REDACTED
Docket No. UE 374
Exhibit PAC/600
Witness: Frank Graves

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED

Direct Testimony of Frank Graves

February 2020

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ATTACHED EXHIBITS

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, position and business address.

A. My name is Frank Graves. I am a Principal at The Brattle Group, located in our headquarters office at One Beacon Street, Suite 2600, Boston, Massachusetts 02108.

Q. Please summarize your education and professional experience.

A. For most of my career spanning over 30 years as a consultant, I have worked in regulatory and financial economics, especially regarding long-range planning for electric and gas utilities, and in litigation matters related to securities litigation and risk management. My education includes an M.S. with a concentration in finance from the M.I.T. Sloan School of Management in 1980, and a B.A. in Mathematics from Indiana University in 1975.

In regard to forecasting, utility resource planning, and cost recovery risks, which are central matters in this case, I have extensive experience in system planning with capacity optimization and production cost models, load forecasting, fuel procurement and risk management, and pollution control compliance. Recently, I have focused on evaluating pathways to deep decarbonization of the energy sector, including the impacts of much greater reliance on renewable generation and distributed energy resources. I have developed, evaluated, or used many power system production and resource planning models as well as utility financial projections for revenue requirements and alternative rate design purposes, and I have evaluated financial risk and cost of capital in a wide variety of settings for energy infrastructure and utility investments. I have given expert testimony on financial and regulatory issues before the Federal Energy Regulatory Commission (FERC), many state regulatory commissions (including Oregon, see below), and state and federal courts. My background and qualifications are described in greater detail in the résumé attached as Exhibit PAC/601.

Q. What testimonies have you previously provided in proceedings before the Public Utility Commission of Oregon (Commission) or in regard to PacifiCorp (PacifiCorp or the Company) in any of its other state jurisdictions?

A. I have provided direct and rebuttal testimony on behalf of companies within PacifiCorp's six-state service territory on several occasions in regard to aspects of fuel and purchased power procurement, forecasting, hedging and cost recovery. Going by state, I testified for PacifiCorp in Utah in 2010 and 2011 in docket 09-035-15 on the need for an Energy Cost Adjustment Mechanism (ECAM) and how that related to risk management practices, and in docket 10-035-124 on the prudence of long-term hedges for natural gas and allowing swap costs in the energy balance account. I testified for PacifiCorp in Wyoming in 2012 (docket 20000-405-ER-11) on utility hedging practices and state practices for cost recovery in rebuttal of suggested 50/50 sharing of gains and losses in those positions, and in 2015 (docket 20000-409-ER-15) regarding a day-ahead versus real-time (DA/RT) adjustment to the net power costs (NPC) in rates to correct for intrinsic under-recovery from short-term transactions in the ECAM. In Oregon that same year, I presented direct and reply testimony in docket UE-296 on the costs of balancing the system and the need for DA/RT adjustments.

Q. What is the scope of your testimony in this proceeding?

A. My testimony discusses the sources of risk and resulting typical under-recovery in the current Power Cost Adjustment Mechanism (PCAM) for PacifiCorp in Oregon to demonstrate how difficult these variances are to forecast or control. I also explain why these difficulties and resulting downward biases in recovered NPC are likely to increase in the coming years, due to increasing reliance on renewable resources and more participation in regional markets. Accordingly, I recommend that the deadbands and profit collars on sharing those NPC variances be eliminated to better align PacifiCorp's financial risks for recovery of NPC with the very limited level of control over the key drivers of the NPC uncertainty. I also discuss the fuel-cost sharing policies of other states, and the ineffectiveness of the sharing rules currently in place (deadbands, profit collars) on NPC variances to create meaningful or useful incentives for PacifiCorp to manage its fuel and purchase power costs differently.

Q. Please summarize your conclusions.

A. A review of the past several years of NPC forecasts and actual costs shows that there has been a systematic under-recovery of those actuals, accumulating to approximately $77 million on an Oregon-allocated basis between 2014 and 2018. The large variances in Oregon have not been passed on in whole or in any part to customers in Oregon because of the wide deadbands and profit collars on PCAM conditions for sharing them, effectively passing the entirety of the NPC shortfall on to PacifiCorp shareholders.

My review shows that the largest and most persistent component of these shortfalls has been the costs of purchases and sales in the wholesale market(s) to balance the system (e.g., when the renewables produce more or less than expected, or load is different than forecast) and to simply trade economically with other utilities that have their own imbalances or less/more cost-effective units available.[1]

Such trading volume is very large—on the order of a quarter of jurisdictional retail sales—and it involves material benefits to PacifiCorp customers from the savings and efficiency gains. On the other hand, it is extremely difficult to forecast when, where, and at what price or cost these numerous short-term transactions will take place. Indeed, it is not likely that modeling improvements could be made to reduce this problem, leading to substantial actual NPC deviations from planned costs that are in rates.

Even more consequential for NPC and the PCAM, these deviations in costs do not tend to balance out over time from a blend of some over- versus some under-forecasting. Instead, it is more likely that both positive and negative deviations from expected volumes will have net costs, for two reasons. First, because the supply curve for available power is usually increasingly upward sloping at higher loads, the positive deviations in load (actuals greater than forecast) will often have greater incremental costs than the comparable incremental savings from the negative deviations (which occur in a lower cost, flatter portion of the supply curve). That is, the extra power needed when the forecast is low will tend to cost more than was

[1] The DA/RT adjustment is designed to capture certain system balancing costs that are otherwise excluded from the NPC forecast by virtue of the nature of the Generation and Regulation Initiative Decision Tools (GRID) model's perfect foresight, among other reasons, as discussed in prior cases and reiterated below. While the DA/RT adjustment has mitigated, to some extent, the under-forecasting bias resulting from system balancing transactions, it remains an imperfect solution, as demonstrated by the under-recovery that has continued in the years subsequent to implementation of the DA/RT adjustment. Nevertheless, the DA/RT adjustment remains necessary because the NPC forecast is more accurate with it than without.

expected if the actual volume had matched expectations, while reduced power needs that do not have to be purchased or generated may not save much relative to the forecast costs. Second, it is possible that lower than expected load volumes will directly involve losses if the planned volumes (of electricity sales or their generation fuel costs) were hedged and those hedges have to be closed out at a lower price than was expected.

Importantly, these under-recovery biases occur in all time frames, e.g., within the day for hourly transactions, even if the day as a whole had actual demands that matched the forecast. This is particularly significant for renewables which can only be forecast for ratemaking on the basis of long-term weather patterns that are not accurate for short-term operations. For instance, if the wind blows more than was expected, and the output is under a long-term contract priced above market energy prices, the excess adds considerable unplanned NPC.

These recurring under-recoveries are not the result of bad forecasting or bad operational management. The planning methods and tools that PacifiCorp uses are consistent with good industry practice, as well as their assumptions and data sources for key inputs. To the contrary, these under-recoveries are a byproduct of the beneficial and cost-saving move to greater reliance on renewables and on market transactions.[2] Because those costs are so difficult to forecast, and they do not occur or arise in the "base case" scenario used to set rates (only in the variances from those projections), they are inadvertently not recognized and are excluded from base rates. A prudently incurred cost is simply missing from the allowed costs in the revenue requirement.

Such difficulties and the associated under-recovery are likely to increase in the future, because of the changes to PacifiCorp's generation portfolio outlined in its 2019 Integrated Resource Plan (IRP), the near-term renewable acquisitions included in the 2019 IRP action plan and because much of the rest of the Western Electricity Coordinating Council (WECC) is similarly transitioning away from coal-fired generation resources towards increased renewable capacity, and the pending move to nodal and state-specific energy pricing by PacifiCorp. These changes will increase forecasting difficulties, will likely make PacifiCorp's supply variances more correlated with other companies across larger areas (hence more impactful on spot energy prices)—at the same time as they will make market participation more beneficial and important.

[2] A significant part of the forecasting problem here is inability to know the short-term deviations from average or typical renewable output. The average (or total output) over moderate time frames, such as a month, can be known in advance with reasonable accuracy, as I show later in Confidential Figure 7. Such average amounts can then be hedged to dampen a material portion of cost risk. However, a year in advance, the rate-setting time in the TAM, it is not possible to have any meaningful insight into intra-month, intra-day or intra-hourly even shorter period renewable output variances, nor into what the corresponding variance and correlation in hourly or shorter term energy prices will be when those wind and solar variances occur. It is possible to do beneficial short-term hedging throughout the year, to further reduce the extent of error exposure, but always subject to volume uncertainty within the hedged period. For instance, it may be that next week's weather forecast features lots of rain, so it is unlikely the solar generation will produce much power. This was not knowable at the beginning of the year, but can be acted upon a week or so in advance to hedge those conditions. Even then, it will not be possible to hedge much or perhaps any of the intra-week variance at that time.

These forecasting and variance-costing problems are widespread throughout the electric industry and so can be considered normal business risk, but what is not normal is for the utility to bear so much and such asymmetric cost-recovery exposure to them. The vast majority of other states have full flow-through cost recovery of NPC-type costs, without deadbands or sharing limitations. This reflects an appreciation that there is no efficiency improvement from putting a utility at risk for largely uncontrollable and unforecastable costs. Therefore, I recommend eliminating the deadbands, sharing bands, and earnings test and allowing full NPC recovery for PacifiCorp, subject to prudence review.

Q. How is your testimony organized?

A. In Section II, I review the terms of the current PCAM established in Oregon, including a summary of the types of costs it includes, how and when the costs are measured, and the risk-sharing between PacifiCorp's ratepayers and shareholders for the deviations between forecast and actual NPC. Then, in Section III, I summarize PacifiCorp's experience in Oregon for the recovery of NPC, and I identify several of the key drivers of the deviations between forecast NPC used to set retail rates versus the actual NPC over the last several years. I explain in Section IV why these cost deviations tend to create under-recovery, rather than to balance out as errors that can go either way. I also explain why they are intrinsically very difficult to capture in forecasts and how they are outside of PacifiCorp's control, together making PCAM variances a poor candidate as an incentive mechanism for improved utility operations. In Section V, I explain the appropriateness of PacifiCorp's proposed modifications to the PCAM approach in Oregon. Finally, in Section VI of my testimony, I provide an overview of how some of the other utility jurisdictions treat similar types of risks associated with cost recovery of NPC-type costs.

II. CURRENT PCAM IN OREGON

Q. What are the components of PCAM costs?

A. As described in Mr. Michael G. Wilding's testimony, the PCAM is a balancing or true-up mechanism with risk-sharing that allows the possibility for PacifiCorp to recover a portion of large differences between the actual PCAM costs incurred to serve its customers and the forecast "base" PCAM costs established during annual transition adjustment mechanism (TAM) filings. The historical PCAM costs include NPC plus other costs/revenues not captured in NPC, such as: ongoing costs associated with PacifiCorp's participation in the Western Energy Imbalance Market (EIM), Production Tax Credits (PTC), and other revenues collected under PacifiCorp's Schedule 205.[3]

Q. How does PacifiCorp estimate the PCAM costs that are reflected in retail rates?

A. The base PCAM costs used to set customer rates in Oregon are estimated in annual TAM filings. PacifiCorp forecasts its system-wide NPC using the GRID model, which simulates the operations of the Company's owned and contracted generators for its entire fleet across all its state jurisdictions, along with market purchases and sales for the future test year based on contracts and expected spot trades for economics and balancing. The NPC is calculated as the sum of fuel costs, wholesale power purchase costs, and wheeling costs, net of wholesale sales revenues. The model results are adjusted to increase the accuracy of system balancing transactions

[3] I understand that the non-NPC EIM costs will be removed from the PCAM process beginning with the 2021 general rate case, and instead will be part of base rates.

(DA/RT adjustment) and to reflect incremental EIM benefits. PTCs and other revenues are estimated outside of the GRID model, included as a part of the TAM filings.

A share of the total Company-wide costs is allocated to Oregon based on Oregon customer's proportion and pattern of the forecast load. Oregon uses a one-year forward projected test year for those calculations (while other PacifiCorp states use somewhat different time frames). The TAM-estimated average cost per kilowatt hour (kWh) for NPC becomes the basis for rates. Any deviation from those forecast prices and the corresponding unit costs in actual NPC (plus a few smaller additional factors, shown below) multiplied by actual retail sales volumes becomes a variance that is subject to possible partial recovery or refund under the risk-sharing terms of the PCAM.

Q. Can you provide a breakdown of the key components of the PCAM costs in recent years?

A. Yes, Figure 1 summarizes the actual and forecast Company-wide PCAM costs that PacifiCorp incurred during 2014-2018, compiled based on the data from Oregon TAM and PCAM filings. As shown, the NPC accounts for the vast majority of the PCAM costs and the resulting unit cost differentials, which will be the focus of my testimony.

Figure 1: Annual Company-Wide PCAM Costs for 2014-2018

	2014	2015	2016	2017	2018
Total Company Adjusted Actual NPC	$1,603	$1,542	$1,447	$1,528	$1,595
Actual Allocated PTC	–	–	–	($89)	($68)
Actual EIM Costs	–	$6	$5	$5	$3
Actual Other Revenues	–	($24)	($16)	($10)	($11)
Total PCAM Adjusted Actual Costs ($million)	**$1,603**	**$1,524**	**$1,437**	**$1,433**	**$1,519**
Actual System Retail Load (MWh)	54,999,277	54,589,759	54,258,193	55,194,054	55,041,477
Actual PCAM Costs ($/MWh)	**$29.15**	**$27.91**	**$26.48**	**$25.97**	**$27.60**
Total Company Adjusted Base NPC	$1,449	$1,466	$1,514	$1,526	$1,474
Base Allocated PTC	–	–	–	($88)	($67)
Base EIM Costs	–	$7	5	$4	$4
Base Other Revenues	–	($24)	(15)	($11)	($12)
Total PCAM Base Costs ($million)	**$1,449**	**$1,448**	**$1,503**	**$1,431**	**$1,400**
Base System Retail Load (MWh)	54,938,054	55,032,984	56,126,562	55,640,607	54,038,127
Base PCAM Costs ($/MWh)	**$26.37**	**$26.32**	**$26.78**	**$25.73**	**$25.90**
System PCAM Unit Cost Differential ($/MWh)	**$2.78**	**$1.59**	**($0.30)**	**$0.25**	**$1.70**
NPC Differential ($/MWh)	*$2.78*	*$1.60*	*($0.30)*	*$0.25*	*$1.71*
Oregon Retail Load (MWh)	12,958,736	12,862,461	12,868,974	13,200,282	12,867,233
Oregon Annual PCAM Differential ($million)	**$36**	**$20**	**($4)**	**$3**	**$22**

Note:
[1] 2016 Adjusted Actual NPC excludes the recovery and abandonment costs for the Joy longwall mining equipment.

In this figure, a positive differential in the shaded row indicates that the actual unit costs of the actual load were greater per megawatt-hour (MWh) than the forecasted unit costs in rates, causing under-recovery. This occurred in every one of the past five years, except a small negative differential in 2016.

Q. How is the difference between the PCAM costs in retail rates and the actual PCAM costs treated for cost recovery under the current PCAM risk-sharing approach?

A. PCAM balances are calculated based on monthly Company-wide per-unit differentials between actual PCAM and base PCAM unit costs, both multiplied by the actual retail load in Oregon. Thus, errors in forecasting volumes do not directly affect the PCAM variances, though those errors may help explain the differences in forecast unit costs that do determine the amount eligible for risk-sharing. Those amounts are subject to four kinds of filters before being recoverable as described in Order 12-493.[4] *First*, for a given year, any difference within an asymmetrical deadband range of -$15 million over-recovery and +$30 million under-recovery are simply absorbed by PacifiCorp, i.e. not shared. *Second*, amounts above or below the deadband limits are eligible to be shared 90 percent by customers and 10 percent kept by PacifiCorp. However, the *third* filter is that this sharing only occurs to the extent that PacifiCorp's return on equity (ROE) without sharing is more than +/-100 basis points (bp) profits collar away from the authorized ROE. If the variance does not pass these thresholds, PacifiCorp gets no recovery from or gives no refund to customers. PacifiCorp may only recover to within 100 bp of its authorized ROE. And *fourth*, the amortization of deferred amounts under the PCAM in a given year is capped at 6 percent of PacifiCorp's revenues for the previous year.

Q. What is your understanding of why these filters have been adopted by the Commission?

A. It is my understanding that these filters have been based on the PCAM adopted for Portland General Electric Company, and they are "designed so that [the utility] will bear normal business risk associated with actual power costs varying from forecast."[5] I would note, however, that the risk-sharing under the PCAM design is quite

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[4] *In the matter of PacifiCorp, dba Pacific Power, Request for a General Rate Case*, Docket No. UE 246, Order No. 12-493 (Dec. 20, 2012).
[5] *In the matter of Portland General Electric Co. Request for a General Rate Revision*, Docket No. UE 180, Order No. 07-015 (Jan. 12, 2007).

asymmetric, with much more potential for Company under-recovery from unexpected losses than for over-recovery from unexpected gains. Thus, even if realized costs tended to vary symmetrically around the forecast used to set rates, i.e., even if there was no long term average forecasting error, the Company would usually end up losing money. This problem is made worse by the fact that even a good forecast will tend to omit the balancing costs (as I explain below). Having such a built-in loss expectation is not normal business risk in the utility industry.

Q. Has the implementation of the current PCAM approach so far resulted in PacifiCorp's Oregon customers bearing some of the PCAM cost deviation?

A. No. Since the beginning of the implementation of the current PCAM approach in Oregon, all of the cost deviations have failed to pass the filters and thus have been absorbed by PacifiCorp in all years. Cumulatively, since 2014, these have resulted in approximately $77 million of unrecovered costs in Oregon equivalent to about 65 basis points per year of shortfall in earned ROE. Importantly, this has not been due to one or two occasional bad years with large losses offset by some years with moderate gains or over-recoveries. In fact, and notably, even unusual events that have adversely affected PacifiCorp operations, such as the Enbridge pipeline rupture in October 2018, have not triggered the PCAM, even though allowing adjustments for major unforeseen events was something the PCAM was designed to accomplish.[6] Instead, actual annual PCAM costs have almost always exceeded the PCAM costs

[6] *In the matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision*, Docket No. UE 246, Order No. 12-493, at 13 (Dec. 20, 2012) ("any adjustment under a PCAM should be limited to unusual events and capture power cost variances that exceed those considered normal business risk for the utility").

recovered in rates in the past several years, except for a small over-recovery in 2016.[7] I explain below why this persistent under-recovery is not a coincidence, nor is it related to bad forecasting or system cost management. It reflects the inherently underestimated costs of using the market to balance the system combined with the biased (asymmetric) design of the PCAM.

III. HISTORICAL NPC UNDER-RECOVERY IN OREGON

Q. Please summarize how PacifiCorp's estimate of system-wide NPC deviated from actual NPCs over the last five years.

A. In the five years spanning 2014-2018, Company-wide actual NPC exceeded the one-year ahead forecast in every year except 2016. My analysis indicates that this is largely due to a downward bias in forecasting NPC unit costs relative to actual unit costs because of modeling and informational limitations, market dynamics (all trading companies tending to have similar, concurrent and even aggravating problems relative to their forecasts), the upward and nonlinear shape of the market supply curve for power, and increasing reliance on renewables, especially wind. There is no reason to expect that these problems are going to abate in the future; to the contrary, they may become worse.

I will focus on the patterns and causes for the Company-wide unitized ($/MWh of retail load) NPC deviation metric for the remainder of my testimony, for the following reason. As noted briefly above, the Company-wide unitized ($/MWh) NPC deviation metric is used in the Oregon PCAM determination as a multiplier to the actual retail load in Oregon. Specifically, the NPC charged to Oregon customers

[7] My understanding is that the small over-recovery in 2016 is after extraordinary costs are adjusted out for the Jim Bridger coal costs. All my analysis includes the 2016 adjusted actual NPC.

in rates is the forecast of Company-wide NPC divided by forecast of Company-wide retail load, while the NPC collected from customers is that forecast and authorized rate multiplied by the actual retail load in Oregon. The actual unitized and Company-wide NPC incurred by PacifiCorp is the actual Company-wide NPC divided by actual Company-wide retail load. Hence, the sign of this unitized NPC deviation metric (forecast for rates minus actual unit costs) for the Company as a whole determines whether PacifiCorp under-recovers NPC. This difference in unit costs is multiplied by the actual retail sales volume to set the amounts eligible for recovery, if they exceed the deadbands and profit collars in Oregon. For this reason, it is more important to examine the factors that influence the unitized NPC deviation metric in $/MWh of retail load.

Q. What have been the key components of NPC deviations as indicated by your analysis?

A. The NPC mainly consists of fuel costs, wheeling costs, and net purchase costs (wholesale market sales minus market purchases). Though all of these can have variances, the net purchase costs are the primary driver of NPC deviations in most of the past five years.

Fuel costs like gas and coal prices to PacifiCorp's own generation can contribute to NPC variances. For instance, the volume of their actual generation could be exactly as was forecasted, but the prices for fuel could have been different than was expected and used to set rates. Alternatively, the forecasted fuel costs could be accurate but the utilization of the plants different than was expected. In that case, depending on load, it is likely that the costs or availability of some other types of supply resources (wind, market purchases) are also different. The third and more likely possibility is that both fuel prices and generation volumes will depart from forecast, and in general this will tend to have partly offsetting influences on NPC for fossil generation.

For instance, if actual gas prices are higher than expected, the usage of the gas units will tend to fall, so the overall gas cost share of NPC will be a variance-dampened blend of higher unit costs but smaller volumes (and vice versa if gas costs are lower than expected). In fact, actual gas prices generally fell below forecasts for most of the past few years, and are recently relatively stable, so they have become less of a driver for NPC under-recovery in recent years. Moreover, gas price can be hedged to help eliminate the unit cost risk. Coal price variances are similarly two-sided with possible increases or decreases in cost pushing volumes burned in the other direction. Additionally, coal prices are generally more stable than gas prices, so coal fuel costs do not contribute significantly to NPC under-recovery either.

In contrast to somewhat predictable generation usage, especially from baseload plants, short-term purchases and sales in the wholesale market(s) can be very unstable. There, deviations in volumes and price do not necessarily have offsetting effects. For instance, if loads are higher than expected, a utility may need to buy more power and buy it at a higher price. For PacifiCorp, adverse price variances (transacting at worse costs than forecast) for net purchases (i.e., as explained below, often for both purchases and sales) have occurred in every one of the past five years.

Market-purchased volumes and the prices at which they occur are also quite sensitive to the time pattern and total quantity of generation from renewable resources, which of course are not controllable or readily predicted, except over moderately long term averages. Thus, even with the annual average performance of these technologies fairly well known and possibly hedged, there is a great deal of volatility and complexity to this component of NPC over shorter time horizons.

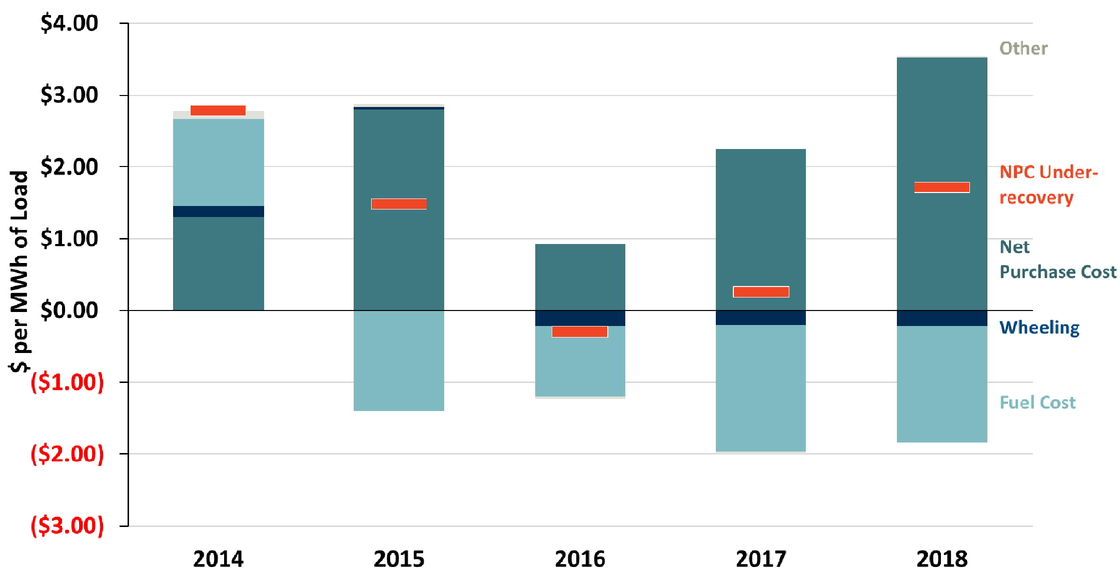
Q. Can you demonstrate these relative shares of influence on NPC variances graphically?

A. Yes, Figure 2 below is a breakdown of the shares of unit cost variance between forecast and actual NPC shown as annual bar charts with stacked layers for the main components. A positive value indicates the actual cost is higher than forecast for that component, thus contributing to the under-recovery in that particular year. Likewise, a component's negative value means that it helps to lower the NPC under-recovery for that year. Of the three main components, net purchase cost was the largest component for 2014-2018, followed by fuel cost and wheeling charges. Fuel cost variance is positive for 2014, though it flipped back to the negative range in the following four years. This is in part driven by large swings in gas prices and gas consumption level during this period. For example, in 2017, both the gas consumption level and the gas prices were lower than forecast, resulting in over-recovery of gas costs.

In addition to being the largest component, net purchase cost remained positive (under-recovered) across the five years in question. As seen in Figure 2, the sign and size of this net purchase cost deficit resulted in an overall shortfall (positive

Net NPC under-recovery), as seen by the red line within the bars, for all years except for 2016, which involved a slight gain.[8] Note however that even when both wheeling and fuel cost deviations were negative in some years, PacifiCorp incurred a NPC under-recovery due to its persistently large positive variance. I decompose this pattern further below to show why it is inherent in NPC.

Figure 2: Composition of NPC Under-recovery for PacifiCorp in Oregon



Notes:
[1] Calculated based on PacifiCorp's PCAM data from 2014 - 2018.
[2] "Other" refers to generating expenses from wind and solar owned by PacifiCorp.

Q. Why do the actual net purchase costs (the subset of NPC shown by the dark teal portions of bars above) exceed the forecasts during all of the years from 2014-2018?

A. Transaction price deviations determine whether actual NPC exceed forecast costs, and the actual volume acts as a multiplier of the difference. Unpredictable natural

[8] The testimony of Mr. Wilding explains why 2016 had a slightly favorable variance, which involved the fact that there were very low gas prices and strong hydro output that year. It is noteworthy that even in a year with such favorable average cost conditions, there was barely any NPC variance (small over-collection), and the under-recovery component from net purchases was still quite positive.

events coupled with complex physical interactions among the participants of the western power grid make it tremendously challenging, if not impossible, for the Company to predict or control the prices at which it buys or sells power other than what is under strict contract. However, as seen in Figure 3, there is naturally a lot of volume of such spot and balancing sales purchases, because of imprecise matching between their supply portfolio and the realized load, similar problems facing other utilities, and the resulting economic opportunities to trade. Note, for instance, that the gross sum (not the net, offsetting sum) of the two is around 25 percent of retail sales. Since each can contribute to NPC, it is this gross sum, not their net, which is most indicative of the scale of the problem. Most of these volumes will be unplanned as to when, where, and at what price they will actually occur at the time of base-rate setting, even if they are fully expected and normal at roughly those levels in the forecast.

Figure 3: PacifiCorp's Short-Term Firm Purchases and Sales

	2014	2015	2016	2017	2018
Short-Term Firm Purchases (MWh)	2,252,456	4,670,988	4,653,654	6,398,082	5,880,090
Percent of Net Retail Load	*4%*	*9%*	*9%*	*12%*	*11%*
Short-Term Firm Sales (MWh)	8,557,501	7,619,541	6,018,797	6,651,663	7,765,501
Percent of Net Retail Load	*16%*	*14%*	*11%*	*12%*	*14%*

For example, if the PacifiCorp service territory experiences an unexpectedly warmer-than-average summer month, demand for electricity will tend to spike upwards for PacifiCorp and for other similarly affected utilities (possibly quite a substantial portion of the WECC). In order to meet this unplanned load increase, PacifiCorp would have to rely on either its more expensive generation assets (the ones not yet being used for planned load levels) or purchase from the market. To the extent that neighboring systems are experiencing similar conditions, market spot prices will be much higher than they would normally be. The supply shortfall may be further exacerbated if other resources that the Company typically relies on generate less than expected—say wind turbines stop operating because of little to no wind (as sometimes happens during heat waves). Consequently, the Company would have to secure even more power than the load increase at a much higher price, which in turn drives up the net purchase costs.

Q. Have you evaluated the key drivers of NPC under-recovery over the last five years to see if a pattern of losses on both under- and over-forecasting (i.e. nearly all unexpected balancing) is evident?

A. Yes, by reviewing the annual and monthly variances in unit costs in relation to net load that is subject to unplanned generation or purchases, I find that the magnitude of the NPC under-recovery has been higher when the actual net load exceeded the forecast, and also when the variances were very small or even negative (actual below forecast)

Net load is a metric designed to identify what supply is needed from dispatchable generation and market purchases (or sales). It is the system load less all wind and hydropower generation on the system. This includes not only resources that PacifiCorp owns, but also all other wind and hydropower resources that it uses that are under long-term contracts, such as qualifying facilities (QF). The net load metric also factors in long-term firm sales and purchases, which are contractual obligations that PacifiCorp has to meet, by subtracting long-term firm purchases and adding long-term firm sales. This definition serves to separate the portion of PacifiCorp's load served by must-take, must-sell, and zero short-run marginal cost (but not necessarily total cost) resources from the remaining load on its more discretionary, dispatchable resources and short-term market purchases, i.e. on the resources that are adjusted to respond to any unplanned requirements (as well as serving a portion of the planned needs).

Additionally, I analyzed how much the forecast for expected net load deviated from the actual net load, both on a monthly and annual basis. If the net load variance is positive for a particular year, the system experiences higher-than-expected net load, resulting in PacifiCorp having to secure more power from dispatchable resources and market purchases than anticipated for that year. As I explained above, power in these instances would have to come from the Company's more expensive generation sources, or from additional purchases.

As seen in Confidential Figure 4, net load variance was positive in 2014, 2015, and 2018, meaning the actual volume exceeded the forecast. Because of the economic dynamics that I explain above, NPC under-recovery was also among the highest for these three years. Vice versa, a negative net load variance indicates that PacifiCorp relied less on its marginal units and market purchases, leading to a lower NPC under-recovery as was the case in 2016 and 2017. In absolute terms, the net load variance is largest in 2016, when forecast net load exceeded the actual by 1.7 million MWh. As a result, 2016 was the only year that PacifiCorp experienced NPC over-recovery.

Confidential Figure 4: Oregon Under-recovery and Related Factors

[redacted]

Notes:
[1] Calculated based on PacifiCorp's PCAM data from 2014 – 2018.
[2] $/MWh values are calculated by dividing under-recovery by total actual retail load of PacifiCorp's system. Retail load is the net system load after taking transmission and distribution losses into account.
[3] Net load variance reflects net system load plus long-term firm sale, subtracting long-term firm purchase and PacifiCorp's own wind and hydro generation. PacifiCorp does not own any solar generation.

The relationship between NPC under-recovery and net load variance is more prominent when shown on a monthly basis. Confidential Figure 5 shows that there is a positive correlation between monthly NPC under-recovery and monthly net load variances for 2014-2018. That is, NPC under-recovery tends to be positive and increasing when actual net load exceeds forecast. Note that the trend line crosses the Y-axis at [redacted], meaning that even when PacifiCorp has accurately forecast its net monthly load, the Company still tends to experience a monthly under-recovery of [redacted].

Confidential Figure 5: 2014-2018 Monthly Average NPC Under-recovery and Company-Wide Net Load Variance

[redacted]

Note:
[1] Calculated based on PacifiCorp's PCAM data from 2014 – 2018.

Q. Why does the magnitude of monthly NPC under-recovery increase at higher levels of net load forecast deviations?

A. Historical data suggests that this is likely due to positive correlation between net load forecast deviations and power price forecast deviations. As shown in Confidential Figure 6 below, actual hub prices at each of the major trading hubs that PacifiCorp uses for purchases and sales tend to exceed forecasts when the actual net load exceed forecast. More specifically, spot prices routinely deviated from the forward market curves at Four Corners, Palo Verde, and Mid-Columbia, three hubs where PacifiCorp historically transacted the most volume. For instance, the difference between actual spot price and forecast price for Mid-Columbia was as high as [redacted] (as in February 2014).

Confidential Figure 6: Monthly Average Hub Price Forecast Variance versus Company-Wide Net Load Variance

[redacted]

Note:
[1] Calculated based on PacifiCorp's electricity hub data from 2014 – 2018. Prices are for flat hours.

This positive correlation means that when PacifiCorp's actual net load exceeds forecast, the Company also tends to experience higher-than-forecast prices for short-term market purchases, increasing the NPC more than proportionally. In contrast, when PacifiCorp's actual net load is less than forecast, actual hub prices do not deviate as much from forecasts. Accordingly, PacifiCorp's sales revenues decrease relative to its forecasts. Therefore, forecast errors in PacifiCorp's net load has an asymmetric impact on NPC deviations as I explain further below.

If the net load volume, which is system load + long term firm sales less (long-term firm purchases + PacifiCorp's wind generation + PacifiCorp's hydro generation), is as forecast, PacifiCorp tends to run its own units at their expected or hedged costs unless the market opportunity to trade is better, which can go both ways.

But if net load volume is higher than forecast for PacifiCorp, it means 1) PacifiCorp has to move further up its own dispatch ladder than was forecast (at higher unit costs per MWh) or purchase more from the market or sell less to the market, and 2) it is likely that the rest of the market is facing similar imbalances, e.g. if it is a hot summer or poor hydro or poor wind conditions. Thus the market price for purchases will also be higher, possibly in a rapidly increasing way as demands push into the high-priced portion of the regional supply curves. Thus, you may have to buy more or sell less at higher prices, for a large adverse NPC variance.

Conversely, if the volume of net load is lower, a utility can move down the supply curve but mostly in the flatter part of the curve (for not much savings compared to moving the other way). If a utility had hedged positions for the expected load, it could sell the excess back to the market, but now likely at a loss to the originally hedged price that was based on higher net demand expectations. Thus a utility is likely to only save a bit or even lose on the adjustment.

Therefore, for both over or under net load forecasts, the error tends to be corrected at a loss.

Q. Does the type of forecasting error and under-recovery that you describe occur at every time scale?

A. Yes. It does occur at every time scale, and sometimes with more variability at shorter intervals, e.g. hourly, where a lot of balancing occurs, and where this is an especially acute issue for wind supply. This component of net load volume can be forecast fairly accurately (or at least usefully) on average over a long time frame (a year or perhaps season), but within those periods may often occur unexpectedly at very different times than planned (e.g., low on-peak day or on-peak hour relative to past patterns of wind), resulting in the same kind of intraday, adverse NPC variances from balancing wind as were shown at the monthly scale for net load. And again, this can occur even if there is no longer-term forecast error for total wind volumes (e.g., over the whole day, month or year).

We can already infer this problem from the above figure by recalling that the fitted trend line crossed the Y-axis at a positive value, i.e. an NPC under-recovery, even though there is no net volume variance at that point. Why is this? It is because the X-axis is measuring average net load error over a whole month. This can be zero, even though there are substantial net load variances (positive and negative) in every day and every hour of that month. Each of those shorter variances will tend to have the same asymmetry of cost as described above, whereby the costs tend to be higher than expected on balancing purchases, and less sensitive (less reduced) on the unforeseen sales or avoided generation.

Q. How does the intermittency of renewable generation influence this shorter term variance problem?

A. It is quite a strong influence. For example, Confidential Figure 7 shows that in 2017 actual hourly wind generation from PacifiCorp's owned and contracted resources deviated from forecast by [redacted] percent (using the absolute hourly deviations), even though on an annual basis, the actual wind generation deviated from forecast by only [redacted] percent. 2018 had similar patterns, with absolute hourly deviations averaging at [redacted] percent versus an annual deviation at only [redacted] percent.[9]

Confidential Figure 7: 2017 Hourly, Monthly, and Annual Wind Generation Deviation

[redacted]

[9] This graphically confirms that the average long-term renewable generation can be meaningfully hedged, but there will be lots of adjustment transactions within the year, some of which can be hedged for blocks of time within the year (though after the TAM forecast) but many not.

Q. Are there other drivers of NPC under-recovery that you have not addressed?

A. Yes. For example in 2014, there were two other adverse surprises in that year that contributed to NPC under-recovery. First, power prices at major trading hubs exceeded the forecasts by about $5/MWh in part due to actual gas prices exceeding forecasts by roughly $1/MMBtu. The higher power prices and gas prices made both the purchases and gas generation more expensive than projections, hence resulting in higher NPC than forecast. Second, PacifiCorp's purchases of third-party wind generation through purchased power agreements (PPAs) from both QFs and non-QFs, exceeded the forecast by about 10 percent. This might seem like good news because it means that fewer market purchases or lower dispatch of higher marginal cost resources are needed. However, the PPA prices of the third-party wind can negate this benefit, if those turn out to be higher than the market energy price at the time of the over-supply variances. This appears to have been the case: The volume-weighted average price paid under these wind PPAs was about $60/MWh, which was roughly double the actual market power prices for energy in that year. Thus PacifiCorp paid more for wind PPAs this year than expected, at costs likely above its own resources' marginal costs or market energy prices.[10] Any such above-market prices for the more-than expected wind output contributed to the NPC under-recovery. (Note that owned wind does not have this problem, because its short-run operating costs are zero, so any increased generation is a source of immediate savings).

[10] This gap is largely because the wind contracts generally recover those resources' fixed costs through variable rates, while the market prices involved in balancing do not generally capture fixed costs from marginal generating facilities.

Q. How does expected wind output enter into the NPC projections that PacifiCorp uses to set rates?

A. It is very difficult if not impossible to forecast when and how much wind will occur, at least not within a forward test year.[11] As a result, PacifiCorp uses a flat average of historical annual wind conditions (at each site) for total output, shaped by the time pattern in the most recent past year of actual output in order to project generation from its wind plants (or it uses the developer's projections if the plant has less than four years of history). This is a reasonable way of projecting those patterns, capturing both the steadiness of the long-term wind patterns and the need to recognize that it typically has a complex (but unstable) seasonal and diurnal pattern. Of course this projection will not match actual realized production patterns, sometimes over-estimating and sometimes under. How that affects NPC depends on whether it occurs for a wind plant owned by PacifiCorp versus under contract for the output at a fixed price per MWh. Positive variances (unexpectedly greater generation) from owned plants will tend to displace fuel use or market purchases, reducing NPC, while such overproduction from a third-party wind resource under a PPA could cause an NPC increase from paying the contract price, if that price is above PacifiCorp's marginal cost.

Note that even if there is exactly the predicted amount of wind over a moderate horizon (a year, or even a day), there can and will be NPC variances arising from what times within that day (or month, etc.) the wind blows and where (because

[11] It is increasingly possible to gain useful, albeit still quite imprecise, forecasts of wind for a day ahead, which helps with unit commitment, but this is not within a horizon that can improve annual forecasting for TAM purposes.

the time of day market prices avoided or incurred are quite volatile). This problem was shown above in Confidential Figure 7 to be extremely common on a daily basis. Thus, wind-based supply, or any intermittent weather-sensitive renewable form of generation, creates an intrinsic NPC variance problem even when it is forecast accurately on average.

This may contribute more NPC variances and under-recovery in the future, as more wind is added to the PacifiCorp fleet and more, older fossil units are retired. Solar power, for which PacifiCorp is planning a significant increase over the next few years, may be slightly more forecast-able, because long-term weather patterns (e.g., annual precipitation) for solar are becoming somewhat predictable by meteorologists albeit still very imprecise. To my knowledge, wind is less amenable to that improvement. The next section describes the increase in planned or required renewables for PacifiCorp and across WECC.

IV. PACIFICORP'S LACK OF CONTROL OVER THE KEY UNCERTAINTIES THAT DRIVE NPC UNDER-RECOVERY

Q. You have explained how forecast errors in either direction induce unplanned net purchases and sales that are likely to create NPC increases. Could PacifiCorp mitigate this problem with better forecasting, or hedging, or changes in operations?

A. No, it is doubtful that much can be done to improve the situation with those adjustments. First, my impression is that the PacifiCorp forecasting methods for these elements of NPC are in keeping with good business practices throughout the industry. While the search for modeling improvements is a good idea, 1) the models and inputs PacifiCorp is using are in keeping with industry standards and are being carefully applied, 2) I am not aware of a model that is capable of capturing the wide variety of unforeseen, stochastic (random) influences that will affect the ultimate NPC, and 3) even if such a model were available, it would not be possible to forecast with any confidence or accuracy the parameters for the random noise from uncontrollable factors that should be overlaid on it to project the coming year. That is, you could perhaps calculate a premium for an assumed level of variance (e.g. based on history), but you would not get a better forecast of what will actually happen.

Likewise, hedging will not help much if at all for the purchased power part of the problem, because the main difficulty is knowing the relevant volumes. Most commercially available hedges are for price protection of a given volume, allowing a utility or producer to hedge specific volumes for specific times. Thus, annual average output can be hedged, but not so much the costs of deviating from that average. The times when there will be an unplanned outage of a generation unit, or there will be more or less wind than in the past from a wind farm, or similar changes on other systems with which PacifiCorp trades, are intrinsically unknowable. Even options, which can be used conditionally, have fixed volumes and periods of allowable exercise. Hedges mostly help the volumes that you can reliably expect. Much of the NPC problem comes from the volumes you cannot plan at least as of the TAM rate-setting time period, except to know in general that they will happen.

Q. Please describe how and why the modeling tools and techniques are limited in ability to work around these problems, such that it would lead you to expect the actual NPC to routinely exceed PacifiCorp's forecasts.

A. Based on my review of the methodology and key assumptions in PacifiCorp's modeling tool GRID to forecast NPC, I conclude that the GRID modeling approach and assumptions include some built-in features (many common to similar models used throughout the industry) that tend to result in under-estimates of the NPC, including the following:

- First, and most insurmountably, system simulation tools like GRID optimize mathematical projections of efficient operations and market transactions under perfect foresight of system conditions and prices, without considering the effects of market uncertainties that create additional unit commitment and dispatch costs, and reduce market participants' ability to find and execute the most profitable transactions. That is not to say that the perfect foresight includes what will actually happen, but as far as the model is concerned, the conditions you project are the only and exact ones that will occur, and then it finds the best way to deal with that. You can run it for different conditions, e.g. higher loads, and perhaps average the two results, but even the alternative scenarios will be perfectly optimized to the parameters of the scenario.
- To be most plausible and useful as an expected cost projection, simulations typically assume "normal" weather, load, hydro generation, without considering the asymmetric impact of deviations from these average conditions. Simulations do not reflect non-standard, challenging and erratic system conditions, such as

transmission outages, fuel supply disruptions (e.g., Aliso Canyon impacts), or extreme weather conditions, such as heat waves, extended droughts, or polar vortexes etc. that can drastically increase power costs and prices. Again, a few such deviant scenarios can be tested, but there are countless perturbations of what they could look like.

- Simulations do not capture inefficiency of fixed-size bilateral trading blocks. Most of PacifiCorp's monthly and day-ahead transactions are executed in blocks (e.g., 16 hour blocks at 25 megawatts (MW) increments), and they are far less flexible and less profitable than the hourly transactions made available in the model.
- Long-term wind and solar forecasts are unable to predict variations within the upcoming year—unlike hydro, which to some degree can be tuned a bit for the coming year because of known and projected weather conditions (like expected snowfall). I am not aware of any such year-to-year conditional shaping of long-term future wind and solar profiles. Thus, they must be simulated as being about like average, all the time (as described above being PacifiCorp's practice), even though after the fact, they never are like average in most days or even for the whole year.[12] This will become more problematic as more renewable resources are added to the PacifiCorp and other WECC members' fleet(s).

[12] There is some net renewable diversity that is gained by relying on a mix of solar and wind, as PacifiCorp is moving towards, but a lot of that benefit is gained at the seasonal and diurnal time frames (spring night-time wind versus summer day-time solar) that can be forecast on average at the beginning of the year, e.g. in the TAM. There may be some additional diversity benefits within shorter time frames, but measuring those would depend on knowing the short-term correlations between solar and wind output (e.g., when the sun goes behind a cloud, does the wind tend to blow more or less?). I am not aware of any utility that has measured or is modeling this level of detail in their renewable resource planning or hedging practices.

- System models do not calculate feedback effects on fuel prices, other suppliers' behavior (such as scarcity bidding), or price-sensitive loads from unforeseen shifts in market conditions.
- Loads depend on circumstances well beyond what a utility considers, especially commercial and industrial loads that can vary with tariffs, competition from other countries, and the price of non-electric commodity inputs to their production.

All of this simply reflects that there is never going to be a forecasting tool for net loads, solar, or wind, or for projecting market balancing operations, that will not have *ex post* errors. Models are intrinsically smoother and nicer than real world conditions, and smoothness typically results in under-estimation. This exposure to errors will persist and will likely grow under the direction the industry is headed. And because the supply curve for the industry is increasingly upward sloping as net demand increases and flatter and more slowly declining when net demand decreases, whatever errors remain will tend to have a positive cost, not wash out. This appears to be a significant cause of the persistent NPC under-recoveries for PacifiCorp.

Q. What are the implication of these key drivers of NPC deviations and under-recovery for the appropriate mechanism to allocate NPC risks between PacifiCorp shareholders and ratepayers?

A. These key drivers of NPC under-recovery (deviations in load, hydro, wind, and market spot power prices) are outside PacifiCorp's control. They may be amenable in principle to better forecasting, though no such mechanism has been identified or approved, or ad hoc adjustments (like including a correction factor based on history as an uplift over forecasted NPC unit costs)—but the difficulties are intrinsic to the fact that this component of NPC arises on the margin in relation to both unforeseen conditions and how those affect the marginal positions of every other power market participant in the WECC that is able to trade with PacifiCorp.

Because these are so uncontrollable (and none of the past variances have been attributed to imprudent or inefficient practices by PacifiCorp) there is no improvement or benefit that can be expected or incentivized by not allowing 100 percent of NPC deviations to pass straight through to customers. Just as one would not be able to do a better job in his or her profession if their bonus was tied to how the weather turned out.

Q. If all of these problems are intrinsic to forecasting and resource planning in the industry, doesn't that just make them a part of normal business risk that the utilities should just incur and internalize, e.g., as part of what their allowed ROE covers?

A. No, they indeed are normal to experience, but it is not normal for them to be systematically under-recovered by virtue of asymmetric risk-sharing and broad exclusions for cost recovery. They reflect prudently incurred costs that are simply extremely difficult to forecast. Thus it is not productive, or equitable, or incentivizing to treat them as just a normal risk that should be absorbed by utility shareholders. In particular, it is not correct to construe them as a risk that is implicitly covered by the allowed ROE. The allowed ROE is predicated on (and will be sufficient to cover comparable financial risks for investors when it is) being added to an allowance for other non-financial costs that is itself unbiased. The intention is to allow a risk-adjusted, time-deferred recovery of prudently incurred costs, including return on and of capital. But that can only occur if indeed <u>all</u> of the prudent costs other than cost of capital are themselves fully in the revenue requirement. [13]

What my analysis demonstrates, and the persistent NPC shortfalls reveal, is that such operating-cost recovery completeness is not the case for PacifiCorp. There is a missing type of cost from the asymmetry of dealing with balancing transactions in a dynamic market. This is a prudent cost, arising because of massive savings that are possible when multiple companies pool and diversify their risks and opportunities in a market. In essence, they are a byproduct of this benefit. It is not reasonable to treat the residual forecasting bias that arises from taking advantage of the market as a cost that should be borne by utility shareholders.

In fact, because it is both normal and prudently incurred, most other states allow their utilities to pass through all of their NPC to their ratepayers without deadbands or earnings tests, as I explain further in Section VI.

Q. Is there any incentive benefit from putting these costs at risk, via the deadbands and profit collars on the current PCAM?

A. No. As noted above, these costs cannot be mitigated by alternative forecasting or hedging, and they are not the result of poor operational decisions. They are prudent, but fundamentally uncontrollable, and therefore should be fully recoverable. Making the utility bear them at risk when they cannot do anything material to reduce or improve them is simply punitive.

[13] Even if one thought that this type of non-recovery risk was something that shareholders anticipate and build in a risk premium for it—which I reiterate is not the case—it is unlikely that the measured cost of capital for PacifiCorp would properly capture that premium. This is because, as shown below in my survey of risk sharing by other utilities, almost no states other than the ones where PacifiCorp operates impose such NPC cost-recovery risks on their utilities. Thus the proxy groups for measuring cost of equity almost certainly would not include this problem. By removing this risk-sharing, PacifiCorp would be put on more equal terms with other utilities against which its risk is measured.

In fact, too much risk exposure tends to induce counterproductive behavior to try to avoid the problem. One way (in principle – NOT a recommendation) for PacifiCorp to do that would be to reduce its use of the market for balancing (sticking to the more knowable state of its own generation fleet) and to reduce its reliance on renewable generation. Those are obviously bad ideas, but they illustrate the fact that the NPC sharing rules currently in place punish PacifiCorp for pursuing those benefits, where the NPC under-recovery is simply a byproduct of being in the market with those resources.

V. NEED FOR PACIFICORP'S PROPOSED MODIFICATIONS TO THE PCAM IN OREGON GIVEN FUTURE MARKET TRENDS

Q. You have shown how the PCAM under-recovery variances have arisen in the past. How is the exposure to this problem likely to change in the coming years as PacifiCorp and other WECC utilities adjust their resource mixes?

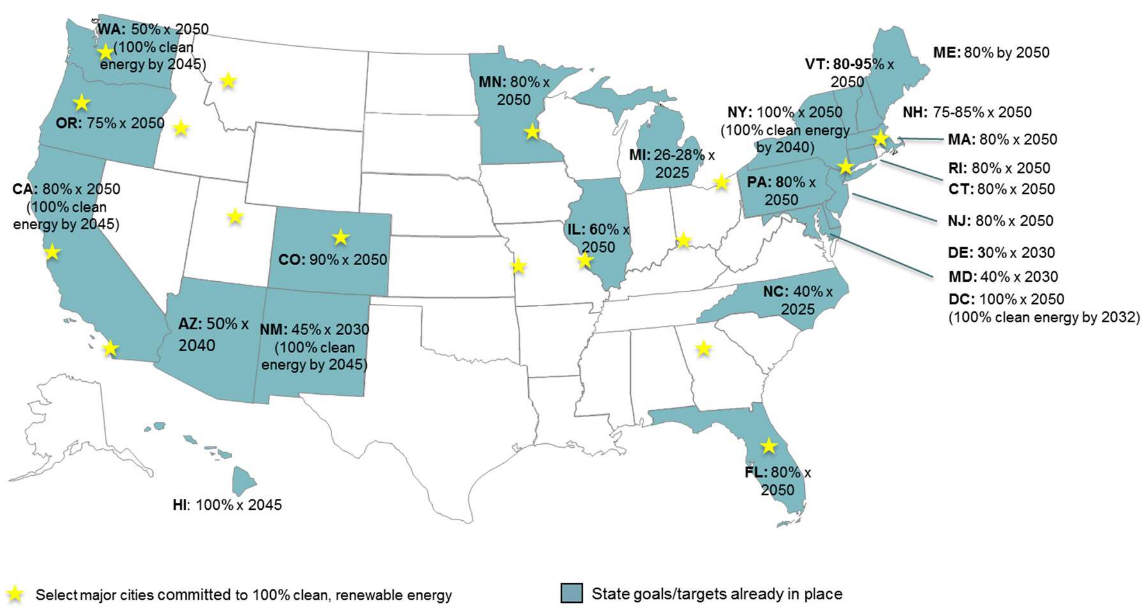
A. I expect under-recovery variances will become more problematic for PacifiCorp in the future, for several related reasons. First, as seen in Figure 8 many of the states or sometimes just the large cities in the WECC are pursuing public policy goals to try to dramatically decarbonize not just their electric sector but their entire economy, by backing out fossil fuel uses from transportation, heating, and some commercial applications. In particular, 10 states (plus Washington D.C. and Puerto Rico), including California, Washington, Nevada, and New Mexico, have made either 100 percent renewable energy or 100 percent clean energy commitments.[14] Other states have goals to at least significantly reduce fossil fuel use in their electricity

[14] *See 100 percent renewable targets*, ENERGYSAGE, https://news.energysage.com/states-with-100-renewable-targets/.

generation, including Oregon with a 75 percent greenhouse gas reduction target by 2050. On top of that, more than 150 cities have committed to transition to 100 percent renewable energy, including Portland, Boise, and Missoula.[15]

Regardless of such policies, the relative cost of renewables versus fossil generation has shifted, generally shifting towards greater economical roles for renewables under more and more conditions. This makes renewable resources attractive whether they are mandated or not. Several utilities have announced plans to back out existing fossil plants and replace them with a mix of renewables and storage (and sometimes gas peakers) over the next decade, including Public Service Company of New Mexico, Arizona Public Service (APS), Idaho Power, Xcel, among others.[16]

Figure 8: Deep Greenhouse Gas Reduction Targets for U.S. States and Cities



Notes:
[1] State goals and targets from https://www.c2es.org/content/state-climate-policy. Different states have different baseline years to measure future reduction goals.
[2] City data from https://www.sierraclub.org/ready-for-100/commitments.

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[15] *See Ready for 100*, SIERRA CLUB, https://www.sierraclub.org/ready-for-100/commitments.
[16] *See Utility Carbon Reduction Tracker*, SMART ELECTRIC POWER ALLIANCE, https://sepapower.org/utility-carbon-reduction-tracker/.

Q. How does PacifiCorp's planned generation resource mix reflect these policy and technology trends for the future?

A. According to the Company's 2019 IRP, PacifiCorp is expecting to substantially increase the share of renewables and energy storage in its resource mix.[17] For instance, the preferred portfolio includes over 6,300 MW of new solar resources and over 4,600 MW of new wind resources over the next 20 years, representing about 100 percent of PacifiCorp's current total fleet capacity. The 2019 IRP's least-cost portfolio also includes about 600 MW of battery storage by 2023 and an additional 2,200 MW by 2038. This is a significant development, given that PacifiCorp does not currently own any solar generation resources or significant battery storage facilities.[18]

Q. Please explain why this shift is likely to exacerbate NPC under-recovery risks.

A. There are two different impacts on NPC from greater use of renewables. The first is to lower the average cost of fuel by virtue of the "free energy" (i.e. zero short run marginal costs, ignoring fixed capital costs) for the new supplies. This will lower the base rates component forecast by the TAM. However, the second impact is more complex, arising because of the difficulty in forecasting the short-term renewable patterns and having to offset deviations from plan in those hours with re-dispatch or market transactions (i.e. the major drivers of the NPC deviations). More specifically:

[17] *See In the matter of PacifiCorp, dba Pacific Power, 2019 Integrated Resource Plan*, Docket No. LC 70, PacifiCorp's 2019 Integrated Resource Plan (Oct. 18, 2019).

[18] Note that battery storage can help with the imbalance problem, by servicing some of the short daily periods when there is less renewable output than expected. However, at the level of roughly 1 MW of storage per 16 MWs of renewables, this will not materially alter the NPC problems described herein. The large increase in renewables will overwhelm the storage offsets.

- In the hours when they do not produce as much as needed or expected, there may be higher than now-typical unit costs from paying fast-response resources or demand-response adjustments to load for absorbing the shortfalls, which can occur on short notice (and will be essentially impossible to forecast over the horizons of annual or longer rate-setting processes). So balancing energy costs may be higher and more volatile than in the past.
- There will tend to be more correlation across the entire power system fleet in output, as PacifiCorp and much of the WECC moves towards more renewables, because they are all responding to shared conditions from the sun or wind. It is of course true that there is geographic diversity across large regions (hundreds of miles or more) for when and where these renewable "fuels" will be active, but it is also true that huge areas (many states at a time) can experience similar weather of being overcast or not windy (or vice versa, very windy). Unlike fossil plants, whose outage characteristics are relatively independent, renewables will tend to face this risk jointly, thus causing much bigger (and perhaps more sudden) shifts over time in what I referred to as net load above.
- As the transportation and heating sectors are decarbonized, there will be more electric load on the system—by some estimates, perhaps doubling (or more) because the majority of greenhouse gases in the economy now stem much more from those sectors than from electricity generation. The apparently most economical way to reduce them is to convert those loads to electricity and

then supply those new needs with lower-emission power.[19] This shift will make weather sensitivity greater for the electric loads served by PacifiCorp and others.

Q. Can you provide some empirical support for these qualitative descriptions of the shift towards renewables?

A. Yes. According to the U.S. Energy Information's Administration (EIA) Annual Energy Outlook 2020, generation from renewables nationally will increase from 18 percent to 38 percent of total generation by 2050, with solar contributing to almost half of that share.[20] In the "West" region, which includes Oregon, Idaho, and Wyoming, EIA projects generation from renewables will double by 2050. Consistent with general market outlook, EIA anticipates that the wave of coal plant retirements will continue. In the last decade, coal plant owners retired (or planned to retire) more than 546 coal plant units, totaling about 102 gigawatts (GW) of generating capacity, or about 1/3 of the total coal fleet relative to 2008.[21] An additional 17 GW of coal capacity is planned to be retired by 2025.

Furthermore, states will need to accelerate their renewable deployment efforts in order to meet the greenhouse gas reduction and/or clean energy targets that I mention above.

[19] It is also possible that biofuels will become available so that those loads do not have to be electrified, but the process of making the clean biofuels may itself involve more electricity production than the end use energy they will serve. So either way, electric demands grow dramatically.

[20] U.S. ENERGY INFORMATION ADMINISTRATION, ANNUAL ENERGY OUTLOOK 2020 – ELECTRICITY, *available at* https://www.eia.gov/outlooks/aeo/pdf/AEO2020%20Electricity.pdf.

[21] U.S. ENERGY INFORMATION ADMINISTRATION, TODAY IN ENERGY (July 26, 2019), *available at* https://www.eia.gov/todayinenergy/detail.php?id=40212.

Q. Please summarize the consequences of this trend for NPC.

A. The main effects are to enlarge the difficulties already experienced. Renewable generation will be more significant but is difficult to forecast, especially far in advance for rate setting. Renewables can also be quite variable over the short run, and will tend to do so en masse rather than independently, creating shared conditions of overall shortfall or excess supply when they vary from expectations, likely pushing replacement market prices far off of their prior expectations as well. And there will be more load exposed to this situation, so the total costs at risk will be larger (offset in part by the expected part of the energy price, when the renewables perform as hoped, lower in cost). Overall, it should be beneficial, but it will make NPC variance due to uncertainty in net load much greater. And as shown above, those variances tend to cause losses on either side, whether positive or negative, because of their correlation with market prices and the asymmetry of prices for unplanned higher demand going up faster than they fall for unplanned softening of demand.

It is also likely that all the utilities in WECC will move to greater and greater reliance on market-mediated coordination as more renewables are used, largely to take advantage of geographic diversity and to share access to non-renewable balancing resources that may be used only occasionally (less often but more acutely) than such plants are now used. This means more of the balancing costs in NPC will depend on actions of other utilities that are not part of the control or forecasts of PacifiCorp.

VI. REVIEW OF PCAM IMPLEMENTATION IN OTHER STATES

Q. Have you reviewed the PCAM implementation in other states?

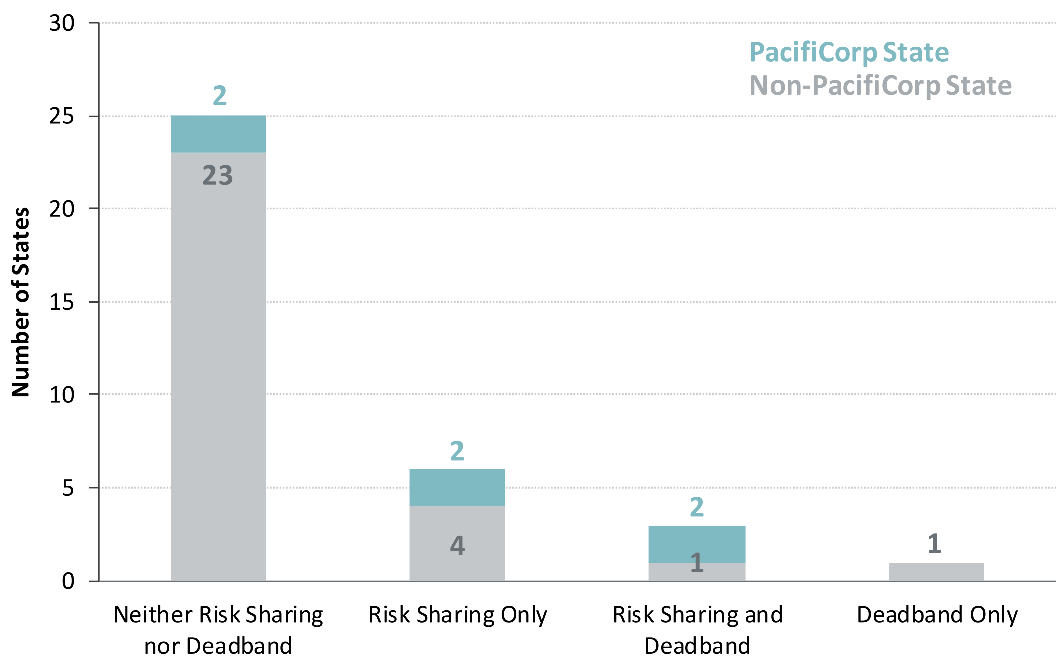
A. Yes. I have compiled state by state profiles of current policies towards PCAM-like cost recovery mechanism for vertically integrated utilities, excluding those that have unbundled generation from delivery services and/or that participate in an independent system operator (ISO) and within have deregulated merchant generation. For instance, this means that Texas utilities in the Electric Reliability Council of Texas are irrelevant, as are the vertically unbundled utilities in PJM, New York, etc.—but the vertically bundled utilities in Midcontinent Independent System Operator (MISO) are relevant. In total, I reviewed the fuel adjustment clauses in force in 2019 across 35 states that have regulated electricity power supply. The results of my survey detailing the structure of each state's enacted adjustment clauses is attached as Exhibit PAC/602.

Q. Based on your review, is the Company's existing PCAM consistent with those of most electric utilities around the country?

A. No. The Company's existing PCAM, which includes risk sharing of 90 percent to customers and 10 percent to stakeholders outside a deadband range of -$15 million to $30 million, and then profit collars on whether the magnitude is material, is inconsistent with prevalent industry practice in two regards. First, of the 35 relevant states, the vast majority do not apply any risk-sharing mechanisms or deadbands, instead passing through all NPC-type costs 100 percent to customers (often subject to an occasional prudence review). A handful apply one or both of risk-sharing or deadbands, but often those are states in which PacifiCorp operates. Thus, PacifiCorp's exposure to this policy is almost unique. Second, the few risk-sharing mechanisms that are applied elsewhere are usually milder and more symmetrical than those facing PacifiCorp.

These findings are summarized in Figure 9 below. For each bar, the teal shading indicates the number of states in which PacifiCorp operates, while the gray shading represents the remaining states in which PacifiCorp does not operate. For example, PacifiCorp states make up two out of the six states with a risk-sharing mechanism only, and two out of three of the states with both a risk-sharing and deadband mechanism. In other words, nearly half of all states with risk sharing are states that lie within PacifiCorp's service territory.

Figure 9: Structure of Fuel Adjustment Clauses in Benchmarked States



Source and Notes:

The Brattle Group interpretation of deadband and risk-sharing mechanisms, based on descriptions of fuel adjustment clauses in SNL Energy Regulatory Research Associates (RRA) summaries and utility filings. PacifiCorp states consist of those in the service territories of Pacific Power (California, Washington, Oregon) or Rocky Mountain Power (Idaho, Utah, and Wyoming).

Digging under the surface of these results, of the three states that have both risk-sharing and deadbands, two are Oregon and Washington where PacifiCorp operates. Of the six other states with just a risk-sharing mechanism, five (Hawaii, Idaho, Missouri, Montana, and Wyoming) generally allow their utilities to recover between 90 percent and 98 percent of cost variations, with the exception of a 70 percent sharing clause for PacifiCorp's PCAM in Wyoming.[22] Thus these other utilities' recovery shares are either consistent with or higher than the one under PacifiCorp's current PCAM in Oregon. Perhaps more importantly, those shared amounts are not subject to asymmetric deadbands or wide profit collars that further skew or restrict cost recovery. Thus they are more amenable to neutral (zero) expected impacts on costs, to the extent that forecasting errors tend to balance out over time.

Q. Is there any important distinction in these patterns when focusing on just vertically integrated utilities in regional-transmission organizations (RTOs) and ISO regions?

A. No. Of the 35 regulated states, 20 operate in RTO/ISO regions.[23] I analyzed the adjustment clauses for their utilities (that participate in these RTO/ISO markets while owning their own generation) and found they almost all have full and unfettered flow-

[22] In Wyoming, Cheyenne Light Fuel & Power can only allocate 85 percent of steam production cost variations to ratepayers, but 95 percent of all other eligible costs, with the latter making up a vast majority of its power costs. The fifth state with a risk sharing mechanism, but no deadband, Arizona, has eliminated the 90/10 cost-sharing mechanism that was in place in 2012, but maintains a $0.004/kWh annual cap on increases or decreases to the adjustment clause. If a true-up stays in keeping with this cap, APS can recover its full fuel and purchased power costs.

[23] The 20 states I reviewed (Arkansas, California, Indiana, Iowa, Kansas, Kentucky, Louisiana, Minnesota, Mississippi, Missouri, Montana, New Mexico, North Carolina, North Dakota, Oklahoma, South Dakota, Vermont, Virginia, West Virginia, and Wisconsin) participate in California Independent System Operator, Independent System Operator of New England, MISO, PJM, and Southwest Power Pool.

through of NPC-type costs. Only two (Vermont and Wisconsin) have fuel and purchased power adjustment clauses with deadbands. But in both cases, these deadbands are narrower than the current one in place for PacifiCorp's PCAM in Oregon, and they are completely symmetric, while the deadbands for Oregon are skewed to impose a larger share of losses for utilities than they allow retention of gains.[24] Similarly, only three states (Vermont, Missouri, Montana) incorporate a risk-sharing mechanism for recovery of fuel and purchased power costs.

VII. CONCLUSIONS

Q. Please summarize your conclusions.

A. Due to Oregon's wide and asymmetric deadbands and profit collars on NPC risk-sharing, PacifiCorp has experienced systematic NPC under-recovery in the past several years, which has accumulated to approximately $77 million of losses since 2014. These shortfalls are not arising because of occasional bad luck in the market, or bad forecasting, or improper or inefficient operations, but because of a flawed design for the PCAM mechanism itself.

As constructed, the PCAM does not accommodate the fact that due to more reliance on renewables and market participation (both beneficial on average), there is more irreducible forecast error in the projected NPCs. Worse, the error is not just noise but a downward bias, whereby the costs of balancing the system are intrinsically missed and omitted from the requested total costs. As a result, realized NPC tend to be higher than were forecast in rates, and there is persistent under-

[24] Wisconsin has a deadband of +/- 2 percent, and Vermont has a deadband of +/- $0.3 million per year. In contrast, the current deadband for PacifiCorp in Oregon is -$15 million over-recovery and +$30 million under-recovery, representing about 4-8 percent of the actual NPC in Oregon. That is, the Company needs a very large (8 percent) under-recovery of its Oregon NPC before it can even qualify for partial sharing.

recovery. Balancing transactions are not forecast precisely because they arise from realized conditions not being like the forecast. Perhaps surprisingly, when they occur, they tend to involve losses whether purchases or sales. This is because if more supply is needed than was expected, it will tend to have to be purchased in a tight market in which others are often experiencing similar shortages (or it must be supplied from the highest part of the dispatch supply curve that was not planned to be used). On the other side, when realized demand is below forecast, sales of unneeded power or fuel will tend to be dumped into a soft market with less than full recovery of whatever covering transactions or expenses were normally expected to have been needed.

These difficulties are normal for utility planning, but it is not normal for a utility to have to absorb most of such variances from forecast costs. It would be one thing to put the variances at risk or disallow the variances if the unrecovered costs stemmed from factors that PacifiCorp could control. Here, that is not the case, so there is no efficiency or incentive benefit to imposing risk-sharing on NPC. As I have demonstrated, the large volume of purchases and sales for system balancing in the wholesale markets are the main drivers. It is intuitive that these transactions occur due to many factors that are beyond PacifiCorp's control or prediction, because the Company would have to not only accurately forecast the conditions of its system (e.g. all the short-term weather) throughout the test year but also to correctly anticipate the needs, surprises, and (re)actions of other market participants throughout the market region(s). This is clearly impossible. Indeed, best-practices market modeling tools do not even support simulating most of those elements.

PacifiCorp's increasing use of renewables and broader participation in regional power markets is a good thing, surely reducing NPC on average. But doing so comes with a side-effect of more exposure to short-term, uncontrollable, difficult to forecast, and only partially hedge-able transactions that tend to have a persistent net cost. This net cost is inadvertently excluded from the base rates. All utilities face this problem, and since it is uncontrollable and not able to be fixed with better forecasting, the vast majority of their state regulators allow full cost recovery of NPC with no risk sharing. Only a handful impose any risk-sharing or deadband conditions, and those are 1) mostly the PacifiCorp states and 2) they mostly have milder and more symmetric risk sharing than Oregon. Thus, it is not normal business risk in the industry to face losses from these prudent costs.

A better solution, which would put PacifiCorp in risk-exposure parity with other investor-owned utilities, would be to go to full cost flow-through of NPC to customers, subject to a prudence review of actual operations. This would be a more relevant form of oversight than the current arrangement, which tends to confound intrinsic forecasting difficulties with business operations. Making this improvement in regulatory practice likely to become even more important in the future, due to the strong shift towards more renewable generation in the PacifiCorp fleet (and throughout much of the WECC).

Q. Does this conclude your direct testimony?

A. Yes it does.