ORDER NO. 20-464

ENTERED Dec 03 2020

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1893

In the Matter of PUBLIC UTILITY COMMISSION OF OREGON, Request for Approval of Energy Efficiency Avoided Cost Data to be Used by Energy Trust.	ORDER

DISPOSITION: STAFF'S RECOMMENDATION ADOPTED

At its public meeting on December 1, 2020, the Public Utility Commission of Oregon adopted Staff's recommendation in this matter. The Staff Report with the recommendation is attached as Appendix A.

BY THE COMMISSION:

Nolan Moser
Chief Administrative Law Judge

A party may request rehearing or reconsideration of this order under ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-001-0720. A copy of the request must also be served on each party to the proceedings as provided in OAR 860-001-0180(2). A party may appeal this order by filing a petition for review with the Circuit Court for Marion County in compliance with ORS 183.484.

ITEM NO. RA2

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: December 1, 2020

REGULAR _X_ **CONSENT** ____ **EFFECTIVE DATE** **December 2, 2020**

DATE: November 23, 2020

TO: Public Utility Commission

FROM: Anna Kim

THROUGH: Bryan Conway, JP Batmale, and Sarah Hall **SIGNED**

SUBJECT: OREGON PUBLIC UTILITY COMMISSION STAFF:
(Docket No. UM 1893)
Request for approval of Energy Efficiency Avoided Cost data to be used by Energy Trust.

STAFF RECOMMENDATION:

The Public Utility Commission of Oregon (Commission) should approve the attached energy efficiency avoided cost data for use by Energy Trust.

DISCUSSION:

Issue

Whether to approve the attached energy efficiency avoided cost data for use by Energy Trust.

Applicable Law

OAR 860-030-0011(1) requires an energy utility to submit its data for calculation of energy efficiency avoided costs in the manner and method specified in a Commission-approved reporting form. The form must be submitted by October 15 of each year for use in the next energy efficiency program budget cycle. See OAR 860-030-0011(1). Under OAR 860-030-0011(2), the Commission may approve, at its discretion, the use of data more recent than data used in the utility's last acknowledged Integrated Resource Plan or general rate case in which the Commission has issued a final order.

Analysis

The rules that govern the submission and review of these data were adopted in May 2019. This is the second formal iteration of data review since the rules were put into effect. As a new process, there continues to be opportunities to improve the transparency and accuracy of identifying values for use in calculating energy efficiency avoided costs.

The analysis is divided into three sections in the memo. Section I presents a summary of activities since the last report. Section II presents Staff's recommendations on data to approve for use by Energy Trust for energy efficiency avoided cost calculations. Section III provides a brief description of results to energy efficiency avoided costs.

Section I: Summary of Activities
In 2020, Staff discussed potential changes to the data collection workbooks and updates were applied to the natural gas workbook. Utilities submitted data, and Staff reviewed the submissions with stakeholder assistance.

On June 25, 2020, Staff contacted the UM 1893 mailing list requesting topics for discussion, particularly any topics that may result in alterations to the data collection workbooks.

On July 9, 2020, Northwest Natural initially shared with Staff a number of opportunities to improve clarity and potentially streamline the natural gas data collection workbook. The workbook is the Commission-approved form used for the purpose of reporting under OAR 860-030-0011. These comments were formally posted to the UM 1893 docket on July 16, 2020. Staff appreciates Northwest Natural's continued engagement and contributions to this docket. Northwest Natural's suggestions led to notable improvements in clarity, and thus transparency.

Staff addressed Northwest Natural's comments as follows:

Real vs. Nominal: Northwest Natural noted that some of the table columns were improperly labeled, assuming real dollars even though the form gives the option to use real or nominal. Staff agrees and has corrected this error.

End Use Profiles: Northwest Natural proposed re-wording "End Use Load Profiles" to "End Use Savings Profiles" to distinguish the fact that a reduction in load may not be equivalent to acquiring savings. Staff agrees that there is a distinction to be made. Further, Staff will accept submissions derived from either loads or savings, and opted to rename "End Use Load Profiles" to "End Use Profiles" to reflect this openness.

System Peak Coincident Factors: Northwest Natural noted that it does not use system peak coincident factors for its calculations and suggests removal if these factors are not in use. Staff clarifies that this can be used by other utilities and updated instructions to distinguish these options.

Inflation Rate: Northwest Natural asked for clarification of whether Energy Trust uses inflation rates from individual utilities. Currently, this is the case and consequently no changes have been made regarding inflation in the workbooks.

Staff, in consultation with Energy Trust, applied changes to the natural gas data collection workbook. Staff posted the draft workbook and a request for comments on the proposed changes to the docket on July 17, 2020. Staff requested comments by July 29, 2020. Staff did not receive further comment on these proposed changes. The updated workbook was approved by the Commission Chair on August 4, 2020.

All five utilities submitted the requested data by the October 15 filing date using the template approved by the Commission in accordance with OAR 860-030-0011(1). Staff reviewed these data for use by Energy Trust for 2022.

After data were submitted, Staff held a stakeholder workshop on November 10, 2020, for Energy Trust to provide an initial look at the resulting avoided costs using the submitted data. In addition to Staff and Energy Trust staff, there were 24 attendees, representing all six utilities. There were also representatives from Northwest Power Conservation Council (NWPCC), Northwest Energy Efficiency Alliance, Northwest Energy Coalition, and Small Business Utility Advocates.

In the workshop, Staff requested that stakeholders consider these questions when reviewing the numbers:

- Are any of these numbers inconsistent with what you had submitted?
- Does anything stand out that you think Staff should investigate?
- Are there alternate numbers that Staff should give particular consideration to?

During the workshop, questions and comments on electric submissions were minimal. On the natural gas side, there was some discussion about the sources of end-use load shapes and the differences between utility submissions on avoided distribution costs. Following up on these discussions, Northwest Natural filed specific suggestions based on the conversations in the workshop and observations of the numbers presented.

Staff addresses Northwest Natural's comments as follows:

Peak Day Factors: Northwest Natural identified some errors in the numbers presented. These have been corrected.

Peak Hour Factors: Northwest Natural recommended that Staff review how the peak hour factors were being applied by end use. Staff discovered an inconsistency where for specific load shapes, Northwest Natural's end-use load shapes were used for the peak day, and NWPCC load shapes were used for the peak hour. Working with Energy Trust, this issue was addressed by determining the peak hour's share of the peak day in NWPCC load shape and applying it to the Northwest Natural peak day, essentially backing out the hourly shape for the peak day. NWPCC was involved in this discussion and assisted stakeholders with the load shape discussion.

Currently, Energy Trust uses Northwest Natural's load shapes for characterizing peak day contributions for commercial and residential space heating end-uses, but not for the purposes of characterizing contributions to the peak hour. Energy Trust could potentially use Northwest Natural's peak hour estimates for its natural gas modeling if this methodology is reviewed by third parties. Energy Trust will continue to identify and use the load shapes they deem most appropriate for their measures.

Distribution Capacity Costs: Northwest Natural notes there is a significant difference in estimates between utilities for distribution capacity costs and it is unlikely that the distribution capacity value is so much greater for Northwest Natural than other gas utilities. Staff agrees that this is unlikely. While Cascade's conceptual methodology was discussed in UM 1893 in 2019, and the numbers submitted in 2019 were accepted and applied, the difference in outcomes was not directly reconciled at the time. Energy Trust has confirmed that the numbers provided this year and last year were interpreted appropriately, and incorporated based on each utility's methods.

Staff expected these calculation methods to evolve, and agrees there could be an opportunity to create more consistent values. Staff will be reviewing and comparing these methodologies over the winter, and as a part of Staff's analysis of LC 76 (Cascade IRP). Staff will further discuss these approaches in UM 1893 in 2021.

Presenting Avoided Costs by End-Use: Northwest Natural recommends presenting avoided costs by end-use as presented last year during the data review workshop, and in the final avoided cost calculations, as a diagnostics tool during the data review. Staff agrees with this suggestion. Staff had intended to show these end-use-specific estimates in this memo, and overlooked the value as a diagnostic tool in the workshop. Staff will ensure end use estimates are presented in future data review workshops.

Blending Avoided Costs: Northwest Natural recommends providing utility-specific previews of avoided costs at the end-use level for diagnostic purposes before values are blended together. Staff is willing to consider the feasibility of providing utility-specific views next year. It may not be feasible given the timeframe for review, but Staff will work with Energy Trust to investigate this and other options.

Alternative Numbers for Consideration: Northwest Natural suggests the use of its alternate submission for environmental compliance costs, which reflects the social cost of carbon. Staff very much appreciates Northwest Natural's preparedness to engage on the implementation of social cost of carbon as stated in the Commission's EO 20-04 workplan.

During the November 10 workshop, Staff also proposed the following topics for discussion in UM 1893 during 2021: Incorporating social cost of carbon consistent with other activities in the Commission's workplan in response to EO 20-04, incorporating capacity decisions made in UM 2011, and discussing improvements to energy efficiency peak modeling. Distribution capacity values will be revisited in 2021.

Staff is also considering risk reduction values as a topic for 2021. On the electric side, risk reduction values are created from the output of the IRPs and are not normally reviewed in the IRP itself. Staff will be working on a review process for these values. Staff is also exploring opportunities to improve the overall review schedule for UM 1893. As Staff only has 60 days to review and gain Commission approval, the memo must go before the Commission before December 14 of each year. In some years, there are significantly fewer calendar days to complete this review process. Staff will consider options to improve the review process and stakeholder engagement within the constraints of this timing.

Section II. Data Recommendations

Staff reviewed the submitted utility data. For the most part, data came from the utilities' Integrated Resource Plans (IRPs). In situations where alternate sets of data were provided, Staff reviewed the alternate data to determine if the data had been reviewed previously by Staff in this docket or in other dockets. In cases where data had been reviewed and found reasonable, such as Cascade's updated inflation and discount rates, Staff recommends using the more recent alternate data.

In some cases, Staff also recommends applying certain data decisions specified in the past, rather than what has been submitted by the utilities. An example of this is the assumption that the deficiency start year is immediate, which is a placeholder until new direction is provided through UM 2011. These recommendations do not reflect inaccurate filings on the part of the utilities, but generally reflect past practices. These recommendations are separated by fuel type, starting with general decisions and then utility-specific recommendations. All final recommended values are attached as Attachment 1.

Electric Utility Data

In 2019, as an outcome of UM 1893, Energy Trust began applying the seasonal contribution of energy savings measures for generating capacity, transmission capacity, and distribution capacity. Generation, transmission, and distribution capacity values may experience different seasonal patterns for a given utility. Seasonal contributions to peak are simplified based on utility estimates to one of: 100 percent winter contribution, 100 percent summer contribution, or a 50/50 split between winter and summer.

PacifiCorp

PacifiCorp submitted values from its acknowledged 2019 IRP as the main submission. PacifiCorp also submitted alternate values for risk reduction calculations as an annual stream of values. Staff appreciates this information, and while there was not enough time to fully review this enhancement in order to recommend Commission approval, Staff will consider this option a later date as a potential update to the workbook. PacifiCorp also volunteered to submit 12x24 matrices for weighting of transmission and distribution for Energy Trust's use in peak identification.

Staff recommends accepting the main submission values with the exceptions described above to the seasonal split of capacity values (100 percent summer for generation and 50/50 split for transmission and distribution), and to the generating capacity deficiency year. Energy Trust has previously been directed to use a generation capacity deficiency start year as the first year values will be used (2022) based on the action plan to acquire wind resources for that year. Staff recommends continuing with this practice at this time, to be revisited when new direction is provided through the Generic Capacity Docket No. UM 2011. These recommendations result in updates to most numbers from PacifiCorp's 2017 IRP values to 2019 IRP values.

Portland General Electric (PGE)

Based on the review of electric utility data, PGE submitted values from its acknowledged 2019 IRP as the main submission. PGE also submitted alternate values for generation capacity credit that includes interconnection costs. The application of interconnection costs is being discussed in UM 2011 and Staff recommends that the Commission not approve the use of this new number. PGE also submitted forward market prices created with the models used in the 2019 IRP with some updated assumptions.

Staff recommends accepting the main submission values with the exceptions described above to the seasonal split of capacity values (50/50 split for generation, transmission, and distribution). These recommendations result in values staying the same as last year except for the risk reduction value, which was pending the final acknowledgement of the PGE 2019 IRP.

Natural Gas Utility Data

IRP modeling for natural gas utilities has undergone changes in recent years as new practices are being adopted over time. There are some cases where a utility has not calculated certain values in past IRPs. In these cases, Staff has directed Energy Trust to represent these values as a weighted average of values provided by other utilities. Staff points out where there are or were missing values and recommends using this practice unless otherwise noted.

Starting in 2019, this docket began to include distribution peak hour values. Utilities have provided estimates that were created through different methods. The approaches seemed reasonable at the time, but the outcomes were different, as well as how these numbers would be incorporated by Energy Trust.[1] Here is a summary of the two methods and how they were applied:

> Cascade's estimate of distribution capacity value was developed by applying a Cascade specific system-wide peak hour factor to their estimated annual distribution capacity [deferral] value. Energy Trust shaped that hourly value using the ratio of Cascade's system wide peak hour factor to the corresponding end-use peak hour factors utilized throughout the avoided cost calculations.
>
> Northwest Natural's estimate of distribution capacity value was represented as the cost of serving an additional dekatherm on a peak hour. Energy Trust then annualized that value and applied end-use specific peak hour factors to determine each end-use profile's coincidence on that peak hour.[2]

Once Energy Trust applied these numbers, they came out with significant differences:

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[1] Order No. 19-430 Appendix A p. 5.
[2] Order No. 19-430 Appendix A p. 35.

Distribution capacity value--hourly ($/Therm/year)	
Avista 2020--between IRPs	$2.46
Cascade 2019--between IRPs	$1.27
Northwest Natural 2018 IRP	$240.88

While Staff has worked to improve the clarity and transparency of the workbooks, and verified the numbers were being interpreted appropriately, this did not result in narrowing the gap between numbers. Before the next filing, Staff will compare these inputs across utilities and develop recommendations to improve the valuation of distribution capacity for energy efficiency avoided costs.

Avista
Avista submitted values from its acknowledged 2018 IRP as the main submission. The Company's next IRP will be filed in April 2021. Avista included alternate values that include a distribution capacity value and risk reduction value, which were not available in the 2018 IRP.

Based on the status of the 2021 IRP, Staff recommends accepting the main submission with exceptions for distribution capacity and risk reduction. Given the discussion in Section II on distribution capacity values, Staff proposes to continue applying a weighted average of Northwest Natural and Cascade's distribution capacity costs to represent Avista. The other utilities provided zero or negative values for risk reduction values. As negative values are represented as a zero value, Staff recommends Avista's risk reduction value be set to zero as well. These recommendations result in no change in values from last year and this year.

Cascade
Cascade submitted values from its acknowledged 2018 IRP as the main submission. Cascade also submitted alternate values from the 2020 IRP. Cascade filed the 2020 IRP in July 2020 and it has not yet been acknowledged, but Staff is in the process of reviewing values submitted through the 2020 IRP.

Based on the status of this IRP, Staff recommends accepting the main submission values with some exceptions:

- Alternate discount and inflation rates: These new values are already in use for calculating the weighted average cost of capital.
- Alternate distribution capacity costs: These numbers were implemented in last year's review.

- Weighted average of other utilities' environmental compliance costs: In the 2018 IRP, Staff had concerns about the application of these numbers and requested improvements in the 2020 IRP.[3] Cascade submitted new environmental compliance costs as applied in the 2020 IRP, but these are still under review.
- Weighted average of other utilities' commodity price forecasts: When Staff proposed to apply 2018 values to Cascade, Cascade expressed concerns about the age of the 2018 values and further argued that the critiques Staff is raising regarding the 2020 forecast also applies to the 2018 forecast. This combination of factors leads Staff to recommend using the weighted average of more recent numbers from the other utilities.

These recommendations result in updates to inflation, discount, and commodity prices.

Northwest Natural
Northwest Natural submitted values from its acknowledged 2018 IRP as the main submission. Northwest Natural also submitted alternate values that were developed for its next IRP, which they expect to file in 2022.

Staff recommends accepting the main submission values. As discussed in Section II, Staff appreciates the forethought in preparing new carbon values and providing this opportunity to review other calculations in advance. These recommendations result in no change in values from last year and this year. Note that the supply value appears to have increased, but that is due to a change in the time period.

Section III: 2020 Filing Results for 2022 Planning
To facilitate the review of data and provide a preview of the impacts of changes to energy efficiency avoided cost data, Energy Trust used the data recommended in this memo to produce generalized high level estimates on impacts for 2022 planning.

Electric costs for use in 2022 have changed only slightly by increasing about one percent overall from the costs in use for 2021. This resulted in projected single-digit impacts on different end uses, with positive or negative impacts depending on the measure.

Natural gas costs have overall increased moderately by roughly 11 percent. This is due to the changes to application of peak hour factors and removing Cascade's 2018 commodity prices, and replacing it with a blend of the other utilities. This resulted in a

[3] See In the Matter of CASCADE NATURAL GAS CORPORATION, 2018 Integrated Resource Plan. Order No. 18-279 Appendix p. 7-8.

projected range of increases across different end uses ranging from minimal to 15 percent, with mostly positive impacts on the bulk of measures.

Please see Attachment 2 and Attachment 3 for more details.

<u>Conclusion</u>

Based on this analysis, Staff believes the attached data are ready for Commission approval and for use by Energy Trust in planning for 2022 activities and for the preparation for the 2022 budget.

PROPOSED COMMISSION MOTION:

Approve the attached energy efficiency avoided cost data for use by Energy Trust.

REG2 UM 1893

Data References

Original submissions and source documentation can be found in the following dockets

Utility	**Report Docket**	**Submission set (main or alternate) unless otherwise specified**
PacifiCorp	RE 181	Main submission and T&D 12x24
PGE	RE 182	Main submission
Avista	RG 85	Main submission and alternate risk reduction value
Cascade	RG 86	Main submission and alternates for inflation, discount rate, and distribution capacity
Northwest Natural	RG 87	Main submission

Global Assumptions Electric

Avoided Cost Element	Units	PacifiCorp Value	PacifiCorp Dollar Year	PGE Value	PGE Dollar Year
Inflation Rate	Percent	2.28%	N/A	2.05%	N/A
Real Discount Rate	Percent	4.54%	N/A	4.41%	N/A
Regional Act Credit	Percent	10.00%	N/A	10.00%	N/A
Transmission Loss Factor	Percent	3.50%	N/A	1.90%	N/A
Distribution Loss Factor, Commercial	Percent	3.69%	N/A	4.15%	N/A
Distribution Loss Factor, Industrial	Percent	3.20%	N/A	1.45%	N/A
Distribution Loss Factor, Residential	Percent	4.46%	N/A	4.74%	N/A
Risk Reduction Value	$/MWh	*$4.02*	2018	$3.00	2020
Transmission Deferral Credit	$/kW-yr	$4.16	2018	$9.38	2019
Seasonal Capacity Split - Summer	Percent	50%*	N/A	50%*	N/A
Seasonal Capacity Split - Winter	Percent	50%*	N/A	50%*	N/A
Summer Peak Period Definition	Month/Day/Hour	Trans. 12x24 profile	N/A	N/A	N/A
Winter Peak Period Definition	Month/Day/Hour	Trans. 12x24 profile	N/A	N/A	N/A
Deficiency start year	Year	2018	N/A	2022	N/A
Distribution Deferral Credit	$/kW-yr	$9.20	2018	$24.39	2019
Seasonal Capacity Split - Summer	Percent	50%*	N/A	50%*	N/A
Seasonal Capacity Split - Winter	Percent	50%*	N/A	50%*	N/A
Summer Peak Period Definition	Month/Day/Hour	Dist. 12x24 profile	N/A	N/A	N/A
Winter Peak Period Definition	Month/Day/Hour	Dist. 12x24 profile	N/A	N/A	N/A
Deficiency start year	Year	2018	N/A	2022	N/A
Generation Capacity Credit	$/kW-yr	$83.76	2018	$103.33	2020
Seasonal Capacity Split - Summer	Percent	100%*	N/A	50%*	N/A
Seasonal Capacity Split - Winter	Percent	0%*	N/A	50%*	N/A
Deficiency start year	Year	2021*	N/A	2022	N/A

* Denotes numbers specified by Staff

Forward Market Prices Electric

Date	PacifiCorp HLH Total ($/MWh)	PacifiCorp LLH Total ($/MWh)
1/1/2021	31.40	25.25
2/1/2021	27.14	23.62
3/1/2021	23.52	20.29
4/1/2021	21.23	14.58
5/1/2021	20.39	12.43
6/1/2021	20.50	12.10
7/1/2021	43.51	24.66
8/1/2021	47.72	29.30
9/1/2021	43.40	28.22
10/1/2021	24.02	22.98
11/1/2021	27.87	24.55
12/1/2021	30.93	26.45
1/1/2022	34.22	27.69
2/1/2022	31.81	27.30
3/1/2022	28.49	23.70
4/1/2022	26.80	21.04
5/1/2022	24.88	17.63
6/1/2022	23.35	14.20
7/1/2022	44.92	27.49
8/1/2022	49.94	32.36
9/1/2022	45.74	32.49
10/1/2022	29.44	26.76
11/1/2022	32.00	27.94
12/1/2022	33.68	29.68
1/1/2023	36.82	29.76
2/1/2023	36.44	30.48
3/1/2023	33.08	26.80
4/1/2023	32.57	29.76
5/1/2023	29.18	22.83
6/1/2023	26.37	17.26
7/1/2023	46.58	29.82
8/1/2023	51.92	34.76
9/1/2023	47.76	34.01
10/1/2023	34.98	30.53
11/1/2023	36.32	32.50
12/1/2023	38.31	32.96
1/1/2024	41.90	33.70
2/1/2024	41.08	32.78
'	'	'
'	'	'
'	'	'
12/1/2070	199.49	152.26

Note: Annual will be shaped to existing monthly shapes

Year	PGE HLH Total ($/MWh)	PGE LLH Total ($/MWh)
2021	$ 25.18	$ 23.32
2022	$ 26.17	$ 24.19
2023	$ 28.37	$ 26.16
2024	$ 32.03	$ 29.87
2025	$ 37.26	$ 34.85
2026	$ 40.17	$ 37.96
2027	$ 43.23	$ 41.57
2028	$ 46.92	$ 44.46
2029	$ 52.26	$ 49.90
2030	$ 56.40	$ 53.88
2031	$ 59.62	$ 56.83
2032	$ 61.70	$ 59.26
2033	$ 67.08	$ 64.61
2034	$ 69.56	$ 67.30
2035	$ 72.12	$ 70.08
2036	$ 73.74	$ 70.34
2037	$ 76.75	$ 74.18
2038	$ 78.41	$ 75.58
2039	$ 82.75	$ 79.63
2040	$ 84.93	$ 81.90
2041	$ 87.69	$ 85.35
2042	$ 88.79	$ 86.36
2043	$ 91.51	$ 88.70
2044	$ 92.28	$ 89.03
2045	$ 95.25	$ 92.61
2046	$ 96.48	$ 93.83
2047	$ 99.45	$ 95.71
2048	$ 99.44	$ 97.38
2049	$ 103.25	$ 101.08
2050	$ 104.93	$ 101.18

Loss of Load Probability Heat Map Input Electric

PacifiCorp

WEEKDAYS & WEEKENDS

Hr Ending	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
14	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01
15	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.03
16	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01
17	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01
18	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.08
19	0.01	0.00	0.00	0.00	0.00	0.01	0.05	0.17
20	0.01	0.00	0.00	0.00	0.00	0.01	0.09	0.17
21	0.00	0.00	0.00	0.00	0.00	0.00	0.06	0.11
22	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00
23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Note: This information is provided to Energy Trust to identify peak definitions.

PGE

WEEKDAYS & WEEKENDS

Hr Ending	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Supplemental T&D information provided by PacifiCorp

Distribution 12x24 Weighting Dist. 12x24 profile

Hour

Season	Monthly Weight	Montl	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21
Winter	21%	1	0%	0%	0%	0%	0%	0%	6%	###	3%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Winter	7%	2	0%	0%	0%	0%	0%	0%	2%	4%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Winter	0%	3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Summer	0%	4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Summer	0%	5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Summer	5%	6	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	1%	1%	0%	0%
Summer	37%	7	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%	8%	###	###	7%	0%	0%
Summer	15%	8	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	3%	4%	4%	3%	0%	0%
Summer	0%	9	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Summer	0%	10	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Winter	3%	11	0%	0%	0%	0%	0%	0%	1%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Winter	13%	12	0%	0%	0%	0%	0%	0%	4%	7%	2%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

Transmission 12x24 Weighting Trans. 12x24 profile

Hour

Season	Monthly Weight	Montl	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21
Winter	25%	1	0%	0%	0%	0%	0%	0%	0%	9%	###	6%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Winter	8%	2	0%	0%	0%	0%	0%	0%	0%	6%	2%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Winter	0%	3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Summer	0%	4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Summer	0%	5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Summer	1%	6	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Summer	37%	7	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%	7%	###	###	4%	0%	0%	0%
Summer	11%	8	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%	5%	4%	1%	0%	0%	0%
Summer	0%	9	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Summer	0%	10	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Winter	3%	11	0%	0%	0%	0%	0%	0%	0%	2%	1%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Winter	15%	12	0%	0%	0%	0%	0%	0%	0%	3%	4%	1%	0%	0%	0%	0%	0%	2%	3%	2%	0%	0%	0%

Note: This information is provided to Energy Trust to identify peak definitions.

Global Assumptions Natural Gas

		Avista	Cascade	Northwest Natural
Avoided Cost Element	**Units**	**Value**	**Value**	**Value**
Discount Rate (Company's Real after-tax weighted average cost of capital (WACC)	Percent	4.45%	7.33%*	4.91%
Inflation Rate	Percent	2.00%	3.68% *	1.96%
Regional Act Credit	Percent	10.00%	10.00%	10.00%
Forecast Period Calendar Start Year	Year	2017	2020	2018
Real Dollar Base Year	Year	2016	2017	2017
System Peak Definition	Calendar Month/Day/Hour	February 15th & December 20th	Day	Day
System Peak Coincident Day Factor (if needed)	Peak Day/Annual Load Ratio	0	Peak Day	
System Peak Coincident Hour Factor (if needed)	Peak Hour/Annual Load Ratio	0	N/A	

* Alternate submissions

Avista

Gas Commodity and Transportation/Storage Costs (Nominal $/Dth)

Year	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV
2017	-$2.17	-$2.41	-$1.32	-$1.42	-$1.39	-$1.39	-$1.43	-$1.43	-$1.40	-$1.53	-$2.09
2018	-$2.17	-$2.08	-$1.86	-$1.56	-$1.55	-$1.62	-$1.69	-$1.69	-$1.62	-$1.67	-$1.87
2019	-$2.30	-$2.21	-$1.99	-$1.75	-$1.75	-$1.76	-$1.80	-$1.83	-$1.79	-$1.88	-$2.02
2020	-$3.32	-$3.29	-$3.16	-$2.92	-$2.91	-$2.94	-$3.01	-$3.03	-$2.96	-$3.03	-$2.08
2021	-$3.56	-$3.59	-$3.49	-$3.22	-$3.23	-$3.22	-$3.27	-$3.29	-$3.30	-$3.35	-$3.31
2022	-$3.78	-$3.76	-$3.68	-$3.42	-$3.47	-$3.49	-$3.50	-$3.56	-$3.55	-$3.59	-$3.53
2023	-$4.23	-$4.23	-$4.18	-$4.00	-$4.00	-$3.97	-$4.09	-$4.18	-$4.16	-$4.24	-$3.95
2024	-$4.57	-$4.58	-$4.44	-$4.29	-$4.31	-$4.38	-$4.44	-$4.47	-$4.42	-$4.45	-$4.40
2025	-$4.77	-$4.75	-$4.60	-$4.47	-$4.51	-$4.59	-$4.68	-$4.70	-$4.64	-$4.69	-$4.54
2026	-$5.06	-$5.05	-$4.96	-$4.85	-$4.83	-$4.92	-$5.02	-$5.05	-$4.99	-$5.05	-$4.79
2027	-$5.53	-$5.44	-$5.36	-$5.28	-$5.27	-$5.39	-$5.46	-$5.51	-$5.40	-$5.43	-$5.22
2028	-$5.96	-$5.92	-$5.79	-$5.70	-$5.71	-$5.73	-$5.83	-$5.86	-$5.79	-$5.87	-$5.64
2029	-$6.41	-$6.35	-$6.17	-$6.08	-$6.11	-$6.15	-$6.26	-$6.30	-$6.24	-$6.30	-$6.07
2030	-$6.73	-$6.70	-$6.54	-$6.38	-$6.43	-$6.48	-$6.63	-$6.67	-$6.60	-$6.62	-$6.41
2031	-$7.01	-$6.94	-$6.80	-$6.65	-$6.68	-$6.73	-$6.86	-$6.92	-$6.86	-$6.94	-$6.74
2032	-$7.40	-$7.38	-$7.22	-$7.07	-$7.08	-$7.12	-$7.31	-$7.34	-$7.26	-$7.27	-$7.06
2033	-$7.74	-$7.75	-$7.54	-$7.39	-$7.40	-$7.47	-$7.65	-$7.67	-$7.56	-$7.63	-$7.44
2034	-$8.15	-$8.12	-$7.95	-$7.81	-$7.76	-$7.83	-$7.99	-$8.05	-$7.94	-$7.89	-$7.80
2035	-$8.69	-$8.46	-$8.29	-$8.12	-$8.13	-$8.26	-$8.57	-$8.68	-$8.48	-$8.49	-$7.96
2036	-$9.36	-$9.12	-$8.82	-$8.39	-$8.40	-$8.50	-$8.79	-$8.88	-$8.61	-$8.62	-$8.68

* These values will be applied as positive values.

Cascade

Gas Commodity and Transportation/Storage Costs (Real 2017$/Dth)

Note: Cascade's commodity values will be calculated as a weighted average of the other utilities.

Northwest Natural

Gas Commodity and Transportation/Storage Costs (Real 2017$/Dth)

Year	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV
2017	$2.96	$2.97	$2.75	$2.41	$2.36	$2.36	$2.37	$2.38	$2.39	$2.42	$2.88
2018	$3.10	$3.12	$2.73	$2.28	$2.27	$2.27	$2.31	$2.32	$2.33	$2.40	$3.01
2019	$3.18	$3.19	$2.71	$2.14	$2.11	$2.11	$2.14	$2.15	$2.17	$2.21	$3.05
2020	$3.09	$3.10	$2.80	$2.29	$2.21	$2.22	$2.22	$2.23	$2.24	$2.31	$2.94
2021	$3.06	$3.07	$2.87	$2.41	$2.37	$2.38	$2.39	$2.40	$2.41	$2.49	$3.05
2022	$3.16	$3.17	$3.03	$2.60	$2.57	$2.58	$2.59	$2.60	$2.61	$2.69	$3.25
2023	$3.36	$3.37	$3.26	$2.99	$2.99	$3.01	$3.02	$3.04	$3.06	$3.11	$3.51
2024	$3.57	$3.58	$3.41	$3.04	$3.01	$3.02	$3.04	$3.05	$3.06	$3.12	$3.39
2025	$3.46	$3.49	$3.31	$3.03	$3.02	$3.03	$3.04	$3.06	$3.08	$3.12	$3.32
2026	$3.42	$3.44	$3.28	$3.06	$3.06	$3.07	$3.09	$3.11	$3.14	$3.18	$3.51
2027	$3.62	$3.64	$3.45	$3.16	$3.14	$3.15	$3.19	$3.20	$3.23	$3.26	$3.51
2028	$3.66	$3.69	$3.52	$3.32	$3.30	$3.33	$3.36	$3.38	$3.40	$3.45	$3.71
2029	$3.86	$3.88	$3.72	$3.46	$3.43	$3.46	$3.50	$3.52	$3.54	$3.59	$3.84
2030	$3.97	$4.00	$3.80	$3.54	$3.52	$3.55	$3.59	$3.60	$3.63	$3.68	$3.92
2031	$4.05	$4.08	$3.85	$3.56	$3.54	$3.59	$3.61	$3.63	$3.66	$3.71	$3.99
2032	$4.17	$4.19	$3.93	$3.70	$3.65	$3.68	$3.75	$3.76	$3.79	$3.82	$4.04

Environmental Compliance Natural Gas

	Avista			Northwest Natural		
Year	Environmental Compliance Cost ($/MTCO2e)	Carbon Intesity (MTCO2e/Dth)	Environmental Compliance Cost ($/Dth)	Environmental Compliance Cost (Real 2017$/MTCO2e)	Carbon Intesity (MTCO2e/ Dth)	Environmental Compliance Cost (Real 2017$/Dth)
2018	$15.57	0.0531	$0.827	$0.00	0.0531	$0.000
2019	$16.67	0.0531	$0.885	$0.00	0.0531	$0.000
2020	$17.86	0.0531	$0.948	$0.00	0.0531	$0.000
2021	$19.11	0.0531	$1.015	$17.64	0.0531	$0.936
2022	$20.44	0.0531	$1.085	$18.62	0.0531	$0.988
2023	$21.86	0.0531	$1.160	$19.65	0.0531	$1.043
2024	$23.36	0.0531	$1.240	$20.73	0.0531	$1.100
2025	$24.98	0.0531	$1.326	$21.88	0.0531	$1.161
2026	$26.70	0.0531	$1.418	$23.09	0.0531	$1.225
2027	$28.57	0.0531	$1.517	$24.37	0.0531	$1.293
2028	$30.58	0.0531	$1.623	$25.71	0.0531	$1.365
2029	$32.72	0.0531	$1.737	$27.14	0.0531	$1.440
2030	$35.02	0.0531	$1.859	$28.64	0.0531	$1.520
2031	$37.48	0.0531	$1.989	$30.22	0.0531	$1.604
2032	$40.10	0.0531	$2.129	$31.89	0.0531	$1.693
2033	$42.91	0.0531	$2.278	$33.66	0.0531	$1.786
2034	$45.91	0.0531	$2.437	$35.52	0.0531	$1.885
2035	$48.66	0.0531	$2.583	$37.48	0.0531	$1.989
2036	$51.58	0.0531	$2.738	$39.55	0.0531	$2.099
2037				$41.74	0.0531	$2.215
2038				$44.05	0.0531	$2.338

Note: Cascade's environmental compliance values will be calculated as a weighted average of the other utilities.

Infrastructure Costs Natural Gas

	Avista	Cascade			Northwest Natural		
Year	Supply (Nominal $/Dth/Day)*	Supply (Real 2017$/ Dth/Day)	Distribution Peak DAY (Real 2017$/ Dth/Day)**	Distribution Peak HOUR (Real 2017$/ Dth/Hour)**	Supply (Real 2017$/ Dth/Day)	Distribution Peak DAY (Real 2017$/ Dth/Day)	Distribution Peak HOUR (Real 2017$/ Dth/Hour)
2020	-$0.002	$1.072	$0.119	$0.006	$0.057	N/A	$0.254
2021	-$0.002	$1.072	$0.127	$0.007	$0.057	N/A	$0.254
2022	-$0.002	$1.072	$0.130	$0.007	$0.057	N/A	$0.254
2023	-$0.002	$1.072	$0.121	$0.006	$0.057	N/A	$0.254
2024	-$0.002	$1.072	$0.141	$0.007	$0.057	N/A	$0.254
2025	-$0.002	$1.072	$0.126	$0.006	$0.057	N/A	$0.254
2026	-$0.002	$1.072	$0.126	$0.006	$0.057	N/A	$0.254
2027	-$0.002	$1.072	$0.128	$0.007	$0.057	N/A	$0.254
2028	-$0.002	$1.072	$0.128	$0.007	$0.057	N/A	$0.254
2029	-$0.002	$1.072	$0.129	$0.007	$0.057	N/A	$0.254
2030	-$0.002	$1.072	$0.129	$0.007	$0.057	N/A	$0.254
2031	-$0.002	$1.072	$0.128	$0.007	$0.518	N/A	$0.254
2032	-$0.002	$1.072	$0.128	$0.007	$0.518	N/A	$0.254
2033	-$0.003	$1.072	$0.130	$0.007	$0.518	N/A	$0.254
2034	-$0.003	$1.072	$0.130	$0.007	$0.518	N/A	$0.254
2035	-$0.003	$1.072	$0.131	$0.007	$0.518	N/A	$0.254
2036	-$0.002	$1.072	$0.131	$0.007	$0.514	N/A	$0.254
2037		$1.072	$0.129	$0.007	$0.514	N/A	$0.254
2038		$1.072	$0.131	$0.007	$0.514	N/A	$0.254
2039		$1.072	$0.132	$0.007	$0.514	N/A	$0.254
2040		$1.072	$0.131	$0.007	$0.514	N/A	$0.254

* These values will be applied as positive values.

** Alternate submissions

Note: Avista's distribution values will be calculated as a weighted average of the other utilities.

Risk Reduction Value Natural Gas

	Avista	Cascade	Northwest Natural
Year	Risk Reduction Value ($/Dth)	Risk Reduction Value (Real 2017$/Dth)*	Risk Reduction Value (Real 2017$/Dth)
2018			-$0.005
2019			-$0.310
2020		-$0.159	-$0.245
2021	$0.000	-$0.139	-$0.260
2022	$0.000	-$0.108	-$0.338
2023	$0.000	-$0.067	-$0.553
2024	$0.000	-$0.104	-$0.935
2025	$0.000	-$0.245	-$1.001
2026	$0.000	-$0.301	-$0.967
2027	$0.000	-$0.221	-$1.047
2028	$0.000	-$0.109	-$1.164
2029	$0.000	-$0.078	-$1.388
2030	$0.000	-$0.105	-$1.544
2031	$0.000	-$0.069	-$1.659
2032	$0.000	$0.000	-$1.679
2033	$0.000	-$0.001	-$1.798
2034	$0.000	-$0.016	-$1.880
2035	$0.000	-$0.030	-$1.926
2036	$0.000	-$0.057	-$2.084
2037	$0.000	-$0.141	-$2.131
2038	$0.000	-$0.459	
2039	$0.000	-$0.304	
2040	$0.000		

* Alternate submission
Note: Negative values will be applied as zero.

End Use Load Profiles Natural Gas

Avista

Sector	End Use	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	mor
		Monthly Share of Normal Weather Annual Load												
Commercial	New Building Construction	0.0293	0.0333	0.0421	0.0601	0.1051	0.1537	0.1592	0.1581	0.1478	0.0690	0.0399	0.0256	4
Commercial	Retrofit	0.0304	0.0345	0.0436	0.0622	0.1088	0.1591	0.1648	0.1636	0.1529	0.0714	0.0413	0.0265	4
Commercial	Replacement on Burnout	0.0101	0.0114	0.0145	0.0206	0.0361	0.0528	0.0546	0.0543	0.0507	0.0237	0.0137	0.0088	1
Commercial	Strategic Energy Management	0.0041	0.0047	0.0059	0.0084	0.0147	0.0215	0.0222	0.0221	0.0206	0.0096	0.0056	0.0036	0
Industrial	Retrofit	0.0038	0.0043	0.0054	0.0078	0.0136	0.0199	0.0206	0.0205	0.0191	0.0089	0.0052	0.0033	5
Industrial	Replacement on Burnout	0.0007	0.0008	0.0010	0.0014	0.0024	0.0036	0.0037	0.0037	0.0034	0.0016	0.0009	0.0006	1
Residential	New Home Construction	0.0649	0.0737	0.0931	0.1329	0.2326	0.3401	0.3523	0.3499	0.3269	0.1526	0.0884	0.0566	9
Residential	Retrofit	0.0252	0.0286	0.0361	0.0516	0.0902	0.1319	0.1366	0.1357	0.1268	0.0592	0.0343	0.0219	3
Residential	Replacement on Burnout	0.0113	0.0129	0.0163	0.0232	0.0406	0.0594	0.0615	0.0611	0.0571	0.0266	0.0154	0.0099	1
Residential	Smart Thermostat	0.0180	0.0205	0.0258	0.0369	0.0645	0.0943	0.0977	0.0970	0.0907	0.0423	0.0245	0.0157	2
Other	Mega-Project Adder	0.0164	0.0186	0.0235	0.0336	0.0587	0.0859	0.0890	0.0883	0.0826	0.0385	0.0223	0.0143	2
20 years (2017 - 2037) avg, by month, normal weather		1495970	1316770	1042250	730500	417320	285450	275600	277500	296980	636380	1098840	1716190	

Average per month of 20 years of EE vs. normal weather annual load. Peak day in for Oregon territories only for the upcoming winter season (2020-2021). Peak hour

Cascade

End Use	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	Monthly Share of Normal Weather Annual Load											
All	0.154	0.126	0.107	0.072	0.05	0.036	0.03	0.031	0.041	0.071	0.119	0.162

* Alternate submission

Northwest Natural

End Use	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	Monthly Share of Normal Weather Annual Load											
Residential Space Heating	0.204	0.145	0.123	0.070	0.033	0.006	0.000	0.001	0.008	0.062	0.129	0.218
Residential Hearths and Fireplaces	0.204	0.145	0.123	0.070	0.033	0.006	0.000	0.001	0.008	0.062	0.129	0.218
Commercial Space Heating	0.204	0.145	0.123	0.070	0.033	0.006	0.000	0.001	0.008	0.062	0.129	0.218
Water Heating	0.101	0.096	0.092	0.088	0.083	0.079	0.073	0.068	0.069	0.073	0.081	0.095
Cooking	0.083	0.083	0.083	0.083	0.083	0.083	0.083	0.083	0.083	0.083	0.083	0.083
Process Load	0.083	0.083	0.083	0.083	0.083	0.083	0.083	0.083	0.083	0.083	0.083	0.083

Memo

EnergyTrust of Oregon

To: Anna Kim, Oregon PUC

From: Ben Cartwright, Energy Trust of Oregon

Date: November 23, 2020

Re: Final 2022 Electric Avoided Cost Update Summary

This memo provides a summary of the updates to Energy Trust's Final 2022 Electric Avoided Cost buildup, including an overview of the utility inputs provided, a discussion of the results, and a comparison of the final updated blended values to current 2021 Avoided Cost values.

Utility Provided Inputs and PUC Direction

Pursuant to AR 621, each funding utility provides Energy Trust with Avoided Cost inputs for use in the Energy Trust Final 2022 Blended Avoided Costs. Each utility provides the individual components in Table 1 below from the most recently acknowledged IRP (IRP Column) and an optional additional input for the OPUC to consider (Alternative Column). Table 1 shows the values currently utilized in 2021 Avoided Costs, the inputs provided by each electric utility from their most recently acknowledged IRPs, and alternative submissions for consideration in 2022 Avoided Costs. The last column for each utility identifies the direction from OPUC staff as to which of the various submittals Energy Trust should incorporate into the final 2022 Avoided Costs; these values are also highlighted in gold.

Table 1. Utility Inputs Pursuant to AR 621 for use in the Final Energy Trust 2022 Blended Avoided Costs

		Pacific Power				Portland General Electric			
	Avoided Cost Element	PAC Current (2021 AC)	PAC 2019 IRP Submission	PAC Alternative Submission	Final Inputs for 2021 Avoided Cost	PGE Current (2021 AC)	PGE 2019 IRP Submission	PGE Alternative Submission	Final Inputs for 2021 Avoided Cost
Global Assumptions	Inflation Rate	2.22%	2.28%	N/A	IRP	2.05%	2.05%	2.05%	IRP
	Real Discount Rate	4.26%	4.54%	N/A	IRP	4.41%	4.41%	4.41%	IRP
	Regional Act Credit	10.00%	10.00%	N/A	IRP	10.00%	10.00%	10.00%	IRP
T&D Line Losses	Transmission Loss Factor	4.53%	3.50%	N/A	IRP	1.90%	1.90%	1.90%	IRP
	Distribution Loss Factor, Commercial	5.06%	3.69%	N/A	IRP	4.15%	4.15%	4.15%	IRP
	Distribution Loss Factor, Industrial	2.59%	3.20%	N/A	IRP	1.45%	1.45%	1.45%	IRP
	Distribution Loss Factor, Residential	5.48%	4.46%	N/A	IRP	4.74%	4.74%	4.74%	IRP
Transmission Capacity Value	Transmission Deferral Credit	$5.94	$4.16	N/A	IRP	$9.38	$9.38	$9.38	IRP
	Seasonal Capacity Split - Summer	50%	48%	N/A	Current	50%	0%	50%	Current
	Seasonal Capacity Split - Winter	50%	52%	N/A	Current	50%	100%	50%	Current
	Deficiency start year	2021	2018	N/A	IRP	2021	2022	2022	IRP
Distribution Capacity Value	Distribution Deferral Credit	$7.63	$9.20	N/A	IRP	$24.39	$24.39	$24.39	IRP
	Seasonal Capacity Split - Summer	50%	57%	N/A	Current	50%	0%	50%	Current
	Seasonal Capacity Split - Winter	50%	43%	N/A	Current	50%	100%	50%	Current
	Deficiency start year	2021	2018	N/A	IRP	2021	2022	2022	IRP
Generation Capacity Value	Generation Capacity Credit	$82.38	$83.76	N/A	IRP	$103.33	$103.33	$106.58	IRP
	Seasonal Capacity Split - Summer	100.0%	92%	N/A	Current	50.0%	50%	50%	Current
	Seasonal Capacity Split - Winter	0.0%	8%	N/A	Current	50.0%	50%	50%	Current
	Deficiency start year	2021	2026	N/A	Current	2022	2022	2022	IRP
Other Values	Risk Reduction Value	$4.33	$4.02	N/A	IRP	$4.78	$3.00	$3.00	IRP
	Forward Market Prices	See Graph for Comparison			IRP	See Graph for Comparison			IRP

Energy Trust took these inputs and blended them into electric Avoided Cost values that can be used throughout Energy Trust territory. The blended values are weighted averages where the weighting is based on forecasted 2022 electric utility expenditures from Energy Trust's 2021-2022 budget.

Some additional notes on Table 1:
1) The values provided in this table are in the dollar years provided by the utility. These values will be inflated to 2022$ for use in the 2022 Avoided Costs.
2) The PacifiCorp seasonal capacity split values for Transmission and Distribution are labeled as 'Current' because the OPUC advised using a simple 50/50 split for 2021 Avoided Costs. This 50/50 split overrode the actual updated values provided by PacifiCorp and were used again for 2022.
3) PacifiCorp did not provide alternative values for 2022 Avoided Costs.
4) PacifiCorp's Deficiency Start year values in the table precede 2022 (first year value) and as a result, 2022 Avoided Cost calculations assume that PacifiCorp's Deficiency start year is 2022.

Table 2 below provides a comparison of the blended 2021 Avoided Cost Component Values to the updated final 2022 Avoided Cost Component values and their percent change from 2021.

Table 2: Comparison of Component Values from 2021 Avoided Costs to the blended Final 2022 Avoided Costs Values

Avoided Cost Component	2022 AC (Updated) Blended Value	2021 Blended Value	Percent Change
Inflation Rate	2.14%	2.12%	1.22%
Real Discount Rate	4.50%	4.50%	0.00%
Northwest Power Act 10% Credit	10.00%	10.00%	0.00%
Risk Reduction Value ($/MWh) ($ 2022)	$3.63	$5.14	-29.32%
Transmission Loss Factor	2.95%	3.00%	-1.78%
Transmission Loss Credit ($/kW-yr.) ($ 2022)	$7.80	$8.61	-9.40%
Distribution Loss Factor, Commercial	3.96%	4.50%	-11.97%
Distribution Loss Factor, Industrial	2.15%	1.89%	13.47%
Distribution Loss Factor, Residential	4.63%	5.03%	-7.95%
Distribution Credit ($/kW-yr.) ($ 2022)	$19.58	$19.07	2.69%
Generation Deferral Credit ($/kW-yr.) ($ 2022)	$101.23	$100.73	0.50%
Forward Market Prices	Varies	Varies	NA

Final Results Summary

Once the updated values provided by Electric Utilities were blended, Energy Trust compared each of the 318 electric load shapes updated in the 2022 Avoided Costs to the current 2021 iteration of Avoided Costs and compared the overall impact of the changes based on end use load profiles from the Energy Trust measure mix from 2019 and 2020 YTD. **Overall, final 2022 electric Avoided Costs increased slightly with overall increases of ~1.4 percent or $0.011/kWh** compared to current 2021 Avoided Costs, when weighted by the 2019 and 2020 YTD savings achievements with overall weighted average Avoided Cost values going from $0.803/kWh in 2021 to $0.814/kWh in 2022**.**

On an end use per load shape basis, the contribution of each individual Avoided Cost component is different depending on how much that load shape contributes to peak savings. To help illustrate the overall impact of the changes to each component, Energy Trust developed a weighted average $/kWh change of each component of the Avoided Cost stack based on the Energy Trust measure mix from 2019 and 2020 YTD. Figure 1 below shows how the individual components contributed to the modest 1.4 percent increase (changes below total to 100% of the observed weighted average $0.011/kWh change). This shows that the increase in forward prices is the largest driver of the increase in Avoided Costs and that the significant decrease in risk reduction value offsets a large portion of the impacts of increased forward prices.

Figure 1. Contribution of Each Component to Overall Weighted Average Avoided Cost Changes

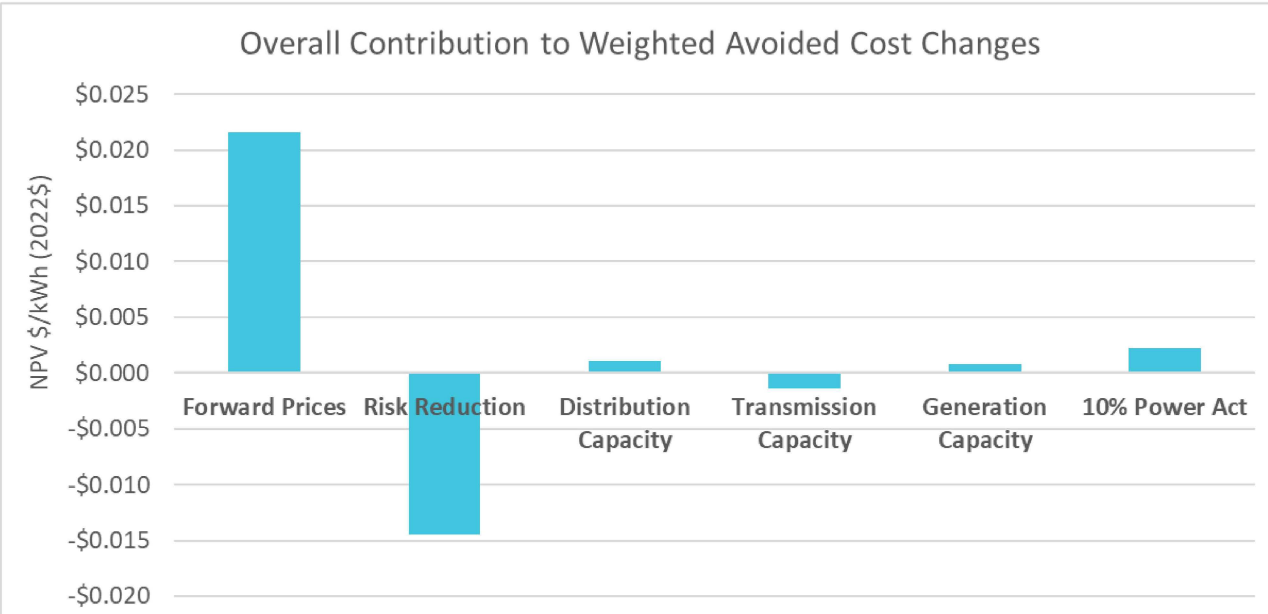
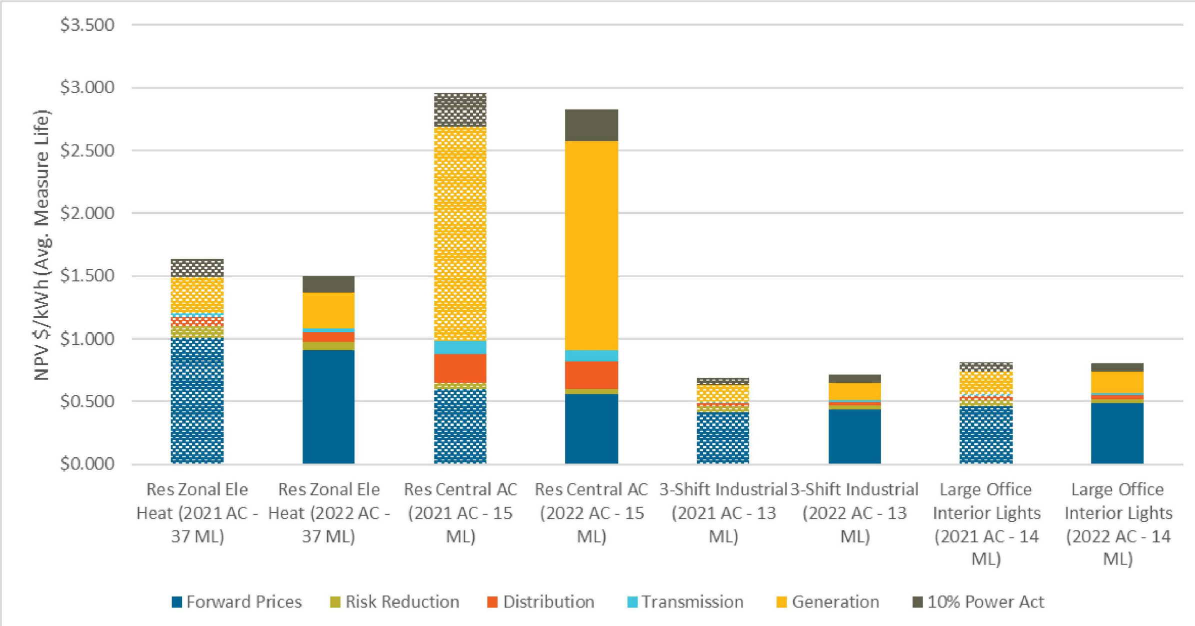


Figure 2 below also illustrates the impact of the individual component parts of both the 2022 and 2021 Avoided Costs based on a sample of end use load profiles. The following load shapes do not necessarily represent load shapes that make up a large portion of Energy Trust's portfolio.

Figure 2. Comparison of Load Shape Value by Component



The next section of this memo details the changes to each component of the Avoided Costs update.

Final 2022 Electric Avoided Cost Component Changes and Impacts

Forward Market Prices

On average Heavy Load Hours price comparison went down in 2022 compared to 2021 as reflected in Figures 3 and 4. However, the overall impact of updated forward market prices is an increase of about 5% compared to 2021 Avoided Cost inputs based on the Energy Trust measure mix from 2019 and 2020 YTD. As seen in Figure 3, this outcome is attributed to a relative increase in winter pricing which coincides to a 2019 and 2020 measure mix which consists of a heavy composition of heating measures. Figure 4 shows average monthly prices for each year over the 20-year planning horizon. However, as indicated above, the increase in prices for a few winter months each year coincide with the heavy mix of winter heating measures which ultimately lead to a net 5% increase when these measure mixes are factored in.

Figure 3. Blended Forward Price Comparison - Heavy Load Hours

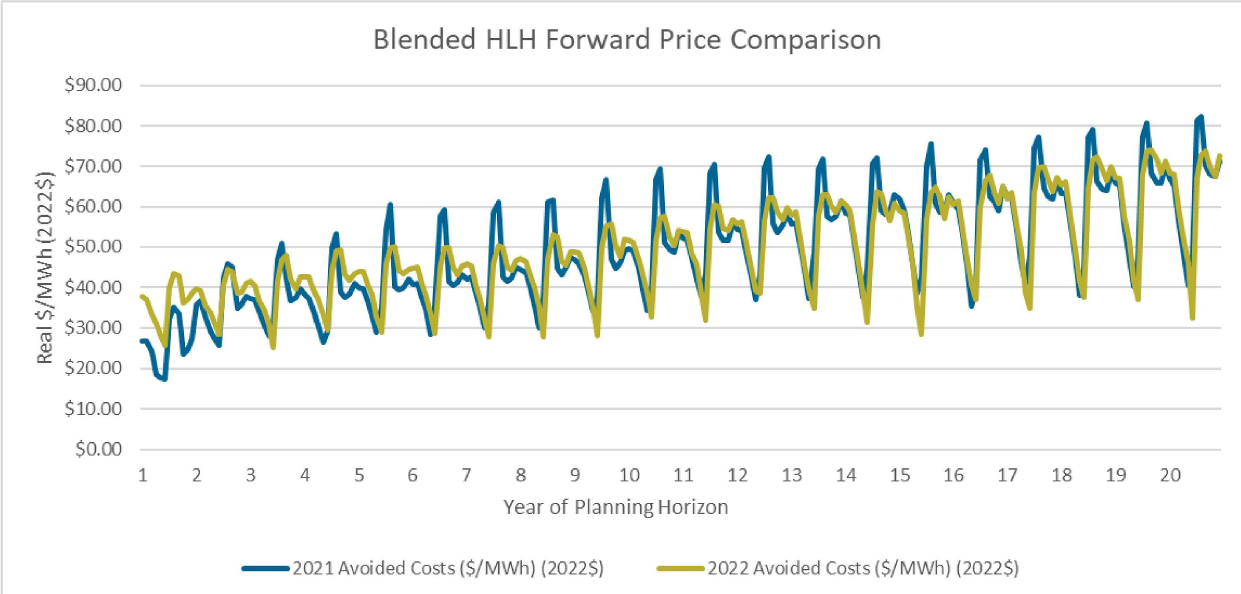
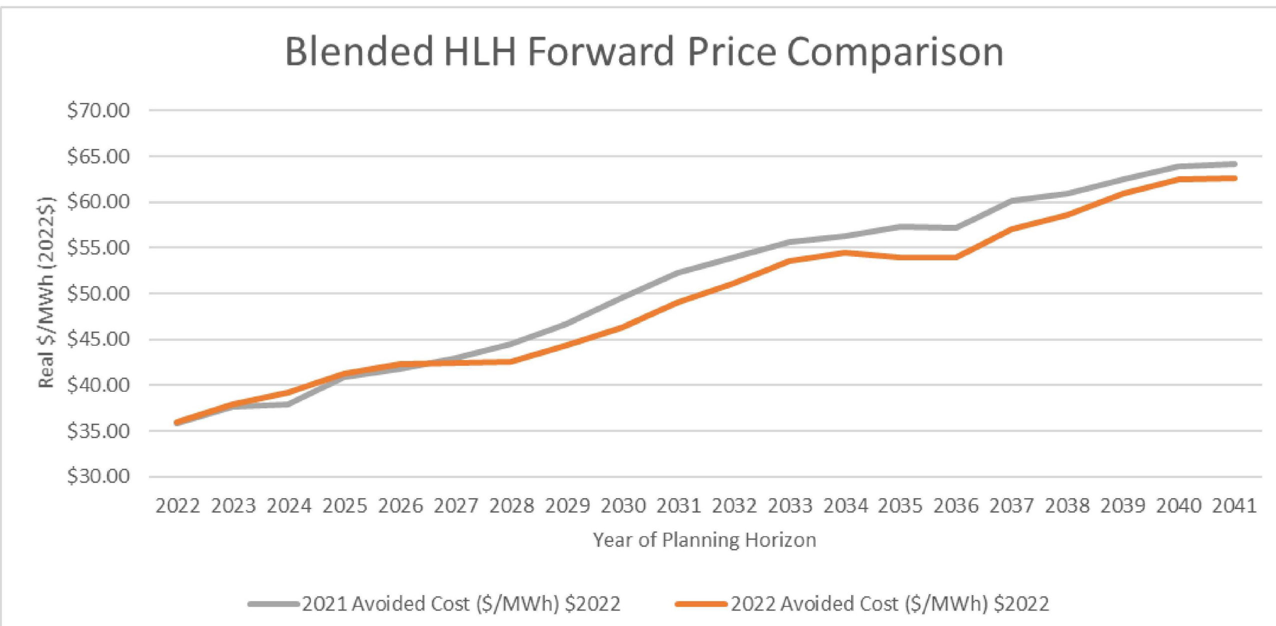


Figure 4. Monthly Average Annual Blended Forward Price Comparison - Heavy Load Hours



Transmission, Distribution and Generation Values

For 2022 Avoided Costs, the blended transmission deferral credit values decreased around 9.5% while distribution deferral credit values increased by about 3%. Generation deferral credit values remained nearly unchanged for 2022 Avoided Costs. Consistent with updates in UM1893 proceedings for 2021 Avoided Costs, a seasonal 50% summer/50% winter split of the transmission and distribution values were again utilized in the updated 2022 Avoided Costs. Furthermore, generation capacity values remained the same in 2022 with a seasonal 50% summer/50% winter split applied for PGE and a 100% summer split applied for PacifiCorp.

Risk Reduction & NW Power Act Credit

Risk Reduction values decreased about 30% in the 2022 Avoided Costs which offsets much of the increase in forward prices described above. Despite the 30% decrease in Risk Reduction value the overall impact on 2022 Avoided Costs remains modest per the "Final Results Summary" and Figure 1 above.

The same NW Power Act Credit value was utilized in the 2022 Avoided Costs as the 2021 Avoided Costs and therefore there was no change in this value. This credit is applied to each of the Avoided Cost components (except risk reduction) and therefore its impact is relative to the changes in other individual components of each load shape.

Measure Level Impacts

On a measure level, the overall impact of the input changes varies significantly by measure and load profile due to changes in the submitted values. Currently the peak coincident factors for transmission and distribution are specific to each utility and then blended, with the value split 50% summer/50% winter for summer and winter peak hours.

The following figures show changes in NPV Avoided Costs per unit of savings for representative measures across each sector. The NPV is shown according to each measure's typical measure life. The measures shown in these graphs are meant to show differential impacts across end uses and do not necessarily represent measures that make up most of the savings within each sector.

Figure 5. Residential Avoided Cost Comparison of Representative Measures

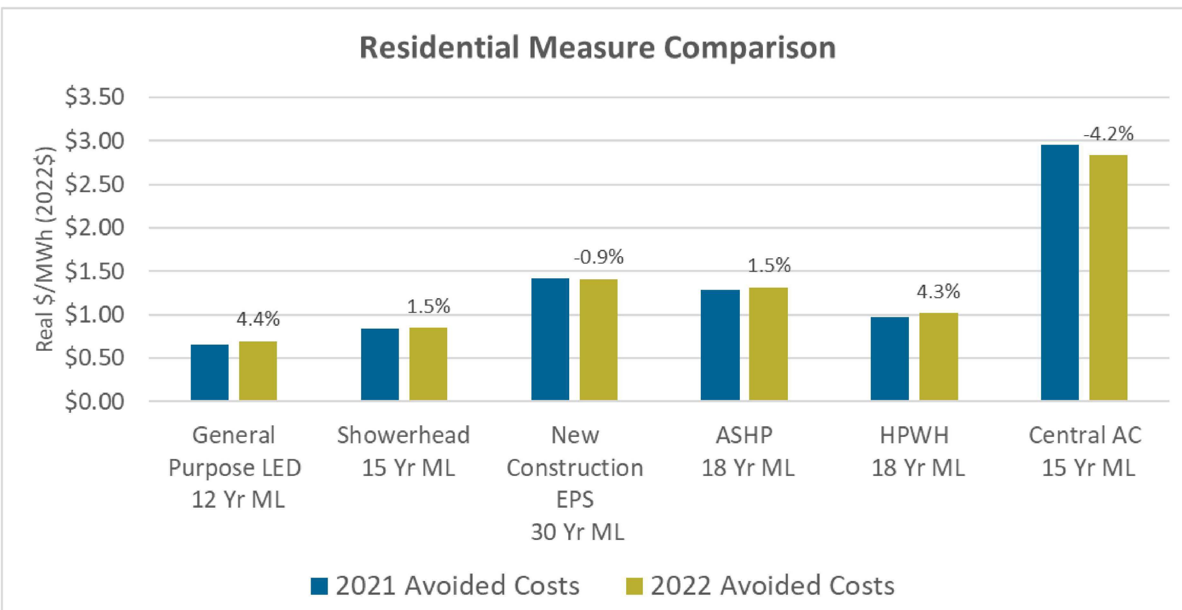


Figure 6. Commercial Avoided Cost Comparison of Representative Measures

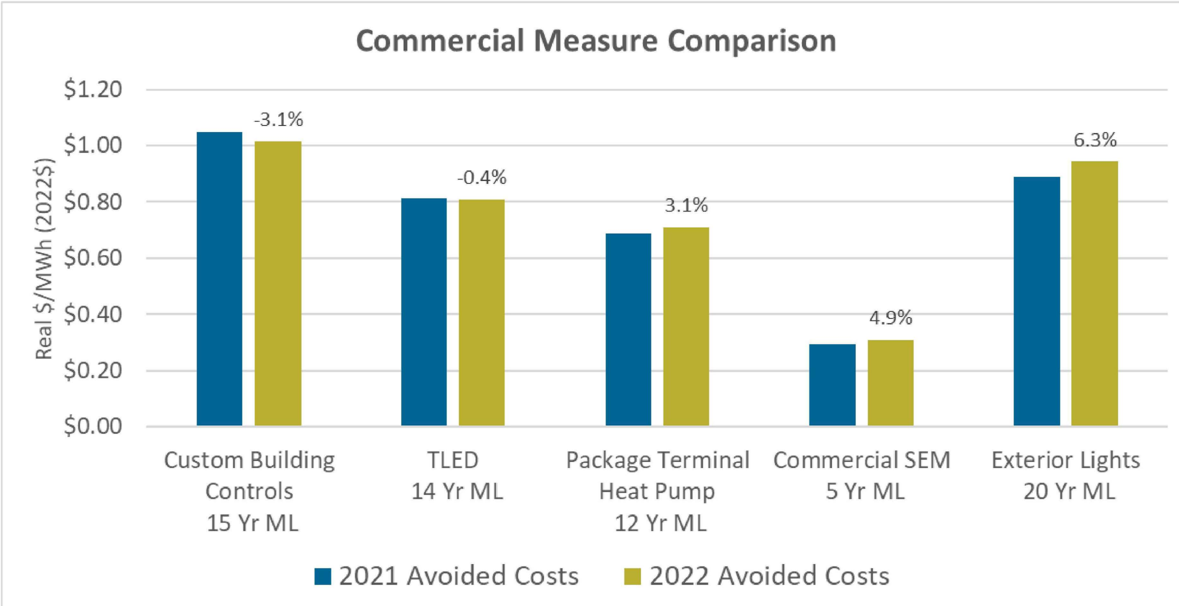
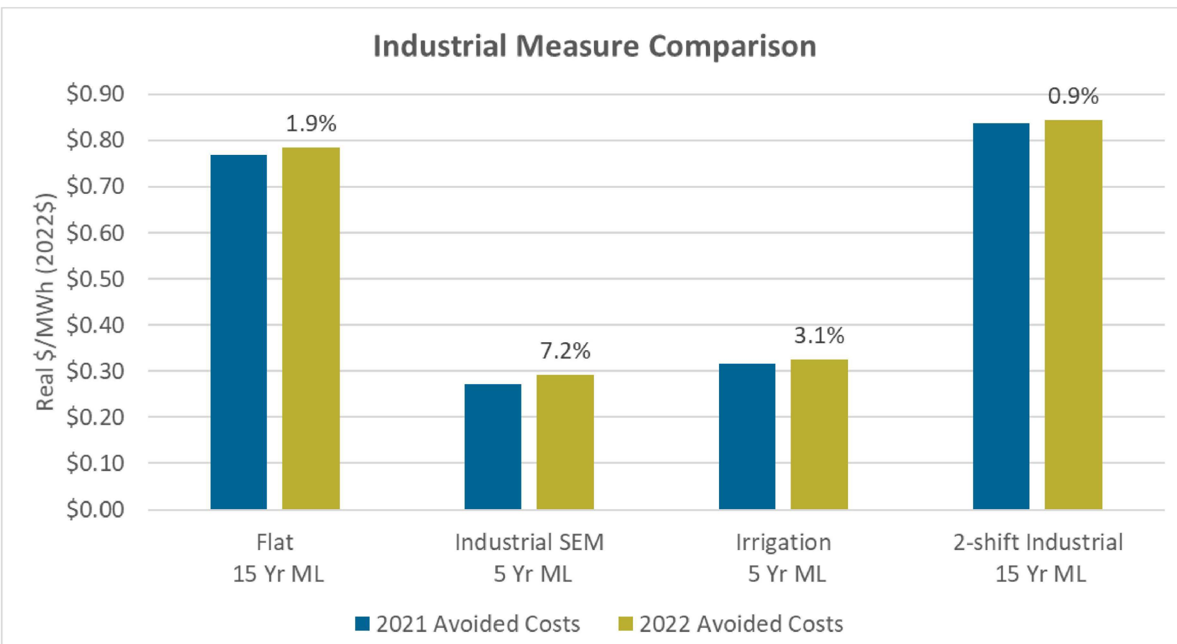


Figure 7. Industrial Avoided Cost Comparison of Representative Measures



Memo

EnergyTrust of Oregon

To: Anna Kim, Oregon PUC

From: Peter Schaffer, Energy Trust of Oregon

Date: November 20, 2020

Re: 2022 Natural Gas Avoided Cost Update Summary

This memo provides a summary of the updates to Energy Trust's 2022 Natural Gas Avoided Cost buildup, including an overview of the utility inputs provided, a discussion of the results, and a comparison of the updated blended values to current 2021 Avoided Cost values.

Utility Provided Inputs and PUC Direction

Pursuant to UM 1893, each funding utility provides Energy Trust with Avoided Cost inputs for use in 2022 Blended Avoided Costs. Each utility provides each component in the table below from the most recently acknowledged IRP and an optional additional input for the OPUC to consider. Table 1 below shows the values currently utilized in 2021 Avoided Costs, the inputs provided by each gas utility from their most recent IRPs and updated utility submissions for consideration in 2022 Avoided Costs. The table also shows the values that Energy Trust used in 2022 Avoided Cost calculations as directed by OPUC staff; these values are identified in their own column as well as being highlighted in orange. Finally, Table 1 compares the blended values used to calculate Avoided Costs for the current 2021 vintage with the blended values used to calculate Avoided Costs for the 2022 vintage.

Table 1. Utility Inputs for use in DRAFT Energy Trust 2022 Blended Avoided Costs

		Northwest Natural				Cascade Natural Gas				Avista				Energy Trust	
Avoided Cost Element	**Units**	**NWN 2018 IRP**	**NWN Alternative**	**Current UM 1893 Input ($2022)**	**Updated Inputs for 2022 Avoided Cost**	**CNG 2018 IRP**	**CNG Alternative**	**Current UM 1893 Input ($2022)**	**Updated Inputs for 2022 Avoided Cost**	**AVI 2018 IRP**	**AVI Alternative**	**Current UM 1893 Input ($2022)**	**Updated Inputs for 2022 Avoided Cost**	**Current UM 1893 Blend ($2022)**	**Final Blend for 2022 Avoided Cost**
Inflation rate	Percentage	1.96%	1.40%	1.96%	IRP	3.68%	3.68%	3.60%	Alternate	2.00%	2.11%	2.00%	IRP	2.14%	2.16%
Real Discount rate	Percentage	4.91%	4.70%	4.91%	IRP	7.33%	7.33%	6.35%	Alternate	4.36%	4.60%	4.36%	IRP	4.50%	4.50%
Regional Act Credit	Percentage	10%	10%	10%	IRP	10%	10%	10%	Alternate	10%	10%	10%	IRP	10%	10%
Commodity and Transport	$/Therm	**See Graphs for Comparison**			IRP	**See Graphs for Comparison**			Blend of NWN and AVI	**See Graphs for Comparison**			IRP	**See Graphs for Comparison**	
Distribution Capacity - Hourly	$/Therm/Year	$240.88	$419.17	$240.88	IRP	N/A	$1.27	$1.27	Current	N/A	$2.46	$213.45	Current	$213.59	$211.42
Supply Capacity	$/Therm/Year	$12.39	$7.77	$11.20	IRP	$46.93	N/A	$46.75	IRP	$0.07	$0.06	$0.07	IRP	$14.36	$15.48
CO2 Compliance	$/therm	$0.16	$0.14	$0.16	IRP	$0.34	$0.32	$0.15	Current	$0.16	$0.20	$0.15	IRP	$0.16	$0.17
Risk Reduction	$/therm	$0.00	$0.04	$0.00	IRP	$0.00	$0.00	$0.00	IRP	N/A	$0.00	$0.00	Current	$0.00	$0.00

Energy Trust took these inputs and blended them into gas Avoided Costs values that can be used throughout Energy Trust territory. The blended values are weighted averages where the weighting is based on forecasted 2022 gas utility expenditures from Energy Trusts 2021-2022 budget.

Some additional notes on Table 1.

1) The values provided by utilities were in dollar years specific to their source. These values were inflated to 2022$ for use in the 2022 Avoided Costs.
2) All values are sourced from each respective utility's IRP or alternate submission with the exception of Avista's hourly distribution value and Cascade's carbon compliance and commodity and transport values. These values rely on a weighted average of values from the other two respective utilities for input.
3) Some values selected for input used the same source as 2021 Avoided Costs, however, the current input shows a difference in value. This difference in value is the result of using a 2022 start year for incorporation of utility inputs instead of 2021.

Table 2 below provides a comparison of the blended 2021 Avoided Cost Component Values to the updated 2022 Avoided Cost Component values and their percent change from 2021. Please note that changes to peak factors also resulted in shifts in avoided cost value, these changes are discussed in the peak factors section below.

Table 2: Comparison of Component Values from 2021 Avoided Costs to DRAFT 2022 Avoided Costs

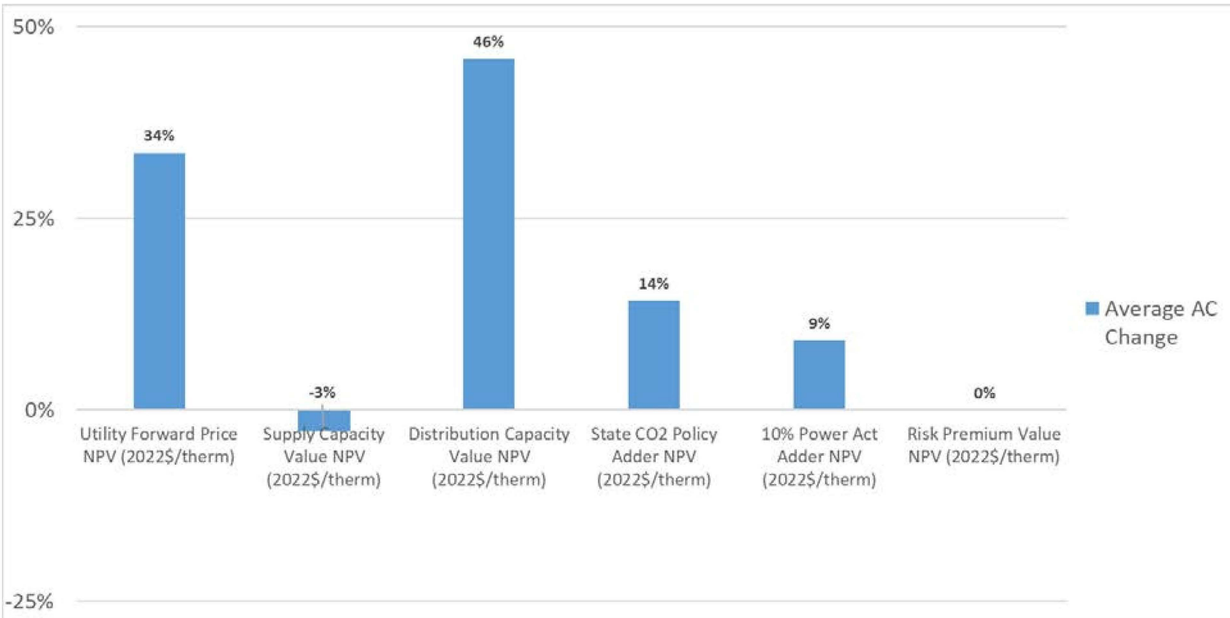
Avoided Cost Component	2022 AC (Updated) Blended Value	2021 AC Blended Value	% Change
Inflation rate	2.15%	2.14%	**1%**
Real Discount rate	4.50%	4.50%	**0%**
Regional Act Credit	10.00%	10.00%	**0%**
Commodity and Transport Prices	Varies	Varies	**N/A**
Distribution Capacity - $/Therm/Year ($2022)	$211.42	$213.59	**-1%**
Supply Capacity - $/Therm/Year ($2022)	$15.46	$14.36	**8%**
CO2 Compliance - $/Therm ($2022)	$0.17	$0.16	**6%**
Risk Reduction	$0.00	$0.00	**0%**

Results Summary

Once the updated values provided by Gas Utilities were blended, Energy Trust compared the respective value components of the Avoided Costs for updated 2022 Avoided Costs to the current 2021 iteration of Avoided Costs and compared the overall impact of the changes based on 2019 program savings achievements. **Overall, 2022 natural gas Avoided Costs increased by 11 percent** compared to current 2021 Avoided Costs, when weighted by the last full year of savings achieved in 2019**.**

On an end use basis represented per loadshape, the contribution of each individual Avoided Cost component is different dependent on how much that loadshape coincides with defined utility peak periods. To help to illustrate the overall impact of the changes to each component, Energy Trust also developed a weighted average percent change of each component of the avoided cost stack based on Energy Trust 2019 savings results and the propotional contribution of each end use's contribution to these 2019 results. Figure 1 below shows how the individual components contributed to the 11% percent increase (changes below total to 100% of observed increase in Avoided Costs).

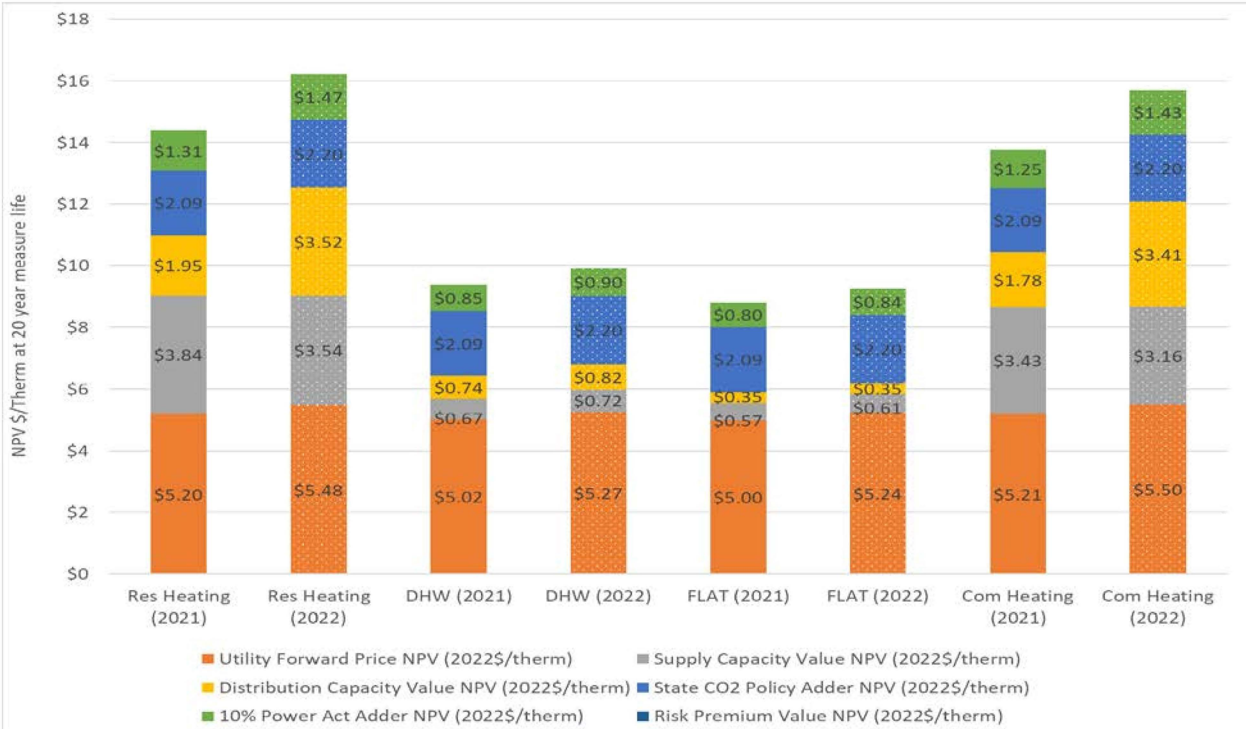
*Figure 1. Overall Contribution to Avoided Cost Changes by Component**



*Components of Figure 1 sum to 100% of avoided cost change.

Figure 2 below illustrates and compares the differential impact of the individual component parts of 2021 and 2022 Avoided Costs associated with specified end use load profiles. The contributions of the value components of the load profiles shown in this graph are based on an assumed 20 year measure life. This figure does not represent the proportional contribution of each loadshape to Energy Trust's overall portfolio.

Figure 2. Comparison of Load Shape Value by Component



The next section of this memo details the changes to each component of the Avoided Costs update.

Natural Gas Avoided Cost Component Changes and Impacts

Forward Market Prices

Figure 3 compares blended commodity and tranport prices from 2021 Avoided Cost inputs and 2022 Avoided Cost inputs. Overall blended commodity and transport prices went up by approximately 4%.

Figure 3. Blended Commodity and Transport Price Comparison

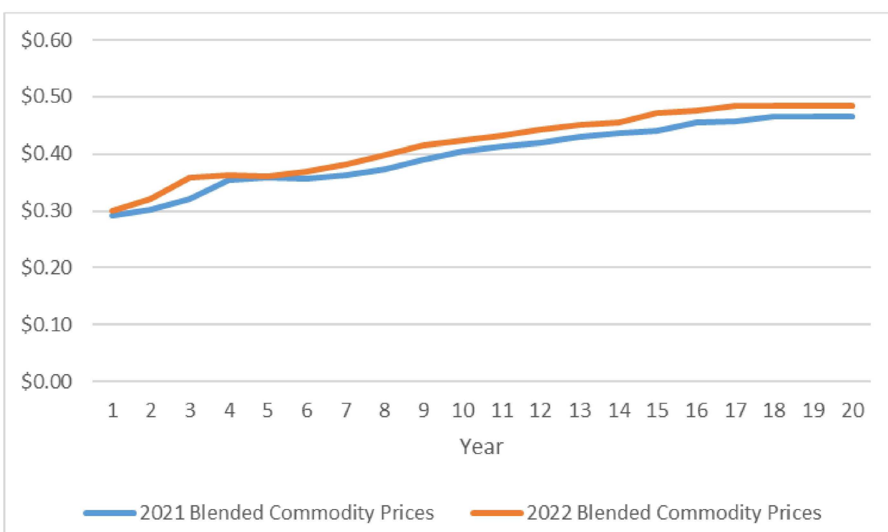
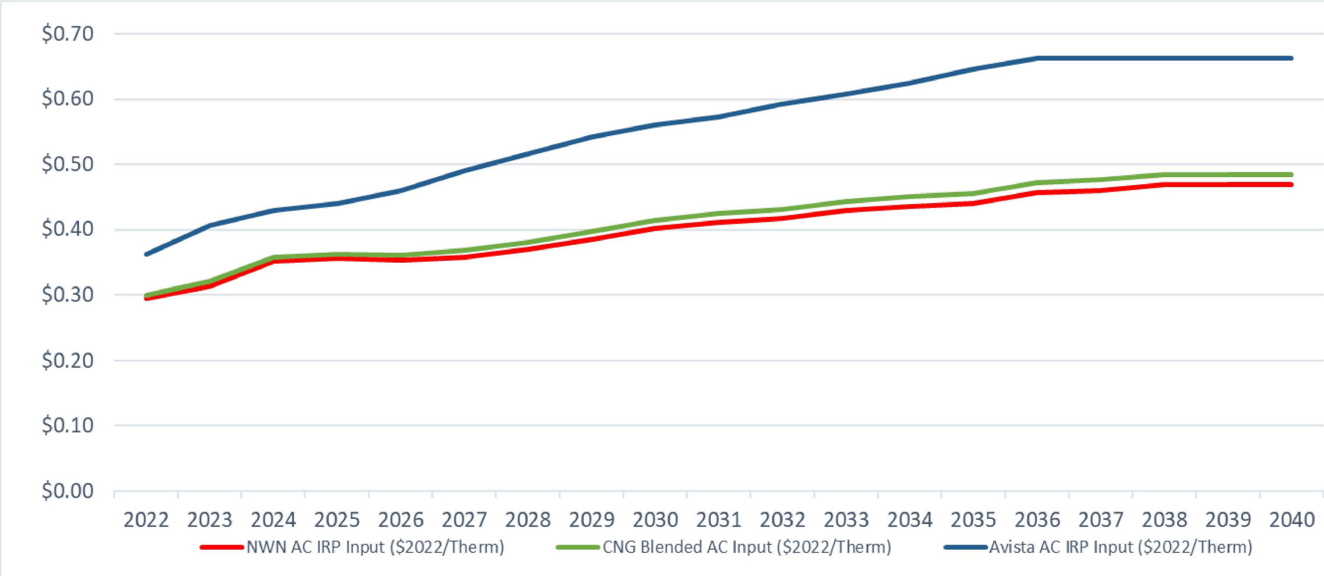


Figure 4. Comparison of Utility Specific Commodity and Transport Price Inputs for 2022 Avoided Costs



Peak Factors

Energy Trust uses peak factors to determine the proportion of end-use consumption that takes place on a peak day or a peak hour for natural gas utilities. Peak day and peak hour factors are defined for each of the end-use load profiles that Energy Trust utlizes in avoided cost calculations.

Supply capacity values are shaped using peak day factors, which represent the proportion of annual end-use consumption that falls on a peak day. A peak day is assumed to be the maximum daily coincidence of end-use consumption on a December or January weekday. For 2022 Avoided Costs, Energy Trust used Northwest Natural's peak day factor from their 2018 IRP for space heating end-uses. Previously Energy Trust relied on peak day factors from Northwest Natural's 2016 IRP for space heating end-uses.

Distribution capacity values are shaped using peak hour factors, which represent the proportion of end-use consumption that falls on a peak hour. In 2021, Energy Trust relied on peak hour factors that were calculated seperately from peak day factors. This separate calculation resulted in some instances where the peak hour factor was less than $1/24^{th}$ of a peak day factor. As a result, Energy Trust altered its method for calcuating peak hour factors for space heating end-uses. For space heating end-uses, a peak hour factor is calculated based on the proportion of consumption during the maximum hour on the peak day as characterized by peak day factors in Table 3.

For non-space heating end-uses a peak hour is characterized as the maximum hourly coincidence of end-use consumption on a December or January weekday morning from 7-10 A.M. Peak day and peak hour factors are derived from a combination of electric analog end-use load profiles from the Northwest Power and Conservation Council and Northwest Natural regression modeling. Table 3 and Table 4 show each of the peak factors used in 2022 Avoided Costs and their respective sources.

Table 3 – Daily Peak Factors for 2022 and 2021 Avoided Costs

Load Shape	2022 Peak Day Factor	Source	2021 Peak Day Factor	Source
Residential Space Heating	1.8%	Northwest Natural 2018 IRP	2.1%	Northwest Natural 2016 IRP
Commercial Space Heating	1.6%	Northwest Natural 2018 IRP	1.8%	Northwest Natural 2016 IRP
Domestic Hot Water	0.4%	NWPCC	0.4%	NWPCC
Flat	0.3%	NWPCC	0.3%	NWPCC
Clotheswasher	0.2%	NWPCC	0.2%	NWPCC

Table 4 – Proportion of Hourly Consumption Used to Derive Space Heating Peak Hour Factors

Load Shape	Shape ID	% of hourly usage on a peak day	Source	Analog Profile
Residential Space Heating	Res Heating	7.27%	NWPCC GLS Shapes	R-All-HVAC-ER-All-All-E
Commercial Space Heating	Com Heating	7.90%	NWPCC GLS Shapes	C-All-HVAC-ER-All-All-E

Table 5 – Hourly Peak Factors for 2022 and 2021 Avoided Costs

Load Shape	2022 Peak Hour Factor	Source	2021 Peak Hour Factor	Source	Analog Profile
Residential Space Heating	0.13%	NWPCC and Northwest Natural	0.07%	NWPCC	R-All-HVAC-ER-All-All-E
Commercial Space Heating	0.12%	NWPCC and Northwest Natural	0.06%	NWPCC	C-All-HVAC-ER-All-All-E
Domestic Hot Water	0.03%	NWPCC	0.03%	NWPCC	R-All-WH-ERWH-All-All-R
Flat	0.01%	NWPCC	0.01%	NWPCC	FLAT
Clotheswasher	0.02%	NWPCC	0.02%	NWPCC	R-All-WH-Cwash-All-All-R

Supply Capacity

The blended supply capacity values increased by 8% from the prior round of Avoided Costs submissions. Utility values used in the 2022 avoded cost calculation are illustrated in Figure 5.

Figure 5. Utility Supply Capacity Values for 2022 Avoided Costs

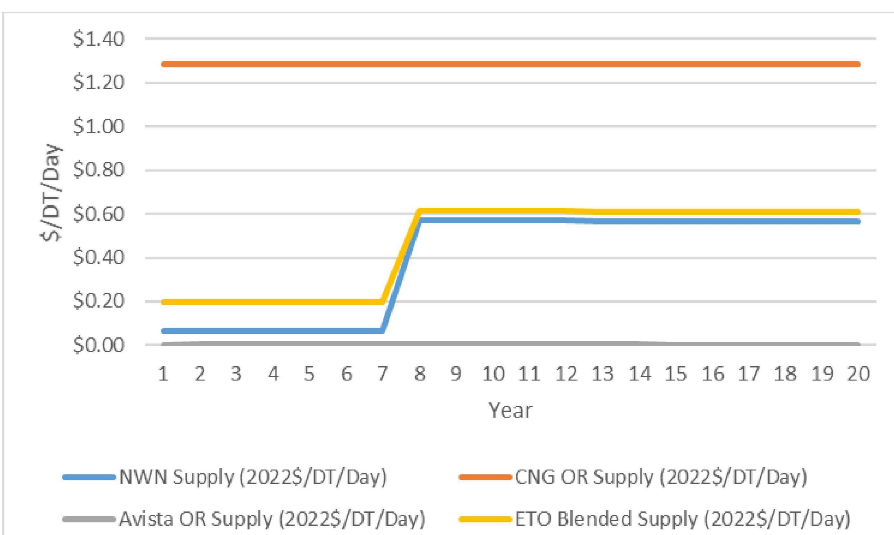
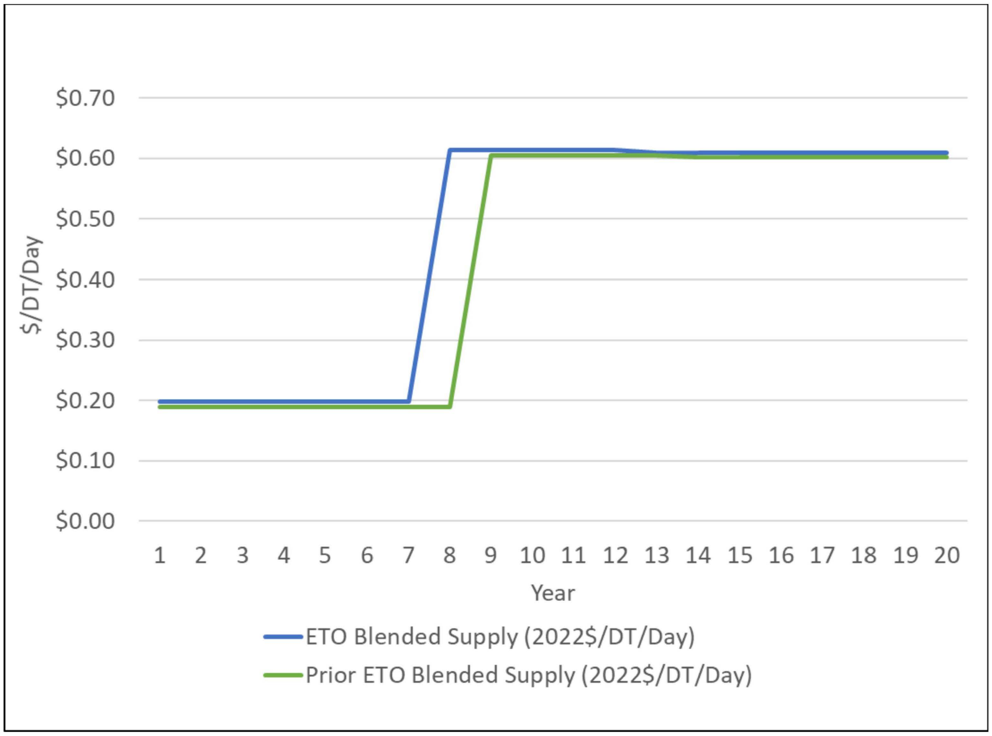


Figure 6 Blended Supply Capacity Values for 2022 Avoided Cost



Distribution Capacity

The blended distribution capacity value increased by 46% on average using each load shape and a 20 year measure life. This increase in value is primarily the result of using the updated peak hour factors presented in Table 5. Table 6 illustrates the change in distribution capacity costs from 2021 blended Avoided Costs to the current 2022 blended avoided cost.

Table 6. 70 Year Average Blended Distribution Capacity Value by Loadshape

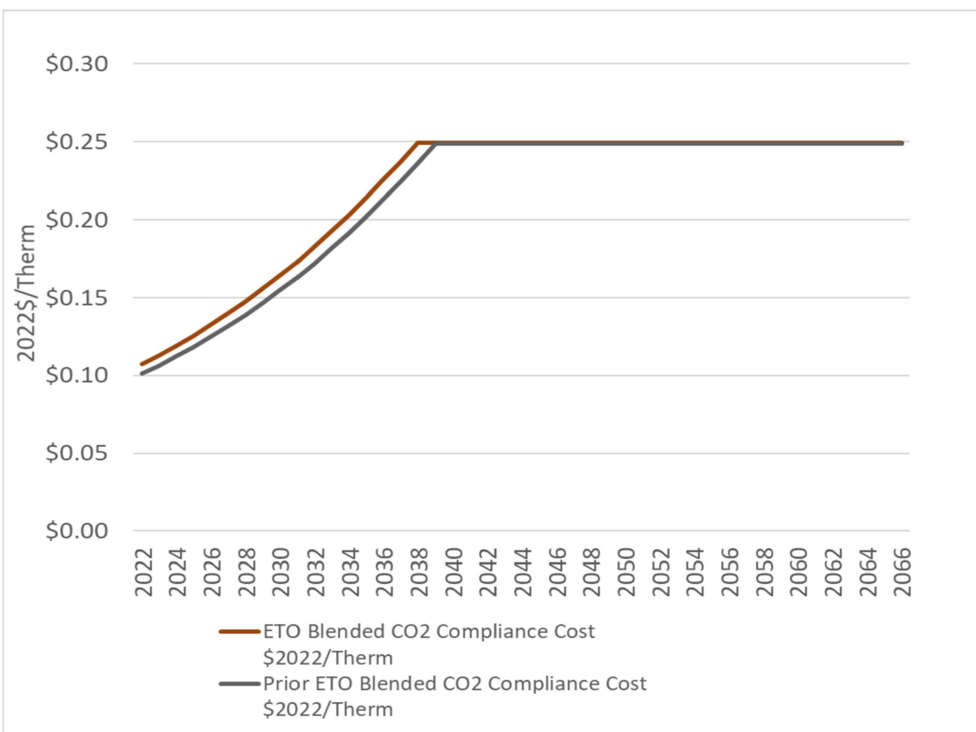
	DHW	FLAT	Res Heating	Com Heating	Clotheswasher
2021 Blended Avoided Costs	$0.62	$0.29	$1.64	$1.49	$0.55
2022 Blended Avoided Costs	$0.68	$0.29	$2.95	$2.85	$0.55

Carbon Policy Compliance Value

Carbon compliance values increased by 8% from the prior submission from a blended value of $0.16 per therm to $0.17 per therm. Figure 6 illustrates the respective values used for each natural gas utility and the blended value for use in Energy Trust avoided cost.

Figure 7 Utility Carbon Compliance Values for 2022 Avoided Costs

Figure 8 Blended Carbon Compliance Values for 2022 Avoided Costs



Risk Reduction & NW Power Act Credit

Risk reduction values stayed the same as the prior 2021 Avoided Costs with a value of $0; this is an outcome of a previous agreement that if utilities submit negative risk reduction values that a $0 value will be applied in the blended avoided cost calculation.

The NW Power Act Credit is applied to each of the avoided cost components and therefore it's impact is relative to the changes in other individual components of each loadshape. The NW Power Act Credit continued to be 10% of avoided cost value.

Measure Level Impacts

For some measures, particularly space heating measures, the change in Avoided Costs is greater due to the increase in distribution capacity values relative to other profiles. These end-uses have higher peak hour coincident factors than other profiles, and therefore their value increased more relative to other profiles.

The following figures show changes in NPV Avoided Costs per unit of savings for representative measures across each sector. The NPV is shown according to each measure's typical measure life. The measures shown in these graphs are meant to show differential impacts across enduses and do not necessarily represent measures that make up the majority of savings within each sector.

Figure 9. Residential Avoided Cost Comparison of Representative Measures

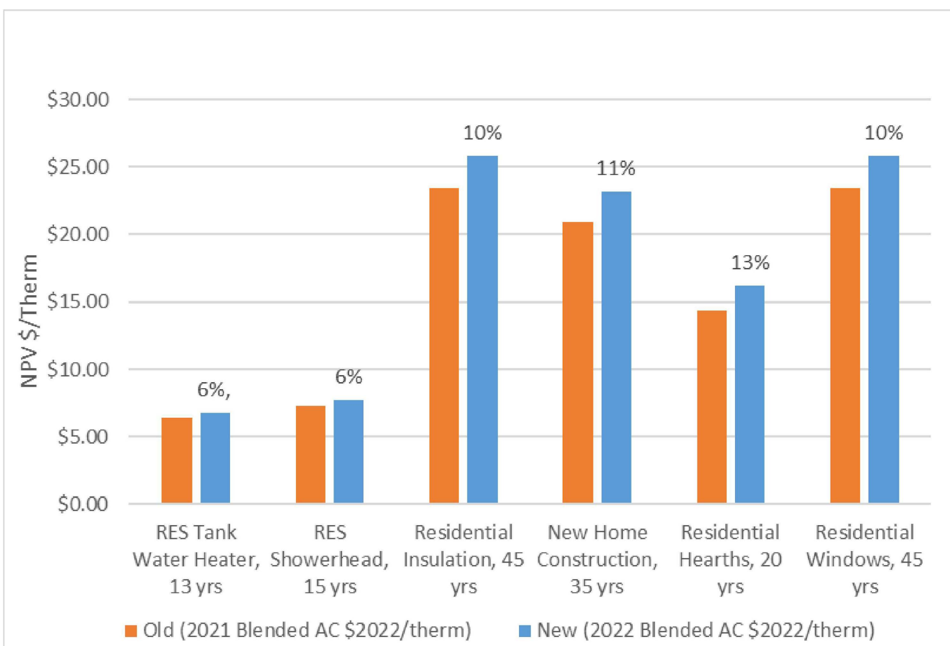


Figure 10. Commercial Avoided Cost Comparison of Representative Measures

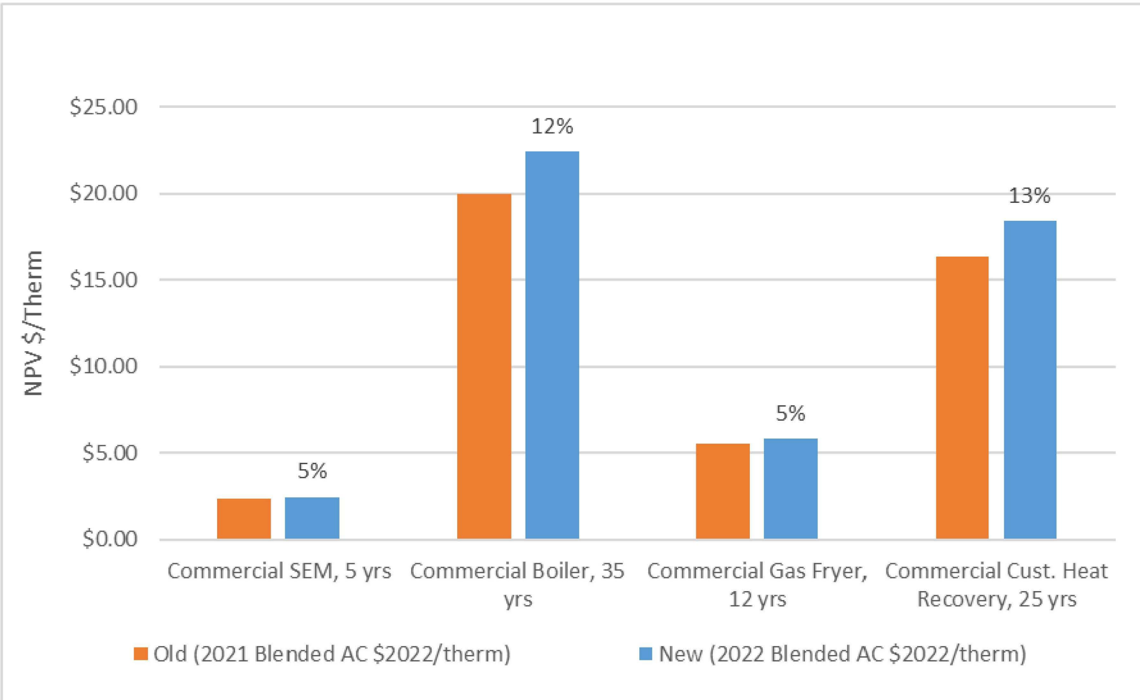


Figure 11. Industrial Avoided Cost Comparison of Representative Measures