Rocky Mountain Power | Pacific Power

STATE OF WASHINGTON DECOUPLING MECHANISM

Three Year Evaluation

August 2021

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Section 1. Executive Summary

PacifiCorp (the Company) currently operates a decoupling mechanism for its Washington service area. The mechanism is a program that decouples a significant level of the Company's Washington revenue from its energy sales. The goal of the mechanism is to increase the stability of this revenue by ensuring it stays at levels consistent with what the Commission allowed in the most recent general rate case, even if energy sales fluctuate. The mechanism is currently the only one the Company has in its six-state service area.

The Company operates the mechanism by tracking the difference between actual revenue and allowed revenue monthly by customer class and recording the differences in balancing accounts that accrue interest at a rate published by the FERC. Each Fall, the Company files to adjust the rates on Schedule 93, Decoupling Revenue Adjustment, to collect or give-back the net deferral amounts for the period tracked. These amounts also include the results of the mechanism's earnings test, which requires a large share of any Company earnings above the Commission-authorized return on equity to be shared amongst decoupling participants.

This evaluation of the mechanism shows it is working well, with four important exceptions:

1) the timing of the mechanism's tracking periods can result in rate increases during Winter, which is a time when many customers are experiencing higher heating costs,

2) for certain customer classes, the mechanism has little effect on revenue stability,

3) tracking each customer class separately increases the volatility of the annual adjustment rates, and

4) the Company's interjurisdictional allocations can cause unique issues for the earnings test that can undermine the mechanism's revenue stability goals.

Section 2. Background

The Company proposed a decoupling mechanism in its limited issue rate case filed on November 25, 2015 (Docket UE-152253). In the previous rate case (Docket UE-140762), the Commission invited a proposal from PacifiCorp to implement a decoupling mechanism similar to those implemented by Puget Sound Energy (PSE) and Avista Corporation (Avista).[1] The rationale for the proposed decoupling mechanism was to provide the Company better fixed cost recovery in light of changes in usage due to weather or energy efficiency.

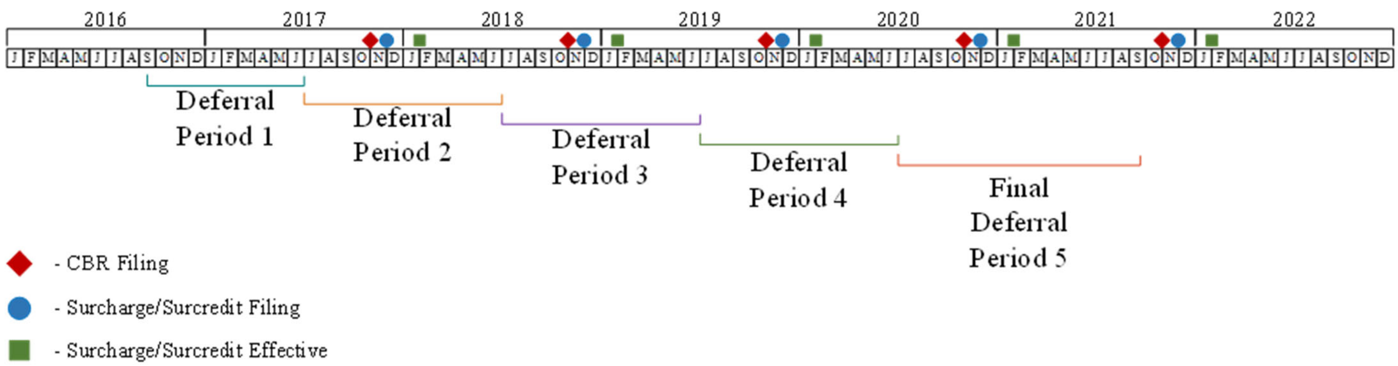
The Commission ultimately approved a mechanism with a duration of at least five years and included the following features:

- Revenue-per-customer mechanism like those approved for PSE and Avista, which compares actual non-weather adjusted revenues to allowed revenues
- Applicable to customers on Schedules 16, 17 and 18 (Residential), Schedule 24 (Small General Service), Schedule 36 (Large General Service under 1 MW), and Schedule 40 (Agricultural Pumping Service)
- Excludes customers on Schedule 48T (Large General Service over 1 MW), Schedule 47T (Partial Requirements Service), and Schedules 15, 51, 52, 53, 54 and 57 (Lighting)
- Deferral and recovery tracked separately by rate class
- Excludes basic charge and net power cost revenue embedded in base revenue
- Cap of five percent on surcharges with no floor on surcredits
- Trigger of 2.5 percent on both surcharges and surcredits
- Earnings test where 50 percent of any earnings above the Commission-authorized return on equity in the Commission Basis Report (CBR) without normalizing adjustments are shared amongst decoupling participants

The Company began tracking deferrals for the mechanism on September 15, 2016, the rate effective date of the limited issue rate case. To align the mechanism with the results from the CBR, the mechanism's first deferral period ended June 30, 2016. Subsequent deferral periods encompassed the twelve-month period ending June 30 with the final deferral period to be from July 1, 2020, through September 14, 2021. This timeline is illustrated in Figure 1.

[1] *Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket UE-140762 et al., Order 08 at 94, ¶ 222 (March 25, 2015)

Figure 1. Timeline



The Commission ordered the Company to, at the end of the third year, evaluate the effectiveness of the mechanism by providing an analysis of the following:

- Impact on conservation achievement;
- Impact on Company revenues (*i.e.*, whether there has been a stabilizing effect);
- Extent to which fixed costs are recovered in fixed charges for the customer classes excluded from the decoupling mechanism;
- Whether allowed revenues from the following rate classes are recovering their cost of service: residential class, non-residential classes, and customers not subject to decoupling; and
- The Company's proposal to separately track and true-up deferrals by rate class.

Since the first deferral period was not a complete twelve calendar months, the Company completed this analysis at the conclusion of the fourth period, which ended on June 30, 2020. The following sections contain the results of this analysis, additional analysis not ordered by the Commission, and recommendations for improvements to the mechanism.

Section 3. Impact on Conservation Achievement

After reviewing Company conservation both before and after the implementation of the mechanism, the Company found no evidence that decoupling had altered its conservation achievement. While decoupling is an important policy tool to remove conservation disincentives, the Company is already obligated by I-937 to pursue all cost-effective conservation measures. Table 1 shows that, in the years just before the implementation of decoupling and through the present period under which the Company has been decoupled, the Company has exceeded its biennial conservation targets. Table 2 and Figure 2 provide a breakdown of the Company's conservation achievement by year and class.[2]

Table 1. Company Conservation – Biennial Targets and Achieved MWh

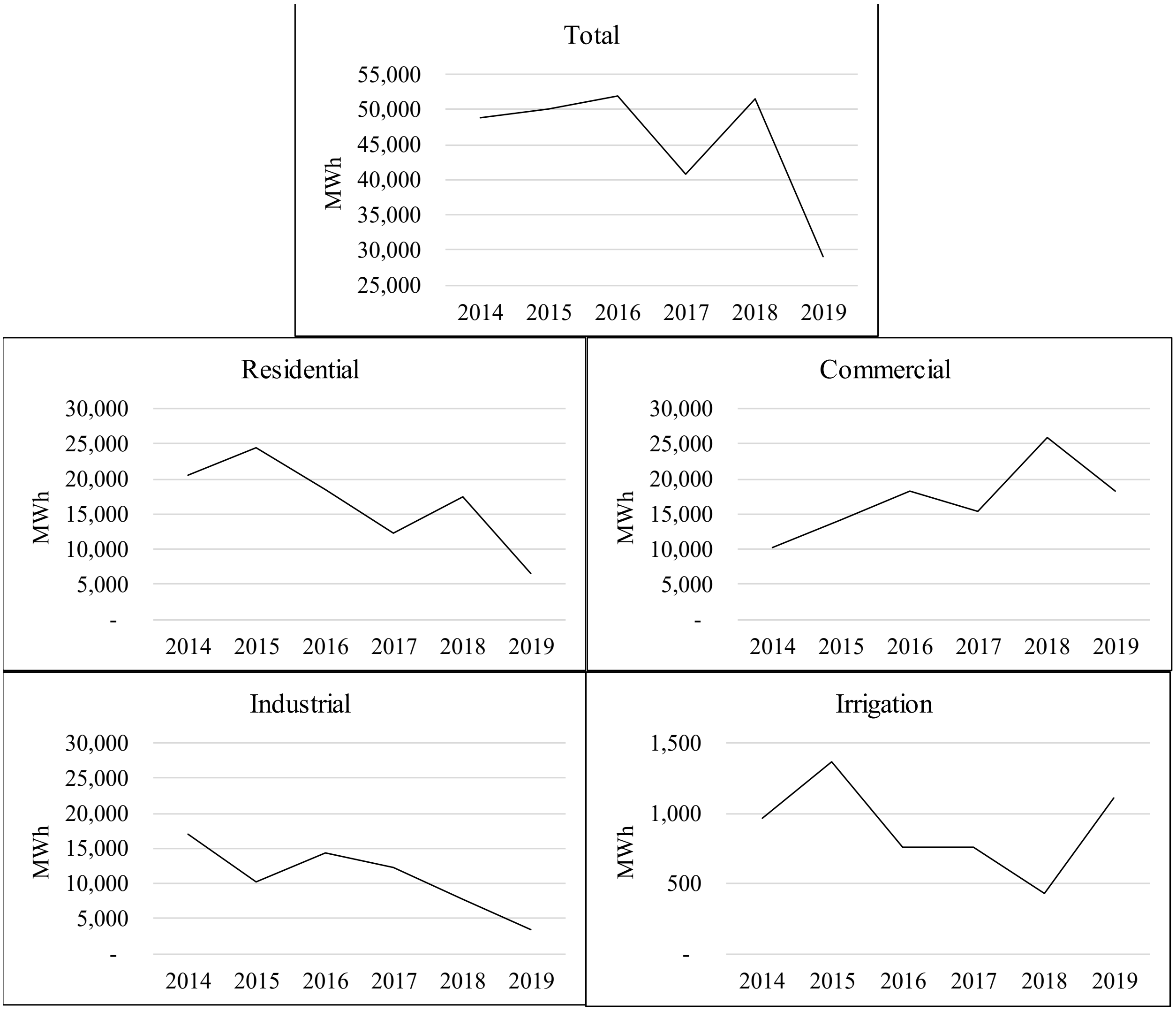
Biennium	Target	Achieved	Excess
2014-15	74,703	98,881	24,178
2016-17	90,009	92,727	2,718
2018-19	78,268	80,604	2,336

Table 2. Company Conservation – Annual Achieved MWh Savings by Class

Year	Total	Residential	Commercial	Industrial	Irrigation
2014	48,735	20,499	10,302	16,969	963
2015	50,146	24,384	14,191	10,204	1,367
2016	51,832	18,558	18,229	14,288	757
2017	40,895	12,350	15,472	12,310	763
2018	51,462	17,356	25,983	7,697	426
2019	29,142	6,415	18,220	3,396	1,111

[2] The data in Table 1, Table 2, and Figure 2 are from the Company's Washington Biennial Conservation Reports for 2014-2015 (filed July 27, 2016), 2016-2017 (filed July 6, 2018), and 2018-2019 (filed June 1, 2020).

Figure 2. Company Conservation – Annual Achieved MWh Savings by Class

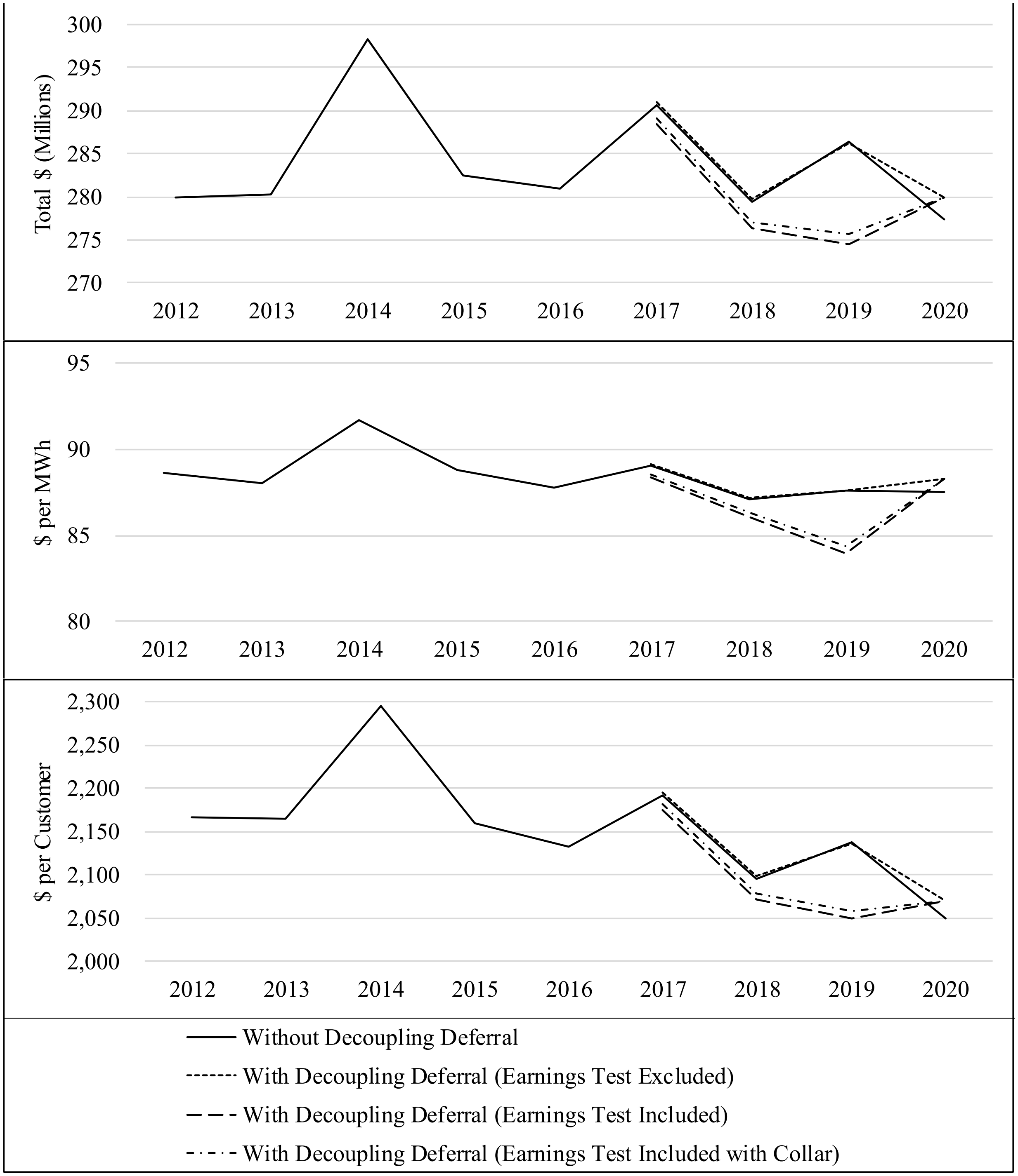


Section 4. Impact on Revenue Stability

To show the impact of the mechanism on its revenue stability, the Company prepared an analysis of its actual, non-temperature-normalized revenue for the past nine years.[3] This included an analysis of the effect of the decoupling deferral, the earnings test, and a hypothetical version of the earnings test assuming it was set at the Company's authorized ROE plus 50 basis points (a 50-basis point "collar"). The revenue from this analysis is shown on a total, per MWh, and per customer basis in Figure 3, which shows that, absent the earnings test, the mechanism helped to slightly stabilize revenue, but that this was significantly offset by a decrease in stability from the earnings test. This is particularly evident in the large impact of the earnings test on revenue for Deferral Period 3 (the twelve months ending June 2019).

[3] The analysis was for the twelve months ending June of 2012 through June of 2020. To put each annual revenue level on a comparable basis, the Company adjusted for base price changes to index the revenue to the rates that became effective on September 15, 2017 (the second-year price change from the Docket UE-152253 limited issues rate filing).

Figure 3. Revenue Stability – Total Dollars, Dollars per MWh, and Dollars per Customer



Section 5: Fixed Cost Recovery in Fixed Charges

One of the ways the mechanism can improve the Company's revenue stability is by ensuring the Company recovers its fixed costs even if its energy sales decline. To analyze how the mechanism is performing in this respect, the Company analyzed the fixed cost to fixed charge relationships of the non-decoupled classes.[4] Figure 4 provides the results of this analysis and shows this relationship for each customer class.[5] This relationship is very close for the Lighting class, since the recovery for a large share of costs for this class is in flat, per-lamp charges. However, this relationship is weaker for the other classes. This is particularly true for Residential and Small General Service (Schedule 24), which have cost recovery predominantly through energy charges. However, because the Company's revenue for these classes is decoupled from its energy sales to them, the Company recovers these costs even if energy sales decline. This is also true for Large General Service (Schedule 36) and Agricultural Pumping Service (Schedule 40), but to a lesser extent.

Figure 4. Fixed Costs and Fixed Charge Cost Recovery by Class

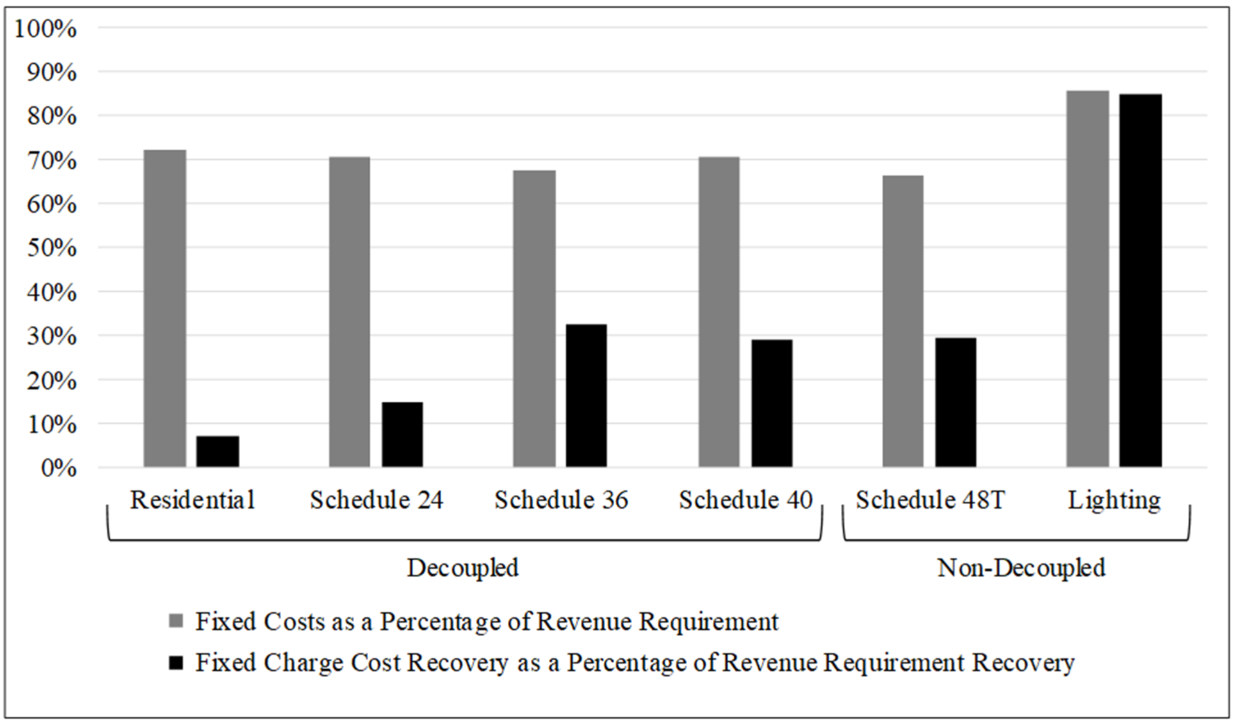


Figure 4 shows that the relationship between fixed costs and fixed charge cost recovery is similar for customers on Schedules 36, 40 and 48T, and that 48T is not currently decoupled. Due to the similarities in cost recovery for customers on these schedules, the Company is recommending removing customers on Schedules 36 and 40 from the mechanism. Additionally, the Company

[4] The Company examined the fixed charge to fixed cost relationship for each class using the rate design and cost of service study from its most recent general rate case (UE-191024)

[5] To produce this figure, the Company defined "fixed" costs as all costs in the cost of service study other than Net Power Costs, and "fixed charges" as all charges in the rate design other than Energy Charges.

recommends continuing to exclude Schedule 48T, since large swings in sales to large customers could introduce an unacceptably high level of volatility to the mechanism. Table 3 shows the difference in average annual energy sales for general service customers on Schedules 36 and 48T.

Table 3. Average Annual Energy Sales – Schedules 36 and 48T

	Customers	Annual kWh	Annual kWh per Customer
Schedule 36	1,076	950,741,261	883,495
Schedule 48T	65	871,440,857	13,309,059
Largest Schedule 48T Customer			471,255,293

The typical Schedule 48T customer is about 15 times larger than the typical Schedule 36 customer. Significantly, the largest Schedule 48T customer comprises over half of the total annual energy sales for all of Schedule 48T. Given the size of the customers in this class, including them in the decoupling mechanism would risk introducing a level of volatility that could undermine the mechanism's revenue stability goals. For example, if Schedule 48T were included in the decoupling mechanism and the energy use of the largest Schedule 48T customer fell by only 10 percent, the Company estimates that rates would increase by 0.4 percent for all other customers.

Section 6. Allowed Revenue and Cost of Service

The Company prepared cost of service studies for the three full calendar year periods of the decoupling mechanism (the twelve months ended June 2018, June 2019, and June 2020) to analyze whether allowed revenues from the following classes are recovering their cost of service: Residential, Non-Residential (Schedules 24, 36, and 40), and Non-Decoupled (Schedule 48T and Lighting).[6] Since the mechanism tracks actual energy, the revenue and energy sales in these studies include no temperature normalization. Also, the revenue requirements the Company used for the studies are the unadjusted versions the Company used for the mechanism's earnings tests and include decoupling deferral revenue. Table 4 shows how allowed revenue compared to cost of service for the twelve months ended June 2018, June 2019, and June 2020 periods. The results of this analysis suggest that recovery compared to cost of service for each class is relatively stable from year to year.

Table 4. Allowed Revenue and Cost of Service

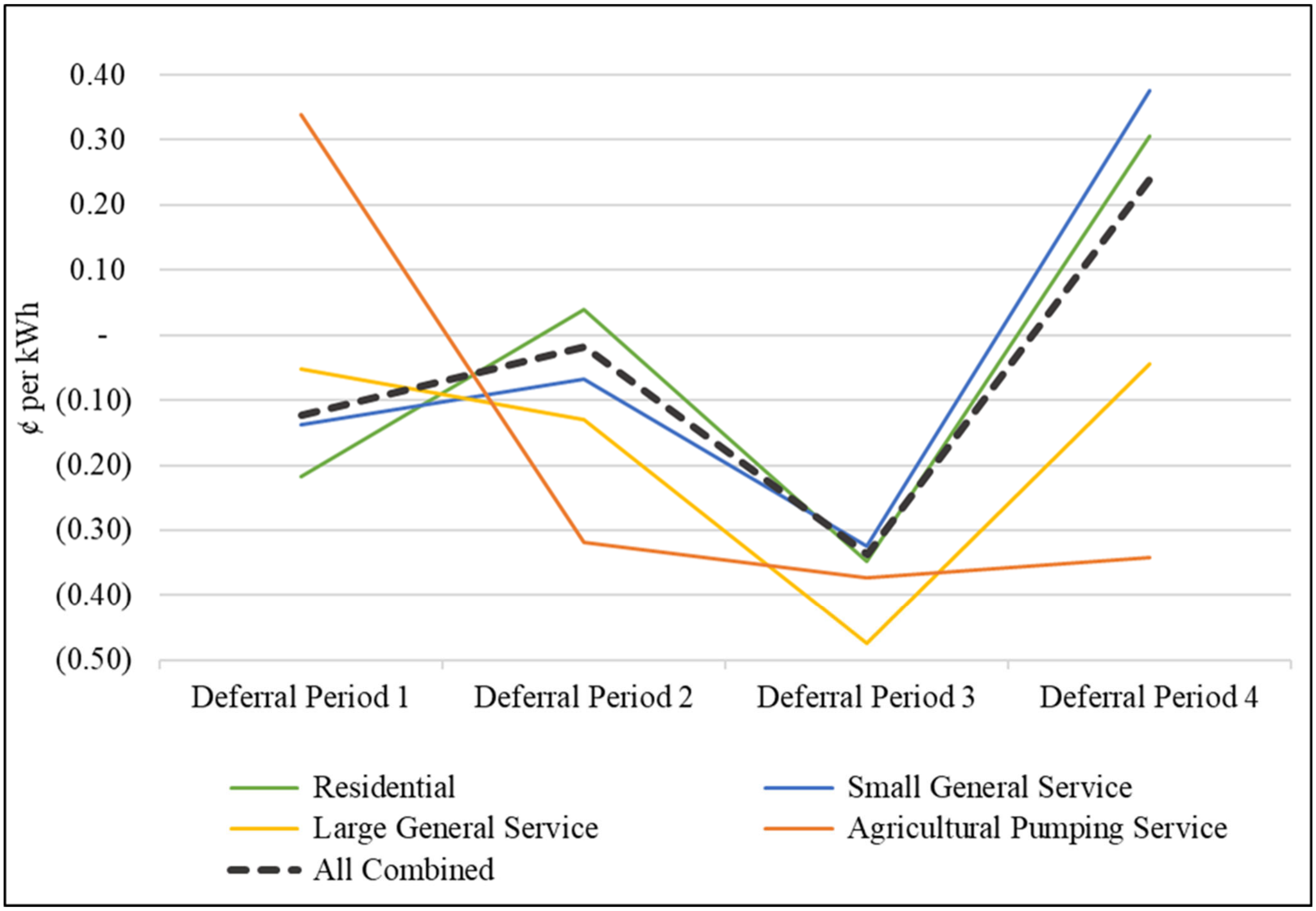
12 months ending June	Line	Description	Residential ($000)	Non-Residential ($000)	Non-Decoupled ($000)
2018	1	Allowed Revenue	147,036	141,093	57,742
	2	COS	157,314	131,770	56,791
	3=1/2	Allowed Revenue/COS	0.93	1.07	1.02
	4	Total Allowed Revenue	345,871	345,871	345,871
	5	Total COS	345,875	345,875	345,875
	6=4/5	Total Allowed Revenue/Total COS	1.00	1.00	1.00
	7=3/6	Parity Ratio	0.93	1.07	1.02
2019	1	Allowed Revenue	153,630	144,951	56,177
	2	COS	152,784	129,554	54,066
	3=1/2	Allowed Revenue/COS	1.01	1.12	1.04
	4	Total Allowed Revenue	354,758	354,758	354,758
	5	Total COS	336,403	336,403	336,403
	6=4/5	Total Allowed Revenue/Total COS	1.05	1.05	1.05
	7=3/6	Parity Ratio	0.95	1.06	0.99
2020	1	Allowed Revenue	148,881	138,467	58,045
	2	COS	170,519	140,642	66,315
	3=1/2	Allowed Revenue/COS	0.87	0.98	0.88
	4	Total Allowed Revenue	345,393	345,393	345,393
	5	Total COS	377,476	377,476	377,476
	6=4/5	Total Allowed Revenue/Total COS	0.92	0.92	0.92
	7=3/6	Parity Ratio	0.95	1.08	0.96

[6] During this timeframe, the Company had one rate case, which used a twelve-months ended June 2019 test period. This case followed the recently adopted electric cost of service rules approved in Docket No. UE-170002. The Company used the model for this case to prepare the models for the other periods, but with period-specific adjustments to revenue, energy sales, customer counts, and cost data.

Section 7. Rate Class Separation

To examine the Company's proposal to separately track and true-up deferrals by rate class, the Company prepared an analysis to show the annual adjustment rates and any resulting cost shifting that the mechanism would have produced if a single deferral had been used for all decoupled classes. Figure 5 shows the rates assuming a single deferral along with the rates produced from tracking the classes separately, and Table 5 shows the difference in the deferral that customers would have paid if all customers had been tracked as a single class.[7]

Figure 5. Annual Decoupling Adjustment Rates - Separate and Combined



[7] To set the revenue for this analysis on a comparable basis, the Company ignored the adjustments it made in its rate adjustment filings for Triggers, Caps, Carryover Balances, and Extended Amortizations.

Table 5. Deferral Change Assuming Single-Class Tracking

	Change ($000)				
	Period 1	Period 2	Period 3	Period 4	Annual Average
	9/1/2016 - 6/30/2017	7/1/2017 - 6/30/2018	7/1/2018 - 6/30/2019	7/1/2019 - 6/30/2020	= Total / 46 * 12
Residential	1,177	(893)	180	(970)	(132)
Small General Service	66	268	(70)	(752)	(127)
Large General Service	(554)	1,042	1,282	2,709	1,168
Agricultural Pumping Service	(726)	484	58	961	203

Figure 5 shows that combining the tracking and true-up of the mechanism would have had a minimal impact on the Residential and Small General Service rates, a moderate impact on the Large General Service rates, and a more significant impact on the Agricultural Pumping Service rates. Table 5 shows that the average impact over the course of all deferral years would have been relatively negligible for each decoupled class. Due to the greater stability that will likely result from combined tracking, the Company recommends making a change to the mechanism such that the tracking and true-up for all decoupled customer classes be done as one class.

Section 8. Approved Modifications

In the recently completed general rate case (Docket UE-191024), the Commission approved changes to the mechanism, which became effective with the new rates on January 1, 2021. This included updating the Company's decoupled revenue to reflect new rate case values for total revenue and embedded net power cost and basic charge revenue. Also, for the monthly comparison between allowed and actual decoupled revenue, the Commission approved the Company's recommendation to improve its monthly estimate of actual decoupled revenue by changing the monthly calculation methodology. Prior to this change, the Company was estimating actual decoupled revenue each month by applying an average revenue-per-kilowatt hour rate from the previous rate case to its monthly kilowatt hour sales. However, the average rate a class pays each month could be different from what the class paid during the GRC Test Period, so the Company will now use actual monthly revenue, less estimates of embedded basic charge, net power cost, and rider[8] revenue.

Table 6 provides a comparison of the previous and new monthly deferral calculation methodologies for a hypothetical Residential monthly deferral calculation. Table 6 shows that, while the previous method requires fewer steps, using actual revenue each month makes the calculation more accurate.[9]

There are three main reasons why the average rate a class pays during a month can be different from what it paid during the GRC Test Period: 1) changes in load factor for classes with demand charges; 2) changes in the ratios of energy sales between the tiered pricing levels for the Residential class; and 3) participation in new time-varying rate options that were not present during the rate case test period. This third reason is new. As part of the recently completed general rate case, the Commission authorized the Company to implement time-varying rate options for all decoupled customers, with customers who choose these options being included in the decoupling mechanism. Conservation, or reduction in overall energy sales, has been an important goal for the state of Washington and the decoupling mechanism has been a tool to remove utility disincentives to its pursuit. Efficiency in terms of the timing of energy consumption, though, is also becoming very important and the changes to the Company's mechanism will ensure that potential disincentives to its pursuit likewise are eliminated. As required by the Commission, the Company will track the impact of the inclusion of time of use pilot rate schedules in the decoupling mechanism in its annual decoupling filings.[10]

[8] As of January 1, 2021, Schedules 93, 191, and 197
[9] For this hypothetical month, the new methodology improves the estimate accuracy by approximately $464,000 (the amount of the difference between Prior and New methodologies), or about 0.3 cents per kilowatt hour
[10] *Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket UE-191024 et al., Final Order 09/07/12 at 48, ¶ 121 (December 14, 2020)

Table 6. Monthly Deferral Calculation Methodologies - Prior and New

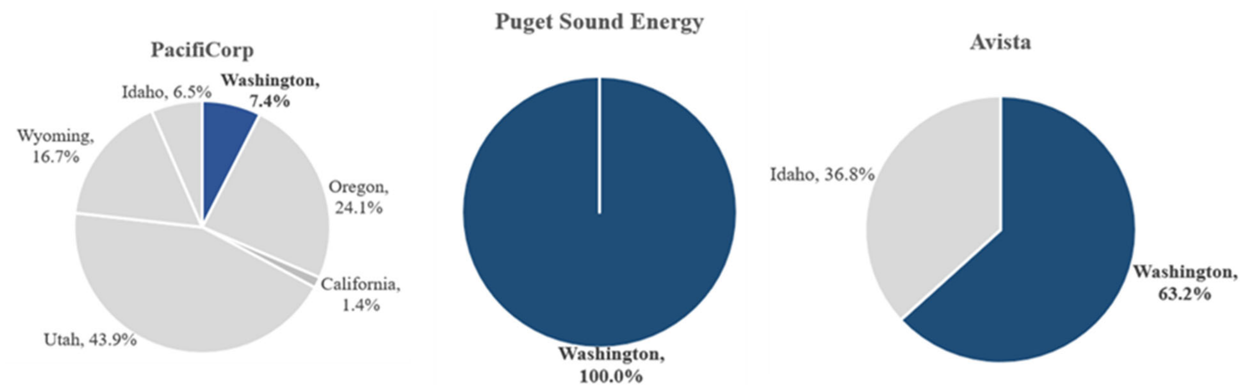
					Prior		New		
Period	Timeframe	Description	Units	Line	Source	Num. Example	Source	Num. Example	Δ
GRC Test	Annual	Actual	$000	1	GRC	148,456	= Prior	= Prior	
GRC Test	Annual	Basic Charge	$000	2	GRC	10,027	= Prior	= Prior	
GRC Test	Annual	Net Power Cost	$000	3	GRC	37,144	= Prior	= Prior	
GRC Test	Annual	Allowed Decoupled	$000	4	= Line 1 - (Lines 2 and 3)	101,285	= Prior	= Prior	
GRC Test	Annual	Average	Bills	5	GRC	107,790	= Prior	= Prior	
GRC Test	Monthly	Normalized	MWh	6	GRC	191,310	= Prior	= Prior	
GRC Test	Annual	Normalized	MWh	7	GRC	1,524,718	= Prior	= Prior	
Booked	Monthly	Actual	Bills	8	Booked Monthly Results	110,218	= Prior	= Prior	
Booked	Monthly	Allowed Decoupled	$000	9	= Line 4 / Line 5 * Line 6 / Line 7 * Line 8	12,995	= Prior	= Prior	
Booked	Monthly	Actual	MWh	10	Booked Monthly Results	188,230	= Prior	= Prior	
Booked	Monthly	Actual	$000	11			Booked Monthly Results	17,688	
Booked	Monthly	Embedded Riders	$000	12			Booked Monthly Results	(719)	
Booked	Monthly	Basic Charge	$000	13			= Line 2 / Line 5 / 12 * Line 8	854	
Booked	Monthly	Net Power Cost	$000	14			= Line 3 / Line 7 * Line 10	4,586	
Booked	Monthly	Actual Decoupled	$000	15	= Line 4 / Line 7 * Line 10	12,504	= Line 11 - (Lines 12 thru 14)	12,967	464
Booked	Monthly	Deferral	$000	16	= Line 15 - Line 9	(491)	= Line 15 - Line 9	(27)	464
					Booked Monthly Actual Decoupled ¢/kWh (Line 15 / Line 10 * 100):	6.6		6.9	0.3

Section 9. Earnings Test Evaluation

The rationale supporting decoupling mechanisms is that they can be an effective means of removing a utility's throughput incentive and thus decouple a utility's earnings from its energy sales. This can take away the disincentive a utility may have for pursuing cost-effective energy efficiency. One of the features of decoupling mechanisms in Washington is an earnings test under which the Company must return to its customers half of any unadjusted over-earnings in Washington during each decoupling deferral period. For the three full calendar year decoupling periods and the partial decoupling period which the Company has had, it has returned $17.8 million in over-earnings, or about $4.5 million on average per deferral period.

While an earnings test may generally be a reasonable component of decoupling mechanisms for investor-owned utilities in Washington, the nature of the Company's interjurisdictional allocations causes unique issues for the Company's earnings test. Unlike PSE and Avista, which have most, if not all, of their electric load in Washington, only about seven percent of PacifiCorp's retail electric energy sales occur in the state. Figure 6 demonstrates how loads in the state compare for these utilities and how PacifiCorp is uniquely situated.[11]

Figure 6. Washington Investor Owned Utilities – Energy Sales by State



To better understand the relative magnitude of the over-earnings in each of the utilities' decoupling mechanisms, the Company prepared Table 7, which shows a comparison of over-earnings with retail electric revenue for each utility's mechanism over the past several years and in total. Table 7 shows that over-earnings have been a much greater share of retail electric revenue for PacifiCorp. At about 2.6 percent of revenue, over-earnings for PacifiCorp are over five times greater than for the other utilities.

[11] PacifiCorp Source: Page 366 of Exhibit SEM-3C in Docket No. UE-191024
PSE Source: PCA Costs' tab of Exhibit BJD-04 in Docket No. UE-190259
Avista Source: Page 2 of Andrews Allocation Workpapers in Docket No. UE-200900

Table 7. Washington Investor Owned Utilities – Decoupling Mechanism Over-Earnings

Washington IOU	Data Description	Year								Total
		2013	2014	2015	2016	2017	2018	2019	2020	
PSE	Over-Earnings ($m)	-	-	23.9	23.9	24.8	-	-		72.6
	Electric Revenue ($m)	2,099.4	2,004.9	2,066.4	2,147.7	2,146.7	2,128.8	2,030.6		14,624.5
	Over-Earnings/Electric Revenue	0.0%	0.0%	1.2%	1.1%	1.2%	0.0%	0.0%		0.5%
Avista	Over-Earnings ($m)			1.8	5.0	2.9	-	-		9.6
	Electric Revenue ($m)			490.8	500.0	500.0	492.1	492.1		2,475.1
	Over-Earnings/Electric Revenue			0.4%	1.0%	0.6%	0.0%	0.0%		0.4%
PacifiCorp	Over-Earnings ($m)					6.5	7.0	23.5	-	36.9
	Electric Revenue ($m)					349.3	349.3	349.3	352.1	1,400.2
	Over-Earnings/Electric Revenue					1.9%	2.0%	6.7%	0.0%	2.6%

To investigate the cause of the Company's uniquely high over-earnings, which were particularly significant for the 2019 deferral period, the Company performed a cost analysis for each period. A key component of this analysis is the relative shares of energy sales and peak demand for the Company's Washington jurisdiction as compared to other Western Control Area jurisdictions (*i.e.*, Oregon and California). With the Company's current dynamic allocation factors, allocations of non-distribution costs are based upon the share of Washington energy, peak demand, and customer counts relative to other jurisdictions, meaning shifts in energy, peak demand, and customer counts in other states impact the allocation of non-distribution costs to Washington. Distribution costs are situs-assigned for each state. Under the 2020 Interjurisdictional Cost Allocation Protocol approved in the most recent general rate case, dynamic allocation factors will be in use through at least 2024. Table 8 provides the results of this analysis and shows that a significant driver of PacifiCorp's high 2019 over-earnings was the unique nature of its interjurisdictional allocations.

Table 8. PacifiCorp Cost Trends by Deferral Period

	12 Months Ended June 30			
	2017	2018	2019	2020
PacifiCorp Fixed Generation and Transmission Cost ($ million)	1,907.0	1,908.5	1,925.3	1,938.7
PacifiCorp WA Distribution Cost ($ million)	44.0	44.4	46.6	47.0
PacifiCorp WA Energy (GWh)	4,522	4,460	4,407	4,488
PacifiCorp OR and CA Energy (GWh)	15,292	15,088	15,100	15,000
PacifiCorp WA Coincident Peaks (MW for 12 mo)	8,515	8,374	7,845	8,353
PacifiCorp OR and CA Coincident Peaks (MW for 12 mo)	28,608	29,019	29,090	29,126
CAGW Interjuridictional Allocation Factor	22.909%	22.500%	21.577%	22.472%
Over-Earnings per Decoupling Mechanism ($ million)	6.5	7.0	23.5	-

Between the 2018 and 2019 deferral periods, both fixed generation and transmission cost, which are allocated across different states, and Washington allocated distribution cost, increased for PacifiCorp. However, during this period, loads decreased for PacifiCorp's Washington customers, while, at the same time, loads in Oregon and California increased. Consequently, the

Washington “CAGW” (Control Area Generation West) interjurisdictional factor, which allocates a large proportion of the generation fixed costs to PacifiCorp’s Washington customers, declined from about 22.5 percent to about 21.6 percent, creating a substantial contribution to the over-earnings for the period. If PacifiCorp had been a single jurisdiction utility or a utility with most of its sales in Washington like the other Washington investor-owned utilities, this abnormally high over-earnings would not likely have occurred. In particular, dynamic allocation factors that shifted costs to Oregon and California as the result of increased load in those states amplified overearnings attributable to Washington in a way that a primarily single state utility would not experience. However, similar to a primarily single state utility, PacifiCorp does not have a mechanism to recover those increased costs from other states absent a rate case (the reverse is also true—PacifiCorp does not recover increased fixed costs from Washington as the result of an increased allocation factor absent a rate case).

Due to PacifiCorp’s unique position, the over-earnings feature of its decoupling mechanism could undermine the mechanism’s ultimate purpose of providing revenue stability. To partially remedy the impact of the earnings test on revenue stability, the Company recommends modifying the earnings test so that it is based only on earnings from the Company’s decoupled customers.

Section 10. Recommendations

The Company finds that the mechanism should be continued at least in the near-term. In a future ratemaking proceeding, the Company may revisit the need for the mechanism in light of potential changes to the regulatory and policy landscape. At present, the Company recommends four important recommendations for improvement:

1) **Deferral Period six should begin September 15, 2021, and last until December 31, 2022, and each subsequent Deferral Period should be a calendar year. Also, the Company's deadline to file the annual Schedule 93 rate adjustment should change from December 1 to June 15, and the effective date of any adjustments associated with this filing should change from February 1 to September 1.** Changing the timing of the deferral periods to be calendar years will simplify the Company's annual Earnings Test calculations. Also, moving the rate change process forward by six months will mean that any Schedule 93 rate increases that customers experience will no longer occur during the typically higher heating cost month of February.

2) **Schedule 36 (Large General Service) and Schedule 40 (Agricultural Pumping Service) customers should be removed from the mechanism.** Limiting the mechanism to residential customers and customers on Schedule 24 (Small General Service) will focus the mechanism on those customers with rate designs that are at the greatest risk of producing unstable revenues.

3) **The tracking and true-up for all decoupled customers should be done as one class**. Separating decoupled customers into distinct classes creates unnecessary volatility in the mechanism's annual adjustment rates without clearly reducing cost-shifting.

4) **The Earnings Test should be based only on earnings from decoupled customers.** The Company's interjurisdictional allocations can cause unique issues for the Earnings Test that may undermine the mechanism's goal of increasing revenue stability. Modifying the Earnings Test to be based only on earnings from the Company's decoupled customers could help mitigate the effect of these allocations while still returning a portion of excess earnings to customers when earnings exceed a reasonable threshold.