BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 400

In the Matter of	)
	)
PACIFICORP, dba PACIFIC POWER,	)
	)
Transition Adjustment Mechanism.	)
	)

REDACTED OPENING TESTIMONY

OF THE

OREGON CITIZENS' UTILITY BOARD

May 25, 2022

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I. INTRODUCTION

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

A. My name is Bob Jenks. I am the Executive Director of the Oregon Citizens' Utility Board (CUB). My business address is 610 SW Broadway, Ste. 400, Portland, Oregon 97205.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in exhibit CUB/101.

Q. What is the purpose of your testimony?

A. My testimony responds to PacifiCorp's Transition Adjustment Mechanism (TAM) filing. I discuss the switch to the Aurora Model, then I discuss CUB's concerns with several of the proposed modeling changes: market caps, regulation reserves, planned maintenance, and the day-ahead real-time (DA/RT) adder. I want to begin by discussing CUB's concern that customers will feel significant rate shock on January 1, 2023, if PacifiCorp's proposals in several cases are granted.

Q. Please describe the concern about rate shock.

A. In this filing, the Company is forecasting 2023 net power costs of $1.684 billion, which is significantly higher than the 2022 forecast of $1.364 billion. Approximately $70 million of this increase is allocated to Oregon, with an average rate increase of 5.6%, and a residential increase of 5.2%. However, this proposed increase is not in isolation. It will coincide with the increase from the PacifiCorp general rate case, where the Company is proposing an increase of $84.4 million or 9.1% for residential customers. In combination, the two cases would raise residential rates by 14.3%. PacifiCorp recently filed its Power Cost Adjustment Mechanism, where it is seeking another $50 million, or 4% rate increase (3.6% residential) beginning on January 1, 2023. In combination, these three filings propose increasing residential rates by 17.9%.

But that is not all the costs that customers are facing. There is also an extremely large deferral related to wildfires and a significant deferral related to COVID-19. Beginning amortization of these could push the residential rate hike to 20%. Finally, we note that the power cost forecasts in this case will be updated later in this case. Because gas prices, including gas futures, have climbed since the initial filing in this docket, the update will likely increase net power costs beyond this filed case.[1] Residential customers face a greater than 20% increase just as the peak of the winter heating season starts in January when many

[1] https://www.marketwatch.com/investing/future/ng00
https://www.cmegroup.com/markets/energy/natural-gas/natural-gas.quotes.html

customers are facing their highest bills of the year. This would be the largest increase to PacifiCorp's Oregon residential rates since the 2001 Western Energy Crisis. It is important to recognize the combined effect of these rate hikes in all of the dockets and look for ways to alleviate rate shock.

Q. How should the Commission consider rate shock?

A. As we go through each of these proceedings, CUB will be making some specific recommendations to address rate shock and try to bring down the size of the residential increase in January. Generally, these recommendations center on traditional ratemaking principles, but will be applied in the context of trying to reduce the rate impact. These measures include avoiding increasing the revenue requirement for items that are not *completely necessary* for providing service to customers in 2023, ensuring that rates are spread in a manner that can alleviate rate shock for individual classes of customers, delaying recovery of some costs beyond January 1, 2023, and spreading some costs over longer time periods. In addition, it might be necessary to look outside of traditional ratemaking to identify additional tools. For example, securitization[2] might be a tool to use for items like the wildfire and COVID deferrals.

II. AURORA

Q. What is Aurora?

A. Aurora is a production cost model used to forecast the Company's net power costs. As used by PacifiCorp in this case, Aurora is a model that simulates the dispatch of the system to meet load. PacifiCorp is replacing its old model, GRID,

[2] CUB Exhibit 102.

with Aurora in this case. Aurora has more inputs, more capabilities, and different optimization logic.

Q. How does Aurora compare to GRID?

A. PacifiCorp ran a validation process to compare the two models. Because the net power costs produced by that validation were within 0.8%, the Company seems satisfied, and attributes the changes in cost from last year's GRID model to this year's Aurora model to wholesales sales revenue, increased natural gas fuel expenses, increased purchased power expense, and wheeling and other expenses. However, because the 2023 forecast for each of these items was only done in Aurora, it is not clear to what degree the differences in modeling logic are causing these changes and to what degree changes in market conditions during the forecast period are causing the changes.

When looking at the details of the validation efforts we find that there are several elements that vary much greater than 0.8%. **[Begin Confidential** [redacted] **[End Confidential]**

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[3] These numbers come from comparing PacifiCorp confidential Exhibits 103 and 104.

These modeling differences then follow through into the various adjustments that PacifiCorp makes to the modeling, such as the DA/RT adjustment. Confidential Table One shows the difference between the GRID and Aurora produced DA/RT adjustment adders from the validation[4] (in dollars): **[Begin Confidential]**

Confidential Table One

[redacted]

[redacted] **[End Confidential]**

Q. What conclusions do you draw concerning PacifiCorp's use of Aurora?

A. The change in production cost models is creating a lot of changes to the 2023 forecast. How these changes interact and affect overall prices are hard to tell. The validation exercise looked at 2021, not 2023. While it did not show a great deal of variation in the overall result, there is a lot of variation in elements of the modeling. Because of this large variation in some of the elements, it is difficult to say whether the lack of variation in the overall result was a somewhat random event.

[4] These numbers come from comparing PacifiCorp's Confidential Exhibits 103 and 104.
[5] These numbers come from comparing PacifiCorp's Confidential Exhibits 103 and 104.

CUB recognizes that Aurora has more granular elements, and that GRID was not known for its accuracy. CUB does not oppose the use of Aurora. However, CUB believes that it is too early to say how much of the increase in power costs in this case were caused by the change to using Aurora absent the changes in market conditions. It is difficult to determine whether Aurora's forecast will prove to be more accurate than the GRID forecast the Company previously used. CUB would have preferred to see PacifiCorp limit additional modeling changes so parties can evaluate the impact of the change in models.

III. MODELING CHANGES

Q. What is CUB's view of the modeling changes that PacifiCorp is proposing?

A. First, it is important to recognize that every modeling change that PacifiCorp has proposed increases forecast power costs. No model is perfect, and CUB would expect that there are individual improvements that would both increase the forecast and decrease the forecast in order to improve its accuracy. However, PacifiCorp only has an incentive to look for modeling improvement that increase the costs charged to customers. In addition, review of these modeling changes must be done in the context of the rate shock expected when these prices get passed through to customers. Modeling changes that increase costs but are not clearly required should be rejected.

CUB has reviewed PacifiCorp's proposed modeling changes and has concerns about the modeling changes related to market caps, regulation reserves, planned maintenance and the DA/RT adder.

1. Market Caps

Q. What is PacifiCorp proposing in terms of market caps?

A. PacifiCorp is proposing to put a lower cap on the allowable market sales than was approved in last year's TAM. The purpose of market capacity limits (market caps) in the model is to prevent GRID or Aurora from assuming that the market has unlimited liquidity. PacifiCorp is proposing to limit market sales by implementing the modeling change it calls the "average of averages." The Company proposed this change last year and it was rejected by the Commission.

Q. What action did the Commission take last year when the Company proposed this?

A. The Commission rejected the modeling change proposed by PacifiCorp. Instead, the Commission accepted "a compromise position" that was proposed by Staff and supported by CUB, which reduced the market caps but not as much as the Company proposed. Staff's approach was commonly referred to as the "third quartile of averages."

Q. What was the Commission's rationale?

A. The Commission recognized, as did CUB,[6] that the prior methodology had been forecasting sales at a level that was greater than the level the Company was able to achieve. But the Commission also recognized that "there are other related and offsetting costs" and that the data "overstates the problem" because PacifiCorp's data focused on the total dollars of sales, not the margin.[7] The cost of fuel to

[6] CUB originally proposed a different methodology that produced results that were generally similar to Staff's proposal.
[7] OPUC Order No 21-379.

meet the sale is included in modeled costs. Therefore the financial impact of those sales is the difference between their revenue and their cost.

The Commission did say that it was approving this compromise for one year only, recognizing that the Company was moving to Aurora and the reasonableness of Aurora's forecast would be reviewed in this year's TAM.

Q. Does CUB believe that with Aurora, the "average of averages" approach is required?

A. No. **[Begin Confidential]** [redacted] **[End Confidential]** Beyond the use of Aurora, most of CUB's concerns from last year are still valid:

- In this year's TAM, PacifiCorp still overstates the problem. PacifiCorp's testimony focuses on the revenue from market sales, not the net revenue or margin. If the market price is $40/MWh, and the Company makes a sale from a coal plant with a variable power cost of $37/MWh, then the revenue is $40, but the margin is only $3. Because Aurora and GRID both included the fuel and dispatch of the underlying resource that serves the sale, the actual impact is the difference between the production cost for the sale and the revenue.[9]

[8] These numbers come from comparing PacifiCorp confidential Exhibits 103 and 104.
[9] UE 390 –CUB/200/Jenks/5-7.

- PacifiCorp's market sales have been increasing, which makes sense because the Company's generation mix is changing. Solar and wind are variable generation with no fuel costs, which means that they virtually are always economic as a market resource. Because of the production tax credit, wind is economic as a market resource even when market prices are below zero. As PacifiCorp's resource base changes to include more renewables, CUB would expect more market sales activity.[10]
- The Company also is over-forecasting short-term market purchases.[11]
- Market sales interact with the Energy Imbalance Market (EIM.) While EIM dollars are smaller, EIM benefits in the TAM are expressed as net margin benefits that reflect the cost of generation.[12] There is a trade-off between EIM and market sales. If the Company commits a generating unit to a short-term sale, that generating unit is no longer available for the EIM. When the Company's market sales use transmission capacity, that transmission capacity is not available for EIM transactions.
- The impact of COVID-19. Economic activity was significantly impacted by the COVID-19 Pandemic in 2020 and 2021, as reflected in Oregon's state of emergency and the Commission's implementation of a disconnection moratorium. These years are not necessarily reflective of the future[13].

Q. What is CUB's recommendation with regards to market caps?

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[10] UE 390 – CUB/100/Jenks/5-6.
[11] UE 390 – CUB/200/Jenks/7.
[12] UE 390 – CUB/200/Jenks/7.
[13] UE 390 – CUB/200/Jenks/8-9.

A. CUB recommends that the Commission retain the compromise methodology it adopted last year. This will reduce the forecasted power cost increase by $5.9 million. PacifiCorp is still overstating the problem. This is the first year we are using Aurora, and we know that **[Begin Confidential]** [redacted] **[End Confidential]** It makes sense to see how a forecast from Aurora using the compromise methodology compares to actual market sales. In addition, we note that customers are facing rate shock and the Company has failed to make the case that this change is necessary.

2. Regulating Reserve Requirement

Q. How did PacifiCorp change the Regulation Reserve Margin?

A. Historically, the Company has modeled regulating reserves based on a one percent Loss of Load Event (LOLE). But in this case, PacifiCorp is proposing to increase the regulating reserves by using a LOLE of 30 minutes per year. This increases net power costs by $17.6 million.

Q. What is the basis of PacifiCorp's increase in this regulation reserve?

A. PacifiCorp seems to be basing this change nearly entirely on NERC standard BAL-001-2 which requires utilities to hold sufficient reserves.[15] BAL-001-2 does not require a specific methodology and has been in place since July 1, 2016. PacifiCorp offers little evidence as to why this is necessary in 2023 and was not necessary in 2022 nor any other year since 2016.

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[14] These numbers come from comparing PacifiCorp confidential Exhibits 103 and 104.
[15] UE 400 – PAC/300/MacNeil/4-20.

Q. What is CUB's recommendation on regulation reserves?

A. The Company offers no evidence that this is a modeling change necessary to provide service in 2023. It has not met its burden of proof to demonstrate that this modeling change is necessary or would result in a more accurate forecast. In light of the rate shock that will fall on customers, CUB recommends the Commission reject this adjustment.

3. Planned Maintenance Outages

Q. What modeling change is PacifiCorp proposing regarding planned maintenance?

A. Planned maintenance has historically been forecasted based on a four-year average of planned maintenance outages. PacifiCorp is proposing to instead use its current schedule of planned maintenance for 2023, which results in a $3.6 million increase to net power costs.

Q. Does CUB support this modeling change?

A. No. CUB does not believe that such a change is required. The number of outages due to planned maintenance vary from year to year. Some years it will be greater than the four-year average and some years it will be less than the four-year average. But by using the four-year average of actual planned maintenance outages, over time, we accurately capture all the planned maintenance outages. While using an actual forecast for the upcoming years seems like it will be more accurate, CUB is concerned that, over time, we will capture more than the actual volume of planned maintenance outages.

Q. Please explain.

A. Maintenance schedules change during the course of a year. While a utility might plan to have a plant down for maintenance at a certain time, that decision is subject to change due to a variety of factors. Market conditions might make it a poor time to take a plant offline. A forced outage at the plant might cause the maintenance to be done ahead of time. A forced outage at a different plant might make the Company reschedule the maintenance. If conditions cause the planned maintenance to be delayed, customers could be asked to pay the costs associated with the planned maintenance two years in a row, even though it only happened once.

Q. Are there any examples of this?

A. Yes. Portland General Electric repeatedly forecasted a planned outage related to repowering of the Faraday hydro project in its annual power cost filing.[16]

Q. Do you have any other concerns with this adjustment?

A. Yes. It creates an incentive for the Company to overestimate the length of time of maintenance outages which increases net power costs. The Company has an incentive to take a "conservative" view and plan for the longest period that the maintenance could take. But if planned maintenance is always based on assuming the longest possible outage, over time planned outages will be over-forecast. Measuring how long planned maintenance has taken over the last four years gives us a factual basis for forecasting next year's maintenance.

[16] *See, e.g.,* UE 377 – CUB/100/Gehrke/5.

In addition, CUB notes that, while over time planned maintenance will equal the rolling average, in any specific year it could be greater or less than the average. But, PacifiCorp is proposing this in a year where the planned maintenance is greater than the average, and this increases rates. PacifiCorp could have proposed this modeling change in a year when it reduced costs.

Q. What is CUB's recommendation with regards to planned maintenance?

A. CUB recommends that the Commission reject this modeling change.

4. DA/RT Adder

Q. What is PacifiCorp proposing regarding its DA/RT adder?

A. PacifiCorp wants to increase the adder by changing it from a dollar amount to a percentage. PacifiCorp provides an example:

> Take, for example, a $5 price adder in an hour when the market price is $25. This resolves a 20 percent price adder. But using the $5 price adder when market prices are $75 would fail to account for the system and market conditions in that hour. Using a 20% adder during hours when the market price is $75 would yield in a $15 adder which is more reflective of the system conditions.[17]

Q. Does CUB agree with this?

A. The math is accurate – 20% of $75 is greater than $5. But the Company is asserting that this is reflective of future system conditions in the day ahead and real-time markets. CUB has two primary problems with this adjustment. Using Aurora changes the elements of the DA/RT compared to GRID. Changing the DA/RT methodology at the same time makes it more difficult to understand the impact of moving to Aurora. In addition, the DA/RT is a number based on

[17] UE 400 – PAC/100/Wilding/36.

historical data. There is no evidence that changing this historical data to a percentage is "more reflective" of future day-ahead and real-time market conditions.

Q. Please explain how this relates to the move to the Aurora model?

A. As we discussed above, Aurora operates differently than GRID. An examination of the Aurora validation,[18] **[**Begin Confidential] [redacted] **[End Confidential]**

With this 2023 power cost forecast, PacifiCorp is changing from GRID to Aurora. This means that there are two changes to the DA/RT adjustment: one is caused by a change in the model (switch to Aurora) and the other is a change to the modeling (switch to a percentage). In order to consider the modeling change, PacifiCorp needs to address how the model affected the DA/RT because it is the Aurora output that is subject to the new modeling change.

Q. Please explain your concern that the DA/RT is based on historical data and there is no evidence that changing this historical data to a percentage is "more reflective" of future market conditions?

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[18] These numbers come from comparing PacifiCorp confidential Exhibits 103 and 104.

A. The reason for the DA/RT is that GRID historically under-forecasts the volume of day ahead and real-time transactions, and that because of the way that the Company purchases and sales power in these markets, GRID was projecting daily and hourly purchase prices that were too low and was projecting daily and hourly sales prices that were too high. The methodology is to look back at recent years and calculate an adjustment based on actual daily and hourly sales and purchase volumes, and daily and hourly sales and purchase prices. The adjustment was in MWh and dollars.

In this case, PacifiCorp is arguing that changing the price adjustment from historical data to a percentage will better represent future market conditions. The Company is not proposing that a percentage should be used for the volume adjustment. CUB is concerned because the historic data represents non-normalized conditions and we do not know what non-normalized conditions will be encountered in 2023. TAM Forecasts are normalized - they assume average weather and average load. If actual load reflected this normalized forecast, there might not be a need for a DA/RT adjustment, and if there was it would be significantly smaller. But in the real world, weather varies. It may be warmer or cooler than forecast. It may be windier or sunnier than forecast. The same thing is true for forecasted loads. They will also be higher or lower than forecast. And these changes from expected weather and load are a large part of the driver for day-ahead and real-time transactions: the Company is trying to adjust from its expected load/resource balance to what increasingly looks to be the likely actuals as it gets closer to the actual deliver time. This is why PacifiCorp requires a DA/RT adjustment. But because we do not know the extent of 2023 variations from a normalized load, it is impossible to say that changing the price adder to a percentage is a better reflection of 2023 day ahead and real-time market conditions.

Q. What is CUB's recommendation concerning the DA/RT adder?

A. CUB recommends that the Commission reject this modeling change and order the Company to maintain the current methodology for the DA/RT adder.

IV. CONCLUSION

Q. Please summarize your testimony.

CUB is very concerned about the impact that this docket, combined with the general rate case, the PCAM, and the wildfire and COVID deferrals will have on customer bills. The combined effect could create a rate increase that is more than 20% for residential customers. CUB recommends that**,** across all these dockets, steps be taken to reduce the impact of the rate shock that customers will experience. In this proceeding CUB is recommending that the Commission reject modeling changes that increase power costs by $32.3 million and have not been demonstrated to be necessary.

Market Capacity Limits. CUB recommends retaining the compromise mechanism adopted by the Commission last year. This reduces power costs by $5.9 million.

Regulation Reserves. There is no reason that this change needs to be implemented in 2023. CUB recommends rejecting it. This reduces power costs by $17.6 million.

Planned Maintenance Outages. CUB recommends maintaining the current methodology which bases the forecast on a four-year rolling average. This reduces power costs by $3.6 million.

Day-Ahead/Real-Time Adder. CUB recommends maintain the current methodology for this adjustment. This reduces power costs by $5.2 million.

Q. Does this conclude your testimony?

A. Yes.

WITNESS QUALIFICATION STATEMENT

NAME: Bob Jenks

EMPLOYER: Oregon Citizens' Utility Board of Oregon

TITLE: Executive Director

ADDRESS: 610 SW Broadway, Suite 400
Portland, OR 97205

EDUCATION: Bachelor of Science, Economics
Willamette University, Salem, OR

EXPERIENCE: Provided testimony or comments in a variety of OPUC dockets, including UE 88, UE 92, UM 903, UM 918, UE 102, UP 168, UT 125, UT 141, UE 115, UE 116, UE 137, UE 139, UE 161, UE 165, UE 167, UE 170, UE 172, UE 173, UE 207, UE 208, UE 210, UE 233, UE 246, UE 283, UG 152, UM 995, UM 1050, UM 1071, UM 1147, UM 1121, UM 1206, UM 1209, UM 1355, UM 1635, UM 1633, and UM 1654. Participated in the development of a variety of Least Cost Plans and PUC Settlement Conferences. Provided testimony to Oregon Legislative Committees on consumer issues relating to energy and telecommunications. Lobbied the Oregon Congressional delegation on behalf of CUB and the National Association of State Utility Consumer Advocates.

Between 1982 and 1991, worked for the Oregon State Public Interest Research Group, the Massachusetts Public Interest Research Group, and the Fund for Public Interest Research on a variety of public policy issues.

MEMBERSHIP: National Association of State Utility Consumer Advocates
Board of Directors, OSPIRG Citizen Lobby
Telecommunications Policy Committee, Consumer Federation of America
Electricity Policy Committee, Consumer Federation of America
Board of Directors (Public Interest Representative), NEEA

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JANUARY 2019

Managing Electricity Rates Amidst Increasing Capital Expenditures: Is Securitization the Right Tool? An Update

Overview

A growing number of states, their utilities, and public utility commissions (PUCs) are facing a critical policy dilemma: How to minimize the rate impact of recouping large-scale capital costs? The question isn't easy; whether it's recouping costs associated with natural disasters, retiring outdated nuclear plants, or investing in renewable energy investments, these large expenses can challenge a utility. Traditional financing mechanisms, which include using a combination of traditional equity and borrowing at the utility's cost of capital, inevitably end up increasing rates.

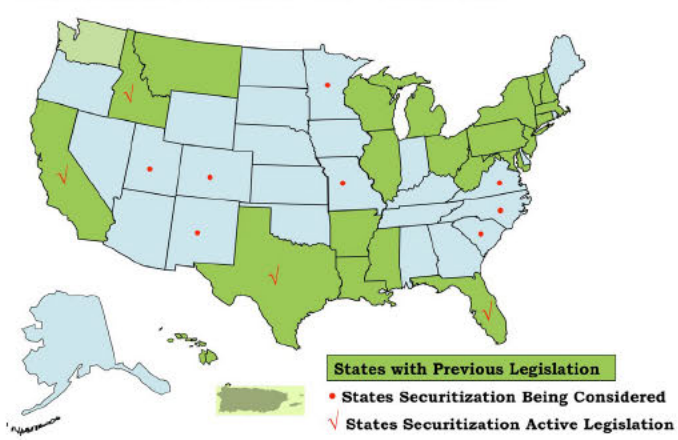
Because investor-owned utilities are generally entitled to returns sufficient to attract investor capital, a risk premium is included in their return on the use of shareholder equity. Utilities generally have little difficulty financing capital plans. However, what happens when their financing needs are unforeseeable or beyond their control or beyond their ability to anticipate and plan? Or, what if the utility is facing economic disruption due to natural disasters, market events, or government-mandated costs?

What is the answer? How can a utility finance required expenditures at a minimum cost to customers and even avoid customer rate shock? For more than 21 years, regulators and utilities around the country have found the answer in a financial product known as "securitization." When a utility has an extraordinary cost, for which it is prudent to recover costs from customers (e.g., sunk costs, pollution control equipment, storm recovery costs, remediation of coal ash ponds), it is reasonable to consider securitization as a mechanism to assure cost recovery at a rate below the utility's cost of capital. It is also a unique and valuable tool for regulators and utilities to avoid customer rate shock.

Essentially, securitization is a special form of financing that is specifically designed to lower a utility's borrowing costs, which in turn lowers the amount of money customers will have to repay. Working with their legislature, utility commissions, and independent financial advisors, utilities can issue high-quality securitized bonds. The bonds receive a "AAA" rating – the highest possible — from Wall Street rating agencies that assess creditworthiness, making them more attractive to investors eager for safe, reliable, long-term returns on their investment. Essentially, it lets utilities and their customers benefit directly from the bond market.

A growing number of utilities have recovered necessary extraordinary costs at the lowest possible financing cost to ratepayers. Think of securitization as akin to a consumer refinancing their credit card debt with a home equity mortgage loan. By refinancing into a secured, higher-quality loan, the consumer can obtain a lower interest rate and significantly lower their borrowing costs over the life of the loan. In much the same way, a utility can replace its existing cost of capital at a lower cost, improving its financial condition in a way that also means less cost to ratepayers over time. Securitization lets them bypass their balance sheet and borrow directly on the broad ratepayer base.

Securitization: 21 States + DC + Puerto Rico



This approach has been successfully used by utilities around the country for a variety of needs. In Florida, securitization was first used after the catastrophic 2004 and 2005 hurricane seasons. More recently, with new legislation, a Florida utility was able to reach an agreement with consumer groups and regulators to issue nearly $1.3 billion in securitized bonds to cover the cost of the early retirement of a nuclear plant. The use of securitization in that case ultimately saved ratepayers more than $680 million in today's dollars.

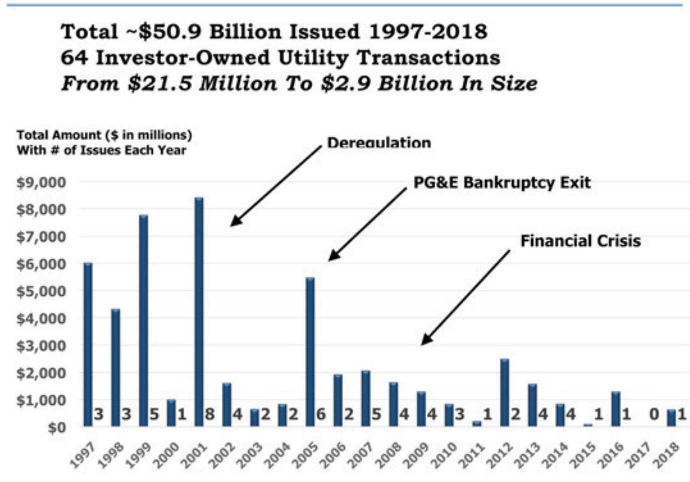
Securitization can be a dynamic change maker for utilities, their regulators, and customers in the face of rising costs in the capital markets and outsized capital expenditures that can drain resources and increase the burden on ratepayers. It can provide needed financial security to all stakeholders, providing utilities with secure, high-quality financing and customers with the security of knowing they are saving money every month.

Securitization and Utilities: How We Got Here

The practice of securitization is not a new concept on Wall Street – railroad-backed bonds date back to the 19th century, and the modern securitization market came of age in the 1970s. The use of securitization by regulators and utilities is of a more recent vintage. It has gained popularity in the last 21 years as states have deregulated their energy markets and utilities have had to deal with the outsized costs of natural disasters and pressure on their capital expenditures.

The approach was first tested in the mid-1990s as California sought to deregulate its energy market. The four investor-owned utilities in the state sold roughly $6 billion in securitized bonds to finance a 10% rate reduction for their residential and small commercial customers. This earned the bonds the nickname "rate reduction bonds," or "RRBs." The technique was later adopted in other states to recover so-called stranded costs of utilities' electric generation facilities; these refer to generation investments that are "stranded" because of a state breaking up a utility's monopoly by separating energy generation from transmission and distribution. The bonds helped the utilities recoup those costs while still securing a sizable rate reduction for their customers when compared to traditional financing involving the utility's cost of capital. Investors offered a new nickname for these securitizations, referring to them as "stranded cost bonds."

Since those initial forays into securitization, states have used the process to help tackle a range of costs. These bonds have been called "storm recovery bonds" when used to help pay for catastrophic hurricane damage, or "nuclear asset recovery bonds" to help finance the early retirement of nuclear plants. The best description is likely "ratepayer-backed bonds." Sometimes, these bonds are used to help finance needed improvements utilities must make. In 2007, Allegheny Energy was able to reach a settlement with consumer groups to use securitization to help finance the construction of newly mandated pollution control equipment at two coal-fired plants in West Virginia. The long-term bond issues were a success, securing the funds while saving customers more than $130 million in today's dollars over the life of the bonds.



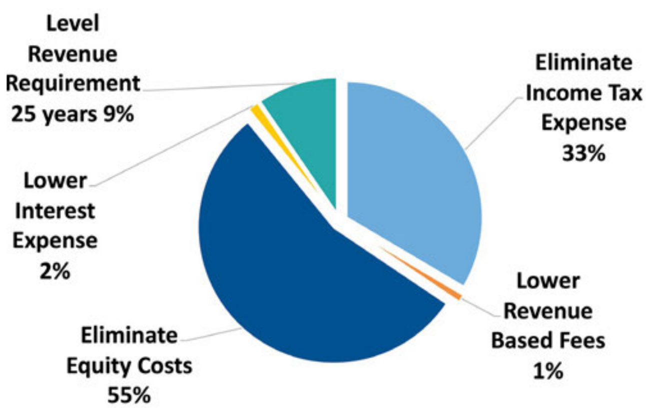
Today, investor-owned and municipal utility securitization bond offerings are authorized in 21 states, the District of Columbia, and Puerto Rico. Since 1997, utility securitization bonds — with the regulator still deciding what prudent costs can be financed — have been used more than 60 times to allow investor-owned utilities to address high-cost events. More recently, legislation proposed in Colorado and Missouri would provide utilities a return of utility capital when certain outdated generation plants are retired early, as well as raise money for transition assistance for affected communities and workers. Both are significant and important innovations.

Utility Securitization: What It Is and How It Works

At its root, although complex, securitization is a special form of bond financing to secure the highest possible rating from credit rating agencies, making the bonds attractive to investors and ensuring that the utility can lower its borrowing costs. Properly structured and implemented, securitization should give a utility additional flexibility to deploy its capital and invest in infrastructure while also benefitting customers. Typically, a properly implemented bond will be sold to investors to replace a corresponding amount of the utility's existing debt and equity. Because these bonds receive a much higher credit rating, this means the utility's costs are being reduced through this new bond issue. That benefits both the utility and its ratepayers, who see their monthly bills reduced.

The example noted below, where a utility was able to save its ratepayers more than $680 million in today's dollars through securitization, provides a good primer on the process. Faced with the early retirement of a nuclear project, Duke Energy Florida worked with customer groups on an agreement allowing the retirement costs to be recouped from ratepayers via the use of long-term securitized bonds that would ultimately lower customers' costs. This agreement significantly altered the equation of traditional utility finance. Working cooperatively with their customers and its PUC, Duke Energy was able to finance the costs in a way that benefited all stakeholders.

Where Securitization Saves Ratepayers in Today's Dollars versus Traditional Utility Cost of Capital



Savings Net of Issuance Costs $1 Billion Bond 15-Year Average Life 25-Year Maturity

The reason this worked and is attractive to investors goes back to the fundamental structure of securitized utility bonds. Their key characteristic is that they are authorized with special legislation to be issued by a separate legal entity specifically set up for the transaction. These "limited purpose entities" as they are known receive revenues from a dedicated tariff rate on utility customers' monthly bill. Direct recovery from customers provides special legal protections that make them more secure in the eyes of credit rating agencies and investors. The legislation allows the utility to have the PUC adjust the rates at least semi-annually to ensure payment of principal, interest, and associated costs when due without further regulatory review.

Under securitization, a newly created property right authorized by the legislation and approved by the PUC is assigned to a limited purpose entity that pledges the property right as collateral for the securitized utility bonds sold to investors. The utility is considered repaid for the investment, and any related rate base or other regulatory asset is removed from the utility's books. Customers stop paying the utility's cost of capital with respect to that item, and instead begin paying the special charge which repays the bondholders. This works to the customers' benefit because the utility's base rates go down significantly more than the securitized charges go up. Over the period of repayment, this means that securitization can save customers a very large amount of money while giving the utility additional flexibility and certainty in its operations.

Making Securitization a Reality

Achieving a successful securitization offering requires a number of steps to be taken before an offering. Buy-in at the state, PUC, and customer levels is crucial to ensure broad-based support, and to help clear legislative and regulatory hurdles to proceed with an offering.

The following elements are critical to ensure a utility and its customers can take advantage of securitization:

- The state legislature passes legislation specifically authorizing the use of securitization by utilities, declaring the right to impose, adjust, bill, collect a dedicated rate component to be a presently existing property right, and granting special authority to the regulators with a "lowest cost" to consumers standard.
- The PUC issues a financing order that allows the utility to charge its customers a dedicated amount per month over the life of the bonds. The charge applies to all, or substantially all, customers and cannot be bypassed.
- The PUC approves an adjustment mechanism that permits and requires the adjustment of the monthly charge to customers over time to make sure that the payments fulfill the obligations of the bonds.
- The PUC orders are irrevocable and the state agrees never to impair the right of the bondholders to the special charge as it is adjusted to repay the bonds in full.

These four elements are what allow the new securitization bonds to receive the highest possible credit ratings from rating agencies such as Moody's, Standard & Poor's, and Fitch. Achieving the highest possible credit ratings allows the bonds to achieve the lowest cost financing with the active oversight of the regulator in the public debt markets, which ultimately help create savings enjoyed by a utility's ratepayers.

The critical piece of the puzzle for a successful securitization hinges on actions by the PUC. Ultimately, the PUC's role in the financing process is three-fold:

1) issuing an irrevocable financing order laying out the parameters of the bond offering and the standard of "lowest cost" to customers;

2) establishing the regular adjustment mechanism; and, finally,

3) actively engaging and negotiating with investors and Wall Street to ensure the bonds are considered of the highest credit quality with the greatest competition among investors for the bonds.

An active, engaged commission (aided by independent financial advisors with a duty to the ratepayers) throughout the process is vital because of the unique nature of securitization; the special legal protections make the bonds an attractive investment, but also bind subsequent PUC's from future oversight. Typically, the necessary up-front PUC costs are paid from the proceeds of the bond sale — as are the utility's advisors/underwriters.

Foregoing future regulatory oversight make the bonds very different from typical utility bonds. There, the utility has a strong incentive to negotiate for the lowest possible interest rates and other costs. Between rate cases, the utility and its shareholders benefit. With securitization, these same ongoing checks and balances do not exist and must be done up-front. Whatever the bond's costs at the time of sale, the utility receives the same amount of pre-approved funds but every dollar of costs is a ratepayer dollar.

That's why it is important to send a clear signal to independent third-party evaluators and investors that the securitization is credible, fully supported and vetted at the regulatory level; promoting confidence and helping underscore the efficacy of the offering. This means ensuring the structuring, marketing, and pricing of the bonds are done properly. Active PUCs (like the models of Florida, West Virginia, New Jersey, and Texas) are also more likely to secure better terms for ratepayers than those that take a passive approach. Ultimately, it's critical that the PUC require full transparency during the financing process, effectively represent the interest of the ratepayers and be active at every step of the securitization process. Nothing is automatic in the capital markets; securitization only provides the opportunity to achieve the lowest cost to consumers.

Conclusion

At its core, securitization gives regulators and utilities unsurpassed flexibility in minimizing the cost of infrastructure investment, service, and financial stability goals. The design of securitized utility bonds is explicitly intended to create a win-win scenario for the utility and its customers; a sharp step away from traditional capital-raising approaches that have led to blowback for utilities who were forced to take on debt and earmark scarce equity for such costs.

The Benefits of Securitization

FOR UTILITIES:

- Allows access to lower borrowing costs
- Provides greater balance sheet flexibility, increasing headroom for rate management
- Grants utilities certainty for funding important infrastructure goals

FOR CONSUMERS:

- Provides security to ratepayers, lowering long-term costs
- Eliminates responsibility for covering utility debt costs, income taxes, return on equity costs
- Saves consumers money while allowing utility to improve balance sheet

FOR REGULATORS:

- Provides an effective tool to mitigate rate shocks and lower ratepayer bills

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About NRRI

The National Regulatory Research Institute (NRRI) was established in 1976 as the research arm of the National Association of Regulatory Utility Commissioners (NARUC). NRRI provides research, training, and technical support to State Public Utility Commissions. NRRI and NARUC are co-located in Washington, D.C.

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UE 400– CERTIFICATE OF SERVICE

I hereby certify that, on this 25th day of May, 2022, I served the **Confidential Opening Testimony of the Oregon Citizens' Utility Board** in the docket UE 400 upon the Commission and each party designated to receive confidential information pursuant to Order 16-128 through a secure, encrypted attachment to an e-mail.

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