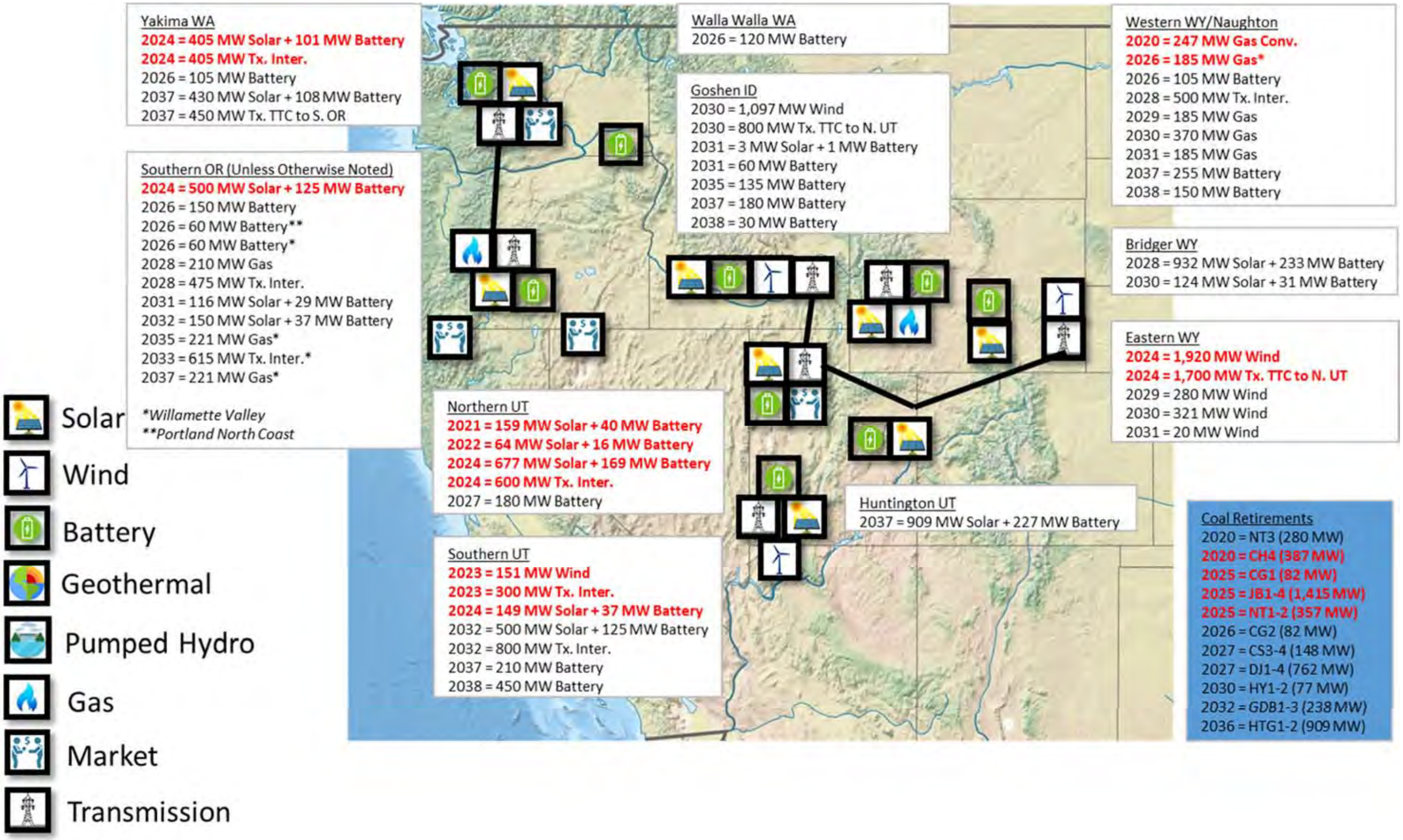
Retirement Assumptions
A variant of case P-14 and a variant of P-36, P-36CP has all of the same retirement assumptions except slows retirement of Jim Bridger Units 1-4 and Naughton Units 1 & 2 three years, from 2022 to 2025. Full retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2026
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2025
Jim Bridger 2	Retire 2025
Jim Bridger 3	Retire 2025
Jim Bridger 4	Retire 2025
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3	Lg. GC 2020 Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Jim Bridger & Naughton 1&2 Retiring 2025 (P-36CP)

P-36CP (Jim Bridger 1 & 2 and Naughton 1 & 2 Retiring 2025)



Portfolio: Jim Bridger 1 Retirement 2023 and Jim Bridger 2 Retirement 2028 (P-45CP)

CP-Cases Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

A variant of case P-45, P-45CP has all of the same retirement assumptions except was processed through Planning and Risk Deterministic runs for reliability beyond the C-Cases' 2023 through 2030 and 2038, to include 2031 through 2037.

PORTFOLIO SUMMARY

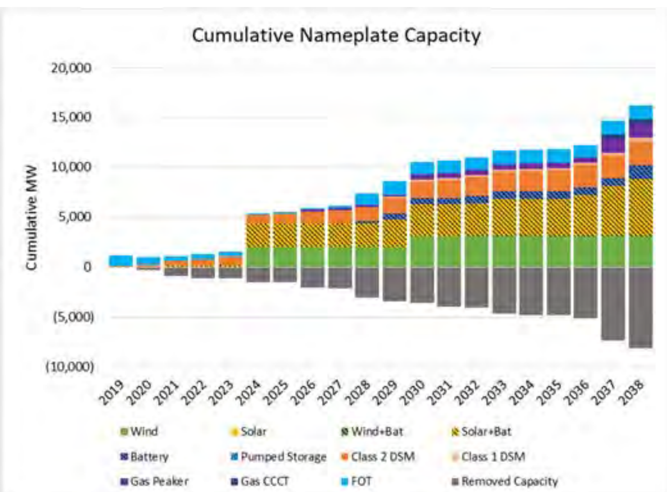
System Optimizer PVRR ($m) ***$21,480***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Yakima – to – S. Oregon/California	*2036*	*450*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

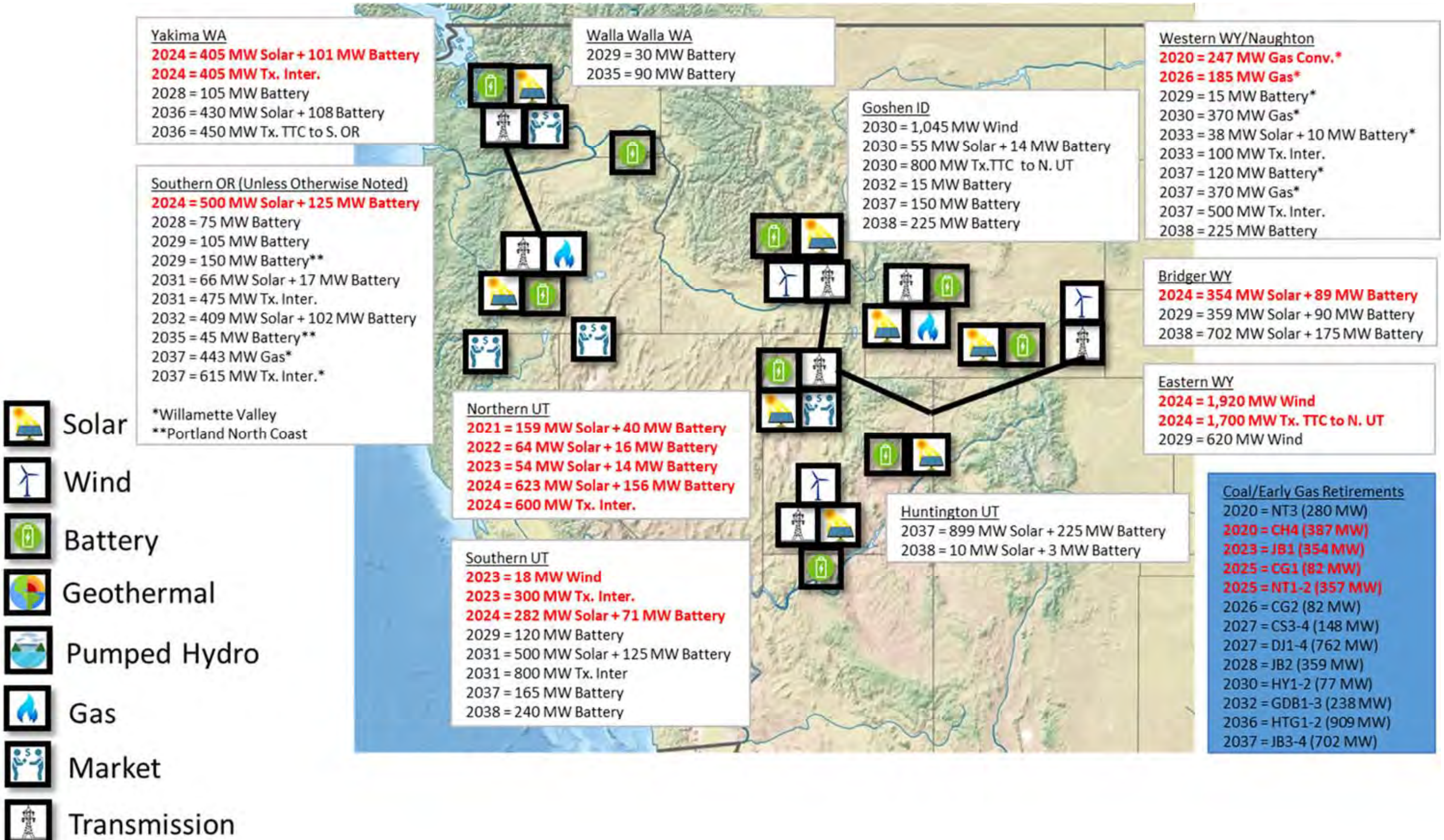
CP-Case portfolio-development case P-45CP is P-31 with Jim Bridger Unit 1 retiring in 2023 and Jim Bridger Unit 2 retiring in 2028. Full retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2026
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2023
Jim Bridger 2	Retire 2028
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3	Lg. GC 2020 Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Jim Bridger 1 Retirement 2023 and Jim Bridger 2 Retirement 2028 (P-45CP)

P-45C (Jim Bridger 1 Retirement 2023 and Jim Bridger 2 Retirement 2028)



Portfolio: Jim Bridger 3 & 4 Retirement 2025 (P-46CP)

CP-Cases Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description
A variant of case P-46, P-46CP has all of the same retirement assumptions except was processed through Planning and Risk Deterministic runs for reliability beyond the C-Cases' 2023 through 2030 and 2038, to include 2031 through 2037.

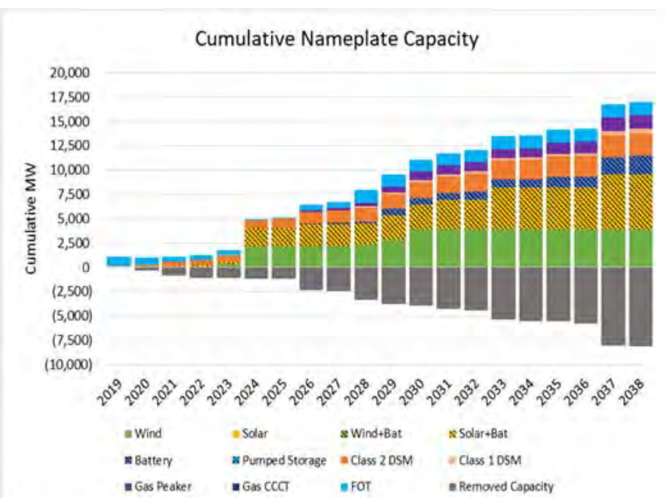
PORTFOLIO SUMMARY

System Optimizer PVRR ($m) ***$21,460***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Yakima – to – S. Oregon/California	*2037*	*450*

Resource Portfolio
Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



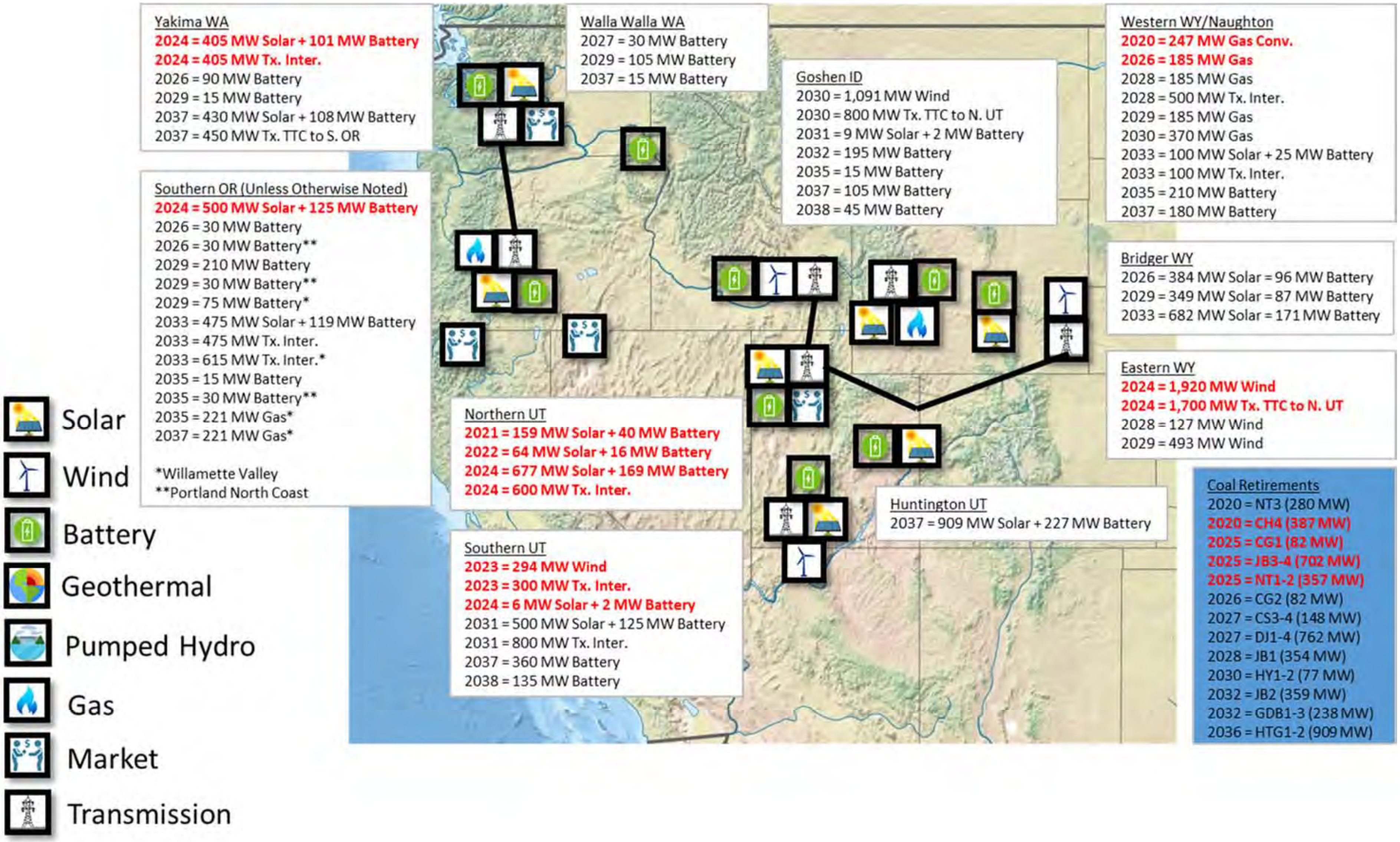
Retirement Assumptions
CP-Case portfolio-development case P-46C is P-31 with Jim Bridger Units 3 & 4 retiring in 2025. Full retirement assumptions are summarized in the following table.

Unit	**Description**
Cholla 4	Retire 2020
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2026
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2028
Jim Bridger 2	Retire 2032
Jim Bridger 3	Retire 2025
Jim Bridger 4	Retire 2025
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3	Lg. GC 2020 Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Jim Bridger 3 & 4 Retirement 2025 (P-46CP)

P-46C (Jim Bridger 3 & 4 Retirement 2025)



Portfolio: Jim Bridger 3 & 4 Retirement 2023 (P-46J23CP)

CP-Cases Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

A variant of case P-46, P-46J23C has all of the same retirement assumptions except was processed through Planning and Risk Deterministic runs for reliability beyond the C-Cases' 2023 through 2030 and 2038, to include 2031 through 2037.

PORTFOLIO SUMMARY

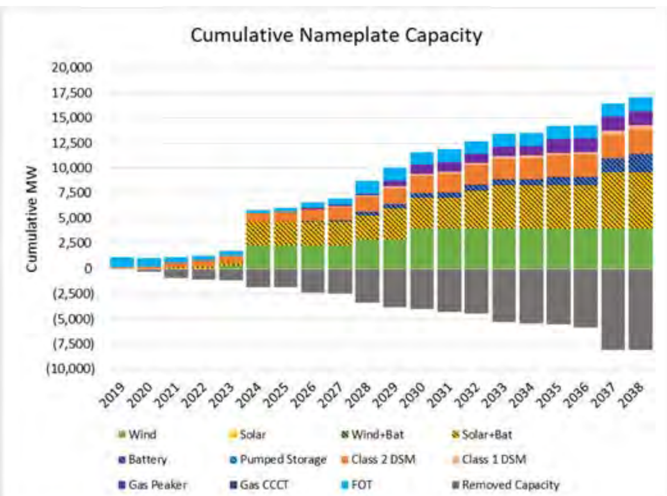
System Optimizer PVRR ($m) ***$21,402***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Yakima – to – S. Oregon/California	*2037*	*450*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

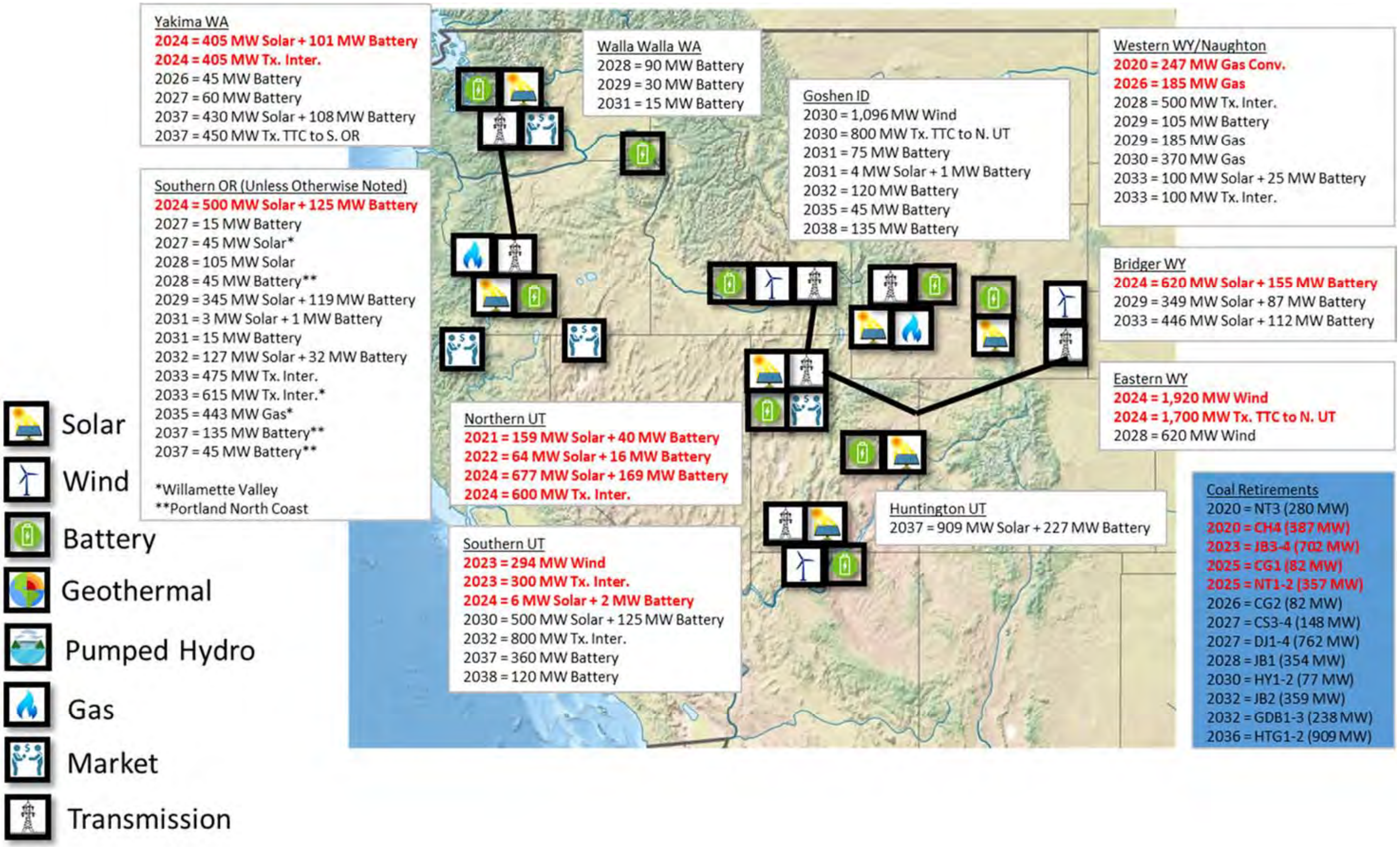
CP-Case portfolio-development case P-46J23C is P-46 with Jim Bridger Units 3 & 4 retiring in 2023. Full retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2026
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2028
Jim Bridger 2	Retire 2032
Jim Bridger 3	Retire 2023
Jim Bridger 4	Retire 2023
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3	Lg. GC 2020 Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Jim Bridger 3 & 4 Retirement 2023 (P-46J23CP)

P-46J23CP (Jim Bridger 3 & 4 Retirement 2023)



Portfolio: Jim Bridger 3 & 4 Retirement 2035 (P-47CP)

CP-Cases Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description
A variant of case P-47C, P-47CP has all of the same retirement assumptions except was processed through Planning and Risk Deterministic runs for reliability beyond the C-Cases' 2023 through 2030 and 2038, to include 2031 through 2037.

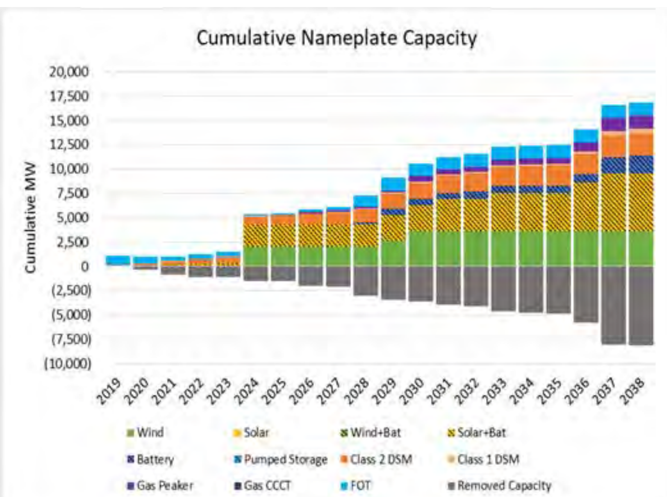
PORTFOLIO SUMMARY

System Optimizer PVRR ($m) ***$21,469***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Yakima – to – S. Oregon/California	*2036*	*450*

Resource Portfolio
Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



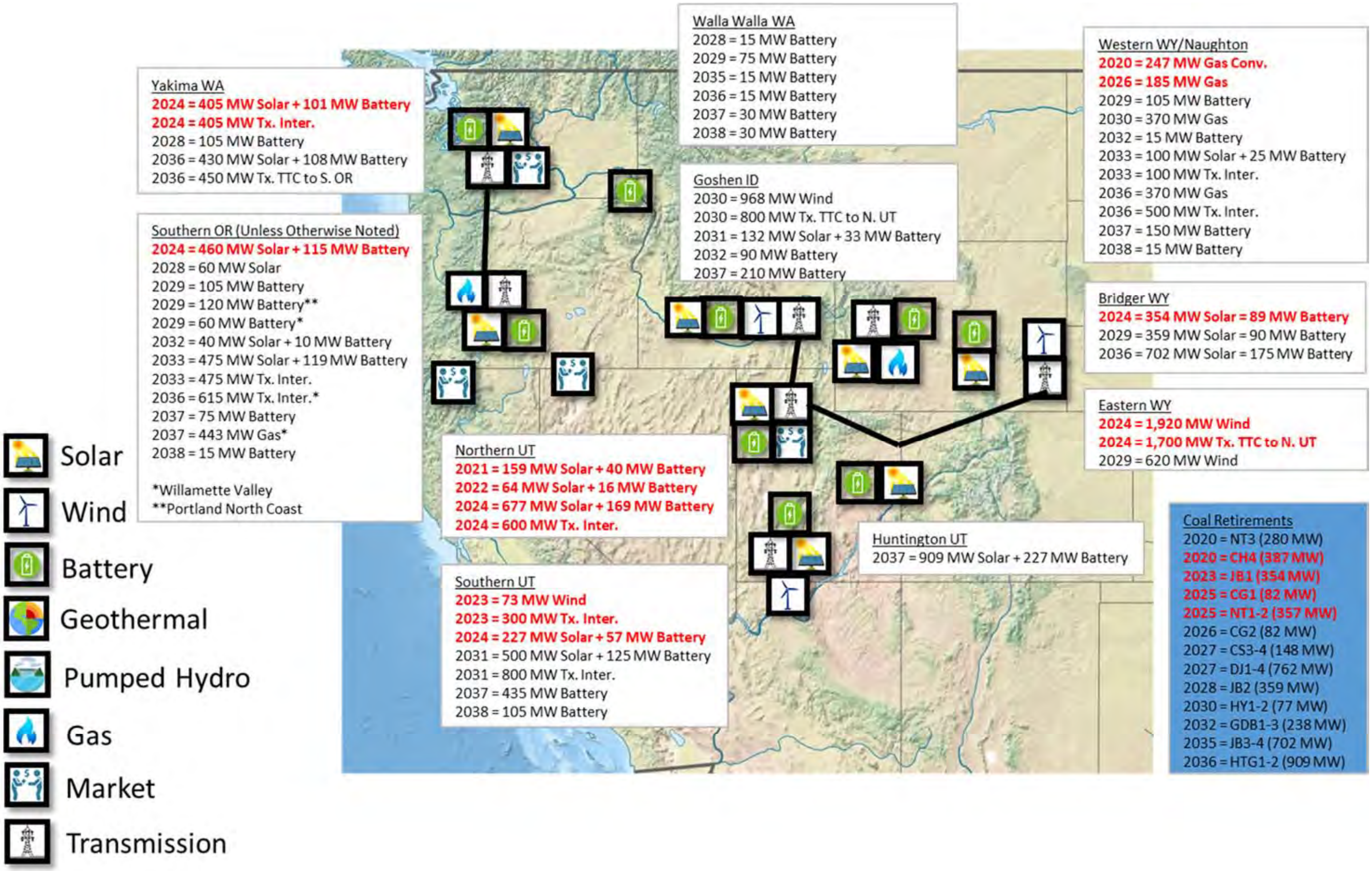
Retirement Assumptions
CP-Case portfolio-development case P-47CP is P-45CP with Jim Bridger Units 3-4 retiring in 2035. Full retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2026
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2023
Jim Bridger 2	Retire 2028
Jim Bridger 3	Retire 2035
Jim Bridger 4	Retire 2035
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3	Lg. GC 2020 Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Jim Bridger 3 & 4 Retirement 2035 (P-47CP)

P-47CP (Jim Bridger 3 & 4 Retirement 2035)



Portfolio: Jim Bridger 3 & 4 Retirement 2033 (P-48CP)

CP-Cases Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

A variant of case P-48C, P-48CP has all of the same retirement assumptions except was processed through Planning and Risk Deterministic runs for reliability beyond the C-Cases' 2023 through 2030 and 2038, to include 2031 through 2037.

PORTFOLIO SUMMARY

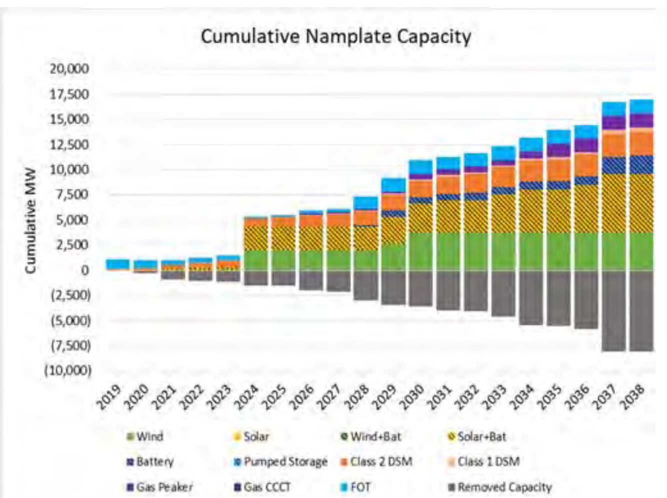
System Optimizer PVRR ($m) ***$21,457***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Yakima – to – S. Oregon/California	*2036*	*450*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



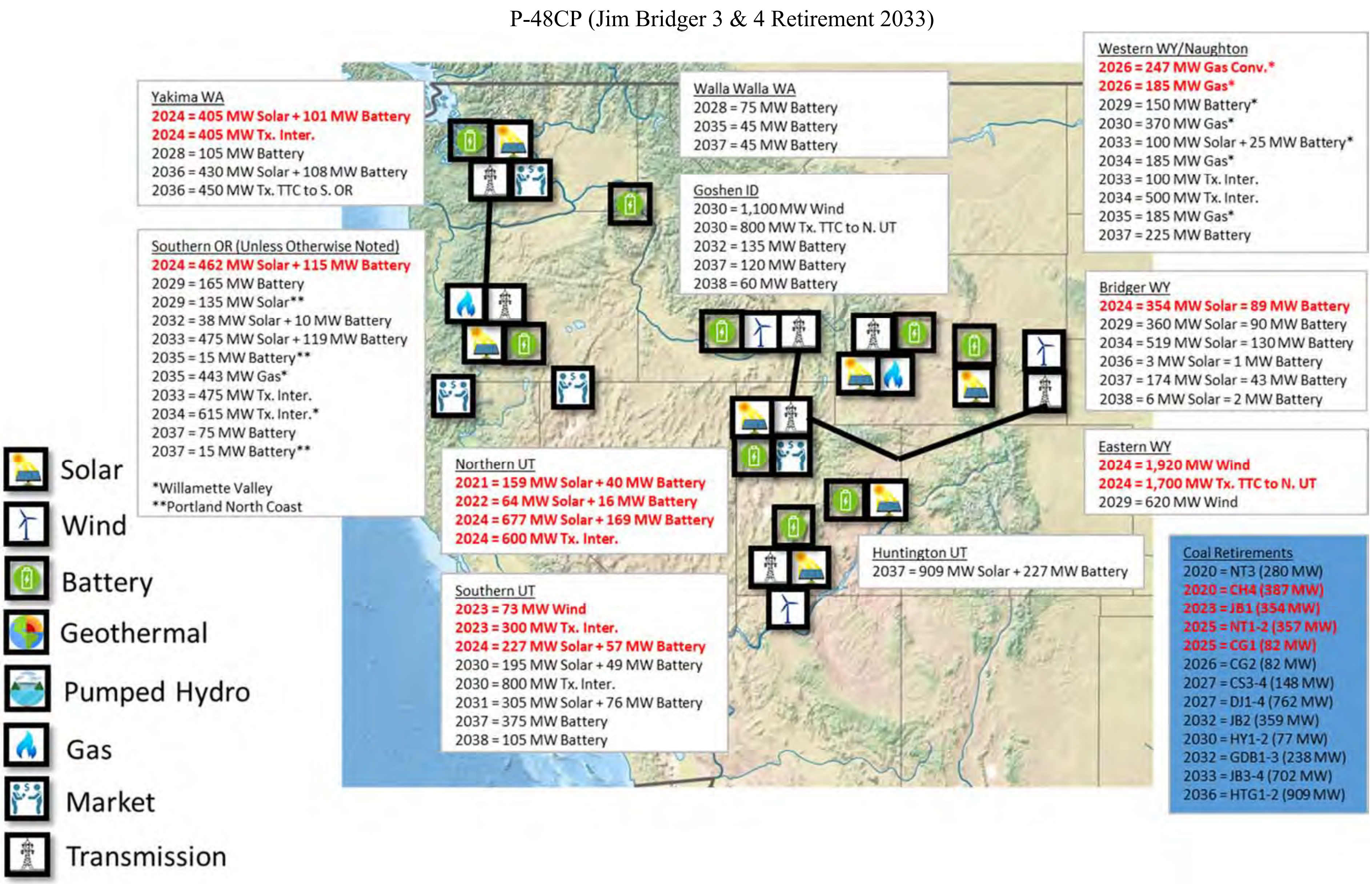
Retirement Assumptions

CP-Case portfolio-development case P-48CP is P-45CP with Jim Bridger Units 3 & 4 retiring in 2033. Full retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2026
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2023
Jim Bridger 2	Retire 2032
Jim Bridger 3	Retire 2033
Jim Bridger 4	Retire 2033
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3	Lg. GC 2020 Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Jim Bridger 3 & 4 Retirement 2033 (P-48CP)



Portfolio: Jim Bridger 1 & 2 Retirement 2025, Jim Bridger 3 Retirement 2028, and Jim Bridger 4 Retirement 2032 (P-53CP)

CP-Cases Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

A variant of case P-53C, P-53CP has all of the same retirement assumptions except was processed through Planning and Risk Deterministic runs for reliability beyond the C-Cases' 2023 through 2030 and 2038, to include 2031 through 2037.

PORTFOLIO SUMMARY

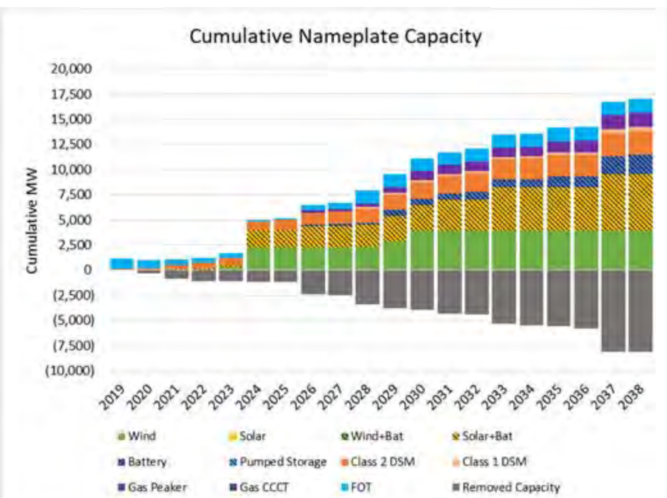
System Optimizer PVRR ($m) ***$21,479***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Yakima – to – S. Oregon/California	*2037*	*450*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

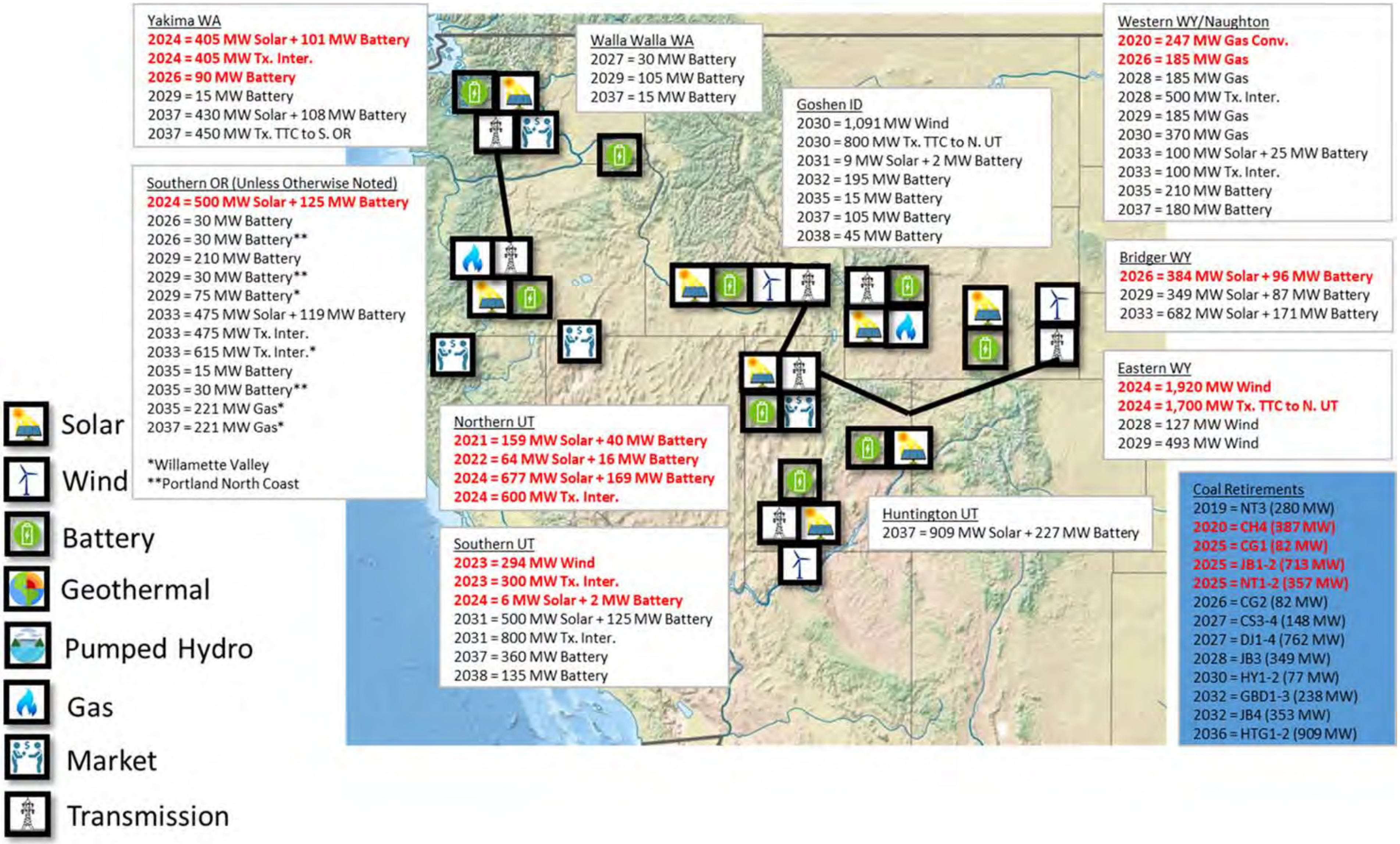
CP-Case portfolio-development case P-53CP is P-31 with Jim Bridger Units 1-2 retiring in 2025, Jim Bridger Unit 3 retiring in 2028, and Jim Bridger Unit 4 retiring in 2032. Full retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2026
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2025
Jim Bridger 2	Retire 2025
Jim Bridger 3	Retire 2028
Jim Bridger 4	Retire 2032
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3	Lg. GC 2019 Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Jim Bridger 1 & 2 Retirement 2025, Jim Bridger 3 Retirement 2028, and Jim Bridger 4 Retirement 2032 (P-53CP)

P-48CP (Jim Bridger 1 & 2 Retirement 2025, Jim Bridger 3 Retirement 2028, and Jim Bridger 4 Retirement 2032)



Portfolio: P-45CNW, No New Gas Option (P-29)

No Gas-Cases Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description
A variant of case P-45CNW, P-29 is a C-Prime case and has all of the same retirement assumptions except was processed through Planning and Risk Deterministic runs for reliability beyond the C-Cases' 2023 through 2030 and 2038, to include 2031 through 2037. In addition, no new gas resources were allowed.

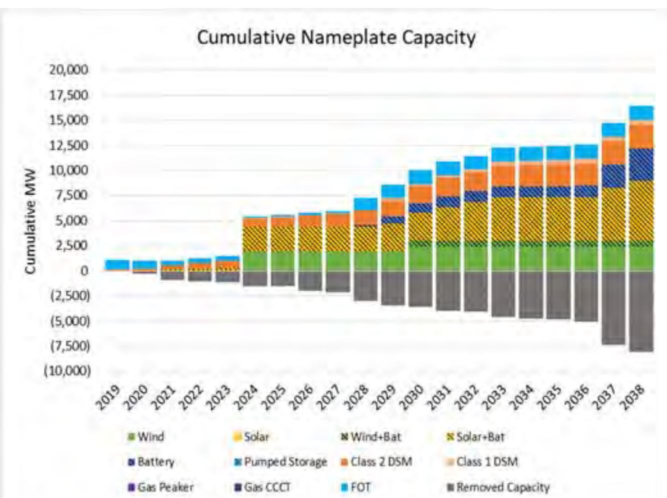
PORTFOLIO SUMMARY

System Optimizer PVRR ($m) $21,798

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Yakima – to – S. Oregon/California	*2033*	*450*

Resource Portfolio
Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



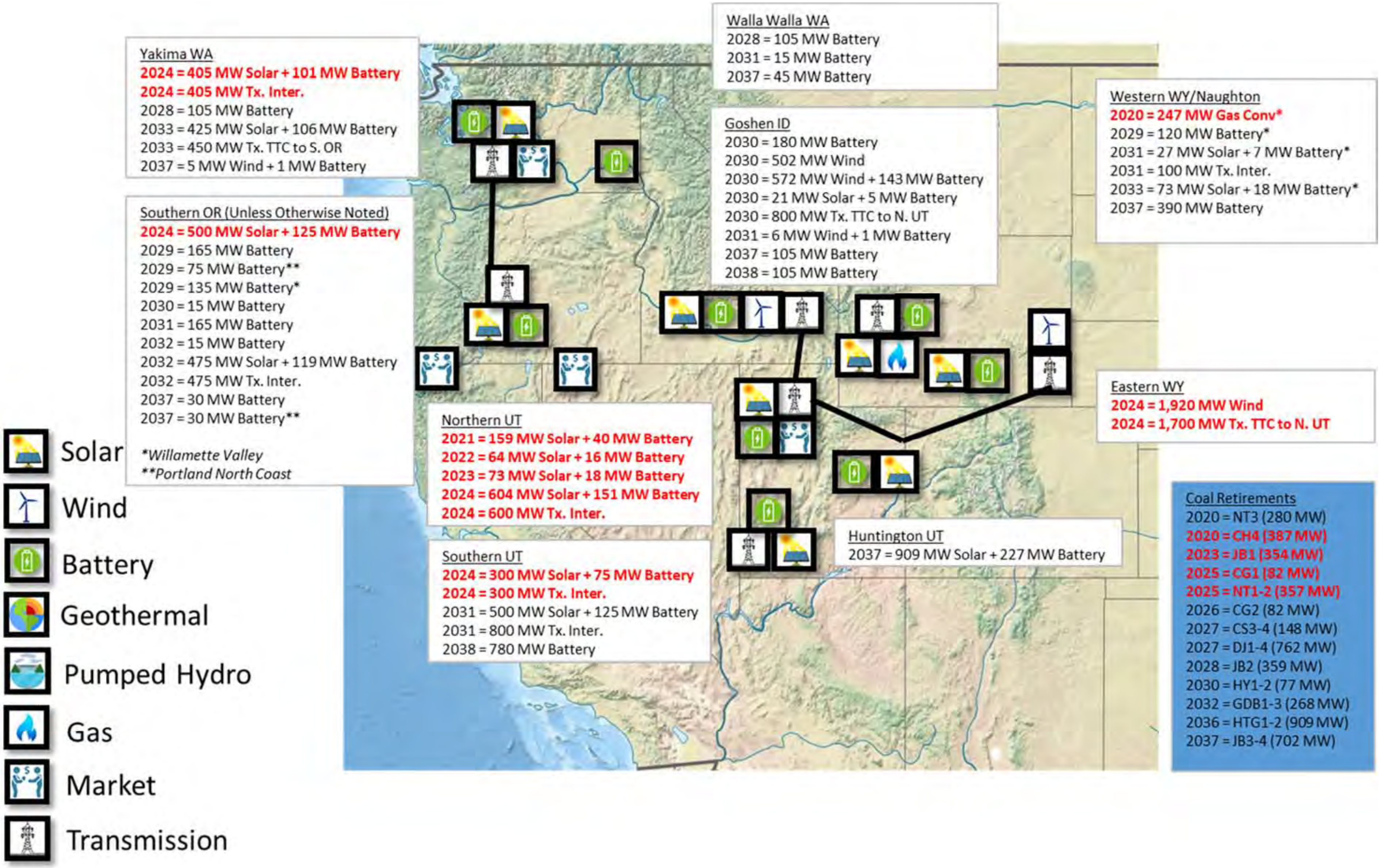
Retirement Assumptions
No Gas-Case portfolio-development case P-29 is P-45CNW with no new gas option. Retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2026
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2023
Jim Bridger 2	Retire 2028
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3	Lg. GC 2020 Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: P-45CNW, No New Gas Option (P-29)

P-429 (P-45CNW, No New Gas Option)



No Gas-Cases Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

A variant of case P-29, and a variant of P-45CNW, P-29PS is a C-Prime case and has all of the same retirement assumptions except was processed through Planning and Risk Deterministic runs for reliability beyond the C-Cases' 2023 through 2030 and 2038, to include 2031 through 2037. In addition to no new gas resource options allowed, it required the addition of pumped hydro.

PORTFOLIO SUMMARY

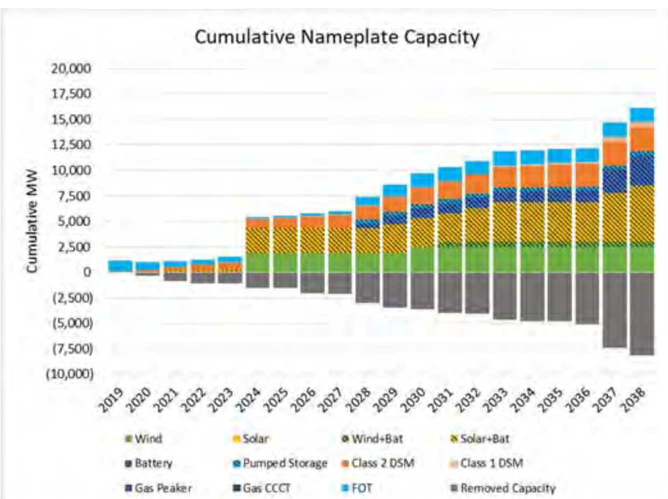
System Optimizer PVRR ($m) $21,970

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

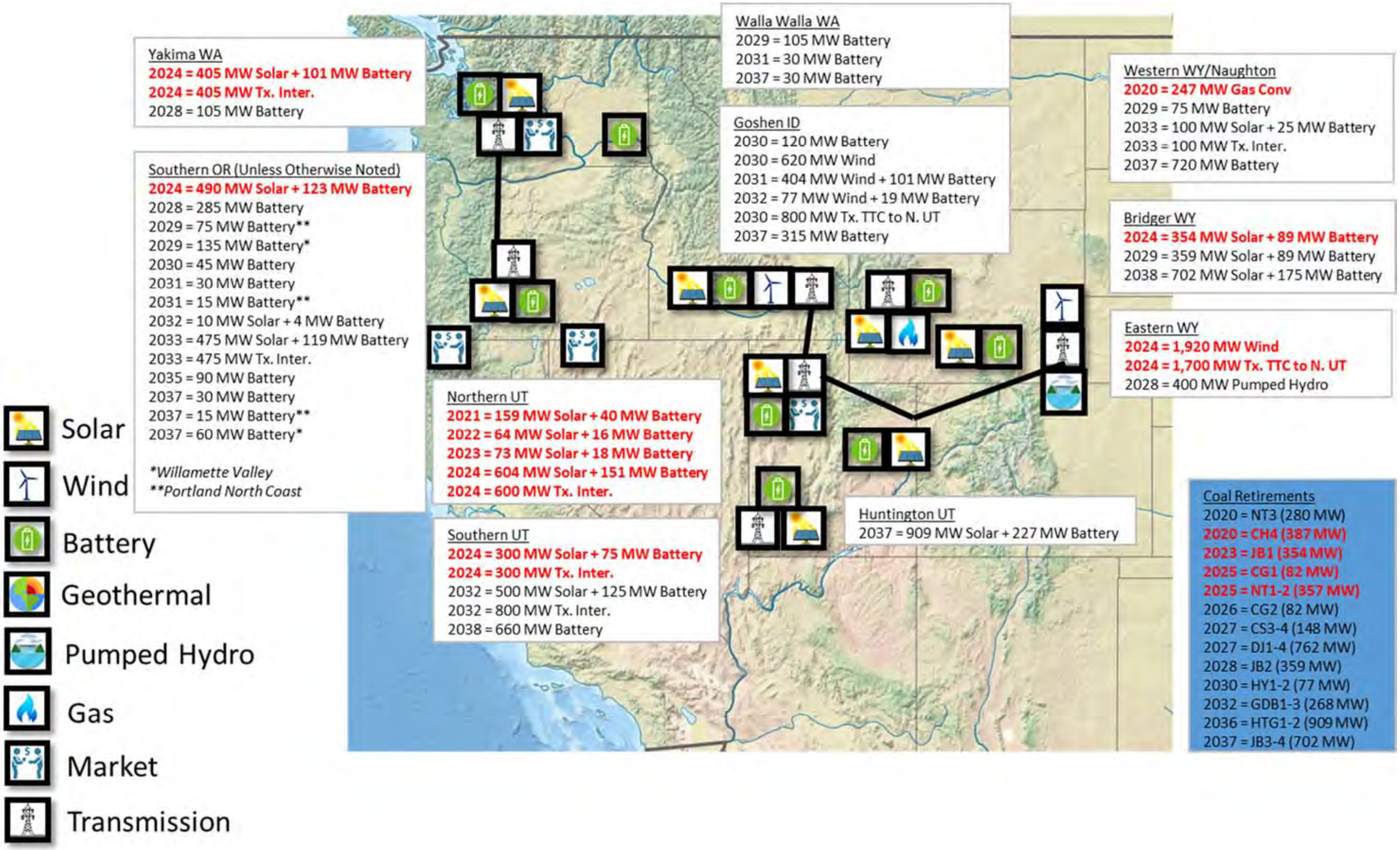
No Gas-Case portfolio-development case P-29PS is P-45CNW with no new gas allowed, but adds pumped hydro storage. Retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2026
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2023
Jim Bridger 2	Retire 2028
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3	Lg. GC 2020 Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: P-45CNW, No New Gas Option With Pumped Hydro Storage (P-29PS)

P-429 (P-45CNW, No New Gas Option with Pumped Hydro Storage)



Energy Gateway Portfolio-Development Fact Sheets

CASE ASSUMPTIONS

Description
Gateway Study P-22CNW includes Segment D.3 – Populus to Bridger/Anticline. This sensitivity is a variant of the preferred portfolio, P-45CNW.

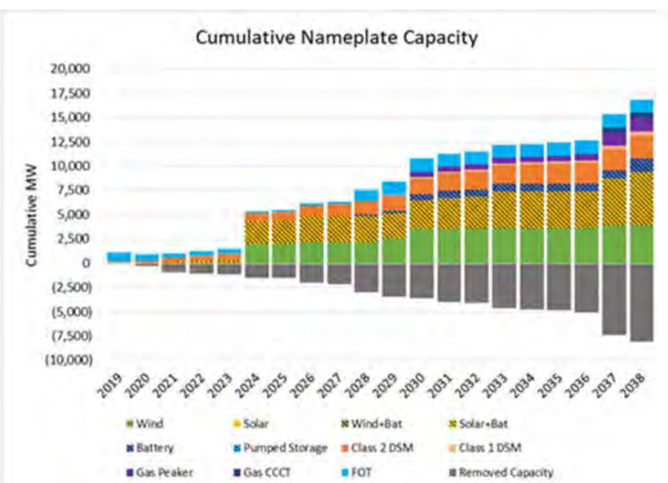
PORTFOLIO SUMMARY

System Optimizer PVRR ($m) ***$21,886***

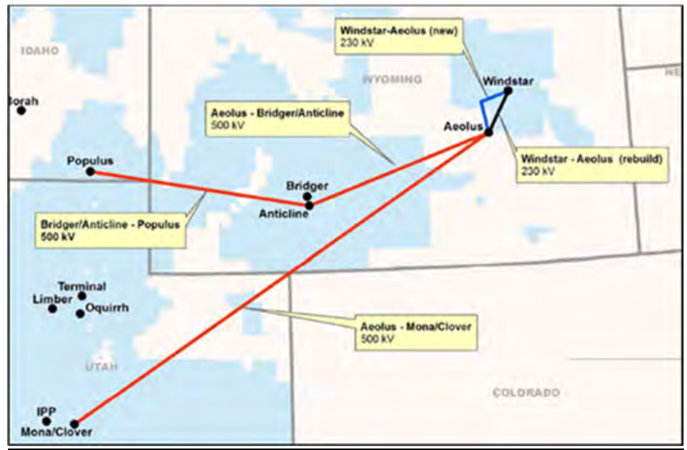
Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus Wyoming – to - Utah S	*2024*	*1,700*
Goshen – to – Utah N	*2030*	*800*
Yakima- to – S. Oregon/California	*2037*	*450*

Resource Portfolio
Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as cumulative nameplate capacity, are summarized in the figure below.

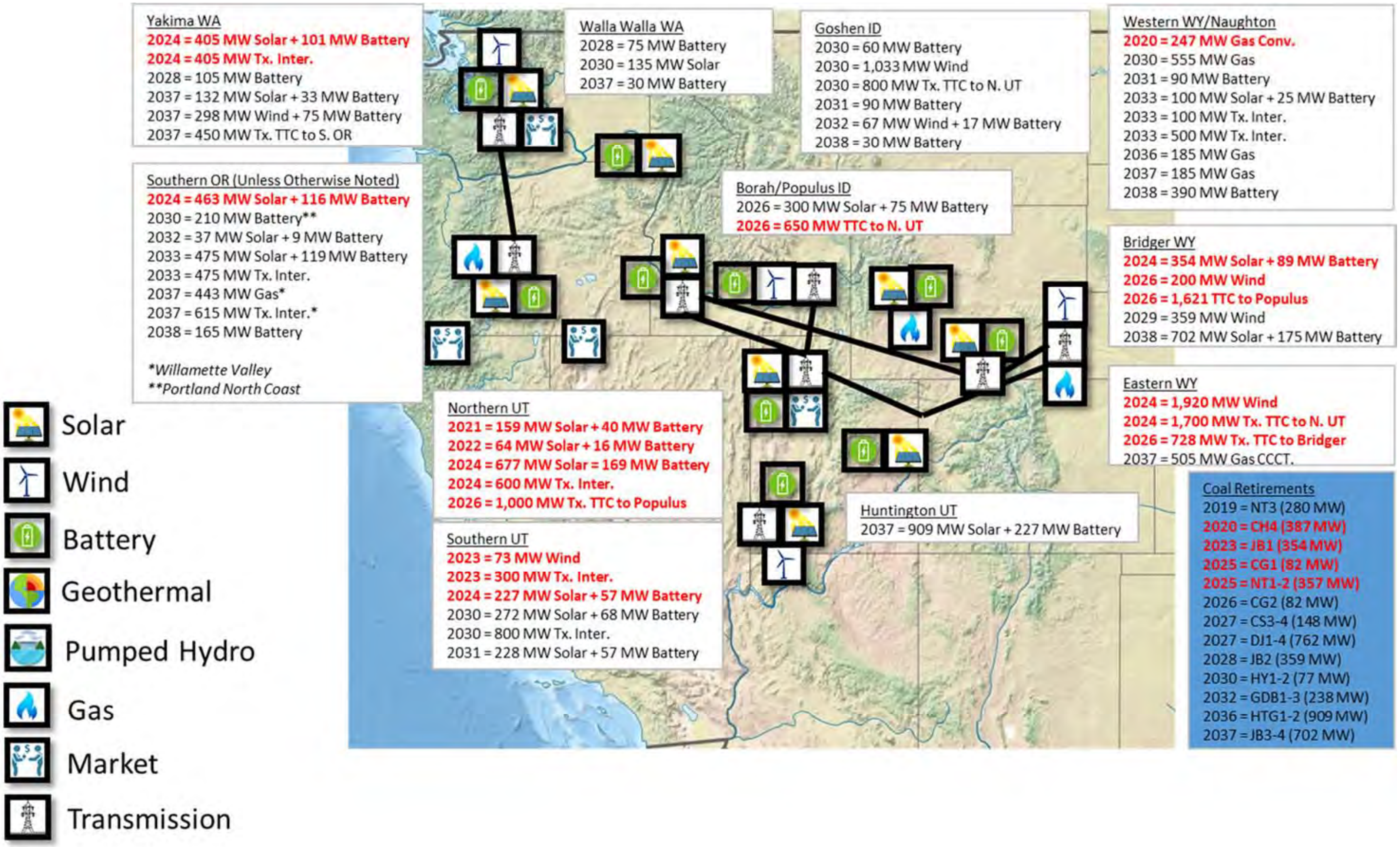


Transmission
Transmission path is shown in the map below



Portfolio: Energy Gateway Segment D3 (P-22)

P-22 (Energy Gateway Segment D3)



Energy Gateway Portfolio-Development Fact Sheets

CASE ASSUMPTIONS

Description

Gateway Study P-23CNW includes all gateway options for System Optimizer to choose. This sensitivity is a variant of the case P-36C.

PORTFOLIO SUMMARY

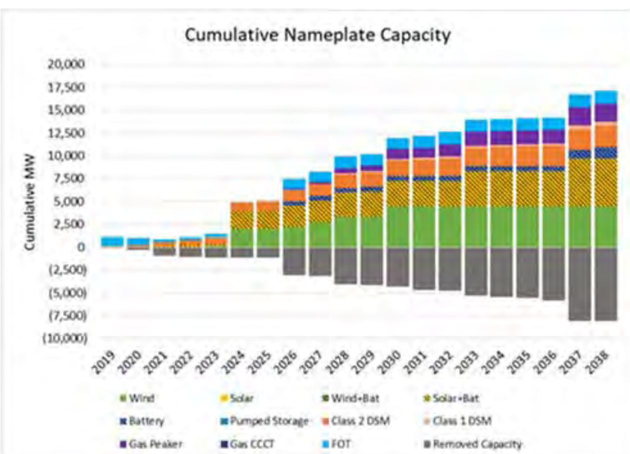
System Optimizer PVRR ($m) ***$22,151***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus Wyoming – to - Utah S	*2024*	*1,700*
Goshen – to – Utah N	*2030*	*800*
Yakima- to – S. Oregon/California	*2037*	*450*

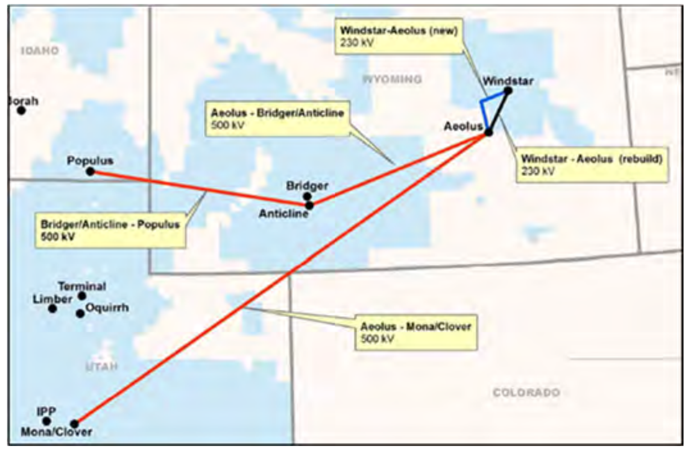
Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as cumulative nameplate capacity, are summarized in the figure below.



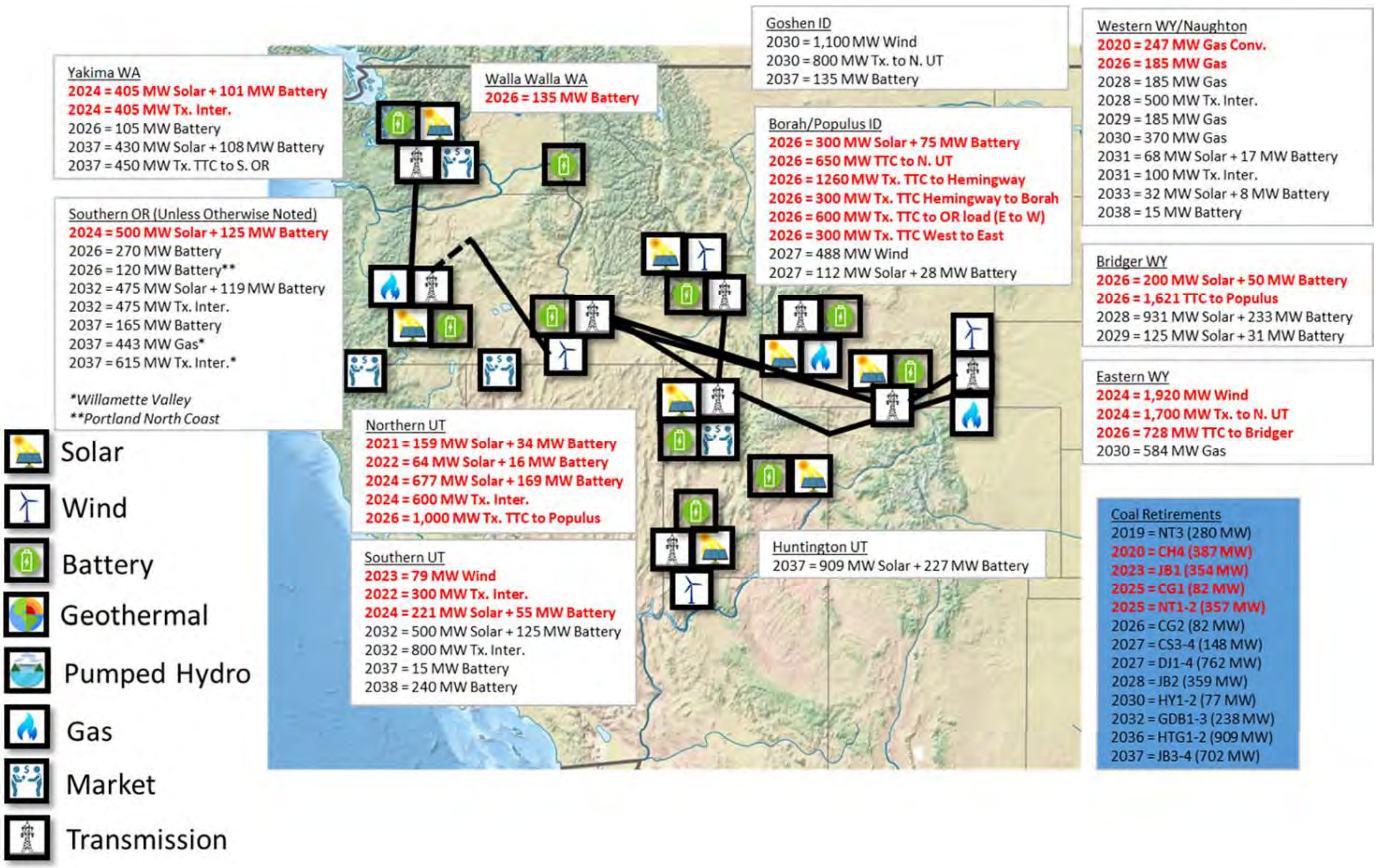
Transmission

Transmission path is shown in the map below



Portfolio: Energy Gateway Segment D1 and F (P-23)

P-23 (Energy Gateway Segment D1 and F)



Portfolio: Energy Gateway Segment D3, E, and H (P-25)

Energy Gateway Portfolio-Development Fact Sheets

CASE ASSUMPTIONS

Description
Gateway Study P-25CNW includes Segment D.3 – Populus to Bridger/Anticline, along with Segment E, Hemingway – Cedar Hill and Segment H, Boardman - Hemingway. This sensitivity is a variant of the preferred portfolio, P-45CNW.

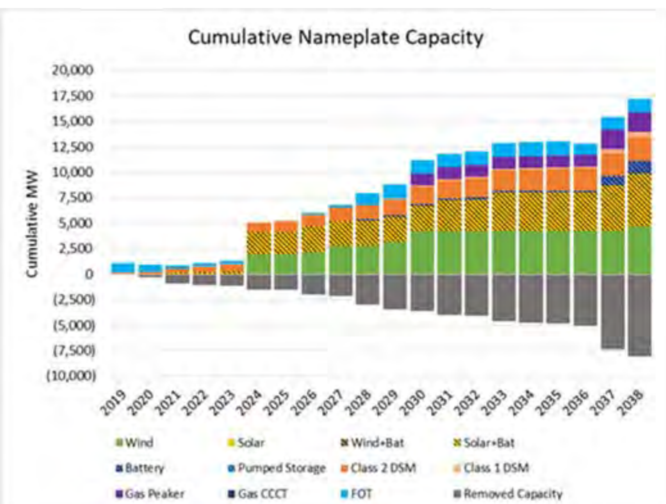
PORTFOLIO SUMMARY

System Optimizer PVRR ($m) ***$22,273***

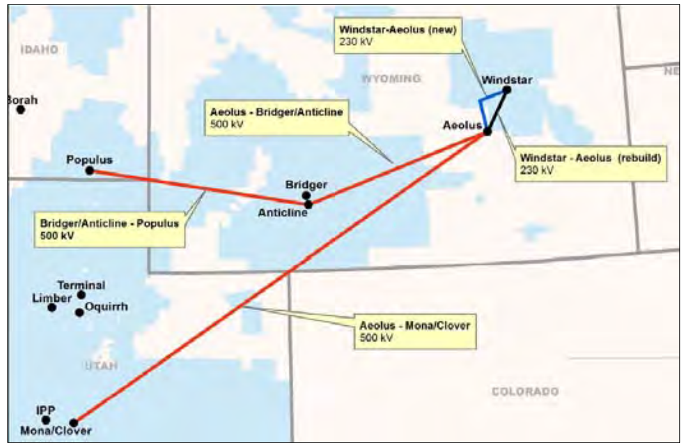
Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus Wyoming – to - Utah S	*2024*	*1,700*
Goshen – to – Utah N	*2030*	*800*
Yakima- to – S. Oregon/California	*2038*	*450*

Resource Portfolio
Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as cumulative nameplate capacity, are summarized in the figure below.

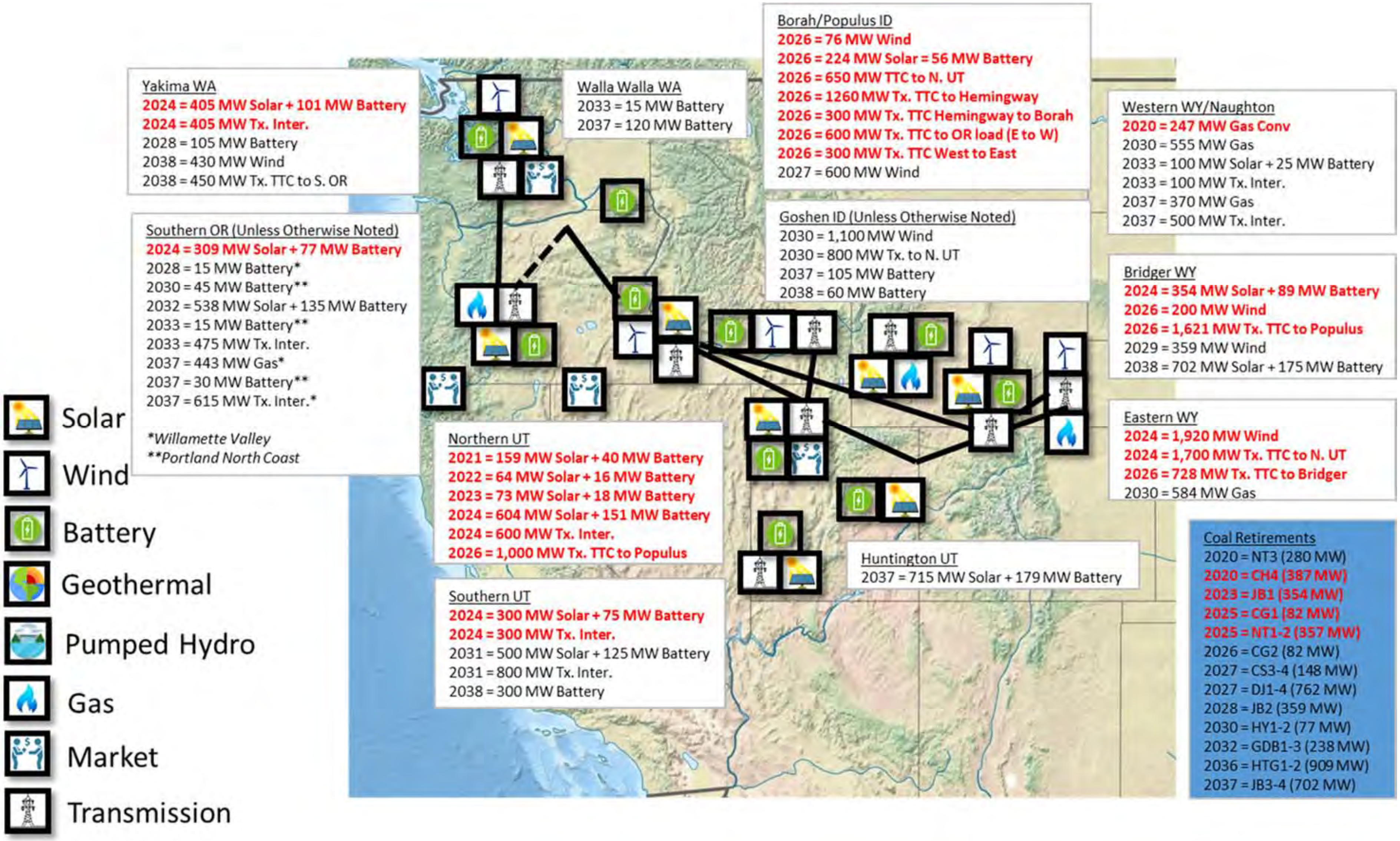


Transmission
Transmission path is shown in the map below



Portfolio: Energy Gateway Segment D3, E, and H (P-25)

P-25 (Energy Gateway Segment D3, E, and H)



Portfolio: Energy Gateway Segment H (P-26)

Energy Gateway Portfolio-Development Fact Sheets

Case Assumptions

Description
Gateway Study P-26CNW includes Segment, Boardman - Hemingway. This sensitivity is a variant of the preferred portfolio, P-45CNW.

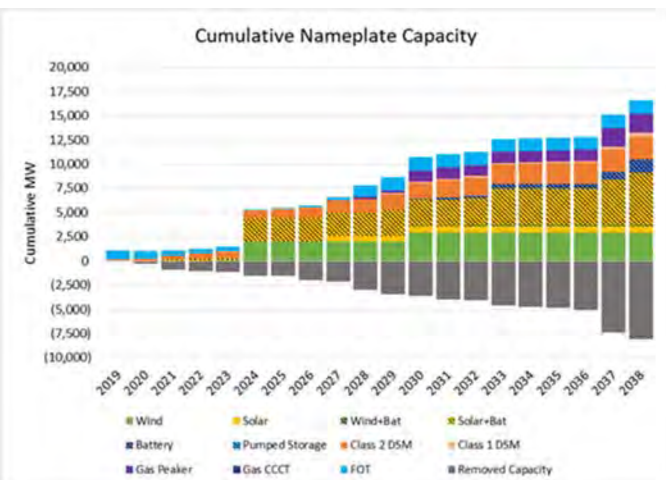
Portfolio Summary

System Optimizer PVRR ($m) ***$21,579***

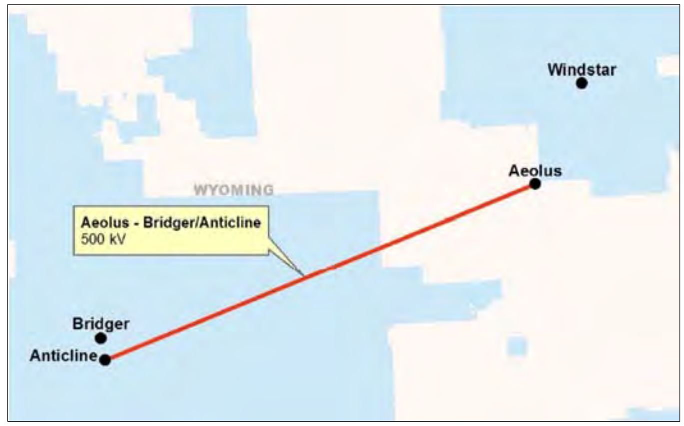
Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus Wyoming – to - Utah S	*2024*	*1,700*
Goshen – to – Utah N	*2030*	*800*

Resource Portfolio
Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as cumulative nameplate capacity, are summarized in the figure below.

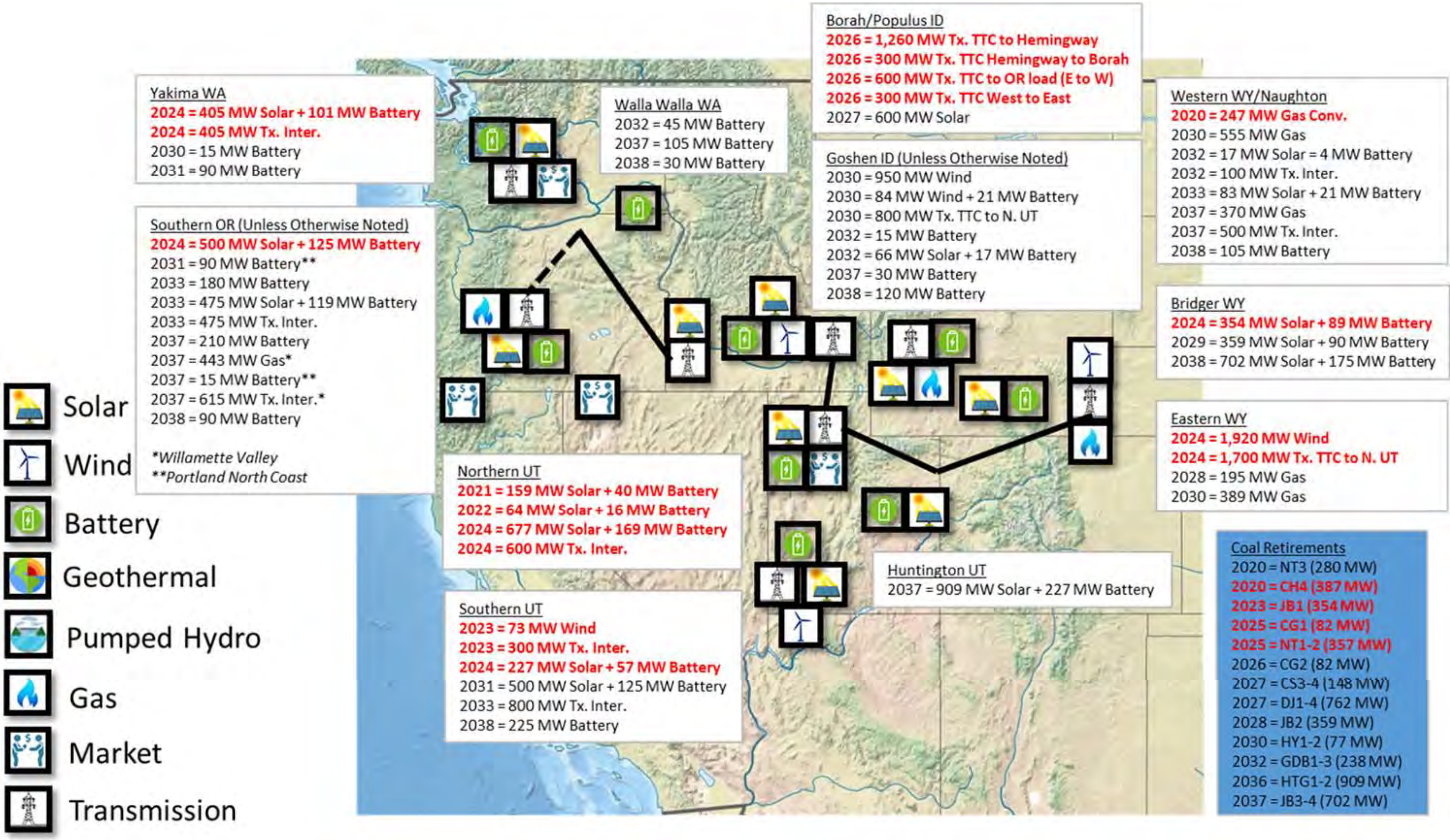


Transmission
Transmission path is shown in the map below



Portfolio: Energy Gateway Segment H (P-26)

P-26 (Energy Gateway Segment H)



Sensitivity Fact Sheets

Case Assumptions

Description

The low load forecast sensitivity reflects pessimistic economic growth assumptions from IHS Global Insight and low Utah and Wyoming industrial loads. The low and high industrial load forecasts focus on increased uncertainty in industrial loads further out in time. To capture this uncertainty, PacifiCorp modeled 1,000 possible annual loads for each year based on the standard error of the medium scenario regression equation. The low industrial load forecast is taken from 5th percentile. This sensitivity is a variant of the preferred portfolio, P-45CNW.

Portfolio Summary

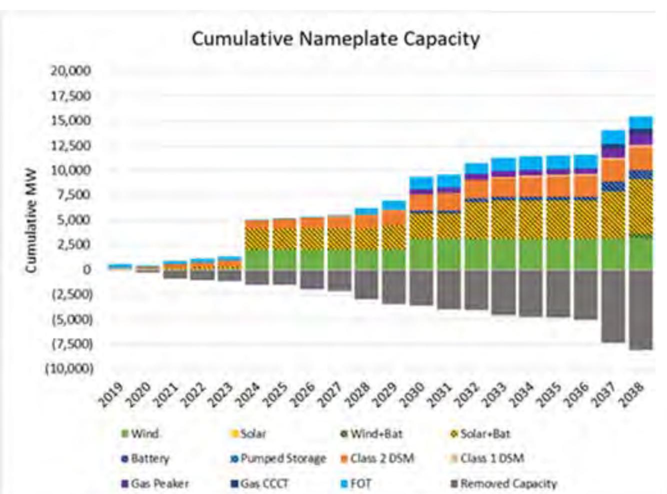
System Optimizer PVRR ($m) $20,617

Incremental Transmission Upgrades

Description	***Year***	***Capacity***
Aeolus Wyoming – to - Utah S	*2024*	*1,700*
Goshen – to – Utah N	*2030*	*800*
Walla Walla- to – Yakima	*2037*	*200*
Portland N Coast - to - Willamette Valley	*2038*	*450*

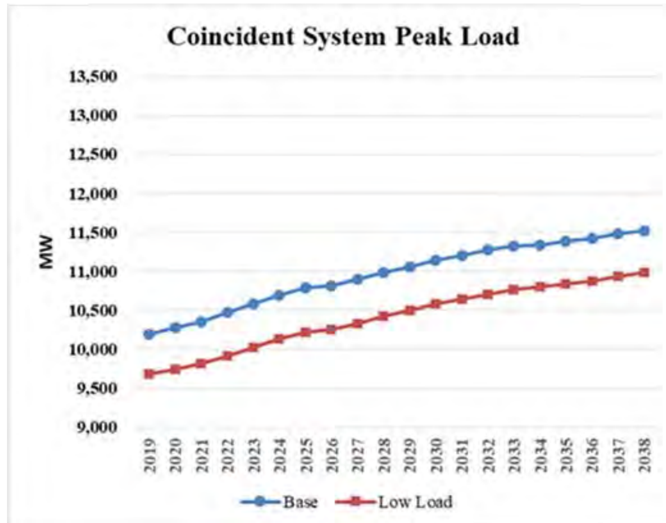
Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as cumulative nameplate capacity, are summarized in the figure below.

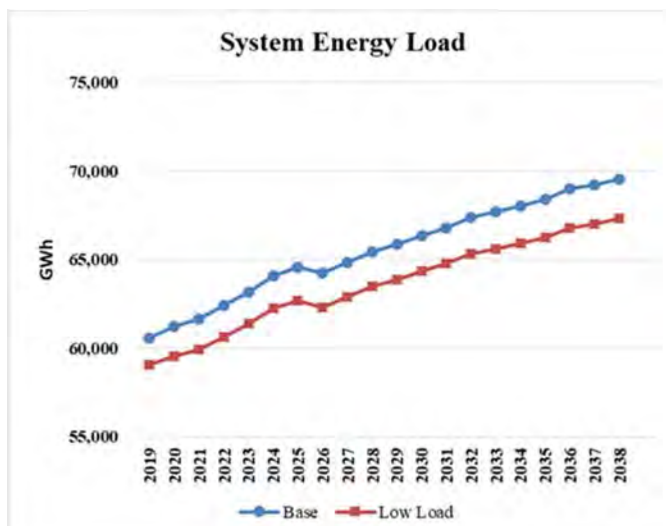


Load Forecast

The figure below shows the base system coincident peak load forecast applicable to this case before accounting for any potential contribution from DSM alongside Base Case forecast. Loads include private generation resources.



The figure below shows the base energy load forecast applicable to this case before accounting for any potential contribution from DSM alongside Base Case forecast. Loads include private generation resources.



Sensitivity Fact Sheets

CASE ASSUMPTIONS

Description

The high load forecast sensitivity reflects optimistic economic growth assumptions from IHS Global Insight and low Utah and Wyoming industrial loads. The low and high industrial load forecasts focus on increased uncertainty in industrial loads further out in time. To capture this uncertainty, PacifiCorp modeled 1,000 possible annual loads for each year based on the standard error of the medium scenario regression equation. The high industrial load forecast is taken from 95th percentile. This sensitivity is a variant of the preferred portfolio, P-45CNW.

PORTFOLIO SUMMARY

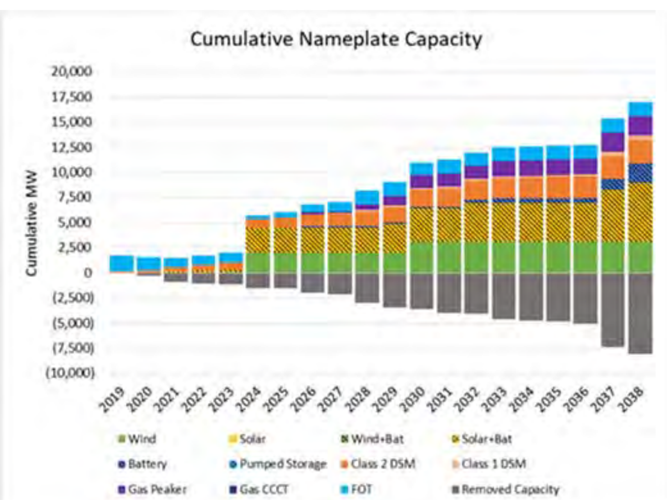
System Optimizer PVRR ($m) $22,602

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus Wyoming – to - Utah S	*2024*	*1,700*
Goshen – to – Utah N	*2030*	*800*
Yakima- to – S. Oregon/California	*2037*	*450*

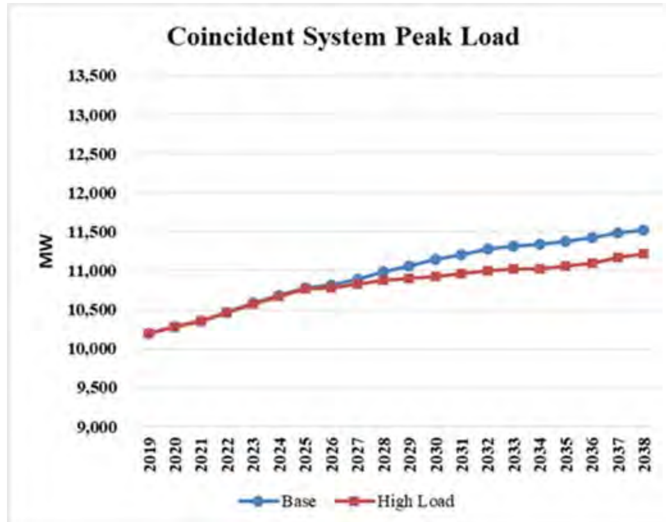
Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as cumulative nameplate capacity, are summarized in the figure below.

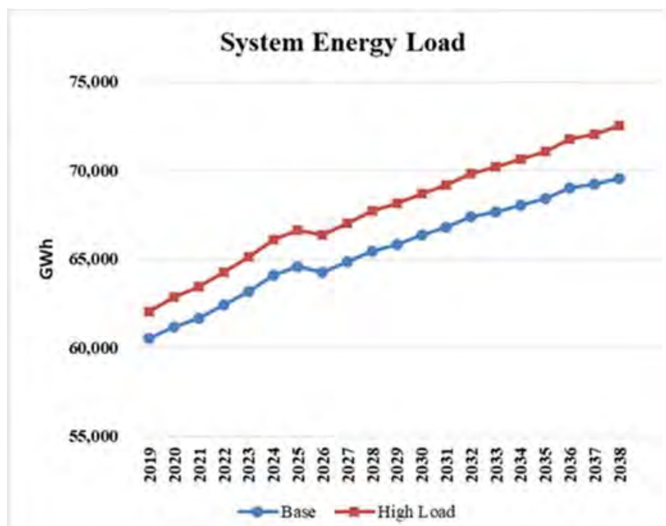


Load Forecast

The figure below shows the base system coincident peak load forecast applicable to this case before accounting for any potential contribution from DSM alongside Base Case forecast. Loads include private generation resources.



The figure below shows the base energy load forecast applicable to this case before accounting for any potential contribution from DSM alongside Base Case forecast. Loads include private generation resources.



Sensitivity Fact Sheets

Case Assumptions

Description
The 1-in-20 peak load sensitivity is a five percent probability extreme weather scenario. The 1-in-20 year peak weather is defined as the year for which the peak has the chance of occurring once in 20 years. This sensitivity is based on 1-in-20 peak weather for July in each state. This sensitivity is a variant of the preferred portfolio, P-45CNW.

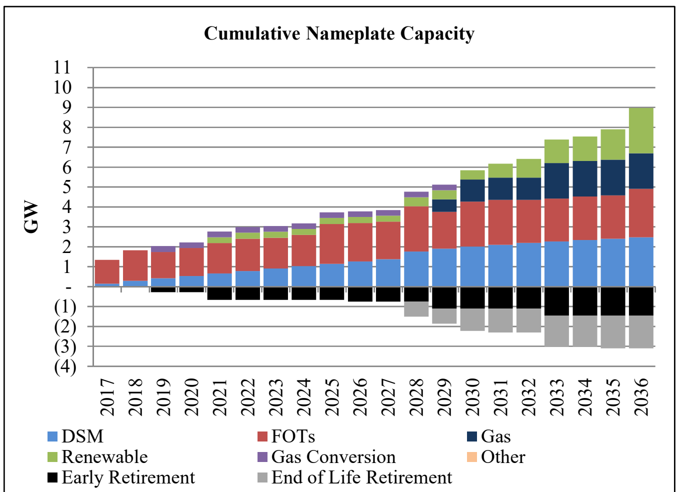
Portfolio Summary

System Optimizer PVRR ($m) ***$21,634***

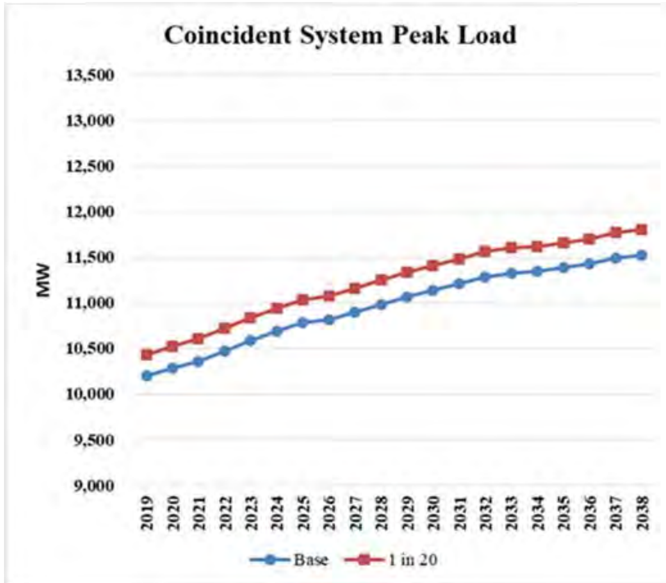
Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus Wyoming – to - Utah S	*2024*	*1,700*
Goshen – to – Utah N	*2030*	*800*
Yakima- to – S. Oregon/California	*2036*	*450*

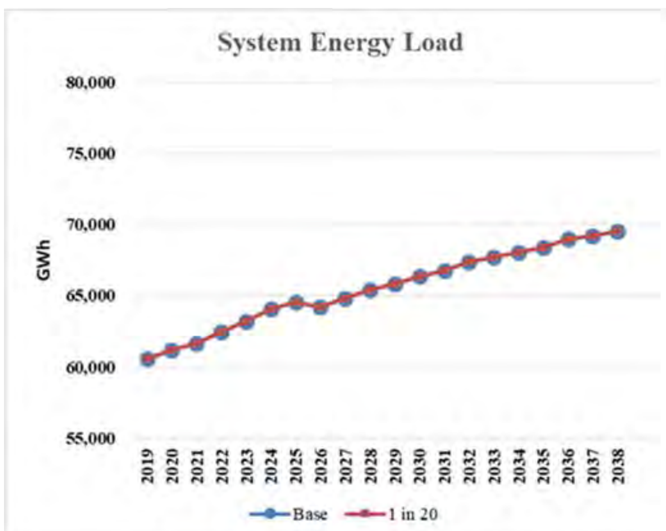
Resource Portfolio
Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as cumulative nameplate capacity, are summarized in the figure below.



Load Forecast
The figure below shows the base system coincident peak load forecast applicable to this case before accounting for any potential contribution from DSM alongside Base Case forecast. Loads include private generation resources. Energy load forecast is identical to Base Case.



The figure below shows the base energy load forecast applicable to this case before accounting for any potential contribution from DSM alongside Base Case forecast. Loads include private generation resources.



Sensitivity Fact Sheets

Case Assumptions

Description
The low private generation sensitivity reflects reductions in technology costs, reduced technology performance levels, and lower retail electricity rates, compared to base penetration levels incorporating annual reductions in technology costs. This sensitivity is a variant of the preferred portfolio, P-45CNW.

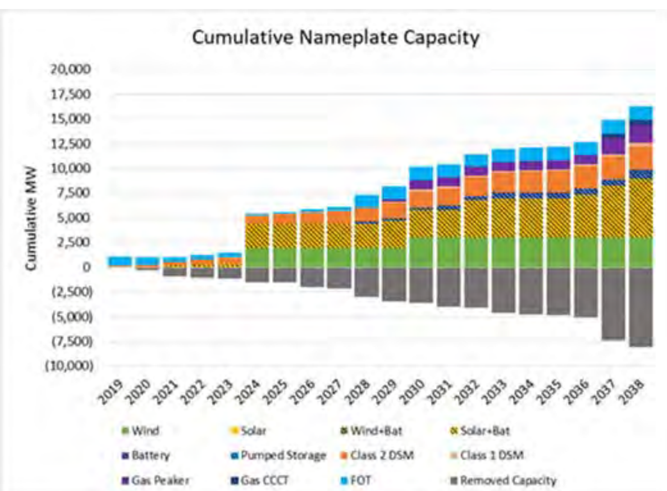
Portfolio Summary

System Optimizer PVRR ($m) $21,758

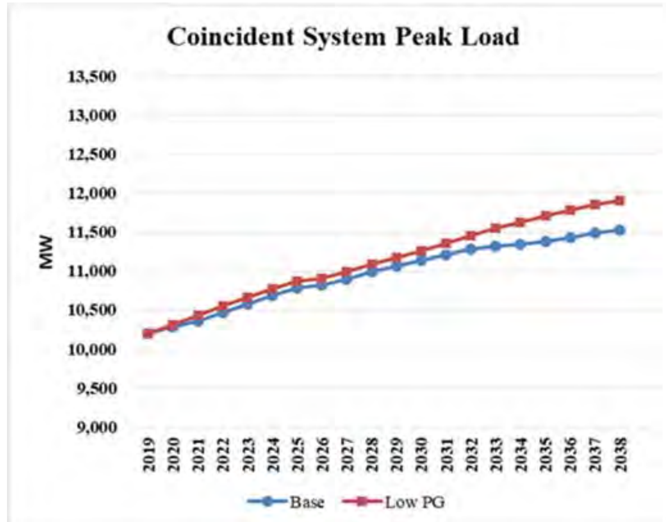
Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus Wyoming – to - Utah S	*2024*	*1,700*
Goshen – to – Utah N	*2030*	*800*
Yakima- to – S. Oregon/California	*2036*	*450*
Willamette Valle - to – S. OR/CA	*2037*	*1500*

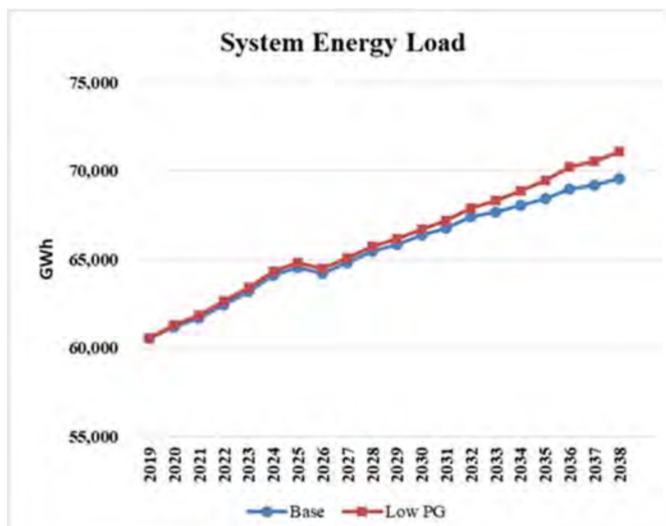
Resource Portfolio
Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as cumulative nameplate capacity, are summarized in the figure below.



Load Forecast
The figure below shows the base system coincident peak load forecast applicable to this case before accounting for any potential contribution from DSM alongside Base Case forecast. Loads include private generation resources.



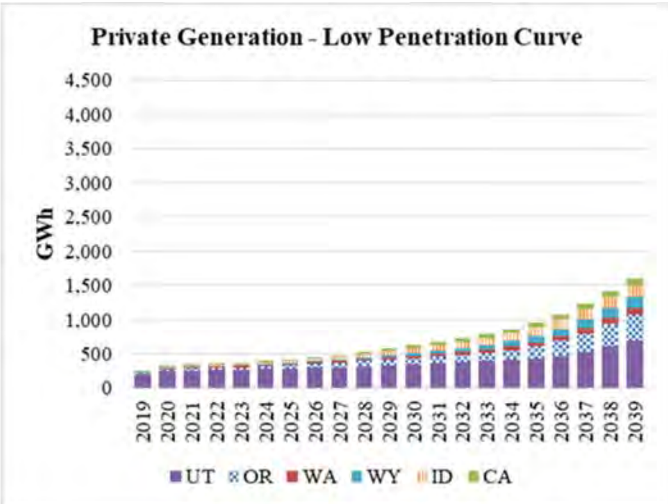
The figure below shows the base energy load forecast applicable to this case before accounting for any potential contribution from DSM alongside Base Case forecast. Loads include private generation resources.



Sensitivity: Low Private Generation (S-04)

Private Generation

Scenario private generation penetration by state and year are summarized in the following figure.



Sensitivity: High Private Generation (S-05)

Sensitivity Fact Sheets

CASE ASSUMPTIONS

Description
The high private generation sensitivity reflects more aggressive technology cost reduction assumptions, higher technology performance levels, and higher retail electricity rates, compared to base penetration levels incorporating annual reductions in technology costs. This sensitivity is a variant of the preferred portfolio, P-45CNW.

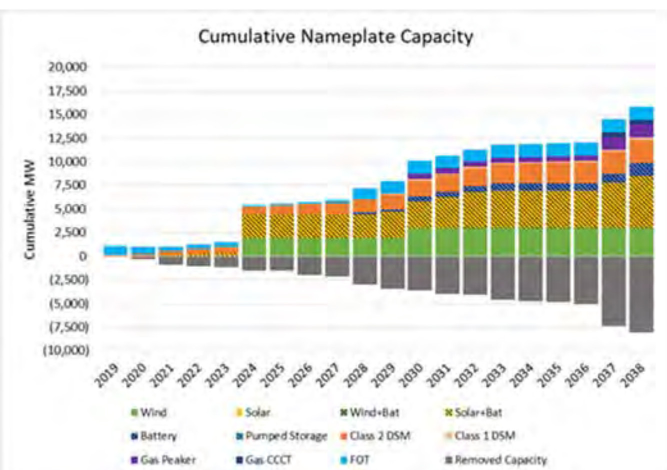
PORTFOLIO SUMMARY

System Optimizer PVRR ($m) $21,371

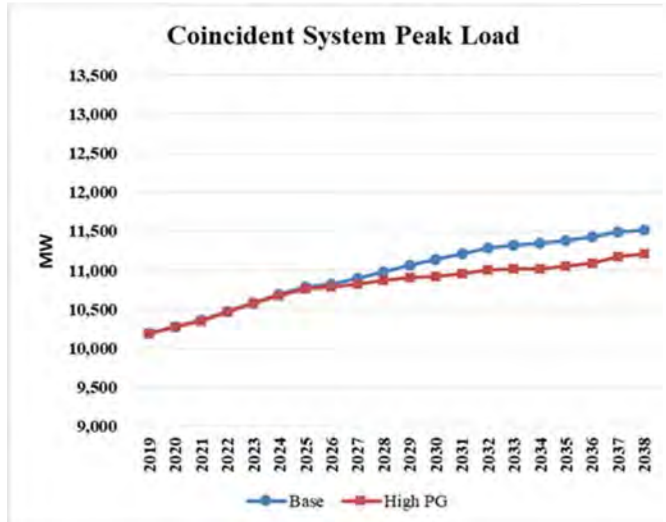
Incremental Transmission Upgrades

Description	***Year***	***Capacity***
Aeolus Wyoming – to - Utah S	*2024*	*1,700*
Goshen – to – Utah N	*2030*	*800*

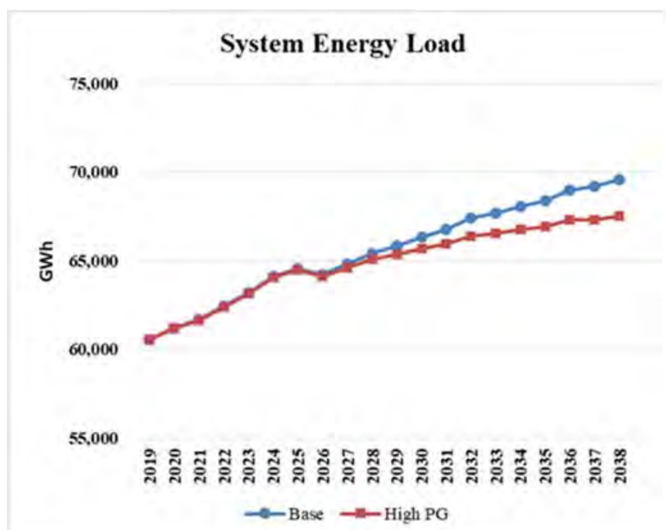
Resource Portfolio
Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as cumulative nameplate capacity, are summarized in the figure below.



Load Forecast
The figure below shows the base system coincident peak load forecast applicable to this case before accounting for any potential contribution from DSM alongside Base Case forecast. Loads include private generation resources.



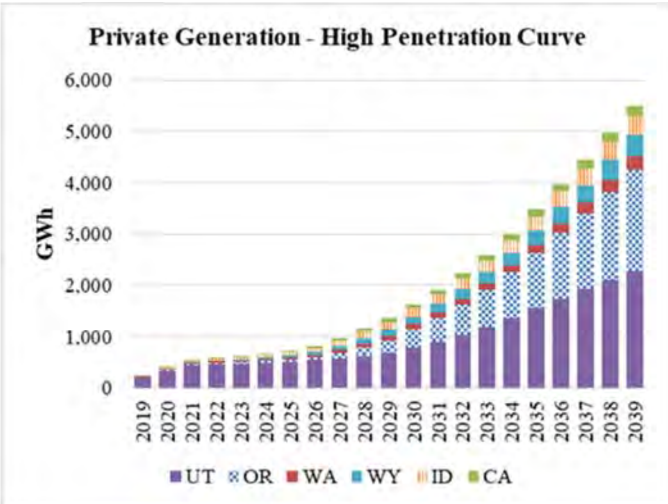
The figure below shows the base energy load forecast applicable to this case before accounting for any potential contribution from DSM alongside Base Case forecast. Loads include private generation resources.



Sensitivity: High Private Generation (S-05)

Private Generation

Scenario private generation penetration by state and year are summarized in the following figure.



Sensitivity Fact Sheets

CASE ASSUMPTIONS

Description

The Business Plan sensitivity complies with the Utah requirement to perform a business plan sensitivity consistent with the commission's order in Docket No. 15-035-04. Over the first three years, resources align with those assumed in PacifiCorp's December 2018 Business Plan. Beyond the first three years of the study period, unit retirement assumptions are aligned with the preferred portfolio. All other resources are optimized. This sensitivity is a variant of the preferred portfolio, P-45CNW.

PORTFOLIO SUMMARY

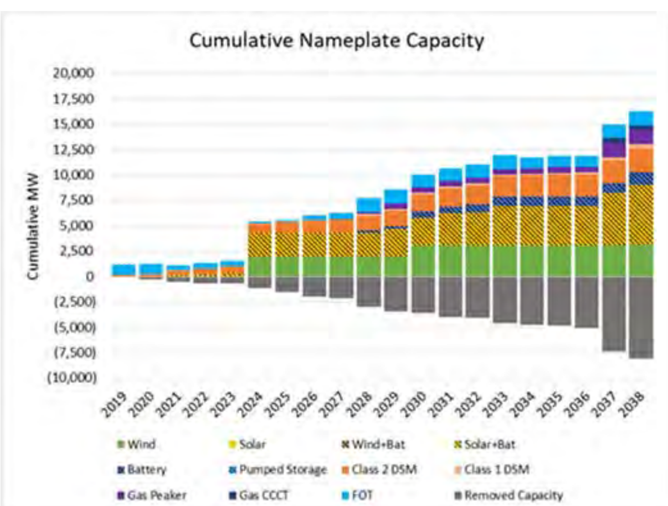
System Optimizer PVRR ($m) $21,695

Incremental Transmission Upgrades

Description	***Year***	***Capacity***
Aeolus Wyoming – to - Utah S	*2024*	*1,700*
Goshen – to – Utah N	*2030*	*800*
Yakima- to – S. OR/CA, Expansion	*2037*	*450*
Walla Walla- to - Yakima, Expansion	*2038*	*200*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as cumulative nameplate capacity, are summarized in the figure below.



Sensitivity Fact Sheets

CASE ASSUMPTIONS

Description

The No Customer Preference sensitivity reflects no renewable resources specifically assigned to customer preference, compared to base renewable resource proxy options. This sensitivity is a variant of the preferred portfolio, P-45CNW.

PORTFOLIO SUMMARY

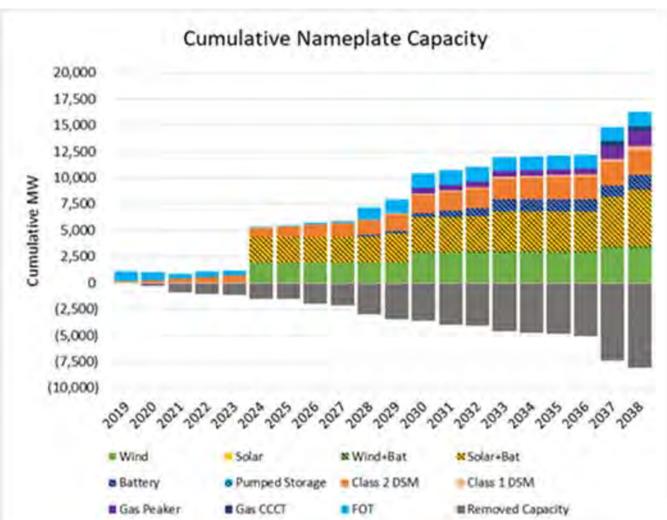
System Optimizer PVRR ($m) $21,609

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus Wyoming – to - Utah S	*2024*	*1,700*
Goshen – to – Utah N	*2030*	*800*
Yakima- to – S. Oregon/California	*2037*	*450*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as cumulative nameplate capacity, are summarized in the figure below.



Customer Preference

The figure below shows the difference between no, base and high Customer Preference Load scenarios for renewable resources.

Sensitivity: High Customer Preference (S-08)

Sensitivity Fact Sheets

CASE ASSUMPTIONS

Description
The High Customer Preference sensitivity reflects higher levels of renewable resource options assigned to customer preference, compared to base renewable resource proxy options. This sensitivity is a variant of the preferred portfolio, P-45CNW.

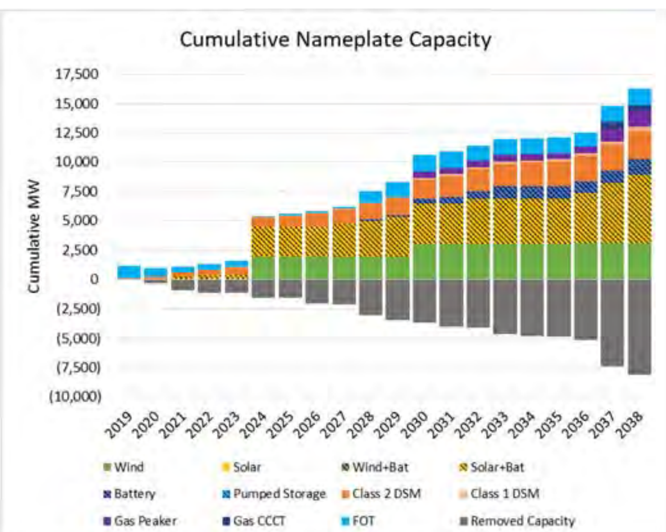
PORTFOLIO SUMMARY

System Optimizer PVRR ($m) ***$21,636***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus Wyoming – to - Utah S	*2024*	*1,700*
Goshen – to – Utah N	*2030*	*800*
Yakima- to – S. OR/CA, Expansion	*2036*	*450*

Resource Portfolio
Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as cumulative nameplate capacity, are summarized in the figure below.



Customer Preference
The figure below shows the difference between no, base and high Customer Preference Load scenarios for renewable resources.

APPENDIX N –CAPACITY CONTRIBUTION STUDY

Introduction

The capacity contribution of a resource is represented as a percentage of that resource's nameplate or maximum capacity and is a measure of the ability of a resource to reliably meet demand. This capacity contribution affects PacifiCorp's resource planning activities, which are intended to ensure there is sufficient capacity on its system to meet its load obligations inclusive of a planning reserve margin. To ensure resource adequacy is maintained over time, all resource portfolios evaluated in the integrated resource plan (IRP) have sufficient capacity to meet PacifiCorp's coincident peak load obligation inclusive of a planning reserve margin throughout a 20-year planning horizon. Consequently, planning for the coincident peak drives the amount and timing of new resources, while resource cost and performance metrics among a wide range of different resource alternatives drive the types of resources that can be chosen to minimize portfolio costs and risks.

In the 2017 IRP, PacifiCorp calculated peak capacity contribution values for wind and solar resources using the capacity factor approximation method (CF Method) as outlined in a 2012 report produced by the National Renewable Energy Laboratory (NREL Report)[1]. The CF Method calculates a capacity contribution based on a resource's expected availability during periods when the risk of loss of load events is highest, based on the loss of load probability (LOLP) in each hour.

At the outset of the 2019 IRP, PacifiCorp calculated updated peak capacity contribution values for an expanded range of resources in addition to wind and solar, including:

- Energy storage, such as batteries and pumped storage,
- Demand response programs,
- Energy efficiency measures,
- Combined wind and battery resources,
- Combined solar and battery resources,
- Natural gas resources.

To better account for the specific characteristics of the expanded range of resources considered, the initial capacity contribution analysis was enhanced from that used in the 2017 IRP to account for the following:

- Distinct capacity contribution values for the summer and winter peaks;
- More granular analysis of LOLP event data to determine capacity contribution values for duration-limited resources such as energy storage and interruptible load programs;
- The impact of peak-producing temperatures on the maximum output of natural gas plants;
- Declining capacity contributions from wind and solar as penetration increases.

[1] Madaeni, S. H.; Sioshansi, R.; and Denholm, P. "Comparison of Capacity Value Methods for Photovoltaics in the Western United States." NREL/TP-6A20-54704, Denver, CO: National Renewable Energy Laboratory, July 2012 (NREL Report) at: www.nrel.gov/docs/fy12osti/54704.pdf

The first three enhancements reflect the CF Method at a more granular level than was considered previously. The final modification uses much of the same inputs and calculations as the CF Method, but examines how reliability varies as a function of changes in the portfolio of resources using a more data-intensive analysis that is comparable to the equivalent conventional power method (ECP Method) described in the NREL Report. In all cases, capacity contribution values reflect the expected availability of resources when the risk of loss of load events is highest.

Both the CF Method and ECP Method rely on loss of load event data associated with PacifiCorp's loads and portfolio of resources. As such, selecting an appropriate portfolio as the basis of this data is important. For the 2019 IRP, the LOLP data used in the initial CF Method is derived from the same portfolio analysis used to select a planning reserve margin, as discussed in Volume II, Appendix I (Planning Reserve Margin Study). Specifically, the LOLP data starts with the 2030 test year results. Because there are so few events in the winter in this data, their distribution appears to be driven by random outage events more than the composition of PacifiCorp's portfolio. To produce a more accurate winter LOLP profile, PacifiCorp replaced the winter events in the 2030 data with the distribution of winter events in the 2036 studies and prorated the results such that the level of outages in the winter season was unchanged.

The ECP Method analysis demonstrates that incremental additions of solar resources have a declining capacity contribution, and that incremental additions of wind resources have a declining capacity contribution. However, these effects do not occur in isolation. For instance, to the extent the additional solar generation is reducing loss of load events during times when wind is low, the remaining loss of load events may occur during times when wind generation is high, resulting in a higher capacity contribution for wind. The portfolio impacts are highest for resources whose output varies across the day and by season, including wind and solar as well as energy efficiency. Portfolio impacts are also relevant to energy limited resources, including energy storage and demand response programs. At the extreme, a portfolio with only energy storage resources has no capacity, since those resources would be unable to charge. In general, adding more energy resources (e.g. wind, solar, thermal, or energy efficiency) will increase the capacity contribution of a given penetration of energy storage resources.

While these portfolio impacts are important, it is not feasible to calculate capacity contribution values for all resources in all possible portfolio combinations. Capacity contribution values are intended to identify a resource's ability to avoid loss of load events, but this is just a preliminary step in the creation of a reliable portfolio. With this outcome in mind, PacifiCorp evaluated the reliability of every portfolio and ensured that the combination of resources in every portfolio achieved a targeted level of reliability.

Although every portfolio is reliable, as a result of portfolio effects and reliability adjustments the capacity contributions attributable to various resource types is uncertain. To help shed light on this, PacifiCorp conducted an additional CF Method analysis based on a 2030 test year and the P-45CP portfolio.[2] The P-45CP portfolio has significant differences from the portfolio used in the initial CF Method results, including additional coal retirements and significantly more wind, solar, and energy storage resources. This final CF Method analysis provides a reasonable capacity contribution value so long as the changes relative to the preferred portfolio are small, since in

[2] The study for the CF Method analysis is lengthy, and there was not time to repeat it based on the final preferred portfolio, which has relatively slight differences. This additional CF Method analysis was not a factor in final portfolio selection.

effect, the CF Method calculates the marginal capacity contribution of a one megawatt resource addition. Note, this is not the same as the average capacity contribution of each megawatt of that resource type already included in the portfolio.

CF Methodology

The NREL Report summarizes several methods for estimating the capacity value of renewable resources that are broadly categorized into two classes: 1) reliability-based methods that are computationally intensive; and 2) approximation methods that use simplified calculations to approximate reliability-based results. The NREL Report references a study from Milligan and Parsons that evaluated capacity factor approximation methods, which use capacity factor data among varying sets of hours, relative to a more computationally intensive reliability-based metric. As discussed in the NREL Report, the CF Method was found to be the most dependable technique in deriving capacity contribution values that approximate those developed using a reliability-based metric.

As described in the NREL Report, the CF Method "considers the capacity factor of a generator over a subset of periods during which the system faces a high risk of an outage event." When using the CF Method, hourly LOLP is calculated and then weighting factors are obtained by dividing each hour's LOLP by the total LOLP over the period. These weighting factors are then applied to the contemporaneous hourly capacity factors for a wind or solar resource to produce a weighted average capacity contribution value.

The weighting factors based on LOLP are defined as:

$$w_i = \frac{LOLP_i}{\sum_{j=1}^{T} LOLP_j}$$

where w_i is the weight in hour i, $LOLP_i$ is the LOLP in hour i, and T is the number of hours in the study period, which is 8,760 hours for the current study. These weights are then used to calculate the weighted average capacity factor as an approximation of the capacity contribution as:

$$CV = \sum_{i=1}^{T} w_i C_i,$$

where C_i is the capacity factor of the resource in hour i, and CV is the weighted capacity value of the resource.

For fixed profile resources, including wind, solar, and energy efficiency, the average LOLP values across all iterations are sufficient, as the output of these resources is the same in each iteration. To determine the capacity contribution of fixed profile resources using the CF Method, PacifiCorp implemented the following three steps:

1. A 500-iteration hourly Monte Carlo simulation of PacifiCorp's system was produced using the Planning and Risk (PaR) model to simulate the dispatch of PacifiCorp's system for the

sample year.[3] This PaR study is based on PacifiCorp's 2019 IRP planning reserve margin study using a 13 percent target planning reserve margin level and the loss of load event data reflect PacifiCorp's participation in the Northwest Power Pool (NWPP) reserve sharing agreement, which allows a participant to receive energy from other participants within the first hour of a contingency event. The LOLP for each hour in the year is calculated by counting the number of iterations in which system load could not be met with available resources and dividing by 500 (the total number of iterations). For example, if in hour 19 on December 22nd there are three iterations with Energy Not Served (ENS) out of a total of 500 iterations, then the LOLP for that hour would be 0.6 percent.[4]

2. Weighting factors were determined based upon the LOLP in each hour divided by the sum of LOLP among all hours within the same summer or winter season. In the example noted above, the sum of LOLP among all winter hours is 58 percent.[5] The weighting factor for hour 19 on December 22nd would be 1.0417 percent.[6] This means that 1.0417 percent of all winter loss of load events occurred in hour 19 on December 22nd and that a resource delivering in only in that single hour would have a winter capacity contribution of 1.0417 percent.

3. The hourly weighting factors are then applied to the capacity factors of fixed profile resources in the corresponding hours to determine the weighted capacity contribution value in those hours. Extending the example noted, if a resource has a capacity factor of 41.0 percent in hour 19 on December 22nd, its weighted winter capacity contribution for that hour would be 0.4271 percent.[7]

For resources which are energy limited, such as energy storage or demand response programs, the LOLP values in each iteration must be examined independently, to ensure that the available storage or control hours are sufficient. Continuing the example of December 22nd described above, consider if hour 18 and hour 19 both have three ENS hours out of 500 iterations. If all six ENS hours are in different iterations, a 1-hour energy storage resource could cover all six hours. However, if the six ENS hours are in the same three iterations in hour 18 and hour 19 (i.e. 2 hour duration events), then a 1-hour storage resource could only cover three of the six ENS hours.

ECP Methodology

The ECP Method identifies how much of a conventional resource can be removed when the resource being evaluated (typically a renewable resource) is added, while maintaining the same system reliability level. Unlike the CF Method, which uses the reliability results from a single study, the ECP Method requires at least two studies. While the CF Method can produce an estimate for any resource profile and represents a single megawatt of resource additions, the ECP Method

[3] Initial CF method results were based on a composite sample year, containing ENS data from a 2030 study period for June through September, and data from a 2036 study period for October through May. These time periods correspond with the periods used to determine summer and winter capacity contribution inputs, respectively.
[4] 0.6 percent = 3 / 500.
[5] For each hour, the hourly LOLP is calculated as the number of iterations with ENS divided by the total of 500 iterations. There are 288 winter ENS iteration-hours out of total of 5,832 winter hours. As a result, the sum of LOLP for the winter is 288 / 500 = 58 percent. There are 579 summer ENS iteration-hours out of total of 2,928 summer hours. As a result, the sum of LOLP for the summer is 579 / 500 = 116 percent.
[6] 1.0417 percent = 0.6 percent / 58 percent, or simply 1.0417 percent = 3 / 288.
[7] 0.4271 percent = 1.0417 percent x 41.0 percent.

produces an estimate for a specific resource profile and a specific megawatt quantity. Just like the CF Method, the ECP Method is dependent on the composition of the starting portfolio. While the ECP Method distills a capacity contribution down to a single value, the studies can also be used with the CF Method to differentiate between periods and resource profiles.

At the outset of the 2019 IRP, PacifiCorp used the ECP method to evaluate wind and solar capacity contributions in four portfolios with varying wind and solar penetrations. The results of these studies were used to estimate the capacity contribution of the wind and solar resources in PacifiCorp's initial portfolio, as well as to estimate the capacity contributions of higher penetrations of wind and solar capacity.

Table N.1 – ECP Method Capacity Contribution Values for Wind and Solar

Study	Nameplate Capacity (MW)	
	Wind	**Solar**
No wind or solar	0	0
No wind	0	2,218
No solar	3,722	0
Initial Portfolio	3,722	2,218
Capacity Contribution of Initial Portfolio		
MW	852	955
%	23%	43%
Capacity Contribution of Incremental Resources		
+1000 MW	15%	15%
+2000 MW	12%	2%
+3000 MW	6%	0%
+4000 MW	1%	0%

This ECP analysis reflects system-wide results based on the characteristics of existing assets, while capacity contribution is inherently related to the characteristics of specific resources. For instance, the latest wind and solar technology may produce higher capacity factors and higher capacity contributions on a per megawatt basis. To account for this, the ECP-based contribution values are not applied directly to the future resources. Instead, the CF Method is applied to individual resources and the results are de-rated by a uniform percentage as successive blocks are reached. To help limit the modeling complexity, two blocks of capacity contribution value for wind and solar were modeled for portfolio selection. The "high" capacity contribution block allowed for up to 2,000 megawatt (MW) of new wind capacity and 1,000 MW of new solar capacity (roughly a 50 percent increase from the initial portfolio levels). Any additional wind and solar capacity beyond the first block was assigned a "low" capacity contribution value, calculated based on an additional 2,000 MW of new wind capacity and 1,000 MW of new solar capacity.

Natural Gas Resources

As ambient temperature rises, the maximum output from many natural gas resources declines. In previous IRPs, the maximum output of natural gas plants was set on a monthly basis, based on average ambient conditions at the plant site for each month. In the development of capacity contribution values for the 2019 IRP, PacifiCorp identified a mismatch between the temperature underlying the maximum output of natural gas units and the peak-producing temperatures on the hottest days in the summer which have the highest risk of loss of load events and drive capacity needs.

To better account for the capability of natural gas resources during peak conditions, the monthly maximum output of existing and potential natural gas units was modified during the summer months of July through September. During these months, the maximum output was calculated based on peak-producing temperatures, rather than average temperatures. This reduction in the maximum output of these resources directly impacts their summer capacity contribution, as well as their ability to provide generation and reserves.

Portfolio-Development Inputs

Table N.2 summarizes the capacity contribution inputs used in the portfolio-development process for stand-alone renewable and storage resources, developed using the methodologies described above.

Table N.2 – Initial Capacity Contribution Values for Wind, Solar, and Storage

	Capacity Factor (%)	Capacity Contribution (%)				
IRP:		**2017**	**2019**	**2019**	**2019**	**2019**
Summer/Winter:	**Annual**	**Annual**	**S**	**W**	**S**	**W**
Solar			**Block 1**		**Block 2**	
Idaho Falls, ID	28%	60%	27%	6%	4%	1%
Lakeview, OR	29%	65%	36%	7%	6%	1%
Milford, UT	32%	60%	20%	15%	3%	2%
Yakima, WA	25%	65%	35%	4%	5%	1%
Rock Springs, WY	30%	60%	22%	10%	3%	2%
Wind			**Block 1**		**Block 2**	
Pocatello, ID	37%	16%	20%	25%	4%	6%
Arlington, OR	37%	12%	37%	16%	9%	4%
Monticello, UT	29%	16%	14%	19%	3%	4%
Goldendale, WA	37%	12%	37%	15%	9%	3%
Medicine Bow, WY	44%	16%	17%	38%	4%	9%
Stand-alone Storage						
2 hour duration			67%	85%		
4 hour duration			91%	99%		
9 hour duration			100%	100%		

When wind and solar resources are combined with storage, the combined resource has a higher capacity contribution than the renewable resource on its own. For the purposes of the 2019 IRP, lithium-ion battery storage can be selected with either wind or solar resources. Combined storage is modeled with a maximum output equal to 25 percent of the renewable resource nameplate and a four-hour storage duration. This combined resource is assumed to be limited to the renewable resource nameplate. Because of this limit to the combined output, the capacity contribution of a renewable and storage is not strictly additive. When renewable resource output exceeds 75 percent during individual hours with ENS under the CF Method, the addition of the battery can only increase the combined resource's capacity contribution to 100 percent for that hour. While such hours are relatively uncommon, the incremental capacity from the combined battery is reduced relative to a stand-alone battery. Table N.3 summarizes the capacity contribution inputs for renewable resources combined with storage.

Table N.3 – Initial Capacity Contribution Values for Wind and Solar Combined with Storage

	Capacity Factor (%)	Capacity Contribution (%)			
IRP:	**n/a**	**2019**	**2019**	**2019**	**2019**
Summer/Winter:	**Annual**	**S**	**W**	**S**	**W**
Solar & Storage		**Block 1**		**Block 2**	
Idaho Falls, ID	28%	48%	31%	26%	26%
Lakeview, OR	29%	58%	32%	27%	26%
Milford, UT	32%	42%	40%	25%	27%
Yakima, WA	25%	56%	29%	27%	25%
Rock Springs, WY	30%	44%	35%	26%	26%
Wind & Storage		**Block 1**		**Block 2**	
Pocatello, ID	37%	42%	47%	27%	28%
Arlington, OR	37%	55%	40%	26%	28%
Monticello, UT	29%	37%	44%	26%	29%
Goldendale, WA	37%	55%	39%	26%	28%
Medicine Bow, WY	44%	39%	57%	26%	28%

Reliability Assessment

The capacity contribution values described above are entered into the System Optimizer model, as one of a variety of parameters used to select an optimized portfolio of expansion resources. Once this portfolio is produced, PacifiCorp conducts a deterministic reliability assessment to assess the reliability of the resulting portfolio. Additional details on this process are provided in the Reliability Study Methodology section of Volume II, Appendix R (Coal Studies).

The deterministic reliability assessment identifies the quantity of incremental resources (if any) necessary to reliably meet load and all operating reserve requirements. If an incremental resource need is identified, the System Optimizer model is rerun with the ability to add or accelerate batteries, energy efficiency, gas peakers, and pumped hydro, relative to the pre-reliability portfolio. This process is analogous to the ECP Method described above in that it sets a uniform reliability target and adds conventional resources to portfolios that do not meet the target.

While the reliability assessment ensures each portfolio is reliable, it does not identify the individual contributions of the resources in that portfolio. For details on the effective capacity provided by the company's existing portfolio and new resources in the preferred portfolio, please refer to

Volume I, Chapter 5 (Resource Needs Assessment). To develop the results in Chapter 5, PacifiCorp first calculated the final CF Method capacity contribution values described below for resources other than wind and solar. Since the portfolio as a whole is reliable, the remaining capacity up to the targeted level of reliability is attributable to wind and solar. This remaining capacity was allocated to each wind and solar resource based on the wind and solar penetration analysis and the final CF Method results.

Final CF Method Results

PacifiCorp conducted an additional CF Method analysis during the final portfolio selection process based on a 2030 test year and the P-45CP portfolio. The P-45CP portfolio has significant differences from the portfolio used in the initial CF Method results, including additional coal retirements and significantly more wind, solar, and energy storage resources. As a result of these portfolio changes, the CF Method results can vary from the initial CF Method results.

The final CF Method results described below provide a reasonable capacity contribution value so long as the changes relative to the preferred portfolio are small, since in effect, the CF Method calculates the marginal capacity contribution of a one megawatt resource addition. Note, this is not the same as the average capacity contribution of each megawatt of that resource type already included in the portfolio.

Table N.4 – Final CF Method Capacity Contribution Values for Wind, Solar, and Storage

	Capacity Factor (%)	Capacity Contribution (%)	
Summer/Winter:	**Annual**	**S**	**W**
Solar			
Idaho Falls, ID	28%	12%	13%
Lakeview, OR	29%	15%	14%
Milford, UT	32%	10%	23%
Yakima, WA	25%	12%	10%
Rock Springs, WY	30%	11%	19%
Wind			
Pocatello, ID	37%	19%	27%
Arlington, OR	37%	57%	21%
Monticello, UT	29%	18%	22%
Goldendale, WA	37%	57%	21%
Medicine Bow, WY	44%	13%	35%
Stand-alone Storage			
2 hour duration		78%	89%
4 hour duration		94%	100%
9 hour duration		98%	100%

Table N.5 – Final CF Method Capacity Contribution Values for Wind and Solar Combined with Storage

	Capacity Factor (%)	Capacity Contribution (%)	
Summer/Winter:	**Annual**	**S**	**W**
Solar & Storage			
Idaho Falls, ID	28%	33%	37%
Lakeview, OR	29%	35%	39%
Milford, UT	32%	30%	48%
Yakima, WA	25%	33%	34%
Rock Springs, WY	30%	31%	43%
Wind & Storage			
Pocatello, ID	37%	38%	50%
Arlington, OR	37%	77%	44%
Monticello, UT	29%	37%	44%
Goldendale, WA	37%	76%	44%
Medicine Bow, WY	44%	32%	58%

The CF Method results are derived from a one year study period (2030) and ENS events are identified separately for every hour in that period. The details of the wind and solar resource modeling in the study period are important for interpreting the results. Where available, that study includes wind and solar shapes that also reflect specific volumes for each hour in the period, including the effects of calm and cloudy days on resource output. Where data was available, the modeled generation profiles for proxy resources are derived from calendar year 2017 hourly generation profiles of existing resources, adjusted to align with the expected annual output of each proxy resource. While the use of a single historical year can produce a reasonable forecast of wind and solar output, including a correlation between the two, additional work is needed in future IRPs to explore the variation and diversity of solar and wind output, and the relationships with load, particularly under peak load conditions.

The use of correlated hourly shapes produces variability across each month and a reasonable correlation between resources in close proximity. It also results in days with higher generation and days with lower generation in each month. As one would expect, days with lower renewable generation are more likely to result in ENS events. As a result, basing CF Method capacity contribution calculations on an average or 12-month by 24-hour forecast of renewable generation will tend to overstate capacity contribution, particularly if there is a significant quantity of resources of the same type already in the portfolio, or if an appreciable quantity of resource additions are being contemplated.

APPENDIX O – PRIVATE GENERATION STUDY

Introduction

Navigant Consulting, Inc. prepared the Private Generation Long-Term Resource Assessment (2019-2038) for PacifiCorp. A key objective of this research is to assist PacifiCorp in developing private generation resource penetration forecasts to support its 2019 Integrated Resource Plan. The purpose of this study is to project the level of private generation resources PacifiCorp's customers might install over the next twenty years.

Private Generation Long-Term Resource Assessment (2019-2038)

Prepared for:

PacifiCorp

Prepared by:

Jay Paidipati
Shalom Goffri
Andrea Romano
Ryan Auker

August 15th, 2018

Navigant Consulting, Inc.
1375 Walnut Street, Suite 100
Boulder, CO 80302

415.356.7100
navigant.com

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August 15th, 2018

EXECUTIVE SUMMARY

Navigant Consulting, Inc. (Navigant) prepared this Private Generation Long-term Resource Assessment on behalf of PacifiCorp. In this study private generation (PG) sources provide customer-sited (behind the meter) energy generation and are generally of relatively small size, generating less than the amount of energy used at a location. The purpose of this study is to support PacifiCorp's 2019 Integrated Resource Plan (IRP) by projecting the level of private generation resources PacifiCorp's customers might install over the next twenty years under base, low, and high penetration scenarios.

This study builds on Navigant's previous assessments, [1, 2] which supported PacifiCorp's 2015 and 2017 IRP, incorporating updated load forecasts, market data, technology cost and performance projections. Navigant evaluated five private generation technologies in detail in this report:

1. Photovoltaic (Solar) Systems
2. Small Scale Wind
3. Small Scale Hydro
4. Reciprocating Engines
5. Micro-turbines

Project sizes were determined based on average customer load across the commercial, irrigation, industrial and residential customer classes.

Private generation technical potential [3] and expected market penetration[4] for each technology was estimated for each major customer class in each state in PacifiCorp's service territory. Shown in Figure 1, PacifiCorp serves customers in California, Idaho, Oregon, Utah, Washington, and Wyoming.

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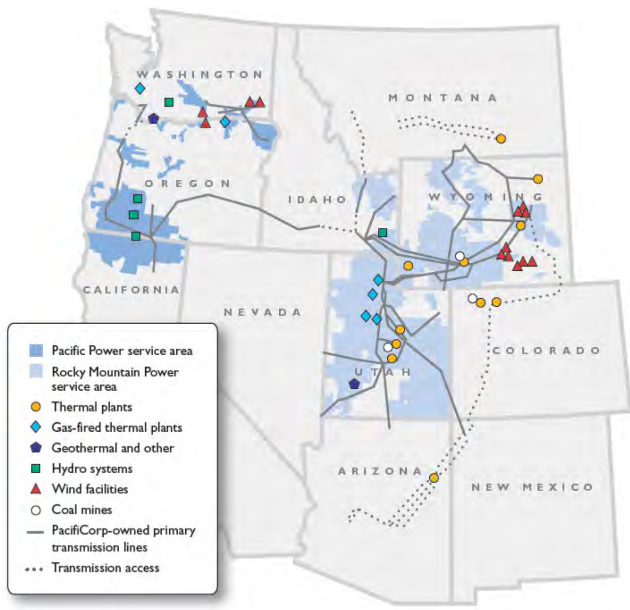
[1] Navigant, Distributed Generation Resource Assessment for Long-Term Planning Study, http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2015IRP/2015IRPStudy/Navigant_Distributed-Generation-Resource-Study_06-09-2014.pdf.

[2] Navigant, Private Generation Long-Term Resource Assessment (2017-2036), http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/PacifiCorp_IRP_PG_Resource_Assessment_Final.pdf.

[3] Total resource potential factoring out resources that cannot be accessed due to non-economic reasons (i.e. land use restrictions, siting constraints and regulatory prohibitions), including those specific to each technology. Technical potential does not vary by scenario.

[4] Based on economic potential (technical potential that can be developed because it's not more expensive than competing options), estimates the timeline associated with the diffusion of the technology into the marketplace, considering the technology's relative economics, maturity, and development timeline.

Figure 1 PacifiCorp Service Territory[5]



Key Findings

Using PacifiCorp-specific information on customer size and retail rates in each state and public data sources for technology costs and performance, Navigant conducted a payback analysis and used Fisher-Pry[6] diffusion curves to determine likely market penetration for PG technologies from 2019 to 2038. This analysis was performed for typical commercial, irrigation, industrial and residential PacifiCorp customers in each state.

In the base scenario, Navigant estimates approximately 1.3 GW AC of PG capacity will be installed in PacifiCorp's territory from 2019-2038.[7] As shown in Figure 2, the low and high scenarios project a cumulative installed capacity of 0.6 GW AC and 2.3 GW AC, respectively. The main differences between scenarios include variation in technology costs, system performance, and electricity rate escalation assumptions. These assumptions are provided in Table 8.

[5] http://www.pacificorp.com/content/dam/pacificorp/doc/About_Us/Company_Overview/Service_Area_Map.pdf.

[6] Fisher-Pry are researchers who studied the economics of "S-curves", which describe how quickly products penetrate the market. They codified their findings based on payback period, which measures how long it takes to recoup initial high first costs with energy savings over time.

[7] All capacity numbers across all five resources are projected in MW-AC. Figures throughout the report are all in MW-AC.

Figure 2 Cumulative Market Penetration Results (MW AC), 2019 – 2038

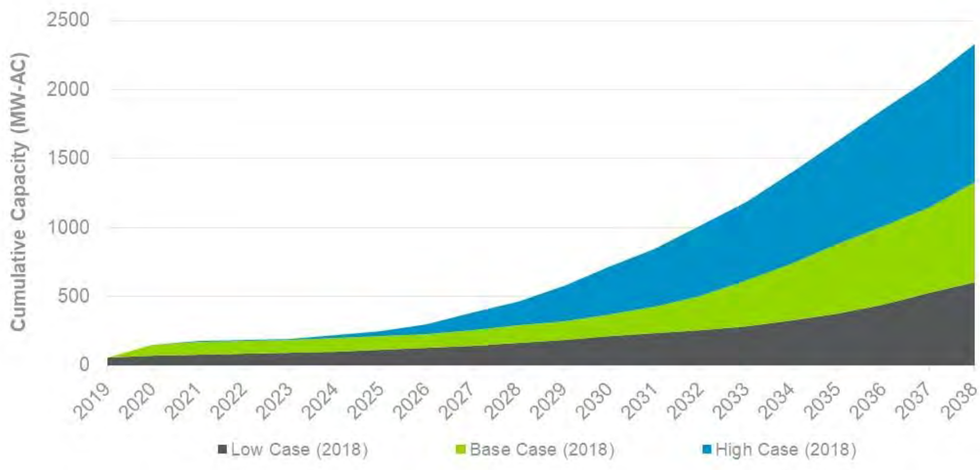


Figure 3 indicates that Utah and Oregon will drive most PG installations over the next two decades, largely because these two states are PacifiCorp's largest markets in terms of customers and sales[8]. Reference APPENDIX A for detailed state-specific customer data. In both states, PG installations are also driven by local tax credits and incentives. As displayed in Figure 4, solar represents the highest expected market penetration across the five technologies examined, with residential solar development leading the way, followed by non-residential solar (commercial, industrial, and irrigation). The Results section of the report contains results by state and technology for the high, base, and low scenarios.

Figure 3 also compares this study's results to Navigant's 2016 report. The three main factors that impacted the adoption results from 2016 to 2018 include: electric rate, system cost and policy. Reference

Table 1 for a detailed comparison of the 2016 and 2018 adoption results. In the short-term, factors impacting adoption have a dampening effect on the market, yet more aggressive reduction in solar PV system costs longer-term, result in increased adoption over time. In 2036, the latest year in both studies, cumulative adoption in the base case is around 1000 MW in the 2018 study and around 1200 MW in the 2016 study.

[8] The report reflects the regulatory modifications to the PG program in Utah, as included in Schedule 136 (Utah Docket 14-035-114)

Figure 3 Cumulative Market Penetration Results by State (MW AC), 2019 – 2038, Base Case

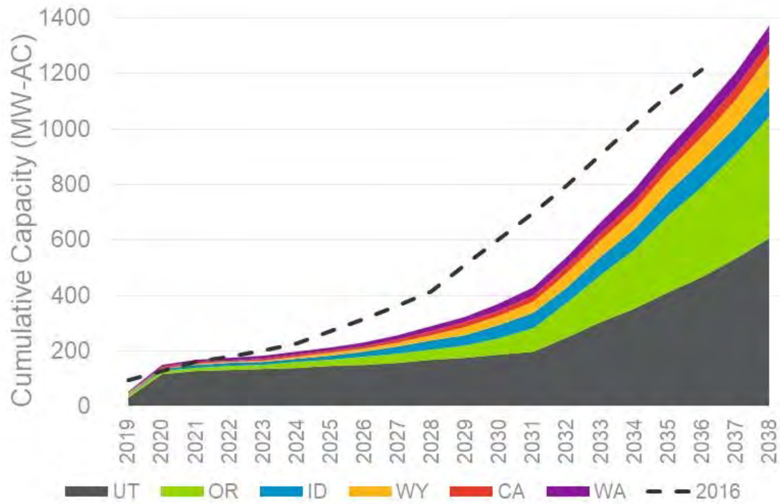
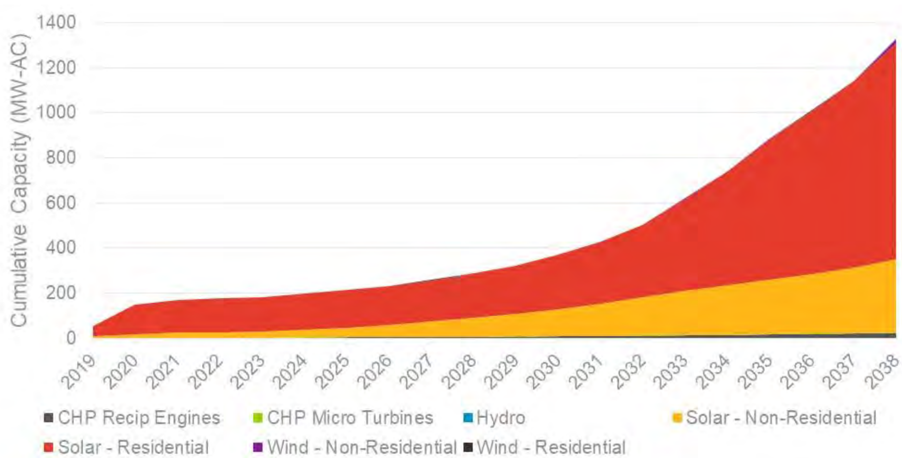


Figure 4 Cumulative Market Penetration Results by Technology (MW AC), 2019 – 2038, Base Case



The main factors that impacted the adoption results from 2016 to 2018 include: retail rates, system cost and policy. In general, the rates used in this study changed relative to the 2016 study as PacifiCorp's ability to calculate more accurate offset rates has increased. The technologies have not changed substantially since 2016, except for solar PV, where costs have continued to decline more rapidly than expected with ongoing declines expected in the future. Solar PV policies in key states (e.g., California, Oregon, Utah and Washington) have continued to fluctuate with an impact on expected near-term and long-term adoption. These changes between the 2016 and 2018 analysis are detailed in

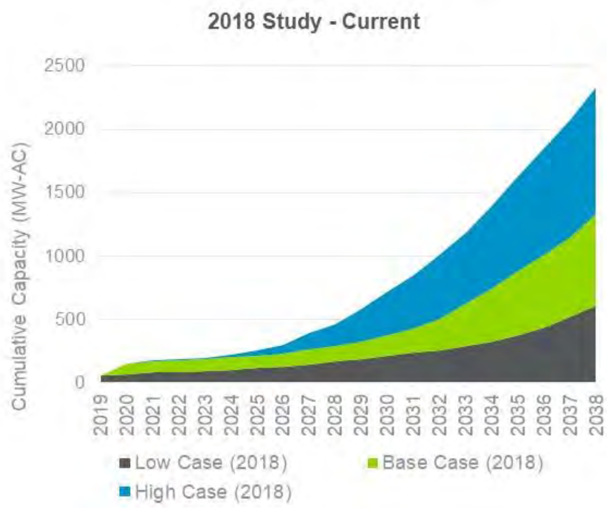
Table 1.

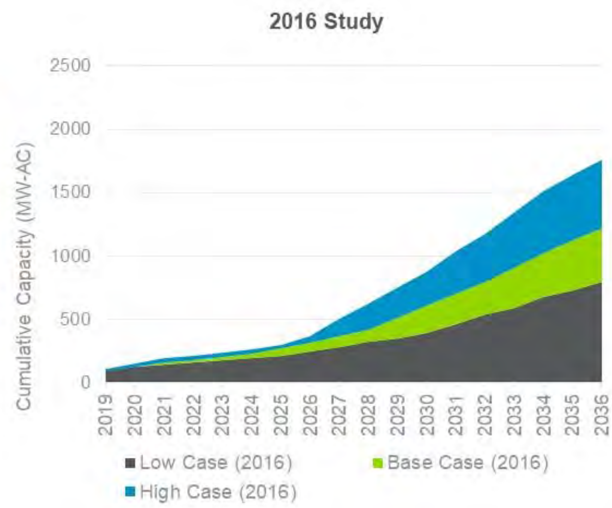
Table 1 Adoption Change from Electric Rate, System Cost and Policy Changes from 2016 to 2018

State	Estimated Adoption Change	Key Adoption Drivers
CA	**2036** – Market increased from 20 MW to 40 MW	• Rates: Increase (residential, commercial, industrial) • Solar PV Cost: Declines in the later years are more sustained • Policy: New mandatory solar for new building is included in the analysis
ID	**2036** – Market increased from 40 MW to 90 MW, primarily in the residential sector	• Rates: Increase (residential, commercial, industrial) • Solar PV Cost: Declines in the later years are more sustained • Policy: No change
OR	**2036** – Market remained relatively consistent, with adoption shifting to later years which seems reasonable given incentive declines offset by cost declines in future years	• Rates: Decrease (commercial, irrigation) • Solar PV Cost: Declines in the later years are more sustained • Policy: Incentive and cap reduced for residential and C&I; Residential Energy Tax Credit – sunset in 2017
UT	**2036** – Market decreased from 800 MW to 470 MW. Decline seems reasonable given residential incentive declines, and commercial rate declines	• Rates: Reduced net metering rates • Solar PV Cost: Declines in the later years are more sustained • Policy: Incentive for residential solar PV reduced from $2000 to $1600 in 2019 declining to $400 in 2024 and $0 beyond; NEM reduction to around 90% of full rates • The report reflects the regulatory modifications to the PG program in Utah, as included in Schedule 136 (Utah Docket 14-035-114)
WA	**2036** – Market increased from 25 MW to 50 MW	• Rates: Small changes only • Solar PV Cost: Declines in the later years are more sustained • Policy: Solar and wind FiT reduced rate for an 8 year period
WY	**2036** – Market increased from 40 MW to 85 MW	• Rate: Small changes only • Solar PV Cost: Declines in the later years are more sustained • Policy: None

The impact of these factors, in aggregate, on PG adoption are shown in Figure 5. In the short-term, factors impacting adoption have a dampening effect on the market, yet more aggressive reduction in solar PV system costs longer-term, result in increased adoption over time. In 2036, the latest year in both studies, cumulative adoption in the base case is around 1,000 MW in the 2018 study and around 1,200 MW in the 2016 study.

Figure 5 Cumulative Market Penetration Results by Scenario (MW AC), 2018 and 2016 Study





Report Organization

The report is organized as follows:

- Private Generation Market Penetration Methodology

- Results
- APPENDIX A: Customer Data
- APPENDIX B: System Capacity Assumptions
- APPENDIX C: Detailed Numeric Results

PRIVATE GENERATION MARKET PENETRATION METHODOLOGY

This section provides a high-level overview of the study methodology.

1.1 Methodology

In assessing the technical and market potential of each private generation (PG) resource and opportunity in PacifiCorp's service area, the study considered many key factors, including:

- Technology maturity, costs, and future cost projections
- Industry practices, current and expected
- Net metering policies
- Federal and state tax incentives
- Utility or third-party incentives
- O&M costs
- Historical performance, and expected performance projections
- Hourly PG Generation
- Consumer behavior and market penetration

1.2 Market Penetration Approach

The following five-step process was used to estimate the market penetration of PG resources in each scenario:

1. **Assess a Technology's Technical Potential:** Technical potential is the amount of a technology that can be physically installed without considering economics or other barriers to customer adoption. For example, technical potential assumes that photovoltaic systems are installed on all suitable residential roofs.
2. **Calculate Simple Payback Period for Each Year of Analysis:** From past work in projecting the penetration of new technologies, Navigant has found that Simple Payback Period is a key indicator of customer uptake. Navigant used all relevant federal, state, and utility incentives in its calculation of paybacks, incorporating their projected reduction and/or discontinuation over time, where appropriate.
3. **Project Ultimate Adoption Using Payback Acceptance Curves:** Payback Acceptance Curves estimate the percentage of a market that will ultimately adopt a technology, but do not factor in how long adoption will take.
4. **Project Market Penetration Using Market Penetration Curves:** Market penetration curves factor in market and technology characteristics, projecting the adoption timeline.
5. **Project Market Penetration under Different Scenarios.** In addition to the base case scenario, high and low case scenarios were created by varying cost, performance, and retail rate projections.[9]

[9] In the case of Utah, the Base and High cases for 2019 and 2020 solar PV installations were adjusted to reflect the capacity cap included within Schedule 136 (Utah Docket 14-035-114)

These five steps are explained in detail in the following sections.

1.3 Assess Technical Potential

Each technology considered has its own characteristics and data sources that influence the technical potential assessment; the amount of a technology that can be physically installed within PacifiCorp's service territory without considering economics or other barriers to customer adoption. For this Navigant used the number of customers, system size, and access factors by technology. Navigant escalated technical potentials at the same rate PacifiCorp projects its sales will change over time. This also does not account for the electrical system's ability to integrate private generation.

1.4 Simple Payback

For each customer class (i.e., residential, commercial, irrigation and industrial), technology, and state, Navigant calculated the simple payback period using the following formula:

Simple Payback Period *= (Net Initial Costs) / (Net Annual Savings)*

Net Initial Costs *= Installed Cost – Federal Incentives – Capacity-Based Incentives*(1 – Tax Rate)*[10]

Net Annual Savings *= Annual Energy Bills Savings + (Performance Based Incentives – O&M Costs – Fuel Costs) * (1 – Tax Rate)*[10]

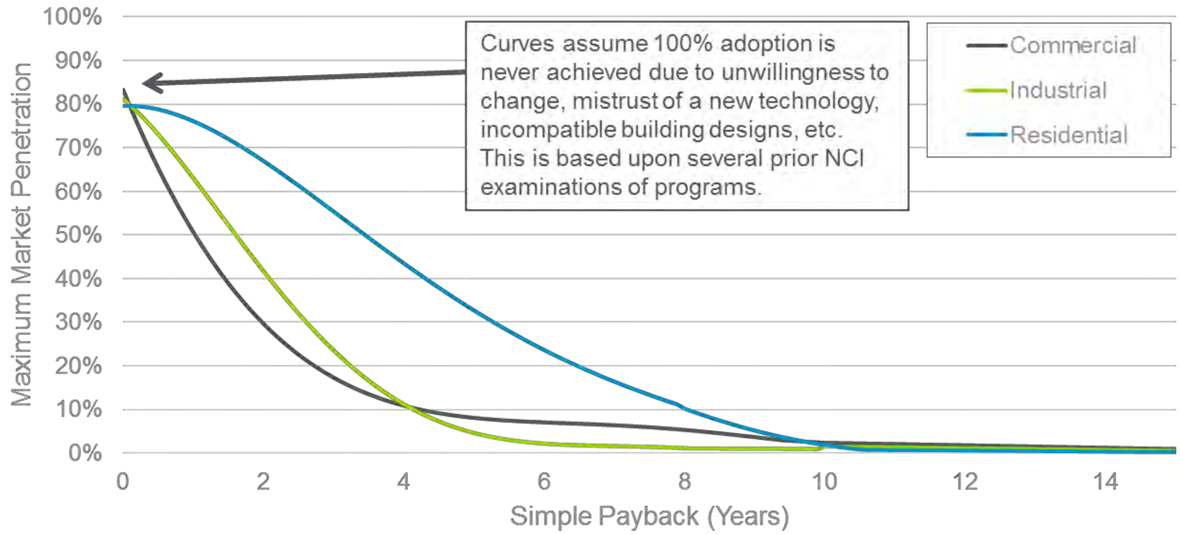
- *Federal tax credits can be taken against a system's full value if other (i.e. utility or state supplied) capacity-based or performance-based incentives are considered taxable.*
- *Navigant's Market Penetration model calculates first year simple payback assuming new installations for each year of analysis.*
- *For electric bills savings, Navigant conducted an 8,760-hourly analysis to consider actual rate schedules, actual output profiles, and demand charges. System performance assumptions are listed in Section 1.3 above. Solar performance and wind performance profiles were calculated for representative locations within each state based on the National Renewable Energy Laboratory (NREL) System Advisory Model (SAM). Building load profiles were provided by PacifiCorp and were scaled to match the average electricity usage for each customer class based on billing data.*

[10] Applies to all non-federal incentives regardless if it's coming from the state or another state-based entity.

1.5 Payback Acceptance Curves

For private generation technologies, Navigant used the following payback acceptance curves to model market penetration of PG sources from the retail customer's perspective.

Figure 6 Payback Acceptance Curves



Source: Navigant Consulting based upon work for various utilities, federal government organizations, and state/local organizations. The curves were developed from customer surveys, mining of historical program data, and industry interviews.

These payback curves are based upon work for various utilities, federal government organizations, and state local organizations. They were developed from customer surveys, mining of historical program data, and industry interviews.[11] Given a calculated payback period, the curve predicts the level of maximum market penetration. For example, if the technical potential is 100 MW, the 3-year commercial payback predicts that 15% of this technical potential, or 15 MW, will ultimately be achieved over the long term.

1.6 Market Penetration Curves

To determine the future PG market penetration within PacifiCorp's territory, Navigant modeled the growth of PG technologies from 2019 thru 2038. The model is a Fisher-Pry based technology adoption model that calculates the market growth of PG technologies. It uses a lowest-cost approach to consumers to develop expected market growth curves based on maximum achievable market penetration and market saturation time, as defined below.[12]

- **Market Penetration** – The percentage of a market that purchases or adopts a specific product or technology. The Fisher-Pry model estimates the achievable market penetration based on characteristics of the technology and industry. Market penetration curves (sometimes called S-

[11] Payback acceptance curves are based on a broad set of data from across the United States and may not predict customer behavior in a specific market (e.g. Utah customers may install solar at different paybacks than indicated by the payback acceptance curves due to market specific reasons).

[12] Michelfelder and Morrin, "Overview of New Product Diffusion Sales Forecasting Models" provides a summary of product diffusion models, including Fisher-Pry. Available: law.unh.edu/assets/images/uploads/pages/ipmanagement-new-product-diffusion-sales-forecasting-models.pdf

curves) are well established tools for estimating diffusion or penetration of technologies into the market. Navigant applies the market penetration curve to the payback acceptance curve shown in Figure 6 Payback Acceptance Curves.

- **Market Saturation Time** – The duration in years for a technology to increase market penetration from around 10% to 80%.

The Fisher-Pry model estimates market saturation time based on 12 different market input factors; those with the most substantial impact include:

- **Payback Period** – Years required for the cumulative cost savings to equal or surpass the incremental first cost of equipment.
- **Market Risk** – Risk associated with uncertainty and instability in the marketplace, which can be due to uncertainty regarding cost, industry viability, or even customer awareness, confidence, or brand reputation. An example of a high market risk environment is a jurisdiction lacking long-term, stable guarantees for incentives.
- **Technology Risk** – Measures how well-proven and the availability of the technology. For example, technologies that are completely new to the industry have a higher risk, whereas technologies that are only new to a specific market (or application) and have been proven elsewhere have lower risk.
- **Government Regulation** – Measure of government involvement in the market. A government-stated goal is an example of low government involvement, whereas a government mandated minimum efficiency requirement is an example of high involvement, having a significant impact on the market.

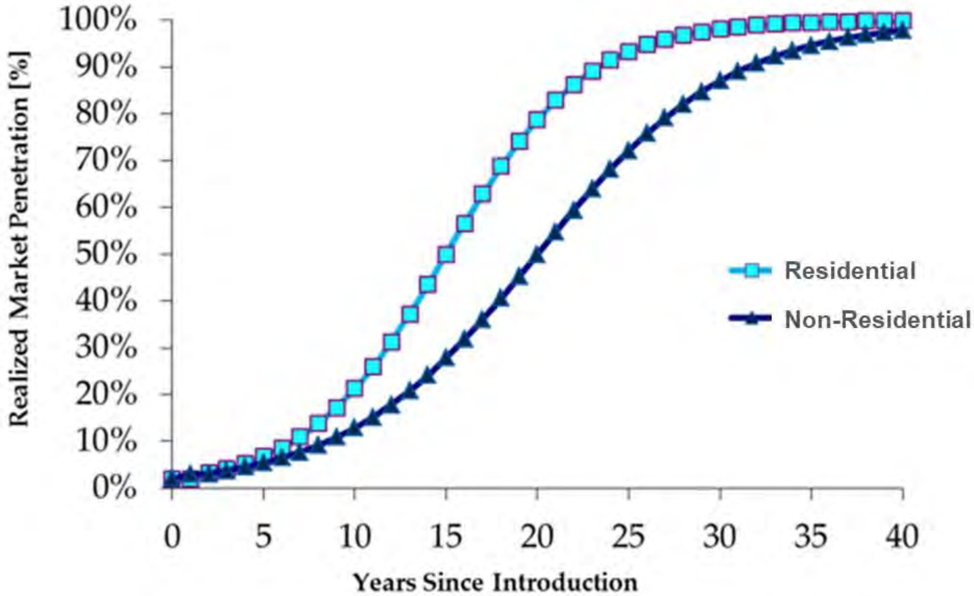
The model uses these factors to determine market growth instead of relying on individual assumptions about annual market growth for each technology or various supply and/or demand curves that may sometimes be used in market penetration modeling. With this approach, the model does not account for other more qualitative limiting market factors, such as the ability to train quality installers or manufacture equipment at a sufficient rate to meet the growth rates. Corporate sustainability, and other non-economic growth factors, are also not modeled.

The Fisher-Pry market growth curves have been developed and refined over time based on empirical adoption data for a wide range of technologies.[13] The model is an imitative model that uses equations developed from historical penetration rates of real products for over two decades. It has been validated in this industry via comparison to historical data for solar photovoltaics, a key focus of this study.

Navigant Consulting has used gathered market data on the adoption of technologies over the past 120 years and fit the data using Fisher-Pry curves. A key parameter when using market penetration curves is the assumed year of introduction. For the market penetration curves used in this study, Navigant assumed that the first-year introduction occurred when the simple payback period was less than 25 years (per the pay-back acceptance curves used, this is the highest pay-back period that has any adoption) or when state or local incentives were first introduced.
When the above payback period, market risk, technology risk, and government regulation factors above are analyzed, our general Fisher-Pry based method gives rise to the following market penetration curves used in this study:

[13] Fisher, J. C. and R. H. Pry, "A Simple Substitution Model of Technological Change", Technological Forecasting and Social Change, 3 (March 1971), 75-88.

Figure 7 **Market Penetration Curves** [14]



Source: Navigant Consulting, November 2008 as taken from Fisher, J.C. and R.H. Pry, A Simple Substitution Model of Technological Change, *Technological Forecasting and Social Change*, Vol 3, Pages 75 – 99, 1971.

The model is designed to analyze the adoption of a single technology entering a market and assumes that the PG market penetration analyzed for each technology is additive because the underlying resources limiting installations (sun, wind, water, high thermal loads) are generally mutually exclusive, and because current levels of market penetration are relatively low (plenty of customers exist for each technology).

1.7 Key Assumptions

The following section details the key technology-specific and base, low and high scenario assumptions.

1.7.1 Technology Assumptions

The following tables summarize cost and performance assumptions for each technology. System size assumptions are provided in APPENDIX B.

1.7.1.1 Reciprocating Engines

A reciprocating engine uses one or more reciprocating pistons to convert pressure into rotating motion. In a combined heat and power (CHP) application, a small CHP source will burn a fuel (natural gas) to produce both electricity and heat. In many applications, the heat is transferred to water, and this hot water is then used to heat a building. In this study we assume the reciprocating engine generates electricity by using natural gas as the fuel.

[14] Realized market penetration is applied to the maximum market penetration (Figure **7**) for each technology, customer payback, and point in time. For example, a residential customer with a five-year payback would have a maximum market penetration of around 35 percent, as indicated by the residential payback acceptance curve (Figure 6). A technology that was introduced 10 years ago will have realized about 20 percent of its maximum market penetration (Figure **7**), having a market penetration of about seven percent of the technical potential.

Navigant sized the system to meet the minimum customer load, assuming the reciprocating engine system would function to meet the customer's base load. Based on system size and product availability, reciprocating engines were assumed a reasonable technology for commercial and industrial customers. Assumptions on system capacity sizes in each state are detailed in APPENDIX B. Table 2 Reciprocating Engine Assumptions provides the cost and performance assumptions used in the analysis and the source for each.

Table 2 Reciprocating Engine Assumptions[15]

PG Resource Costs	Units	2019 Baseline	Sources
Installed Cost – 100kW	$/kW	$2,970	EPA, Catalog of CHP Technologies, March 2015, pg. 2-15
Change in Annual Installed Cost	%	0.4%	ICF International Inc., Combined Heat and Power: Policy Analysis and 2011-2030 Market Assessment, pg. 92
Variable O&M	$/MWh	$20	ICF International Inc., Combined Heat and Power: Policy Analysis and 2011-2030 Market Assessment, pg. 92
Change in Annual O&M Cost	%	-1.0%	Navigant Assumption
Fuel Cost	$/MWh	PacifiCorp Gas Forecast	PacifiCorp Forecast
PG Performance Assumptions			
Electric Heat Rate (HHV)	Btu/kWh	12,637	EPA, Catalog of CHP Technologies, March 2015, pg. 2-10

1.7.1.2 Micro-turbines

Micro-turbines use natural gas to start a combustor, which drives a turbine. The turbine in turn drives an AC generator and compressor, and the waste heat is exhausted to the user. The device therefore produces electrical power from the generator, and waste heat to the user. In this study we assume the micro-turbine generates electricity by using natural gas as the fuel.

Navigant sized the system to meet the minimum customer load, assuming the reciprocating engine system would function to meet the customer's base load. Based on system size and product availability, reciprocating engines were assumed a reasonable technology for commercial and industrial customers. Assumptions on system capacity sizes in each state are detailed in APPENDIX B. Table 3 Micro-turbines Assumptions provides the cost and performance assumptions used in the analysis and the source for each.

[15] EPA, Catalog of CHP Technologies: www.epa.gov/sites/production/files/2015-07/documents/catalog_of_chp_technologies.pdf; ICF, Combined Heat and Power Policy Analysis, www.energy.ca.gov/2012publications/CEC-200-2012-002/CEC-200-2012-002.pdf

Table 3 Micro-turbines Assumptions[16]

PG Resource Costs	Units	2019 Baseline	Sources
Installed Cost – 30kW	$/kW	$2,685	EPA, Catalog of CHP Technologies, March 2015, pg. 5-7
Change in Annual Installed Cost	%	-0.3%	ICF International Inc., Combined Heat and Power: Policy Analysis and 2011-2030 Market Assessment, pg. 97
Variable O&M	$/MWh	$23	ICF International Inc., Combined Heat and Power: Policy Analysis and 2011-2030 Market Assessment, pg. 97
Change in Annual O&M Cost	%	-1.0%	Navigant Assumption
Fuel Cost	$/MWh	PacifiCorp Gas Forecast	PacifiCorp Forecast
PG Performance Assumptions			
Electric Heat Rate (HHV)	Btu/kWh	15,535	EPA, Catalog of CHP Technologies, March 2015, pg. 5-6

1.7.1.3 Small Hydro

Small hydro is the development of hydroelectric power on a scale serving a small community or industrial plant. The detailed national small hydro studies conducted by the Department of Energy (DOE) from 2004 to 2013,[17] formed the basis of Navigant's small hydro technical potential estimate. In the Pacific Northwest Basin, which covers WA, OR, ID, and WY, a detailed stream-by-stream analysis was performed in 2013, and DOE provided these data to Navigant directly. For these states, Navigant combined detailed GIS PacifiCorp service territory data with detailed GIS data on each stream / water source. Using this method, Navigant could sum the technical potentials of only those streams located in PacifiCorp's service territory. For the other two states, Utah and California, Navigant relied on an older 2006 national analysis, and multiplied the given state figures by the area served by PacifiCorp within that state. Table 4 provides the cost and performance assumptions used in the analysis and the source for each.

[16] EPA, Catalog of CHP Technologies: www.epa.gov/sites/production/files/2015-07/documents/catalog_of_chp_technologies.pdf; ICF, Combined Heat and Power Policy Analysis, www.energy.ca.gov/2012publications/CEC-200-2012-002/CEC-200-2012-002.pdf

[17] Navigant used the same methodology and sources as in the 2014 study.

Table 4 Small Hydro Assumptions[18]

PG Resource Costs	Units	2019 Baseline	Sources
Installed Cost	$/kW	$4,000	Double average plant costs in "Quantifying the Value of Hydropower in the Electric Grid: Plant Cost Elements." Electric Power Research Institute, November 2011; this accounts for permitting/project costs
Change in Annual Installed Cost	%	0.00%	Mature technology, consistent with other mature technologies in the IRP.
Fixed O&M	$/kW-yr.	$52	Renewable Energy Technologies: Cost Analysis Series. "Hydropower." International Renewable Energy Agency, June 2012.
Change in Annual O&M Cost	%	-1.0%	Navigant Assumption
PG Performance Assumptions			
Capacity Factor	%	50% ±5%	Average capacity factor variance will be reflected in the low and high penetration scenarios.

1.7.1.4 Solar Photovoltaics

Solar photovoltaic (solar) systems convert sunlight to electricity. Navigant applied a 15% discount factor to account DC to AC conversion[19]. System size was then multiplied by the number of customers and the roof access factor. Assumptions on system capacity sizes in each state are detailed in APPENDIX B and access factors remained consistent with the 2014 and 2016 studies. Table 5 Solar Assumptions provides the cost and performance assumptions used in the analysis and the source for each.

[18] Note: No change from 2014 study.

[19] Navigant used a 15% discount factor to account for DC to AC conversion in PV systems. This value is consistent with industry standards and current system design.

Table 5 Solar Assumptions

PG Resource Costs	Units	2019 Baseline	Sources
Installed Cost – Res	$/kW DC	UT: ~$2,500 Other: $2,750	Navigant Forecast validated by NREL, U.S. Photovoltaic Prices and Cost Breakdowns: Q1 2017 Benchmarks for Residential, Commercial and Utility-Scale Systems
Installed Cost – Non-Res	$/kW DC	All Markets: ~$1,900	
Average Change in Annual Installed Cost (2015-2034)	%	-2.8% (Res) -2.5% (Non-Res)	
Fixed O&M – Res	$/kW-yr.	$25	National Renewable Energy Laboratory, U.S. Residential Photovoltaic (PV) System Prices, Q4 2017 Benchmarks: Cash Purchase, Fair Market Value, and Prepaid Lease Transaction Prices, Oct. 2014; National Renewable Energy Laboratory, Distributed Generation Renewable Energy Estimate of Costs, Accessed February 1, 2016
Fixed O&M – Non-Res	$/kW-yr.	$23	
Change in Annual O&M Cost	%	-1.0%	Navigant Assumption
DC to AC Derate Factor	#	0.85	Industry Standard

As shown in Figure 8 and Figure 9, the rapid decline in solar costs over the past decade has driven private solar adoption across the country for all customer classes. In the past, these cost declines were primarily due to reduction in the cost of equipment (e.g. panels, inverters and balance of system components) driven by economies of scale and improvements in efficiency. Solar costs are expected to continue to decline over the next decade as system efficiencies continue to increase, although these declines are expected to occur at a slower rate than what occurred in recent years. In the long term, Navigant expects price reductions to decline as the industry matures and efficiency gains become harder to achieve.

Navigant's national solar cost forecast includes a low, base and high forecast. For this project, Navigant developed a PacifiCorp forecast which is the average between the national base and high forecast. Navigant decided to use this forecast for California, Idaho, Oregon, Washington and Wyoming, as all those states currently have small solar markets in PacifiCorp territory, resulting in less competition and economies of scale to drive down local solar costs. For Utah, Navigant used the base cost forecast, as Utah has a larger and more mature private solar market.

Figure 8. Non-Residential Solar System Costs, 2019-2038

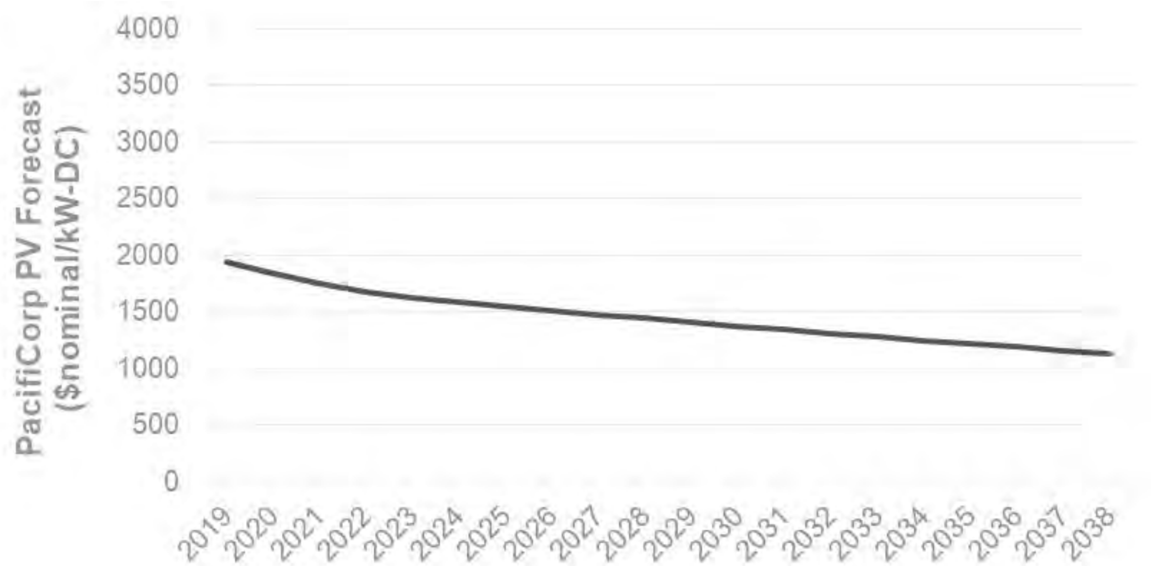
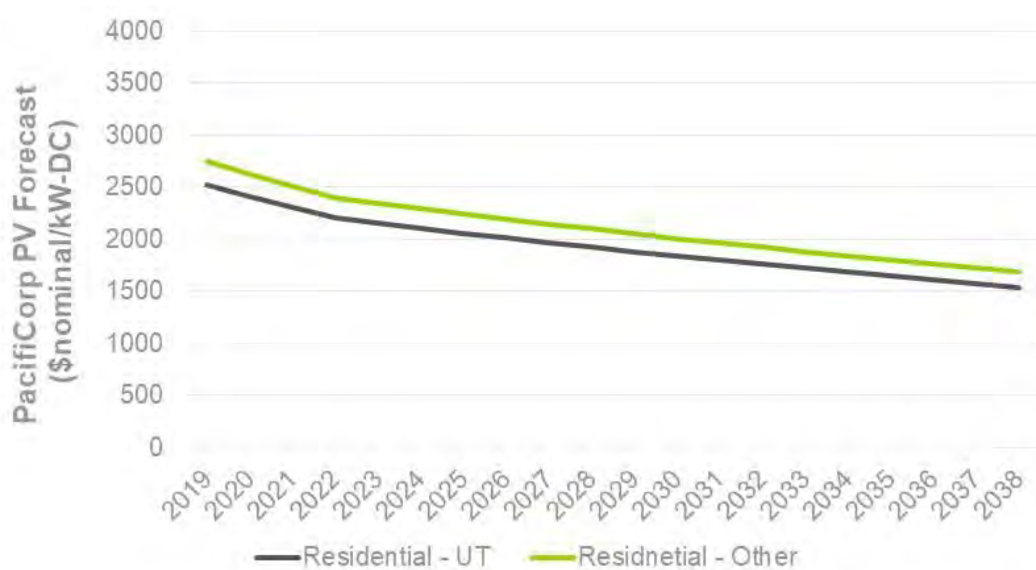


Figure 9 Residential Solar System Costs, 2019-2038



The solar capacity factors (Table 5) were calculated using NREL's System Advisory Model for each state territory.

Table 6 Solar Capacity Factors[20]

Performance Assumptions		
		(kW-DC/kWh AC)
Capacity Factor	UT	16.3%
	WY	16.8%
	WA	14.0%
	CA	16.6%
	ID	16.0%
	OR	12.4%

1.7.1.5 Small Wind

Wind power is the use of air flow through wind turbines to mechanically power generators for electricity. Navigant sized the wind systems at 80% of customer load to reduce the chance that the wind system will produce more than the customer's electric load in a given year. System size was then multiplied by the number of customers and the access factor. The 2014 and 2016 study access factors were used for this study.

The following cost and performance assumptions were used in the analysis.

Table 7 Wind Assumptions

PG Resource Costs	Units	2019 Baseline	Sources
Installed Cost – Res (2.5-10kW)	$/kW	$7,200	Department of Energy, 2014 Distributed Wind Market Report, August 2015
Installed Cost – Com (11-100kW)	$/kW	$6,000	
Change in Annual Installed Cost	%	0.0%	Mature technology, consistent with other mature technologies in the IRP.
Fixed O&M	$/kW-yr.	$40	Department of Energy, 2014 Distributed Wind Market Report, August 2015
Change in Annual O&M Cost	%	-1.0%	Navigant Assumption
PG Performance Assumptions			
Capacity Factor	%	20% (2013) - 25% (2034)	Small scale wind hub heights are lower, with shorter turbine blades, relative to 30% capacity factor large scale turbines.

[20] Navigant used a DC to AC solar PV derate factor of 85%.

1.7.2 Scenario Assumptions

Navigant used the market penetration model to analyze three scenarios, capturing the impact of major changes that could affect market penetration. For the low and high penetration cases, Navigant varied technology costs, system performance, and electricity rate assumptions.

Table 8 Scenario Variable Modifications

Scenarios				
Cases	Technology Costs	Performance	Electricity Rates	Other
Base Case	• See technology and cost section	• As modeled	• Increase at inflation rate, assumed at 2.0%	• Assumes the net metering cap is achieved. Solar PV adoption forecast was adjusted in 2019 and 2020 to reflect this • Adoption in all other years is based on customer economics.
Low Attractiveness	• PV: Years 1-10: Same as Base Case • Years 11+: Rate of decline is 25% lower than base case • Other: Mature technologies. Same as base case	• PV: Same as Base Case • Other: 5% worse	• Increases at 1.6%, 0.4%/year lower than the Base Case	• Assumes adoptions in based on customer economics for all years.
High Attractiveness	• PV: Years 1-10: Same as Base Case • Years 11+: rate of decline is 50% higher than base case • Other: Mature technologies. Same as base case	• Reciprocating Engines: 0.5% better (mature) • Micro-turbines: 2% better • Hydro: 5% better (reflecting wide performance distribution uncertainty) • PV/Wind: 1% better (relatively mature)	• Increases at 2.4%, 0.4%/year higher than the Base Case	• Assumes the net metering cap is achieved. Solar PV adoption forecast was adjusted in 2019 and 2020 to reflect this • Adoption in all other years is based on customer economics.

Technology cost reduction is the variable with the largest impact on market penetration over the next 20 years. Average technology performance assumptions are relatively constant across states and sites. Changes in electricity rates are modeled conservatively, reflecting the long-term stability of electricity rates in the United States. Navigant expects short-term volatility for all variables but when averaged over the 20-year IRP period, long-term trends show less variation.

1.7.3 Incentives

Federal and state incentives are a very important PG market penetration driver, as they can reduce a customer's payback period significantly.

1.7.3.1 Federal

The Federal Business Energy Investment Tax Credit (ITC) allows the owner of the system to claim a tax credit for a certain percentage of the installed PG system price.[21] The ITC, originally set to expire in 2016 for residential solar systems and reduce to 10% for commercial solar systems, was extended for solar PV systems in December 2015 through the end of 2021, with step downs occurring in 2020 through 2022. The table below details how the ITC applies to the technologies evaluated in this study, however, this schedule may change in the future.

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[21] Business Energy Investment Tax Credit, http://energy.gov/savings/business-energy-investment-tax-credit-itc.

Table 9 Federal Tax Incentives

Technology	2019	2020	2021	2022	2023	>2023
Recip. Engines	**10%**	**10%**	**10%**	**0%**	**0%**	**0%**
Micro Turbines	**10%**	**10%**	**10%**	**0%**	**0%**	**0%**
Small Hydro	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**
PV - Com	**30%**	**26%**	**22%**	**10%**	**10%**	**10%**
PV - Res	**30%**	**26%**	**22%**	**0%**	**0%**	**0%**
Wind - Com	**12%**	**0%**	**0%**	**0%**	**0%**	**0%**
Wind - Res	**30%**	**26%**	**22%**	**22%**	**0%**	**0%**

1.7.3.2 State

State incentives drive the local market and are an important aspect promoting PG market penetration. Currently, all states evaluated have full retail rate net energy metering (NEM) in place for all customer classes considered in this analysis. The study assumes that NEM policy remains constant, although future uncertainty exists surrounding NEM policy. Longer-term uncertainty also exists regarding other state incentives. Idaho also has a local state residential personal tax deduction for solar and wind projects. Currently, state incentives do not exist in California[22] or Wyoming.

The report reflects the regulatory modifications to the PG program in Utah, as included in Schedule 136[23]. The value of generated energy takes into consideration the reduced compensation for exported energy included in the tariff as well as the capacity cap (see section 1.8.4 for more detail).

The following tables detail the assumptions made regarding local state incentives.

[22] In 2007, California launched the California Solar Initiative, however, incentives no longer remain in most utility territories, http://csi-trigger.com/.

[23] Utah Docket 14-035-114

Table 10 Oregon Incentives

Technology	2019	2020	2021	2022	2023	>2023
Recip. Engines	**0**	**0**	**0**	**0**	**0**	**0**
Micro Turbines	**0**	**0**	**0**	**0**	**0**	**0**
Small Hydro	**0**	**0**	**0**	**0**	**0**	**0**
PV – Com ($/W)	**$0.50-$0.20/W**	**$0.50-$0.20/W**	**$0.50-$0.20/W**	**$0.50-$0.20/W**	**$0.50-$0.20/W**	**$0.50-$0.20/W**
PV – Res ($/W)	**$0.55/W**	**$0.55/W**	**$0.55/W**	**$0.55/W**	**$0.55/W**	**$0.55/W**
Wind – Com ($/kWh)	**0**	**0**	**0**	**0**	**0**	**0**
Wind – Res ($)	**0**	**0**	**0**	**0**	**0**	**0**

* Energy Trust of Oregon Solar Incentive (capped at $1.5M/year for residential).

Table 11 Utah Incentives

Technology	2019	2020	2021	2022	2023	2023	>2024
Recip. Engines (%)	**10**	**10**	**10**	**10**	**10**	**10**	**10**
Micro Turbines (%)	**10**	**10**	**10**	**10**	**10**	**10**	**10**
Small Hydro (%)	**10**	**10**	**10**	**10**	**10**	**10**	**10**
PV – Com (%)	**10**	**10**	**10**	**10**	**10**	**10**	**10**
PV – Res ($)*	**$1,600**	**$1,600**	**$1,600**	**$1,200**	**$800**	**$400**	**$0**
Wind – Com (%)	**10**	**10**	**10**	**10**	**10**	**10**	**10**
Wind – Res ($)*	**$1,200**	**$800**	**$400**	**$0**	**$0**	**$0**	**$0**

*Renewable Energy Systems Tax Credit, Program Cap: Residential cap = $2,000; commercial systems <660kW, no limit

Table 12 Washington Incentives

Technology	2019	2020	2021	2022	2023	>2023
Recip. Engines	**0**	**0**	**0**	**0**	**0**	**0**
Micro Turbines	**0**	**0**	**0**	**0**	**0**	**0**
Small Hydro	**0**	**0**	**0**	**0**	**0**	**0**
PV - Com ($/kWh)*	**$0.04 (+$0.04)**	**$0.02 (+$0.03)**	**$0.02 (+$0.02)**	**0**	**0**	**0**
PV - Res ($/kWh)*	**$0.14 (+$0.04)**	**$0.12 (+$0.03)**	**$0.10 (+$0.02)**	**0**	**0**	**0**
Wind - Com ($/kWh)*	**$0.04 (+$0.04)**	**$0.02 (+$0.03)**	**$0.02 (+$0.02)**	**0**	**0**	**0**
Wind - Res ($/kWh)*	**$0.14 (+$0.04)**	**$0.12 (+$0.03)**	**$0.10 (+$0.02)**	**0**	**0**	**0**

* Feed-in Tariff: $/kWh for all kWh generated through mid-2020; annually capped at $5,000/year, http://programs.dsireusa.org/system/program/detail/5698

Table 13 Idaho Incentives

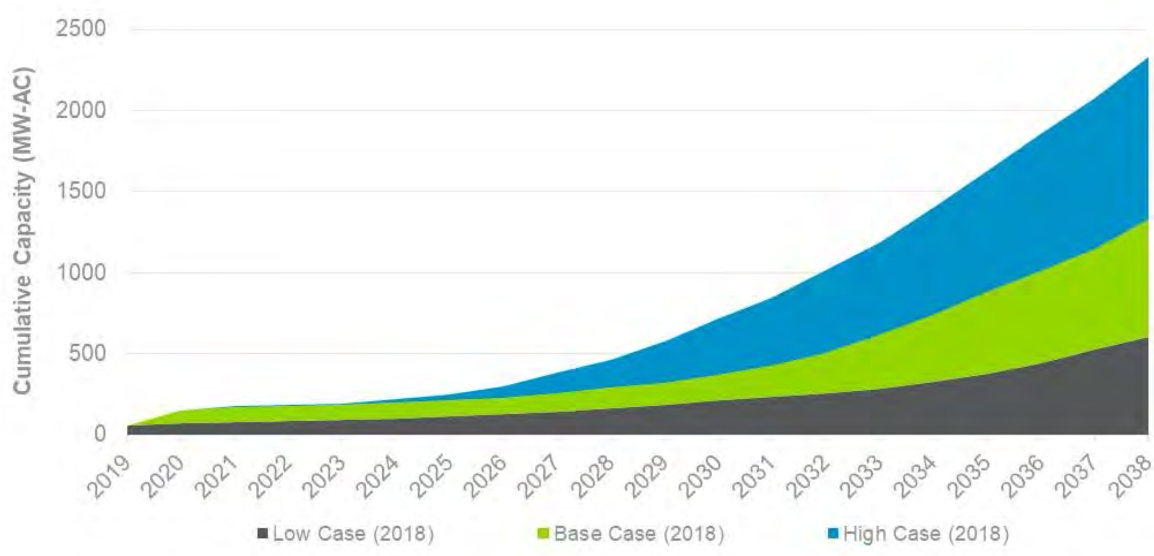
Technology	2019	2020	2021	2022	2023	>2023
Recip. Engines	**0**	**0**	**0**	**0**	**0**	**0**
Micro Turbines	**0**	**0**	**0**	**0**	**0**	**0**
Small Hydro	**0**	**0**	**0**	**0**	**0**	**0**
PV - Com	**0**	**0**	**0**	**0**	**0**	**0**
PV – Res (%)*	**40,20,20,20**	**40,20,20,20**	**40,20,20,20**	**40,20,20,20**	**40,20,20,20**	**40,20,20,20**
Wind – Com	**0**	**0**	**0**	**0**	**0**	**0**
Wind – Res (%)*	**40,20,20,20**	**40,20,20,20**	**40,20,20,20**	**40,20,20,20**	**40,20,20,20**	**40,20,20,20**

* Residential Alternative Energy Income Tax Deduction: 40% in the first year and 20% for the next three years, http://programs.dsireusa.org/system/program/detail/137.

RESULTS

Navigant estimates approximately 1.3 GW of PG capacity will be installed in PacifiCorp's territory from 2019-2038 in the base case scenario. As shown in Figure 10, the low and high scenarios project a cumulative installed capacity of 0.60 GW and 2.3 GW by 2038, respectively. The main drivers between the different scenarios include variation in technology costs, system performance, and electricity rate assumptions.

Figure 10. Cumulative Market Penetration Results (MW AC), 2019 – 2038



1.8 PacifiCorp Territories

The following sections report the results by state, providing high, base and low scenario installation projections. Results for each scenario are also broken out by technology. The solar sector exhibits the highest adoption across all states. Generally non-residential solar adoption is less sensitive to high and low scenario adjustments when compared to the residential sector. This is because the residential customer payback is more sensitive to scenario changes (e.g. technology costs, performance, electricity rates) when compared to non-residential sectors.

1.8.1 California

PacifiCorp's customers in northern California are projected to install about 48 MW of capacity over the next two decades in the base case, averaging about 2.4 MW, annually. California does not currently have any state incentives promoting the installation of PG and the ratcheting down of the Federal ITC from 2020 to 2022 has a negative impact on annual capacity installations after 2020. The main driver of PG in California is its high electricity rates relative to other states. Over time, the increase in PG installation capacity is driven by escalating electricity rates (benchmarked to inflation) and declining technology costs. Both residential and non-residential solar installations are responsible for the majority of PG growth over the horizon of this study.

While the low and high scenarios follow similar market trends as the base case, the cumulative installations over the planning horizon differ significantly, as shown in Figure 11. The 48 MW from the base case decreases by 35% to 31 MW in the low case and increases by 40% to 67 MW in the high case.

Figure 11. Cumulative Capacity Installations by Scenario (MW AC), California

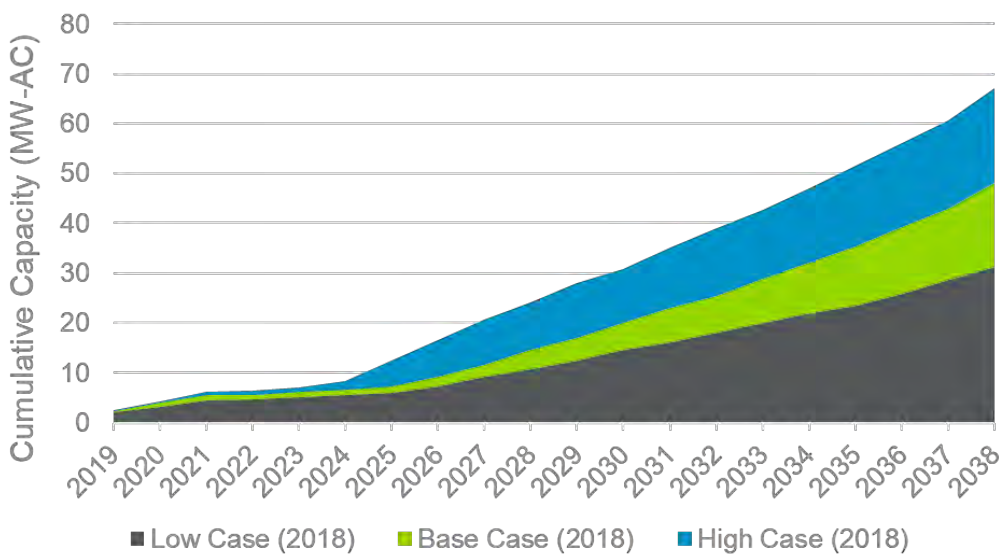


Figure 12. Cumulative Capacity Installations by Technology (MW AC), California Base Case

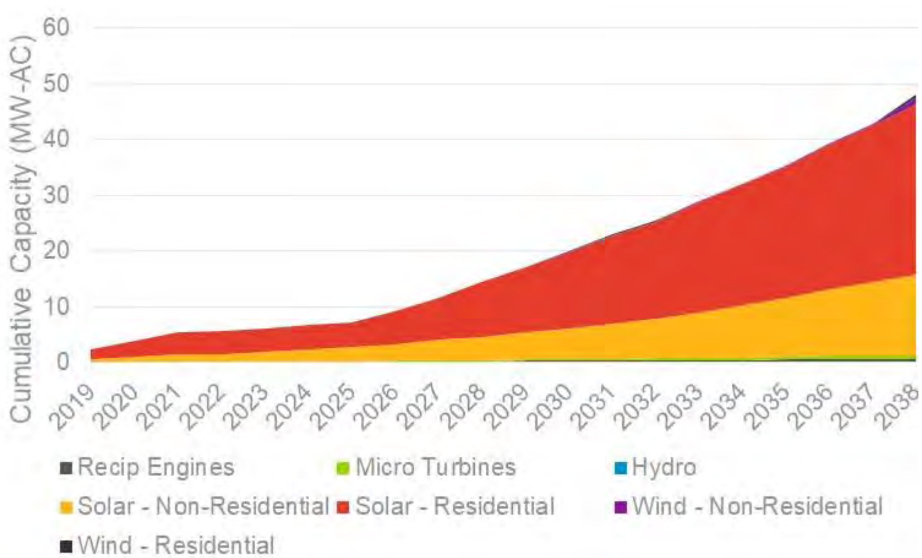


Figure 13. Cumulative Capacity Installations by Technology (MW AC), California High Case

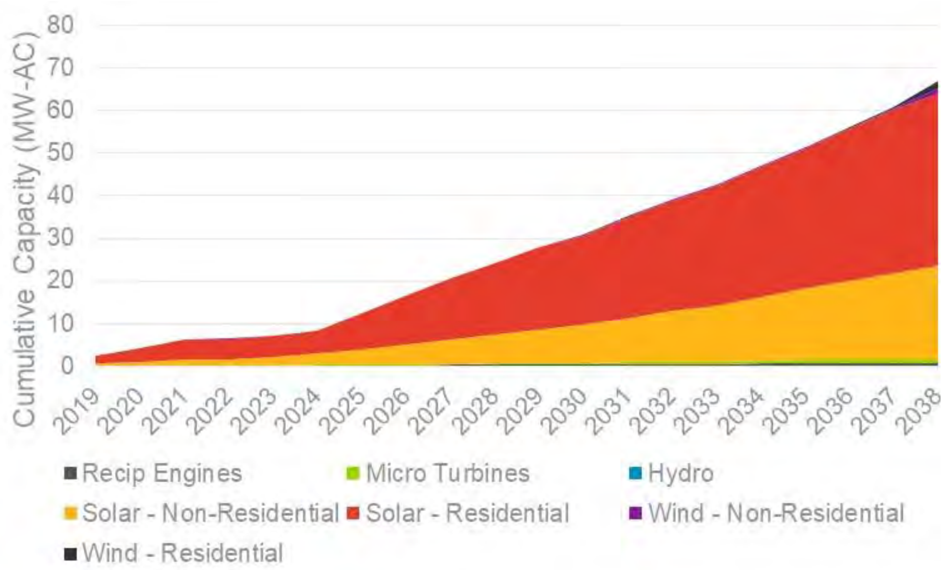
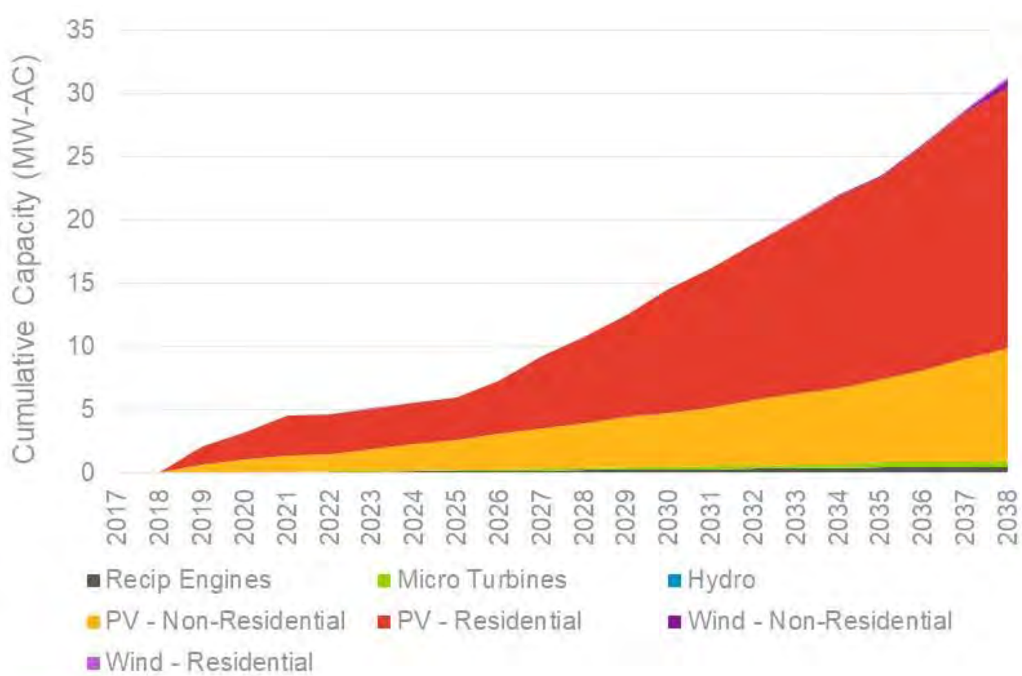


Figure 14. Cumulative Capacity Installations by Technology (MW AC), California Low Case



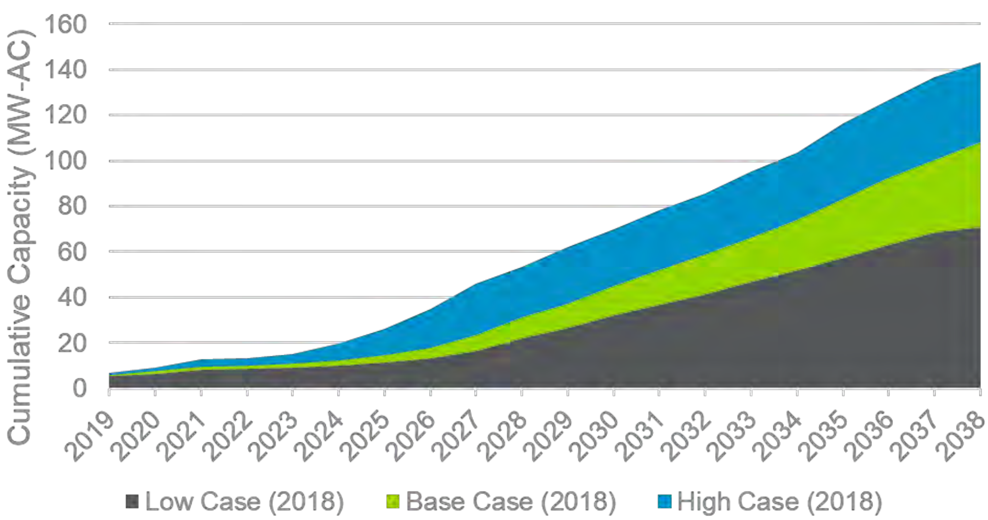
1.8.2 Idaho

PacifiCorp's Idaho customers are projected to install about 108 MW of capacity over the next two decades in the base case, averaging about 5.4 MW annually. Idaho currently has a Residential

Alternative Energy Income Tax Deduction for residential solar and wind installations[24], although this incentive seems to have had minimal impact on the market, as non-residential solar installations are responsible for the majority of PG growth in the early years due to a combination of technical potential and escalating electric rates. The ratcheting down of the Federal ITC from 2020 to 2022 has a negative impact on annual capacity installations in the short term and overtime the increase in PG installation capacity is driven by escalating electricity rates (benchmarked to inflation) and declining technology costs.

While the low and high scenarios follow similar market trends as the base case, the cumulative installations over the planning horizon differ significantly, as shown in Figure 15. The 108 MW from the base case decreases by 34% to 71 MW in the low case and increases by 32% to 143 MW in the high case.

Figure 15. Cumulative Capacity Installations by Scenario (MW AC), Idaho



[24] Residential Alternative Energy Income Tax Deduction: 40% in the first year and 20% for the next three years, http://programs.dsireusa.org/system/program/detail/137.

Figure 16. Cumulative Capacity Installations by Technology (MW AC), Idaho Base Case

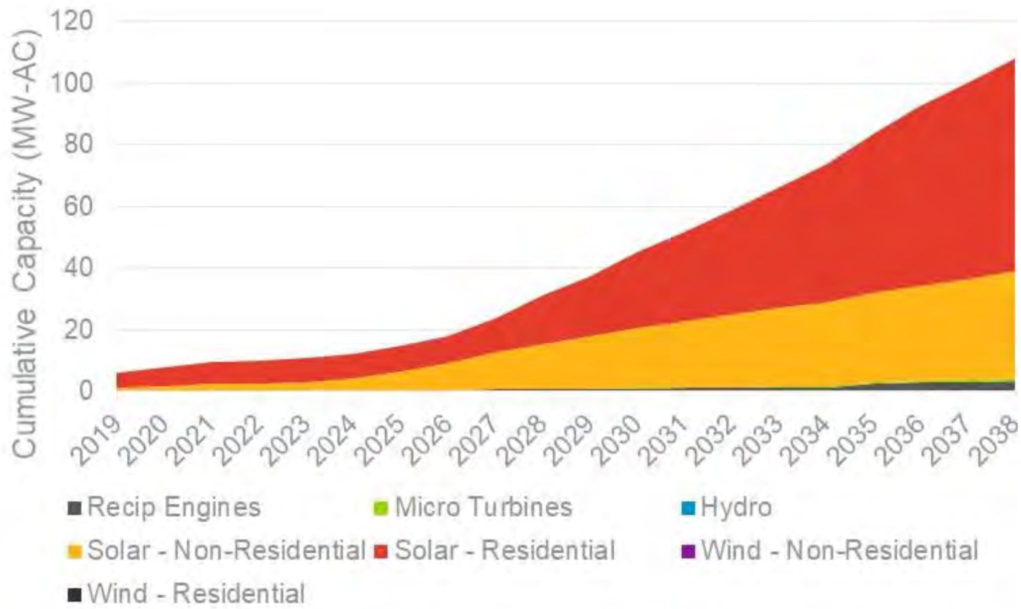


Figure 17. Cumulative Capacity Installations by Technology (MW AC), Idaho High Case

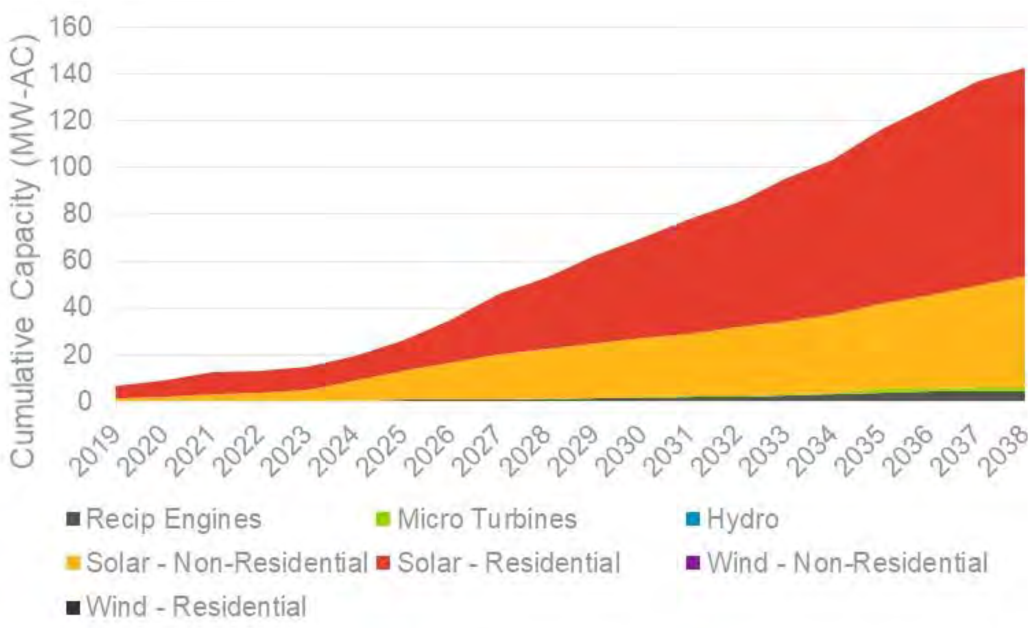
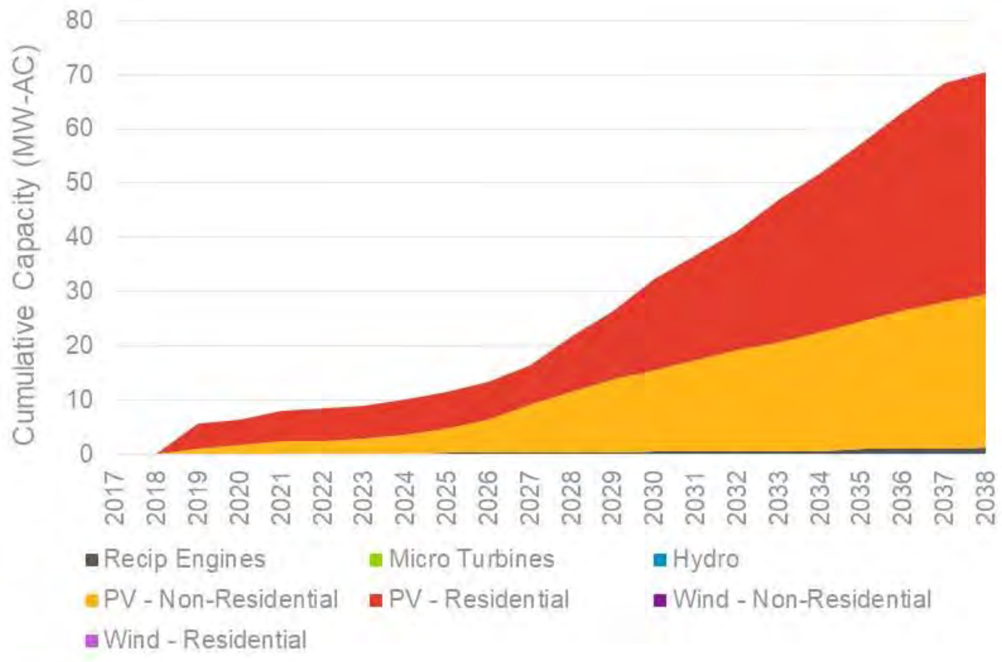


Figure 18. Cumulative Capacity Installations by Technology (MW AC), Idaho Low Case



1.8.3 Oregon

PacifiCorp's Oregon customers are projected to install about 435 MW of PG capacity over the next two decades in the base case, averaging about 21.75 MW annually. Solar is responsible for the majority of PG growth over the horizon of this study, with small growth from CHP reciprocating engines and non-residential wind. The stronger solar resource in Oregon relative to most of other states in PacifiCorp's territory and the Energy Trust of Oregon's Solar Incentive drive solar market adoption. The ratcheting down of the Federal ITC from 2020 to 2022 results in a relatively flat market in the short term but overtime the increase in solar capacity installation is driven by escalating electricity rates (benchmarked to inflation) and declining technology costs.

While the low and high scenarios follow similar market trends as the base case, the cumulative installations over the planning horizon differ significantly, as shown in Figure 19. The 435 MW from the base case decreases by 58% to 184 MW in the low case and increases by 123% to 968 MW in the high case.

Figure 19. Cumulative Capacity Installations by Scenario (MW AC), Oregon

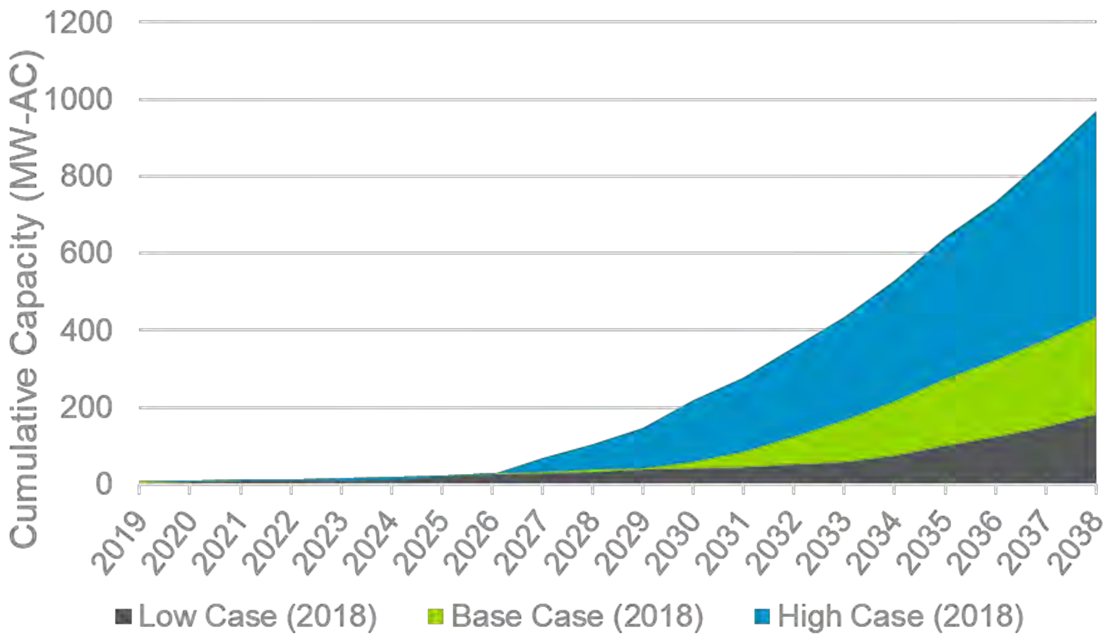


Figure 20. Cumulative Capacity Installations by Technology (MW AC), Oregon Base Case

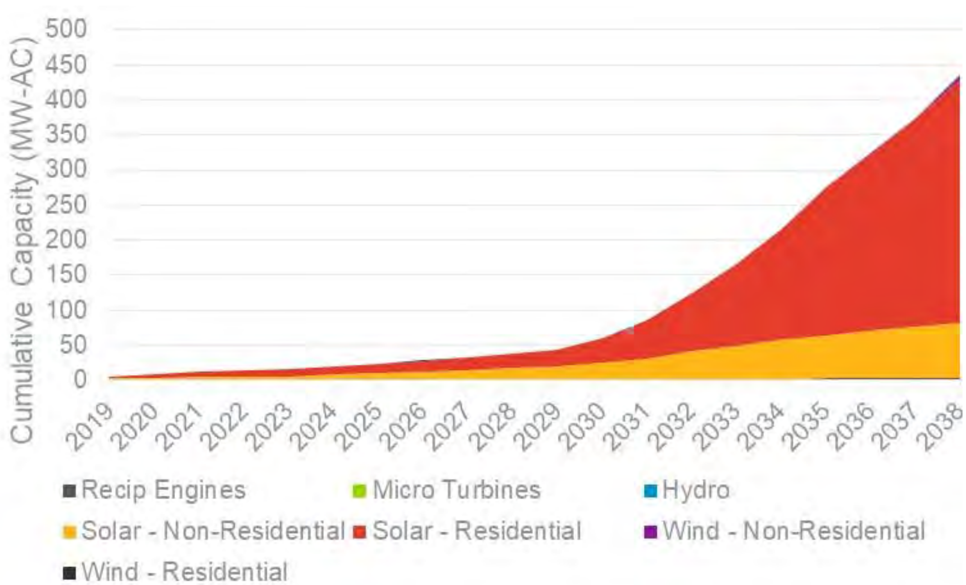


Figure 21. Cumulative Capacity Installations by Technology (MW AC), Oregon High Case

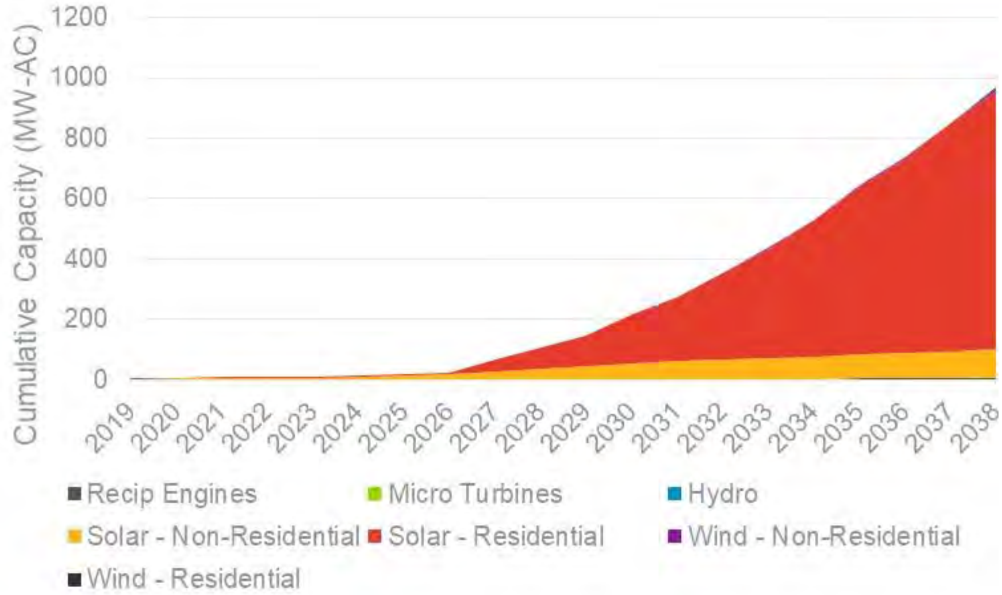
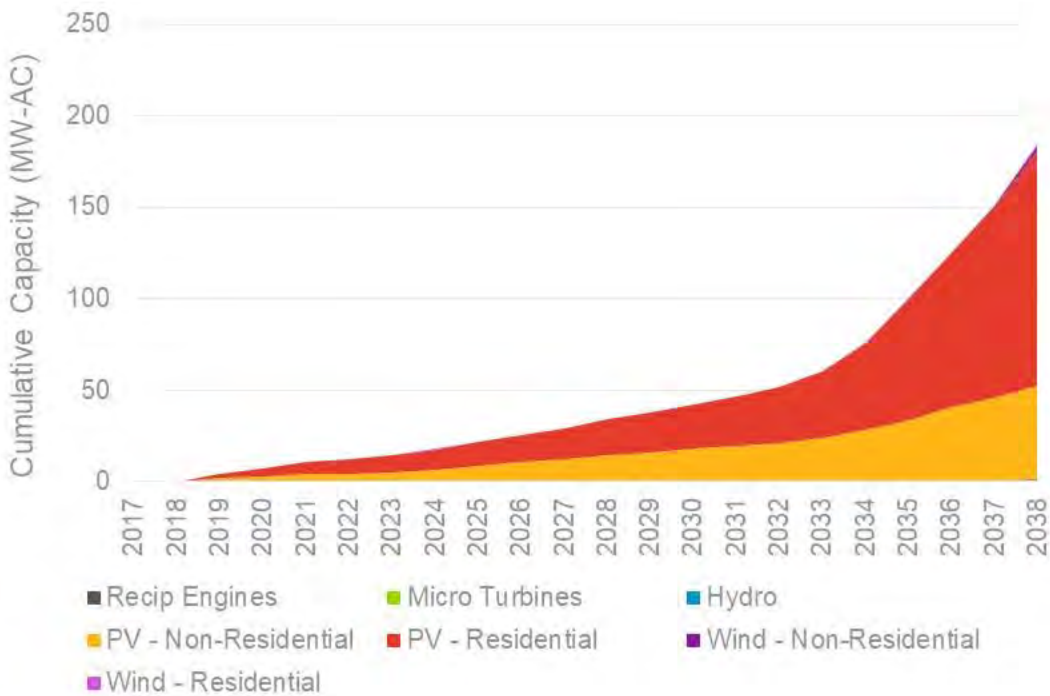


Figure 22 Cumulative Capacity Installations by Technology (MW AC), Oregon Low Case



1.8.4 Utah

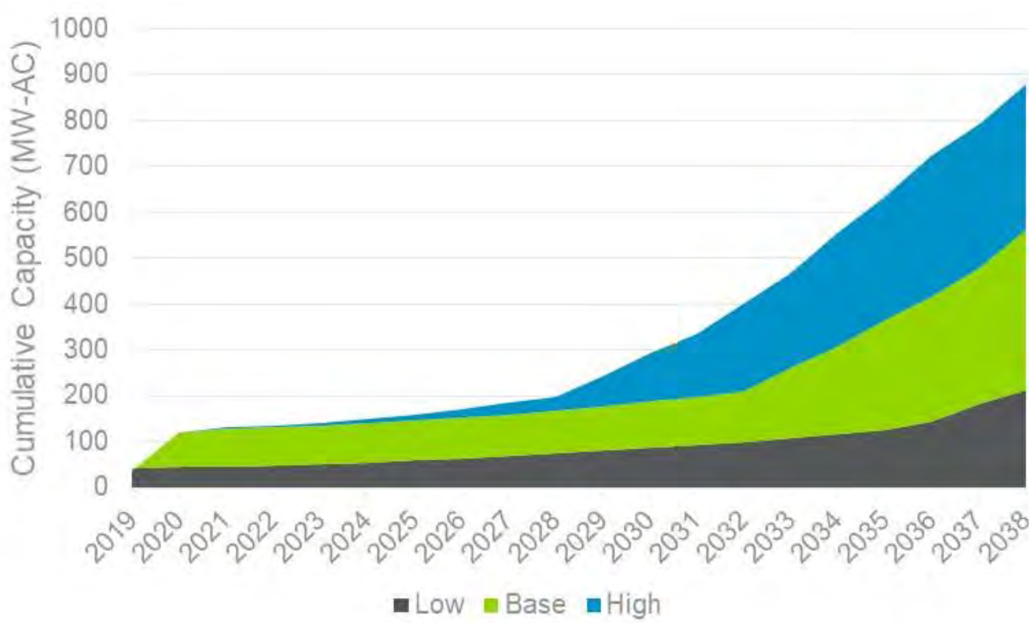
PacifiCorp's Utah customers are projected to install about 560 MW of PG capacity over the next two decades in the base case, averaging 28 MW annually. Solar is responsible for most PG installations over the horizon of this study, with reciprocating engines being installed in small numbers in future years. Utah has the strongest solar resource in PacifiCorp's territory and system costs are lower than in other states due to Utah's larger and more mature market.

The projection in the early years is dominated by residential customers adopting solar. The state Renewable Energy Systems Tax Credit applies to all technologies evaluated and has an impact on solar adoption. Solar adoption declines dramatically in 2020 as the ITC ratchets down. In 2025 projected capacity installation increases as solar prices continue to decline and utility rates escalate (benchmarked to inflation).

The report reflects the regulatory modifications to the PG program in Utah, as included in Schedule 136.[25] The value of generated energy takes into consideration the recently approved compensation for exported energy included in the tariff. Additionally, the forecast installations for years 2019 and 2020 in the base and high case reflects the capacity cap included within Schedule 136, while low case reflects the assumptions as outlined in Table 11.

While the low and high scenarios follow similar market trends as the base case, the cumulative installations over the planning horizon differ significantly, as shown in Figure 23. The 560 MW from the base case decreases by 62% to 213 MW in the low case and increases by 56% to 879 MW in the high case.

Figure 23. Cumulative Capacity Installations by Scenario (MW AC), Utah



[25] Utah Docket 14-035-114

Figure 24. Cumulative Capacity Installations by Technology (MW AC), Utah Base Case

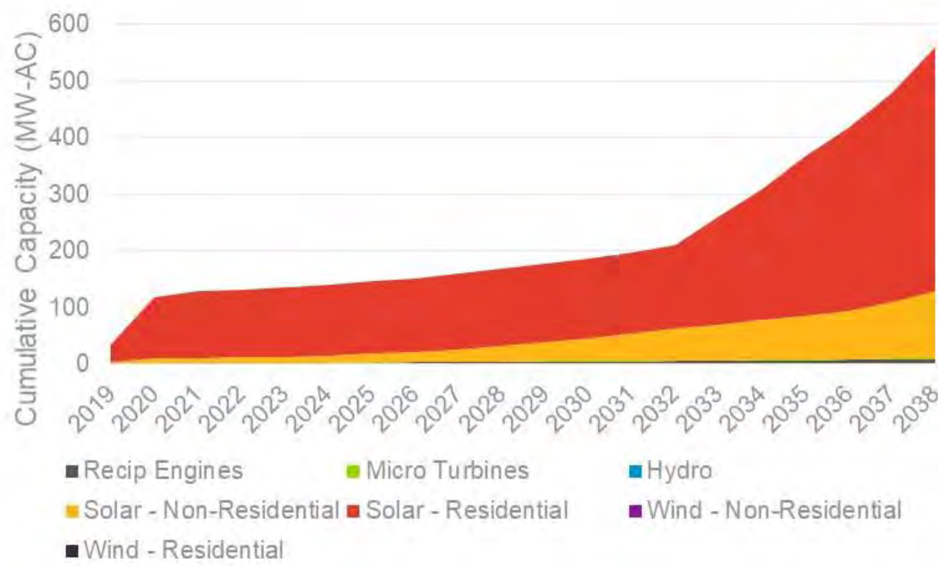


Figure 25. Cumulative Capacity Installations by Technology (MW AC), Utah High Case

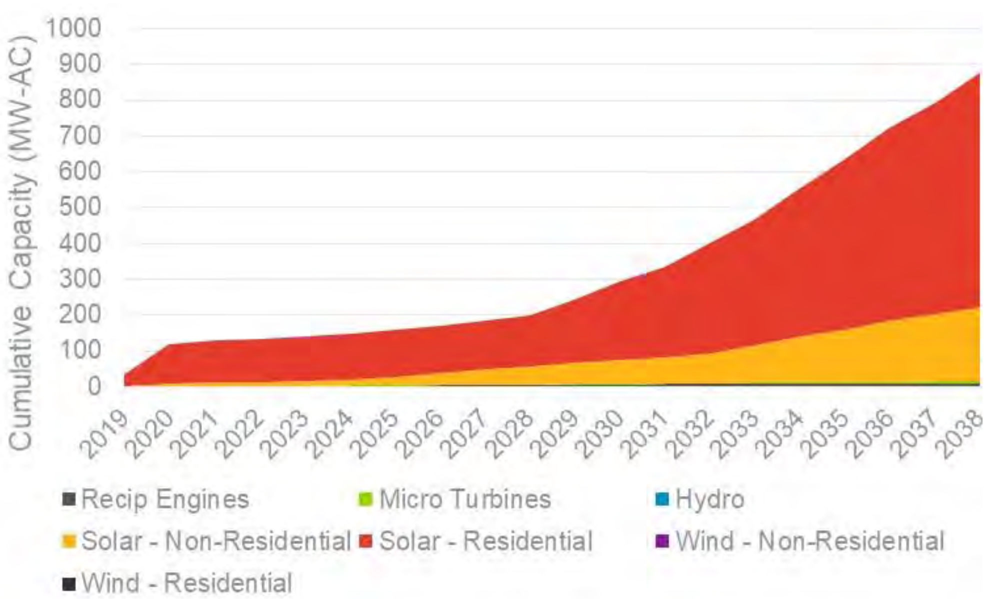
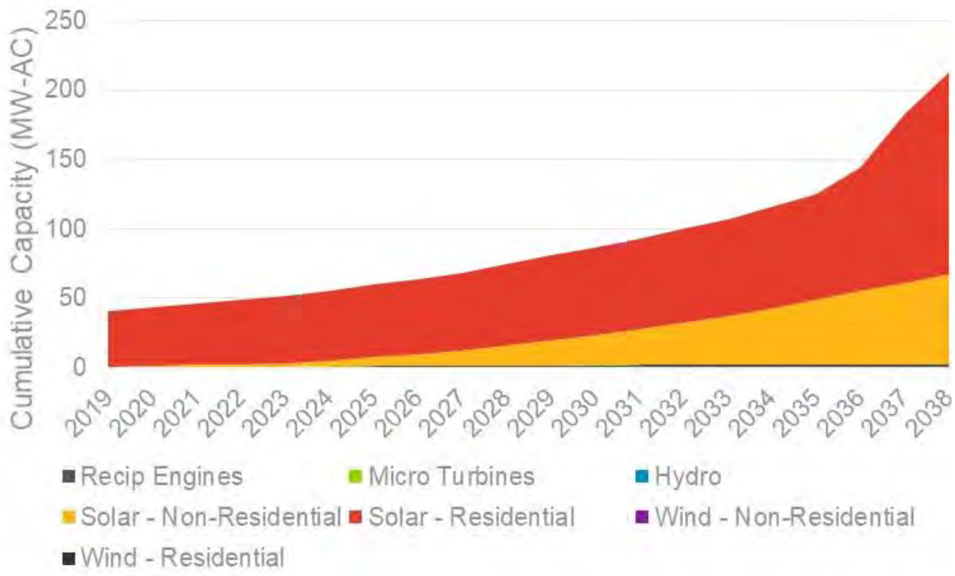


Figure 26. Cumulative Capacity Installations by Technology (MW AC), Utah Low Case



1.8.5 Washington

PacifiCorp's Washington customers are expected to install about 59.6 MW of PG capacity over the next two decades in the base case, averaging 2.98 MW annually. Solar is responsible for most PG installations over the horizon of this study, with reciprocating engines being installed in small numbers in future years. Washington does not have a very strong solar resource, yet the lucrative Feed-In-Tariff in Washington, which extends through 2021, should drive the solar market in the near term. The solar market is driven by non-residential solar installations, most likely due to the lower cost of installing larger systems. Solar adoption declines dramatically in 2020 as the ITC ratchets down. In 2025, installation capacity increases as solar prices continue to decline and utility rates escalate (benchmarked to inflation).

While the low and high scenarios follow similar market trends as the base case, the cumulative installations over the planning horizon differ significantly, as shown in Figure 27. The 59.6 MW from the base case decreases by 35% to 38.5 MW in the low case and increases by 83% to 109 MW in the high case.

Figure 27. Cumulative Capacity Installations by Scenario (MW AC), Washington

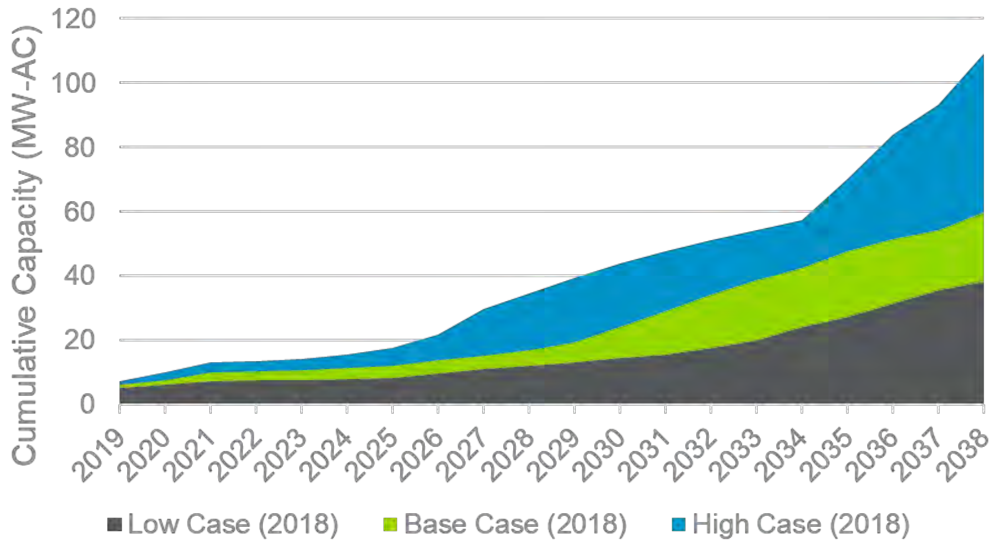


Figure 28. Cumulative Capacity Installations by Technology (MW AC), Washington Base Case

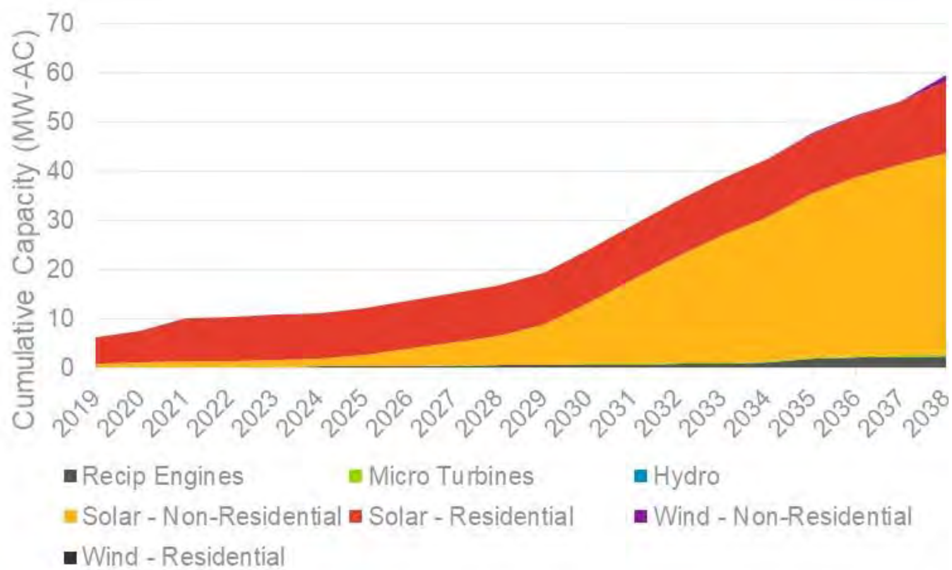


Figure 29. Cumulative Capacity Installations by Technology (MW AC), Washington High Case

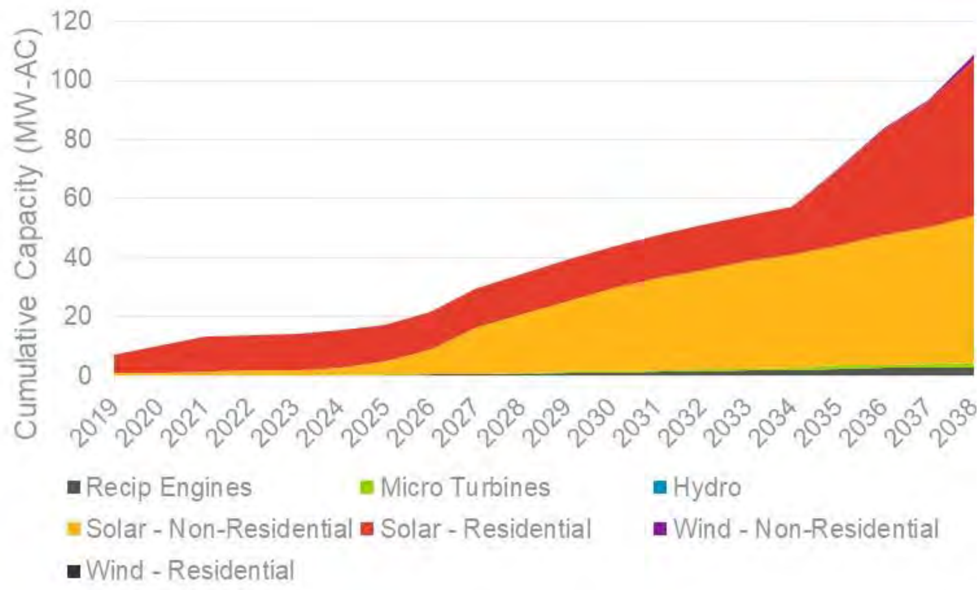
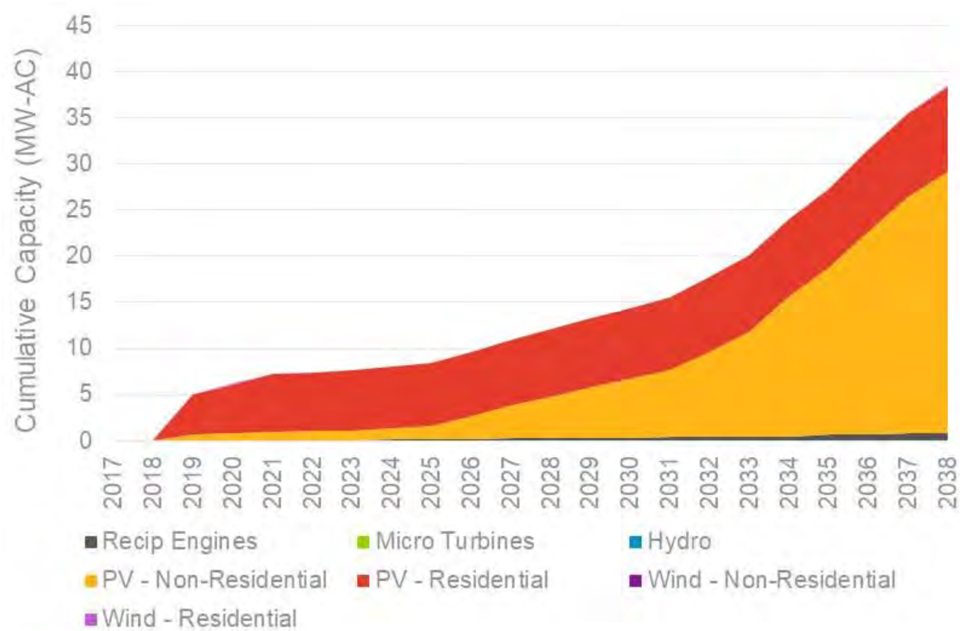


Figure 30. Cumulative Capacity Installations by Technology (MW AC), Washington Low Case



1.8.6 Wyoming

PacifiCorp's Wyoming customers are projected to install about 114 MW of capacity over the next two decades in the base case, averaging about 5.7 MW annually. Solar is responsible for most PG installations over the horizon of this study, with reciprocating engines, and small wind being installed in small numbers in future years. Wyoming does not have any state incentives promoting the installation of PG. Similar to other states, the ratcheting down of the Federal ITC from 2020 to 2022 has a negative impact on annual capacity installations but in 2023 the market begins to grow at a faster pace, driven by escalating electricity rates (benchmarked to inflation) and declining technology costs. Both residential and non-residential solar installations are responsible for the majority of PG growth over the horizon of this study.

While the low and high scenarios follow similar market trends as the base case, the cumulative installations over the planning horizon differ significantly, as shown in Figure 31. The 114 MW from the base case decreases by 40% to 68 MW in the low case and increases by 45% to 165 MW in the high case.

Figure 31. Cumulative Capacity Installations by Scenario, Wyoming

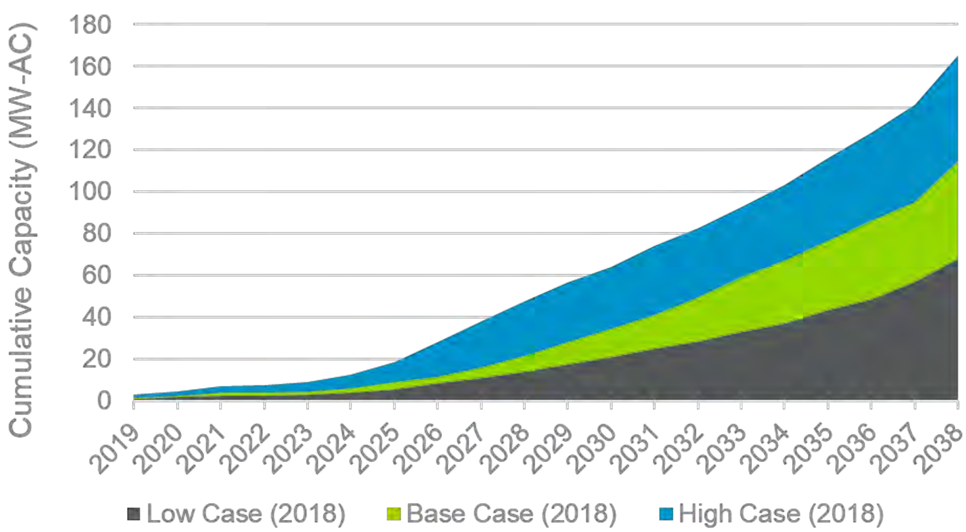


Figure 32. Cumulative Capacity Installations by Technology (MW AC), Wyoming Base Case

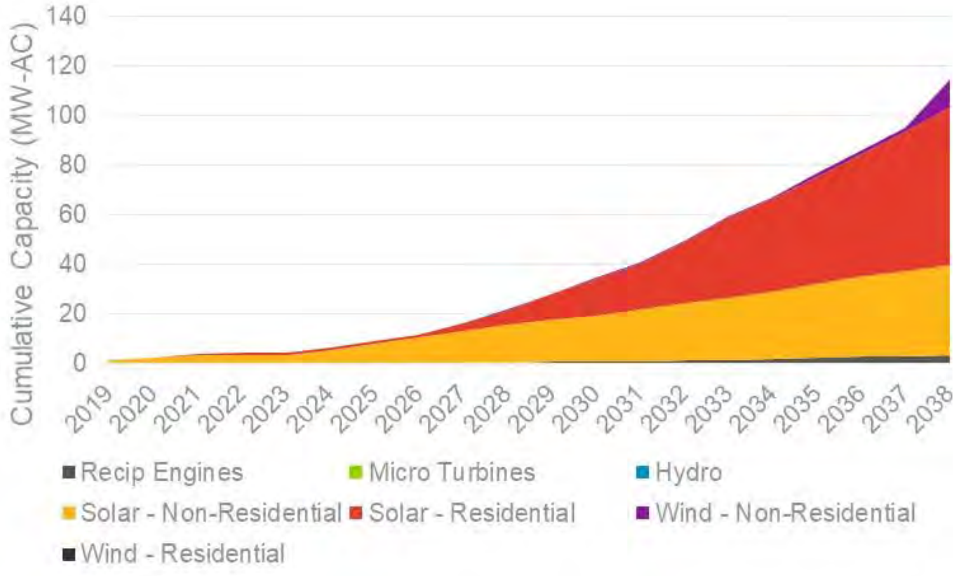


Figure 33. Cumulative Capacity Installations by Technology, Wyoming High Case

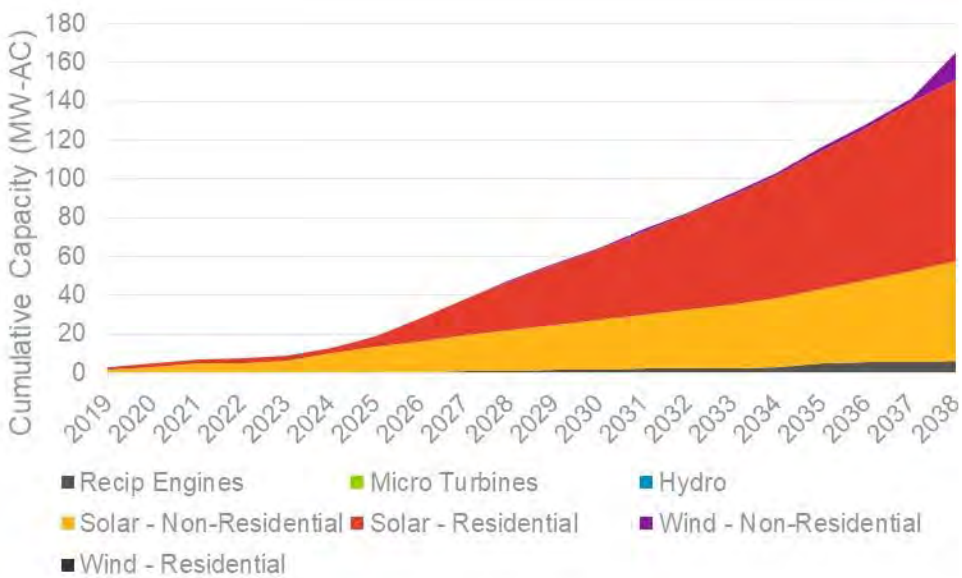
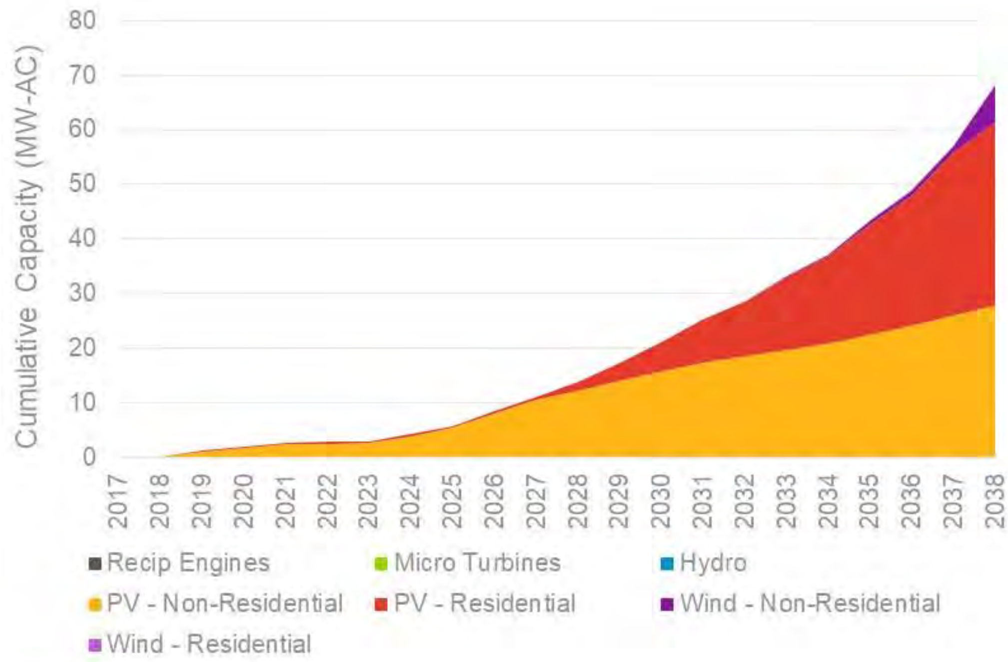


Figure 34. Cumulative Capacity Installations by Technology (MW AC), Wyoming Low Case



APPENDIX A. CUSTOMER DATA

Table 14 California

Rate Class	# Customers	2018 MWh Sales	Avg. Rates ($/kWh)
Residential	35,741	374,836	0.166
Commercial	7,262	226,557	0.151
Industrial	117	57,571	0.137
Irrigation	1,841	96,201	0.132

Table 15 Idaho

Rate Class	# Customers	2018 MWh Sales	Avg. Rates ($/kWh)
Residential	63,910	697,043	0.132
Commercial	8,868	517,881	0.089
Industrial	608	1,712,919	0.072
Irrigation	5,025	643,351	0.091

Table 16 Oregon

Rate Class	# Customers	2018 MWh Sales	Avg. Rates ($/kWh)
Residential	507,660	5,587,970	0.101
Commercial	67,474	5,244,915	0.091
Industrial	1,540	1,700,386	0.078
Irrigation	7,725	332,594	0.096

Table 17 Utah

Rate Class	# Customers	2018 MWh Sales	Avg. Rates ($/kWh)
Residential	807,897	6,824,025	0.110
Commercial	87,524	8,766,980	0.058
Industrial	4,892	7,725,402	0.065
Irrigation	3,249	222,757	0.077

Table 18 Washington

Rate Class	# Customers	2018 MWh Sales	Avg. Rates ($/kWh)
Residential	109,376	1,582,882	0.099
Commercial	16,021	1,528,895	0.084
Industrial	477	753,191	0.072
Irrigation	5,057	160,403	0.087

Table 19 Wyoming

Rate Class	# Customers	2018 MWh Sales	Avg. Rates ($/kWh)
Residential	115,479	1,016,366	0.119
Commercial	23,010	1,382,275	0.090
Industrial	2,064	6,878,595	0.066
Irrigation	764	24,564	0.092

APPENDIX B. SYSTEM CAPACITY ASSUMPTIONS

Table 20 Access Factors (%)

Technology	CA	ID	OR	UT	WA	WY
Recip. Engines	N/A	N/A	N/A	N/A	N/A	N/A
Micro Turbines	N/A	N/A	N/A	N/A	N/A	N/A
Small Hydro	N/A	N/A	N/A	N/A	N/A	N/A
PV - Com	42%	42%	42%	42%	42%	42%
PV - Res	35%	35%	35%	35%	35%	35%
Wind - Com	5%	5%	8%	16%	8%	51%
Wind - Res	5%	5%	8%	16%	8%	51%

Table 21 California (kW AC)

Technology	Commercial	Irrigation	Residential	Industrial
Recip. Engines	2	N/A	N/A	28
Micro Turbines	2	N/A	N/A	28
Small Hydro	500	N/A	N/A	500
PV - Com	18	29	N/A	212
PV - Res	N/A	N/A	6	N/A
Wind - Com	10	16	N/A	113
Wind - Res	N/A	N/A	3	N/A

Table 22 Idaho (kW AC)

Technology	Commercial	Irrigation	Residential	Industrial
Recip. Engines	4	N/A	N/A	185
Micro Turbines	4	N/A	N/A	185
Small Hydro	500	N/A	N/A	500
PV - Com	31	68	N/A	250
PV - Res	N/A	N/A	6	N/A
Wind - Com	29	62	N/A	1515
Wind - Res	N/A	N/A	6	N/A

Table 23 Oregon (kW AC)

Technology	Commercial	Irrigation	Residential	Industrial
Recip. Engines	6	N/A	N/A	110
Micro Turbines	6	N/A	N/A	110
Small Hydro	500	N/A	N/A	500
PV - Com	25	32	N/A	100
PV - Res	N/A	N/A	6	N/A
Wind - Com	30	17	N/A	584
Wind - Res	N/A	N/A	4	N/A

Table 24 Utah (kW AC)

Technology	Commercial	Irrigation	Residential	Industrial
Recip. Engines	7	N/A	N/A	150
Micro Turbines	7	N/A	N/A	150
Small Hydro	500	N/A	N/A	500
PV - Com	58	39	N/A	130
PV - Res	N/A	N/A	5	N/A
Wind - Com	56	N/A	N/A	938
Wind - Res	N/A	N/A	5	N/A

Table 25 Washington (kW AC)

Technology	Commercial	Irrigation	Residential	Industrial
Recip. Engines	6	N/A	N/A	88
Micro Turbines	6	N/A	N/A	88
Small Hydro	500	N/A	N/A	500
PV - Com	65	21	N/A	250
PV - Res	N/A	N/A	10	N/A
Wind - Com	41	13	N/A	655
Wind - Res	N/A	N/A	6	N/A

Table 26 Wyoming (kW AC)

Technology	Commercial	Irrigation	Residential	Industrial
Recip. Engines	150	N/A	N/A	150
Micro Turbines	150	N/A	N/A	150
Small Hydro	500	N/A	N/A	500
PV - Com	25	17	N/A	150
PV - Res	N/A	N/A	5	N/A
Wind - Com	23	11	N/A	1192
Wind - Res	N/A	N/A	3	N/A

APPENDIX C. WASHINGTON HIGH-EFFICIENCY COGENERATION LEVELIZED COSTS

Section 480.109.100 of the Washington Administrative Code[26] establishes high-efficiency cogeneration as a form of conservation that electric utilities must assess when identifying cost-effective, reliable, and feasible conservation for the purpose of establishing 10-year forecasts and biennial targets. To supplement the analysis in the main body of this report addressing reliability and feasibility, this appendix, analyzes the levelized cost of energy (LCOE) of these resources, for use in cost-effectiveness analysis.

Key assumptions for the analysis are presented in Table 27 and Table 28. It is worth noting that the LCOE calculation is for the electrical generation component only and the cost of the heat recapture and recovery was taken out of the total installed system cost. PacifiCorp provided the natural gas pricing and the weighted average cost of capital (WACC) assumptions.

C.1 Key Assumptions

Table 27 Reciprocating Engines LCOE – Key Assumptions[27]

DG Resource Costs	Units	2019	2028	2038	Notes
Installed System Cost	$/W	$2.67/W	$2.77/W	$2.88/W	• EPA, Catalog of CHP Technologies, March 2015, pg. 2-15 • Assumed cost for electrical generation only, system cost was reduced by 10% to exclude heating generation costs.
Asset Life	Years	25	25	25	
Capacity Factor	%	85%	85%	85%	Navigant Assumption
Variable O&M	$/MWh	$20	$20	$20	ICF International Inc., Combined Heat and Power: Policy Analysis and 2011-2030 Market Assessment, pg. 92
Fuel Cost	$/MMBtu	PacifiCorp Gas Forecast	PacifiCorp Gas Forecast	PacifiCorp Gas Forecast	Provided by PacifiCorp
WACC	%	6.57%	6.57%	6.57%	Provided by PacifiCorp

[26] http://apps.leg.wa.gov/WAC/default.aspx?cite=480-109-100

[27] EPA, Catalog of CHP Technologies: www.epa.gov/sites/production/files/2015-07/documents/catalog_of_chp_technologies.pdf; ICF, Combined Heat and Power Policy Analysis, www.energy.ca.gov/2012publications/CEC-200-2012-002/CEC-200-2012-002.pdf

Table 28 Micro-turbines LCOE – Key Assumptions[28]

DG Resource Costs	Units	2019	2028	2038	Notes
Installed System Cost	$/W	$2.56/W	$2.55/W	$2.54/W	• EPA, Catalog of CHP Technologies, March 2015, pg. 2-15 • Assumed cost for electrical generation only, system cost was reduced by 5% to exclude heating generation costs.
Asset Life	Years	25	25	25	Assumption
Capacity Factor	%	85%	85%	85%	Assumption
Variable O&M	$/MWh	$20	$20	$20	ICF International Inc., Combined Heat and Power: Policy Analysis and 2011-2030 Market Assessment, pg. 92
Fuel Cost	$/MMBtu	PacifiCorp Gas Forecast	PacifiCorp Gas Forecast	PacifiCorp Gas Forecast	Provided by PacifiCorp
WACC	%	6.57%	6.57%	6.57%	Provided by PacifiCorp

C.2 Results

The results of the LCOE analysis are presented in Table 29, with levelized costs estimated to range from $92/MWh to $115/MWh over the forecast period, varying by year and technology.

Table 29 LCOE Results – Electric Component Only

Technology	Units	2017	2026	2036
Reciprocating Engines	$/MWh	91.1	103.4	115.0
Microturbines	$/MWh	92.5	101.8	111.6

[28] EPA, Catalog of CHP Technologies: www.epa.gov/sites/production/files/2015-07/documents/catalog_of_chp_technologies.pdf; ICF, Combined Heat and Power Policy Analysis, www.energy.ca.gov/2012publications/CEC-200-2012-002/CEC-200-2012-002.pdf

APPENDIX D. DETAILED NUMERIC RESULTS

D.1 Utah

Table 30. Utah – Incremental Annual Market Penetration (MW AC) – Base Case

Technology	Sector	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.3	0.3	0.3	0.3	0.4	0.5	0.4	0.5	0.6	0.3	0.5	0.5	0.2	0.6	0.5	0.3	0.7	0.5	0.4	0.5
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.1	0.1	0.1	0.0	0.0	0.1	0.1	0.1	0.1	0.0	0.0	0.1	0.0	0.1	0.1	0.1	0.2	0.2	0.2	0.2
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	31.4	77.6	9.3	2.5	2.5	2.8	2.2	2.0	2.5	3.1	2.6	2.8	2.8	4.0	42.0	41.3	48.3	43.1	46.2	62.8
PV	Commercial	2.3	6.2	0.3	0.3	0.3	1.4	2.0	1.3	4.0	5.0	5.0	4.6	4.5	4.9	4.9	4.5	4.7	5.1	12.7	17.9
PV	Industrial	0.4	0.3	0.4	0.1	0.1	0.5	0.7	0.5	0.6	0.7	1.3	1.8	2.6	3.3	1.9	2.3	2.1	1.6	1.4	1.1
PV	Irrigation	0.0	0.0	0.1	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.4	0.5	0.5	0.4	0.4
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Table 31. Utah – Incremental Annual Market Penetration (MWh) – Base Case

Technology	Sector	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	2067	2214	2513	2444	3023	3907	3257	3923	4172	1919	3629	3390	1496	4459	3989	2275	5401	3675	3141	3821
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	737	739	891	14	15	607	386	1055	796	61	365	454	45	583	761	440	1734	1806	1408	1634
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	66047	163371	19580	5207	5279	5893	4569	4264	5240	6445	5388	5827	5927	8331	88522	86962	101780	90825	97299	132218
PV	Commercial	4798	13016	575	718	728	2963	4131	2654	8412	10447	10621	9604	9534	10334	10258	9449	9906	10696	26686	37792
PV	Industrial	806	537	808	181	183	1112	1425	1039	1307	1402	2681	3698	5578	6903	4084	4901	4340	3333	2879	2334
PV	Irrigation	72	90	106	35	36	86	205	135	211	227	221	230	182	518	490	908	950	974	917	800
Wind	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	70
Wind	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table 32. Utah – Incremental Annual Market Penetration (MW AC) – Low Case

Technology	Sector	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.2	0.1	0.2	0.0	0.0	0.2	0.1	0.2	0.2	0.1	0.2	0.1	0.1	0.2	0.1	0.0	0.2	0.1	0.1	0.1
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	40.2	2.1	1.8	2.0	2.0	2.3	1.8	1.9	2.0	2.5	2.1	2.3	2.3	2.8	2.3	2.8	3.0	12.9	33.0	24.4
PV	Commercial	0.3	0.3	0.3	0.3	0.3	0.9	2.1	1.3	1.8	2.8	3.5	2.9	3.6	3.1	3.1	4.2	3.6	3.8	3.7	3.4
PV	Industrial	0.1	0.3	0.3	0.1	0.1	0.4	0.7	0.4	0.6	0.6	0.5	0.5	0.4	0.9	1.2	1.9	2.3	2.4	1.7	2.1
PV	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Table 33. Utah – Incremental Annual Market Penetration (MWh) – Low Case

Technology	Sector	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	1393	815	1527	27	153	1556	820	1403	1680	999	1385	975	472	1199	959	261	1120	1108	927	670

Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	385	153	112	8	8	15	0	4	8	21	9	13	14	27	14	26	28	37	23	0
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	84618	4421	3809	4241	4299	4800	3721	3994	4268	5249	4388	4746	4827	5920	4908	5953	6215	27176	69416	51343
PV	Commercial	735	611	548	685	695	1936	4479	2656	3703	5890	7343	6161	7592	6634	6514	8768	7489	8089	7875	7190
PV	Industrial	159	542	627	165	167	848	1386	865	1267	1171	949	984	932	1974	2446	3996	4846	5021	3490	4350
PV	Irrigation	34	72	76	34	35	45	201	135	208	186	142	147	176	154	145	163	170	287	384	363
Wind	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	27
Wind	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table 34. Utah – Incremental Annual Market Penetration (MW AC) – High Case

Technology	Sector	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.3	0.3	0.4	0.4	0.5	0.6	0.6	0.6	0.7	0.7	0.6	0.7	0.5	0.6	0.5	0.5	0.6	0.4	0.4	0.3
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.1	0.1	0.2	0.0	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.2	0.2	0.3	0.6	0.6	1.0
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	31.4	77.6	10.5	3.0	3.0	3.4	2.6	2.4	3.0	3.7	37.1	41.3	35.7	52.5	44.6	65.4	57.8	65.0	49.5	67.8
PV	Commercial	2.3	6.2	0.4	0.4	0.9	3.1	7.2	5.7	7.1	4.8	4.8	5.0	4.1	9.7	18.9	22.2	17.4	21.7	15.4	15.9
PV	Industrial	0.4	0.3	0.4	0.1	0.4	1.0	1.0	1.5	3.8	3.0	2.3	2.0	1.4	1.6	1.1	1.5	1.4	1.7	1.5	2.1
PV	Irrigation	0.0	0.0	0.1	0.0	0.0	0.1	0.2	0.1	0.2	0.3	0.3	0.5	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.2
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Table 35. Utah – Incremental Annual Market Penetration (MWh) – High Case

Technology	Sector	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	2143	2550	2997	3229	3986	4477	4655	4195	5525	5016	4566	5092	3895	4590	3874	3741	4216	3317	2669	2548
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	904	876	1218	17	1032	1586	1377	1681	1818	1448	1740	1681	1295	2126	1650	1650	1919	4306	4311	7285
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	66047	163371	22026	6274	6359	7100	5504	5137	6313	7764	78119	87069	75261	110677	94037	137753	121666	136974	104183	142724
PV	Commercial	4798	13016	792	755	1830	6616	15157	12058	14868	10165	10064	10494	8697	20401	39833	46730	36685	45636	32442	33541
PV	Industrial	806	537	854	196	743	2012	2034	3192	8055	6357	4743	4255	2898	3355	2402	3058	2897	3570	3094	4389
PV	Irrigation	72	90	111	37	38	295	354	203	379	582	706	1095	828	832	756	731	679	528	580	365
Wind	Residential	0	0	0	0	0	0	0	-1	0	0	0	0	0	0	0	0	0	0	0	80
Wind	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

D.2 Oregon

Table 36. Oregon – Incremental Annual Market Penetration (MW AC) – Base Case

Technology	Sector	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.5	0.4	0.4	0.7
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2

Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	2.5	2.1	2.2	1.6	1.7	1.7	1.7	1.8	2.2	3.1	2.9	11.4	20.2	27.1	33.9	41.6	52.4	41.3	45.1	50.0
PV	Commercial	2.2	1.0	0.9	0.2	0.3	2.0	1.8	1.9	1.7	1.8	1.7	3.5	4.7	9.1	7.1	6.7	4.7	5.4	3.6	3.2
PV	Industrial	0.1	0.0	0.1	0.0	0.0	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.1	0.2	0.2	0.5	0.6	0.7	0.7	0.6
PV	Irrigation	0.3	0.1	0.1	0.0	0.1	0.2	0.3	0.2	0.3	0.2	0.6	1.1	1.0	1.0	0.9	0.7	0.7	0.5	0.4	0.4
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.4	0.1	0.1	5.1
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4

Table 37. Oregon – Incremental Annual Market Penetration (MWh) – Base Case

Technology	Sector	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	255	302	370	101	518	599	641	803	1259	1424	1338	1397	1623	1257	1386	1394	3687	2823	2791	4964
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1389
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	4066	3364	3595	2617	2690	2778	2783	2871	3491	4897	4706	18274	32353	43453	54434	66701	83996	66306	72260	105385
PV	Commercial	3449	1674	1438	256	418	3157	2834	2974	2681	2834	2768	5686	7606	14623	11403	10677	7604	8702	5755	6698
PV	Industrial	157	74	83	14	39	126	146	278	290	271	272	282	240	254	248	726	1007	1168	1097	1296
PV	Irrigation	532	227	229	43	142	377	423	389	454	365	941	1684	1671	1633	1445	1043	1150	855	721	888
Wind	Residential	30	2	-1	27	0	0	0	0	0	1	0	0	0	0	11	25	25	25	20	868
Wind	Commercial	0	0	0	0	0	0	0	0	0	0	0	26	167	156	164	173	841	202	161	7613
Wind	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Irrigation	0	0	0	0	0	0	0	0	0	4	8	9	10	11	11	12	50	11	11	558

Table 38. Oregon – Incremental Annual Market Penetration (MW AC) – Low Case

Technology	Sector	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.1	0.1	0.0
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	2.2	2.1	2.1	1.6	1.7	1.7	1.7	1.8	1.8	2.6	2.6	2.6	2.7	2.8	6.3	11.4	18.4	17.9	20.6	23.6

PV	Commercial	1.9	0.7	1.0	0.1	0.2	1.3	1.7	1.8	1.6	1.5	1.2	1.5	1.1	1.2	1.8	3.2	4.2	6.2	4.3	6.0
PV	Industrial	0.1	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
PV	Irrigation	0.3	0.1	0.1	0.0	0.0	0.2	0.3	0.2	0.2	0.2	0.2	0.2	0.3	0.4	0.6	0.8	0.6	0.9	0.6	0.8
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.1	0.1	2.6
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2

Table 39. Oregon – Incremental Annual Market Penetration (MWh) – Low Case

Technology	Sector	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	12	117	170	0	0	103	320	358	424	491	533	511	464	545	457	536	1769	493	445	259
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	3600	3352	3351	2597	2667	2752	2763	2848	2912	4098	4122	4238	4350	4496	10131	18216	29544	28670	33055	49628
PV	Commercial	3062	1060	1643	235	259	2097	2744	2885	2598	2352	1877	2345	1835	1962	2857	5060	6703	9881	6867	12639
PV	Industrial	154	63	72	13	24	112	110	126	246	225	189	195	191	203	158	210	216	189	179	237
PV	Irrigation	484	216	218	40	44	349	412	378	388	295	339	289	411	719	922	1359	977	1404	936	1625

Wind	Residential	17	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	278
Wind	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	599	145	144	3794
Wind	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5	58	8	10	339

Table 40. Oregon – Incremental Annual Market Penetration (MW AC) – High Case

Technology	Sector	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.0	0.0	0.1	0.0	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.2	0.2	0.4	0.6	2.3	0.6	0.5	0.3
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.3	0.2	0.3	0.3
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	1.4	0.6	0.8	0.2	0.3	0.3	0.6	2.9	32.9	27.2	33.5	62.1	52.2	72.6	75.1	88.7	105.5	87.9	109.0	103.2
PV	Commercial	2.2	1.1	1.3	0.2	1.2	2.5	2.5	3.0	7.6	8.6	6.8	6.2	5.3	4.6	3.1	3.6	3.0	3.5	3.8	4.7
PV	Industrial	0.1	0.0	0.1	0.0	0.1	0.2	0.2	0.3	0.2	0.2	0.3	0.5	0.7	0.8	0.6	0.5	0.5	0.3	0.3	0.3
PV	Irrigation	0.3	0.2	0.2	0.0	0.2	0.4	0.3	1.0	1.4	1.2	0.9	0.8	0.6	0.5	0.4	0.5	0.5	0.5	0.7	0.9
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.4	0.1	0.1	6.7
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5

Table 41. Oregon – Incremental Annual Market Penetration (MWh) – High Case

Technology	Sector	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	301	358	598	52	732	1182	1311	1419	1729	1770	1650	1870	1694	1700	2840	4386	17299	4434	3691	2312
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	1189	1392	1123	1184	2461	1857	2333	2103
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	2292	932	1219	371	409	478	901	4644	52710	43642	53724	99619	83645	116465	120358	142286	169183	140895	174726	217446
PV	Commercial	3577	1770	2121	293	1942	4027	4080	4764	12205	13868	10856	10020	8449	7418	4952	5796	4822	5590	6049	9872
PV	Industrial	162	78	87	16	96	396	379	402	384	262	461	822	1058	1291	942	846	726	539	549	559
PV	Irrigation	547	278	285	48	310	599	551	1606	2284	1894	1380	1214	982	743	643	832	788	760	1090	1842
Wind	Residential	36	8	3	39	0	1	0	0	0	1	0	0	21	25	29	25	37	38	37	1456
Wind	Commercial	1	-1	0	0	0	0	0	0	10	137	184	183	200	186	217	195	828	186	205	10000
Wind	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Irrigation	0	0	0	0	0	0	0	6	9	11	12	13	12	15	11	13	51	12	11	702

D.3 Washington

Table 42. Washington – Incremental Annual Market Penetration (MW AC) – Base Case

Technology	Sector	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.8	0.2	0.2	0.1
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	5.4	1.1	2.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.2	0.3	0.3	0.3	0.2	0.3	0.3	0.4	0.3	1.8
PV	Commercial	0.7	0.1	0.2	0.1	0.1	0.1	0.6	1.1	1.0	1.0	1.8	3.6	4.1	4.1	3.6	2.7	3.0	2.2	1.9	1.7
PV	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.3	0.5	0.6	0.5	0.4	0.4
PV	Irrigation	0.1	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.2	0.3	0.4	0.4	0.4	0.3	0.3	0.2	0.3	0.2	0.2
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.8
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1

Table 43. Washington – Incremental Annual Market Penetration (MWh) – Base Case

Technology	Sector	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	220	266	331	68	370	460	455	540	565	531	556	551	449	693	829	848	6114	1411	1224	1086
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	38	40	65	-1	-1	0	81	187	170	134	226	174	178	265	262	242	752	418	620	523
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	9834	2066	4032	281	331	427	312	407	414	512	382	456	467	562	422	530	554	651	485	3832
PV	Commercial	1294	191	314	165	194	251	1034	1936	1735	1839	3275	6597	7408	7384	6592	4836	5414	4055	3347	3542
PV	Industrial	87	18	11	15	18	23	17	131	220	233	199	241	204	294	484	836	1172	926	640	829
PV	Irrigation	140	21	40	18	21	27	142	206	159	316	588	780	759	726	622	453	413	472	327	369
Wind	Residential	8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	163
Wind	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	131	50	50	1254
Wind	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	21	5	5	157

Table 44. Washington – Incremental Annual Market Penetration (MW AC) – Low Case

Technology	Sector	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038

Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.0	0.0	0.0
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	4.4	0.9	1.0	0.1	0.1	0.2	0.1	0.2	0.2	0.2	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
PV	Commercial	0.5	0.1	0.1	0.1	0.1	0.1	0.2	0.9	0.9	0.7	0.8	0.7	0.7	1.8	1.8	3.3	2.4	3.5	3.3	2.2
PV	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2
PV	Irrigation	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.2	0.1	0.3	0.4	0.4	0.3	0.3	0.2
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Table 45. Washington – Incremental Annual Adoption (MWh) – Low Case

Technology	Sector	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Reciprocating Engine	Industrial	150	162	222	-8	3	246	223	333	304	195	288	285	195	342	228	223	1556	338	290	171
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	7958	1717	1754	191	225	291	213	277	282	348	260	310	318	382	287	361	377	443	330	349
PV	Commercial	939	184	112	156	184	237	392	1650	1685	1277	1453	1262	1186	3178	3208	5993	4384	6387	5954	4641
PV	Industrial	84	17	10	15	17	22	16	21	137	165	160	169	164	143	169	149	155	168	239	475
PV	Irrigation	103	20	33	17	20	26	60	176	180	137	155	198	321	253	606	637	636	462	578	446
Wind	Residential	6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	141
Wind	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	106
Wind	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	20

Table 46. Washington – Incremental Annual Market Penetration (MW AC) – High Case

Technology	Sector	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.0	0.0	0.1	0.0	0.1	0.1	0.1	0.1	0.1	0.2	0.3	0.2	0.2	0.2	0.2	0.2	0.5	0.1	0.1	0.1
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.1	0.2	0.3
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	6.5	2.5	2.7	0.2	0.3	0.3	0.2	0.3	0.3	0.4	0.3	0.3	0.4	0.4	0.3	0.5	9.5	10.6	6.9	9.8
PV	Commercial	0.7	0.1	0.3	0.1	0.1	0.9	1.3	3.2	6.4	3.9	3.4	3.1	2.5	1.9	1.9	1.7	1.9	2.4	2.0	3.2
PV	Industrial	0.1	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.4	0.5	0.6	0.4	0.4	0.3	0.2	0.3	0.2	0.2
PV	Irrigation	0.1	0.0	0.0	0.0	0.0	0.1	0.2	0.5	0.7	0.4	0.3	0.3	0.2	0.2	0.2	0.2	0.2	0.3	0.2	0.4
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	1.4
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2

Table 47. Washington – Incremental Annual Market Penetration (MWh) – High Case

Technology	Sector	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	259	341	461	8	446	517	556	986	931	1212	1873	1569	1584	1593	1454	1409	3809	1021	795	677
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	80	99	130	-3	148	205	222	288	303	292	423	546	572	682	591	609	1687	774	1362	2251

Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	11727	4539	4830	388	458	590	432	562	572	707	528	630	646	777	583	876	17133	19138	12529	20644
PV	Commercial	1339	199	575	174	206	1568	2402	5849	11621	6995	6209	5561	4508	3423	3473	3098	3443	4312	3560	6662
PV	Industrial	113	19	12	16	19	48	298	315	296	391	672	891	1053	807	683	606	438	509	369	441
PV	Irrigation	145	22	88	19	23	175	366	885	1198	688	588	517	345	403	292	339	397	515	433	832
Wind	Residential	9	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	173
Wind	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	9	62	261	56	45	2043
Wind	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	3	6	6	27	5	6	241

D.4 Idaho

Table 48. Idaho – Incremental Annual Market Penetration (MW AC) – Base Case

Technology	Sector	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.0	0.0	0.1	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	1.1	0.3	0.3	0.4
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Micro Turbine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.2	0.1	0.1	0.1
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	4.9	1.1	1.1	0.3	0.3	0.3	0.3	0.3	2.3	5.0	3.6	5.1	4.4	4.9	5.3	5.9	6.4	7.1	5.3	5.1
PV	Commercial	0.4	0.2	0.2	0.1	0.2	0.3	0.8	1.1	1.5	1.0	1.1	1.0	0.6	0.6	0.6	0.5	0.5	0.7	0.7	0.8
PV	Industrial	0.2	0.1	0.1	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.1	0.4	0.6	0.7	0.6	0.6	0.5	0.4	0.3	0.3
PV	Irrigation	0.5	0.3	0.4	0.1	0.1	0.7	1.0	1.5	1.5	1.5	1.3	0.9	0.9	0.7	0.6	0.7	0.7	0.7	1.0	1.1
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Table 49. Idaho – Incremental Annual Market Penetration (MWh) – Base Case

Technology	Sector	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	314	364	470	50	567	660	728	874	852	786	854	956	684	907	704	678	8049	2373	2225	3307
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	0	0	0	0	0	0	0	0	0	0	108	360	280	481	465	394	1382	491	430	442
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	10086	2201	2267	614	642	684	584	620	4825	10247	7337	10553	9093	10154	10896	12139	13297	14657	10969	10823
PV	Commercial	830	441	482	115	391	607	1605	2215	3082	1978	2271	2013	1340	1253	1315	1106	942	1346	1534	1745
PV	Industrial	402	186	218	39	68	341	345	315	322	382	285	900	1216	1405	1334	1235	1087	786	674	562
PV	Irrigation	1044	638	805	153	224	1532	2030	3098	3127	2997	2647	1914	1935	1457	1306	1385	1531	1429	2048	2381
Wind	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	0
Wind	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table 50. Idaho – Incremental Annual Market Penetration (MW AC) – Low Case

Technology	Sector	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.4	0.1	0.1	0.1
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	4.5	0.2	1.0	0.2	0.3	0.3	0.2	0.2	0.3	3.1	2.3	4.1	2.5	2.7	4.1	3.2	3.5	3.8	3.9	0.7

PV	Commercial	0.4	0.2	0.2	0.1	0.1	0.3	0.3	0.7	1.0	1.0	1.0	0.7	0.9	0.6	0.6	0.8	0.5	0.5	0.5	0.4
PV	Industrial	0.2	0.1	0.1	0.0	0.0	0.1	0.1	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.3	0.3	0.5	0.6	0.4	0.5
PV	Irrigation	0.5	0.3	0.2	0.1	0.2	0.4	0.6	0.8	1.5	1.2	1.2	0.9	0.8	1.0	0.7	0.7	0.6	0.6	0.7	0.4
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Table 51. Idaho – Incremental Annual Market Penetration (MWh) – Low Case

Technology	Sector	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	183	199	236	3	172	293	314	360	346	316	361	311	244	352	183	448	2641	497	453	415
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	9306	500	2007	507	530	564	482	512	613	6362	4846	8415	5193	5665	8450	6640	7155	7805	8076	1430
PV	Commercial	814	426	469	111	220	668	575	1360	1974	2048	2032	1457	1846	1308	1202	1554	1100	1083	964	889
PV	Industrial	391	176	175	36	37	303	293	348	314	233	275	233	218	233	581	622	1132	1180	817	1124
PV	Irrigation	959	620	515	142	384	745	1187	1737	3132	2551	2468	1758	1596	2105	1397	1380	1323	1308	1472	774

Wind	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table 52. Idaho – Incremental Annual Market Penetration (MW AC) – High Case

Technology	Sector	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.0	0.1	0.1	0.0	0.1	0.1	0.1	0.1	0.1	0.2	0.3	0.2	0.3	0.4	0.3	0.4	1.0	0.3	0.2	0.2
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.4	0.1	0.1	0.2
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	5.5	1.2	2.6	0.4	0.4	0.4	2.3	5.5	7.6	4.7	6.6	5.7	6.2	4.9	7.0	5.6	8.1	6.4	6.4	1.4
PV	Commercial	0.4	0.3	0.5	0.1	0.4	1.6	1.6	1.4	1.2	0.6	0.7	0.6	0.5	0.7	0.6	1.0	1.3	1.2	1.4	1.6
PV	Industrial	0.2	0.1	0.1	0.0	0.1	0.2	0.2	0.4	0.8	0.8	0.6	0.5	0.4	0.3	0.3	0.3	0.3	0.3	0.4	0.5
PV	Irrigation	0.6	0.5	0.5	0.1	0.6	2.3	1.9	1.7	1.2	0.9	0.7	0.7	0.7	0.9	1.1	1.0	1.7	1.6	1.9	2.1
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2

Table 53. Idaho – Incremental Annual Market Penetration (MWh) – High Case

Technology	Sector	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	362	427	553	197	660	821	915	1009	1076	1254	1863	1613	2359	3307	2452	3241	7409	2218	1426	1172
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	94	113	159	1	81	282	330	424	464	458	519	508	475	789	1024	1205	2994	1009	965	1274
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	11266	2475	5341	792	829	882	4673	11318	15614	9759	13595	11777	12783	10129	14535	11465	16801	13228	13225	2972
PV	Commercial	846	519	1025	133	870	3404	3358	2968	2388	1317	1360	1151	1118	1376	1201	2029	2668	2492	2851	3365
PV	Industrial	443	198	265	44	245	482	452	769	1739	1616	1235	1115	916	669	698	570	597	693	790	991
PV	Irrigation	1234	1030	1055	176	1157	4818	4023	3442	2443	1851	1413	1452	1451	1823	2216	2125	3609	3349	3835	4524
Wind	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	26
Wind	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	8	15	189
Wind	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	8	18	16	300

D.5 California

Table 54. California – Incremental Annual Market Penetration (MW AC) – Base Case

Technology	Sector	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	1.8	1.1	1.1	0.1	0.1	0.1	0.1	1.6	1.7	2.2	1.8	2.0	2.1	1.7	2.4	1.9	2.0	2.2	2.2	2.5
PV	Commercial	0.4	0.2	0.2	0.0	0.2	0.3	0.2	0.3	0.4	0.4	0.4	0.5	0.6	0.4	0.7	0.9	0.6	1.2	0.7	0.8
PV	Industrial	0.1	0.1	0.1	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.1	0.2	0.2
PV	Irrigation	0.2	0.1	0.1	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.1	0.2	0.2	0.3	0.2	0.3	0.4	0.3
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.7
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2

Table 55. California – Incremental Annual Market Penetration (MWh) – Base Case

Technology	Sector	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	115	115	168	49	204	242	199	284	305	220	313	320	164	314	294	105	995	100	326	64
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	102	113	139	56	170	200	218	243	260	281	279	285	285	295	277	287	746	349	326	64
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	3784	2374	2456	121	127	166	125	3392	3737	4790	3911	4220	4559	3540	5174	3997	4307	4754	4696	5202
PV	Commercial	755	531	488	73	446	629	508	581	902	850	929	1099	1224	821	1553	1879	1189	2464	1423	1626
PV	Industrial	191	123	110	17	118	128	119	108	153	148	156	186	205	258	288	355	423	281	525	341
PV	Irrigation	328	201	180	33	215	210	151	198	222	215	222	378	314	397	443	549	357	738	818	534
Wind	Residential	26	-1	3	13	-1	0	-1	-1	-1	2	3	5	3	5	3	3	15	47	54	770
Wind	Commercial	3	0	6	8	9	10	12	12	14	13	12	12	13	11	9	18	137	19	28	1076
Wind	Industrial	0	0	0	1	1	1	1	1	1	2	1	2	1	1	1	3	10	2	2	100
Wind	Irrigation	0	0	1	2	3	4	4	4	5	5	4	5	4	5	3	4	15	8	7	276

Table 56. California – Incremental Annual Market Penetration (MW AC) – Low Case

Technology	Sector	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038

Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	1.5	0.7	1.0	0.0	0.0	0.1	0.0	0.8	1.5	1.2	1.2	1.7	1.2	1.3	1.4	1.5	0.9	1.7	1.7	1.11083
PV	Commercial	0.3	0.2	0.2	0.0	0.2	0.2	0.2	0.3	0.3	0.2	0.3	0.2	0.2	0.4	0.3	0.3	0.3	0.4	0.7	0.5
PV	Industrial	0.1	0.1	0.1	0.0	0.0	0.1	0.1	0.0	0.1	0.0	0.1	0.0	0.1	0.0	0.1	0.1	0.1	0.1	0.1	0.1
PV	Irrigation	0.2	0.1	0.1	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.1	0.1
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1

Table 57. California – Incremental Annual Market Penetration (MWh) – Low Case

Technology	Sector	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Reciprocating Engine	Industrial	92	94	132	37	156	150	190	210	166	228	149	214	212	113	189	75	786	73	39	232
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	72	87	105	46	124	160	156	171	142	181	174	173	169	172	156	161	534	210	195	43
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	3122	1524	2067	99	104	136	67	1799	3228	2528	2612	3571	2648	2889	2892	3175	1924	3675	3671	2340
PV	Commercial	722	510	464	71	461	474	427	627	553	436	669	462	440	935	551	650	726	838	1543	1026
PV	Industrial	179	121	108	17	99	125	108	95	125	84	114	83	132	99	172	121	137	159	285	196
PV	Irrigation	333	174	178	28	183	212	147	180	147	170	165	122	185	143	239	174	196	396	238	284
Wind	Residential	11	6	5	10	0	0	-1	0	0	0	0	0	3	3	3	3	3	3	3	215
Wind	Commercial	2	0	3	7	7	9	9	10	10	11	10	12	10	10	6	8	30	18	16	585
Wind	Industrial	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	4	1	2	59
Wind	Irrigation	0	0	1	2	2	2	2	3	4	4	3	4	3	3	4	3	14	3	3	184

Table 58. California – Incremental Annual Market Penetration (MW AC) – High Case

Technology	Sector	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.1	0.1	0.0	0.1
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.2	0.0	0.1	0.1
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	1.8	1.2	1.7	0.1	0.1	0.5	3.2	3.0	2.7	2.4	2.5	1.8	2.8	2.2	2.1	2.4	2.5	2.8	2.7	1.8
PV	Commercial	0.4	0.3	0.2	0.0	0.3	0.5	0.6	0.6	0.8	0.7	0.8	0.5	1.0	1.1	0.7	1.4	0.9	1.0	1.0	1.1
PV	Industrial	0.1	0.1	0.1	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.1	0.2	0.3	0.2	0.4	0.2	0.2
PV	Irrigation	0.1	0.1	0.1	0.0	0.1	0.1	0.1	0.2	0.2	0.2	0.3	0.2	0.3	0.3	0.4	0.2	0.5	0.3	0.6	0.4
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.5
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.9
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3

Table 59. California – Incremental Annual Market Penetration (MWh) – High Case

Technology	Sector	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	121	151	187	46	226	269	297	334	360	255	372	381	383	183	353	366	952	440	65	425
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	105	130	160	83	204	242	267	389	340	371	372	381	383	183	353	366	1268	124	410	449

Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	3849	2658	3562	145	152	1107	6861	6468	5856	5092	5258	3945	5987	4673	4596	5061	5416	5945	5767	3794
PV	Commercial	860	559	519	75	659	1001	1291	1386	1739	1556	1716	1092	2056	2459	1398	2993	1850	2081	2049	2321
PV	Industrial	192	126	113	24	169	181	216	306	320	294	324	380	422	276	527	628	392	809	463	526
PV	Irrigation	319	205	184	42	272	274	310	431	453	421	682	328	608	740	821	523	1073	695	1304	829
Wind	Residential	55	-1	-1	19	-1	-1	-1	-1	-1	0	-1	-1	-1	43	86	68	119	91	96	2198
Wind	Commercial	2	0	7	9	10	12	12	14	15	15	13	22	21	21	44	33	132	26	21	1264
Wind	Industrial	0	0	0	1	1	1	1	2	2	2	2	3	3	3	3	3	9	2	3	122
Wind	Irrigation	1	0	1	3	3	4	4	5	5	6	5	5	5	5	4	4	44	19	12	431

D.6 Wyoming

Table 60. Wyoming – Incremental Annual Market Penetration (MW AC) – Base Case

Technology	Sector	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.3	0.2	0.2	0.2	0.7	0.2	0.2	0.5
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	0.2	0.1	0.6	0.0	0.0	0.0	0.0	0.0	2.0	2.8	4.4	4.5	4.0	6.1	7.1	5.2	5.7	6.4	6.8	7.4
PV	Commercial	0.8	0.8	0.8	0.1	0.1	1.5	2.2	2.2	2.1	2.0	1.3	1.2	1.2	1.0	0.9	0.8	1.2	1.6	1.3	1.5
PV	Industrial	0.3	0.2	0.2	0.0	0.0	0.3	0.4	0.3	0.3	0.3	0.3	0.3	0.8	1.2	1.3	1.3	1.2	1.1	0.7	0.6
PV	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.5	0.1	0.1	9.0
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2

Table 61. Wyoming – Incremental Annual Market Penetration (MWh) – Base Case

Technology	Sector	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	0	0	0	0	0	0	0	0	246	1402	1802	1728	1885	1850	1689	1752	5406	1506	1368	3452
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

PV	Residential	480	118	1253	87	87	98	70	100	4395	5996	9603	9698	8631	13127	15412	11311	12422	13949	14681	15538
PV	Commercial	1831	1639	1672	257	256	3290	4770	4854	4611	4264	2910	2688	2674	2178	1981	1827	2625	3395	2848	3255
PV	Industrial	716	345	416	64	80	676	764	620	732	676	654	686	1829	2576	2879	2815	2575	2320	1518	1303
PV	Irrigation	62	31	50	7	7	91	111	110	102	92	63	58	48	50	47	57	52	85	71	118
Wind	Residential	7	3	2	8	0	0	0	0	0	0	0	1	3	4	6	5	5	5	5	248
Wind	Commercial	-1	-1	-1	0	0	0	-1	0	66	228	225	251	270	289	245	301	1237	289	212	13392
Wind	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Irrigation	0	0	0	0	0	0	0	1	4	4	4	5	5	5	5	5	21	5	5	249

Table 62. Wyoming – Incremental Annual Market Penetration (MW AC) – Low Case

Technology	Sector	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	0.2	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.1	1.1	1.7	2.1	2.5	2.1	3.4	2.7	4.3	3.4	6.2	3.5
PV	Commercial	0.8	0.4	0.5	0.1	0.2	0.9	1.2	2.2	2.3	1.3	1.7	1.2	1.4	1.0	0.9	0.9	0.9	0.9	0.8	0.8

PV	Industrial	0.2	0.1	0.2	0.0	0.0	0.3	0.3	0.3	0.3	0.3	0.2	0.3	0.2	0.2	0.2	0.3	0.6	0.8	1.1	1.1
PV	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.6	0.1	0.1	5.7
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1

Table 63. Wyoming – Incremental Annual Market Penetration (MWh) – Low Case

Technology	Sector	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	424	115	111	62	62	70	49	59	200	2408	3576	4531	5511	4454	7260	5749	9328	7377	13471	7414
PV	Commercial	1652	897	1145	222	325	1923	2671	4858	4979	2902	3626	2590	3059	2229	1922	1957	1886	1964	1670	1612
PV	Industrial	522	325	325	57	57	559	657	599	712	559	439	561	434	471	445	732	1260	1702	2385	2335
PV	Irrigation	42	28	38	6	6	51	98	90	113	87	58	57	66	48	42	43	42	45	39	39
Wind	Residential	5	2	0	5	0	0	0	0	0	0	0	0	0	0	1	3	3	3	3	134

Wind	Commercial	-1	0	0	0	0	0	0	0	0	0	0	0	0	0	226	202	1389	202	239	8429
Wind	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	1	4	4	4	24	5	3	165

Table 64. Wyoming – Incremental Annual Market Penetration (MW AC) – High Case

Technology	Sector	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.0	0.0	0.0	0.0	0.0	0.1	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.2	0.6	1.7	0.5	0.5	0.4
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	1.1	0.5	1.0	0.1	0.1	0.1	2.6	6.1	7.0	6.7	5.7	5.0	7.1	6.3	6.6	7.4	8.2	6.5	9.2	7.0
PV	Commercial	1.4	1.0	1.2	0.1	1.2	3.1	2.7	2.2	1.6	1.3	1.0	1.2	1.2	1.2	1.9	1.8	2.2	3.8	3.2	3.8
PV	Industrial	0.4	0.2	0.2	0.0	0.2	0.4	0.5	0.4	1.0	1.3	1.5	1.2	1.0	0.9	0.7	0.6	0.5	0.6	0.6	0.7
PV	Irrigation	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.5	0.1	0.1	11.1
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2

Table 65. Wyoming – Incremental Annual Market Penetration (MWh) – High Case

Technology	Sector	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	0	0	0	0	0	1057	1406	1674	1895	1933	2234	2099	2173	2264	1818	4194	12773	4049	3806	3093
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	2289	1013	2190	162	161	182	5643	13270	15206	14495	12445	10734	15361	13570	14349	16133	17679	14178	19965	14671
PV	Commercial	3041	2175	2652	315	2556	6675	5854	4811	3411	2785	2184	2491	2702	2661	4060	3904	4674	8277	6952	7945
PV	Industrial	878	439	444	73	530	974	982	941	2271	2751	3320	2574	2209	1968	1575	1216	1182	1303	1303	1527
PV	Irrigation	90	61	64	8	63	151	127	103	74	56	52	61	67	91	78	98	169	156	174	199
Wind	Residential	9	5	3	10	0	0	0	0	0	0	3	6	6	5	6	5	7	6	5	326
Wind	Commercial	-2	-1	-1	0	0	0	98	204	245	287	278	340	316	287	322	331	1213	311	328	16419
Wind	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Irrigation	0	0	0	0	0	0	4	4	5	5	6	6	5	6	6	6	21	6	5	308

APPENDIX P – RENEWABLE RESOURCES ASSESSMENT

A study on renewable resources and energy storage was commissioned to support PacifiCorp's 2019 Integrated Resource Plan (IRP). The 2018 Renewable Resources Assessment, prepared by Burns & McDonnell Engineering Company, Inc. (BMcD) is screening-level in nature and includes a comparison of technical capabilities, capital costs, and operations and maintenance costs that are representative of renewable energy and storage technologies. BMcD evaluated energy storage options of Pumped Hydro Energy Storage, Compressed Air Energy Storage, Lithium Ion Battery, Flow Battery, as well as wind and solar and combinations of these resource types.

This report compiles the assumptions and methodologies used by BMcD during the Assessment. Its purpose is to articulate that the delivered information is in alignment with PacifiCorp's intent to advance its resource planning initiatives.

2018 Renewable Resources Assessment

PacifiCorp

2018 Renewable Resources Assessment
Project No. 109571

Revision 3
October 2018

2018 Renewable Resources Assessment

prepared for

PacifiCorp
2018 Renewable Resources Assessment
Salt Lake City, Utah

Project No. 109571

Revision 3
October 2018

prepared by

Burns & McDonnell Engineering Company, Inc.
Kansas City, Missouri

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1.0 INTRODUCTION

PacifiCorp (Owner) retained Burns & McDonnell Engineering Company (BMcD) to evaluate various renewable energy resources in support of the development of the Owner's 2019 Integrated Resource Plan (IRP) and associated resource acquisition portfolios and/or products. The 2018 Renewable Resources Assessment (Assessment) is screening-level in nature and includes a comparison of technical capabilities, capital costs, and O&M costs that are representative of renewable energy and storage technologies listed below.

It is the understanding of BMcD that this Assessment will be used as preliminary information in support of the Owner's long-term power supply planning process. Any technologies of interest to the Owner should be followed by additional detailed studies to further investigate each technology and its direct application within the Owner's long-term plans.

1.1 Evaluated Technologies

- Single Axis Tracking Solar
- Onshore Wind
- Energy Storage
  - Pumped Hydro Energy Storage (PHES)
  - Compressed Air Energy Storage (CAES)
  - Lithium Ion Battery
  - Flow Battery
- Solar + Energy Storage
- Wind + Energy Storage

1.2 Assessment Approach

This report accompanies the Renewable Resources Assessment spreadsheet files (Summary Tables) provided by BMcD. The Summary Tables are broken out into three separate files for Solar, Wind, and Energy Storage options. The costs are expressed in mid-2018 dollars for a fixed price, turn-key resource implementation. Appendix A includes the Summary Tables.

This report compiles the assumptions and methodologies used by BMcD during the Assessment. Its purpose is to articulate that the delivered information is in alignment with PacifiCorp's intent to advance its resource planning initiatives.

1.3 Statement of Limitations

Estimates and projections prepared by BMcD relating to performance, construction costs, and operating and maintenance costs are based on experience, qualifications, and judgment as a professional consultant. BMcD has no control over weather, cost and availability of labor, material and equipment, labor productivity, construction contractor's procedures and methods, unavoidable delays, construction contractor's method of determining prices, economic conditions, government regulations and laws (including interpretation thereof), competitive bidding and market conditions or other factors affecting such estimates or projections. Actual rates, costs, performance ratings, schedules, etc., may vary from the data provided.

2.0 STUDY BASIS AND ASSUMPTIONS

2.1 Scope Basis

Scope and economic assumptions used in developing the Assessment are presented below. Key assumptions are listed as footnotes in the summary tables, but the following expands on those with greater detail for what is assumed for the various technologies.

2.2 General Assumptions

The assumptions below govern the overall approach of the Assessment:

- All estimates are screening-level in nature, do not reflect guaranteed costs, and are not intended for budgetary purposes. Estimates concentrate on differential values between options and not absolute information.
- All information is preliminary and should not be used for construction purposes.
- All capital cost and O&M estimates are stated in mid-2018 US dollars (USD). Escalation is excluded.
- Estimates assume an Engineer, Procure, Construct (EPC) fixed price contract for project execution.
- Unless stated otherwise, all wind and solar options are based on a generic site with no existing structures or underground utilities and with sufficient area to receive, assemble and temporarily store construction material. Battery options are assumed to be located on existing Owner land.
- Sites are assumed to be flat, with minimal rock and with soils suitable for spread footings.
- Wind and solar technologies were evaluated across five states within Owner's service areas: Washington, Oregon, Idaho, Utah, and Wyoming. The specific locations within each state for potential wind/solar sites were determined by Owner.
- All performance estimates assume new and clean equipment. Operating degradation is excluded.
- Electrical scope is assumed to end at the high side of the generator step up transformer (GSU) unless otherwise specified in the summary table (most notably for CAES and PHES).
- Demolition or removal of hazardous materials is not included.

2.3 EPC Project Indirect Costs

The following project indirect costs are included in capital cost estimates:

- Construction/startup technical service
- Engineering and construction management

- Freight
- Startup spare parts
- EPC fees & contingency

2.4 Owner Costs

Allowances for Owner's costs are included in the pricing estimates. The cost buckets for Owner's costs varies slightly by technology, but is broken out in the summary tables in Appendix A.

2.5 Cost Estimate Exclusions

The following costs are excluded from all estimates:

- Financing fees
- Interest during construction (IDC)
- Escalation
- Performance and payment bond
- Sales tax
- Property taxes and insurance
- Off-site infrastructure
- Utility demand costs
- Decommissioning costs
- Salvage values

2.6 Operating and Maintenance Assumptions

Operations and maintenance (O&M) estimates are based on the following assumptions:

- O&M costs are based on a greenfield facility with new and clean equipment.
- O&M costs are in mid-2018 USD.
- Property taxes allowance included for solar and onshore wind options.
- Land lease allowance included for PV and onshore wind options.
- Li-Ion battery O&M includes costs for additional cells to be added over time.

3.0 SOLAR PHOTOVOLTAIC

This Assessment includes 5 MW, 50 MW, and 200 MW single axis tracking photovoltaic (PV) options evaluated at five locations within the PacifiCorp services area.

3.1 PV General Description

The conversion of solar radiation to useful energy in the form of electricity is a mature concept with extensive commercial experience that is continually developing into a diverse mix of technological designs. PV cells consist of a base material (most commonly silicon), which is manufactured into thin slices and then layered with positively (i.e. Phosphorus) and negatively (i.e. Boron) charged materials. At the junction of these oppositely charged materials, a "depletion" layer forms. When sunlight strikes the cell, the separation of charged particles generates an electric field that forces current to flow from the negative material to the positive material. This flow of current is captured via wiring connected to an electrode array on one side of the cell and an aluminum back-plate on the other. Approximately 15% of the solar energy incident on the solar cell can be converted to electrical energy by a typical silicon solar cell. As the cell ages, the conversion efficiency degrades at a rate of approximately 2% in the first year and 0.5% per year thereafter. At the end of a typical 30-year period, the conversion efficiency of the cell will still be approximately 80% of its initial efficiency.

3.2 PV Performance

BMcD pulled Typical Meteorological Year (TMY) weather data for each site to determine expected hourly irradiance. BMcD then ran simulations of each PV option using PVSYST software. The resultant capacity factors for single axis tracking systems are shown in the Summary Tables. Inverter loading ratios (ILR) for each base plant nominal output at the point of electrical interconnect are indicated in Table 3-1.

Table 3-1: Inverter Loading Ratios in Assessment

Nominal Output	Single-Axis Tracking (SAT) DC/AC Ratio
5 MW	1.32
50 MW	1.46
200 MW	1.46

There are different panel technologies which may exhibit different performance characteristics depending on the site. This assessment assumes poly-crystalline panels. The alternative, thin film technologies, are typically cheaper per panel, but they are also less energy dense, so it’s likely that more panels would be required to achieve the same output. In addition, the two technologies respond differently to shaded conditions. The two technologies are also impacted differently by current solar tariffs which has also impacted availability of the two.

Appendix B shows the PVSYST model output for a 5 MW block with the input assumptions, losses, and output summary. Appendix C shows an additional output summary page unique for each solar option size and location. TMY data for each site as well as PVSYST 8760 outputs are provided to accompany this report outside of the formal report appendices.

3.3 PV Cost Estimates

Cost estimates were developed using in-house information based on BMcD project experience as an EPC contractor as well as an Owner's Engineer for EPC solar projects. Cost estimates assume an EPC project plus typical Owner's costs. A typical solar project cash flow is included in Appendix F.

PV cost estimates for the single axis tracking systems are included in the Summary Tables. Costs are based on the DC/AC ratios in Table 4-1 above, and $/kW costs, based on the nominal AC output, are shown in Appendix A. The project scope assumes a medium voltage interconnection for the 5 MW options, and a high voltage interconnection for the 50 and 200 MW options. Owner's costs include a switchyard allowance for the larger scale options, but no transmission upgrade costs or high voltage transmission interconnect line costs are included.

PV installed costs have steadily declined for years. The main drivers of cost decreases include substantial module price reductions, lower inverter prices, and higher module efficiency. However, recent US tariffs have had an impact on PV panels and steel imports. Pricing in the summary table is based on actual competitive EPC market quotes since these tariffs have been in place to take into account this impact. The panel tariffs only impact crystalline solar modules, however the availability of CdTe is limited for the next couple years, so it is prudent to assume similar cost increases for thin film panels until the impacts of the tariff are clearer.

The 2018 Assessment excludes land costs from capital and Owner costs. It is assumed that all PV projects will be on leased land with allowances provided in the O&M costs.

3.4 PV O&M Cost Estimate

O&M costs for the PV options are shown in the Summary Tables. O&M costs are derived from BMcD project experience and vendor information. The 2018 Assessment includes allowances for land lease and property tax costs.

The following assumptions and clarifications apply to PV O&M:

- O&M costs assume that the system is remotely operated and that all O&M activities are performed through a third-party contract. Therefore, all O&M costs are modeled as fixed costs, shown in terms of $MM per year.
- Land lease and property tax allowances are included based on in house data from previous projects.
- Equipment O&M costs are included to account for inverter maintenance and other routine equipment inspections.
- BOP costs are included to account for monitoring & security and site maintenance (vegetation, fencing, etc.).
- Panel cleaning and snow removal are not included in O&M costs.
- The capital replacement allowance is a sinking fund for inverter replacements, assuming they will be replaced once during the project life. It is a 15-year levelized cost based on the current inverter capital cost.

3.5 PV Plus Storage

The PV plus storage options combine the PV technology discussed in section 3.0 with the lithium ion batteries described in section 7.0. The battery storage size is set at approximately 25% of the total nominal output of the base solar options, with options for two, four, and eight hours of storage duration.

The storage system is assumed to be electrically coupled to the PV system on the AC side, meaning the PV and storage systems have separate inverters. However, there are use cases such as PV clipping that may be better served by a DC-DC connection. In a DC coupled system, the storage side would have a DC-DC voltage converter and connect to the PV system upstream of the DC-AC inverters. For a clipping application, a DC-DC connection allows the storage system to capture the DC output from the PV modules that may have otherwise been clipped by the inverters. Further study beyond the scope of this assessment would be required to determine the best electrical design for a particular application or site, but at this level of study, the capital costs provided are expected to be suitable for either AC or DC coupled systems.

Capital costs are show as add-on costs, broken out as project and owner’s costs. These represent the additional capital above the PV base cost, intended to capture modest savings to account for shared system costs such as transformer(s) and switchgear. In addition, overlapping owner costs are eliminated or reduced. Finally, a line for O&M add-on costs is also included which can be added with the base PV O&M costs to determine overall facility O&M.

As with the Li-Ion battery options, the co-located storage option assumes an operation profile of one cycle per day, which is used for calculating the O&M costs.

4.0 ON-SHORE WIND

4.1 Wind Energy General Description

Wind turbines convert the kinetic energy of wind into mechanical energy, which can be used to generate electrical energy that is supplied to the grid. Wind turbine energy conversion is a mature technology and is generally grouped into two types of configurations:

- Vertical-axis wind turbines, with the axis of rotation perpendicular to the ground.
- Horizontal-axis wind turbines, with the axis of rotation parallel to the ground.

Over 95 percent of turbines over 100 kW are horizontal-axis. Subsystems for either configuration typically include the following: a blade/rotor assembly to convert the energy in the wind to rotational shaft energy; a drive train, usually including a gearbox and a generator; a tower that supports the rotor and drive train; and other equipment, including controls, electrical cables, ground support equipment and interconnection equipment.

Wind turbine capacity is directly related to wind speed and equipment size, particularly to the rotor/blade diameter. The power generated by a turbine is proportional to the cube of the prevailing wind, that is, if the wind speed doubles, the available power will increase by a factor of eight. Because of this relationship, proper siting of turbines at locations with the highest possible average wind speeds is vital.

Appendix D includes NREL wind resource maps for Idaho, Oregon, Utah, Washington, and Wyoming with the locations of interest marked as provided by Owner.

4.2 Wind Performance

This Assessment includes 200 MW onshore wind generating facilities in Idaho, Oregon, Utah, Washington, and Wyoming service areas. BMcD relied on publicly available data and proprietary computational programs to complete the net capacity factor characterization. Generic project locations were selected within the area specified by Owner.

The Vestas V136-3.6 and GE3.8-137 wind turbine models were assumed for this analysis. The respective nameplate capacity, rotor diameter, and a hub height are provided in the Table 4-1. The maximum tip height of this package is under 500 feet, which means there are less likely to be conflicts with the Federal Aviation Administration (FAA) altitudes available for general aircraft. A generic power curve at standard atmospheric conditions for each of the sites was assumed for the V136-3.6 and GE3.8-137. Note that this turbine is intended only to be representative of a typical International Electrotechnical Commission wind turbine. Because this analysis assumes generic site locations, the turbine selection is not optimized for a specific location or condition. Actual turbine selection requires further site-specific analysis.

Table 4-1: Summary of Wind Turbine Model Information

	Vestas V136-3.6	GE3.8-137
Name Plate Capacity, MW	3.6	3.6
Rotor Diameter, meters	136	137
Hub Height, meters	80	80

Using the NREL wind resource maps, the mean annual hub height wind speed at each potential project location was estimated and then extrapolated for the appropriate hub height to determine a representative wind speed. Using a Rayleigh distribution and power curve for the turbine technology described above, a gross annual capacity factor (GCF) was subsequently estimated for each site for both turbine types.

Annual losses for a wind energy facility were estimated at approximately 17 percent, which is a common assumption for screening level estimates in the wind industry. This loss factor was applied to the gross capacity factor estimates to derive a net annual capacity factor (NCF) for each potential site. Ideally, a utility-scale generation project should have an NCF of 30 percent or better. The NCF estimates for the PacifiCorp service areas are shown in the Summary Tables and represent an average of the two evaluated technologies.

4.3 Wind Cost Estimate

The wind energy cost estimate is shown in the Summary Tables. A typical cash flow for a wind project is included in Appendix F. Cost estimates assume an EPC project plus typical Owner's costs. Costs are based on a 200 MW plant with 3.6 MW turbines (56 total turbines) and 80-meter hub heights.

- Equipment and construction costs are broken down into subcategories per PacifiCorp's request. These breakouts represent the general scale of a 200 MW wind project but are not intended to indicate the expected scope for a specific site.
- The EPC scope includes a GSU transformer for interconnection at 230 kV.
- Land costs are excluded from the EPC and Owner's cost. For the 2018 Study, it is assumed that land is leased, and those costs are incorporated into the O&M estimate.

- Cost estimates also exclude escalation, interest during construction, financing fees, off-site infrastructure, and transmission.

4.4 Wind Energy O&M Estimates

O&M costs in the Summary Tables are derived from in-house information based on BMcD project experience and vendor information. Wind O&M costs are modeled as fixed O&M, including all typical operating expenses including:

- Labor costs
- Turbine O&M
- BOP O&M and other fixed costs (G&A, insurance, environmental costs, etc.)
- Property taxes
- Land lease payments

An allowance for capital replacement costs is not included within the annual O&M estimate in the Summary Table. A capital expenditures budget for a wind farm is generally a reserve that is funded over the life of the project that is dedicated to major component failures. An adequate capital expenditures budget is important for the long-term viability of the project, as major component failures are expected to occur, particularly as the facility ages.

If a capital replacement allowance is desired for planning purposes, Table 4-2 shows indicative budget expectations as a percentage of the total operating cost. As with operating expenses, however, these costs can vary with the type, size, or age of the facility, and project-specific considerations may justify deviations in the budgeted amounts.

Table 4-2: Summary of Indicative Capital Expenditures Budget by Year

Operational Years	Capital Expenditure Budget
0 – 2	None (warranty)
3 – 5	3% – 5%
6 – 10	5% – 10%
11 – 20	10% – 15%
21 – 30	15% – 20%
31 – 40	20% – 25%

4.5 Wind Energy Production Tax Credit

Tax credits such as the production tax credit (PTC) and investment tax credit (ITC) are not factored into the cost or O&M estimates in this Assessment, but an overview of the PTC is included below for reference.

To incentivize wind energy development, the PTC for wind was first included in the Energy Policy Act of 1992. It began as a $15/MWh production credit and has since been adjusted for inflation, currently worth approximately $24/MWh.

The PTC is awarded annually for the first 10 years of a wind facility's operation. Unlike the ITC that is common in the solar industry, there is no upfront incentive to offset capital costs. The PTC value is calculated by multiplying the $/MWh credit times the total energy sold during a given tax year. At the end of the tax year, the total value of the PTC is applied to reduce or eliminate taxes that the owners would normally owe. If the PTC value is greater than the annual tax bill, the excess credits can potentially go unused unless the owner has a suitable tax equity partner.

Since 1992, the changing PTC expiration/phaseout schedules have directly impacted market fluctuations, driving wind industry expansions and contractions. The PTC is currently available for projects that begin construction by the end of 2019, but with a phaseout schedule that began in 2017. Projects that started construction in 2015 and 2016 will receive the full value of the PTC, but those that start(ed) construction in later years will receive reduced credits:

- 2017: 80% of the full PTC value
- 2018: 60% of the full PTC value
- 2019: 40% of the full PTC value
- 2020: PTC Expires

To avoid receiving a reduction in the PTC, a "Safe Harbor" clause allowed for developers to avoid the reduction through an upfront investment in wind turbines by the end of 2016. The Safe Harbor clause allowed for wind projects to be considered as having begun construction by the end of the year if a minimum of 5% of the project's total capital cost was incurred before January 1st, 2017.

Many wind farms were planned for construction and operation when it was assumed they would receive 100% of the PTC. However, with the reduction in the PTC, some of these projects are no longer financially viable for developers to operate. This may result in renegotiated or canceled PPAs, or transfers to utilities for operation.

4.6 Wind Plus Storage

The wind plus storage options combine the wind technology discussed in section 4.0 with the lithium ion batteries described in section 7.0. The battery storage size is set at approximately 25% of the total nominal output of the base solar options, with options for two, four, and eight hours of storage duration. The storage system is assumed to be electrically coupled to the wind system on the AC side, meaning the storage system has its own inverter.

Capital costs are shown as add-on costs, broken out as project and owner's costs. These represent the additional capital above the wind base cost, intended to capture modest savings to account for shared system costs such as transformer(s) and switchgear. In addition, overlapping owner costs are eliminated or reduced. Finally, a line for O&M add-on costs is also included which can be added to the base wind O&M costs to determine overall facility O&M. As with the Li-Ion battery options, the co-located storage option assumes an operation profile of one cycle per day, which is used for calculating the O&M costs.

5.0 PUMPED HYDRO ENERGY STORAGE

5.1 General Description

Pumped-hydro Energy Storage (PHES) offers a way of storing off peak generation that can be dispatched during peak demand hours. This is accomplished using a reversable pump-turbine generator-motor where water is pumped from a lower reservoir to an upper reservoir using surplus off-peak electrical power. Energy is then recaptured by releasing the water back through the turbine to the lower reservoir during peak demand. To utilize PHES, locations need to be identified that have suitable geography near high-voltage transmission lines.

PHES provides the ability to optimize the system for satisfying monthly or even seasonal energy needs and PHES can provide spinning reserve capacity with its rapid ramp-up capability. Energy stored off-peak and delivered on-peak can help reduce on-peak prices and is therefore beneficial to consumers. PHES is well suited for markets where there is a high spread in day-time and night-time energy costs, such that water can be pumped at a low cost and used to generate energy when costs are considerably higher.

PHES also has the ability to reduce cycling of existing generation plants. Additionally, PHES has a direct benefit to renewable resources as it is able to absorb excess energy that otherwise would need to be curtailed due to transmission constraints. This could increase the percentage of power generated by clean technologies and delivered during peak hours.

5.2 PHES Cost Estimate

The PHES cost estimate was based on information provided by developers with limited scope definition. We aligned the costs as closely as possible based on the information provided. The reason information from developers was used versus using a generic site for PHES is due to the significant importance of geographical location for this type of energy storage. The cost estimate is shown in the Summary Tables. PHES can see life cycle benefits as their high capital cost is offset by long lifespan of assets.

6.0 COMPRESSED AIR ENERGY STORAGE

6.1 General Description

Compressed air energy storage (CAES) offers a way of storing off peak generation that can be dispatched during peak demand hours. CAES is a proven, utility-scale energy storage technology that has been in operation globally for over 30 years. To utilize CAES, the project needs a suitable storage site, either above ground or below ground, and availability of transmission and fuel source. CAES facilities use off-peak electricity to power a compressor train that compresses air into an underground reservoir at approximately 850 psig. Energy is then recaptured by releasing the compressed air, heating it (typically) with natural gas firing, and generating power as the heated air travels through an expander.

This method of operation takes advantage of less expensive, off-peak power to charge the system to later be used for generation during periods of higher demand. CAES provides the ability to optimize the system for satisfying monthly, or even seasonal, energy needs and CAES can provide spinning reserve capacity with its rapid ramp-up capability. Energy stored off-peak and delivered on-peak can help reduce on-peak prices and is therefore beneficial to consumers. Additionally, CAES has a direct benefit to renewable resources as it is able to absorb excess energy that otherwise would need to be curtailed due to transmission constraints. This could increase the percentage of power generated by clean technologies and delivered during peak hours.

There have been two commercial CAES plants built and operated in the world. The first plant began commercial operations in 1978 and was installed near Huntorf, Germany. This 290 MW facility included major equipment by Brown, Boveri, and Company (BBC). The second is located near McIntosh, Alabama and is currently owned and operated by PowerSouth (originally by Alabama Electric Cooperative). This 110 MW facility began commercial operations in 1991 and employs Dresser Rand (DR) equipment. BMcD served as the Owner's engineer for this project.

"Second generation" CAES designs have recently been developed, but do not have commercial operating experience. The compression-expansion portion of these designs is similar to "first generation" CAES designs. The designs differ in that a simple cycle gas turbine plant operates in parallel to the compression-expansion train and the exhaust is used in a recuperator instead of utilizing a combustor to preheat the stored air.

CAES is well suited for markets where there is a high spread in day-time and night-time energy costs, such that air can be compressed at a low cost and used to generate energy when costs are considerably higher.

6.2 CAES Cost Estimate

The CAES cost estimate is shown in the Summary Tables. It was developed using generic Siemens information that includes the power island, balance of plant and reservoir. Cost estimates assume an EPC project plus typical Owner's costs.

6.3 CAES Emissions Control

A Selective Catalytic Reduction (SCR) system is utilized in the CAES design along with demineralized water injection in the combustor to achieve NOx emissions of 2 parts per million, volumetric dry (ppmvd). A carbon monoxide (CO) catalyst is also used to control CO emissions to 2 ppmvd at the exit of the stack.

The use of an SCR and a CO catalyst requires additional site infrastructure. An SCR system injects ammonia into the exhaust gas to absorb and react with the exhaust gas to strip out NOx. This requires onsite ammonia storage and provisions for ammonia unloading and transfer.

7.0 BATTERY STORAGE TECHNOLOGY

This Assessment includes standalone battery options for both lithium ion (Li-Ion) and flow battery technologies. Li-Ion options included 1 MW output with 15-minute, 2-hour, 4-hour, and 8-hour storage capacities as well as a 15 MW option with 4-hours of storage. A 1 MW, 6-hour flow cell battery option was also included. Additionally, the solar and wind summary tables include optional costs for adding Li-Ion battery capacity of 25% of the nominal renewable output to the site with 2, 4, or 8-hours of storage.

7.1 General Description

Electrochemical energy storage systems utilize chemical reactions within a battery cell to facilitate electron flow, converting electrical energy to chemical energy when charging and generating an electric current when discharged. Electrochemical technology is continually developing as one of the leading energy storage and load following technologies due to its modularity, ease of installation and operation, and relative design maturity. Development of electrochemical batteries has shifted into three categories, commonly termed “flow,” “conventional,” and “high temperature” battery designs. Each battery type has unique features yielding specific advantages compared to one another.

7.1.1 Flow Batteries

Flow batteries utilize an electrode cell stack with externally stored electrolyte material. The flow battery is comprised of positive and negative electrode cell stacks separated by a selectively permeable ion exchange membrane, in which the charge-inducing chemical reaction occurs, and liquid electrolyte storage tanks, which hold the stored energy until discharge is required. Various control and pumped circulation systems complete the flow battery system in which the cells can be stacked in series to achieve the desired voltage difference.

The battery is charged as the liquid electrolytes are pumped through the electrode cell stacks, which serve only as a catalyst and transport medium to the ion-inducing chemical reaction. The excess positive ions at the anode are allowed through the ion-selective membrane to maintain electroneutrality at the cathode, which experiences a buildup of negative ions. The charged electrolyte solution is circulated back to storage tanks until the process is allowed to repeat in reverse for discharge as necessary.

In addition to external electrolyte storage, flow batteries differ from traditional batteries in that energy conversion occurs as a direct result of the reduction-oxidation reactions occurring in the electrolyte solution itself. The electrode is not a component of the electrochemical fuel and does not participate in the chemical reaction. Therefore, the electrodes are not subject to the same deterioration that depletes electrical performance of traditional batteries, resulting in high cycling life of the flow battery. Flow batteries are also scalable such that energy storage capacity is determined by the size of the electrolyte storage tanks, allowing the system to approach its theoretical energy density. Flow batteries are typically less capital intensive than some conventional batteries but require additional installation and operation costs associated with balance of plant equipment.

7.1.2 Conventional Batteries

A conventional battery contains a cathodic and an anodic electrode and an electrolyte sealed within a cell container that can be connected in series to increase overall facility storage and output. During charging, the electrolyte is ionized such that when discharged, a reduction-oxidation reaction occurs, which forces electrons to migrate from the anode to the cathode thereby generating electric current. Batteries are designated by the electrochemicals utilized within the cell; the most popular conventional batteries are lead acid and Li-Ion type batteries.

Lead acid batteries are the most mature and commercially accessible battery technology, as their design has undergone considerable development since conceptualized in the late 1800s. The Department of Energy (DOE) estimates there is approximately 110 MW of lead acid battery storage currently installed worldwide. Although lead acid batteries require relatively low capital cost, this technology also has inherently high maintenance costs and handling issues associated with toxicity, as well as low energy density (yields higher land and civil work requirements). Lead acid batteries also have a relatively short life cycle at 5 to 10 years, especially when used in high cycling applications.

Li-Ion batteries contain graphite and metal-oxide electrodes and lithium ions dissolved within an organic electrolyte. The movement of lithium ions during cell charge and discharge generates current. Li-Ion technology has seen a resurgence of development in recent years due to its high energy density, low self-discharge, and cycling tolerance. Many Li-Ion manufacturers currently offer 15-year warranties or performance guarantees. Consequently, Li- Ion has gained traction in several markets including the utility and automotive industries.

Li-Ion battery prices are trending downward, and continued development and investment by manufacturers are expected to further reduce production costs. While there is still a wide range of project cost expectations due to market uncertainty, Li-Ion batteries are anticipated to expand their reach in the utility market sector.

7.1.3 High Temperature Batteries

High temperature batteries operate similarly to conventional batteries, but they utilize molten salt electrodes and carry the added advantage that high temperature operation can yield heat for other applications simultaneously. The technology is considered mature with ongoing commercial development at the grid level. The most popular and technically developed high temperature option is the Sodium Sulfur (NaS) battery. Japan-based NGK Insulators, the largest NaS battery manufacturer, installed a 4 MW system in Presidio, Texas in 2010 following operation of systems totaling more than 160 MW since the project's inception in the 1980s.

The NaS battery is typically a hermetically sealed cell that consists of a molten sulfur electrolyte at the cathode and molten sodium electrolyte at the anode, separated by a Beta-alumina ceramic membrane and enclosed in an aluminum casing. The membrane is selectively permeable only to positive sodium ions, which are created from the oxidation of sodium metal and pass through to combine with sulfur resulting in the formation of sodium polysulfides. As power is supplied to the battery in charging, the sodium ions are dissociated from the polysulfides and forced back through the membrane to re-form elemental sodium. The melting points of sodium and sulfur are approximately 98ºC and 113ºC, respectively. To maintain the electrolytes in liquid form and for optimal performance, the NaS battery systems are typically operated and stored at around 300ºC, which results in a higher self-discharge rate of 14 percent to 18 percent. For this reason, these systems are usually designed for use in high-cycling applications and longer discharge durations.

NaS systems are expected to have an operable life of around 15 years and are one of the most developed chemical energy storage technologies. However, unlike other battery types, costs of NaS systems have historically held, making other options more commercially viable at present.

7.2 Battery Emissions Controls

No emission controls are currently required for battery storage facilities. However, Li-Ion batteries can release large amounts of gas during a fire event. While not currently an issue, there is potential for increased scrutiny as more battery systems are placed into service.

7.3 Battery Storage Performance

This assessment includes performance for multiple Li-Ion options as well as one flow battery option. Li-Ion systems can respond in seconds and exhibit excellent ramp rates and round-trip cycle efficiencies. Because the technology is rapidly advancing, there is uncertainty regarding estimates for cycle life, and these estimates vary greatly depending on the application and depth of discharge. The systems in this Assessment are assumed to perform one full cycle per day, and capacity factors are based on the duration of full discharge for 365 days. OEMs typically have battery products that are designed to suit different use-cases such as high power or high energy applications. The power to energy ratio is commonly shown as a C-ratio (for example, a 1MW / 4 MWh system would use a 0.25C battery product). However, the 8-hour battery option is based on a 0.25C system that is sized for twice the power and discharged for eight hours instead of four. While the technology continues to advance, commercially available, high energy batteries for utility scale applications are generally 0.25C and above.

Flow batteries are a maturing technology that is well suited for longer discharge durations (>4 hours, for example). Flow batteries can provide multiple use cases from the same system and they are not expected to exhibit performance degradation like lithium ion technologies. However, they typically have lower round trip efficiency than Li-Ion batteries. Storage durations are currently limited to commercial offerings from select vendors but are expected to broaden over the next several years. Performance guarantees of 20 years are expected with successful commercialization, but there is not necessarily a technical reason that original equipment manufacturer (OEM) and/or balance of plant (BOP) designs could not accommodate 30+ year life.

7.4 Regulatory Trends

Two (2) Federal Energy Regulatory Commission (FERC) Orders released in 2018 are expected to provide clarity on the role of storage in wholesale markets, and potentially drive continued growth. FERC Order 841 requires RTOs and ISOs to develop clear rules regulating the participation of energy storage systems in wholesale energy, capacity, and ancillary services markets. Prior to the final release of FERC 841, the California Public Utilities Commission introduced 11 rules to determine how multi-use storage products participate in California Independent System Operator (CAISO). FERC Order 842 addresses requirements for some generating facilities to provide frequency response, including accommodations for storage technologies. In addition, the Internal Revenue Service (IRS) is considering new guidance for the ITC that will impact projects combining storage with renewables.

7.5 Battery Storage Cost Estimate

The estimated costs of the Li-Ion and flow battery systems are included in the Summary Tables, based on BMcD experience and vendor correspondence. The key cost elements of a Li-Ion battery system are the inverter, the battery cells, the interconnection, and the installation. The capital costs reflect recent trends for overbuild capacity to account for short term degradation. The battery enclosures include space for future augmentation, but the costs associated with augmentation are covered in the O&M costs. It is assumed that land is available at an existing PacifiCorp facility and is therefore excluded from the cost estimate. These options assume the battery interconnects at medium voltage.

Flow battery estimates for the 1 MW option are based on zinc-bromine technology with a 6-hour storage duration. This is a modular design in which the OEM scope includes the stack, electrolyte storage, and associated pumps and controls in a factory assembled package. The EPC scope includes the inverters, switchgear, MV transformer, and installation.

7.6 Battery Storage O&M Cost Estimate

O&M estimates for the Li-Ion and flow battery systems are shown in the Summary Tables, based on BMcD experience and recent market trends. The battery storage system is assumed to be operated remotely.

The technical life of a Li-Ion battery project is expected to be 15 years, but battery performance degrades over time, and this degradation is considered in the system design. Systems can be "overbuilt" by including additional capacity in the initial installation, and they can also be designed for future augmentation. Augmentation means that designs account for the addition of future capacity to maintain guaranteed performance.

Overbuild and augmentation philosophies can vary between projects. Because battery costs are expected to continue falling, many installers/integrators are aiming for lower initial overbuild percentages to reduce initial capital costs, which means guarantees and service contracts will require more future augmentation to maintain capacity. Because costs should be lower in the future, the project economics may favor this approach. This assessment assumes minimal overbuild beyond system efficiency losses, and the O&M estimates include allowances for augmentation.

Battery storage O&M costs are modeled to represent the fixed and variable portions of performance guarantees and augmentation from recent BMcD project experience. The fixed O&M cost for the Li-Ion systems include a nominal fixed cost to administer and maintain the O&M contract with an OEM/integrator, plus an allowance for calendar degradation fees. Calendar degradation represents performance degradation and subsequent augmentation expected to occur regardless of the system's operation profile, even if the batteries sit unused. Because calendar degradation is not tied to system operation or output, it is modeled as part of the fixed O&M.

Variable O&M estimates for Li-ion options account for cycling degradation fees. Cycling the batteries increases performance degradation, so the performance guarantees provided by the OEM and/or integrator are commonly modeled to account for augmentation based on the expected operating profile. The variable O&M estimates in this assessment are based on an operation profile of one charge/discharge cycle per day and may not be valid for increased cycling.

Flow battery O&M costs are modeled around an annual service contract from the OEM or a factory trained third party. Costs are based on correspondence with manufacturers and are subject to change as the technology achieves greater commercialization and utilization in the utility sector. Unlike Li-Ion technologies, flow batteries generally do not exhibit calendar or cycle degradation, so there is not a variable O&M component per cycle. There is mechanical equipment that requires service based on an OEM recommended schedule, which is modeled as a levelized annual cost for the life of the system.

8.0 CONCLUSIONS

This Renewable Energy Resource Technology Assessment provides information to support PacifiCorp's power supply planning efforts. Information provided in this Assessment is screening level in nature and is intended to highlight indicative, differential costs associated with each technology. BMcD recommends that PacifiCorp use this information to update production cost models for comparison of renewable resource alternatives and their applicability to future resource plans. PacifiCorp should pursue additional engineering studies to define project scope, budget, and timeline for technologies of interest.

Renewable options include PV and wind systems. PV is a proven technology for daytime peaking power and a viable option to pursue renewable goals. PV capital costs have steadily declined for years, but recent import tariffs on PV panels and foreign steel may impact market trends. Wind energy generation is a proven technology and turbine costs dropped considerably over the past few years.

Utility-scale battery storage systems are being installed in varied applications from frequency response to arbitrage, and recent cost reduction trends are expected to continue. Li-Ion technology is achieving the greatest market penetration, aided in large part by its dominance in the automotive industry, but other technologies like flow batteries should be monitored, as well.

PacifiCorp's region has several geological sites that can support large scale storage options including PHES and CAES. This gives PacifiCorp flexibility in terms of energy storage. Smaller applications will be much better suited for battery technologies, but if a larger need is identified PHES or CAES could provide excellent larger scale alternatives. Both of these technologies benefit from economies of scale in regard to their total kWh of storage, allowing them to decrease the overall $/kWh project costs.

APPENDIX A – SUMMARY TABLES

PACIFICORP RENEWABLE TECHNOLOGY ASSESSMENT SUMMARY TABLE
ENERGY STORAGE

PROJECT TYPE	**Pumped Hydro**						**Li-Ion Battery**					**Flow Battery**
BASE PLANT DESCRIPTION	**Swan Lake**	**Goldendale**	**Seminoe**	**Flat Canyon**	**Idaho PS 1**							
Nominal Output	400 MW 3,800 MWh	1200 MW 16,800 MWh	700 MW 7,000 MWh	300 MW 1,800 MWh	360 MW 2,880 MWh	320 MW 15,360 MWh	1 MW 0.25 MWh	1 MW 2 MWh	1 MW 4 MWh	1 MW 8 MWh	15 MW 60 MWH	1 MW 6 MWh
Capacity Factor (%)	17%	17%	17%	17%	17%	20%	2%	8%	17%	33%	17%	25%
Startup Time (Cold Start), minutes	1.5	1.5	1.5	1.5	1.5	10	N/A	N/A	N/A	N/A	N/A	N/A
Full Pumping to Full Gen, minutes	4	4	4	4	4	7	N/A	N/A	N/A	N/A	N/A	N/A
Transition Time from Charging to Discharging, minutes (note 10)	6	6	6	6	6	3	<1 sec in active mode	<1 sec in active mode	<1 sec in active mode	<1 sec in active mode	<1 sec in active mode	<1 sec in active mode
Availability Factor, %	90%	90%	90%	90%	90%	96%	97%	97%	97%	97%	97%	95%
Technology Rating	Mature	Mature	Mature	Mature	Mature	Mature	Mature	Mature	Mature	Mature	Mature	Commercial
Life Cycle, yrs	60	60	60	60	60	30+	15	15	15	15	15	20
Permitting & Construction Schedule, year (note 1)	6	10	8	6	12	3	1	1	1	1	1	2
ESTIMATED PERFORMANCE												
Base Load Performance @ (Annual Average)												
Net Plant Output, kW	393,300	1,200,000	700,000	300,000	360,000	320,000	1,000	1,000	1,000	1,000	15,000	1,000
Total Plant Storage, kWh (note 4)	3,736,350	16,800,000	7,000,000	1,800,000	2,880,000	15,360,000	250	2,000	4,000	8,000	60,000	6,000
Time for Full Discharge, hours	9.5	14	10	6	8	48	0.25	2	4	8	4	6
Time for Full Charge, hrs	9.5	14	12	7.5	8	192	0.3	2.3	4.6	9.2	4.6	8
Heat Rate (HHV), Btu/kWh	N/A	N/A	N/A	N/A	N/A	4,230	N/A	N/A	N/A	N/A	N/A	N/A
Round-Trip Efficiency (%) (note 5)	79%	79%	79%	79%	79%	55%	88%	88%	88%	88%	88%	65%
ESTIMATED CAPITAL AND O&M COSTS (Note 11)												
EPC Project Capital Costs, 2018 MM$ (w/o Owner's Costs)	**$814**	**$2,146**	**$1,352**	**$545**	**$635**	**$384**	**$1.0**	**$1.8**	**$2.5**	**$3.8**	**$21.8**	**$2.8**
Owner's Costs, 2018 MM$	**$163**	**$429**	**$270**	**$109**	**$127**	**$77**	**$0.4**	**$0.6**	**$0.6**	**$0.8**	**$2.1**	**$0.7**
Owner's Project Development	Included	Included	Included	Included	Included	Included	$0.1	$0.1	$0.1	$0.1	$0.2	$0.1
Owner's Engineer	Included	Included	Included	Included	Included	Included	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1
Owner's Project Management	Included	Included	Included	Included	Included	Included	$0.1	$0.1	$0.1	$0.1	$0.2	$0.1
Owner's Legal Costs	Included	Included	Included	Included	Included	Included	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1
Permitting and Licensing Fees	Included	Included	Included	Included	Included	Included	$0.1	$0.1	$0.1	$0.1	$0.2	$0.1
Generation Switchyard (note 6)	Included in Project Costs	Included in Project Costs	Included in Project Costs	Included in Project Costs	Included in Project Costs	Included in Project Costs	N/A	N/A	N/A	N/A	N/A	N/A
Transmission to Interconnection Point	Included in Project Costs	Included in Project Costs	Included in Project Costs	Included in Project Costs	Included in Project Costs	Included in Project Costs	N/A	N/A	N/A	N/A	N/A	N/A
Training/Testing	Included in Project Costs	Included in Project Costs	Included in Project Costs	Included in Project Costs	Included in Project Costs	Included in Project Costs	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1
Land	Included in Project Costs	Included in Project Costs	Included in Project Costs	Included in Project Costs	Included in Project Costs	Included in Project Costs	Assumes Co-located	Assumes Co-located	Assumes Co-located	Assumes Co-located	Assumes Co-located	Assumes Co-located
Builders Risk Insurance (0.45% of Project Cost)	Included	Included	Included	Included	Included	Included	$0.00	$0.01	$0.01	$0.02	$0.1	$0.01
Owner's Contingency	Included	Included	Included	Included	Included	Included	$0.1	$0.1	$0.1	$0.2	$1.1	$0.2
Total Screening Level Project Costs, 2018 MM$	**$977**	**$2,575**	**$1,622**	**$654**	**$762**	**$461**	**$1.4**	**$2.4**	**$3.1**	**$4.7**	**$24.0**	**$3.5**
EPC Project Costs, 2018 $/kW	**$2,070**	**$1,790**	**$1,930**	**$1,820**	**$1,760**	**$1,200**	**$990**	**$1,780**	**$2,470**	**$3,850**	**$1,450**	**$2,790**
EPC Project Costs, 2018 $/kWh	**$220**	**$130**	**$190**	**$300**	**$220**	**$30**	**$3,940**	**$890**	**$620**	**$480**	**$360**	**$460**
Total Screening Level Project Costs, 2018 $/kW	**$2,480**	**$2,150**	**$2,320**	**$2,180**	**$2,120**	**$1,440**	**$1,420**	**$2,380**	**$3,110**	**$4,670**	**$1,600**	**$3,520**
Total Screening Level Project Costs, 2018 $/kWh	**$260**	**$150**	**$230**	**$360**	**$260**	**$30**	**$5,670**	**$1,190**	**$780**	**$580**	**$400**	**$590**
O&M Cost, 2018 MM$/yr	$7	$15	$12	$5	$6	$2	$0.009	$0.035	$0.056	$0.094	$0.489	$0.032
Fixed O&M Cost, 2018 MM$/yr							$0.008	$0.024	$0.035	$0.052	$0.172	$0.032
Variable O&M Cost, 2018 MM$/yr							$0.001	$0.011	$0.021	$0.042	$0.317	Incl. in FOM

Notes

Note 1. Permitting & Construction Schedule is based on earliest COD date for some of the pumped hydro options
Note 2. Swan Lake Capital Cost and Fixed O&M Cost is middle of range given by Rye Development and National Grid Ventures
Note 3. Owner's cost is assumed to be 20% of capital costs for pumped hydro and CAES options. Based on information provided by developers and includes items listed above.
Note 4. CAES storage is based on full charge. Typical operation is to not fully discharge, but rather to discharge only a portion of the capacity to maintain cavern pressure.
Note 5. Round trip efficiency for CAES is based on the electric energy input to compress air plus the energy in the gas input compared to the electrical output.
Note 6. Battery options (Li-Ion and Flow) assumes interconnection at distribution voltage and therefore excludes GSU and switchyard.
Note 7. Battery O&M assumes the site is remotely controlled. Capital costs assume the system is slightly oversized initially to accommodate normal degradation at the start of the project life, and then degradation supplement cost throughout the project life. O&M accounts for the parasitic power draw of the system, including HVAC and efficiency losses.

Note 8. Pumped Hydro O&M excludes major maintenance cost items, like generator rewinds, that are viewed as end of life repairs to extend the intended life of the asset.
Note 9. Battery capacity factor and annual O&M is based on one full cycle per day.
Note 10. CAES storage supports simultaneous operation of compression and expansion.
Note 11. EPC and Owner's Cost estimates exclude AFUDC, Sales Tax, Insurance and Property Tax During Construction

PACIFICORP RENEWABLE TECHNOLOGY ASSESSMENT SUMMARY TABLE
SOLAR GENERATION

PROJECT TYPE	**Solar Photovoltaic - Single Axis Tracking**														
PROJECT LOCATION	**Idaho Falls, ID**			**Lakeview, OR**			**Milford, UT**			**Rock Springs, WY**			**Yakima, WA**		
BASE PLANT DESCRIPTION	**5 MW**	**50 MW**	**200 MW**	**5 MW**	**50 MW**	**200 MW**	**5 MW**	**50 MW**	**200 MW**	**5 MW**	**50 MW**	**200 MW**	**5 MW**	**50 MW**	**200 MW**
Nominal Output, MW	5	50	200	5	50	200	5	50	200	5	50	200	5	50	200
Annualized Energy Production, MWh (Yr 1)	11,597	122,929	491,714	12,292	130,139	520,556	13,451	142,375	569,501	12,355	131,702	526,808	10,609	114,065	456,258
AC Capacity Factor at POI (%) (Note 1)	26.5%	28.1%	28.1%	28.1%	29.7%	29.7%	30.7%	32.5%	32.5%	28.2%	30.1%	30.1%	24.2%	26.0%	26.0%
Availability Factor, % (Note 2)	99%	99%	99%	99%	99%	99%	99%	99%	99%	99%	99%	99%	99%	99%	99%
Assumed Land Use, Acres	40	400	1600	40	400	1600	40	400	1600	40	400	1600	40	400	1600
PV Inverter Loading Ratio (DC/AC)	1.32	1.32	1.32	1.32	1.32	1.32	1.32	1.32	1.32	1.32	1.32	1.32	1.32	1.32	1.32
PV POI Ratio (DC/AC)	1.32	1.46	1.46	1.32	1.46	1.46	1.32	1.46	1.46	1.32	1.46	1.46	1.32	1.46	1.46
PV Degradation, %/yr (Note 3)	1st year: 2% After 1st Year: 0.5% per year	1st year: 2% After 1st Year: 0.5% per year	1st year: 2% After 1st Year: 0.5% per year	1st year: 2% After 1st Year: 0.5% per year	1st year: 2% After 1st Year: 0.5% per year	1st year: 2% After 1st Year: 0.5% per year	1st year: 2% After 1st Year: 0.5% per year	1st year: 2% After 1st Year: 0.5% per year	1st year: 2% After 1st Year: 0.5% per year	1st year: 2% After 1st Year: 0.5% per year	1st year: 2% After 1st Year: 0.5% per year	1st year: 2% After 1st Year: 0.5% per year	1st year: 2% After 1st Year: 0.5% per year	1st year: 2% After 1st Year: 0.5% per year	1st year: 2% After 1st Year: 0.5% per year
Technology Rating	Mature	Mature	Mature	Mature	Mature	Mature	Mature	Mature	Mature	Mature	Mature	Mature	Mature	Mature	Mature
Permitting & Construction Schedule, year	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
ESTIMATED PERFORMANCE															
Base Load Performance @ (Annual Average)															
Net Plant Output, kW	5,000	50,000	200,000	5,000	50,000	200,000	5,000	50,000	200,000	5,000	50,000	200,000	5,000	50,000	200,000
ESTIMATED CAPITAL AND O&M COSTS (Note 7)															
EPC Project Capital Costs, 2018 MM$ (w/o Owner's Costs)	**$7**	**$71**	**$277**	**$8**	**$76**	**$297**	**$7**	**$71**	**$276**	**$7**	**$70**	**$275**	**$8**	**$76**	**$296**
Modules	$2	$27	$107	$2	$27	$107	$2	$27	$107	$2	$27	$107	$2	$27	$107
Racking w/ Piles	$1	$9	$35	$1	$9	$35	$1	$9	$35	$1	$9	$35	$1	$9	$35
Inverter & MV Transformer	$0	$3	$13	$0	$3	$13	$0	$3	$13	$0	$3	$13	$0	$3	$13
Labor, Materials, and BOP Equiment	$2	$25	$102	$3	$30	$121	$2	$25	$101	$2	$25	$100	$3	$30	$120
Project Indirects, Fee, and Contingency	$1	$7	$20	$1	$7	$21	$1	$7	$20	$1	$7	$20	$1	$7	$21
Owner's Costs, 2018 MM$	**$1**	**$54**	**$67**	**$2**	**$54**	**$68**	**$1**	**$54**	**$67**	**$1**	**$54**	**$67**	**$2**	**$54**	**$68**
Owner's Project Development	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3
Owner's Project Management	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1
Owner's Legal Costs	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3
Permitting and Licensing Fees	$0.4	$0.5	$0.6	$0.4	$0.5	$0.6	$0.4	$0.5	$0.6	$0.4	$0.5	$0.6	$0.4	$0.5	$0.6
Generation Switchyard (Note 5)	$0.0	$2.0	$2.0	$0.0	$2.0	$2.0	$0.0	$2.0	$2.0	$0.0	$2.0	$2.0	$0.0	$2.0	$2.0
Transmission Interconnection (Note 8)	$0.0	$34.5	$34.5	$0.0	$34.5	$34.5	$0.0	$34.5	$34.5	$0.0	$34.5	$34.5	$0.0	$34.5	$34.5
Transmission Interconnection Application and Upgrades (Note 9)	$0.0	$9.8	$9.8	$0.0	$9.8	$9.8	$0.0	$9.8	$9.8	$0.0	$9.8	$9.8	$0.0	$9.8	$9.8
Land (Note 4)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Operating Spare Parts	$0.0	$0.4	$1.6	$0.0	$0.4	$1.6	$0.0	$0.4	$1.6	$0.0	$0.4	$1.6	$0.0	$0.4	$1.6
Builders Risk Insurance (0.45% of Project Cost)	$0.0	$0.3	$1.2	$0.0	$0.3	$1.3	$0.0	$0.3	$1.2	$0.0	$0.3	$1.2	$0.0	$0.3	$1.3
Owner's Contingency	$0.4	$5.9	$16.4	$0.4	$6.2	$17.4	$0.4	$5.9	$16.3	$0.4	$5.9	$16.3	$0.4	$6.2	$17.3
Total Screening Level Project Costs, 2018 MM$	**$9**	**$125**	**$343**	**$9**	**$130**	**$365**	**$9**	**$125**	**$343**	**$9**	**$124**	**$342**	**$9**	**$130**	**$364**
EPC Project Costs, 2018 $/kW	**$1,430**	**$1,420**	**$1,380**	**$1,520**	**$1,520**	**$1,490**	**$1,420**	**$1,410**	**$1,380**	**$1,420**	**$1,410**	**$1,380**	**$1,510**	**$1,510**	**$1,480**
Total Screening Level Project Costs, 2018 $/kW	**$1,720**	**$2,500**	**$1,720**	**$1,820**	**$2,600**	**$1,820**	**$1,720**	**$2,490**	**$1,710**	**$1,710**	**$2,490**	**$1,710**	**$1,810**	**$2,600**	**$1,820**
O&M Cost, 2018 MM$/yr	$0.2	$2.0	$8.1	$0.2	$2.0	$8.1	$0.2	$2.0	$8.1	$0.2	$2.0	$8.1	$0.2	$2.0	$8.1
O&M Cost, 2018 $/kW-yr	$42.20	$40.40	$40.40	$42.20	$40.40	$40.40	$42.20	$40.40	$40.40	$42.20	$40.40	$40.40	$42.20	$40.40	$40.40
Co-Located Energy Storage - 2 hr Capacity	1 MW | 2 MWh	10 MW | 20 MWh	50 MW | 100 MWh	1 MW | 2 MWh	10 MW | 20 MWh	50 MW | 100 MWh	1 MW | 2 MWh	10 MW | 20 MWh	50 MW | 100 MWh	1 MW | 2 MWh	10 MW | 20 MWh	50 MW | 100 MWh	1 MW | 2 MWh	10 MW | 20 MWh	50 MW | 100 MWh
Add-On Costs															
Capital Costs, 2018 MM$	$1.7	$10.8	$33.7	$1.9	$11.6	$36.3	$1.7	$10.8	$33.7	$1.7	$10.8	$33.7	$1.9	$11.6	$36.3
Owner's Costs, 2018 MM$	$0.5	$1.2	$2.7	$0.5	$1.3	$2.8	$0.5	$1.2	$2.7	$0.5	$1.2	$2.7	$0.5	$1.3	$2.8
Incremental O&M Cost, 2018 MM$/Yr	$0.03	$0.19	$0.77	$0.03	$0.19	$0.77	$0.03	$0.19	$0.77	$0.0	$0.19	$0.77	$0.03	$0.19	$0.77
Co-Located Energy Storage - 4 hr Capacity	1 MW | 4 MWh	10 MW | 40 MWh	50 MW | 200 MWh	1 MW | 4 MWh	10 MW | 40 MWh	50 MW | 200 MWh	1 MW | 4 MWh	10 MW | 40 MWh	50 MW | 200 MWh	1 MW | 4 MWh	10 MW | 40 MWh	50 MW | 200 MWh	1 MW | 4 MWh	10 MW | 40 MWh	50 MW | 200 MWh
Add-On Costs															
Capital Costs, 2018 MM$	$2.4	$16.3	$58.7	$2.6	$17.6	$63.3	$2.4	$16.3	$58.7	$2.4	$16.3	$58.7	$2.6	$17.6	$63.3
Owner's Costs, 2018 MM$	$0.6	$1.5	$4.0	$0.6	$1.6	$4.28	$0.4	$1.5	$4.0	$0.4	$1.5	$4.0	$0.4	$1.6	$4.3
Incremental O&M Cost, 2018 MM$/Yr	$0.06	$0.35	$1.43	$0.06	$0.35	$1.43	$0.06	$0.35	$1.43	$0.0	$0.35	$1.43	$0.06	$0.35	$1.43
Co-Located Energy Storage - 8 hr Capacity	1 MW | 8 MWh	10 MW | 80 MWh	50 MW | 400 MWh	1 MW | 8 MWh	10 MW | 80 MWh	50 MW | 400 MWh	1 MW | 8 MWh	10 MW | 80 MWh	50 MW | 400 MWh	1 MW | 8 MWh	10 MW | 80 MWh	50 MW | 400 MWh	1 MW | 8 MWh	10 MW | 80 MWh	50 MW | 400 MWh
Add-On Costs															
Capital Costs, 2018 MM$	$3.8	$26.6	$107.8	$4.1	$28.6	$116.2	$3.8	$26.6	$107.8	$3.8	$26.6	$107.8	$4.1	$28.7	$116.2
Owner's Costs, 2018 MM$	$0.6	$2.1	$6.7	$0.7	$2.2	$7.2	$0.8	$2.1	$6.7	$0.8	$2.1	$6.7	$0.8	$2.2	$7.2
Incremental O&M Cost, 2018 MM$/Yr	$0.09	$0.63	$2.72	$0.09	$0.63	$2.72	$0.09	$0.63	$2.72	$0.0	$0.63	$2.72	$0.09	$0.63	$2.72

Notes

Note 1. Solar capacity factor accounts for typical losses. 50 and 200 MW options have AC capacity overbuilt for high voltage losses. Additional inverters and economic efficiencies for overbuilding for larger sizes results in the capacity factor different between the two larger sizes and the 5 MW installation.
Note 2. Availability estimates are based on vendor correspondence and industry publications.
Note 3. PV degradation based on typical warranty information for polycrystalline products. Assuming factory recommended maintenance is performed, PV performance is estimated to degrade ~2% in the first year and 0.5% each following year. The first year 2% degradation is accounted for in the PVSyst model output for year 1.
Note 4. PV projects assume that land is leased and therefore land costs are included in O&M, not capital costs. Assumes eight acres per MW for tracking.
Note 5. 5 MW options assume interconnection at medium voltage. 50 & 200 MW options assume high voltage connection with switchyard.
Note 6. Oregon and Washington cost estimates assume union labor.
Note 7. EPC and Owner's Cost estimates exclude AFUDC, Sales Tax, Insurance and Property Tax During Construction
Note 8. Transmission interconnect allowance assumes 15 miles of transmission line at high voltage for 50 & 200 MW options. Land costs are excluded.
Note 9. Transmission interconnect application costs and upgrade costs are representative only. These costs can vary greatly depending on the site location and existing infrastructure.

PACIFICORP RENEWABLE TECHNOLOGY ASSESSMENT SUMMARY TABLE **WIND GENERATION**					
PROJECT TYPE	**Onshore Wind**				
PROJECT LOCATION	**Pocatello, ID**	**Arlington, OR**	**Monticello, UT**	**Medicine Bow, WY**	**Goldendale, WA**
BASE PLANT DESCRIPTION	**200 MW**	**200 MW**	**200 MW**	**200 MW**	**200 MW**
Nominal Output, MW	200	200	200	200	200
Number of Turbines	56 x 3.6 MW	56 x 3.6 MW	56 x 3.6 MW	56 x 3.6 MW	56 x 3.6 MW
Capacity Factor (Note 1)	37.1%	37.1%	29.5%	43.6%	37.1%
Availability Factor, % (Note 2)	95%	95%	95%	95%	95%
Assumed Land Use, Acres	56	56	56	56	56
Technology Rating	Mature	Mature	Mature	Mature	Mature
Permitting & Construction Schedule, year	2.5	2.5	2.5	2.5	2.5
ESTIMATED PERFORMANCE					
Base Load Performance @ (Annual Average)					
Net Plant Output, kW	200,000	200,000	200,000	200,000	200,000
ESTIMATED CAPITAL AND O&M COSTS (Note 6)					
Project Capital Costs, 2018 MM$ (w/o Owner's Costs)	**$228**	**$229**	**$228**	**$228**	**$228**
Wind Turbine Generators	$160	$160	$160	$160	$161
Roads	$5	$5	$5	$5	$5
O&M Building	$2	$2	$2	$2	$2
Collection System	$8	$8	$8	$8	$8
Other BOP, Materials, Labor, Indirects	$53	$54	$53	$53	$53
Owner's Costs, 2018 MM$	**$103**	**$103**	**$103**	**$103**	**$103**
Project Development (Note 3)	$22.8	$22.8	$22.8	$22.8	$22.8
Wind Resource Assessment	$1.0	$1.0	$1.0	$1.0	$1.0
Land Control	$2.4	$2.4	$2.4	$2.4	$2.4
Permitting and Licensing Fees	$3.2	$3.2	$3.2	$3.2	$3.2
Generation Switchyard	$2.0	$2.0	$2.0	$2.0	$2.0
Transmission Interconnection (Note 7)	$34.5	$34.5	$34.5	$34.5	$34.5
Transmission Interconnection Application and Upgrades (Note 8)	$9.8	$9.8	$9.8	$9.8	$9.8
Land (Note 4)	$0.0	$0.0	$0.0	$0.0	$0.0
Operating Spare Parts	Included in O&M	Included in O&M	Included in O&M	Included in O&M	Included in O&M
Temporary facilities and Construction Utilities	$12.0	$12.0	$12.0	$12.0	$12.0
Builders Risk Insurance (0.45% of Project Cost)	Included in Project Costs	Included in Project Costs	Included in Project Costs	Included in Project Costs	Included in Project Costs
Owner's Contingency	$15.8	$15.8	$15.8	$15.8	$15.8
Total Screening Level Project Costs, 2018 MM$	**$332**	**$333**	**$332**	**$332**	**$332**
EPC Project Costs, 2018 $/kW	**$1,140**	**$1,150**	**$1,140**	**$1,140**	**$1,140**
Total Screening Level Project Costs, 2018 $/kW	**$1,660**	**$1,660**	**$1,660**	**$1,660**	**$1,660**
O&M Cost, 2018 MM$/yr	$10.2	$10.2	$9.8	$9.2	$9.8
O&M Cost, 2018 $/kW-yr	$51.0	$51.0	$49.0	$46.0	$49.0
Co-Located Energy Storage - 2 hr Capacity	50 MW | 100 MWh	50 MW | 100 MWh	50 MW | 100 MWh	50 MW | 100 MWh	50 MW | 100 MWh
Add-On Costs					
Capital Costs, 2018 MM$	$33.7	$35.9	$33.7	$33.7	$35.8
Owner's Costs, 2018 MM$	$2.7	$2.8	$2.7	$2.7	$2.8
Incremental O&M Cost, 2018 MM$/Yr	$0.77	$0.77	$0.77	$0.77	$0.77
Co-Located Energy Storage - 4 hr Capacity	50 MW | 200 MWh	50 MW | 200 MWh	50 MW | 200 MWh	50 MW | 200 MWh	50 MW | 200 MWh
Add-On Costs					
Capital Costs, 2018 MM$	$58.7	$62.6	$58.7	$58.7	$62.5
Owner's Costs, 2018 MM$	$4.0	$4.3	$4.0	$4.0	$4.3
Incremental O&M Cost, 2018 MM$/Yr	$1.4	$1.4	$1.4	$1.4	$1.4
Co-Located Energy Storage - 8 hr Capacity	50 MW | 400 MWh	50 MW | 400 MWh	50 MW | 400 MWh	50 MW | 400 MWh	50 MW | 400 MWh
Add-On Costs					
Capital Costs, 2018 MM$	$107.8	$114.9	$107.8	$107.8	$114.8
Owner's Costs, 2018 MM$	$6.7	$7.2	$6.7	$6.7	$7.2
Incremental O&M Cost, 2018 MM$/Yr	$2.7	$2.7	$2.7	$2.7	$2.7

Notes

Note 1. Wind capacity factor based on NREL 80 meter wind speed maps.
Note 2. Availability estimates are based on vendor correspondence and industry publications.
Note 3. Development costs include legal costs, developer costs prior to COD, Owner project management, engineering, and interconnect studies.
Note 4. Wind projects assume that land is leased and therefore land costs are included in O&M, not capital costs. Assumes one acre per turbine.
Note 5. Oregon and Washington cost estimates assume union labor.
Note 6. EPC and Owner's Cost estimates exclude AFUDC, Sales Tax, Insurance and Property Tax During Construction
Note 7. Transmission interconnect allowance assumes 15 miles of transmission line at high voltage. Land costs are excluded.
Note 8. Transmission interconnect application and upgrade costs are representative only. These costs can vary greatly depending on the site location and existing infrastructure.

APPENDIX B – SOLAR PVSYST MODEL OUTPUT (5MW)

Grid-Connected System: Simulation parameters

Project :	**PC18-Grid-IdahoFallsID-SAT**			
Geographical Site	**Idaho Falls Fanning Field**		Country	**USA**
Situation	Latitude	43.5°N	Longitude	112.1°W
Time defined as	Legal Time	Time zone UT-7	Altitude	1441 m
	Albedo	0.20		
Meteo data:	**Idaho Falls Fanning Field**	TMY - NREL: TMY3 hourly DB (1991-2005)		

Simulation variant :	**PC18_IdahoFalls_Rev3**	
	Simulation date	31/08/18 13h50

Simulation parameters

Tracking plane, tilted Axis	Axis Tilt	0°	Axis Azimuth	0°
Rotation Limitations	Minimum Phi	-60°	Maximum Phi	60°
Backtracking strategy	Tracker Spacing	5.50 m	Collector width	1.98 m
Inactive band	Left	0.20 m	Right	0.20 m
Models used	Transposition	Perez	Diffuse	Imported
Horizon	Free Horizon			
Near Shadings	Linear shadings			

PV Array Characteristics

PV module	Si-poly Model	**CS3U-340P 1500V**		
	Manufacturer	Canadian Solar Inc.		
	Orientation	#1	Tilt/Azimuth	30°/0°
Number of PV modules	In series	26 modules	In parallel	738 strings
Total number of PV modules	Nb. modules	19188	Unit Nom. Power	340 Wp
Array global power	Nominal (STC)	**6524 kWp**	At operating cond.	5890 kWp (50°C)
Array operating characteristics (50°C)	U mpp	895 V	I mpp	6580 A
Total area	Module area	**38069 m²**	Cell area	33931 m²

Inverter	Model	**SMA SC2500 EV Prelim!**		
	Manufacturer	SMA		
Characteristics	Operating Voltage	850-1425 V	Unit Nom. Power	2500 kWac
Inverter pack	Nb. of inverters	2 units	Total Power	5000 kWac

PV Array loss factors

Array Soiling Losses

Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.
2.5%	2.5%	2.5%	2.5%	2.0%	2.0%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%

Thermal Loss factor	Uc (const)	25.0 W/m²K	Uv (wind)	1.2 W/m²K / m/s
Wiring Ohmic Loss	Global array res.	2.3 mOhm	Loss Fraction	1.5 % at STC
LID - Light Induced Degradation			Loss Fraction	2.0 %
Module Quality Loss			Loss Fraction	-0.4 %
Module Mismatch Losses			Loss Fraction	1.0 % at MPP

Grid-Connected System: Simulation parameters (continued)

Incidence effect, user defined profile

10°	20°	30°	40°	50°	60°	70°	80°	90°
1.00	1.00	1.00	0.99	0.99	0.97	0.92	0.76	0.00

System loss factors
Wiring Ohmic Loss Wires 0 m 3x0.0 mm² Loss Fraction 0.0 % at STC

User's needs : Unlimited load (grid)

Grid-Connected System: Main results

Project : **PC18-Grid-IdahoFallsID-SAT**

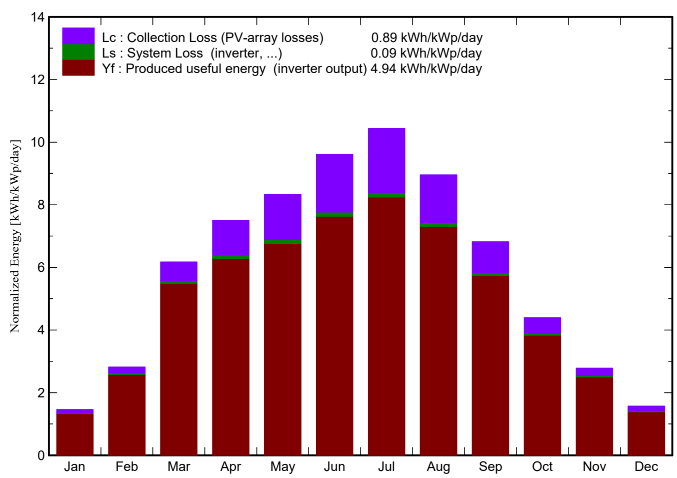
Simulation variant : **PC18_IdahoFalls_Rev3**

Main system parameters	System type	**Grid-Connected**		
Near Shadings	Linear shadings			
PV Field Orientation	tracking, tilted axis, Axis Tilt	0°	Axis Azimuth	0°
PV modules	Model	CS3U-340P 1500V	Pnom	340 Wp
PV Array	Nb. of modules	19188	Pnom total	**6524 kWp**
Inverter	Model	SMA SC2500 EV Prelim!	Pnom	2500 kW ac
Inverter pack	Nb. of units	2.0	Pnom total	**5000 kW ac**
User's needs	Unlimited load (grid)			

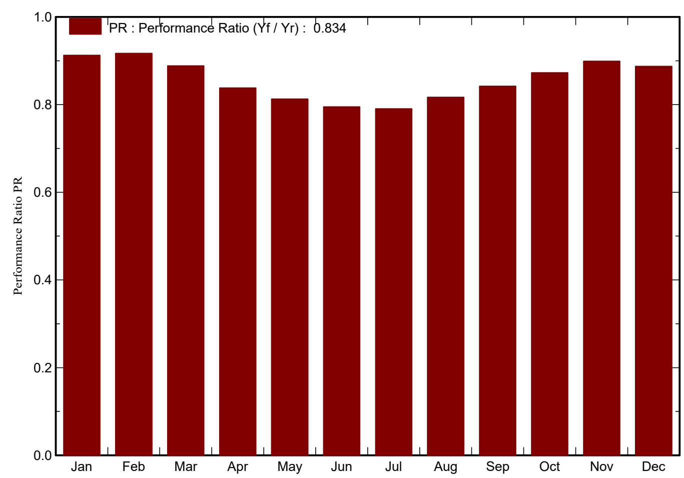
Main simulation results

System Production	**Produced Energy**	**11763 MWh/year**	Specific prod.	1803 kWh/kWp/year
	Performance Ratio PR	83.4 %		

Normalized productions (per installed kWp): Nominal power 6524 kWp



Performance Ratio PR



PC18_IdahoFalls_Rev3

Balances and main results

	GlobHor kWh/m²	T Amb °C	GlobInc kWh/m²	GlobEff kWh/m²	EArray MWh	E_Grid MWh	EffArrR %	EffSysR %
January	34.6	-7.63	45.3	41.6	276	270	16.00	15.64
February	62.3	-6.02	78.9	73.2	481	472	16.02	15.72
March	138.9	1.52	191.4	180.6	1129	1109	15.50	15.23
April	170.8	8.07	225.0	212.6	1252	1230	14.62	14.36
May	200.8	12.25	258.1	244.9	1393	1369	14.18	13.93
June	219.3	16.42	288.2	274.8	1521	1495	13.86	13.62
July	241.0	20.60	323.5	307.7	1698	1669	13.78	13.55
August	203.6	19.01	277.6	263.8	1505	1479	14.24	14.00
September	149.5	13.70	204.5	193.1	1143	1123	14.69	14.43
October	98.8	6.88	136.2	127.8	790	775	15.23	14.96
November	59.9	0.19	83.5	77.6	499	490	15.70	15.41
December	38.7	-2.59	48.6	44.5	288	282	15.56	15.21
Year	1618.2	6.94	2160.8	2042.0	11975	11763	14.56	14.30

Legends:				
GlobHor	Horizontal global irradiation		EArray	Effective energy at the output of the array
T Amb	Ambient Temperature		E_Grid	Energy injected into grid
GlobInc	Global incident in coll. plane		EffArrR	Effic. Eout array / rough area
GlobEff	Effective Global, corr. for IAM and shadings		EffSysR	Effic. Eout system / rough area

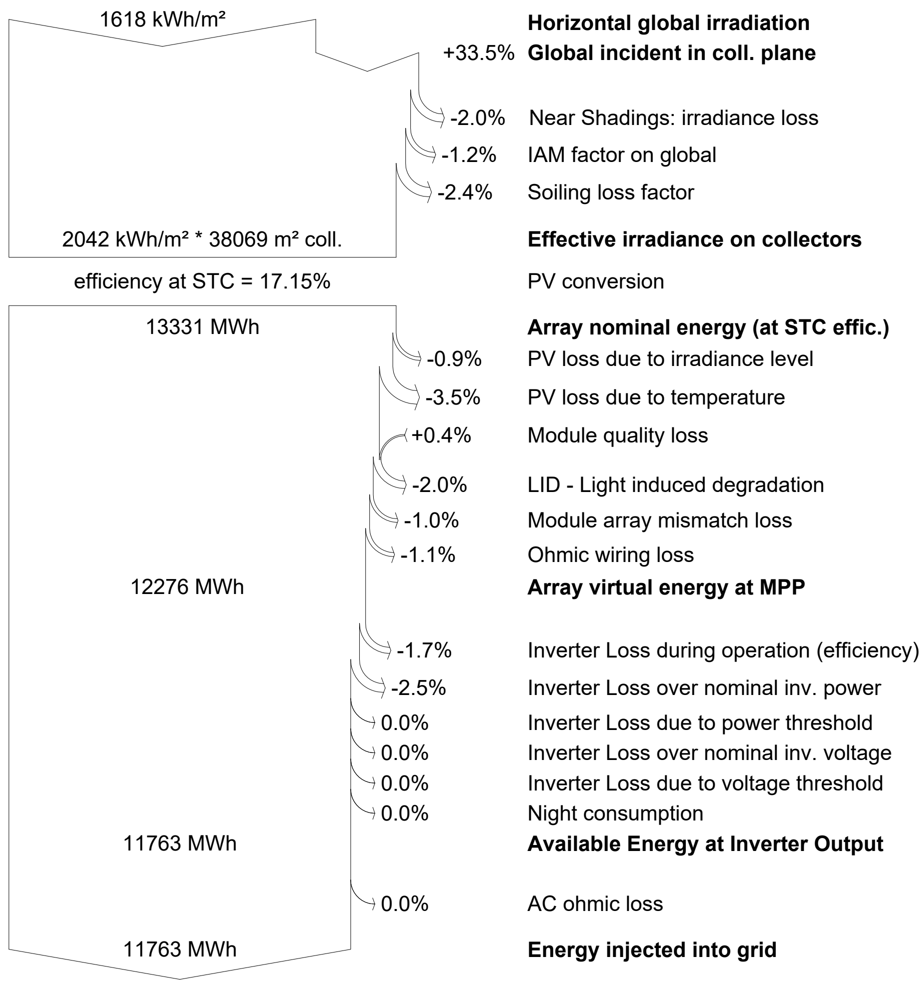
Grid-Connected System: Loss diagram

Project : **PC18-Grid-IdahoFallsID-SAT**

Simulation variant : **PC18_IdahoFalls_Rev3**

Main system parameters	System type	**Grid-Connected**		
Near Shadings	Linear shadings			
PV Field Orientation	tracking, tilted axis, Axis Tilt	0°	Axis Azimuth	0°
PV modules	Model	CS3U-340P 1500V	Pnom	340 Wp
PV Array	Nb. of modules	19188	Pnom total	**6524 kWp**
Inverter	Model	SMA SC2500 EV Prelim!	Pnom	2500 kW ac
Inverter pack	Nb. of units	2.0	Pnom total	**5000 kW ac**
User's needs	Unlimited load (grid)			

Loss diagram over the whole year



Grid-Connected System: Simulation parameters

Project : **PC18-LakeviewOR**

Geographical Site	**Lakeview**		Country	**United States**
Situation	Latitude	42.2°N	Longitude	120.4°W
Time defined as	Legal Time	Time zone UT-8	Altitude	1441 m
	Albedo	0.20		
Meteo data:	**Lakeview**	TMY - NREL: TMY3 hourly DB (1991-2005)		

Simulation variant : **PC18-LakeviewOR_Rev2**

Simulation date 31/08/18 14h20

Simulation parameters

Tracking plane, tilted Axis	Axis Tilt	0°	Axis Azimuth	0°
Rotation Limitations	Minimum Phi	-60°	Maximum Phi	60°
Backtracking strategy	Tracker Spacing	5.50 m	Collector width	1.98 m
Inactive band	Left	0.20 m	Right	0.20 m
Models used	Transposition	Perez	Diffuse	Imported
Horizon	Average Height	2.4°		
Near Shadings	Linear shadings			

PV Array Characteristics

PV module Si-poly	Model	**CS3U-340P 1500V**		
	Manufacturer	Canadian Solar Inc.		
	Orientation	#1	Tilt/Azimuth	30°/0°
Number of PV modules	In series	26 modules	In parallel	738 strings
Total number of PV modules	Nb. modules	19188	Unit Nom. Power	340 Wp
Array global power	Nominal (STC)	**6524 kWp**	At operating cond.	5890 kWp (50°C)
Array operating characteristics (50°C)	U mpp	895 V	I mpp	6580 A
Total area	Module area	**38069 m²**	Cell area	33931 m²

Inverter	Model	**SMA SC2500 EV Prelim!**		
	Manufacturer	SMA		
Characteristics	Operating Voltage	850-1425 V	Unit Nom. Power	2500 kWac
Inverter pack	Nb. of inverters	2 units	Total Power	5000 kWac

PV Array loss factors

Array Soiling Losses

Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.
2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.5%	2.5%	2.5%	2.0%	2.0%	2.0%

Thermal Loss factor	Uc (const)	25.0 W/m²K	Uv (wind)	1.2 W/m²K / m/s
Wiring Ohmic Loss	Global array res.	2.5 mOhm	Loss Fraction	1.6 % at STC
LID - Light Induced Degradation			Loss Fraction	2.0 %
Module Quality Loss			Loss Fraction	-0.4 %
Module Mismatch Losses			Loss Fraction	1.0 % at MPP

Grid-Connected System: Simulation parameters (continued)

Incidence effect, user defined profile

10°	20°	30°	40°	50°	60°	70°	80°	90°
1.00	1.00	1.00	0.99	0.99	0.97	0.92	0.76	0.00

System loss factors
Wiring Ohmic Loss Wires 0 m 3x0.0 mm² Loss Fraction 0.0 % at STC

User's needs : Unlimited load (grid)

Grid-Connected System: Horizon definition

Project : **PC18-LakeviewOR**

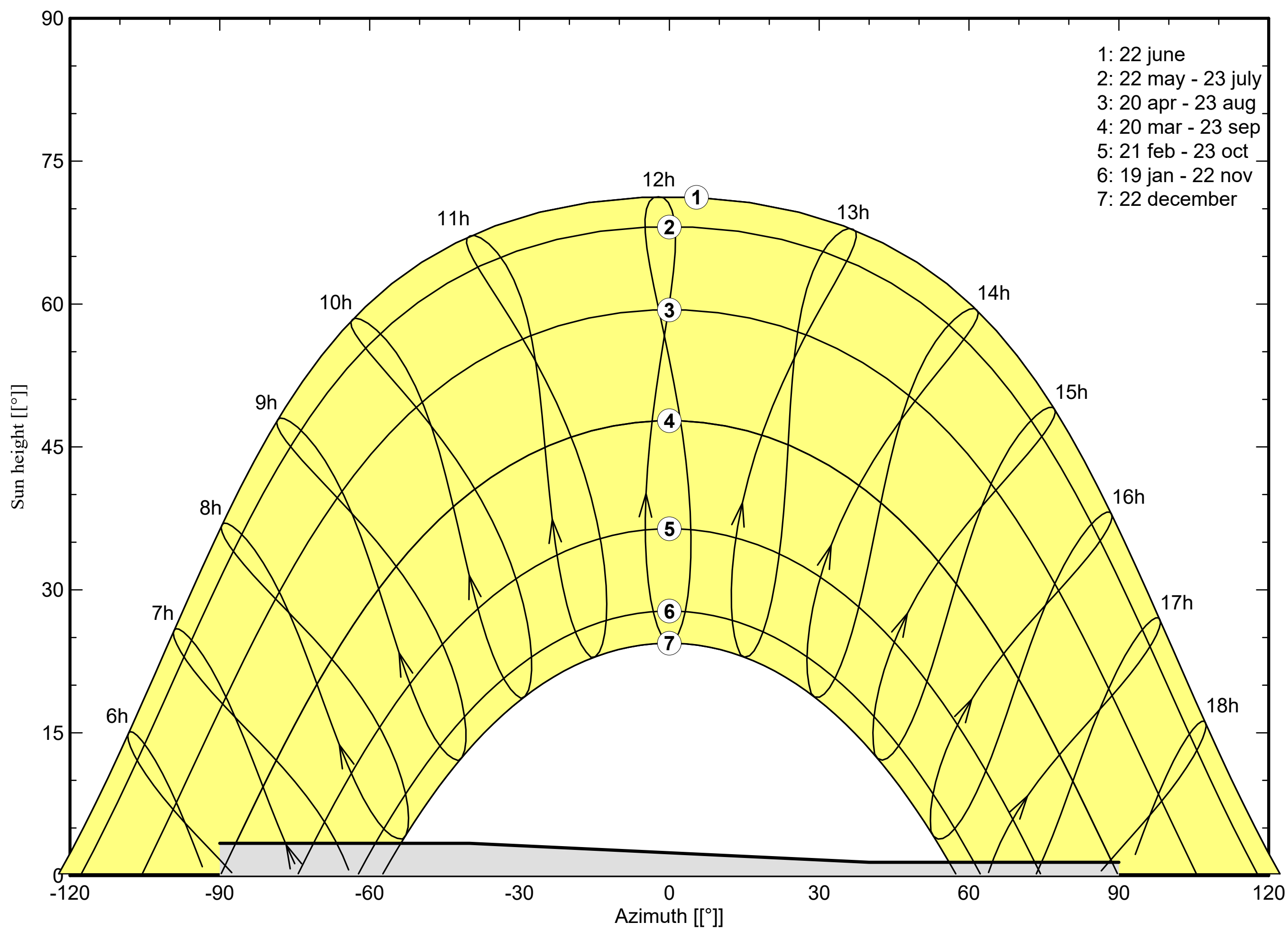
Simulation variant : **PC18-LakeviewOR_Rev2**

Main system parameters	System type	**Grid-Connected**		
Horizon	Average Height	2.4°		
Near Shadings	Linear shadings			
PV Field Orientation	tracking, tilted axis, Axis Tilt	0°	Axis Azimuth	0°
PV modules	Model	CS3U-340P 1500V	Pnom	340 Wp
PV Array	Nb. of modules	19188	Pnom total	**6524 kWp**
Inverter	Model	SMA SC2500 EV Prelim!	Pnom	2500 kW ac
Inverter pack	Nb. of units	2.0	Pnom total	**5000 kW ac**
User's needs	Unlimited load (grid)			

Horizon	Average Height	2.4°	Diffuse Factor	0.99
	Albedo Factor	100 %	Albedo Fraction	0.96

Height [°]	3.4	3.4	1.4	1.4
Azimuth [°]	-90	-40	40	90

Horizon



Grid-Connected System: Main results

Project : **PC18-LakeviewOR**

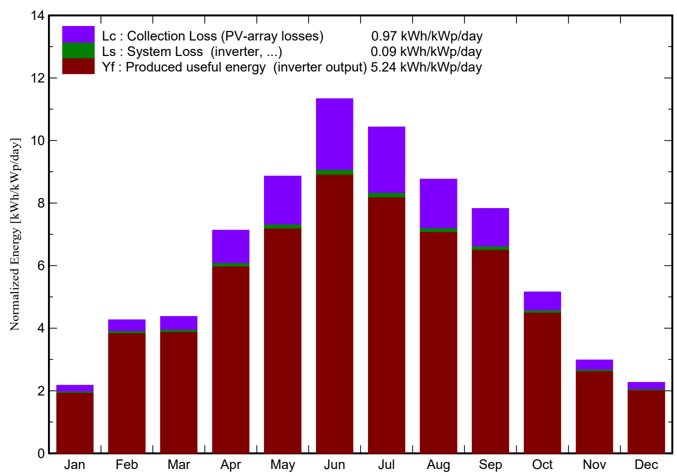
Simulation variant : **PC18-LakeviewOR_Rev2**

Main system parameters	System type	**Grid-Connected**		
Horizon	Average Height	2.4°		
Near Shadings	Linear shadings			
PV Field Orientation	tracking, tilted axis, Axis Tilt	0°	Axis Azimuth	0°
PV modules	Model	CS3U-340P 1500V	Pnom	340 Wp
PV Array	Nb. of modules	19188	Pnom total	**6524 kWp**
Inverter	Model	SMA SC2500 EV Prelim!	Pnom	2500 kW ac
Inverter pack	Nb. of units	2.0	Pnom total	**5000 kW ac**
User's needs	Unlimited load (grid)			

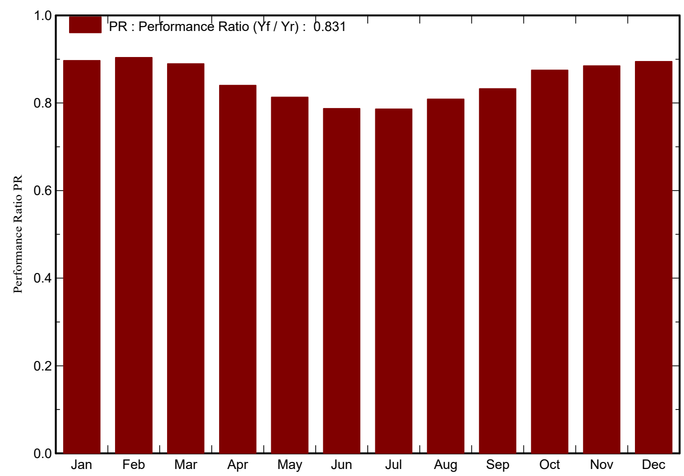
Main simulation results

System Production	**Produced Energy**	**12468 MWh/year**	Specific prod.	1911 kWh/kWp/year
	Performance Ratio PR	83.1 %		

Normalized productions (per installed kWp): Nominal power 6524 kWp



Performance Ratio PR



PC18-LakeviewOR_Rev2

Balances and main results

	GlobHor kWh/m²	T Amb °C	GlobInc kWh/m²	GlobEff kWh/m²	EArray MWh	E_Grid MWh	EffArrR %	EffSysR %
January	52.8	-1.22	67.4	62.3	402	394	15.68	15.37
February	85.1	-0.46	119.4	112.0	717	704	15.77	15.49
March	106.7	2.86	135.6	127.4	802	787	15.53	15.24
April	163.1	5.42	213.8	202.5	1193	1172	14.66	14.40
May	209.3	9.94	274.6	261.2	1482	1457	14.18	13.94
June	251.2	16.42	340.1	325.4	1777	1747	13.72	13.49
July	242.7	20.83	323.3	307.4	1687	1659	13.71	13.48
August	198.5	17.73	271.7	258.0	1459	1434	14.11	13.86
September	167.3	14.61	234.7	222.3	1297	1275	14.52	14.27
October	114.2	6.91	159.8	150.6	928	912	15.26	14.99
November	63.8	1.73	89.5	83.4	527	517	15.45	15.16
December	49.6	-0.87	70.3	65.0	418	410	15.63	15.33
Year	1704.3	7.87	2300.2	2177.6	12690	12468	14.49	14.24

Legends:

GlobHor	Horizontal global irradiation	EArray	Effective energy at the output of the array
T Amb	Ambient Temperature	E_Grid	Energy injected into grid
GlobInc	Global incident in coll. plane	EffArrR	Effic. Eout array / rough area
GlobEff	Effective Global, corr. for IAM and shadings	EffSysR	Effic. Eout system / rough area

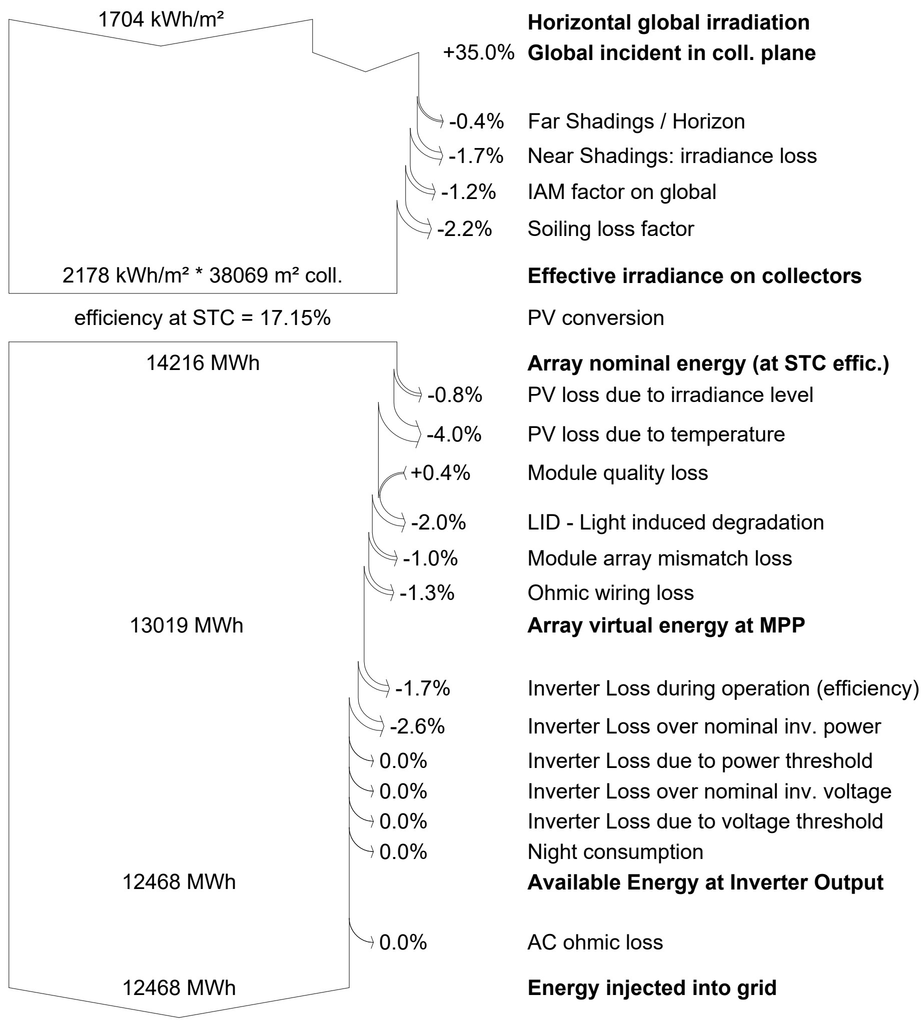
Grid-Connected System: Loss diagram

Project : **PC18-LakeviewOR**

Simulation variant : **PC18-LakeviewOR_Rev2**

Main system parameters	System type	**Grid-Connected**		
Horizon	Average Height	2.4°		
Near Shadings	Linear shadings			
PV Field Orientation	tracking, tilted axis, Axis Tilt	0°	Axis Azimuth	0°
PV modules	Model	CS3U-340P 1500V	Pnom	340 Wp
PV Array	Nb. of modules	19188	Pnom total	**6524 kWp**
Inverter	Model	SMA SC2500 EV Prelim!	Pnom	2500 kW ac
Inverter pack	Nb. of units	2.0	Pnom total	**5000 kW ac**
User's needs	Unlimited load (grid)			

Loss diagram over the whole year



Grid-Connected System: Simulation parameters

Project : **PC18-Grid-MildfordUT-SAT**

Geographical Site	**MilfordUT_S1**		Country	**United States**
Situation	Latitude	38.4°N	Longitude	113.0°W
Time defined as	Legal Time	Time zone UT-7	Altitude	1563 m
	Albedo	0.20		
Meteo data:	**MilfordUT_NSRDB**	TMY - NREL: TMY3 hourly DB (1991-2005)		

Simulation variant : **PC18-MilfordUT_Rev0**

Simulation date 31/08/18 14h47

Simulation parameters

Tracking plane, tilted Axis	Axis Tilt	0°	Axis Azimuth	0°
Rotation Limitations	Minimum Phi	-60°	Maximum Phi	60°
Backtracking strategy	Tracker Spacing	5.50 m	Collector width	1.98 m
Inactive band	Left	0.20 m	Right	0.20 m
Models used	Transposition	Perez	Diffuse	Imported
Horizon	Average Height	3.0°		
Near Shadings	Linear shadings			

PV Array Characteristics

PV module Si-poly	Model	**CS3U-340P 1500V**		
	Manufacturer	Canadian Solar Inc.		
	Orientation	#1	Tilt/Azimuth	30°/0°
Number of PV modules	In series	26 modules	In parallel	738 strings
Total number of PV modules	Nb. modules	19188	Unit Nom. Power	340 Wp
Array global power	Nominal (STC)	**6524 kWp**	At operating cond.	5890 kWp (50°C)
Array operating characteristics (50°C)	U mpp	895 V	I mpp	6580 A
Total area	Module area	**38069 m²**	Cell area	33931 m²
Inverter	Model	**SMA SC2500 EV Prelim!**		
	Manufacturer	SMA		
Characteristics	Operating Voltage	850-1425 V	Unit Nom. Power	2500 kWac
Inverter pack	Nb. of inverters	2 units	Total Power	5000 kWac

PV Array loss factors

Array Soiling Losses

Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.
2.5%	2.5%	2.0%	2.0%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%

Thermal Loss factor	Uc (const)	25.0 W/m²K	Uv (wind)	1.2 W/m²K / m/s
Wiring Ohmic Loss	Global array res.	2.3 mOhm	Loss Fraction	1.5 % at STC
LID - Light Induced Degradation			Loss Fraction	2.0 %
Module Quality Loss			Loss Fraction	-0.4 %
Module Mismatch Losses			Loss Fraction	1.0 % at MPP

Grid-Connected System: Simulation parameters (continued)

Incidence effect, user defined profile

10°	20°	30°	40°	50°	60°	70°	80°	90°
1.00	1.00	1.00	0.99	0.99	0.97	0.92	0.76	0.00

System loss factors

Wiring Ohmic Loss — Wires 0 m 3x5000.0 mm² — Loss Fraction 0.0 % at STC

User's needs : Unlimited load (grid)

Grid-Connected System: Horizon definition

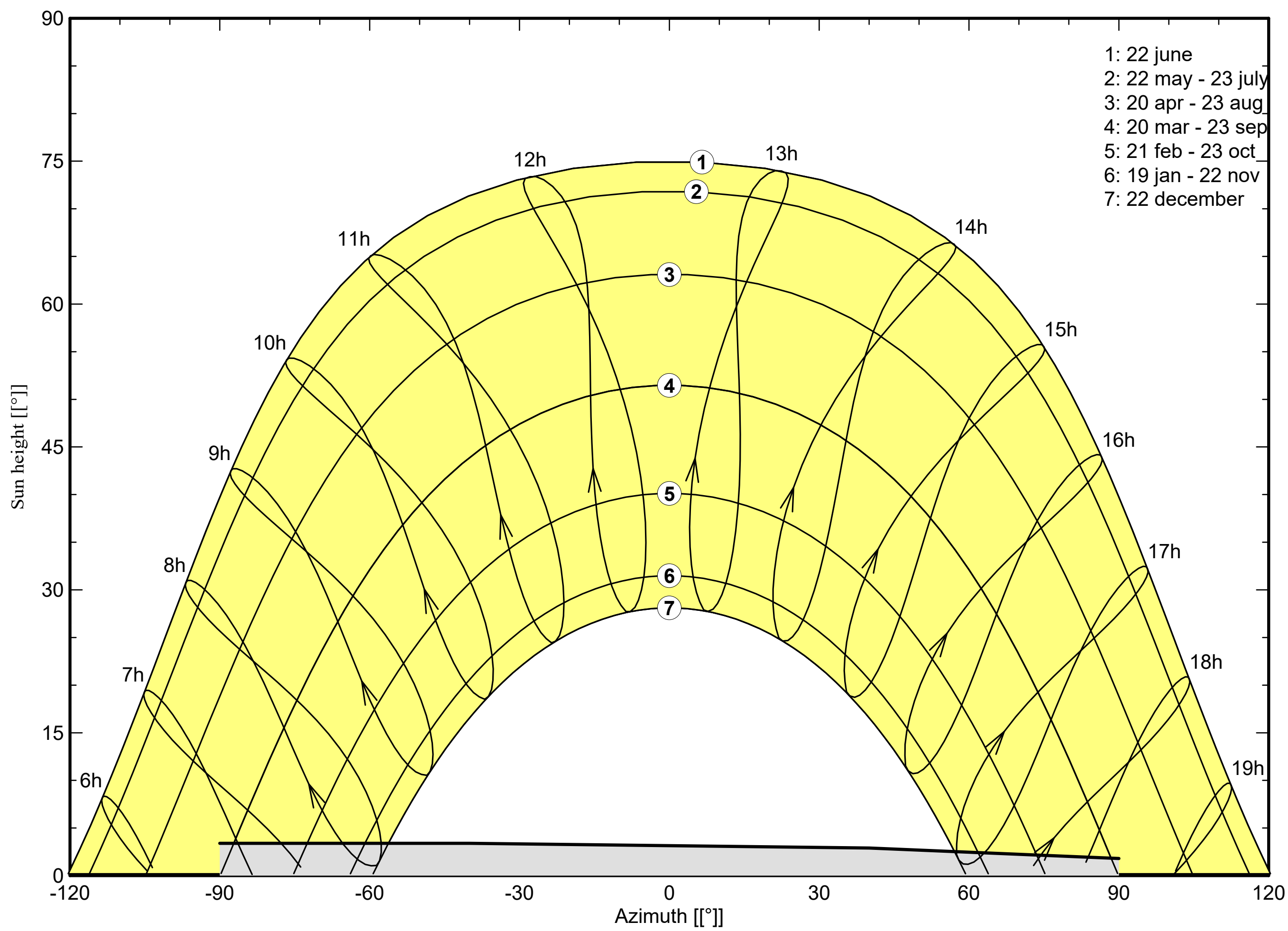
Project : **PC18-Grid-MildfordUT-SAT**

Simulation variant : **PC18-MilfordUT_Rev0**

Main system parameters	System type	**Grid-Connected**		
Horizon	Average Height	3.0°		
Near Shadings	Linear shadings			
PV Field Orientation	tracking, tilted axis, Axis Tilt	0°	Axis Azimuth	0°
PV modules	Model	CS3U-340P 1500V	Pnom	340 Wp
PV Array	Nb. of modules	19188	Pnom total	**6524 kWp**
Inverter	Model	SMA SC2500 EV Prelim!	Pnom	2500 kW ac
Inverter pack	Nb. of units	2.0	Pnom total	**5000 kW ac**
User's needs	Unlimited load (grid)			

Horizon	Average Height	3.0°	Diffuse Factor	0.98
	Albedo Factor	100 %	Albedo Fraction	0.94

Height [°]	3.4	3.4	2.9	1.8
Azimuth [°]	-90	-40	40	90



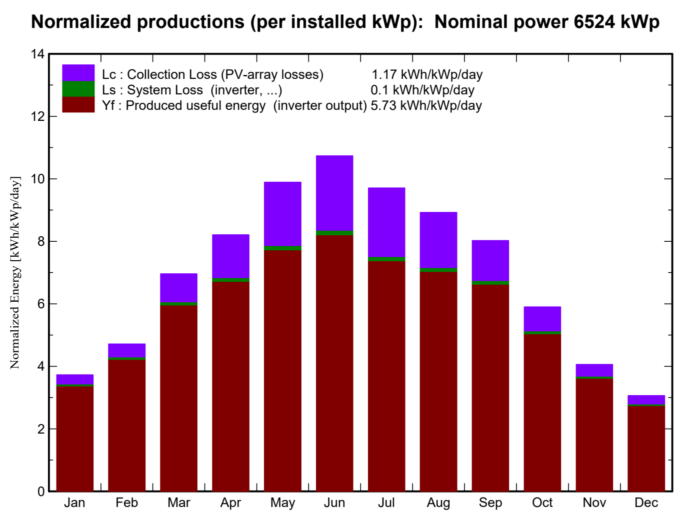
Grid-Connected System: Main results

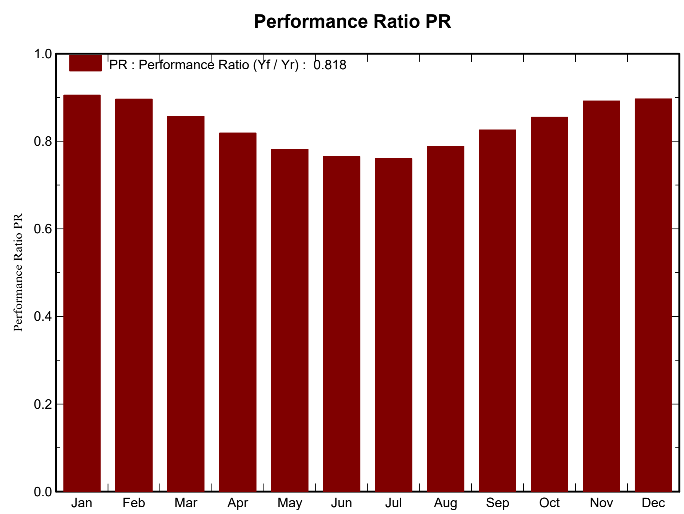
Project : **PC18-Grid-MildfordUT-SAT**

Simulation variant : **PC18-MilfordUT_Rev0**

Main system parameters	System type	**Grid-Connected**		
Horizon	Average Height	3.0°		
Near Shadings	Linear shadings			
PV Field Orientation	tracking, tilted axis, Axis Tilt	0°	Axis Azimuth	0°
PV modules	Model	CS3U-340P 1500V	Pnom	340 Wp
PV Array	Nb. of modules	19188	Pnom total	**6524 kWp**
Inverter	Model	SMA SC2500 EV Prelim!	Pnom	2500 kW ac
Inverter pack	Nb. of units	2.0	Pnom total	**5000 kW ac**
User's needs	Unlimited load (grid)			

Main simulation results				
System Production	**Produced Energy**	**13645 MWh/year**	Specific prod.	2092 kWh/kWp/year
	Performance Ratio PR	81.8 %		





PC18-MilfordUT_Rev0

Balances and main results

	GlobHor	T Amb	GlobInc	GlobEff	EArray	E_Grid	EffArrR	EffSysR
	kWh/m²	°C	kWh/m²	kWh/m²	MWh	MWh	%	%
January	83.0	-1.63	115.6	107.5	695	683	15.80	15.52
February	97.2	0.96	132.0	123.7	786	772	15.63	15.36
March	158.1	2.97	215.8	204.6	1227	1206	14.94	14.68
April	188.5	7.14	246.3	234.0	1339	1315	14.28	14.03
May	233.1	15.67	306.7	290.9	1591	1563	13.63	13.39
June	243.9	19.11	322.0	306.2	1635	1607	13.34	13.11
July	230.2	23.97	301.0	285.9	1519	1493	13.26	13.03
August	207.6	23.16	276.7	262.8	1448	1423	13.75	13.51
September	175.2	15.35	240.8	228.6	1320	1297	14.40	14.15
October	132.0	11.70	182.9	172.2	1038	1020	14.91	14.65
November	86.8	1.58	121.9	113.8	722	709	15.56	15.28
December	67.8	-1.75	94.9	87.6	566	555	15.66	15.37
Year	1903.4	9.92	2556.6	2417.9	13887	13645	14.27	14.02

Legends:				
	GlobHor	Horizontal global irradiation	EArray	Effective energy at the output of the array
	T Amb	Ambient Temperature	E_Grid	Energy injected into grid
	GlobInc	Global incident in coll. plane	EffArrR	Effic. Eout array / rough area
	GlobEff	Effective Global, corr. for IAM and shadings	EffSysR	Effic. Eout system / rough area

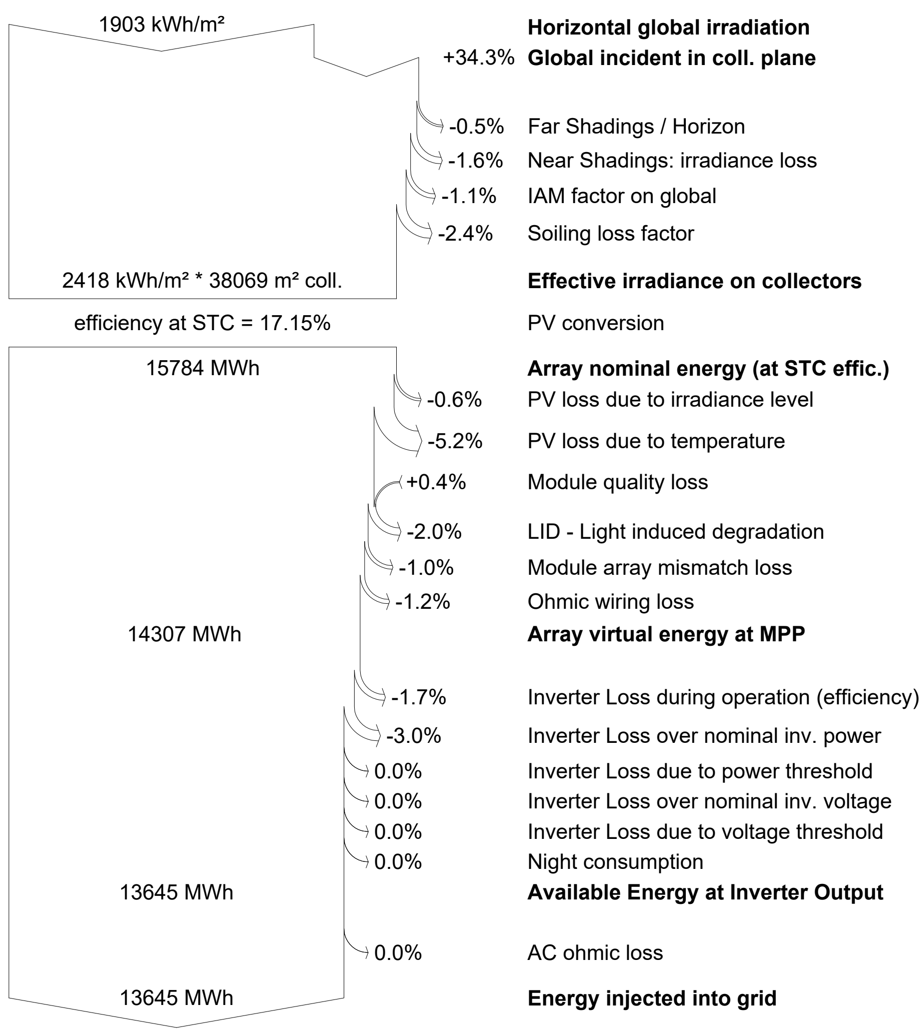
Grid-Connected System: Loss diagram

Project : **PC18-Grid-MildfordUT-SAT**

Simulation variant : **PC18-MilfordUT_Rev0**

Main system parameters	System type	**Grid-Connected**		
Horizon	Average Height	3.0°		
Near Shadings	Linear shadings			
PV Field Orientation	tracking, tilted axis, Axis Tilt	0°	Axis Azimuth	0°
PV modules	Model	CS3U-340P 1500V	Pnom	340 Wp
PV Array	Nb. of modules	19188	Pnom total	**6524 kWp**
Inverter	Model	SMA SC2500 EV Prelim!	Pnom	2500 kW ac
Inverter pack	Nb. of units	2.0	Pnom total	**5000 kW ac**
User's needs	Unlimited load (grid)			

Loss diagram over the whole year



Grid-Connected System: Simulation parameters

Project : **PC18-Grid-RockSpringsWY-SAT**

Geographical Site	**Rock Springs Arpt**		Country	**United States**
Situation	Latitude	41.5°N	Longitude	109.4°W
Time defined as	Legal Time	Time zone UT-7	Altitude	1000 m
	Albedo	0.20		
Meteo data:	**Rock Springs Arpt**	TMY - NREL: TMY3 hourly DB (1991-2005)		

Simulation variant : **PC18-RockSpringsWY_Rev2**

Simulation date 31/08/18 15h16

Simulation parameters

Tracking plane, tilted Axis	Axis Tilt	0°	Axis Azimuth	0°
Rotation Limitations	Minimum Phi	-60°	Maximum Phi	60°
Backtracking strategy	Tracker Spacing	5.50 m	Collector width	1.98 m
Inactive band	Left	0.20 m	Right	0.20 m
Models used	Transposition	Perez	Diffuse	Imported
Horizon	Average Height	4.2°		
Near Shadings	Linear shadings			

PV Array Characteristics

PV module Si-poly	Model	**CS3U-340P 1500V**		
	Manufacturer	Canadian Solar Inc.		
	Orientation	#1	Tilt/Azimuth	30°/0°
Number of PV modules	In series	26 modules	In parallel	738 strings
Total number of PV modules	Nb. modules	19188	Unit Nom. Power	340 Wp
Array global power	Nominal (STC)	**6524 kWp**	At operating cond.	5890 kWp (50°C)
Array operating characteristics (50°C)	U mpp	895 V	I mpp	6580 A
Total area	Module area	**38069 m²**	Cell area	33931 m²

Inverter	Model	**SMA SC2500 EV Prelim!**		
	Manufacturer	SMA		
Characteristics	Operating Voltage	850-1425 V	Unit Nom. Power	2500 kWac
Inverter pack	Nb. of inverters	2 units	Total Power	5000 kWac

PV Array loss factors

Array Soiling Losses

Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.
2.5%	2.5%	2.5%	2.5%	2.0%	2.0%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%

Thermal Loss factor	Uc (const)	25.0 W/m²K	Uv (wind)	1.2 W/m²K / m/s
Wiring Ohmic Loss	Global array res.	2.3 mOhm	Loss Fraction	1.5 % at STC
LID - Light Induced Degradation			Loss Fraction	2.0 %
Module Quality Loss			Loss Fraction	-0.4 %
Module Mismatch Losses			Loss Fraction	1.0 % at MPP

Grid-Connected System: Simulation parameters (continued)

Incidence effect, user defined profile

10°	20°	30°	40°	50°	60°	70°	80°	90°
1.00	1.00	1.00	0.99	0.99	0.97	0.92	0.76	0.00

System loss factors
Wiring Ohmic Loss   Wires 0 m 3x5000.0 mm²   Loss Fraction 0.0 % at STC

User's needs :   Unlimited load (grid)

Grid-Connected System: Horizon definition

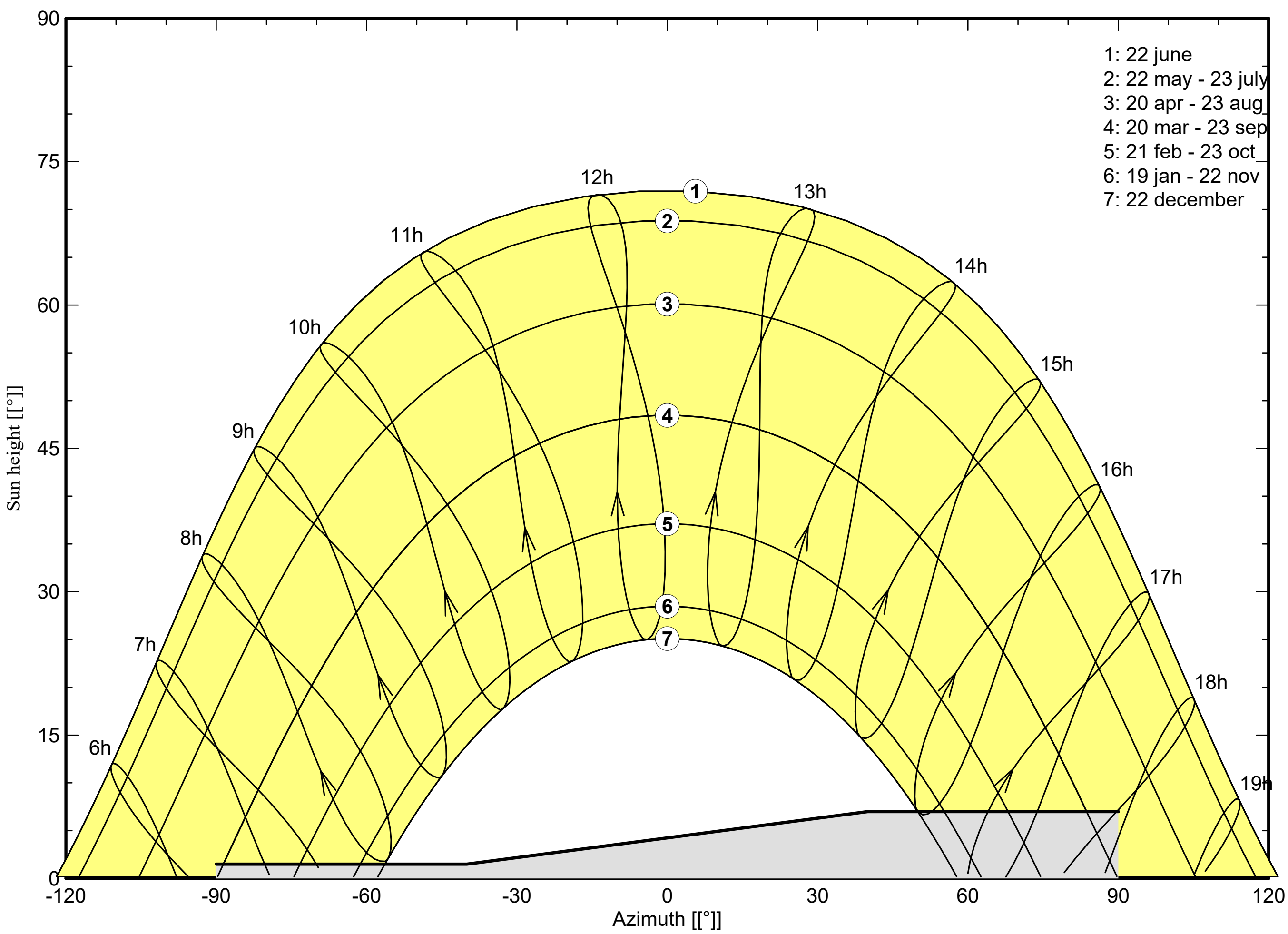
Project : **PC18-Grid-RockSpringsWY-SAT**

Simulation variant : **PC18-RockSpringsWY_Rev2**

Main system parameters	System type	**Grid-Connected**		
Horizon	Average Height	4.2°		
Near Shadings	Linear shadings			
PV Field Orientation	tracking, tilted axis, Axis Tilt	0°	Axis Azimuth	0°
PV modules	Model	CS3U-340P 1500V	Pnom	340 Wp
PV Array	Nb. of modules	19188	Pnom total	**6524 kWp**
Inverter	Model	SMA SC2500 EV Prelim!	Pnom	2500 kW ac
Inverter pack	Nb. of units	2.0	Pnom total	**5000 kW ac**
User's needs	Unlimited load (grid)			

Horizon	Average Height	4.2°	Diffuse Factor	0.96
	Albedo Factor	100 %	Albedo Fraction	0.83

Height [°]	1.5	1.5	7.0	7.0
Azimuth [°]	-90	-40	40	90



Grid-Connected System: Main results

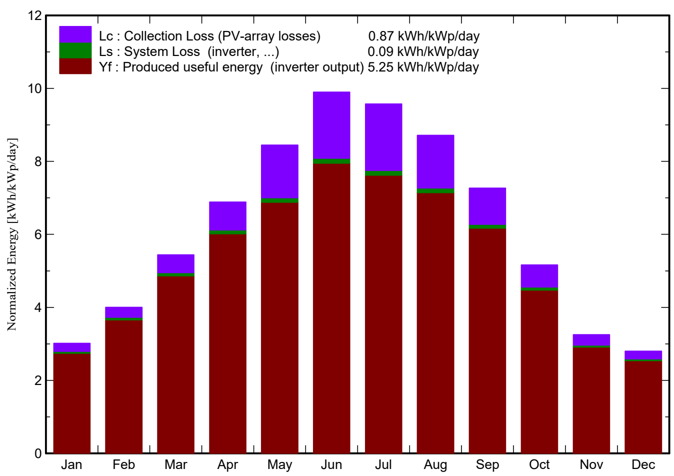
Project : **PC18-Grid-RockSpringsWY-SAT**

Simulation variant : **PC18-RockSpringsWY_Rev2**

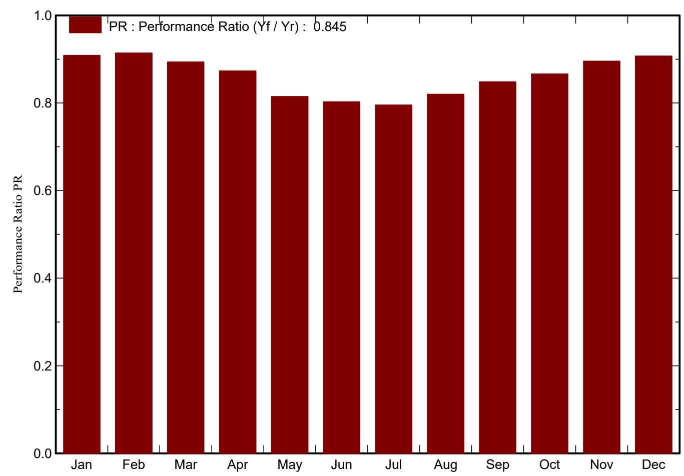
Main system parameters	System type	**Grid-Connected**		
Horizon	Average Height	4.2°		
Near Shadings	Linear shadings			
PV Field Orientation	tracking, tilted axis, Axis Tilt	0°	Axis Azimuth	0°
PV modules	Model	CS3U-340P 1500V	Pnom	340 Wp
PV Array	Nb. of modules	19188	Pnom total	**6524 kWp**
Inverter	Model	SMA SC2500 EV Prelim!	Pnom	2500 kW ac
Inverter pack	Nb. of units	2.0	Pnom total	**5000 kW ac**
User's needs	Unlimited load (grid)			

Main simulation results				
System Production	**Produced Energy**	**12510 MWh/year**	Specific prod.	1918 kWh/kWp/year
	Performance Ratio PR	84.5 %		

Normalized productions (per installed kWp): Nominal power 6524 kWp



Performance Ratio PR



PC18-RockSpringsWY_Rev2

Balances and main results

	GlobHor	T Amb	GlobInc	GlobEff	EArray	E_Grid	EffArrR	EffSysR
	kWh/m²	°C	kWh/m²	kWh/m²	MWh	MWh	%	%
January	68.3	-4.70	93.6	85.6	565	555	15.86	15.57
February	84.1	-3.58	112.0	103.5	681	668	15.96	15.67
March	127.1	0.22	168.6	157.3	1001	983	15.59	15.32
April	156.6	4.99	206.7	194.1	1198	1177	15.23	14.96
May	200.6	10.16	261.8	248.2	1416	1392	14.21	13.96
June	224.4	17.24	297.0	282.8	1582	1555	14.00	13.76
July	223.3	19.89	296.9	281.4	1568	1541	13.87	13.63
August	202.1	18.73	270.2	255.6	1470	1445	14.29	14.05
September	158.0	12.84	218.1	204.9	1228	1207	14.79	14.54
October	116.0	7.61	160.1	149.2	921	905	15.11	14.84
November	72.1	-0.85	97.5	89.7	580	570	15.63	15.34
December	60.8	-5.39	86.8	79.4	523	514	15.84	15.54
Year	1693.5	6.49	2269.3	2131.7	12734	12510	14.74	14.48

Legends:				
	GlobHor	Horizontal global irradiation	EArray	Effective energy at the output of the array
	T Amb	Ambient Temperature	E_Grid	Energy injected into grid
	GlobInc	Global incident in coll. plane	EffArrR	Effic. Eout array / rough area
	GlobEff	Effective Global, corr. for IAM and shadings	EffSysR	Effic. Eout system / rough area

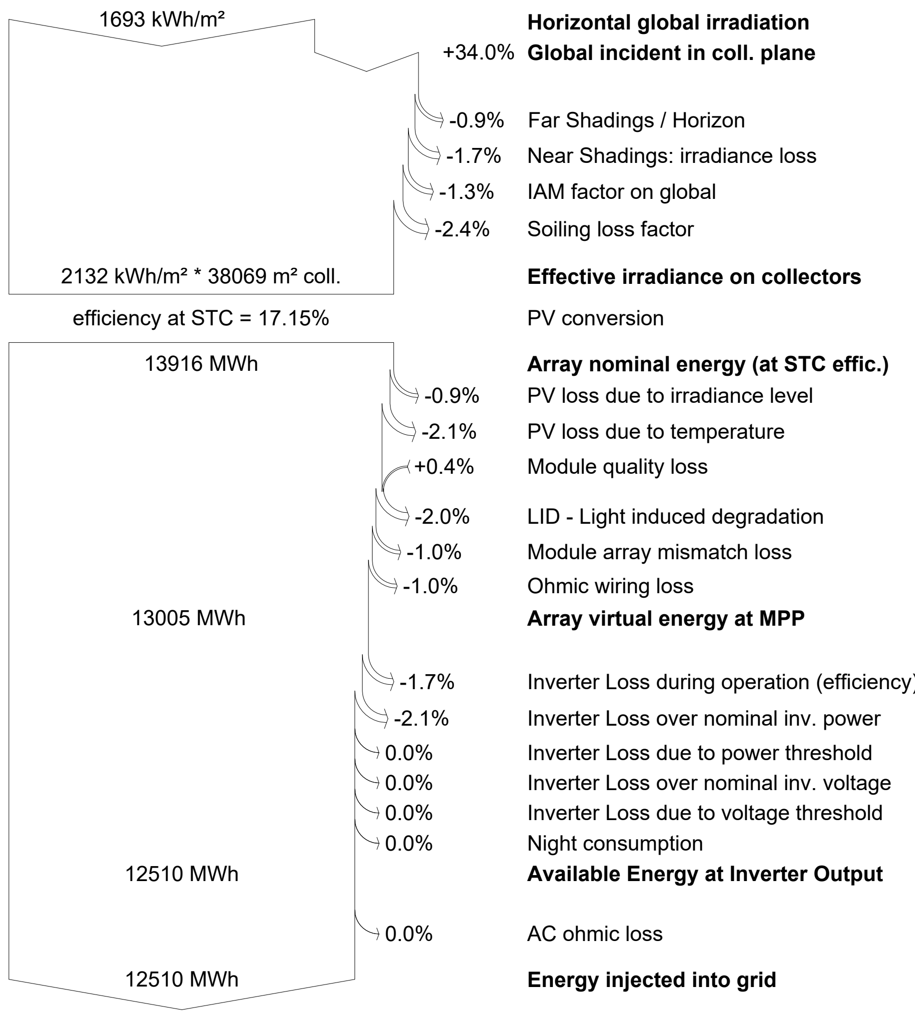
Grid-Connected System: Loss diagram

Project : **PC18-Grid-RockSpringsWY-SAT**

Simulation variant : **PC18-RockSpringsWY_Rev2**

Main system parameters	System type	**Grid-Connected**		
Horizon	Average Height	4.2°		
Near Shadings	Linear shadings			
PV Field Orientation	tracking, tilted axis, Axis Tilt	0°	Axis Azimuth	0°
PV modules	Model	CS3U-340P 1500V	Pnom	340 Wp
PV Array	Nb. of modules	19188	Pnom total	**6524 kWp**
Inverter	Model	SMA SC2500 EV Prelim!	Pnom	2500 kW ac
Inverter pack	Nb. of units	2.0	Pnom total	**5000 kW ac**
User's needs	Unlimited load (grid)			

Loss diagram over the whole year



Grid-Connected System: Simulation parameters

Project : **PC18-Grid-YakimaWA-SAT**

Geographical Site	**Yakima**		Country	**United States**
Situation	Latitude	46.6°N	Longitude	120.5°W
Time defined as	Legal Time	Time zone UT-8	Altitude	320 m
	Albedo	0.20		
Meteo data:	**Yakima Air Terminal**	TMY - NREL: TMY3 hourly DB (1991-2005)		

Simulation variant : **YakimaWA_5MW-SAT_Report**

Simulation date 31/08/18 15h29

Simulation parameters

Tracking plane, tilted Axis	Axis Tilt	0°	Axis Azimuth	0°
Rotation Limitations	Minimum Phi	-60°	Maximum Phi	60°
Backtracking strategy	Tracker Spacing	5.50 m	Collector width	1.98 m
Inactive band	Left	0.20 m	Right	0.20 m
Models used	Transposition	Perez	Diffuse	Imported
Horizon	Free Horizon			
Near Shadings	Linear shadings			

PV Array Characteristics

PV module Si-poly	Model	**CS3U-340P 1500V**		
	Manufacturer	Canadian Solar Inc.		
	Orientation	#1	Tilt/Azimuth	30°/0°
Number of PV modules	In series	26 modules	In parallel	738 strings
Total number of PV modules	Nb. modules	19188	Unit Nom. Power	340 Wp
Array global power	Nominal (STC)	**6524 kWp**	At operating cond.	5890 kWp (50°C)
Array operating characteristics (50°C)	U mpp	895 V	I mpp	6580 A
Total area	Module area	**38069 m²**	Cell area	33931 m²
Inverter	Model	**SMA SC2500 EV Prelim!**		
	Manufacturer	SMA		
Characteristics	Operating Voltage	850-1425 V	Unit Nom. Power	2500 kWac
Inverter pack	Nb. of inverters	2 units	Total Power	5000 kWac

PV Array loss factors

Array Soiling Losses

Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.
2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%

Thermal Loss factor	Uc (const)	25.0 W/m²K	Uv (wind)	1.2 W/m²K / m/s
Wiring Ohmic Loss	Global array res.	2.5 mOhm	Loss Fraction	1.6 % at STC
LID - Light Induced Degradation			Loss Fraction	2.0 %
Module Quality Loss			Loss Fraction	-0.4 %
Module Mismatch Losses			Loss Fraction	1.0 % at MPP

Grid-Connected System: Simulation parameters (continued)

Incidence effect, user defined profile

10°	20°	30°	40°	50°	60°	70°	80°	90°
1.00	1.00	1.00	0.99	0.99	0.97	0.92	0.76	0.00

System loss factors
Wiring Ohmic Loss Wires 0 m 3x0.0 mm² Loss Fraction 0.0 % at STC

User's needs : Unlimited load (grid)

Grid-Connected System: Main results

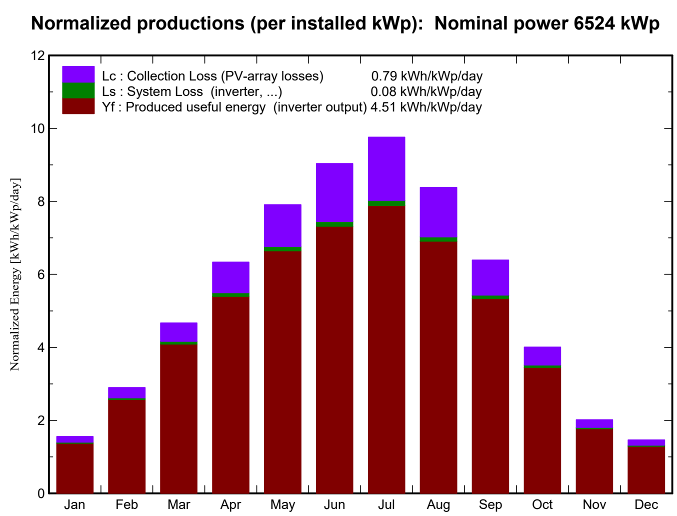
Project : **PC18-Grid-YakimaWA-SAT**

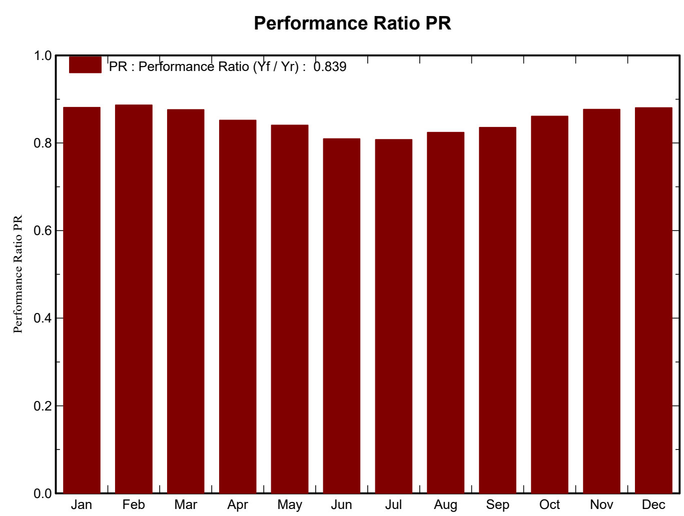
Simulation variant : **YakimaWA_5MW-SAT_Report**

Main system parameters	System type	**Grid-Connected**		
Near Shadings	Linear shadings			
PV Field Orientation	tracking, tilted axis, Axis Tilt	0°	Axis Azimuth	0°
PV modules	Model	CS3U-340P 1500V	Pnom	340 Wp
PV Array	Nb. of modules	19188	Pnom total	**6524 kWp**
Inverter	Model	SMA SC2500 EV Prelim!	Pnom	2500 kW ac
Inverter pack	Nb. of units	2.0	Pnom total	**5000 kW ac**
User's needs	Unlimited load (grid)			

Main simulation results

System Production	**Produced Energy**	**10749 MWh/year**	Specific prod.	1648 kWh/kWp/year
	Performance Ratio PR	83.9 %		





YakimaWA_5MW-SAT_Report

Balances and main results

	GlobHor kWh/m²	T Amb °C	GlobInc kWh/m²	GlobEff kWh/m²	EArray MWh	E_Grid MWh	EffArrR %	EffSysR %
January	41.1	-1.43	48.3	43.9	284	278	15.45	15.10
February	62.8	2.53	81.1	75.2	478	469	15.50	15.20
March	108.9	5.93	144.8	135.8	842	827	15.29	15.01
April	146.2	11.57	190.1	178.8	1076	1056	14.86	14.60
May	188.4	14.18	245.1	231.0	1368	1344	14.66	14.40
June	208.6	19.24	271.1	256.3	1458	1432	14.12	13.87
July	225.0	22.28	302.6	287.1	1623	1595	14.09	13.84
August	190.6	19.68	259.9	246.3	1422	1397	14.37	14.12
September	140.7	15.67	191.7	180.6	1064	1045	14.57	14.32
October	91.2	9.06	124.3	116.2	711	698	15.03	14.76
November	47.3	2.49	60.6	55.6	354	346	15.35	15.02
December	36.2	-2.00	45.4	41.2	267	261	15.43	15.09
Year	1486.8	9.97	1964.9	1847.9	10946	10749	14.63	14.37

Legends:				
GlobHor	Horizontal global irradiation		EArray	Effective energy at the output of the array
T Amb	Ambient Temperature		E_Grid	Energy injected into grid
GlobInc	Global incident in coll. plane		EffArrR	Effic. Eout array / rough area
GlobEff	Effective Global, corr. for IAM and shadings		EffSysR	Effic. Eout system / rough area

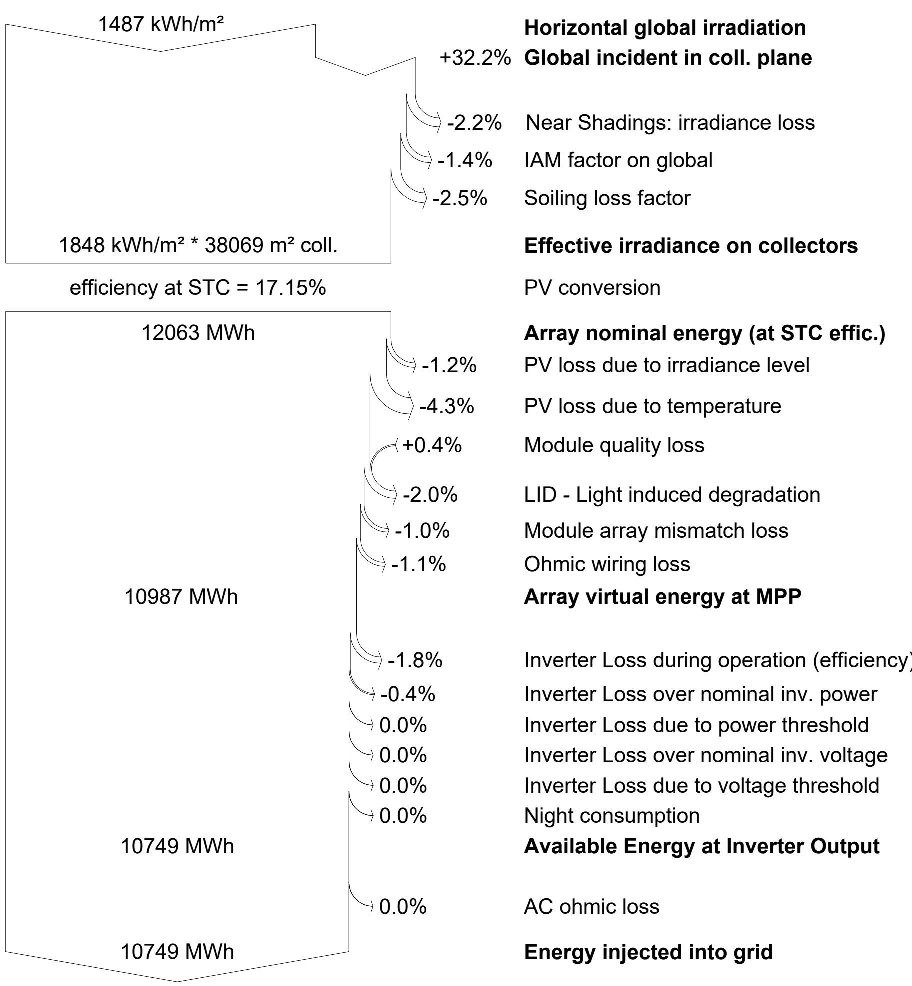
Grid-Connected System: Loss diagram

Project : **PC18-Grid-YakimaWA-SAT**

Simulation variant : **YakimaWA_5MW-SAT_Report**

Main system parameters	System type	**Grid-Connected**		
Near Shadings	Linear shadings			
PV Field Orientation	tracking, tilted axis, Axis Tilt	0°	Axis Azimuth	0°
PV modules	Model	CS3U-340P 1500V	Pnom	340 Wp
PV Array	Nb. of modules	19188	Pnom total	**6524 kWp**
Inverter	Model	SMA SC2500 EV Prelim!	Pnom	2500 kW ac
Inverter pack	Nb. of units	2.0	Pnom total	**5000 kW ac**
User's needs	Unlimited load (grid)			

Loss diagram over the whole year



APPENDIX C – SOLAR OUTPUT SUMMARY

Energy Production Summary

Burns & McDonnell, Energy Division

Project Name: **Pacificorp 2018 Renewables Technology Assessment**

Variant: VC3 Date: 31-Aug-18

Site Information	
City / State:	Idaho Falls, Idaho
Latitude (N):	43.5 °
Longitude (W):	-112 °
Altitude	1441 m
ASHRAE Cooling DB Temp.	32 °C
ASHRAE Extreme Mean Min. Temp.	-25 °C

Estimated Annual Energy Production	
P50 net production (yr-1)	11597.3 MWh
AC capacity factor - Inv Rating	26.48%
AC capacity factor - POI Rating	26.48%
DC capacity factor	20.00%
Specific Production	1752 kWh/kWp/yr
Performance Ratio PR	81.08%
Night time losses	-21.1 MWh
Plant Output Limitations	0.00%

Design Parameters	
System DC Voltage	1500 VDC
GCR	36 %
Row spacing	5.5 m
Mounting	Tracker
Tilt angle or rotation limits	60 °
Azimuth	0 °
Tracking strategy	TRUE
Availability	100.0 %
Degradation	N/A %/yr

Facility Level Information	
Nameplate Capacity	**6.62 MWDC**
Number of modules	19188
Nameplate Capacity	**5.00 MWAC**
Number of arrays	1
Interconnection Limit	**5.00 MWAC**
Inteconnection Voltage	34.5 kV
DC/AC ratio - POI Rating	1.324

Array Level Information	
Module rating	345 W
# Modules per string	26
Strings in parallel	738
Total number of modules	19188
DC capacity	6620 kW
Inverter rating	5000 kW
DC/AC ratio - Inv Rating	1.324

Weather	
Source	TMY3
GHI	1618.2 kWh/m2
DHI	kWh/m2
Global POA	2160.8 kWh/m2
Average Temp.	6.94 °C
Average Temp. (Generation)	11.48 °C
Average Wind	3.84 m/s
Average Wind (Generation)	4.53 m/s

PVsyst Input Parameters	
Transposition model	Perez
Constant thermal loss factor (Uc)	25.0 W/m2-K
Wind loss factor (Uv)	1.2 W/m2-K/m/s
Soiling losses	2.4 %
Light induced degradation	2.0 %
DC wiring loss	1.5 %
Module quality loss	-0.4 %
Module mismatch loss	1.0 %
DC health loss	1.0 %

AC System Losses	
MV transformer no-load losses	0.07%
MV transformer full load losses	0.85%
MV collection system	0.70%
HV transformer no-load losses	0.00%
HV transformer full load losses	0.00%
HV line	0.00%
Auxiliary	0.01%

Energy Production Summary

Burns & McDonnell, Energy Division

Project Name: **Pacificorp 2018 Renewables Technology Assessment**

Variant: VC3 Date: 28-Aug-18

Site Information	
City / State:	Idaho Falls, Idaho
Latitude (N):	43.5 °
Longitude (W):	-112 °
Altitude	1441 m
ASHRAE Cooling DB Temp.	32 °C
ASHRAE Extreme Mean Min. Temp.	-25 °C

Estimated Annual Energy Production	
P50 net production (yr-1)	122928.5 MWh
AC capacity factor - Inv Rating	25.51%
AC capacity factor - POI Rating	28.07%
DC capacity factor	19.27%
Specific Production	1688 kWh/kWp/yr
Performance Ratio PR	78.13%
Night time losses	-408.8 MWh
Plant Output Limitations	2.63%

Design Parameters	
System DC Voltage	1500 VDC
GCR	36 %
Row spacing	5.5 m
Mounting	Tracker
Tilt angle or rotation limits	60 °
Azimuth	0 °
Tracking strategy	TRUE
Availability	100.0 %
Degradation	N/A %/yr

Facility Level Information	
Nameplate Capacity	**72.82 MWDC**
Number of modules	211068
Nameplate Capacity	**55.00 MWAC**
Number of arrays	11
Interconnection Limit	**50.00 MWAC**
Inteconnection Voltage	115 kV
DC/AC ratio - POI Rating	1.456

Array Level Information	
Module rating	345 W
# Modules per string	26
Strings in parallel	738
Total number of modules	19188
DC capacity	6620 kW
Inverter rating	5000 kW
DC/AC ratio - Inv Rating	1.324

Weather	
Source	TMY3
GHI	1618.2 kWh/m2
DHI	kWh/m2
Global POA	2160.8 kWh/m2
Average Temp.	6.94 °C
Average Temp. (Generation)	11.48 °C
Average Wind	3.84 m/s
Average Wind (Generation)	4.53 m/s

PVsyst Input Parameters	
Transposition model	Perez
Constant thermal loss factor (Uc)	25.0 W/m2-K
Wind loss factor (Uv)	1.2 W/m2-K/m/s
Soiling losses	2.4 %
Light induced degradation	2.0 %
DC wiring loss	1.5 %
Module quality loss	-0.4 %
Module mismatch loss	1.0 %
DC health loss	1.0 %

AC System Losses	
MV transformer no-load losses	0.07%
MV transformer full load losses	0.85%
MV collection system	1.30%
HV transformer no-load losses	0.07%
HV transformer full load losses	0.48%
HV line	0.05%
Auxiliary	0.01%

BURNS & McDONNELL

Energy Production Summary

Burns & McDonnell, Energy Division

Project Name: **Pacificorp 2018 Renewables Technology Assessment**

Variant: VC3 Date: 31-Aug-18

Site Information	
City / State:	Idaho Falls, Idaho
Latitude (N):	43.5 °
Longitude (W):	-112 °
Altitude	1441 m
ASHRAE Cooling DB Temp.	32 °C
ASHRAE Extreme Mean Min. Temp.	-25 °C

Design Parameters	
System DC Voltage	1500 VDC
GCR	36 %
Row spacing	5.5 m
Mounting	Tracker
Tilt angle or rotation limits	60 °
Azimuth	0 °
Tracking strategy	TRUE
Availability	100.0 %
Degradation	N/A %/yr

Array Level Information	
Module rating	345 W
# Modules per string	26
Strings in parallel	738
Total number of modules	19188
DC capacity	6620 kW
Inverter rating	5000 kW
DC/AC ratio - Inv Rating	1.324

PVsyst Input Parameters	
Transposition model	Perez
Constant thermal loss factor (Uc)	25.0 W/m2-K
Wind loss factor (Uv)	1.2 W/m2-K/m/s
Soiling losses	2.4 %
Light induced degradation	2.0 %
DC wiring loss	1.5 %
Module quality loss	-0.4 %
Module mismatch loss	1.0 %
DC health loss	1.0 %

Estimated Annual Energy Production	
P50 net production (yr-1)	491714.0 MWh
AC capacity factor - Inv Rating	25.51%
AC capacity factor - POI Rating	28.07%
DC capacity factor	19.27%
Specific Production	1688 kWh/kWp/yr
Performance Ratio PR	78.13%
Night time losses	-1635.2 MWh
Plant Output Limitations	2.63%

Facility Level Information	
Nameplate Capacity	**291.27 MWDC**
Number of modules	844272
Nameplate Capacity	**220.00 MWAC**
Number of arrays	44
Interconnection Limit	**200.00 MWAC**
Inteconnection Voltage	230 kV
DC/AC ratio - POI Rating	1.456

Weather	
Source	TMY3
GHI	1618.2 kWh/m2
DHI	kWh/m2
Global POA	2160.8 kWh/m2
Average Temp.	6.94 °C
Average Temp. (Generation)	11.48 °C
Average Wind	3.84 m/s
Average Wind (Generation)	4.53 m/s

AC System Losses	
MV transformer no-load losses	0.07%
MV transformer full load losses	0.85%
MV collection system	1.30%
HV transformer no-load losses	0.07%
HV transformer full load losses	0.48%
HV line	0.05%
Auxiliary	0.01%

Energy Production Summary

Burns & McDonnell, Energy Division

Project Name: **Pacificorp 2018 Renewables Technology Assessment**

Variant: VC2 Date: 31-Aug-18

Site Information	
City / State:	Lakeview, OR
Latitude (N):	42.2 °
Longitude (W):	-120 °
Altitude	1441 m
ASHRAE Cooling DB Temp.	31 °C
ASHRAE Extreme Mean Min. Temp.	-22 °C

Estimated Annual Energy Production	
P50 net production (yr-1)	12291.9 MWh
AC capacity factor - Inv Rating	28.06%
AC capacity factor - POI Rating	28.06%
DC capacity factor	21.20%
Specific Production	1857 kWh/kWp/yr
Performance Ratio PR	80.72%
Night time losses	-21.2 MWh
Plant Output Limitations	0.00%

Design Parameters	
System DC Voltage	1500 VDC
GCR	36 %
Row spacing	5.5 m
Mounting	Tracker
Tilt angle or rotation limits	60 °
Azimuth	0 °
Tracking strategy	TRUE
Availability	100.0 %
Degradation	0.5 %/yr

Facility Level Information	
Nameplate Capacity	**6.62 MWDC**
Number of modules	19188
Nameplate Capacity	**5.00 MWAC**
Number of arrays	1
Interconnection Limit	**5.00 MWAC**
Inteconnection Voltage	34.5 kV
DC/AC ratio - POI Rating	1.324

Array Level Information	
Module rating	345 W
# Modules per string	26
Strings in parallel	738
Total number of modules	19188
DC capacity	6620 kW
Inverter rating	5000 kW
DC/AC ratio - Inv Rating	1.324

Weather	
Source	TMY3
GHI	1704.3 kWh/m2
DHI	kWh/m2
Global POA	2300.2 kWh/m2
Average Temp.	7.87 °C
Average Temp. (Generation)	12.57 °C
Average Wind	3.33 m/s
Average Wind (Generation)	3.63 m/s

PVsyst Input Parameters	
Transposition model	Perez
Constant thermal loss factor (Uc)	25.0 W/m2-K
Wind loss factor (Uv)	1.2 W/m2-K/m/s
Soiling losses	2.2 %
Light induced degradation	2.0 %
DC wiring loss	1.5 %
Module quality loss	-0.4 %
Module mismatch loss	1.0 %
DC health loss	1.0 %

AC System Losses	
MV transformer no-load losses	0.07%
MV transformer full load losses	0.85%
MV collection system	0.70%
HV transformer no-load losses	0.00%
HV transformer full load losses	0.00%
HV line	0.00%
Auxiliary	0.01%

Energy Production Summary

Burns & McDonnell, Energy Division

Project Name: **Pacificorp 2018 Renewables Technology Assessment**

Variant: VC2 Date: 31-Aug-18

Site Information	
City / State:	Lakeview, OR
Latitude (N):	42.2 °
Longitude (W):	-120 °
Altitude	1441 m
ASHRAE Cooling DB Temp.	31 °C
ASHRAE Extreme Mean Min. Temp.	-22 °C

Estimated Annual Energy Production	
P50 net production (yr-1)	130139.1 MWh
AC capacity factor - Inv Rating	27.01%
AC capacity factor - POI Rating	29.71%
DC capacity factor	20.40%
Specific Production	1787 kWh/kWp/yr
Performance Ratio PR	77.70%
Night time losses	-411.2 MWh
Plant Output Limitations	2.75%

Design Parameters	
System DC Voltage	1500 VDC
GCR	36 %
Row spacing	5.5 m
Mounting	Tracker
Tilt angle or rotation limits	60 °
Azimuth	0 °
Tracking strategy	TRUE
Availability	100.0 %
Degradation	0.5 %/yr

Facility Level Information	
Nameplate Capacity	**72.82 MWDC**
Number of modules	211068
Nameplate Capacity	**55.00 MWAC**
Number of arrays	11
Interconnection Limit	**50.00 MWAC**
Inteconnection Voltage	115 kV
DC/AC ratio - POI Rating	1.456

Array Level Information	
Module rating	345 W
# Modules per string	26
Strings in parallel	738
Total number of modules	19188
DC capacity	6620 kW
Inverter rating	5000 kW
DC/AC ratio - Inv Rating	1.324

Weather	
Source	TMY3
GHI	1704.3 kWh/m2
DHI	kWh/m2
Global POA	2300.2 kWh/m2
Average Temp.	7.87 °C
Average Temp. (Generation)	12.57 °C
Average Wind	3.33 m/s
Average Wind (Generation)	3.63 m/s

PVsyst Input Parameters	
Transposition model	Perez
Constant thermal loss factor (Uc)	25.0 W/m2-K
Wind loss factor (Uv)	1.2 W/m2-K/m/s
Soiling losses	2.2 %
Light induced degradation	2.0 %
DC wiring loss	1.5 %
Module quality loss	-0.4 %
Module mismatch loss	1.0 %
DC health loss	1.0 %

AC System Losses	
MV transformer no-load losses	0.07%
MV transformer full load losses	0.85%
MV collection system	1.30%
HV transformer no-load losses	0.07%
HV transformer full load losses	0.48%
HV line	0.05%
Auxiliary	0.01%

Energy Production Summary

Burns & McDonnell, Energy Division

Project Name: **Pacificorp 2018 Renewables Technology Assessment**

Variant: VC2 Date: 31-Aug-18

Site Information	
City / State:	Lakeview, OR
Latitude (N):	42.2 °
Longitude (W):	-120 °
Altitude	1441 m
ASHRAE Cooling DB Temp.	31 °C
ASHRAE Extreme Mean Min. Temp.	-22 °C

Estimated Annual Energy Production	
P50 net production (yr-1)	520556.4 MWh
AC capacity factor - Inv Rating	27.01%
AC capacity factor - POI Rating	29.71%
DC capacity factor	20.40%
Specific Production	1787 kWh/kWp/yr
Performance Ratio PR	77.70%
Night time losses	-1644.8 MWh
Plant Output Limitations	2.75%

Design Parameters	
System DC Voltage	1500 VDC
GCR	36 %
Row spacing	5.5 m
Mounting	Tracker
Tilt angle or rotation limits	60 °
Azimuth	0 °
Tracking strategy	TRUE
Availability	100.0 %
Degradation	0.5 %/yr

Facility Level Information	
Nameplate Capacity	**291.27 MWDC**
Number of modules	844272
Nameplate Capacity	**220.00 MWAC**
Number of arrays	44
Interconnection Limit	**200.00 MWAC**
Inteconnection Voltage	230 kV
DC/AC ratio - POI Rating	1.456

Array Level Information	
Module rating	345 W
# Modules per string	26
Strings in parallel	738
Total number of modules	19188
DC capacity	6620 kW
Inverter rating	5000 kW
DC/AC ratio - Inv Rating	1.324

Weather	
Source	TMY3
GHI	1704.3 kWh/m2
DHI	kWh/m2
Global POA	2300.2 kWh/m2
Average Temp.	7.87 °C
Average Temp. (Generation)	12.57 °C
Average Wind	3.33 m/s
Average Wind (Generation)	3.63 m/s

PVsyst Input Parameters	
Transposition model	Perez
Constant thermal loss factor (Uc)	25.0 W/m2-K
Wind loss factor (Uv)	1.2 W/m2-K/m/s
Soiling losses	2.2 %
Light induced degradation	2.0 %
DC wiring loss	1.5 %
Module quality loss	-0.4 %
Module mismatch loss	1.0 %
DC health loss	1.0 %

AC System Losses	
MV transformer no-load losses	0.07%
MV transformer full load losses	0.85%
MV collection system	1.30%
HV transformer no-load losses	0.07%
HV transformer full load losses	0.48%
HV line	0.05%
Auxiliary	0.01%

Energy Production Summary

Burns & McDonnell, Energy Division

Project Name: **Pacificorp 2018 Renewables Technology Assessment**

Variant: VC2 Date: 31-Aug-18

Site Information	
City / State:	Milford, UT
Latitude (N):	38.4 °
Longitude (W):	-113 °
Altitude	1534 m
ASHRAE Cooling DB Temp.	34.9 °C
ASHRAE Extreme Mean Min. Temp.	-23.1 °C

Design Parameters	
System DC Voltage	1500 VDC
GCR	36 %
Row spacing	5.5 m
Mounting	Tracker
Tilt angle or rotation limits	60 °
Azimuth	0 °
Tracking strategy	TRUE
Availability	100.0 %
Degradation	0.5 %/yr

Array Level Information	
Module rating	345 W
# Modules per string	26
Strings in parallel	738
Total number of modules	19188
DC capacity	6620 kW
Inverter rating	5000 kW
DC/AC ratio - Inv Rating	1.324

PVsyst Input Parameters	
Transposition model	Perez
Constant thermal loss factor (Uc)	25.0 W/m2-K
Wind loss factor (Uv)	1.2 W/m2-K/m/s
Soiling losses	2.2 %
Light induced degradation	2.0 %
DC wiring loss	1.5 %
Module quality loss	-0.4 %
Module mismatch loss	1.0 %
DC health loss	1.0 %

Estimated Annual Energy Production	
P50 net production (yr-1)	13450.8 MWh
AC capacity factor - Inv Rating	30.71%
AC capacity factor - POI Rating	30.71%
DC capacity factor	23.20%
Specific Production	2032 kWh/kWp/yr
Performance Ratio PR	79.48%
Night time losses	-20.8 MWh
Plant Output Limitations	0.00%

Facility Level Information	
Nameplate Capacity	**6.62 MWDC**
Number of modules	19188
Nameplate Capacity	**5.00 MWAC**
Number of arrays	1
Interconnection Limit	**5.00 MWAC**
Inteconnection Voltage	34.5 kV
DC/AC ratio - POI Rating	1.324

Weather	
Source	NSRDB PSMv3
GHI	1903.4 kWh/m2
DHI	kWh/m2
Global POA	2556.6 kWh/m2
Average Temp.	9.92 °C
Average Temp. (Generation)	14.91 °C
Average Wind	2.11 m/s
Average Wind (Generation)	2.82 m/s

AC System Losses	
MV transformer no-load losses	0.07%
MV transformer full load losses	0.85%
MV collection system	0.70%
HV transformer no-load losses	0.00%
HV transformer full load losses	0.00%
HV line	0.00%
Auxiliary	0.01%

Energy Production Summary

Burns & McDonnell, Energy Division

Project Name: Pacificorp 2018 Renewables Technology Assessment

Variant: VC2 Date: 31-Aug-18

Site Information		
City / State:	Milford, UT	
Latitude (N):	38.4	°
Longitude (W):	-113	°
Altitude	1534	m
ASHRAE Cooling DB Temp.	34.9	°C
ASHRAE Extreme Mean Min. Temp.	-23.1	°C

Design Parameters		
System DC Voltage	1500	VDC
GCR	36	%
Row spacing	5.5	m
Mounting	Tracker	
Tilt angle or rotation limits	60	°
Azimuth	0	°
Tracking strategy	TRUE	
Availability	100.0	%
Degradation	0.5	%/yr

Array Level Information		
Module rating	345	W
# Modules per string	26	
Strings in parallel	738	
Total number of modules	19188	
DC capacity	6620	kW
Inverter rating	5000	kW
DC/AC ratio - Inv Rating	1.324	

PVsyst Input Parameters		
Transposition model	Perez	
Constant thermal loss factor (Uc)	25.0	W/m2-K
Wind loss factor (Uv)	1.2	W/m2-K/m/s
Soiling losses	2.2	%
Light induced degradation	2.0	%
DC wiring loss	1.5	%
Module quality loss	-0.4	%
Module mismatch loss	1.0	%
DC health loss	1.0	%

Estimated Annual Energy Production		
P50 net production (yr-1)	142375.3	MWh
AC capacity factor - Inv Rating	29.55%	
AC capacity factor - POI Rating	32.51%	
DC capacity factor	22.32%	
Specific Production	1955	kWh/kWp/yr
Performance Ratio PR	76.48%	
Night time losses	-401.9	MWh
Plant Output Limitations	2.76%	

Facility Level Information		
Nameplate Capacity	**72.82**	**MWDC**
Number of modules	211068	
Nameplate Capacity	**55.00**	**MWAC**
Number of arrays	11	
Interconnection Limit	**50.00**	**MWAC**
Inteconnection Voltage	115	kV
DC/AC ratio - POI Rating	1.456	

Weather		
Source	NSRDB PSMv3	
GHI	1903.4	kWh/m2
DHI		kWh/m2
Global POA	2556.6	kWh/m2
Average Temp.	9.92	°C
Average Temp. (Generation)	14.91	°C
Average Wind	2.11	m/s
Average Wind (Generation)	2.82	m/s

AC System Losses	
MV transformer no-load losses	0.07%
MV transformer full load losses	0.85%
MV collection system	1.30%
HV transformer no-load losses	0.07%
HV transformer full load losses	0.48%
HV line	0.05%
Auxiliary	0.01%

BURNS & McDONNELL

Energy Production Summary

Burns & McDonnell, Energy Division

Project Name: **Pacificorp 2018 Renewables Technology Assessment**

Variant: VC2 Date: 31-Aug-18

Site Information	
City / State:	Milford, UT
Latitude (N):	38.4 °
Longitude (W):	-113 °
Altitude	1534 m
ASHRAE Cooling DB Temp.	34.9 °C
ASHRAE Extreme Mean Min. Temp.	-23.1 °C

Estimated Annual Energy Production	
P50 net production (yr-1)	569501.1 MWh
AC capacity factor - Inv Rating	29.55%
AC capacity factor - POI Rating	32.51%
DC capacity factor	22.32%
Specific Production	1955 kWh/kWp/yr
Performance Ratio PR	76.48%
Night time losses	-1607.7 MWh
Plant Output Limitations	2.76%

Design Parameters	
System DC Voltage	1500 VDC
GCR	36 %
Row spacing	5.5 m
Mounting	Tracker
Tilt angle or rotation limits	60 °
Azimuth	0 °
Tracking strategy	TRUE
Availability	100.0 %
Degradation	0.5 %/yr

Facility Level Information	
Nameplate Capacity	**291.27 MWDC**
Number of modules	844272
Nameplate Capacity	**220.00 MWAC**
Number of arrays	44
Interconnection Limit	**200.00 MWAC**
Inteconnection Voltage	230 kV
DC/AC ratio - POI Rating	1.456

Array Level Information	
Module rating	345 W
# Modules per string	26
Strings in parallel	738
Total number of modules	19188
DC capacity	6620 kW
Inverter rating	5000 kW
DC/AC ratio - Inv Rating	1.324

Weather	
Source	NSRDB PSMv3
GHI	1903.4 kWh/m2
DHI	kWh/m2
Global POA	2556.6 kWh/m2
Average Temp.	9.92 °C
Average Temp. (Generation)	14.91 °C
Average Wind	2.11 m/s
Average Wind (Generation)	2.82 m/s

PVsyst Input Parameters	
Transposition model	Perez
Constant thermal loss factor (Uc)	25.0 W/m2-K
Wind loss factor (Uv)	1.2 W/m2-K/m/s
Soiling losses	2.2 %
Light induced degradation	2.0 %
DC wiring loss	1.5 %
Module quality loss	-0.4 %
Module mismatch loss	1.0 %
DC health loss	1.0 %

AC System Losses	
MV transformer no-load losses	0.07%
MV transformer full load losses	0.85%
MV collection system	1.30%
HV transformer no-load losses	0.07%
HV transformer full load losses	0.48%
HV line	0.05%
Auxiliary	0.01%

Energy Production Summary

Burns & McDonnell, Energy Division

Project Name: **Pacificorp 2018 Renewables Technology Assessment**

Variant: VC2 Date: 31-Aug-18

Site Information	
City / State:	Rock Springs, Wyoming
Latitude (N):	41.6 °
Longitude (W):	-109 °
Altitude	2055 m
ASHRAE Cooling DB Temp.	29.8 °C
ASHRAE Extreme Mean Min. Temp.	-25.1 °C

Design Parameters	
System DC Voltage	1500 VDC
GCR	36 %
Row spacing	5.5 m
Mounting	Tracker
Tilt angle or rotation limits	60 °
Azimuth	0 °
Tracking strategy	TRUE
Availability	100.0 %
Degradation	0.5 %/yr

Array Level Information	
Module rating	345 W
# Modules per string	26
Strings in parallel	738
Total number of modules	19188
DC capacity	6620 kW
Inverter rating	5000 kW
DC/AC ratio - Inv Rating	1.324

PVsyst Input Parameters	
Transposition model	Perez
Constant thermal loss factor (Uc)	25.0 W/m2-K
Wind loss factor (Uv)	1.2 W/m2-K/m/s
Soiling losses	2.2 %
Light induced degradation	2.0 %
DC wiring loss	1.5 %
Module quality loss	-0.4 %
Module mismatch loss	1.0 %
DC health loss	1.0 %

Estimated Annual Energy Production	
P50 net production (yr-1)	12343.3 MWh
AC capacity factor - Inv Rating	28.18%
AC capacity factor - POI Rating	28.18%
DC capacity factor	21.29%
Specific Production	1865 kWh/kWp/yr
Performance Ratio PR	82.17%
Night time losses	-20.0 MWh
Plant Output Limitations	0.00%

Facility Level Information	
Nameplate Capacity	**6.62 MWDC**
Number of modules	19188
Nameplate Capacity	**5.00 MWAC**
Number of arrays	1
Interconnection Limit	**5.00 MWAC**
Inteconnection Voltage	34.5 kV
DC/AC ratio - POI Rating	1.324

Weather	
Source	TMY3
GHI	1693.5 kWh/m2
DHI	kWh/m2
Global POA	2269.3 kWh/m2
Average Temp.	6.49 °C
Average Temp. (Generation)	10.35 °C
Average Wind	4.81 m/s
Average Wind (Generation)	5.32 m/s

AC System Losses	
MV transformer no-load losses	0.07%
MV transformer full load losses	0.85%
MV collection system	0.70%
HV transformer no-load losses	0.00%
HV transformer full load losses	0.00%
HV line	0.00%
Auxiliary	0.01%

Energy Production Summary

Burns & McDonnell, Energy Division

Project Name: **Pacificorp 2018 Renewables Technology Assessment**

Variant: VC2 Date: 31-Aug-18

Site Information	
City / State:	Rock Springs, Wyoming
Latitude (N):	41.6 °
Longitude (W):	-109 °
Altitude	2055 m
ASHRAE Cooling DB Temp.	29.8 °C
ASHRAE Extreme Mean Min. Temp.	-25.1 °C

Design Parameters	
System DC Voltage	1500 VDC
GCR	36 %
Row spacing	5.5 m
Mounting	Tracker
Tilt angle or rotation limits	60 °
Azimuth	0 °
Tracking strategy	TRUE
Availability	100.0 %
Degradation	0.5 %/yr

Array Level Information	
Module rating	345 W
# Modules per string	26
Strings in parallel	738
Total number of modules	19188
DC capacity	6620 kW
Inverter rating	5000 kW
DC/AC ratio - Inv Rating	1.324

PVsyst Input Parameters	
Transposition model	Perez
Constant thermal loss factor (Uc)	25.0 W/m2-K
Wind loss factor (Uv)	1.2 W/m2-K/m/s
Soiling losses	2.2 %
Light induced degradation	2.0 %
DC wiring loss	1.5 %
Module quality loss	-0.4 %
Module mismatch loss	1.0 %
DC health loss	1.0 %

Estimated Annual Energy Production	
P50 net production (yr-1)	131702.0 MWh
AC capacity factor - Inv Rating	27.34%
AC capacity factor - POI Rating	30.07%
DC capacity factor	20.65%
Specific Production	1809 kWh/kWp/yr
Performance Ratio PR	79.70%
Night time losses	-387.3 MWh
Plant Output Limitations	2.04%

Facility Level Information	
Nameplate Capacity	**72.82 MWDC**
Number of modules	211068
Nameplate Capacity	**55.00 MWAC**
Number of arrays	11
Interconnection Limit	**50.00 MWAC**
Inteconnection Voltage	115 kV
DC/AC ratio - POI Rating	1.456

Weather	
Source	TMY3
GHI	1693.5 kWh/m2
DHI	kWh/m2
Global POA	2269.3 kWh/m2
Average Temp.	6.49 °C
Average Temp. (Generation)	10.35 °C
Average Wind	4.81 m/s
Average Wind (Generation)	5.32 m/s

AC System Losses	
MV transformer no-load losses	0.07%
MV transformer full load losses	0.85%
MV collection system	1.30%
HV transformer no-load losses	0.07%
HV transformer full load losses	0.48%
HV line	0.05%
Auxiliary	0.01%

Energy Production Summary

Burns & McDonnell, Energy Division

Project Name: **Pacificorp 2018 Renewables Technology Assessment**

Variant: VC2 Date: 31-Aug-18

Site Information	
City / State:	Rock Springs, Wyoming
Latitude (N):	41.6 °
Longitude (W):	-109 °
Altitude	2055 m
ASHRAE Cooling DB Temp.	29.8 °C
ASHRAE Extreme Mean Min. Temp.	-25.1 °C

Design Parameters	
System DC Voltage	1500 VDC
GCR	36 %
Row spacing	5.5 m
Mounting	Tracker
Tilt angle or rotation limits	60 °
Azimuth	0 °
Tracking strategy	TRUE
Availability	100.0 %
Degradation	0.5 %/yr

Array Level Information	
Module rating	345 W
# Modules per string	26
Strings in parallel	738
Total number of modules	19188
DC capacity	6620 kW
Inverter rating	5000 kW
DC/AC ratio - Inv Rating	1.324

PVsyst Input Parameters	
Transposition model	Perez
Constant thermal loss factor (Uc)	25.0 W/m2-K
Wind loss factor (Uv)	1.2 W/m2-K/m/s
Soiling losses	2.2 %
Light induced degradation	2.0 %
DC wiring loss	1.5 %
Module quality loss	-0.4 %
Module mismatch loss	1.0 %
DC health loss	1.0 %

Estimated Annual Energy Production	
P50 net production (yr-1)	526808.1 MWh
AC capacity factor - Inv Rating	27.34%
AC capacity factor - POI Rating	30.07%
DC capacity factor	20.65%
Specific Production	1809 kWh/kWp/yr
Performance Ratio PR	79.70%
Night time losses	-1549.3 MWh
Plant Output Limitations	2.04%

Facility Level Information	
Nameplate Capacity	**291.27 MWDC**
Number of modules	844272
Nameplate Capacity	**220.00 MWAC**
Number of arrays	44
Interconnection Limit	**200.00 MWAC**
Inteconnection Voltage	230 kV
DC/AC ratio - POI Rating	1.456

Weather	
Source	TMY3
GHI	1693.5 kWh/m2
DHI	kWh/m2
Global POA	2269.3 kWh/m2
Average Temp.	6.49 °C
Average Temp. (Generation)	10.35 °C
Average Wind	4.81 m/s
Average Wind (Generation)	5.32 m/s

AC System Losses	
MV transformer no-load losses	0.07%
MV transformer full load losses	0.85%
MV collection system	1.30%
HV transformer no-load losses	0.07%
HV transformer full load losses	0.48%
HV line	0.05%
Auxiliary	0.01%

Energy Production Summary

Burns & McDonnell, Energy Division

Project Name: **Pacificorp 2018 Renewables Technology Assessment**

Variant: VC3 Date: 31-Aug-18

Site Information		
City / State:	Yakima, WA	
Latitude (N):	46.6	°
Longitude (W):	-120.5	°
Altitude	324	m
ASHRAE Cooling DB Temp.	34.1	°C
ASHRAE Extreme Mean Min. Temp.	-17	°C

Estimated Annual Energy Production		
P50 net production (yr-1)	10609.2	MWh
AC capacity factor - Inv Rating	24.22%	
AC capacity factor - POI Rating	24.22%	
DC capacity factor	18.29%	
Specific Production	1603	kWh/kWp/yr
Performance Ratio PR	81.56%	
Night time losses	-20.1	MWh
Plant Output Limitations	0.00%	

Design Parameters		
System DC Voltage	1500	VDC
GCR	36	%
Row spacing	5.5	m
Mounting	Tracker	
Tilt angle or rotation limits	60	°
Azimuth	0	°
Tracking strategy	TRUE	
Availability	100.0	%
Degradation	0.5	%/yr

Facility Level Information		
Nameplate Capacity	**6.62**	**MWDC**
Number of modules	19188	
Nameplate Capacity	**5.00**	**MWAC**
Number of arrays	1	
Interconnection Limit	**5.00**	**MWAC**
Inteconnection Voltage	34.5	kV
DC/AC ratio - POI Rating	1.324	

Array Level Information		
Module rating	345	W
# Modules per string	26	
Strings in parallel	738	
Total number of modules	19188	
DC capacity	6620	kW
Inverter rating	5000	kW
DC/AC ratio - Inv Rating	1.324	

Weather		
Source	TMY3	
GHI	1486.8	kWh/m2
DHI		kWh/m2
Global POA	1964.9	kWh/m2
Average Temp.	9.97	°C
Average Temp. (Generation)	14.53	°C
Average Wind	3.17	m/s
Average Wind (Generation)	3.30	m/s

PVsyst Input Parameters		
Transposition model	Perez	
Constant thermal loss factor (Uc)	25.0	W/m2-K
Wind loss factor (Uv)	1.2	W/m2-K/m/s
Soiling losses	2.4	%
Light induced degradation	2.0	%
DC wiring loss	1.5	%
Module quality loss	-0.4	%
Module mismatch loss	1.0	%
DC health loss	1.0	%

AC System Losses	
MV transformer no-load losses	0.07%
MV transformer full load losses	0.85%
MV collection system	0.70%
HV transformer no-load losses	0.00%
HV transformer full load losses	0.00%
HV line	0.00%
Auxiliary	0.01%

Energy Production Summary

Burns & McDonnell, Energy Division

Project Name: **Pacificorp 2018 Renewables Technology Assessment**

Variant: VC3 Date: 31-Aug-18

Site Information	
City / State:	Yakima, WA
Latitude (N):	46.6 °
Longitude (W):	-120.5 °
Altitude	324 m
ASHRAE Cooling DB Temp.	34.1 °C
ASHRAE Extreme Mean Min. Temp.	-17 °C

Estimated Annual Energy Production	
P50 net production (yr-1)	114064.6 MWh
AC capacity factor - Inv Rating	23.67%
AC capacity factor - POI Rating	26.04%
DC capacity factor	17.88%
Specific Production	1566 kWh/kWp/yr
Performance Ratio PR	79.72%
Night time losses	-389.2 MWh
Plant Output Limitations	1.32%

Design Parameters	
System DC Voltage	1500 VDC
GCR	36 %
Row spacing	5.5 m
Mounting	Tracker
Tilt angle or rotation limits	60 °
Azimuth	0 °
Tracking strategy	TRUE
Availability	100.0 %
Degradation	0.5 %/yr

Facility Level Information	
Nameplate Capacity	**72.82 MWDC**
Number of modules	211068
Nameplate Capacity	**55.00 MWAC**
Number of arrays	11
Interconnection Limit	**50.00 MWAC**
Inteconnection Voltage	115 kV
DC/AC ratio - POI Rating	1.456

Array Level Information	
Module rating	345 W
# Modules per string	26
Strings in parallel	738
Total number of modules	19188
DC capacity	6620 kW
Inverter rating	5000 kW
DC/AC ratio - Inv Rating	1.324

Weather	
Source	TMY3
GHI	1486.8 kWh/m2
DHI	kWh/m2
Global POA	1964.9 kWh/m2
Average Temp.	9.97 °C
Average Temp. (Generation)	14.53 °C
Average Wind	3.17 m/s
Average Wind (Generation)	3.30 m/s

PVsyst Input Parameters	
Transposition model	Perez
Constant thermal loss factor (Uc)	25.0 W/m2-K
Wind loss factor (Uv)	1.2 W/m2-K/m/s
Soiling losses	2.4 %
Light induced degradation	2.0 %
DC wiring loss	1.5 %
Module quality loss	-0.4 %
Module mismatch loss	1.0 %
DC health loss	1.0 %

AC System Losses	
MV transformer no-load losses	0.07%
MV transformer full load losses	0.85%
MV collection system	1.30%
HV transformer no-load losses	0.07%
HV transformer full load losses	0.48%
HV line	0.05%
Auxiliary	0.01%

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Energy Production Summary

Burns & McDonnell, Energy Division

Project Name: Pacificorp 2018 Renewables Technology Assessment

Variant: VC3 Date: 31-Aug-18

Site Information	
City / State:	Yakima, WA
Latitude (N):	46.6 °
Longitude (W):	-120.5 °
Altitude	324 m
ASHRAE Cooling DB Temp.	34.1 °C
ASHRAE Extreme Mean Min. Temp.	-17 °C

Design Parameters	
System DC Voltage	1500 VDC
GCR	36 %
Row spacing	5.5 m
Mounting	Tracker
Tilt angle or rotation limits	60 °
Azimuth	0 °
Tracking strategy	TRUE
Availability	100.0 %
Degradation	0.5 %/yr

Array Level Information	
Module rating	345 W
# Modules per string	26
Strings in parallel	738
Total number of modules	19188
DC capacity	6620 kW
Inverter rating	5000 kW
DC/AC ratio - Inv Rating	1.324

PVsyst Input Parameters	
Transposition model	Perez
Constant thermal loss factor (Uc)	25.0 W/m2-K
Wind loss factor (Uv)	1.2 W/m2-K/m/s
Soiling losses	2.4 %
Light induced degradation	2.0 %
DC wiring loss	1.5 %
Module quality loss	-0.4 %
Module mismatch loss	1.0 %
DC health loss	1.0 %

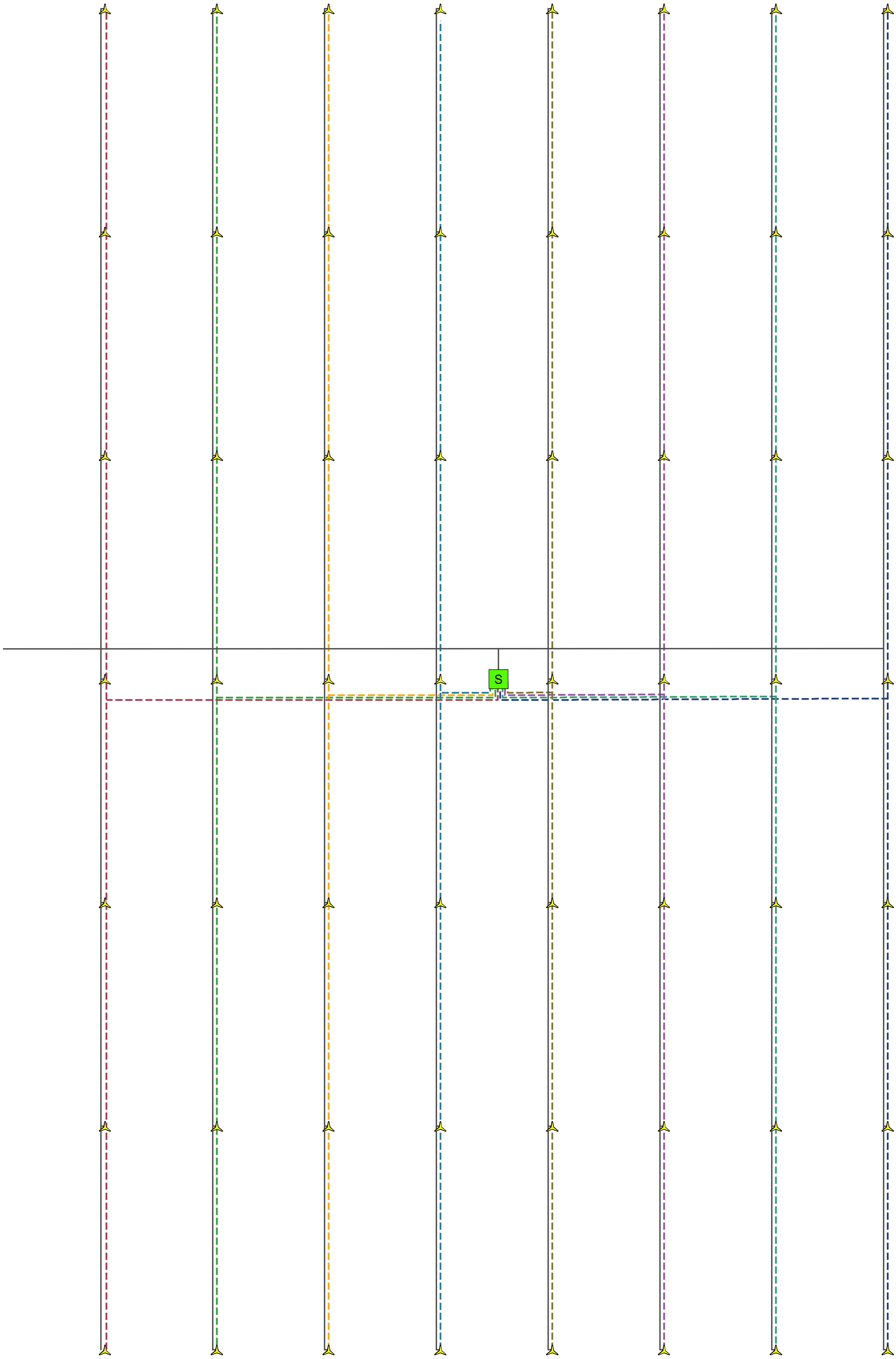
Estimated Annual Energy Production	
P50 net production (yr-1)	456258.5 MWh
AC capacity factor - Inv Rating	23.67%
AC capacity factor - POI Rating	26.04%
DC capacity factor	17.88%
Specific Production	1566 kWh/kWp/yr
Performance Ratio PR	79.72%
Night time losses	-1556.8 MWh
Plant Output Limitations	1.32%

Facility Level Information	
Nameplate Capacity	**291.27 MWDC**
Number of modules	844272
Nameplate Capacity	**220.00 MWAC**
Number of arrays	44
Interconnection Limit	**200.00 MWAC**
Inteconnection Voltage	230 kV
DC/AC ratio - POI Rating	1.456

Weather	
Source	TMY3
GHI	1486.8 kWh/m2
DHI	kWh/m2
Global POA	1964.9 kWh/m2
Average Temp.	9.97 °C
Average Temp. (Generation)	14.53 °C
Average Wind	3.17 m/s
Average Wind (Generation)	3.30 m/s

AC System Losses	
MV transformer no-load losses	0.07%
MV transformer full load losses	0.85%
MV collection system	1.30%
HV transformer no-load losses	0.07%
HV transformer full load losses	0.48%
HV line	0.05%
Auxiliary	0.01%

APPENDIX D – WIND PERFORMANCE INFORMATION



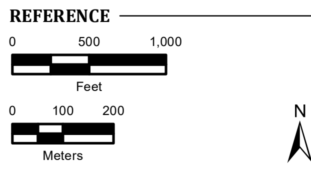
Drawing Notes:
1. Layout is intended to be generic / conceptual and not necessarily representative of a site that would be constructed. Layout based upon generic turbine model with approx. 414m by 828m gridded spacing. Final turbine model, project size, and site conditions will alter layout.

PRELIMINARY
NOT FOR CONSTRUCTION

LEGEND

- Proposed Turbine
- Collector Substation
- Access Roads
- Circuit 1
- Circuit 2
- Circuit 3
- Circuit 4
- Circuit 5
- Circuit 6
- Circuit 7
- Circuit 8

REFERENCE



GENERIC SITE LAYOUT
200 MW Wind Farm

LOCATION:	Generic
CLIENT:	Pacificorp
PROJ. NO.:	109571
CREATED:	09/06/2018

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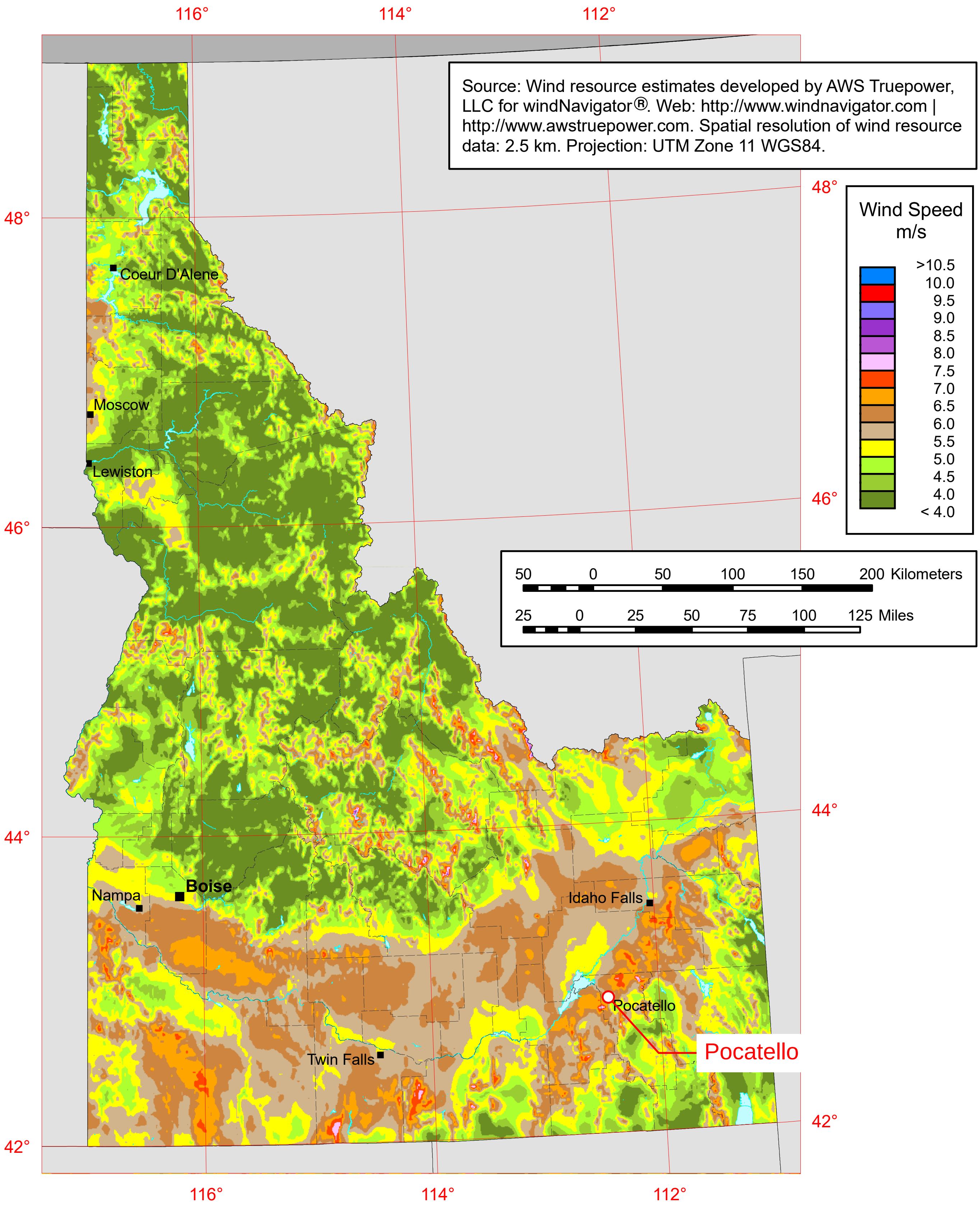
Idaho - Annual Average Wind Speed at 80 m



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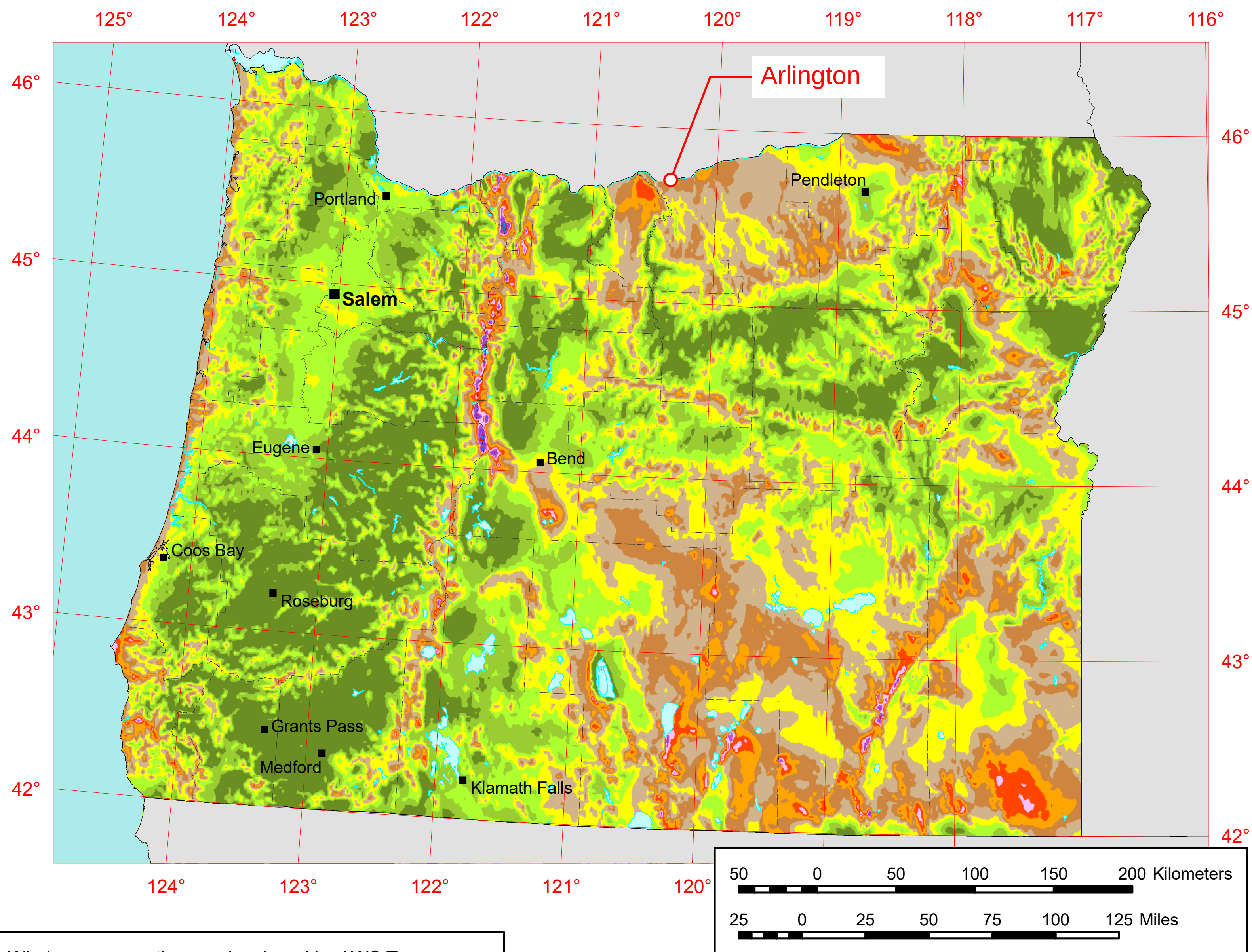
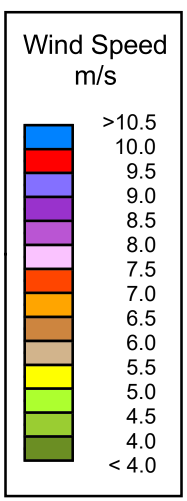
06-OCT-2010 1.1.1

Oregon - Annual Average Wind Speed at 80 m





Source: Wind resource estimates developed by AWS Truepower, LLC for windNavigator®. Web: http://www.windnavigator.com | http://www.awstruepower.com. Spatial resolution of wind resource data: 2.5 km. Projection: UTM Zone 11 WGS84.

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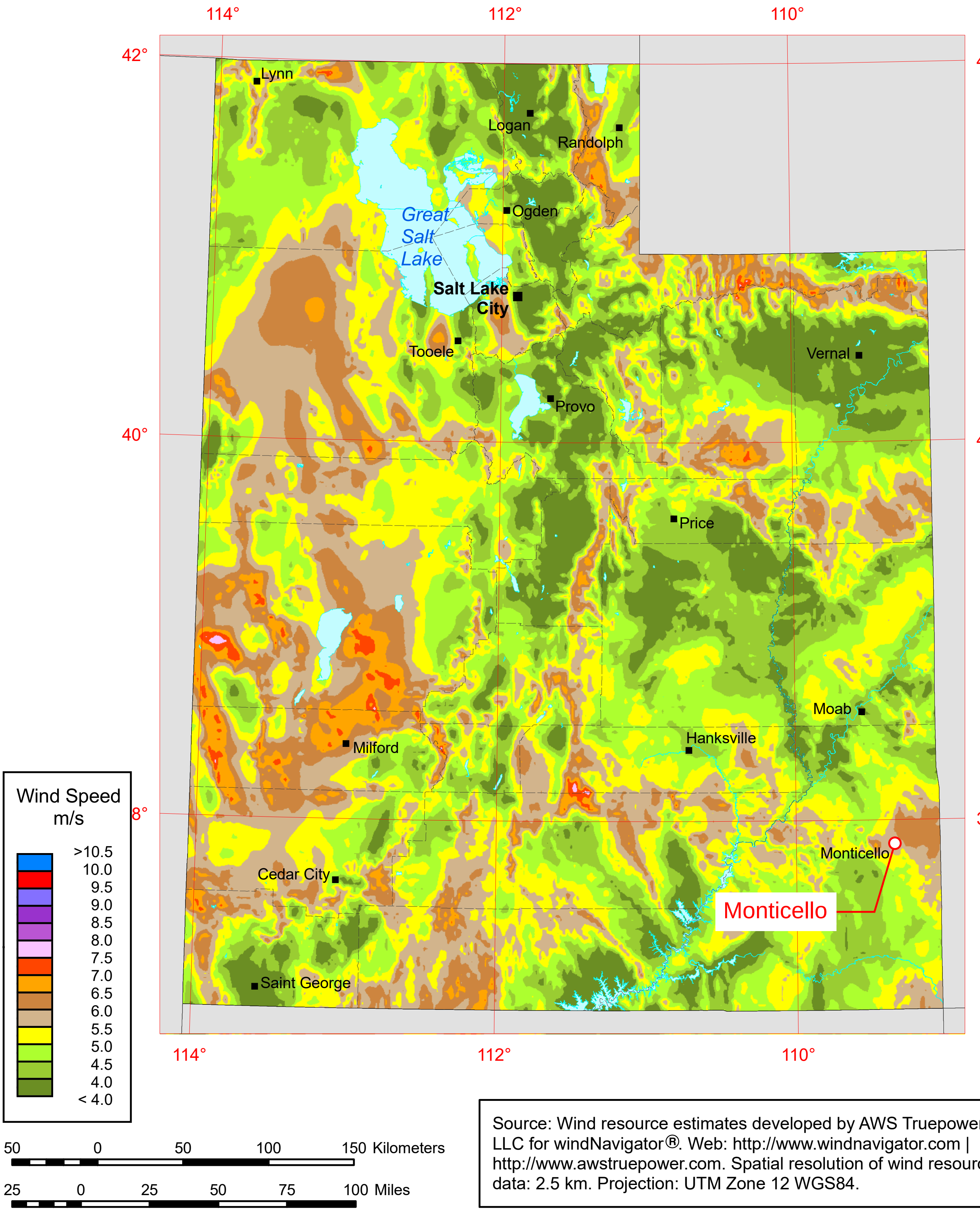
05-OCT-2010 1.1.1

Utah - Annual Average Wind Speed at 80 m



Source: Wind resource estimates developed by AWS Truepower, LLC for windNavigator®. Web: http://www.windnavigator.com | http://www.awstruepower.com. Spatial resolution of wind resource data: 2.5 km. Projection: UTM Zone 12 WGS84.

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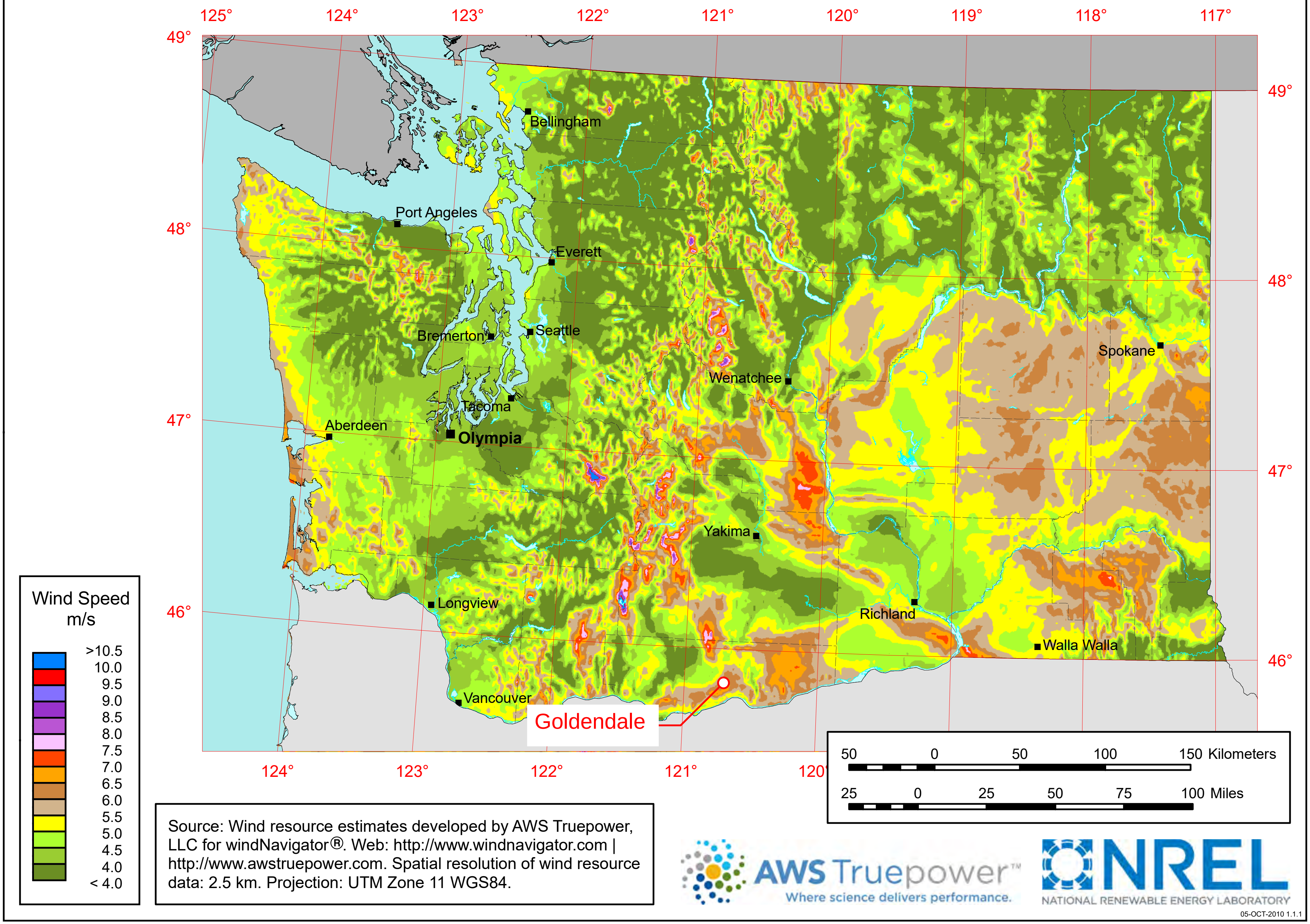
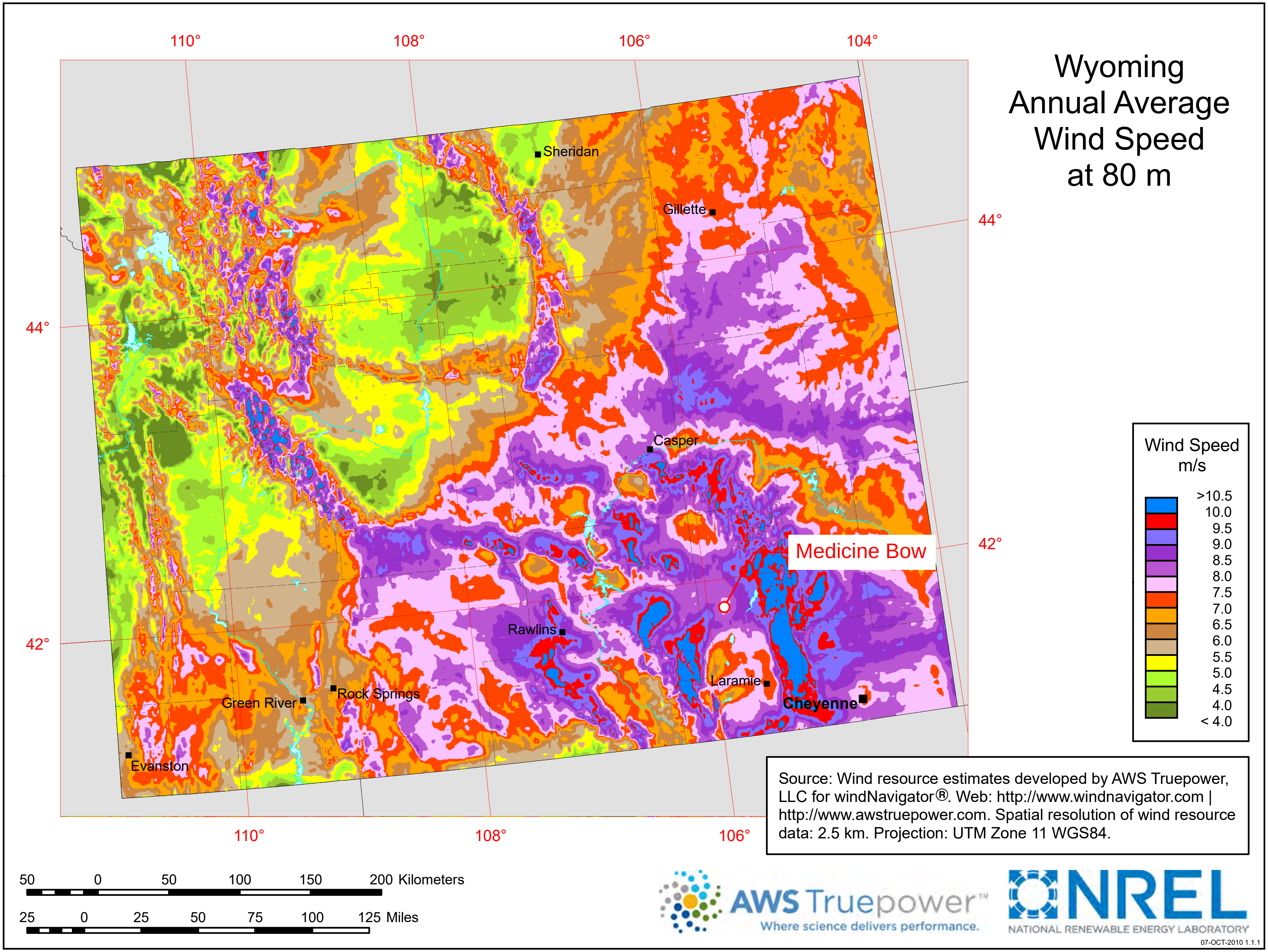
29-SEP-2010 1.1.1

Washington - Annual Average Wind Speed at 80 m




Wyoming
Annual Average
Wind Speed
at 80 m
110°
108°
106°
104°
44°
42°
Sheridan
Gillette
Casper
Medicine Bow
Rawlins
Laramie
Cheyenne
Green River
Rock Springs
Evanston
Wind Speed
m/s
>10.5
10.0
9.5
9.0
8.5
8.0
7.5
7.0
6.5
6.0
5.5
5.0
4.5
4.0
< 4.0
Source: Wind resource estimates developed by AWS Truepower, LLC for windNavigator®. Web: http://www.windnavigator.com | http://www.awstruepower.com. Spatial resolution of wind resource data: 2.5 km. Projection: UTM Zone 11 WGS84.
50 0 50 100 150 200 Kilometers
25 0 25 50 75 100 125 Miles
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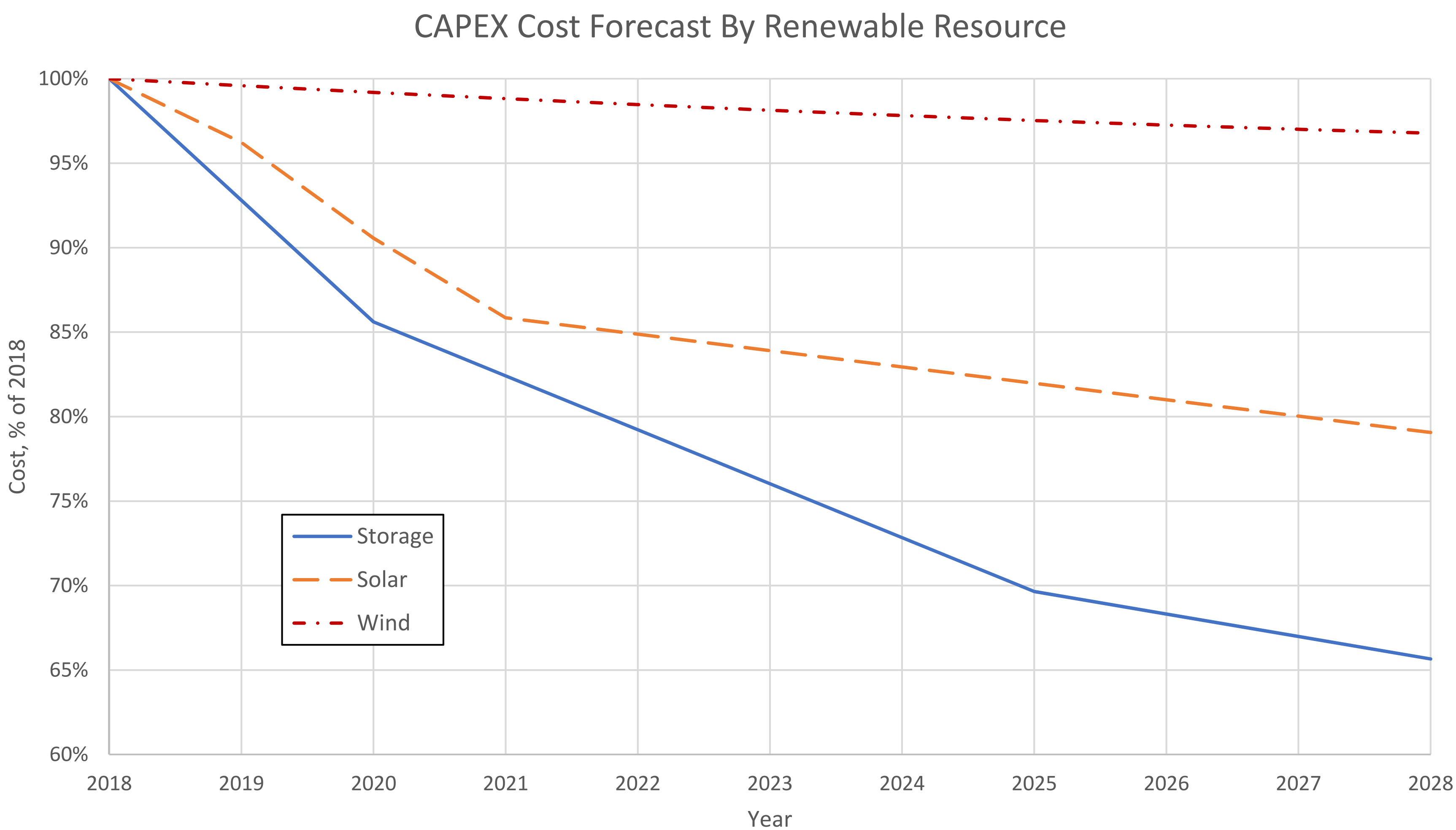
NATIONAL RENEWABLE ENERGY LABORATORY
07-OCT-2010 1.1.1

APPENDIX E – DECLINING COST CURVES



Notes:
1. The declining cost curve for onshore wind was developed using NREL Techno-Resource Group (TRG) mid CAPEX cost inforamtion. The cost for TRG 4 - TRG 8 were averaged which represent the Pacificorp identified sites.
2. The declining cost curve for utility solar photovoltaic was developed using NREL mid CAPEX cost inforamtion. From the inforamation provided, the costs for Seattle, Los Angeles, and Daggett were averaged.
3. The declining cost curve for battery storage was developed using NREL mid CAPEX cost information for an 8-hour storage device with 15-year life and 90% round-trip efficiency. Linear interpolation was used between NREL provided data points.

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9785 Maroon Circle, Suite 400
Centennial, CO 80112
O 303-721-9292
F 303-721-0563
www.burnsmcd.com

APPENDIX Q – ENERGY STORAGE POTENTIAL EVALUATION

Introduction

Energy storage resources can provide a wide range of grid services and can be flexibly sized and sited. Many of these grid services have been increasing in value with increasing penetration of variable energy resources such as wind and solar, while energy storage costs have been falling. As a result, storage resources are an increasing component of PacifiCorp's least-cost, least-risk preferred portfolio. While the 2019 IRP portfolio analysis captures the system benefits of energy storage, it does not fully account for localized benefits and siting opportunities. This appendix provides details on how energy storage resources can be configured to maximize the benefits they provide.

Because energy storage resources are highly flexible, with the ability to respond to dispatch signals and act as both a load and a resource, they can potentially provide any of the grid services discussed herein. Other types of resources, including distributed generation, energy efficiency, and interruptible loads can also provide one or more of these grid services, and can complement or provide lower-cost alternatives to energy storage. Given that broad applicability, Part 1 of this appendix first discusses a variety of grid services as generically and broadly as possible. Part 2 discusses the key operating parameters of energy storage and how those operating parameters relate to the grid services in Part 1. Finally, Part 3 discusses how to optimize the configuration and dispatch of energy storage and other distributed resources to maximize the benefits to the local grid and the system. Part 3 also provides examples of specific applications and examples of applications that may be cost-effective in the future.

Part 1: Grid Services

PacifiCorp must ensure that sufficient energy is generated to meet retail customer demand at all times. It also must maintain resources that can respond to changing system conditions at short notice, these operating reserves are held in accordance with reliability standards established by the National Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC). Both energy and operating reserves are dispatch-based, and dependent on the specific conditions at a specific place and time. These values are generally independent from hour to hour, as removing a resource in a subset of hours may not impact the value in the remaining hours.

Because load can be higher than expected and some resources may be unavailable at any given time, sufficient generation resources are needed to ensure that energy and operating reserve requirements can be met with a high degree of confidence. This is referred to as generation capacity. The transfer of energy from the locations where it is generated to the locations where it is delivered to customers requires poles, wires, and transformers, and the capability of these assets is referred to as transmission and distribution (T&D) capacity. Generation and T&D capacity are both generally asset-based, and provide value by allowing changes in the resources and T&D elements. In general, assets cannot be avoided based on changes to a subset of the hours in which they are needed and only limited changes are possible once constructed or contracted. It should also be noted that the impact of asset or capacity changes on dispatch must also be included in any valuation.

These obligations are broken down into the following grid services, which are discussed in this section:

- Energy, including losses;
- Operating reserves, including:
  - Spinning reserve;
  - Non-spinning reserve;
  - Regulation and load following reserves; and
  - Frequency response;
- Transmission and distribution capacity; and
- Generation capacity.

Energy Value

Background

Because PacifiCorp's load and resources must be balanced at all times, when an increment of generation is added to PacifiCorp's system, an increment of generation must also be removed. This could take the form of a generator that is backed down, an avoided market purchase, or an additional market sale. The cost of the increment that is removed (or the revenue from the sale), represents the energy value, and this value varies by location and by time. Location can also impact losses relative to the generation which would otherwise have been dispatched, with losses manifesting as a larger effective volume. With regard to time, there are two relevant time scales: hourly values, and sub-hourly values.

The energy value in a location is dependent on PacifiCorp's load and resource balance, the dispatch cost of its resources, and the transmission capability connecting those resources to load. Differences in energy value occur when the economic resources in area exceed the transmission export capability to an area that must then use higher cost resources to serve load. Once transmission is fully utilized, the higher cost resources must be deployed to serve the importing area and lower cost resources will be available in the exporting area. As a result, the value in each location will reflect the marginal resources used to serve load in each area. If transfers are not fully utilized in either direction, the marginal resource in both areas would be the same, and the energy value would be the same.

Both load and resource availability change significantly across the day and across the year. Differences in value over time are driven by the cost of the marginal resource needed to serve load, which changes when load or resource availability change. When load goes up, or the supply of lower-cost resources goes down, the marginal resource needed to serve load will be more expensive.

The value by location is also dependent on the losses relative to the generation which would otherwise have been dispatched. Losses occur during the transfer of energy across the T&D system to a customer's location. As distance and voltage transformation increase, more generation must be injected to meet a customer's demand. As a result, a distributed resource that is close to customer load or located on the same voltage level can avoid both energy at its location as well as the losses which otherwise would have occurred in delivering energy to that location. As a result, the marginal generation resource's output may be reduced by an amount greater than the metered output of a distributed resource. This increase in volume due to losses is also relevant to generation and T&D capacity value. In addition to varying by location and voltage, losses vary across time, primarily due to line loading, as loss rates increase as loading increases. To the extent distributed resources impact line loading, it is reasonable to incorporate the marginal losses that they avoid.

Modeling

There are two basic sources of energy values: market price forecasts and production cost models. There are also two relevant time scales: hourly values, and sub-hourly values.

PacifiCorp produces a non-confidential official forward price curve (OFPC) for the major market points in which it typically transacts on a quarterly basis. The OFPC represents the price at which power would be transacted today, for delivery in a future period. The OFPC contains prices for each month for heavy load hour (HLH) and light load hour (LLH) periods and goes forward approximately 20 years.[1] However, not all hours in the HLH or LLH periods have equal value. To differentiate between hours, PacifiCorp uses scalars calculated based on historical hourly results. For PacifiCorp's operations and production cost modeling, scalars are based on the California Independent System Operator's day-ahead hourly market prices. Because these values are used in operations, the details on the methodology and the resulting prices are treated confidentially. To allow for transparency, PacifiCorp has also developed non-confidential scalars using historical Energy Imbalance Market prices. With either scalars, the result is a forecast of hourly market prices that averages to the values in the OFPC over the course of a month. Using hourly market price to calculate energy value implies that market transactions are either the avoided resource, or a reasonable representation of the avoided resource's cost.

Production cost models contain a representation of an electric power system, including its load, resources, and transmission rights, as well as markets where power can be bought or sold. They also account for operating reserve obligations and the resources held to cover those obligations. All models are simplified representations, and there are several key simplifying assumptions. The granularity of a model is its smallest calculated timestep. While calculating twice as many timesteps should take roughly twice as long from a mechanical standpoint, maintaining inputs to represent those timesteps is more complicated, and a model is only as good as its inputs. To simplify the representation of location, transmission areas can be defined by the key transmission constraints which separate them, with transmission within each area assumed to be unconstrained. Another simplifying assumption is to model all load and resources at a level equivalent to generator input. For instance, load is "grossed up" from the metered volume to a level that includes the estimated losses necessary to serve it. This allows for a one for one relationship between all volumes, which vastly simplifies the model.

PacifiCorp's production cost models with these representations include the Planning and Risk (PaR) model, used to evaluate portfolios in the IRP, and the Generation and Regulation Initiative Decision Tools model (GRID), used to calculate net power costs in general rate cases and for some qualifying facility avoided cost rates. Both of these models reflect the system down to an hourly granularity. While these production cost models use the hourly market prices from the OFPC, a distributed resource's energy value in these models will depend on its location and other

[1] HLH is 6:00 a.m. to 10:00 p.m. Pacific Prevailing Time Monday through Saturday, excluding NERC holidays. LLH is all other hours.

characteristics and can be either higher or lower than the market price in a given hour. Generally, a resource's value is based on the difference between two production cost model studies: one with the resource included, and one with the resource excluded. This explicitly identifies the marginal resources dispatched in the absence of the resource being evaluated.

More detailed models of the electrical power system also exist, for instance PacifiCorp uses physical models for grid operations and planning that account for power flows and the loading of individual system elements. Similarly, the California Independent System Operator (CAISO) uses a "Full Network Model" with detailed representations of all resources and loads, as well as the transmission system. CAISO's model includes a representation of PacifiCorp's system for the purpose of dispatching resources in the Western Energy Imbalance Market (EIM), and models a five minute granularity for that purpose. The added detail these physical models produce comes from a significant increase in the complexity of inputs and computational requirements.

Hourly market prices can be used to provide a readily available estimate of energy value, as shown in Table Q.1 for various energy storage technologies. The variables which impact energy margin include: hours of storage, efficiency, forced outage rates, and variable degradation costs. Table Q.1 contains twenty-year nominal levelized values for 2019-2038, and reflects an average of the margins at the Mid-Columbia and Four Corners markets.

Table Q.1 - Energy Margin by Energy Storage Technology

Technology	Hours of Storage	Efficiency (%)	Forced Outage (%)	Variable Cost ($/MWh)	Energy Margin ($/kw-yr)
Lithium Ion	2	88%	1%	12.48	32.13
Lithium Ion	4	88%	1%	12.48	49.77
Flow	6	65%	2%	0	53.03
Pumped Hydro	9	79%	3%	0	81.67

These market values do not account for the effects of location, volume, or operating reserve requirements. For instance, PacifiCorp is obligated to hold contingency reserves equal to three percent of all generation in its balancing authority areas, but is not required to hold those reserves for market purchases. This is analogous to the additional regulation reserves held to account for the variability and uncertainty in the output of wind and solar (a.k.a. integration costs). Adjustments can be applied to account for these differences, but the results are likely to diverge as market prices and resource portfolios change. Hourly market prices are also more likely to understate the value of dispatchable resources.

The PaR model and the GRID model both identify resources to carry operating reserves for each hour, but do not include the intra-hour changes that would cause those resources to be deployed. Because resources that are dispatchable within the hour can be dispatched up when marginal energy costs are high, and down when marginal energy costs are low, this can result in incremental value relative to an hourly market price or hourly production cost model result. In practice, sub-hourly dispatch benefits are largely derived from PacifiCorp's participation in EIM, and the specific rules associated with that market. For instance, resources must be participating in EIM in order to receive settlement payments based on their five-minute dispatches. Resources that are not participating receive settlement payments based on their hourly imbalance. Because non-participating resources are not visible to the market, their sub-hourly dispatch would not impact the market solution. Because distributed resources can be aggregated for purposes of EIM participation, size should not be an impediment; however, the structure of the EIM may dictate some aspects of their use and would need to be aligned with the other services a distributed resource provides.

To help identify sub-hourly energy value not captured in its hourly production cost models, during the development of the 2019 IRP, PacifiCorp calculated intra-hour flexible resource credits (IHFRC) for a variety of resource types, based on expected economic dispatch relative to historical EIM sub-hourly pricing. Unsurprisingly given their flexibility, energy storage resources provide the highest value of the resources evaluated, as shown in Table Q.2 below. Values shown are in 2018$.

Table Q.2 – Intra-hour Flexible Resource Credits by Resource Type

Resource	Credit ($/kw-year)	Dispatch (% of Nameplate)	Cycles/day	Source
Pumped Hydro 6-14hr	30.44	9.2% - 9.8%	0.2 - 0.4	Proxy
CAES 48hr	30.28	11%	0.05	Proxy
Flow 6hr	27.24	10%	0.38	Proxy
Li-Ion 4hr	25.60	9%	0.56	Proxy
Li-Ion 2hr	25.02	8%	0.90	Proxy
Load Control - 528 hrs/yr	19.20	6%	n/a	Proxy
Load Control - 30 hrs/yr	6.00	0.3%	n/a	Proxy
Resource			**Minimum operating level (%)**	
SCCT Intercooled	18.51	8%	15%	Proxy
SCCT Aero	16.58	10%	40%	Proxy
Baseload Steam	5.54	*	24%	Actual
Peak Steam	4.89	*	24%	Actual
CCCT	3.77	*	70%	Actual
SCCT Frame F	3.47	1%	43%	Proxy
Resource/Bid Price			**% of annual output**	
Solar/$0	1.22	-1.7%	5.6%	Proxy
Wind/$0	0.87	-1.1%	2.9%	Proxy
Wind/PTC	0.14	-0.04%	0.1%	Proxy

*Resources are dispatched up and down from base schedule in EIM.

PacifiCorp initially proposed that IHFRC values be netted out of the resource costs identified in its supply-side resource table, such that the net costs would be used for portfolio selection and valuation. In response to stakeholder feedback about the concept and methodology, the adjustment for IHFRC values was not incorporated as part of the 2019 IRP. PacifiCorp anticipates that the resources above would generate incremental value relative to the hourly granularity of the 2019 IRP modeling, but additional work is required to engage stakeholders and ensure that the results are truly additional.

Operating Reserve Value

Background

Operating reserve is defined by NERC as “the capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages and local area protection."[2] Operating reserves are capability that is not currently providing energy, but which can be called upon at short notice in response to changes in load or resources. Operating reserves and energy are additive – a resource can provide both at the same time, but not with the same increment of its generating capability. Operating reserves can also be provided by interruptible loads, which have an effect comparable to incremental resources. Additional details on operating reserve requirements are provided in Volume II, Appendix F (Flexible Reserve Study).

As with energy value, operating reserve value is based on the marginal resource that would otherwise supply operating reserves, and varies by both location, time, and the speed of the response. Because operating reserve requirements are primarily applied at the Balancing Authority Area (BAA) level, the associated value is typically uniform within each of PacifiCorp's BAAs. An exception to this is that operating reserves must be deliverable to balance load or resources, so unused capability in a constrained bubble without additional export capability does not count toward the meeting the requirements. Operating reserve value is somewhat indirect in comparison to energy value, as it relates to the use of the freed up capacity on units that would otherwise be holding reserves. If that resource's incremental energy is less expensive that what is currently dispatched, it can be dispatched up, and more expensive energy can be dispatched down. The value of the operating reserves in that instance is the margin between the freed up energy and the resource that is dispatched down. Note that the dispatch price of the resource being evaluated does not impact the value, since holding operating reserves does not require dispatch. When the freed up resource is more expensive than what is currently dispatched, it will not generate more when the operating reserve requirement is removed, and the value of operating reserves would be zero. With this in mind, operating reserves are generally held on the resources with the highest dispatch price. Finally, operating reserve value is limited by the speed of the response: how fast a unit can ramp up in a specified time period, and how soon it begins to respond after receiving a dispatch signal. Reliability standards require a range of operating reserve types, with response times ranging from seconds to thirty minutes.

Modeling

As discussed above, the value of incremental operating reserves is equal to the positive margin between the dispatch cost of the lowest cost resource that was being held for reserve, and the dispatch cost of the highest cost resource that was dispatched for energy. Similar to the value of energy, the price of different operating reserve types could be forecasted by hour, based on forecasts of reserve capability, demand, and resource dispatch costs. Given the range and variability in these components, this would be an involved calculation. In addition, because operating reserves are a small fraction of load, they are more sensitive to volume than energy. For instance, spinning reserve obligations are approximately three percent of load in each hour. As a result, resource additions may rapidly cover that portion of PacifiCorp's requirement met by resources that could otherwise provide economic generation and which produce a margin when released from reserve holding. This is particularly true for batteries and interruptible load resources that can respond rapidly and thus count all or most of their output toward reserve obligations.

While a market price for operating reserve products does not align well with PacifiCorp's system, the specifics of the calculation described above are embedded within PacifiCorp's production cost models. Those models allocate reserves first to energy limited resources in those periods where

[2] NERC Glossary of Terms: http://www.nerc.com/files/glossary_of_terms.pdf, updated May 13, 2019.

they could generate, but are not scheduled to do so. Examples of energy limited resources include interruptible loads, hydro, and energy storage. If called on for reserves, these resources would lose the ability to generate in a different period, so the net effect on energy value for that resource is relatively small. As a result, the unused capacity on these resources can't be used for generation, but that also means it can count as reserves without forgoing any generation and incurring a cost to do so. After operating reserves have been fully allocated to the available energy-limited resources, reserves are allocated to the highest cost generators with reserve capability in the supply stack, up to each unit's reserve capability, until the entire requirement is met. This is generally done prior to generation dispatch and balancing, because the requirements are input to the model or based on a formula and aren't typically restricted based on transmission availability. After the reserve allocations are complete, the remaining dispatch capability of each unit is used to develop an optimized balance of load and resources.

As part of the calculation of wind and solar integration costs for the 2019 IRP, as reported in Volume II, Appendix F (Flexible Reserve Study), PacifiCorp prepared a study assessing the cost of holding incremental operating reserves. That study identified a cost of $50/kw-yr (2018$), based on a 2018-2036 study period. This value would be applicable to any resource that provided operating reserves uniformly throughout the year.

Transmission and Distribution Capacity

For the first time, the 2019 IRP has endogenously included transmission upgrades as part of portfolio selection. This allows the cost of transmission upgrades to be considered as part of the modeled cost of resources in each area. However, energy efficiency, load control, and stand-alone energy storage resources were not subject to these constraints, placing them at an advantage relative to both thermal and renewable resource options. In addition, while the cost of specific T&D projects varies, a generic system wide estimate of transmission upgrade costs is included as a credit to energy efficiency in the 2019 IRP, and amounts to $4.16/kw-year (2018$). In practice, these costs would vary by project and some transmission upgrades would not be suitable for deferral by distributed resources. Because of the large scale of many transmission upgrades, and the binary nature of the expenditures, it may be difficult to procure adequate distributed resources to cover the need in a timely fashion and in accordance with reliability requirements, though it is always appropriate to consider the available options when considering expenditures on an upgrade. Distribution capacity upgrades are more likely to be suitable for deferral by a distributed resource, as the scale of the need is closer to that of these types of resources.

To that end, PacifiCorp maintains an "Alternative Evaluation Tool" which is used to screen the list of projects identified during T&D planning to assess where distributed resources, including energy storage, could be both technically feasible and cost competitive as compared to traditional T&D solutions. If a study shows that distributed resource alternatives are feasible and potentially cost-competitive that project is flagged for detailed analysis.

To help illustrate the potential for distribution capacity deferral, PacifiCorp assessed the peak loading and forecasted growth at each of the distribution substations across its system. Once peak loading reaches 90 percent of a distribution substations capability, PacifiCorp takes steps to either reconfigure the loads or add capacity to ensure that it remains sufficient to serve customers. For this analysis, substations were classified as having a high potential for distribution capacity deferral if their current loading is at or above the 90 percent threshold, medium if they are anticipated to exceed the 90 percent threshold within the next twenty years, and low if they are not expected to exceed the 90 percent threshold in the next twenty years. The results shown in Table Q.3 identify the portion of PacifiCorp's distribution load that is part of each of these three categories in each state. The "low" category represents a majority of PacifiCorp's system, which indicates that programs targeting distributed resources in specific locations have the potential to provide significantly greater value.

Table Q.3 – Share of Distribution Load by State with Potential Upgrade Deferral

State	High	Medium	Low
CA	13%	3%	84%
ID	38%	38%	23%
OR	13%	36%	51%
UT	8%	30%	62%
WA	24%	32%	43%
WY	7%	21%	72%
Total	**13%**	**31%**	**56%**

Because distribution upgrades are primarily driven by load growth, distributed resources need to be sufficient to maintain load within existing peaks to defer distribution upgrades. Energy storage resources can be cost-effective to cover brief peaks, but are less cost-effective as the duration of the shortfall increases. To the extent load in an area continues to grow, the deferred distribution upgrade is likely to be necessary eventually. Table Q.4 illustrates the distribution load growth by state that is likely to trigger distribution upgrades during the IRP planning period. The forecasted distribution capacity deferral value is $21.89/kw-yr (2018$) for substations with a planned upgrade that can be deferred indefinitely. If distributed resource programs result in resources on a mix of substations that include medium or low value areas, the effective distribution capacity deferral value would be reduced.

Table Q.4 - Forecasted Distribution Load Growth Above the 90 Percent Planning Threshold

Year	CA	ID	OR	UT	WA	WY	Total
2019	1	19	30	79	12	9	151
2020	1	22	30	108	18	11	190
2021	1	22	30	116	18	11	199
2022	1	23	42	123	21	11	221
2023	1	23	42	164	25	11	266
2024	1	31	51	164	25	11	283
2025	1	34	63	165	26	11	300
2026	2	35	72	170	26	11	315
2027	2	35	74	172	30	14	327
2028	2	35	77	194	33	14	354
2029	2	35	86	196	33	55	406
2030	2	39	90	206	33	55	424
2031	2	40	94	248	33	59	476
2032	2	40	99	279	33	59	511
2033	2	43	99	313	36	61	554
2034	2	46	101	353	36	63	601
2035	2	46	106	357	36	68	615
2036	2	51	108	367	36	68	633
2037	2	51	115	384	36	68	655
2038	2	52	118	395	43	70	679

Generation Capacity

Background

To provide reliable service to customers, a utility must have sufficient resources in every hour to:

- Serve customer load, including losses and any unanticipated load increase.
- Hold operating reserves to meet NERC and WECC reliability standards, including contingency, regulation, and frequency response.
- Replace resources that are unavailable due to:
  - Forced and planned outages
  - Dry hydro conditions
  - Wind and solar conditions
  - Market conditions

PacifiCorp refers to “Generation Capacity” as the total quantity of resources necessary to reliably serve customers, after accounting for the items above. The level of resources needed for reliable operation is discussed in Volume II, Appendix I (Planning Reserve Margin Study). For the 2019 IRP, PacifiCorp selected a planning reserve margin of 13 percent over its coincidental peak loads and this is applied to both summer and winter peaks. The planning reserve margin does not translate directly into either resources or need. Instead, PacifiCorp assesses the capacity contribution of each of its resources in Volume II, Appendix N (Capacity Contribution Study). Capacity contribution represents the portion of a resource that can be counted on to reliably meet peak demand. This is inherently dependent on the composition of a portfolio, so for the first time in the 2019 IRP, PacifiCorp performed a detailed assessment of the hourly reliability of each portfolio and increased requirements for portfolios that failed to achieve a minimum reliability level.

All resources contribute to a reliable portfolio, but they do so in ways that are not straightforward to measure. Removing a resource from a portfolio will make that portfolio less reliable unless it is replaced with something else, ideally in a quantity that provides an equal capacity contribution and results in equivalent reliability. As indicated above, reliability is difficult to predetermine, hence PacifiCorp’s reliance on a reliability assessment for the 2019 IRP.

As a result, the most direct measurement of the generation capacity value of a resource is to build a portfolio that includes it, and compare that portfolio to one without it. But even that analysis would identify more than just generation capacity value, as it would also include energy and operating reserve impacts related to both the resource being added and resources that were delayed or removed. This is an essential description of the steps used to develop portfolios in the IRP, and while powerful, the IRP models and tools do not lend themselves to ease of use, rapid turnaround, or the evaluation of small differences in portfolios.

As an alternative, a simplified approach to generation capacity value can be used when the resources being evaluated are similar to the proxy resource additions identified in the IRP preferred portfolio. The premise of the approach is that the IRP preferred portfolio resources represent the least-cost, least-risk path to reliably meet system load. The appropriate level of generation capacity value is inherently embedded in the IRP preferred portfolio resource costs, because those resources achieve the stated goal of reliable operation. Again, while it is difficult to identify exactly what portion of the resource cost should be considered generation capacity as opposed to energy or operating reserve value, the total resource cost is straightforward and known.

The 2019 IRP preferred portfolio includes stand-alone four-hour lithium-ion battery storage resources starting in 2028. These resources have annual fixed costs (capital recovery and fixed operations and maintenance) of approximately $173/kw-yr in 2028. After netting out energy values based on market as described above, the remainder is $111/kw-yr (2028$) based on Four Corners market prices and $130/kw-yr (2028$) based on Mid-Columbia market prices. In 2018 dollars, this is equivalent to $89-$104/kw-yr (2018$). These values do not include any value from operating reserves or from charging during periods of renewable resource over-supply when the marginal dispatch cost on PacifiCorp's system is less than market due to transmission congestion or limits on market volumes.

While uncertainty remains in these generation capacity values, the uncertainty in the conclusions can be small to the extent a resource being evaluated provides largely the same services as the resource in the 2019 IRP. As a result, it is reasonable to compare the costs and benefits of energy storage resources that provide energy value, operating reserves, and charging during renewable resource over-supply to the costs and implicit benefits of energy storage resources in the 2019 IRP, which also provide those same services. To the extent the resources being evaluated vary significantly in characteristics or timing relative to the resources in the 2019 IRP preferred portfolio, a more thorough analysis using a production cost model would be necessary to ensure the relative benefits of preferred portfolio resources and a resource being evaluated are characterized accurately.

Part 2: Energy Storage Operating Parameters

This section discusses some of the key operating parameters associated with energy storage resources. Beyond just defining the basic concepts, it is important to recognize the specific ways in which these parameters are measured, and ensure that any comparison of different technologies or proposals reports equivalent values. For example, many battery systems operate using direct current (DC) rather than the alternating current (AC) of the vast majority of the electrical grid. When charging or discharging from the grid, inverters must convert DC power to AC power, which creates losses that reduce the effective output when measured at the grid, rather than at the battery. To handle this distinction, PacifiCorp uses the AC measurement at the connection to the electrical grid for all parameters, as this aligns with the effective "generation input" of an energy storage resource. As previously discussed, an additional adjustment for line losses on the electrical grid may also be necessary, but that is dependent on the location and conditions on the electrical grid, rather than the energy storage resource.

- **Discharge capacity**: The maximum output of the energy storage system to the grid, on an AC-basis, measured in megawatts (MW). This is generally equivalent to nameplate capacity.
- **Storage capacity:** The maximum output of the energy storage system to the grid, on an AC-basis, when starting from fully charged, measured in megawatt-hours (MWh).
- **Hours of storage:** The length of time that an energy storage system can operate at its maximum discharge capacity, when starting from fully charged, measured in hours. Generally, the hours of storage will be equal to storage capacity divided by discharge capacity.
- **Charge capacity:** The maximum input from the grid to the energy storage system, on an AC-basis, measured in megawatts (MW).

- **Round-trip efficiency:** The output of the energy storage system to the grid, divided by the input from the grid necessary to achieve that level of output, stated as a percentage. A storage resource with eighty percent efficiency will output eight MWh when charged with ten MWh. If charge and discharge capacity are the same, losses result in a longer charging time. For instance, an energy storage system with four hours of storage, eighty percent efficiency, and identical charge and discharge capacity would require five hours to fully charge (4 hours of discharge divided by 80 percent discharge MWh per charge MWh).
- **State of charge:** This is a measure of how full a storage system is, calculated based on the maximum MWh of output at the current charge level, divided by the storage capacity when fully charged, and is stated as a percentage. One hundred percent state of charge indicates the storage system is full and can't store any additional energy, while zero percent state of charge indicates the storage system is empty and can't discharge any energy. As previously indicated, PacifiCorp's state of charge metric is based on output to the grid. As a result, the entire round-trip efficiency loss is applied during charging before reporting the state of charge. For example, a storage system with a ten MWh storage capacity and eighty percent efficiency would only have an eighty percent state of charge after ten MWh of charging had been completed, starting from empty.
- **Station service:** Round-trip efficiency is a measure of the losses from charging and discharging. Some energy storage systems also draw power for temperature control and other needs. This is typically drawn from the grid, rather than the energy storage resource.

Some energy storage technologies experience degradation of their operating parameters over time and based on use. The following parameters are used to quantify the effects of degradation.

- **Storage capacity degradation:** The primary impact of degradation is on storage capacity. Much of the degradation occurs as part of charge-discharge cycles, and can be measured as the degradation per thousand cycles. After one thousand cycles, a four-hour storage system might only be capable of storing 3.5 hours of output. Some storage resources also experience degradation that isn't tied to cycles, for instance based on differing state of charge levels or time.
- **Cycle life:** This is the total number of full charge and discharge cycles that energy storage equipment is rated for. Three thousand cycles is common for lithium-ion resources, but operating under harsh conditions can also cause the effective cycle count to decline faster. Once storage capacity has degraded by thirty percent degradation per cycle may accelerate.
- **Depth of discharge:** Operating at a very high or very low state of charge, particularly for an extended period of time, can cause more rapid degradation. This metric can be used to identify how particular operations impact the effective remaining cycle life.
- **Variable degradation cost:** Lithium-ion energy storage equipment is composed of a large number of battery modules, each of which experience degradation. These modules can be gradually replaced over time to maintain a more consistent storage capacity, or they can be replaced all at once when cycle limits are reached, at the expense of a reduced storage capacity in the interim. In either case, the replacement cost of storage equipment can be expressed per MWh of discharge, and accounted for as part of resource dispatch.

Part 3: Distributed Resource Configuration and Applications

This section described the potential benefits of different distributed resource siting and configuration options. Due to economies of scale, distributed resource solutions generally higher cost relative to utility-scale assets. For example, the 2019 IRP supply-side table shows fixed costs for a fifteen megawatt, four-hour lithium-ion battery costs that are approximately half that of the costs for a one megawatt, four-hour battery. While these savings are appreciable, it should be noted that a fifteen megawatt battery is small and can be considered modular relative to traditional resources such as a simple cycle combustion turbine. Many of PacifiCorp's distribution substations have capacity in excess of fifteen megawatts, such that a battery of that size could be feasible at the distribution level, with the potential for incremental benefits relative to the transmission-connected battery resources modeled as part of the 2019 IRP preferred portfolio. The most cost-effective locations for distributed resource deployment are likely to reflect a balance of local requirements and economies of scale.

Secondary Voltage

A distributed resource which is located downstream from the high voltage transmission grid will have a larger energy impact than its metered output would indicate, due to line losses. This is true for both charging and discharging; however, the marginal loss rate increases with load, so the effects are not equal. To the extent discharging is aligned with periods with higher load, and charging is aligned with periods with lower load, the benefits will increase. For example, the marginal primary voltage losses for Oregon are estimated at 9.5 percent on average across the year. Savings based on primary losses would be appropriate to apply to a resource connected at the secondary voltage level so long as it is not generating exports to the higher voltage system, as losses would still occur within that level, but would be reduced due to lower deliveries across the higher voltage system. When the hourly loss profile is applied to the hourly market prices used to calculate the energy values described in Part 1, the result is 16 percent higher for a four-hour lithium-ion battery. Much of the incremental benefit is due to high loss rates in summer and winter peak load months, when prices are relatively high. For lithium-ion batteries, there is also an incremental benefit related to variable degradation costs. While the effect of losses makes the battery appear larger from a system benefits perspective, it discharges the same amount, so the variable cost component doesn't scale with losses, creating an additional benefit that is captured in this energy margin.

In addition to incremental energy value, resources connected at primary or secondary voltage will also have a proportionately higher generation capacity value. In the example for Oregon above, this amounts to a roughly 11 percent increase in effective capacity contribution based on avoided primary losses.

T&D Capacity Deferral

As indicated in the grid services section, distributed resources can allow for the deferral of upgrades by reducing the peak loading of the transmission and distribution system elements serving their area. In order for deferral to be achieved, a distributed resource must reliably reduce load under peak conditions. However, the timing of peak conditions for a given area is likely to vary from the peak conditions for the system as a whole. As a result, the energy or generation capacity value of energy-limited resources used for a T&D capacity deferral application are likely to be reduced. For instance, when energy-limited resources are reserved for local area requirements they would not be available for system reliability events or a period of high energy prices.

Combined Solar and Storage

Solar resources can qualify for a thirty percent federal investment tax credit (ITC) if they come online prior to the end of 2023. Thereafter, solar resources will continue to qualify for a ten percent ITC. Storage that is constructed in combination with a solar resource and which is charged using that solar resource for the first five years of operation qualifies for the same ITC as the solar resource. This can result in 10-30 percent reduction in the costs of combined solar and storage, relative to stand-alone storage. There are also construction and operational efficiencies that can further improve the economics of combined storage and solar assets, including shared construction crews, inverters, property, and maintenance.

As a result of the items benefits above, the 2019 IRP found that the inclusion of storage with solar resources produced an across the board benefit relative to portfolios that included new solar resources without storage. The 2019 IRP analysis assumed that storage resources combined with solar would be sized equivalent to 25 percent of the solar nameplate and have four hours of storage. These sizing parameters will evolve as PacifiCorp goes out to procure specific resources to capture the benefits of the expiring ITC at the end of 2023, based on both the costs and effective capabilities of different configurations. In general, energy storage should be sized to allow it to be fully filled each day using co-located solar output.

Cost-Effectiveness Results

Table Q.5 provides details on the year-by-year benefits of various lithium-ion battery applications, and identifies years and configurations that are estimated to be cost-effective, either on a stand-alone basis or with the applicable solar ITC at that time.

Since a stand-alone battery is included in the preferred portfolio starting in 2028, it is assumed to be cost effective and providing benefits equal to its costs starting in 2028. Prior to 2028, benefits are based on the intra-hour flexible reserve credit values and operating reserve benefits through 2023, as the battery penetration in this time frame is unlikely to fully cover the operating reserve requirements. Starting in 2024, benefits are assumed to be based on hourly market energy value and the intra-hour flexible reserve credit values, as the higher value operating reserve values are assumed to be fully satisfied with the 2024 battery resources in the preferred portfolio.

Table Q.5 - Energy Storage Applications - Annual Benefits Stream and Cost-Effectiveness

$/kw-yr	Stand-alone Li-Ion 4hr Fixed Cost	Hourly Market Energy	Intra-hour Flex Credit	Operating Reserve	Utility-scale Resource	Primary Losses Energy	Primary Losses Gen Capacity	Primary Losses	T&D Deferral	Primary + T&D Deferral
2019		22.90	26.19	51.17	77.36	4.00		81.35	22.39	103.74
2020		22.64	26.78	52.34	79.12	3.98		83.10	22.90	106.00
2021		25.52	27.39	53.53	80.93	4.36		85.28	23.42	108.70
2022		29.53	28.02	54.75	82.77	4.78		87.56	23.95	111.51
2023		34.02	28.66	56.00	84.66	5.28		89.94	24.50	114.44
2024		40.54	29.31	57.28	69.85	5.99		75.84	25.06	100.90
2025		46.87	29.98	58.58	76.85	6.36		83.21	25.63	108.84
2026		51.12	30.66	59.92	81.79	6.79		88.58	26.22	114.79
2027		51.43	31.36	61.29	82.79	6.72		89.50	26.81	116.32
2028	172.72	52.15	32.08	62.68	172.72	6.73	18.69	198.13	27.42	225.56
2029	176.66	57.36	32.81	64.11	176.66	7.21	19.11	202.98	28.05	231.03
2030	180.69	64.79	33.56	65.57	180.69	7.92	19.55	208.15	28.69	236.84
2031	184.81	69.40	34.32	67.07	184.81	8.30	19.99	213.11	29.34	242.45
2032	189.02	74.71	35.10	68.60	189.02	8.78	20.45	218.26	30.01	248.27
2033	193.33	79.63	35.90	70.16	193.33	9.20	20.92	223.45	30.70	254.14
2034	197.74	84.30	36.72	71.76	197.74	9.57	21.39	228.70	31.40	260.10
2035	202.25	84.73	37.56	73.40	202.25	9.49	21.88	233.61	32.11	265.73
2036	206.86	88.33	38.42	75.07	206.86	9.68	22.38	238.92	32.84	271.76
2037	211.57	94.67	39.29	76.78	211.57	10.36	22.89	244.82	33.59	278.41
2038	216.40	103.07	40.19	78.53	216.40	11.15	23.41	250.96	34.36	285.32
2039	221.33	105.42	41.10	80.32	221.33	11.41	23.95	256.68	35.14	291.83
2040	226.38	107.83	42.04	82.16	226.38	11.67	24.49	262.54	35.94	298.48
2041	231.54	110.29	43.00	84.03	231.54	11.93	25.05	268.52	36.76	305.28
2042	236.82	112.80	43.98	85.95	236.82	12.20	25.62	274.64	37.60	312.25

- Valuation inputs
- Cost-effective w/ 30% ITC
- Cost-effective w/ 10% ITC
- Cost-effective 0% ITC

APPENDIX R –COAL STUDIES

Introduction

The 2019 Integrated Resource Plan (IRP) includes a thorough and robust economic analysis of PacifiCorp's coal units. The coal study analysis conducted in the 2019 IRP was initially prompted by the Public Utility Commission of Oregon (OPUC) in its 2017 IRP acknowledgement order, which administratively established certain study parameters that defined the scope and breadth of the analysis. PacifiCorp met these requirements and then developed a more complete study to ensure that it adequately captured the costs to maintain system reliability. The coal study analyses that informed the 2019 IRP portfolio-development process were completed in three phases:

- Phase One
  Unit-by-unit early retirement studies, which focused on impacts to resource portfolio selections and system costs from the System Optimizer (SO) model, were developed. Each unit-specific early retirement scenario assumes closure at the end of 2022. This phase met requirements set forth by the OPUC 2017 IRP acknowledgement order (Order No. 18-138), and concluded with the June 28-29, 2018 2019 IRP public-input meeting and compliance filing to the OPUC in Docket No. LC-70 on June 29, 2018.

- Phase Two
  A series of studies were produced that expanded the scope of the phase one studies. The expanded scope included an evaluation of unit-by-unity early retirement scenarios using the Planning and Risk model (PaR), stacked retirement scenarios, where multiple early closures were evaluated in a single scenario, and alternative year scenarios, which considered changes in the timing of assumed early closure dates for certain coal units. At this point in the process, PacifiCorp had identified capacity shortfalls in the early retirement scenarios that would compromise system reliability if not remedied. The second phase concluded with the December 2018 coal analysis presented to stakeholders at the December 3-4, 2018 public-input meeting, where PacifiCorp communicated to its stakeholders that additional analysis would need to be developed to address the capacity shortfalls identified in the phase two results.

- Phase Three
  Additional analysis was performed on the stacked retirement scenarios evaluated in phase two of the coal study analyses. The third phase concluded with the April 2019 coal analysis, presented to stakeholders at the April 25, 2019 public-input meeting.

Each of the coal study phases show that early retirement of certain coal units has potential to reduce overall system costs. In particular, the coal studies showed that the greatest customer benefits were most likely to be realized with potential early retirement of coal units at the Naughton and Jim Bridger coal plants located in Wyoming.

This appendix describes the methodology and approach taken in each of the three phases of the coal studies and reports modeling and performance evaluation results. Aligning with expectations communicated to stakeholders at public-input meetings held as the 2019 IRP was being developed, the outcomes of the coal studies were used to inform the 2019 IRP portfolio-development process, which is described in Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach).

Phase One: Unit-by-Unit Coal Studies

In its 2017 IRP acknowledgement order (Order No. 18-138), the OPUC established requirements for a unit-by-unit series of coal retirement studies, which were to be completed by June 30, 2018. The requirements set forth in Order No. 18-138 are as follows:

- PacifiCorp agrees to perform 25 SO model runs, one for each coal unit and a base case.

- PacifiCorp agrees to summarize results and provide:

  - A table of the difference in present-value revenue requirement (PVRR) resulting from the early retirement of each unit;
  - An itemized list of coal unit retirement cost assumptions used in each SO model run; and
  - A list of coal units that would free up transmission along the path from the proposed Wyoming wind projects if retired.

These requirements are consistent with OPUC staff data request 65, which was submitted to PacifiCorp during the 2017 IRP acknowledgement proceeding. In this data request, OPUC staff provided additional guidance that established expectations for the scope of the unit-by-unit coal study analysis described in OPUC Order No 18-138. The specific guidance provided in OPUC staff data request 65 include:

- PacifiCorp should assume a December 2022 retirement date for each early retirement run.

- PacifiCorp should assume Reference Case Regional Haze assumptions (from the 2017 IRP) that are modified to exclude incremental selective catalytic reduction (SCR) costs for Jim Bridger, Hunter, and Huntington in the benchmark case.

- In agreeing to perform this analysis, PacifiCorp cautioned that:

  - The studies would not provide a complete, portfolio-level view of the economics of PacifiCorp's coal portfolio;
  - The structure of the analysis requested by OPUC staff would not capture the system-cost impact that would result from retiring more than one coal unit; and
  - Results from these studies would therefore provide limited insight into a least-cost, least-risk resource portfolio.

Recognizing PacifiCorp's concerns outlined above, the Utah Public Service Commission in its 2017 IRP acknowledgment order in Docket No. 17-035-16 states "we find that additional analysis will be helpful only if it supplements, rather than replaces, the type of coal plant modeling PacifiCorp utilized for its 2017 IRP."

Unit-by-Unit Study Methodology

To meet the requirements set forth in OPUC Order No. 18-138, PacifiCorp developed a portfolio optimization for each coal unit using the SO model, and compared those model results to a benchmark case that assumed continued operation of coal units through their depreciable life, which for certain units, extends beyond the life assumed in the 2017 IRP preferred portfolio.[1] Consequently, in this context, the benchmark case developed for the coal studies is not intended to represent PacifiCorp's default plan. Rather, the benchmark case developed for the coal studies is only intended to serve as a point of comparison for the unit-by-unit retirement scenarios. Table R.1 summarizes the steps that were followed to produce the unit-by-unit analysis.

Table R.1 – Summary of Unit-by-Unit Methodology Steps

Step	Measure	Description
A	2017-2036 System PVRR (x1)	Base Case (One SO Model Run) • 2017 IRP Update with following modifications • Removal of 161 MW Uinta Wind Project (2021-2036) • 2017 IRP Reference Case Regional Haze assumptions • March 2018 official forward price curve with medium CO_2 price inputs • Results are calculated with and without incremental selective catalytic reduction costs for Jim Bridger 1 and 2
B	2017-2036 System PVRR (x22)	Retirement Cases (22 SO Model Runs) • 2017 IRP Update with following modifications • Removal of 161 MW Uinta Wind Project (2021-2036) • 2017 IRP Reference Case Regional Haze assumptions • March 2018 official forward price curve with medium CO_2 price inputs • No incremental selective catalytic reduction costs • Each run assumes the retirement of a single coal unit at the end of 2022
C	2017-2036 System PVRR(d) (x22)	Present-Value Revenue Requirement Differential (PVRR(d)) • Change in system PVRR between the Base Case (A) and each of 22 Retirement Cases (B)

- High-level estimates of transmission reinforcement costs are applied as an adder to the results from step C.
- Each SO model run reflects unique coal-unit operating cost assumptions consistent with assumed retirement dates (*i.e.*, fuel cost, run-rate operating costs, and decommissioning costs).
- PacifiCorp did not perform SO model runs in step B for Naughton Unit 3 and Cholla Unit 4, which are already assumed to retire before 2022.

Unit-by-Unit Study Results

Table R.2 lists the coal units studied in the unit-by-unit analysis, including each unit's relative ranking of potential customer benefits from a potential early closure based on the SO model optimized portfolio results. Units with the lowest numeric rankings (starting with 1) reported the greatest potential for customer benefits from early retirement. Relative to the Reference Case from the 2017 IRP, the SO model reported lower system costs with an assumed 2022 early retirement date for eight of the 22 units studied (39 percent on a capacity basis). The units with the greatest potential for customer benefits from early retirement on a unit-by-unit basis were Jim Bridger Unit 1, Jim Bridger Unit 2, Naughton Unit 1, and Naughton Unit 2, followed by Hayden Unit 1, Hayden Unit 2, Hunter Unit 1, and Craig Unit 2.

[1] For instance, the 2017 IRP preferred portfolio assumed Jim Bridger Unit 1 would retire at the end of 2028 and Jim Bridger Unit 2 would retire at the end of 2032. The coal study benchmark case assumes that these units continue to operate through 2037.

Table R.2 – Unit-by-Unit Coal Study Results Ranked by Potential Customer Benefits

Coal Unit	PacifiCorp Share Capacity (MW)	PacifiCorp Percentage Share (%)	State	Ranking (High to Low Potential Customer Benefits)
Colstrip 3	74	10	MT	17
Colstrip 4	74	10	MT	16
Craig 1	82	19	CO	11
Craig 2	83	19	CO	9
Dave Johnston 1	106	100	WY	12
Dave Johnston 2	106	100	WY	13
Dave Johnston 3	220	100	WY	14
Dave Johnston 4	330	100	WY	18
Hayden 1	44	24	CO	7
Hayden 2	33	13	CO	8
Hunter 1	418	94	UT	10
Hunter 2	269	60	UT	15
Hunter 3	471	100	UT	20
Huntington 1	459	100	UT	22
Huntington 2	450	100	UT	19
Jim Bridger 1	354	67	WY	1
Jim Bridger 2	359	67	WY	2
Jim Bridger 3	349	67	WY	6
Jim Bridger 4	353	67	WY	5
Naughton 1	156	100	WY	4
Naughton 2	201	100	WY	3
Wyodak	268	80	WY	21

- In the benchmark case, Jim Bridger Unit 1 and Jim Bridger Unit 2 include SCR costs. The installation of SCR equipment would be required to maintain operation of this facility through 2037.
- Cholla Unit 4 and Naughton Unit 3 are not presented because PacifiCorp already assumes that these units will cease operating as a coal fired facility before the end of 2022 and the intent of the unit-by-unit analysis was not to evaluate whether there might be economic savings from operating these units longer.

The unit-by-unit studies completed in phase one of the coal studies have several limitations, described in detail in both the June 29, 2018 compliance filing in OPUC Docket No. LC-70 and as communicated to stakeholders during the June 28-29, 2018 public-input meeting. These limitations include:

- The potential benefits of early retirement for individual units are not additive and system impacts are not linear. The studies did not attempt to capture the impact on system costs if coal unit retirements are stacked (where more than one unit is assumed to retire early).

- The studies did not capture the operational and other system-reliability impacts associated with:
  - Meeting balancing area reserve requirements;
  - Meeting balancing area frequency response requirements;

- Reduced flexibility between balancing areas (*i.e.*, Jim Bridger provides energy and other reliability services in both the east and west balancing areas); and
- Reduced ability to participate in the energy-imbalance market due to a reduction in flexible generation and inability to pass the flex ramp sufficiency test.

- The studies reflect 2017 IRP system planning assumptions and do not capture system planning assumptions that were being updated for the 2019 IRP (*i.e.*, load forecasts, recent resource additions, planning reserve margins, capacity-contribution values, conservation-potential assessment, supply-side resources, *etc*.)

- The studies were limited to SO model analysis and therefore do not analyze scenario-risk and stochastic-risk analysis.

Considering these limitations, PacifiCorp engaged in phase two of the coal studies to advance and improve upon results from phase one. The phase one results helped to prioritize the more detailed analysis that would be prepared in phase two.

Phase Two: Stacked Coal Studies

PacifiCorp presented the results of its stacked study coal analysis at its December 3-4, 2018 public-input meeting. As illustrated below, additional analysis was performed at this stage, including updated unit-by-unit analysis, stacked retirement analysis, and additional analysis to evaluate alternative retirement dates for certain coal units.

All studies in phase two were performed using the most current system planning assumptions under development for the 2019 IRP (*i.e.*, load forecasts, recent resource additions, planning reserve margins, capacity-contribution values, conservation-potential assessment, supply-side resources, *etc*.). Additionally, all studies in phase two reflect enhancements in the form of additional resource options, transmission modeling enhancements, and PaR stochastic analysis. These updates provided significant improvements to the quality of the results used to indicate which units to study further when developing stacked retirement scenarios.

Additional Resource Options

In updating modeling assumptions to align with the 2019 IRP, the updated and expanded coal study analysis developed for this phase included roughly 250 more renewable resource options that were available for selection in the SO model when it develops resource portfolios, inclusive of customer-preference[2] resources, more geographic locations, more resource types (*i.e.*, solar and wind resources combined with storage), and with updated capacity-contribution levels. This enhancement aligns IRP modeling with the growing diversity of potential projects across PacifiCorp's service area.

Transmission Modeling Enhancement

In the September 27-28, 2019 public-input meeting, PacifiCorp discussed an improvement to overcome transmission modeling limitations in the SO model while reasonably maintaining model performance. Historically, the SO model has been unable to endogenously select among transmission upgrade options when developing its optimized, least-cost mix of resources for a given portfolio. Subsequently, transmission upgrade needs and costs had to be manually evaluated and developed outside the SO model. This advancement of endogenous transmission modeling represents a leap forward in the portfolio-optimization process, despite some resulting impacts on run-time performance. Between June and December 2018, endogenous transmission options were developed, tested and adopted in SO modeling along with validation and reporting features.

This enhancement had important implications for improving the quality of the coal study results. The cost or benefit of a unit retirement at a specific time and location may swing significantly in relation to transmission projects and opportunities to develop replacement resources and brownfield locations following a plant retirement. Additional detail regarding the endogenous transmission modeling approach implemented in the 2019 IRP is provided in Volume I, Chapter 6 (Resource Options).

Stochastic Risk Analysis

Once unique resource portfolios were developed by the SO model, additional modeling was performed to produce metrics that support comparative cost and risk analysis among the different resource portfolio alternatives. Stochastic risk modeling of resource portfolio alternatives is performed using PaR. The stochastic simulation in PaR produces a dispatch solution that accounts for chronological commitment and dispatch constraints. The PaR simulation incorporates stochastic risk in its production cost estimates by using the Monte Carlo sampling of stochastic variables, which include: load, wholesale electricity and natural gas prices, hydro generation, and thermal unit outages.[3] The Monte Carlo sampling approach is discussed in more detail in Volume I, Chapter 6 (Resource Options).

Updated Unit-by-Unit Summary Results

Updated unit-by-unit studies were developed in phase two incorporating the enhancements described above. The SO model was used to establish a portfolio for each unit retirement case and the resulting portfolios were then run through the PaR model to assess stochastic performance for the following price-policy scenarios (assumptions for the price-policy scenarios are summarized in Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach)):

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[2] Refer to Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach) for a description of customer preference resources and modeling.
[3] Front-office transactions, or FOTs, included in resource portfolios developed using the SO model are subject to the Monte Carlo random sampling of wholesale electricity prices in PaR.

- Base/Base: Medium gas price assumption with medium carbon dioxide (CO_2) price assumption
- High/High: High gas price assumption combined with high CO_2 price assumption
- Low/None: Low gas price conditions combined with no CO_2 price assumption

Table R.3 summarizes the unit-by-unit rankings from phase two, calculated on a nominal levelized basis under the each of the different price-policy scenarios. A negative value represents the potential for reduced costs when the unit is assumed to retire early. Conversely, a positive value represents the potential for increased costs when a unit is assumed to retire early. As was the case in phase one, the potential benefits of early retirement for individual units are not additive and system impacts are not linear. The potential benefits of retiring more than one unit would not be the same as adding up the potential benefits from the unit-by-unit results. Moreover, as discussed previously, these results (and the results presented in Tables R.4 through Table R.7) do not account for the costs to remedy capacity shortfalls in any given scenario. The cost to remedy capacity shortfalls as necessary to maintain a reliable system were captured in phase three.

Table R.3 – Unit-by-Unit Update (Benefit)/Cost of Retirement

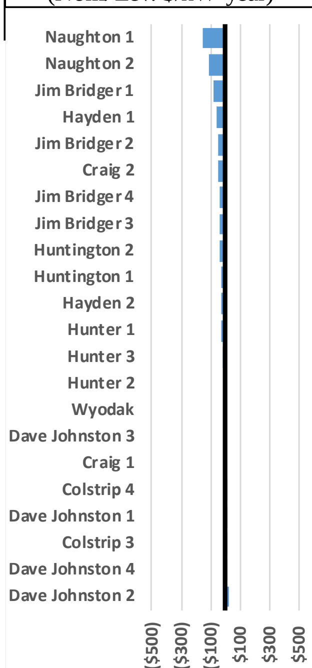
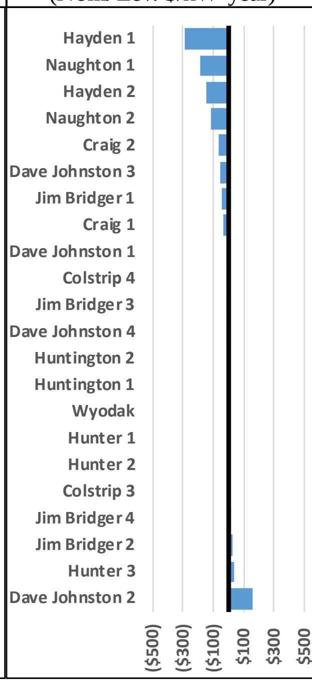
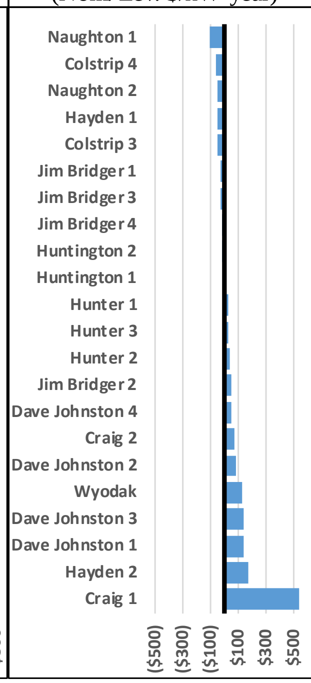
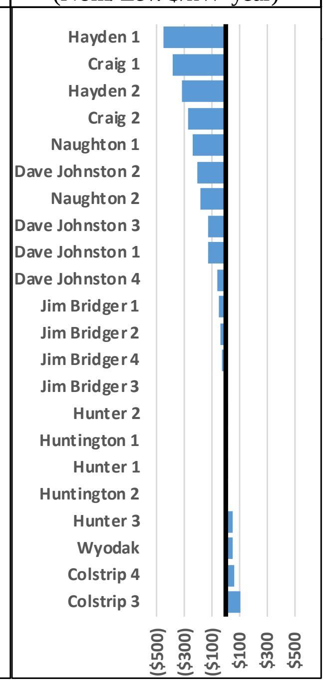
SO, Base/Base (Nom. Lev. $/kW-year)	PaR, Base/Base (Nom. Lev. $/kW-year)	PaR, High/High (Nom. Lev. $/kW-year)	PaR, Low/None (Nom. Lev. $/kW-year)
			

Table R.4 through Table R.7 summarize the unit-by-unit rankings on a present value revenue requirement basis, reporting SO model and PaR results as presented in the December 3-4, 2018 public input meeting.

Table R.4 – SO Model Medium Gas, Medium CO_2 PVRR by Unit

Study	PVRR ($m)	PVRR(d) (Benefit)/Cost of 2022 Retirement
C-01 (Benchmark)	$21,897	n/a
C-02 (Colstrip 3)	$21,906	$9
C-03 (Colstrip 4)	$21,902	$5
C-04 (Craig 1)	$21,897	($0)
C-05 (Craig 2)	$21,875	($22)
C-06 (Dave Johnston 1)	$21,903	$6
C-07 (Dave Johnston 2)	$21,905	$8
C-08 (Dave Johnston 3)	$21,895	($2)
C-09 (Dave Johnston 4)	$21,916	$19
C-10 (Hayden 1)	$21,885	($12)
C-11 (Hayden 2)	$21,893	($4)
C-12 (Hunter 1)	$21,816	($81)
C-13 (Hunter 2)	$21,878	($19)
C-14 (Hunter 3)	$21,853	($44)
C-15 (Huntington 1)	$21,808	($89)
C-16 (Huntington 2)	$21,794	($103)
C-17 (Jim Bridger 1)	$21,690	($207)
C-18 (Jim Bridger 2)	$21,761	($136)
C-19 (Jim Bridger 3)	$21,800	($97)
C-20 (Jim Bridger 4)	$21,797	($100)
C-21 (Naughton 1)	$21,794	($102)
C-22 (Naughton 2)	$21,801	($96)
C-23 (Wyodak)	$21,880	($17)

Table R.5 – PaR Medium Gas, Medium CO_2 PVRR by Unit

Study	PVRR ($m)	PVRR(d) (Benefit)/Cost of 2022 Retirement
C-01 (Benchmark)	$23,310	n/a
C-02 (Colstrip 3)	$23,317	$7
C-03 (Colstrip 4)	$23,302	($8)
C-04 (Craig 1)	$23,304	($6)
C-05 (Craig 2)	$23,281	($29)
C-06 (Dave Johnston 1)	$23,305	($5)
C-07 (Dave Johnston 2)	$23,363	$53
C-08 (Dave Johnston 3)	$23,273	($37)
C-09 (Dave Johnston 4)	$23,304	($6)
C-10 (Hayden 1)	$23,252	($58)
C-11 (Hayden 2)	$23,287	($23)
C-12 (Hunter 1)	$23,341	$31
C-13 (Hunter 2)	$23,334	$24
C-14 (Hunter 3)	$23,438	$128
C-15 (Huntington 1)	$23,326	$17
C-16 (Huntington 2)	$23,310	$0
C-17 (Jim Bridger 1)	$23,197	($113)
C-18 (Jim Bridger 2)	$23,381	$71
C-19 (Jim Bridger 3)	$23,283	($27)
C-20 (Jim Bridger 4)	$23,349	$39
C-21 (Naughton 1)	$23,187	($123)
C-22 (Naughton 2)	$23,212	($98)
C-23 (Wyodak)	$23,323	$13

Table R.6 – PaR High Gas, High CO_2 PVRR by Unit

Study	PVRR ($m)	PVRR(d) (Benefit)/Cost of 2022 Retirement
C-01 (Benchmark)	$28,176	n/a
C-02 (Colstrip 3)	$28,152	($25)
C-03 (Colstrip 4)	$28,145	($31)
C-04 (Craig 1)	$28,265	$89
C-05 (Craig 2)	$28,214	$37
C-06 (Dave Johnston 1)	$28,225	$48
C-07 (Dave Johnston 2)	$28,205	$28
C-08 (Dave Johnston 3)	$28,275	$98
C-09 (Dave Johnston 4)	$28,234	$58
C-10 (Hayden 1)	$28,167	($9)
C-11 (Hayden 2)	$28,203	$26
C-12 (Hunter 1)	$28,258	$81
C-13 (Hunter 2)	$28,255	$79
C-14 (Hunter 3)	$28,297	$121
C-15 (Huntington 1)	$28,215	$38
C-16 (Huntington 2)	$28,172	($4)
C-17 (Jim Bridger 1)	$28,107	($69)
C-18 (Jim Bridger 2)	$28,307	$131
C-19 (Jim Bridger 3)	$28,123	($53)
C-20 (Jim Bridger 4)	$28,156	($20)
C-21 (Naughton 1)	$28,110	($66)
C-22 (Naughton 2)	$28,134	($42)
C-23 (Wyodak)	$28,434	$258

Table R.7 – PaR Low Gas, Zero CO_2 PVRR by Unit

Study	PVRR ($m)	PVRR(d) (Benefit)/Cost of 2022 Retirement
C-01 (Benchmark)	$19,644	n/a
C-02 (Colstrip 3)	$19,701	$57
C-03 (Colstrip 4)	$19,678	$35
C-04 (Craig 1)	$19,579	($64)
C-05 (Craig 2)	$19,513	($131)
C-06 (Dave Johnston 1)	$19,601	($42)
C-07 (Dave Johnston 2)	$19,572	($71)
C-08 (Dave Johnston 3)	$19,554	($89)
C-09 (Dave Johnston 4)	$19,581	($62)
C-10 (Hayden 1)	$19,553	($91)
C-11 (Hayden 2)	$19,596	($48)
C-12 (Hunter 1)	$19,675	$31
C-13 (Hunter 2)	$19,658	$14
C-14 (Hunter 3)	$19,796	$153
C-15 (Huntington 1)	$19,670	$26
C-16 (Huntington 2)	$19,696	$53
C-17 (Jim Bridger 1)	$19,504	($140)
C-18 (Jim Bridger 2)	$19,553	($90)
C-19 (Jim Bridger 3)	$19,642	($2)
C-20 (Jim Bridger 4)	$19,578	($65)
C-21 (Naughton 1)	$19,484	($160)
C-22 (Naughton 2)	$19,488	($156)
C-23 (Wyodak)	$19,746	$103

Alternate Year Unit Analysis

PacifiCorp selected units for further alternate-year analysis based on the unit-by-unit SO model results. Based on the initial SO model results, the following units were selected to test the impacts of delaying individual unit retirements:

- Naughton Unit 1
- Naughton Unit 2
- Jim Bridger Unit 1
- Hayden Unit 1

Table R.8 reports the SO model outcomes of the alternate year studies, and indicates that delaying the retirement of individual units, before accounting for incremental reliability resources needed to remedy capacity shortfalls, in the unit-by-unit studies would reduce potential benefits.

Table R.8 – SO Model Alternate Year Analysis, Medium Gas, Medium CO_2

Study	Alternate Year	PVRR ($m)	PVRR(d) (Benefit)/Cost of 2022 Retirement	Change from 2022 Retirement Assumption
C-01 (Benchmark)	n/a	$21,897	n/a	n/a
C-25 (Naughton 1)	2025	$21,887	($10)	$92
C-26 (Naughton 1)	2028	$21,915	$18	$120
C-27 (Naughton 2)	2025	$21,882	($15)	$81
C-28 (Naughton 2)	2028	$21,915	$18	$114
C-29 (Jim Bridger 1)	2025	$21,756	($141)	$66
C-30 (Jim Bridger 1)	2028	$21,773	($124)	$83
C-31 (Jim Bridger 1)	2031	$21,788	($109)	$99
C-32 (Hayden 1)	2025	$21,884	($13)	($1)
C-33 (Hayden 1)	2028	$21,888	($9)	$3

To confirm this finding, PacifiCorp conducted additional analysis of these studies using PaR. Table R.9 reports results consistent with the SO Model results—before accounting for incremental reliability resources needed to remedy capacity shortfalls, potential benefits for early retirement are greatest with assumed retirement at the end of 2022. Based on results of the alternate-year cases, the stacked-retirement cases developed in phase two of the coal studies assume early retirement of units at the end of 2022.

Table R.9 – PaR Alternate Year Analysis, Medium Gas, Medium CO_2

Study	Alternate Year	PVRR ($m)	PVRR(d) (Benefit)/Cost of 2022 Retirement	Change from 2022 Retirement Assumption
C-01 (Benchmark)	n/a	$23,310	n/a	n/a
C-25 (Naughton 1)	2025	$23,275	($35)	$87
C-26 (Naughton 1)	2028	$23,290	($20)	$103
C-27 (Naughton 2)	2025	$23,277	($33)	$65
C-28 (Naughton 2)	2028	$23,298	($12)	$86
C-29 (Jim Bridger 1)	2025	$23,270	($40)	$73
C-30 (Jim Bridger 1)	2028	$23,262	($48)	$64
C-31 (Jim Bridger 1)	2031	$23,238	($72)	$40
C-32 (Hayden 1)	2025	$23,271	($39)	$20
C-33 (Hayden 1)	2028	$23,277	($33)	$25

Stacked Study Methodology

Based on the outcomes of the updated unit-by-unit analysis, eight stacked-retirement cases were defined to analyze retirement depth for nine coal resources with the highest potential for customer benefits. Table R.10 identifies these cases by name, retired units and the total nameplate of the included retirements.

Each stacked case required the development of a unique set of assumptions, accounting for fuel costs, decommissioning costs, contractual obligations, and the potential loss of existing cost-savings for co-located facilities.

The SO model was used to establish a portfolio for each stacked-retirement case and the resulting portfolios were then run through PaR to assess stochastic performance for the following price-policy scenarios (assumptions for the price-policy scenarios are summarized in Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach)):

- Base/Base: Medium gas price assumption with medium CO_2 price assumption
- High/High: High gas price assumption combined with high CO_2 price assumption
- Low/Zero: Low gas price conditions combined with no CO_2 price assumption

Table R.10 – Stacked Retirement Cases

Case Name	2022 Retirements	Nameplate Retired (MW)
C-34	Naughton 1-2 (2022)	357
C-35	Naughton 1-2 (2022) Jim Bridger 1 (2022)	711
C-36	Naughton 1 (2022) Jim Bridger 1 (2022)	510
C-37	Naughton 1 (2022) Jim Bridger 1 (2022) Hayden 1 (2022)	554
C-38	Naughton 1-2 (2022) Hayden 1 (2022) Jim Bridger 1 (2022)	755
C-39	Naughton 1-2 (2022) Hayden 1 (2022) Jim Bridger 1 (2022) Craig 2 (2022)	834
C-40	Naughton 1-2 (2022) Hayden 1 (2022) Jim Bridger 1-2 (2022) Craig 2 (2022)	1,193
C-41	Naughton 1-2 (2022) Jim Bridger 1-2 (2022) Hayden 1-2 (2022) Craig 1-2 (2022) Dave Johnston 3 (2022)	1,529

Stacked Study Results

Table R.11 summarizes the stacked study results under the Base/Base price-policy scenario. Cases C-35, C-38, and C-39 show the largest potential benefits, and the PVRR(d) results for these three cases are very close to one another. Cases C-40 and C-41, both in excess of 1,000 megawatts (MW) of incremental early retirements relative to the benchmark case, show a net cost. As discussed previously, these results (and the results presented in Table R.12 and Table R.13) do not account for the costs to remedy capacity shortfalls.

Table R.11 – Planning and Risk Medium Gas, Medium CO_2 PVRR by Study

Base/Base Case	PVRR	PVRR(d) (Benefit)/Cost of Retirement ($m)
C-01 (Benchmark)	$23,310	n/a
C-34	$23,180	($130)
C-35	$23,009	($301)
C-36	$23,286	($24)
C-37	$23,288	($22)
C-38	$23,002	($307)
C-39	$22,993	($317)
C-40	$23,483	$173
C-41	$23,600	$290

Table R.12 summarizes the stacked study results under the High/High price-policy scenario. As in the base/base price-policy scenario, Cases C-35, C-38, and C-39 show the largest potential benefits. Cases C-40 and C-41, both in excess of 1,000 MW of incremental early retirements relative to the benchmark case, continue to show a net cost.

Table R.12 – Planning and Risk High Gas, High CO_2 PVRR by Study

High/High Case	PVRR ($m)	PVRR(d) (Benefit)/Cost of Retirement ($m)
C-01 (Benchmark)	$28,176	n/a
C-34	$28,109	($67)
C-35	$27,897	($279)
C-36	$28,252	$76
C-37	$28,249	$72
C-38	$27,896	($280)
C-39	$27,877	($299)
C-40	$28,397	$221
C-41	$28,249	$368

Table R.13 summarizes the stacked study results under the low/zero price-policy scenario. As in the base/base and high/high price-policy scenarios, Cases C-35, C-38, and C-39 show the largest potential benefits, and the PVRR(d) results for these three cases are reasonably close. Cases C-40 and C-41, both in excess of 1,000 MW of incremental early retirements relative to the benchmark case, continue to show a net cost.

Table R.13 – Planning and Risk Low Gas, No CO_2 PVRR by Study

Low/Zero Case	PVRR ($m)	PVRR(d) (Benefit)/Cost of Retirement ($m)
C-01 (Benchmark)	$19,644	n/a
C-34	$19,487	($156)
C-35	$19,386	($257)
C-36	$19,549	($95)
C-37	$19.573	($71)
C-38	$19,359	($285)
C-39	$19,336	($308)
C-40	$19,747	$103
C-41	$19,828	$184

Initial Reliability Assessment

While the December 2018 stacked coal studies incorporated important enhancements in methodology and the alignment of data to the 2019 IRP planning assumptions, a method had not yet been fully developed to capture the operational and other system-reliability impacts associated with potential early coal unit retirements.

PacifiCorp performed an initial reliability assessment on a sampling of three cases using an hourly deterministic PaR run for 2023, which is the first full year after assumed coal unit retirements. The deterministic run provides the granularity necessary to represent system reliability shortfalls that may be lost in aggregated data, a factor of increasing importance as flexible resources are retired and potentially replaced with non-dispatchable variable resources. Because deterministic studies lack stochastic shocks, thermal units are modeled using de-rated capacity to account for unplanned outages.

For these initial reliability studies, system balances were summarized for load, net load (load net of energy efficiency, private generation, wind, and solar), spinning reserves, non-spinning reserves, and regulation reserves and compared to the type and amounts of resources providing system services across each hour of several selected days. Selected days included peak load days and peak net-load ramp days. Shortfalls were measured for spinning, non-spinning, and regulating reserves, as well as load. Table R.14 summarizes the aggregated findings of the initial reliability assessment.

Capacity shortfalls were observed in 2023, the year after early retirements, in each of the sample cases, and the number of occurrences and the magnitude of the worst occurrence increased in cases with more stacked retirements. The results confirmed that the retirement cases could degrade system reliability, and the potential cost to remedy these capacity shortfalls was not directly factored into the phase two results (i.e., via a potential addition or change in the resource mix to alleviate capacity shortfalls). Addressing these capacity shortfalls observed in the phase two results was the primary objective of phase three of the coal studies.

Table R.14 – Reliability Analysis Capacity Shortfalls

Case	Shortfall Hours	Maximum Shortfall (MW)
C-01 (Benchmark)	29 (0.3%)	290
C-35	146 (1.7%)	318
C-40	609 (7.0%)	351

Phase Three: Reliability Analysis of Coal Studies

From December 2018 through April 2019, PacifiCorp continued in its efforts to address the capacity shortfalls observed in preliminary results as part of this stage of the coal studies. Four public-input meetings were held including the April 25, 2019 meeting, which concluded the coal studies. During these months several shortfall mitigation enhancements were made to improve model representation, and a path forward was identified to address reliability concerns.

Stakeholder Feedback

As an outcome of the phase two stacked-retirement results, two additional cases were developed in response to stakeholder interest, cases C-42 and C-43. Case C-42 examined the impacts of retiring the four coal units most consistently reporting high customer benefits over the course of the coal studies. C-43 examined the impacts of replacing a Jim Bridger unit with a Dave Johnston unit. Table R.15 provides the assumed retirements of the two additional cases plus the total retired nameplate capacity assumed for each case.

Table R.15 – Additional Stacked Coal Studies

Case Name	2022 Retirements	Nameplate Retired (MW)
C-42	Naughton 1-2 (2022) Jim Bridger 1-2 (2022)	1,063
C-43	Naughton 1-2 (2022) Jim Bridger 1 (2022) Dave Johnston 3 (2022)	928

Coal Unit Focus

At the March 21, 2019 public-input meeting, PacifiCorp presented analysis of real levelized cost rankings of the coal units as an additional verification of the coal units which were to be the focus of the stacked-retirement cases. While this analysis is independent of direct locational factors tied to the IRP topology, the findings reported in Table R.16 generally confirms the focus of specific units established by the phase two coal studies completed in December, 2018.

Table R.16 – Real Levelized Cost Rankings of Coal Units

	Real Levelized Cost Rankings				
	Aggregate Rank	O&M Rank	CapEx Rank	Full Load Fuel Rank	Dec 3-4 PVRR(d) Rank
C-02 (Colstrip 3)	14	7	5	18	15
C-03 (Colstrip 4)	12	6	3	16	10
C-04 (Craig 1)	6	3	14	9	11
C-05 (Craig 2)	5	4	4	10	7
C-06 (Dave Johnston 1)	19	11	21	19	13
C-07 (Dave Johnston 2)	20	10	20	20	21
C-08 (Dave Johnston 3)	21	9	22	21	6
C-09 (Dave Johnston 4)	22	12	19	22	11
C-10 (Hayden 1)	1	1	10	1	4
C-11 (Hayden 2)	2	2	16	3	9
C-12 (Hunter 1)	11	14	12	11	19
C-13 (Hunter 2)	15	15	13	14	18
C-14 (Hunter 3)	13	18	15	12	22
C-15 (Huntington 1)	18	17	17	15	17
C-16 (Huntington 2)	16	16	18	13	14
C-17 (Jim Bridger 1)	7	20	2	6	2
C-18 (Jim Bridger 2)	9	19	1	8	5
C-19 (Jim Bridger 3)	10	21	7	7	8
C-20 (Jim Bridger 4)	8	22	11	5	20
C-21 (Naughton 1)	4	5	6	4	1
C-22 (Naughton 2)	3	8	9	2	3
C-23 (Wyodak)	17	13	8	17	16

The top candidate list in both views include Naughton, Jim Bridger, Hayden and Craig units. While the Dave Johnston units were not indicated in this new analysis, Dave Johnston Unit 3 was retained in certain cases for completeness and in response to stakeholder interest.

Shortfall Mitigation

Renewable Regulation Reserves

Wind and solar resources with requisite contractual rights and controls can provide regulation reserves when forecasted output can be curtailed to free-up operating capacity on the system. Curtailment results in:

- Replacement energy cost (typically market)
- Lost renewable energy credit revenue, where applicable (only included where explicitly known)
- Lost production tax credits, where applicable

- Avoided taxes (Wyoming wind only)

To mitigate the impacts of curtailments, wind and solar resources with requisite contractual rights and controls were modeled as dispatchable resources in PaR.

Hydro Dispatch Configuration
To better account for the flexibility of dispatchable hydro resources, these resources were configured for spring months (February through May in this context) to maximize reserve capability by establishing a consistent monthly dispatch rather than shaping to load.

Non-Peak Front Office Transaction Modeling
Modeling enhancements that address the modeling of dispatchable wind, solar, and hydro resources can result in less energy to serve load, so their viability in mitigating operating-reserve shortfalls may be restricted by limits on market purchases. Recognizing that market conditions vary by season, front office transaction (FOT) limits, which were established with a focus on summer and winter peak-load periods, are increased during the spring and fall to align with firm transmission rights. The increase is from 1,425 MW to 2,277 MW in these periods.

Lewis River Hydro Project Refinement
The original and standard model configuration led PaR to use the Lewis River Hydro project to shave peak load using available energy over a sample week for a given month. Any remaining capacity was then available for use as operating reserves.

PacifiCorp tested and implemented a modeling enhancement allowing PaR to shave peak load, using available energy of a sample week for a given month, net of wind, solar, battery storage, energy efficiency, and private generation resources (i.e., net load). Any remaining capacity, but no less than 10 percent of the Lewis River Hydro project, is considered available for use as operating reserves.

Battery Storage Optimization
PacifiCorp initially attempted to mimic the model settings used to enhance PaR's use of the Lewis River Hydro project to improve its use of battery-storage resources (dispatch, charging, and reserve resources). However, unlike the Lewis River Hydro project, battery-storage resources do not have an established volume of energy to use over a sample week in a given month.

Given complexity of PacifiCorp's system, the PaR model experienced difficulty optimizing the dispatch for battery storage resources. To improve upon this shortcoming in the PaR model, PacifiCorp developed and tested a method to produce an optimized peak-shave/valley-fill profile for these resource outside of PaR that is based on load net of wind, solar, energy efficiency, and private generation resources in any given portfolio. Fixed hourly dispatch, charging, and operating reserves are entered as inputs to the PaR model. This was presented and discussed in the March 21, 2019 public-input meeting.

Model Granularity Cost-Driver Adjustment
At the January 24, 2019 public-input meeting, PacifiCorp discussed that differences between portfolios in some cases were contributing to differences in reserve deficiencies (primarily 2038). These portfolio differences were causing disproportionate impacts on present-value portfolio costs in PaR relative to the SO model. Subsequent testing confirmed that differences in the granularity

between the two models contributes to alternative resource selections and that these resource selections are influencing these seemingly incongruent results.

When cost-driver adjustments based on the differences in hourly granularity between the SO model and PaR model are applied to resource cost inputs used in the SO model, differences to resource portfolio results for seemingly similar cases are more stable and the cost disparity driven by reserve deficiencies are mitigated. Accounting for the reduced hourly granularity in the SO model yields the average solar and wind resource costs shown in Table R.17.

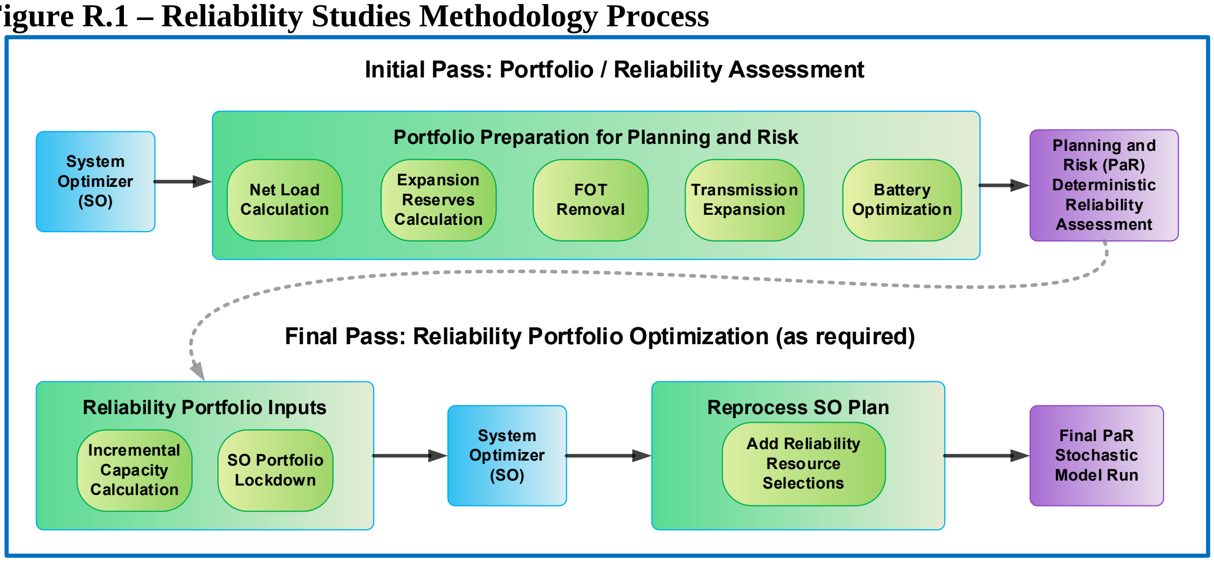
Table R.17 – Model Granularity Cost-Driver Adjustment Summary

Resource Location	Average Resource Cost (increase)/decrease ($/MWh of expected output)	
	Solar	Wind
Oregon	($7.06)	$0.95
Washington	($7.17)	$1.05
Idaho	($7.28)	($0.14)
Utah	($7.73)	($0.35)
Wyoming	($7.33)	($0.90)

Reliability Study Methodology

The modeling enhancements previously described give the SO model and PaR improved insight into the value and capabilities of various resources, and are applicable to every case. This allows the SO model to provide portfolios that are better-aligned with how PaR evaluates the performance and reliability of resources in its more granular perspective. In addition, due to the unique combination of resource types, locations and timing, and their interactions with transmission option modeling, a methodology was necessary to identify and address remaining reliability shortfalls on a case-by-case basis. This method was developed, tested and implemented, and subsequently presented to stakeholders at PacifiCorp's April 25, 2019 IRP public-input meeting. Figure R.1 outlines the development steps followed in this process.

Figure R.1 – Reliability Studies Methodology Process



The reliability methodology is an expansion of the initial reliability analysis explored at the end of 2018 and previously described in Stage Two of the coal studies and is described in more detail below.

Deterministic Reliability Assessment
In the initial reliability analysis, a single deterministic run for the year 2023 was used to assess reliability shortfalls. The methodology adopted in this reliability stage includes a deterministic reliability assessment for three years, 2023, 2030, and 2038. Years 2030 was added as an outcome of a 20-year analysis which determined that 2030 was most frequently the year with highest measured shortfall. Likewise 2038 was added as a bookend, and also because the final year was observed to have relatively high shortfalls.

In evaluating the reliability of the deterministic studies, portfolios must meet four hourly requirements: energy, non-spinning reserve, spinning reserve, and regulation reserve. Separate requirements for East and West are developed in the methodology, but transfers are allowed up to transmission limits. Using the method described in the Initial Reliability Analysis above, the hourly balance of net load and all resource contributions were compared to calculate the shortfall or unused available capacity for each hour. The maximum hourly shortfall (or minimum available) is identified by season. The resulting measures describe four reliability requirements for each proxy year: summer east, summer west, winter east and winter west.

Reliability requirements for the test year 2023 were applied to simulation years 2023 through 2027. Requirements for the test year 2030 were applied to simulation years 2028 through 2036. Requirements for the test year 2038 were applied to simulation years 2037 and 2038.

Uncertainty Requirement
Deterministic studies have the advantage of increased detail through hourly granularity appropriate to identifying potential shortfalls in an increasingly complex system. In the absence of stochastic variance, these studies also reflect “perfect foresight” for the following assumptions:

- Normal load (1-in-2 exceedance)
- Average thermal outages in all hours
- Average hydro conditions
- Fixed variable energy resource generation profiles, and
- Average market prices without electric or natural gas price volatility and physical supply risks

Additional flexible capacity is required beyond the capacity needed to “cure” hourly shortfalls to reliably serve customers considering that the above factors vary from day to day and hour to hour and are not known in advance. To account for these intrinsic uncertainties, 500 MW of additional reliability requirement was added to address significant day-ahead, hour-ahead and real-time unknowns in market supply. This 500 MW capacity requirement is in addition to capacity to sufficient to cover the maximum hourly shortfall identified in the deterministic studies.

The 500 MW incremental requirement relative to a deterministic forecast of loads, outages, market prices, and hydro generation was established upon review of operational data and with consideration of operational experience. In operations, capacity held in reserve for contingency, forecast error and intra-hour variability is approximately 16 percent of peak load. In the summer months, additional capacity is held in reserve to mitigate risks associated with high volatility in load and resource availability. In 2018, capacity held in reserve that is incremental to the 13 percent planning margin for contingency, forecast error, and intra-hour volatility totaled 295 MW. In 2018, capacity held in reserve to mitigate risk during peak load conditions in the summer months was approximately 241 MW. Combined, these sum to 536 MW. PacifiCorp conservatively adopted the 500 MW figure for planning purposes in the 2019 IRP.

Reliability Portfolio
Once the reliability requirements are known, the SO model is run with the ability to add or accelerate the following resource types relative to the pre-reliability portfolio to meet seasonal east and west incremental requirements: batteries, energy efficiency, gas peaking resources, and pumped storage resources. Other resource types are locked-in at levels determined by the pre-reliability portfolio. The four types of reliability resources are allowed as additions because they provide the necessary flexibility to effectively meet identified shortfalls.

Stochastic Outcomes
The last step in the process is to run a 20-year, 50-iteration PaR study on the resulting reliability portfolio, providing stochastic risk analysis over the full IRP study period.

Reliability Study Results

Table R.18 summarizes the assumed retirements for the complete set of stacked coal reliability cases, including retired capacity and PaR model measured (benefit)/cost.

Table R.18 – Early Retirement Assumptions Summary for all Reliability Coal Studies

Case	Inc. Retired Capacity in 2023 (MW)	PVRR ($m)	Naughton 1	Naughton 2	Bridger 1	Bridger 2	Hayden 1	Hayden 2	Craig 1	Craig 2	Dave Johnston 3
C-34	357	$23,536	✓	✓							
C-35	711	$23,381	✓	✓	✓						
C-36	510	$23,418	✓		✓						
C-37	554	$23,405	✓		✓		✓				
C-38	755	$23,398	✓	✓	✓		✓				
C-39	834	$23,434	✓	✓	✓		✓			✓	
C-40	1,193	$23,317	✓	✓	✓	✓	✓			✓	
C-41	1,529	$23,390	✓	✓	✓	✓	✓	✓	✓	✓	✓
C-42	1,063	$23,302	✓	✓	✓	✓					
C-43	928	$23,458	✓	✓	✓						✓

Note: in all cases it is assumed that Naughton 3 (280 MW) is retired in 2019 and that Cholla 4 (387 MW) is retired at the end of 2020; these units are retired in the benchmark case and therefore not incremental to the stacked-retirement cases listed above.

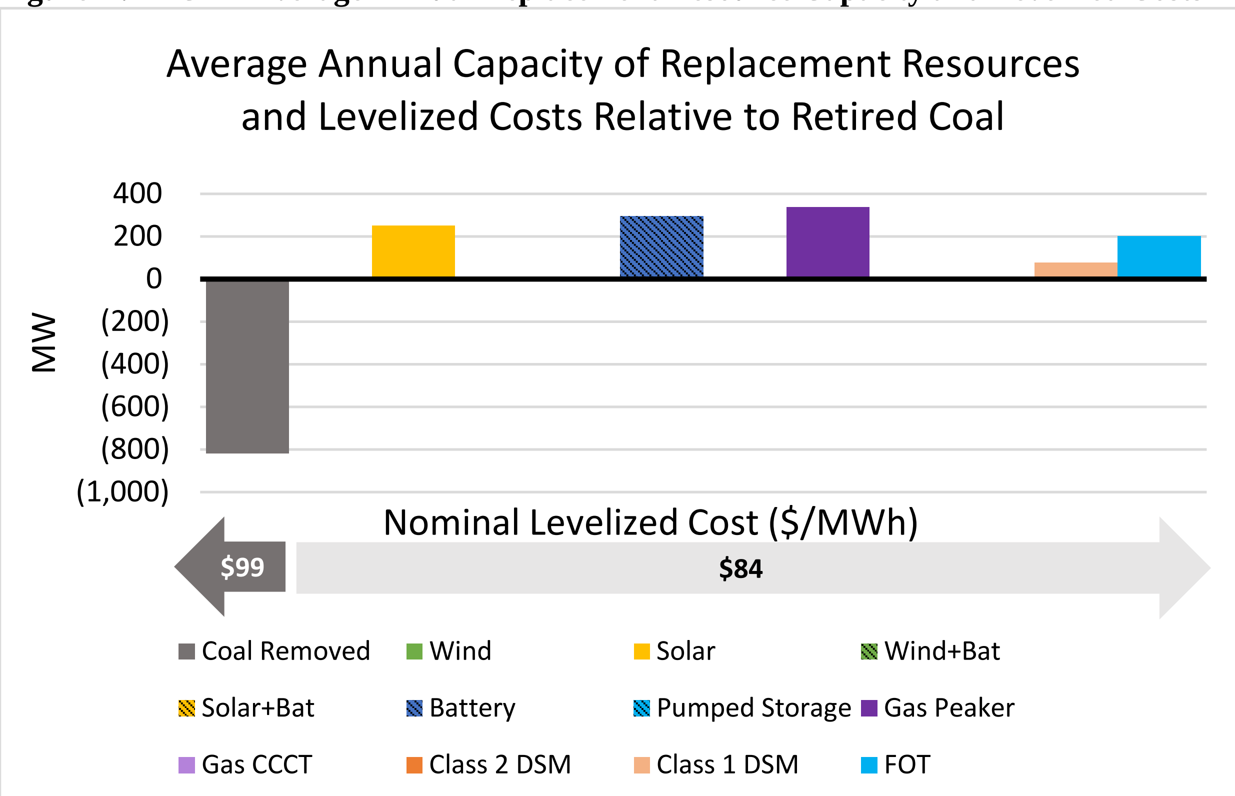
In the final coal study analysis, case C-42 produced the lowest present value revenue requirement (PVRR) total system cost, and therefore the highest potential customer benefits associated with potential early retirement. Cases retiring greater amounts of coal resource (C-40, C-41), or those emphasizing different coal units for early retirement (C-43) reported reduced benefits. This outcome is broadly supported by findings from phase one and two, and again by the real levelized cost rankings of coal unit run-rate costs across the fleet, as reported previously in Table R.16.

Stacked Coal Case C-42

At the April 25, 2019 public-input meeting, PacifiCorp reported a PVRR differential benefit of \$248m against the C-01 benchmark case. As noted in the Unit-by-Unit Methodology discussion, above, the benchmark was an administratively established in phase one of the coal studies, and is not representative of PacifiCorp's plan. Also, the \$248m figure did not include a correction to the granularity adjustment driver included in the reliability coal studies. Corrected, the PVRR values (given in Table R.18, above) did not alter the conclusions of the April 2019 analysis, which continue to confirm that the greatest potential benefit for early retirements resides with the potential early closure of units at the Naughton and Jim Bridger plants in Wyoming.

Aligned with the April 25, 2019 results, Figure R.2 reports the average annual cost of replacement resources and levelized costs relative to the assumed 2022 accelerated retirements of Jim Bridger Units 1 and 2, and Naughton Units 1 and 2.

Figure R.2 – C-42 Average Annual Replacement Resource Capacity and Levelized Costs



- The nominal levelized cost of retired coal resources is \$14.21/MWh higher than the nominal levelized costs of the portfolio of replacement resources.
- CO_2 emission cost savings account for 77.0 percent of the overall benefit associated with accelerated retirement.
- Run-rate fixed costs would need to drop by 26.3 percent to achieve break-even economics with the replacement portfolio.

Conclusions

The updated coal-retirement cases account for incremental resource costs to address reliability issues identified and discussed at the December 3-4, 2018 public-input meeting. The updated analysis shows there are potential customer benefits from accelerating the retirement of certain coal units, where the greatest customer benefits are associated with the potential accelerated retirement of units at the Naughton and Jim Bridger plants located in Wyoming.

Aligning with the long-term study plan established during the 2019 IRP public-input process, the identification of these key units informed PacifiCorp's 2019 IRP portfolio-development process, described in detail in Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach). The portfolio-development process considers other planning factors not fully evaluated in the coal studies (i.e., Regional Haze compliance, alternative retirement dates for jointly owned coal plants where PacifiCorp is a minority owner and not an operator, alternative timing of potential retirements when accounting for incremental capacity to maintain reliability). Consistent with the findings from the coal study, more than half of the cases developed in the initial phase of the portfolio-development process evaluated varying combinations of retirement dates for Naughton and Jim Bridger units, including coal retirement assumptions from case C-42.