

APPENDIX Q: SECURITIZATION PLAN

Background

In December 2020, Minnesota Power (“Company”) was the first in the state of Minnesota to reach the milestone of providing 50 percent renewable, carbon-free energy to its customers. In January 2021, the Company unveiled its commitment to reduce carbon emissions 80 percent by 2035, along with a goal to provide 100 percent carbon-free energy by 2050. This plan will require changes at the Company’s two remaining coal generating facilities, Boswell Energy Center (“BEC”) Units 3 and 4, located in Cohasset, Minnesota. To achieve 80 percent carbon reduction by 2035, Minnesota Power is proposing in the current Integrated Resource Plan (“IRP”) to move BEC Unit 3 to economic dispatch in 2021 and retire the unit in 2030, five years early. Additionally, BEC Unit 4 will cease coal operations by 2035 and the Company will continue to evaluate opportunities for economic dispatch at that unit as well.

Boswell Energy Center Units 3 and 4, at a combined 823 MW¹, are Minnesota Power’s last remaining coal units and only source of Baseload Power. As the Center for Energy and the Environment (“CEE”) noted in its 2020 Host Community Study *“Power Plant Retirements: Community’s Perspectives and Realities”*, Cohasset is the smallest and most geographically isolated coal plant host community in Minnesota. In 2018, property taxes from BEC accounted for nearly 70 percent of Cohasset’s tax base, nearly 20 percent of the Grand Rapids School District tax base and 13 percent of Itasca County’s tax base. The approximate \$725 million of remaining balances on the Boswell Energy Center is due in significant part to investments Minnesota Power made to install a variety of emission control equipment on the units as recently as 2015. Driven by the Minnesota Mercury Reduction Act and federal environmental regulations, the emissions control projects resulted in significant air and water quality benefits. For example, BEC Units 3 and 4 mercury air emissions were reduced by over 90 percent, nitrogen oxides emissions by over 70 percent, and sulfur dioxide emissions by around 80 percent in aggregate. The emission control equipment investments also achieved substantial reductions in air emissions of particulate matter and acid gases, as well as lowering freshwater use and reducing wastewater generation.

Securitization is a financial tool and has most frequently been used to address significant costs that were unforeseen, such as storm damage. More recently there are instances where it has been utilized by combining with supporting tools in other states to minimize the rate impact from closure of coal-burning power plants ahead of schedule. The Public Utilities Commission (“Commission”)² directed the Company to investigate whether securitizing the outstanding costs of BEC 3 and 4 could help mitigate the costs of an early plan retirement. Beginning in late 2019, the Company engaged the Rocky

¹ Boswell Unit 4, totaling 585 MW, is co-owned by Minnesota Power and WPPI Energy. Minnesota Power owns 80 percent of Boswell Unit 4 at 468 MW, and WPPI owns 20 percent at 117 MW.

² Docket No. E015/RP-15-690, E015/AI-17-568, E015/GR-16-664.

Mountain Institute (“RMI”) to evaluate securitization as a possible mechanism to accelerate the retirement of BEC 3 and 4. The ability to use securitization to address BEC’s remaining balances was evaluated in both the Phase 1 report from RMI, titled *“Using Ratepayer-Backed Bond Securitization for Cost Recovery in Accelerated Asset Retirement: Feasibility Study for Minnesota Power – Phase 1”* submitted on October 1, 2020 and in the attached report, titled *Using Ratepayer-Backed Bond Securitization for Cost Recovery in Accelerated Asset Retirement Feasibility Study for Minnesota Power – Phase 2*. The Phase 1 report assessed various transition mechanisms for early retirement, but did not consider specific replacement assets.³ This second phase of the study approached the topic of securitization through financial modeling and BEC specific retirement scenarios and performing a case study.

The BEC Units 3-4 retirement scenario provided by the Company to RMI was assembled prior to the completion of the Integrated Resource Plan (IRP) analysis, and as such does not sync perfectly with the IRP submitted on February 1, 2021. The RMI study should be read as a hypothetical model to understand how securitization could change the customer cost profile and credit rating metrics for the Company if implemented.

As noted in the report, the specific financing scenarios, as well as the specific retirement and replacement options chosen, resulted in the following key findings. Material divergence from the assumptions of the securitization tool underlying those scenarios or the retirement and replacement option would result in different insights and impacts.

RMI’s Key Insights from the Phase 2 Report Include:

- Securitization upon plant retirement in 2030 may substantially mitigate, but not eliminate, a near-term post-retirement rate increase that is driven by new 100 percent utility-owned asset investments, while reducing customer costs on an NPV basis and providing meaningful transition assistance to coal plant workers and communities. Additional rate mitigation tools would be needed to fully mitigate near-term cost impacts from accelerated retirement and replacement.
- Early securitization in the absence of early reinvestment in 100 percent utility-owned clean energy or other assets creates significant risk for the utility prior to plant retirement and replacement. RMI analysis suggests that securitization charges in all scenarios modeled remain below 10 percent of total customer collections—even under “stress-testing” conditions. Nevertheless, based on RMI’s simplified analysis of the potential impacts of securitization on ALLETE’s earnings and credit metrics, securitization timed to coincide with reinvestment in replacement resources in 2030 may offer improved financial resilience to a persistent 20 percent demand increase relative to the BAU case. RMI analysis suggests that securitization charges in all scenarios modeled remain below 10% of total customer collections—even under “stress-testing” conditions.

³ Docket Numbers 15-690, 16-664, 17-568

Nevertheless, based on RMI's simplified analysis of the potential impacts of securitization on ALLETE's earnings and credit metrics, securitization timed to coincide with reinvestment in replacement resources in 2030 may offer improved financial resilience to a persistent 20% demand increase relative to the BAU case.

- Consideration of additional tools and retirement, replacement, and securitization scenarios outside the scope of this analysis would be needed to fully mitigate the residual near-term post-retirement rate increase. As an example of such a tool, state legislation could allow the use of "market-indexed" tariffs for utility-owned replacement assets. A market-indexed tariff is set based on the competitively determined "market" clearing price for a power purchase agreement ("PPA") for assets bidding to provide similar services, mitigating the rate increase from new rate-based assets. Similarly, analysis of additional scenarios to take advantage of the recent extensions to the Investment Tax Credit ("ITC") and Production Tax Credit ("PTC") through the end of 2025 may also offer cost benefits that could further mitigate rate increases. However, such analyses would need to carefully consider constraints around tax capacity at the ALLETE level.

Minnesota Power's Initial Assessment of RMI's Phase II Report

As with any study, the Phase II report included a number of key assumptions. Adjusting these key assumptions would naturally affect the outcome of the overall findings. A few assumptions worth noting are: RMI assumes utility investment for 100 percent of the securitization proceeds with 6 percent additional going to transition assistance for impacted workers and communities, the embedded cost of debt, a current yield curve for 2030 rates, the ability for ALLETE to pay off debt without penalty, generic utility credit metrics, and generic tax utilization assumptions. Minnesota Power, as one of the most unique utilities in the country, has several attributes that would challenge these assumptions, including: make whole payments for debt, current tax appetite after reaching the 50 percent renewable milestone, and ALLETE-specific credit rating metrics. As with any research, general industry information is helpful in understanding complex topics, but precise utility assumptions would need to be considered before further evaluation of specific applications.

Typically, the earlier securitization is initiated, the more beneficial it is, using pre-retirement securitization in 2025 as the example. However, the Phase Two report findings suggest when evaluating from a financial perspective the earlier year of 2025 applied specifically to Minnesota Power, presents additional significant and unacceptable risk and creates little value to customers. In addition, the difficulty of implementing such a scenario also arises from BEC's role in generating baseload power distribution. As noted in Appendix J of the IRP, the Company cannot replace the necessary baseload generation and transmission/distribution buildout required to retire BEC in 2025.⁴ Early

⁴ Docket No. E015/RP-21-33, Appendix J

implementation of securitization would be further delayed by the fact that it is not currently legislated. Additionally the development of a regulatory financing order would have to follow successful legislation prior to securitization being implemented in Minnesota.

Finally, RMI's Phase Two report notes that other tools would be needed to fully mitigate the residual near-term post-retirement rate increase, even with securitization of the remaining plant balances ten years from now in 2030. Some of the tools mentioned include state legislation that could allow for the use of "market-indexed" tariffs for utility-owned replacement assets and extensions to the federal ITC and PTCs. However, it is the Company's position that the remaining plant balances are not a barrier to further decarbonization or early plant retirement, as outlined in Minnesota Power's bold carbon reduction plan in this IRP.

Additionally, Minnesota Power believes other rate mitigation options for the retirement costs of BEC are more immediately available, like the options presented in Company's August 31, 2020 Supplemental Report in Docket E,G999/CI-20-492, including: the sale of residential lease lots along traditional hydroelectric reservoirs, additional PTCs available through the repowering of Taconite Ridge Wind Energy Center or extended depreciation of utility assets. These previously-proposed options can mitigate customer rate increases without the complicated structure, automatic rate increases if sales decrease, and reduced flexibility inherent in potential securitization for Minnesota Power.

Conclusion

This report represents RMI's findings and perspective and Minnesota Power is grateful for their thorough analysis of these complex issues. Though securitization may not be necessary as a rate mitigation effort in Minnesota Power's specific case of retiring the Boswell Energy Center units early, it has high potential as a useful tool in mitigating other energy transition issues. In the event that securitization is legislated in Minnesota, the Company may consider it for other costs, such as transmission and distribution infrastructure or potential future storm response costs. The Company looks forward to continued evaluation of its proposed rate mitigation efforts – like land sales, extended depreciation and PTC utilization – as it takes the next steps in this IRP to effectuate it's vision of an 80 percent carbon reduction by 2035 and a sustainable pathway to a 100 percent carbon free future by 2050.

Using Ratepayer-Backed Bond Securitization for Cost Recovery in Accelerated Asset Retirement

Feasibility Study for Minnesota Power – Phase 2

Rocky Mountain Institute

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Authors:

Uday Varadarajan*, David Posner, Becky Li, Pintian Chen, Austen Sharpe
**Stanford Sustainable Finance Initiative and Rocky Mountain Institute*

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About Rocky Mountain Institute:

Rocky Mountain Institute (RMI)—an independent nonprofit founded in 1982—transforms global energy use to create a clean, prosperous, and secure low-carbon future. It engages businesses, communities, institutions, and entrepreneurs to accelerate the adoption of market-based solutions that cost-effectively shift from fossil fuels to efficiency and renewables. RMI has offices in Basalt and Boulder, Colorado; New York City; the San Francisco Bay Area; Washington, D.C.; and Beijing.



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Executive Summary

This report is the second stage of a collaboration between Minnesota Power, an operating division of ALLETE, and Rocky Mountain Institute (RMI), to assess the feasibility of using ratepayer-backed bond securitization to mitigate customer, financial, and community impacts of accelerating retirement of Boswell Energy Center, Minnesota Power’s last remaining coal plant.

This report has two main components:

- Analytical Results (Chapter 2), presenting the results of a financial modeling analysis that evaluates the costs and benefits of potential scenarios for the use of securitization (“*financing scenarios*”) to mitigate the impacts of one specific physical option for accelerating the retirement and replacement of Boswell Energy Center to 2030 (“*physical retirement and replacement option*”). The physical retirement/replacement option was generated by Minnesota Power’s IRP process; and
- Case Study Review (Chapter 3), identifying best practices for securitization legislation and implementation based on an examination of recent transactions.

The financial modeling analysis performed by RMI and described in Chapter 2 addresses the question of whether securitization—a financing mechanism—could materially mitigate the potential impacts of accelerating the retirement and replacement of Boswell Energy Center. As discussed in the Phase 1 report, these potential impacts and challenges may include a near-term rate increase, utility credit metric erosion, and losses of jobs and tax revenues for communities.

The analysis compared the relative financial, customer, and community impacts of several financing scenarios, each with different securitization terms, on a *single early physical retirement and replacement option* that foresees the plant being replaced in 2030 with a portfolio of owned renewable and gas capacity as well as market purchases. This replacement portfolio was generated by Minnesota Power’s IRP process.

RMI’s modeling suggests that this early retirement and replacement option could provide long-term benefits to customers. However, the analysis also suggests that if this option were to be undertaken using traditional utility financing in the absence of securitization, a significant but temporary rate increase may be required in 2030.¹

RMI then compared various *financing scenarios* for the use of securitization—**with varying bond tenors, sizing, and timing**—on this single retirement and replacement option in order to gain insight into how

¹ RMI’s analysis did not attempt to compare different retirement timelines, replacement resource mixes, or ownership assumptions for those resources. Further, the analysis utilized replacement resource cost assumptions provided by Minnesota Power.



securitization could best be used to mitigate the potential 2030 rate increase while also addressing the utility financing and community challenges.² The financing scenarios were chosen to examine potential trade-offs between stakeholders and to identify whether a “triple win” scenario—with benefits for ratepayers, shareholders, and coal workers and communities—would be achievable.

The modeled financing scenarios can be divided into two key groups:

- 1) Securitization in 2030 of all unrecovered costs as well as a 6% premium to provide community transition assistance, with varying securitization bond tenors ranging from five to fifteen years and tenor-specific interest rates. Securitization is coincident with the physical plant retirement and replacement. Except for the 6% premium for transition assistance, the securitization proceeds are returned to the utility to pay for plant decommissioning and to recover outstanding plant balances due to the company’s shareholders and lenders. In the RMI model, these recovered investor funds are reinvested in full in the replacement option assets, along with considerable additional capital, to achieve 100% utility ownership of the option’s gas and renewable assets. The replacement option also foresees a modicum of market purchases that do not constitute owned assets for the company.
- 2) Securitization executed in 2025, five years prior to physical plant retirement and replacement. The securitization amount is 75% of unrecovered costs in 2025 as well as a 6% premium to provide community transition assistance in anticipation of accelerated retirement, with varying bond tenors ranging from ten to twenty years and tenor-specific interest rates. The remaining unrecovered costs are accounted for through regular rates as the plant continues to operate through 2030. Upon physical retirement in 2030, utility reinvestment of capital recovered from securitization (net of decommissioning costs and transition assistance) are 100% included in the pool of capital needed to 100% utility ownership of replacement option’s gas and renewable assets, excluding the modicum of purchased power.

Each financing scenario and tenor variant was compared with

- i. a Business-As-Usual (BAU) case without early retirement of Boswell, and
- ii. a Traditional Utility financing case without securitization for the financing of Boswell retirement but the same physical retirement and replacement option assessed in all the securitization scenarios.

² While RMI’s model was able to capture many of the specific financial and regulatory issues relevant to Minnesota Power, it could not capture all the relevant company-specific challenges that may be relevant in all securitization scenarios or options of interest, such as issues related to the company’s ability to use renewable tax incentives or costs associated with early repayment of debt in scenarios where the company cannot immediately reinvest the proceeds from securitization. In particular, analysis of securitization for retirement with replacement options involving the use of the recent extension of renewable tax credits through 2025 would require additional modeling.



As noted in the Phase 1 report, Minnesota Power’s unique size and concentrated industrial customer base suggests particular attention needed to be paid to potential revenue volatility in assessing the viability of securitization. For the 10-year securitization tenor case in Scenario 1 (2030 securitization) and the 15-year securitization tenor case in Scenario 2 (2025 securitization), RMI “stress-tested” results to assess the financial impacts on the company of such a potentially sudden and permanent reduction in revenue by comparing the impact on customers and utility debt and equity metrics of a 20% permanent revenue shock designed to mimic the impact of the permanent loss of one or more of its industrial customers, relative to the BAU case.

Based on these specific financing scenarios as well as the specific retirement and replacement option, our modeling analysis yielded the following key insights. Material divergence from the assumptions underlying these financing scenarios or the retirement and replacement option would result in different insights.

- **Key Insight 1:** Securitization upon early plant retirement in 2030 may substantially mitigate—but not eliminate—a near-term post-retirement rate increase that is driven by new 100% utility-owned asset investments, while reducing customer costs on an NPV basis and providing meaningful transition assistance to coal plant workers and communities. Additional rate mitigation tools would be needed to fully mitigate near-term cost impacts from accelerated retirement and replacement. Longer-tenor securitizations may provide greater moderation. On a Net Present Value (NPV) basis, the securitization tenor variants we tested for 2030 securitization—5-, 10-, and 15-year tenors—are cheaper than both BAU and traditional utility financing of the retirement without the use of securitization but with same physical replacement option.³ Longer-tenor securitizations slightly increase NPV benefits.
- **Key Insight 2:** Early securitization in the absence of early reinvestment in of 100% utility-owned clean energy or other assets creates significant risk for the utility prior to plant retirement and replacement. Early securitization of a portion of the remaining plant balance five years prior to retirement and reinvestment in replacement resources can front-load transition assistance and may also mitigate, but not eliminate, a 2030 rate increase for a 2030 retirement. This misalignment of the timing of securitization with utility reinvestment could translate to higher future utility financing costs and customer rates.
- **Key Insight 3:** RMI analysis suggests that securitization charges in all scenarios modeled remain below 10% of total customer collections—even under “stress-testing” conditions. Nevertheless, based on RMI’s simplified analysis of the potential impacts of securitization on ALLETE’s earnings and credit metrics, securitization timed to coincide with reinvestment in replacement resources in 2030 may offer improved financial resilience to a persistent 20% demand shock relative to the BAU case.
- **Key Insight 4:** Consideration of additional tools and retirement, replacement, and securitization scenarios outside the scope of this analysis would be needed to fully mitigate the residual near-

³ The BAU assumptions are explained in Chapter 2.



term post-retirement rate increase. As an example of such a tool, state legislation could allow the use of “market-indexed” tariffs for utility-owned replacement assets. A market-indexed tariff is set based on the competitively determined “market” clearing price for a power purchase agreement (PPA) for assets bidding to provide similar services, mitigating the rate increase from new rate-based assets. Similarly, analysis of additional scenarios to take advantage of the recent extensions to the Investment Tax Credit (ITC) and Production Tax Credit (PTC) through the end of 2025 may also offer cost benefits that could further mitigate rate increases. However, such analyses would need to carefully consider constraints around tax capacity at the ALLETE level.

Chapter 3 presents insights from other state and utility experiences using securitization to mitigate rate impacts from accelerated plant retirement as follows, though not all these insights may be directly applicable to Minnesota Power:

- **Key Insight 1:** Securitization legislation in some states have included provisions to protect customers by requiring the use of rate adjustment mechanisms (e.g., bill credits) that ensure that customers see savings immediately upon bond issuance.
- **Key Insight 2:** Implementing the securitization charge as a volumetric (per kWh) charge that is allocated across customer classes consistent with the basis of allocation in the most recent rate case is a simple and relatively non-controversial approach that has been commonly used historically. However, alternative allocation methods have also been considered. For instance, bond revenue certainty could be enhanced with minimal cost-shifting across customer classes by implementing securitization charges as fixed or demand charges, even for residential customers.
- **Key Insight 3:** Utilities have balanced intergenerational equity and least-cost considerations by carefully structuring the securitization bond issuances through judicious choices of multiple tranches of bonds with different tenors.
- **Key Insight 4:** Utilities have been able to stagger the timing of securitization, retirement, and replacement while still minimizing risks to utility investors and providing customers with immediate bill savings.
- **Key Insight 5:** Recent securitization legislation (in particular, in New Mexico) allows the proceeds of securitization transactions to also be used to support the transition of coal plant workers and communities.

Based on these insights, RMI offers the following recommendations:

- **Recommendation 1:** Securitization timed to coincide with utility reinvestment should be made available to Minnesota Power as an additional option to finance community transition assistance and help mitigate the near-term rate increase from accelerated retirement and replacement of Boswell.
- **Recommendation 2:** Minnesota Power should work with regulators and policymakers to identify and analyze additional tools—such as market indexing policies and tax equity financing—as well as additional physical retirement and replacement options for Boswell that could help fully



mitigate the residual near-term rate increase. In light of recent tax credit extensions through the end of 2025, this analysis should consider carefully the tax capacity constraints that Minnesota Power could face in utilizing those tax benefits.

- **Recommendation 3:** Securitization legislation should provide regulators with the flexibility, means, and authority to work with utilities to adjust the timing of bond issuance relative to plant retirement, structure the bond issuances, and design the resulting surcharge to minimize bill impacts and risks for utility customers while also sufficiently mitigating risks for utility and securitization bond investors so as to minimize short and long-run financing costs.
- **Recommendation 4:** Rate adjustment mechanisms, such as bill credits, should be used to help stabilize customer costs throughout the transition, while alternative surcharge rate designs should be considered to enhance revenue stability for the utility.
- **Recommendation 5:** The structuring of a securitization transaction—the tenors and tranches of bonds issues—can have significant impacts on costs and benefits. Securitization legislation should provide the means and authority for regulators to engage financial sector experts to advise commissioners and their staff throughout the securitization process.
- **Recommendation 6:** Minnesota Power should work with key stakeholders to ensure securitization legislation includes transition assistance as an allowed use of proceeds.



Chapter 1. Introduction

This report is the second stage of a collaboration between Minnesota Power, an operating division of ALLETE, and Rocky Mountain Institute (RMI), to assess the feasibility of using a ratepayer-backed bond securitization to manage the costs of a potential early retirement of Boswell Energy Center, Minnesota Power's last remaining coal plant. As of 2020, historical investments in the Boswell plant that had yet to be recovered from customers in rates were estimated at \$725 million.

In October 2020, Minnesota Power submitted the Phase 1 Report of this collaboration to the Minnesota Public Utilities Commission, which had ordered a feasibility study of the use of securitization in connection with early retirement of Boswell. The Phase 1 Report:

- considered how Minnesota Power's relatively small size and high historical revenue volatility could complicate a securitization;
- compared Minnesota Power with 45 other utilities that have used securitization and provided three case studies, including two of "peers" close in size to Minnesota Power; and
- identified policy, regulatory, and financial structuring options that could mitigate challenges of particular relevance for Minnesota Power.

This Phase 2 Report adds rigorous financial modeling to the feasibility assessment and also includes additional and expanded case studies. Specifically,

- **Chapter 2** presents the modeling results of a financial analysis that evaluates the costs and benefits of various retirement financing tools and schedules. Significant financial benefits from securitization are demonstrated;
- **Chapter 3** identifies best practices for securitization legislation and implementation in the context of unanticipated or accelerated plant retirement based on case study reviews of recent/pending transactions in Michigan, Florida, Wisconsin, and New Mexico, as well reviews of recently passed legislation in Colorado and Montana; and
- **Chapter 4** puts forth recommendation for Minnesota Power to consider as it pursues securitization.

This report was informed by Minnesota Power's concurrently prepared Integrated Resource Plan (IRP) and Baseload Retirement Study.



- *Key Insight 1: Securitization upon early plant retirement in 2030 may substantially mitigate—but not eliminate—a near-term post-retirement rate increase that is driven by new 100% utility-owned asset investments, while reducing customer costs on an NPV basis and providing meaningful transition assistance to coal plant workers and communities. Additional rate mitigation tools would be needed to fully mitigate near-term cost impacts from accelerated retirement and replacement. Longer-tenor securitizations may provide greater moderation. On a Net Present Value (NPV) basis, the securitization tenor variants we tested for 2030 securitization—5-, 10-, and 15-year tenors—are cheaper than both BAU and traditional utility financing of the retirement without the use of securitization but with same physical replacement option. Longer-tenor securitizations slightly increase NPV benefits.*
- *Key Insight 2: Early securitization in the absence of early reinvestment in of 100% utility-owned clean energy or other assets creates significant risk for the utility prior to plant retirement and replacement. Early securitization of a portion of the remaining plant balance five years prior to retirement and reinvestment in replacement resources can front-load transition assistance and may also mitigate, but not eliminate, a 2030 rate increase for a 2030 retirement. This misalignment of the timing of securitization with utility reinvestment could translate to higher future utility financing costs and customer rates.*
- *Key Insight 3: RMI analysis suggests that securitization charges in all scenarios modeled remain below 10% of total customer collections—even under “stress-testing” conditions. Nevertheless, based on RMI’s simplified analysis of the potential impacts of securitization on ALLETE’s earnings and credit metrics, securitization timed to coincide with reinvestment in replacement resources in 2030 may offer improved financial resilience to a persistent 20% demand shock relative to the BAU case.*
- *Key Insight 4: Consideration of additional tools and retirement, replacement, and securitization scenarios outside the scope of this analysis would be needed to fully mitigate the residual near-term post-retirement rate increase. As an example of such a tool, state legislation could allow the use of “market-indexed” tariffs for utility-owned replacement assets. A market-indexed tariff is set based on the competitively determined “market” clearing price for a power purchase agreement (PPA) for assets bidding to provide similar services, mitigating the rate increase from new rate-based assets. Similarly, analysis of additional scenarios to take advantage of the recent extensions to the Investment Tax Credit (ITC) and Production Tax Credit (PTC) through the end of 2025 may also offer cost benefits that could further mitigate rate increases. However, such analyses would need to carefully consider constraints around tax capacity at the ALLETE level.*



The core goal of the Phase 2 Report is to demonstrate how financing approaches not customarily used in the regulated utility sector can help minimize ratepayer costs that would arise if Boswell Units 3 and 4 are retired prior to their currently scheduled retirement dates and replaced with a portfolio of renewable energy assets and natural gas generation along with some market purchases.

The timing of the early retirement—2030—and the specific composition of the replacement portfolio were inputs to the modeling. They were generated through the IRP process, not by the RMI team.⁴

On the basis of company-supplied estimated capital and operating costs of the Boswell units as well as company-supplied estimates of the costs of the replacement assets, the RMI team first modeled the annual financial burdens on ratepayers from the IRP-informed retirement and replacement option using traditional utility finance and compared this burden with a scenario that assumes no early retirement of the Boswell units. Traditional utility finance is defined by rate-basing assets, with deployed capital earning an approved rate of *return on capital* that is determined by regulators who stipulate the cost of equity for the company as well as the fraction of equity that can be included in a capital stack that also contains debt. Rate-based assets are depreciated in straight-line fashion, effecting a *return of capital* to equity and debt investors. With each year of depreciation, there is less capital in rate base, so the return on capital declines in absolute size even if the approved rate of return remains the same. If an asset is retired before depreciation is completed, the traditional utility finance approach can still be applied to a so-called regulatory asset. A regulatory asset can maintain the depreciation schedule of the retired asset, though often the period is compressed, with the more rapid return of capital causing near-term rates to rise.

In a critical further step, the RMI team then tested the ratepayer impacts of using a fundamentally different financing approach—securitization—to manage the return of, and on, undepreciated capital. This chapter details our modeling approach and identifies key insights derived from the modeling analysis.

Background

In the Phase 1 Report, the RMI team qualitatively discussed the risks and rewards of various transition mechanisms, including regulatory assets and securitization. Phase 1 did not consider specific replacement assets.

In Phase 2, the RMI team and Minnesota Power extracted from the IRP assumptions and data for a replacement portfolio—one capable of supplying the energy and services that would be lost if the Boswell units were to retire early in 2030—in order to satisfy the input requirements of the RMI Securitization Model. Using this single replacement portfolio, the RMI team used its model to quantify the ratepayer cost impacts of different refinancing approaches and schedules for the Boswell plant. The results presented below are intended to provide a directional assessment of what securitization would

⁴ As noted below, the RMI time telescoped a three-year retirement-replacement scenario into a single year for modeling simplicity, but it did not alter the composition of the replacement portfolio.



mean for various stakeholders. Several significant simplifications were incorporated into the modeling—most notably, retirement and replacement occur in a single year—but we believe the insights from the analysis are nonetheless informative.

Modeling Overview

The RMI Securitization Model calculates near-term and levelized cost impacts for alternative investment and operating futures associated with the potential accelerated retirement and replacement of one or more operating assets. The model creates a Business-as-Usual (BAU) baseline that is extrapolated from the historical investment and performance data for the existing assets and then measures this future against alternatives that replicate the generation of the BAU assets and also recover their capital. Typically, the replacement assets have expected lives that are longer than the remaining life of the BAU asset. In this case, the model extends the BAU scenario so that futures are compared over equivalent time horizons. The model does not calculate rates by rate class, nor does it output the total revenue requirement for a modeled utility experiencing a larger or smaller projected total system load.

In the model, every alternative future has two components:

- i. a mechanism and pathway for financing the capital balance of the BAU asset(s); and
- ii. a mechanism and pathway for replacing the energy output of the BAU asset(s).

An alternative future can differ from the BAU baseline with regard to either component i, component ii, or both components.

For component i—mechanism and pathway for financing the capital balance of the BAU asset(s)—the following financing mechanisms can be modeled:

- a. accelerated depreciation of some or all of the existing rate base associated with the BAU asset(s) over a period shorter than the currently scheduled life of those asset(s);
- b. creation of a regulatory asset comprising some or all of the existing rate base associated with the BAU asset(s), over an agreed-upon time period; and
- c. securitization of some or all of the existing rate base associated with the BAU asset(s), assuming the existence of legislation that can support the issuance of highly rated (AA or better) fixed-payment, amortizing bonds with estimated interest rates based on current Treasury yield curves and credit spreads, adjusted to forward rates for future issuance dates of bonds of various tenors.

For component ii—mechanism and pathway for replacing the energy output of the BAU asset(s)—the following replacement options can be modeled:

- a. a wind PPA,
- b. utility-owned wind,
- c. a solar PPA ,



- d. utility-owned solar assets,
- e. utility-owned existing or new natural gas assets, and
- f. a combination of any of the above.

Note: in this analysis, component ii is the physical retirement and replacement option; it is fixed for all of the financing scenarios. The model incorporates the effects of the tax benefits of accelerated depreciation and federal tax credits for renewable energy, where applicable, including the impact of estimated Accumulated Deferred Income Taxes (ADIT) and Accumulated Deferred Income Tax Credits (ADITC) for public utility property subject to “normalization.”

All variable costs are subject to macro inflation, currently estimated at 2.0% annually, except for fuel and operations & maintenance (O&M) costs for the BAU scenario, which are inflated at 2.8%.

Minnesota Power Details

Two main “futures” were examined:

- Scenario 1: retire and securitize Boswell 3 and 4 in 2030.
- Scenario 2: retire in 2030 but execute a partial securitization in 2025.

Securitization assumptions:

- for the 2030 securitization, 5-year, 10-year, and 15-year bond tenors were tested, while for the 2025 partial securitization, 10-year, 15-year, and 20-year tenors were tested. This allows for comparison in each scenario of bonds maturing in 2035, 2040, and 2045.
- the 2030 securitization scenario assumes 100% of the unrecovered costs (including any decommissioning costs net of salvage are securitized);
- the 2025 partial securitization case assumes that 75% of unrecovered costs are securitized, roughly sufficient to ensure that plant depreciation and bond amortization expenses with securitization do not exceed depreciation expenses in the BAU case;
- securitization interest rate varies with tenor and reflect current estimated spreads for securitization bonds of comparable tenors relative to treasuries as well as implied future treasury yields of comparable weighted average life based on the current treasury yield curve;
- securitization proceeds include transition assistance for workers and communities impacted by the plant retirements at the rate of 6% of the plant retirement costs securitized; this is a premium above the funds needed to decommission the plant and recover the outstanding plant capital balance.
- securitization issuance costs are capitalized and included in the bond amount;
- annual securitization servicing costs are included in the annual ratepayer charges collected to repay the securitization bonds; and
- yield curve is upward sloping.



BAU assumptions:

- unchanged financial treatment of the plants through their current remaining lives (through 2035);
- annually inflation of historical operating, maintenance, and fuel costs through 2035; and
- for replacement of services during the post-retirement period until the end of life of our envisioned replacement assets, operating costs and offsetting annual additions and recovery of capital to reflect needed investment for increased dispatch elsewhere in the system or life extension of the Boswell plants. Operating costs, but not capital outlays, are subject to annual inflation escalator of 2.8%

Replacement assumptions:

- RMI adapted a three-year replacement portfolio specified by the company, compressing the transition into one year, comprising (see Table 1 below for more details):
 - 403 MW utility-owned wind;
 - 625 MW utility-owned combined cycle natural gas turbine;
 - 300 MW utility-owned solar;
 - transmission additions as specified by the company;
 - and market purchases (see Table 1 below).
- Annual inflation of variable costs set at 2.0%.
- Capital costs and operating costs specified by the company.

Outputs:

- ratepayer near-term and levelized cost impacts for each scenario and securitization tenor combination;
- credit rating impacts on ALLETE for all the scenario/tenor combinations; and
- “stress-tested” credit rating impacts for select scenario/tenor combinations subjected to a 20% loss of revenue (e.g., through the departure of at least two of its largest major industrial customers).

Levelized costs are calculated with a 7.06% discount rate, as specified by the company. For credit ratings analyses, tax benefits are monetized in the year recorded. Consistent with rating agency guidance, we calculate credit-relevant quantitative metrics for the utility in two ways: assuming that the securitization is consolidated on the utility’s balance sheet and also without consolidation.⁵ RMI adopted a simplified

⁵ Consolidated financial statements include information from a company's subsidiaries and special purpose entities (SPEs) on a single set of financial statements. Whether or not consolidation is required to satisfy Generally Accepted Accounting Principles (GAAP) is a complicated decision that must consider various factors, including the reporting entity’s degree of control over any entity being evaluated for consolidation. Even if the reporting company does not choose to consolidate an SPE (e.g., the holder of the property right in a ratepayer-backed securitization), credit rating agencies may, out of conservatism, opt to conduct their rating both with and without consolidation.



credit metric analysis that used industry-wide thresholds, not those specifically applied to ALLETE by agencies. Cashflow and debt levels are based on ALLETE data from fiscal year 2019.



Table 1. Scenario Assumptions Summary

Scenario	Securitization Year	Retirement Year	Securitization Tenor (yrs.)	Total Retirement Costs	Transition Assistance	Transaction Costs	Total Bond Size	Interest Rate
1	2030	2030	15	\$391,725,833	\$23,503,550	\$5,906,606	\$421,135,989	3.57%
1	2030	2030	10	\$391,725,833	\$23,503,550	\$5,906,606	\$421,135,989	3.31%
1	2030	2030	5	\$391,725,833	\$23,503,550	\$5,906,606	\$421,135,989	2.72%
2	2025	2030	20	\$587,588,750	\$35,255,325	\$7,359,909	\$630,203,984	3.48%
2	2025	2030	15	\$587,588,750	\$35,255,325	\$7,359,909	\$630,203,984	3.06%
2	2025	2030	10	\$587,588,750	\$35,255,325	\$7,359,909	\$630,203,984	2.68%

Replacement Resource Cost and Capacity Assumptions (2030) -- Minnesota Power estimates

Resource	Initial Capital Investment (\$/MW)	O&M + Fuel (\$/MWh)	Capacity (MW)	Generation (MWh)
Wind	\$2,013,926	\$9.63	403	1,623,352
Solar	\$1,217,500	\$3.56	300	640,440
Natural Gas (NGCC)	\$1,260,120	\$35.93	600	2,102,400
Market Purchases	-	\$49.20	81	649,785
Transmission	\$145,339	-	-	-

Assumed BAU Post-Retirement Replacement Energy Costs (2035) -- RMI estimates

Resource	Annual Recurring Capital Investment (\$/MW)	O&M + Fuel (\$/MWh)
Boswell 3 + 4 life extension	\$90,454	\$42.16



Results Summary

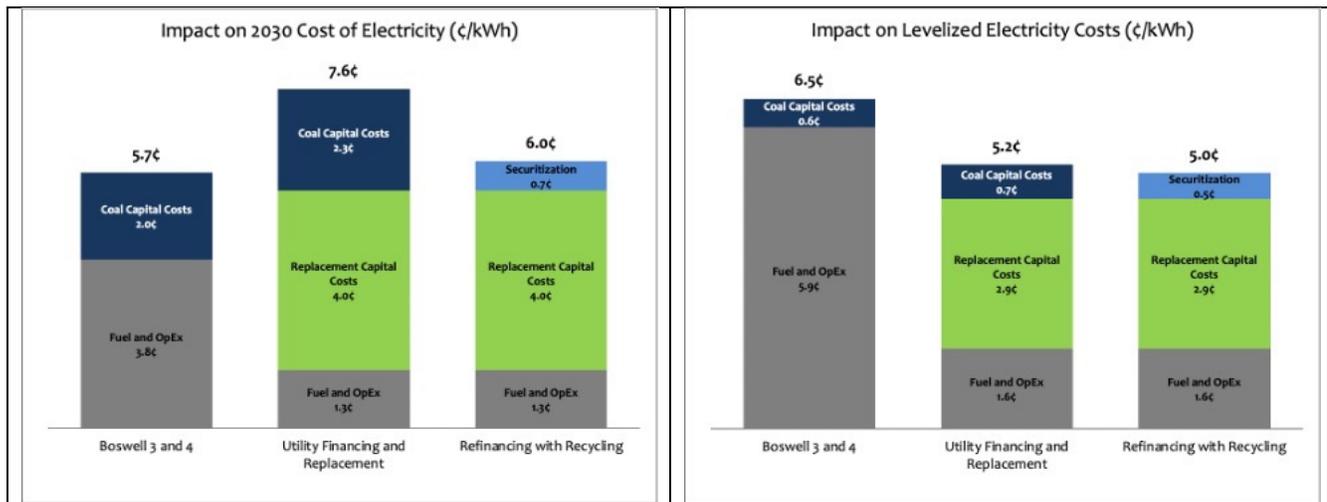
Scenario 1: Retire and Securitize in 2030

Securitization with a 15-year bond tenor can significantly mitigate the 2030 rate increase that could result from retirement and replacement of Boswell Units 3 and 4 using traditional utility finance and also provide levelized cost benefits relative to a shorter tenor. However, this approach cannot eliminate rate increases.

15-year tenor

Securitization charges in 2030 would comprise roughly 3% of total utility revenues, well below the 20% rule-of-thumb threshold that some credit rating agencies use to indicate potential challenges for achieving a AAA bond rating. Levelized costs over the 2030-2059 horizon are roughly 23% lower with securitization versus BAU:

Chart 1. Securitization Impact Summary (Scenario 1, 15-year tenor)



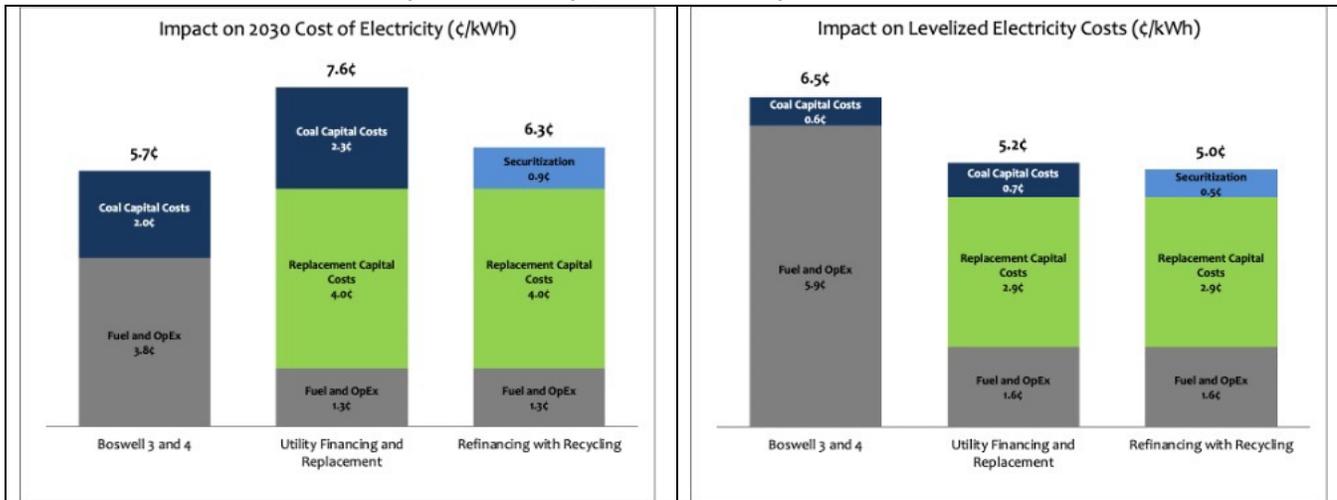
10-year tenor

Securitization charges in 2030 jump to roughly 4% of total utility revenues, still well below the 20% threshold. Levelized costs for the scenario are similar to the 15-year case,⁶ while near-term benefits of securitization are 0.3¢/kWh less, in both cases because of more rapid amortization of principal:

⁶ Numbers in charts are rounded.



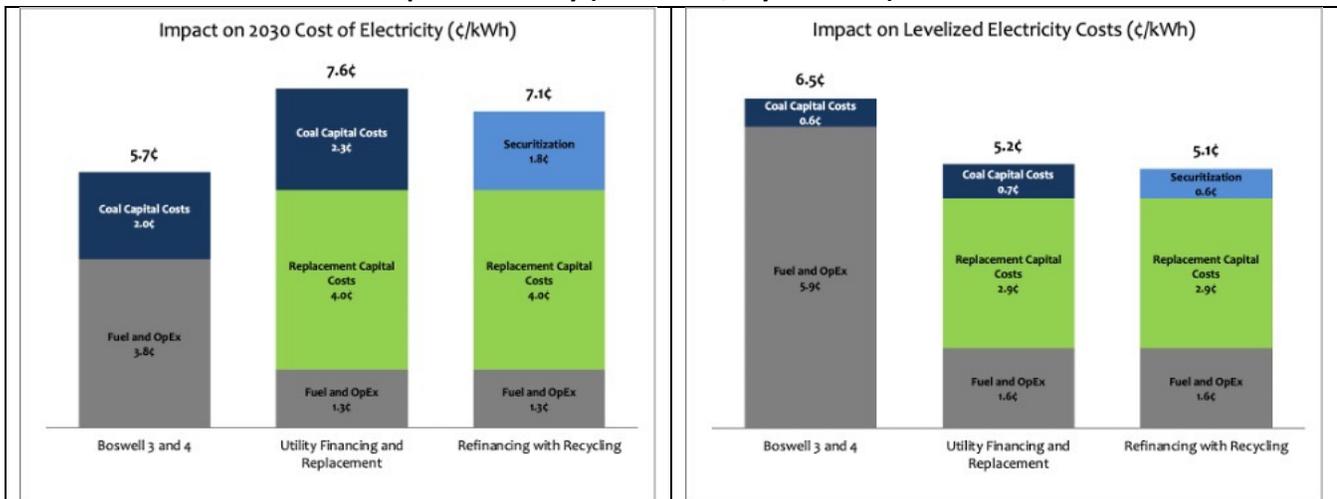
Chart 2. Securitization Impact Summary (Scenario 1, 10-year tenor)



5-year tenor

Securitization charges in 2030 jump to roughly 7% of total utility revenues, still well below 20%. Levelized costs savings are roughly 0.1¢/kWh less than with a 15-year or 10-year tenor. Near-term benefits of securitization are 0.8¢/kWh less than with 10-year tenor (1.1¢/kWh less than with 15-year tenor), because of even more rapid amortization of principal:

Chart 3. Securitization Impact Summary (Scenario 1, 5-year tenor)



For all three tenors, RMI estimated the impact of the retirement and replacement transaction with securitization relative to the BAU case on ALLETE’s earnings and its consolidated quantitative credit metrics, under the simplifying assumption that ALLETE’s financial metrics at the time of the transaction



were unchanged from the end of 2019. We found that the transaction would be accretive to earnings per share and credit neutral for all three tenors, regardless of whether the securitized debt was consolidated on ALLETE's balance sheet or not.



Scenario 2: Retire in 2030 but securitize 75% of unrecovered balances in 2025

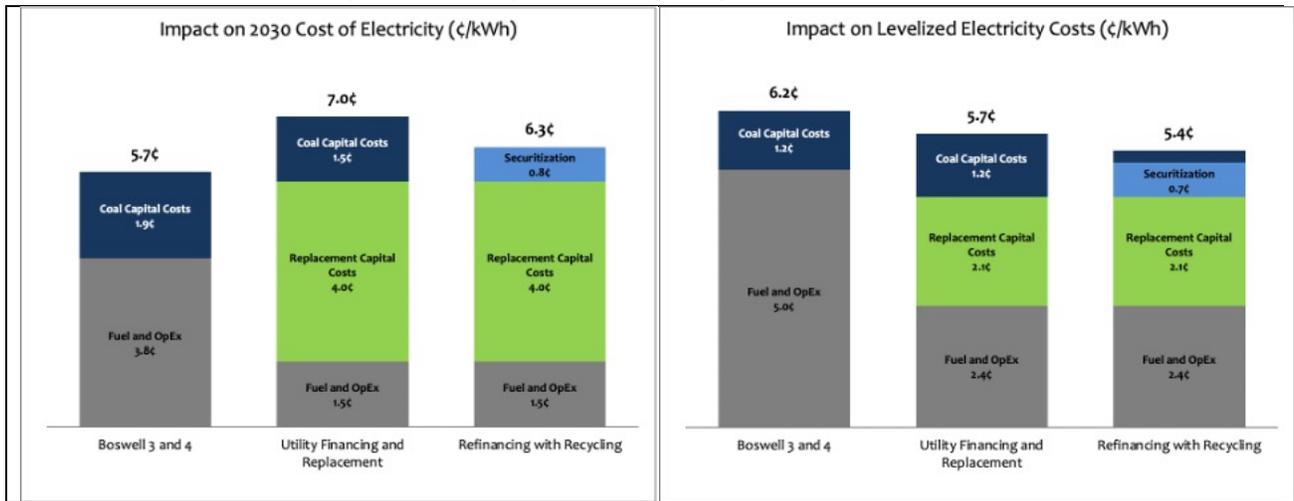
Moving the securitization forward in time but securitizing only a fraction of the unrecovered capital still cannot eliminate the near-term rate increase in 2030.

Note: levelized costs below are over the 2025-2059 timeframe and thus are in \$2025 dollars. Scenario 1 results are in 2030 dollars.

20-year tenor

Securitization charges in 2025 would comprise roughly 3.8% of total utility revenues, and 3.5% of revenues in 2030, well below the 20% rule-of-thumb threshold for triggering challenges to achieving a AAA bond rating. Levelized costs are roughly 13% lower with securitization versus BAU:

Chart 4. Securitization Impact Summary (Scenario 2, 20-year tenor)

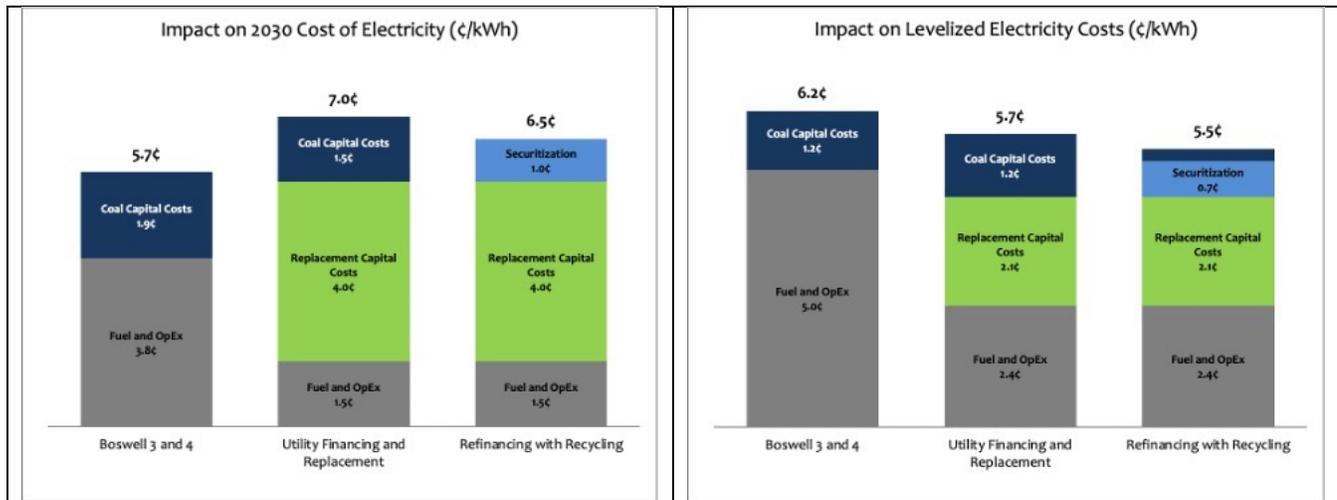


15-year tenor

Securitization charges in 2025 would comprise roughly 4.5% of total utility revenues, and 4.2% of revenues in 2030, well below 20%. Levelized cost savings are roughly 0.1¢/kWh less than with a 20-year tenor, while near-term benefits of securitization are 0.2¢/kWh less than with 20-year tenor, because of more rapid amortization of principal:



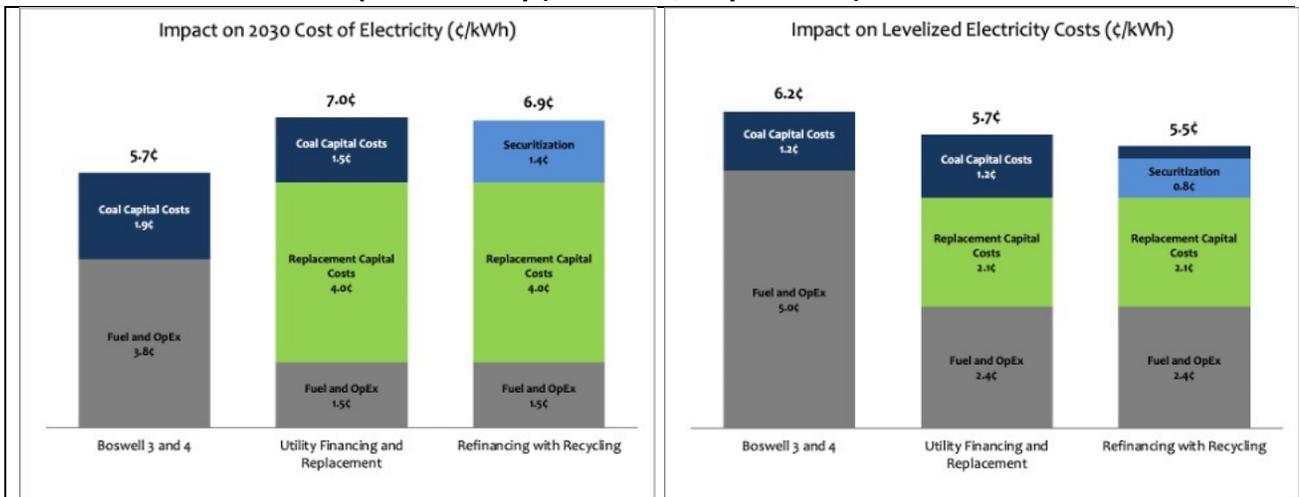
Chart 5. Securitization Impact Summary (Scenario 2, 15-year tenor)



10-year tenor

Securitization charges in 2025 would comprise roughly 6% of total utility revenues, and 5.6% of revenues in 2030, well below 20%. Levelized cost savings are similar to the 15-year case, while near-term benefits of securitization are 0.4¢/kWh less than with 15-year tenor, because of more rapid amortization of principal:

Chart 6. Securitization Impact Summary (Scenario 2, 10-year tenor)



Just as with the first scenario, RMI estimated the impact of the retirement and replacement transaction with securitization relative to the BAU case on ALLETE’s earnings and its consolidated quantitative credit metrics under the simplifying assumption that ALLETE’s financial metrics at the time of the transaction were unchanged from the end of 2019. For all three tenors, the transaction is initially mildly dilutive to



shareholders in 2025 with the initial securitization, but significantly accretive to earnings per share (EPS) by 2030 after investment in replacement resources. The quantitative credit rating is unchanged on an aggregate level through 2030.

Stress Test

The 10-year securitization tenor case in Scenario 1 (2030 securitization) and the 15-year securitization tenor case in Scenario 2 (2025 securitization) were “stress-tested” to assess the financial impacts of the sudden, unanticipated loss of major industrial customers, permanently reducing sales by 20%.

Securitization charges would, in this case, be subject to automatic adjustment to maintain the total surcharge collections level—increasing charges on a per kWh basis by 25% to make up for the lost revenue. We assess the stress test by comparing the impact on utility financial metrics (prior to any adjustment to utility rates through a subsequent rate case) in both the BAU and securitization cases.

Scenario 1 (2030 securitization, 10-year tenor)

In the BAU case, a sudden 20% drop in sales in 2030 would result in an 84% reduction in earnings prior to any potential subsequent rate case. Aggregate credit-relevant metrics appear to be able to withstand the initial shock but would be negatively impacted if no rate adjustments were made to compensate.

With a 10-year securitization in 2030, retirement of Boswell, and the deployment of replacement resources, *the earnings per share impact of the stress case is actually less severe than in BAU*; earnings per share fall by 65%, as a higher fraction of revenues are generating earnings (the transition to renewables having reduced pass-through operating expenses). Securitized charges comprise roughly 5% of total revenues (well below the 20% threshold), while credit metrics remain resilient relative to BAU.

Scenario 2 (2025 securitization, 15-year tenor)

In the BAU case, a sudden 20% drop in sales in 2025 would result in an 86% reduction in earnings prior to any potential subsequent rate case; just as above, there would be an 84% reduction in earnings in 2030. Again, aggregate credit-relevant metrics appear to be able to withstand the initial shock but would be negatively impacted if no rate adjustments were made to compensate.

However, unlike what we saw for Scenario 1, the financial distress associated with the stress test in the context of securitization is *more severe relative to BAU*, both for shareholders (96% reduction in 2025 earnings per share) and for aggregate credit-relevant metrics in 2025 *because there been no boost to rate base from new assets*. Further, the adverse EPS impact in this scenario remains greater in 2030 than is the case for Scenario 1. It should be noted, of course, that a demand shock prior to investment in new renewables would perhaps delay—or reduce the size of that—renewable deployment, which would constitute a further headwind to earnings.



Summary of Key Insights

Key Insight 1: Securitization upon early plant retirement in 2030 may substantially mitigate—but not eliminate—a near-term post-retirement rate increase that is driven by new 100% utility-owned asset investments, while reducing customer costs on an NPV basis and providing meaningful transition assistance to coal plant workers and communities. Additional rate mitigation tools would be needed to fully mitigate near-term cost impacts from accelerated retirement and replacement. Longer-tenor securitizations may provide greater moderation. On a Net Present Value (NPV) basis, the securitization tenor variants we tested for 2030 securitization—5-, 10-, and 15-year tenors—are cheaper than both BAU and traditional utility financing of the retirement without the use of securitization but with same physical replacement option. Longer-tenor securitizations slightly increase NPV benefits.

Explanation: Securitization offers two paths to cost reduction for ratepayers. First, as the plant's unrecovered balance (or, to be more precise, the amount securitized) is financed with extremely highly rated (AA or AAA) debt, the associated carrying (i.e., interest) charges are significantly lower than if the same capital balance were subject to the company's approved rate of return (which blends lower-rated, costlier debt and even more expensive equity). Second, securitization can be used to extend the period of capital recovery beyond the plant's currently expected remaining life (in the case of Boswell, through 2035). Since the interest rate of securitization debt will in almost all conceivable applications be lower than the discount rate that reflects the financial outlook of average ratepayers, the NPV of a longer-tenor securitization will be lower than that of shorter securitization. However, given the expectation of an upward-sloping yield curve, a longer securitization will also entail a higher weighted average interest rate, offsetting some of the NPV benefits of a longer tenor.

As discussed in the Phase 1 report, longer securitization tenors can present intergenerational equity issues, as some future customers will be paying for assets that they never received service from. This concern must be balanced against the benefits those future customers will receive from a cost-optimized retirement and replacement scenario, for instance one that takes advantage of low interest rates for refinancing and tax credits for new clean investments.

If the tenor of the securitization is at least the same length as the plant's previous expected remaining life (5 years in this case), lower carrying costs will reduce the nominal capital costs of the old asset post retirement and help offset the costs of investment in and operation of the replacement assets (which may or may not be lower than the avoided operating costs of the retired asset). Extending the tenor of a securitization with an interest rate below the discount rate will further increase savings in NPV terms.

Ultimately, the magnitude of the savings is dependent on the size of the refinanced amount, the number of years added to the recovery period, the spread between the rate of return and the securitization yield, and choice of discount rate. Given the current low level of long-term interest rate and the difference between most utility weighted averages costs of capital and long-term interest rates for AAA-



rated securities, there is a strong case to be made for taking advantage of the yield curve by implementing earlier securitizations with longer tenors.

Key Insight 2: Early securitization in the absence of early reinvestment in of 100% utility-owned clean energy or other assets creates significant risk for the utility prior to plant retirement and replacement. Early securitization of a portion of the remaining plant balance five years prior to retirement and reinvestment in replacement resources can front-load transition assistance and may also mitigate, but not eliminate, a 2030 rate increase for a 2030 retirement. This misalignment of the timing of securitization with utility reinvestment could translate to higher future utility financing costs and customer rates.

Explanation: Securitization prior to retirement reduces by five years the length of time that that capital is exposed to the full approved rate of return; this capital instead incurs a very low interest rate (on the near end of the upward sloping yield curve). It does not eliminate the rate increase in 2030, however.

Further, our stress test suggests that the utility would experience materially greater credit and earnings risk with an early securitization in the event of the loss of a customer in this scenario.

Key Insight 3: RMI analysis suggests that securitization charges in all scenarios modeled remain below 10% of total customer collections—even under “stress-testing” conditions. Nevertheless, based on RMI’s simplified analysis of the potential impacts of securitization on ALLETE’s earnings and credit metrics, securitization timed to coincide with reinvestment in replacement resources in 2030 may offer improved financial resilience to a persistent 20% demand shock relative to the BAU case.

Explanation: New asset investments add debt to the company balance sheet and increase interest charges. Even if the company does not consolidate securitization debt and interest charges on its financial statements, credit rating agencies are likely to perform their analyses both with and without consolidation.

Either debt or interest charges is a factor in each of the four key financial strength metrics.

Table 9. Moody’s Financial Strength Metrics

Moody's Financial Strength Metrics
CFO pre-WC + Interest / Interest (x)
CFO pre-WC / Debt (%)
CFO pre-WC Minus Dividends / Debt (%)
Debt/Capitalization (%)

The revenue requirements for new investments and the ratepayer charges for securitization if consolidated will increase cash flow from operations (CFO), which serves to strengthen metrics weakened by increased debt or interest charges (except Debt/Capitalization).



CFO is subject to stress testing by rating agencies, since it may be negatively impacted by operational and economic developments that would not alter debt load and interest payments.

A comprehensive qualitative and quantitative corporate credit profile will positively assess not only the long-term revenue prospects from new generation assets, but also the recovery of capital from fossil assets that may be impaired by any future strengthening of pollution regulations.

Key Insight 4: Consideration of additional tools and retirement, replacement, and securitization scenarios outside the scope of this analysis would be needed to fully mitigate the residual near-term post-retirement rate increase. As an example of such a tool, state legislation could allow the use of “market-indexed” tariffs for utility-owned replacement assets. A market-indexed tariff is set based on the competitively determined “market” clearing price for a power purchase agreement (PPA) for assets bidding to provide similar services, mitigating the rate increase from new rate-based assets. Similarly, analysis of additional scenarios to take advantage of the recent extensions to the Investment Tax Credit (ITC) and Production Tax Credit (PTC) through the end of 2025 may also offer cost benefits that could further mitigate rate increases. However, such analyses would need to carefully consider constraints around tax capacity at the ALLETE level.

Explanation: Market-indexing is a legislative option that has been adopted in three states (Virginia, Utah, and Nevada) that allows regulated utilities to own assets and claim an ITC without the requirement to “normalize” tax benefits.⁷ A market-indexed asset is not placed in rate base. Instead, its output is priced like the generation purchased via a power purchase agreement (PPA); in this case, however, the utility—not a third party—is the owner of the generation and incorporates a return on investment in the energy sales prices. This price must be competitive with the price offered by third parties. Thus, market-indexing is a departure from cost-of-service ratemaking that is intended to allow regulated utilities to effectively compete with third-party providers in the pricing of solar assets that are eligible for sizable ITC benefits. Customers are no worse off than if the PPA had been chosen. In turn, utility shareholders gain new opportunities to earn on assets that, absent this approach, would likely be owned by third parties with their corresponding PPA contract costs charged to ratepayers on a pass-through basis.

PPAs are priced to deliver flat or nominally upward trending revenue from an asset over its life. In contrast, the revenue profile of a rate-based asset starts higher than an equivalently priced PPA asset and declines. Thus, market-indexed pricing further reduces the initial rate increase from a new asset.

The IRS has confirmed in private letter rulings that market-indexed utility-owned assets are not “public utility property” in the sense that imposes the normalization requirement under the Internal Revenue Code.⁸ Avoiding normalization of the ITC allows the utility to significantly reduce ratepayer costs for solar assets. (Market-indexing is chiefly of relevance for solar because the solar ITC is sizable (as much as

⁷ Virginia 2015 House Bill 2237, Utah 2018 House Bill 261, and Nevada 2019 Senate Bill 358.

⁸ See PLR 201923019, available at <https://www.irs.gov/pub/irswd/201923019.pdf>.



26% for assets that enter service before 2026) and enduring (a 10% ITC for solar is in effect without sunset), and because, unlike for wind and various other clean energy technologies, solar is not eligible for production tax credits (PTC), which, by law, are not subject to normalization.

Freed from the normalization requirement and assuming it has sufficient tax capacity, the utility can realize the monetary benefits of the ITC upon the asset's entry into service and pass through that amount in full—if so desired/compelled by competitive pricing pressure of third-party PPA providers—to ratepayers by reducing the amount of capital that must be financed and recovered over time. In contrast, with normalization, ratepayers receive less value from the ITC, and thus pay a higher total amount for the asset. To illustrate with a quantitative example, given a \$1 million solar asset eligible for a 30% ITC not subject to normalization, the company can set the price of energy sales to recover \$700,000 in invested capital over time. With normalization, ratepayers are compelled to finance a \$1 million asset adjusted downward by the carrying cost of an ITC credit amortized over the life of the asset. Assuming for simplicity's sake a pretax rate of return and a ten-year asset life/ITC asset amortization period, ratepayers receive an ITC benefit of $\$300,000 \times 10\%$, or \$30,000 in year 1, while in year 2 they receive a benefit of only $\$270,000 \times 10\%$, or \$27,000, reflecting the one-tenth amortization of the ITC offset to rate base. And so forth through 10 years. All the while they must still pay depreciation expenses to recover \$1 million over ten years, not \$700,000. The NPV of this diminishing stream of benefits is less than the benefit of having \$300,000 lopped of the cost of the asset at the outset of its financing life.⁹

Market-indexing reduces CFO relative to traditional utility financing but also results in an even greater reduction in debt load (if the tax credit is monetized), since the credits are treated effectively as a return of capital.

The benefits of market-indexing are highly dependent on the relative size of the ITC. Investing in new assets before 2026, when the ITC declines sharply, could result in greater ratepayers benefits (and also unlock PTC benefits that under current law will not be available after 2025 for most onshore wind assets).¹⁰ These benefits must be weighed against the capital expenditures of the technologies in the year of deployment, especially if large cost declines are expected. Further modeling is needed in this regard to reach a conclusion.

⁹ This example ignores the reduction in depreciable basis in the amount of 50% of the ITC that is required when the ITC is claimed. This reduction occurs both with and without normalization.

¹⁰ The IRS has provided a longer safe harbor for onshore wind projects, if at least half of the project is built on federal land and it includes construction of a major new transmission line.



Chapter 3. Securitization Risk and Feasibility Assessment

- *Key Insight 1: Securitization legislation in some states have included provisions to protect customers by requiring the use of rate adjustment mechanisms (e.g., bill credits) that ensure that customers see savings immediately upon bond issuance.*
- *Key Insight 2: Implementing the securitization charge as a volumetric (per kWh) charge that is allocated across customer classes consistent with the basis of allocation in the most recent rate case is a simple and relatively non-controversial approach that has been commonly used historically. However, alternative allocation methods have also been considered. For instance, bond revenue certainty could be enhanced with minimal cost-shifting across customer classes by implementing securitization charges as fixed or demand charges, even for residential customers.*
- *Key Insight 3: Utilities have balanced intergenerational equity and least-cost considerations by carefully structuring the securitization bond issuances through judicious choices of multiple tranches of bonds with different tenors.*
- *Key Insight 4: Utilities have been able to stagger the timing of securitization, retirement, and replacement while still minimizing risks to utility investors and providing customers with immediate bill savings.*
- *Key Insight 5: Recent securitization legislation (in particular, in New Mexico) allows the proceeds of securitization transactions to also be used to support the transition of coal plant workers and communities.*

In the Phase 1 report, the RMI team conducted a preliminary assessment of risks and rewards associated with securitization. As part of the feasibility assessment, we discussed several key criteria that need to be met to ensure a successful execution of securitization:

Key Criterion 1: The overall ratepayer cost reduction from securitization should outweigh the transaction costs.

Key Criterion 2: The bond issuance should be structured to balance cost reductions and risks (e.g., to ratepayer classes, existing shareholder, and bondholders).

Key Criterion 3: The bond should not cause significant cross-subsidization; intergenerational impacts, both direct and indirect, should be explicitly addressed and, to the extent possible, quantitatively modeled.



Key Criterion 4: Legislative and regulatory processes needed to allow the use of securitization and to achieve a AAA rating should be executed in a coordinated and timely fashion.

Key Criterion 5: All stakeholders should be clearly aligned regarding the costs to be borne, benefits to be received, and roles expected from each other.

The deeper dive on feasibility assessment in Phase 2 underscored that utilities often face the following challenges as they implement securitizations:

Challenge 1: Ensuring that the securitization results in lower customer bills from day one

Even when the overall ratepayer cost reduction from a securitization outweighs any transaction costs (criterion 1), benefits may not translate into customer bill savings if different components of rates are not adjusted in coordination. For instance, there may be timing differences between the securitization transactions and rate cases. Securitization charges will be added to customer bills immediately after the bond is issued (or with a lag of no more than a few months¹¹), while the removal of a securitized plant balance will need to be approved through a rate case that may not be filed for several more years. Therefore, net bill savings may not be reflected immediately.

Challenge 2: Fairly allocating securitization charges and any related rate adjustments across customer classes so as not to exacerbate cross-subsidization or create intergenerational inequities

Utilities and customer advocates often have different views regarding the optimal tenor of the securitization bond, as this determines the split of costs between current and future customers. The allocation of securitization costs across customer classes and the design of the surcharge itself can determine how securitization impacts are distributed among different customer classes. These issues often trigger heated discussion in securitization proceedings.

Challenge 3: Coordinating the timing of legislation, regulatory and utility planning processes

The simplest approach is to align securitization with retirement and deployment of additional capital investment in replacement generation. In practice, these activities often have different legislative, regulatory, and planning timelines.

Challenge 4: Designing the transition package so that all key stakeholders can achieve desirable outcomes

Securitization is a financing tool whose benefits are typically measured for the service territory as a whole. However, local community impacts such as job losses from retired plants and tax revenue reductions in retired plant communities need to be addressed to build the necessary support for the process, especially if securitization legislation has not yet been enacted.

In Phase 2, we reviewed recent securitization transactions pertinent to Minnesota Power, examining the legislative and regulatory approaches that were employed to help resolve the challenges listed above.

¹¹ Testimony of Charles N. Atkins before the New Mexico Public Regulation Commission, Docket 19-000195-UT, 1 July 2019, 18.



Some of characteristics of the individual securitizations were driven by state legislative requirements and, thus, were not at the discretion of the utilities. We will highlight these as we discuss the key insights derived from the case studies.



Table 10. Securitization Case Study Summary Overview

Utility	Consumers Energy (2014 and 2020)	PNM (2020)	WEPCO (2020)	Duke Energy Florida (2016)
State	Michigan	New Mexico	Wisconsin	Florida
Issuance/Approved Amount/Date*	\$378 million issued in 2014; \$688 million approved in 2020	\$361 million approved in 2020	\$118 million approved in 2020, pending financing costs at the time of bond issuance	\$1,294 million issued in 2016
Use of Proceeds	Coal plant cost recovery	Coal plant cost recovery	Coal plant cost recovery (environmental control device cost only)	Nuclear plant cost recovery
Cost Allocation**	Same as the most recent rate case (4CP, 50/25/25)	Same as the most recent rate case (“3S1W”)	Same as the most recent rate case (12CP, 75/25)	Same as the one approved in the retirement settlement (12CP and 1/13 AD)
Surcharge Design	Per kWh rates	Customized (fixed or per kW) rates based on customer characteristics	Per kW rates for General Primary customers; Per kWh rates for all others	Per kWh rates
Rate Base Adjustment	Used bill credit for interim rate adjustment	Used bill credit for interim rate adjustment	No credit as the plant was already removed from the rate base	No credit as the plant was already removed from the rate base
Transition Plan	Handled separately in the IRP settlement	Transition assistance included as qualified cost	No concrete commitment in either the financing order or the retirement settlement	No concrete commitment in either the financing order or the retirement settlement
Securitization Bond Tenor	15 years for the 2014 bond; 8 years for the 2020 bond	25 years	13 years	20 years
Timing of Securitization and Retirement	2014: securitize before retirement (2015); 2020: simultaneous securitization and retirement (2023)	Simultaneous securitization and retirement (2022)	Securitize (2021) after retirement (2018)	Securitize (2016) after retirement (2013)
Timing of Replacement	Purchased the Jackson Gas Plant to partially replace the assets retired in 2015; 2019 IRP plans to add 550MW wind, 6,000 MW solar by 2040 to replace the rest of the retired coal.	A Clean Energy Portfolio was proposed in 2020 and undergoing RFPs.	No concrete commitment in either the financing order or the retirement settlement	Purchased a combined cycle plant (Citrus) as the replacement and included it into the rate base in July 2018

**Issuance/Approved Amount/Date: If the bond has been issued, this row indicates the full bond amount at the issuance date; if the bond has not been issued, this row indicates the amount that has been approved in the financing order at the approval date.*

***Cost Allocation: detailed explanation of the allocation principles can be found in the case study section below.*



Summary of Key Insights

Key Insight 1: Securitization legislation in some states have included provisions to protect customers by requiring the use of rate adjustment mechanisms (e.g., bill credits) that ensure that customers see savings immediately upon bond issuance.

Legislators can require that utilities provide rate adjustment mechanisms to address timing mismatches between the realization of the securitization savings and the elimination of old asset costs from bills. This requirement was not included in the legislation for Michigan, Wisconsin and Florida, while the more recent New Mexico bill does have specific language in this regard. It is worth noting that the securitization bills in Montana and Colorado—both passed in 2019, with no transactions yet—included a dedicated section on rate reduction that requires the utility to adjust cost-of-service rates in sync with the inclusion of the securitization surcharge on bills, as detailed in Table 11 below.

Table 11. Securitization Bill Summary – Customer Protection and Rate Adjustment

State	Rate Adjustment
Michigan	Not specified in the securitization bill
New Mexico	A financing order application should include: “a proposed ratemaking method to account for the reduction in the qualifying utility’s cost of service associated with the amount of undepreciated investments being recovered by the energy transition charge at the time that charge becomes effective” ¹²
Wisconsin	Not specified in the securitization bill
Florida	Not specified in the securitization bill
Montana	“A financing order must require the applicant utility, simultaneously with the inception of the collection of Montana energy impact assistance charges, to reduce its rates through a reduction in base rates. ” ¹³
Colorado	“A financing order must require the applicant electric utility, simultaneously with the inception of the collection of CO-EI charges, to reduce its rates through a reduction in base rates or by a negative rider on customer bills in an amount equal to the revenue requirement associated with the utility assets being financed by CO-EI bonds.” ¹⁴

Even absent a requirement in legislation, bill credits are used frequently for adjusting the *balance if securitization occurs before the plants are removed from the rate base*. In its 2014 transaction, Consumers Energy implemented a customer bill credit equivalent to annual depreciation and authorized returns associated with the securitized plants at the time of the bond issuance. This allowed customers

¹² New Mexico, SB0489, Energy Transition Act, signed 3/22/2019.

<https://www.nmlegis.gov/Sessions/19%20Regular/final/SB0489.pdf>

¹³ Montana, HB467, Montana Energy Impact Assistance Act, signed 5/10/2019.

<https://leg.mt.gov/bills/2019/billpdf/HB0467.pdf>

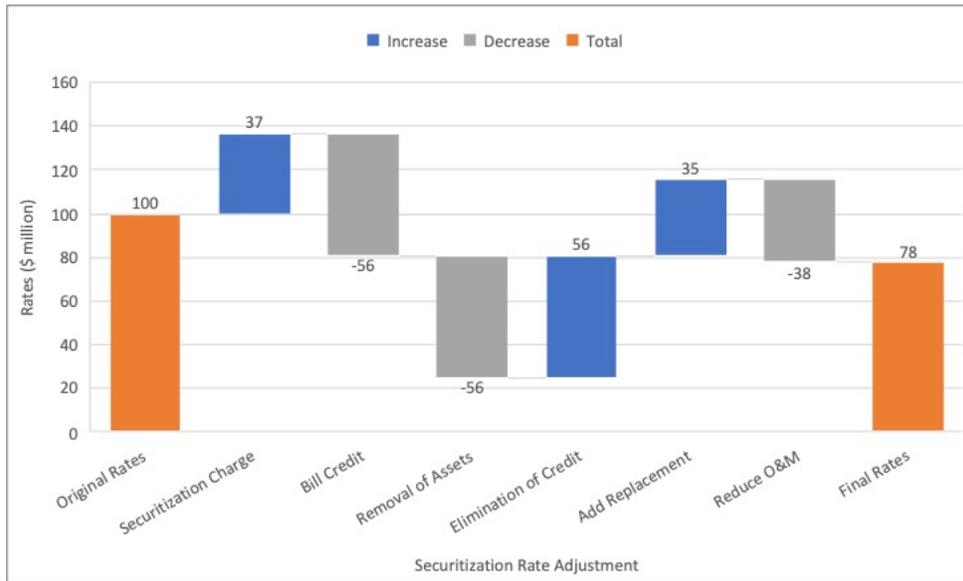
¹⁴ Colorado, SB19-236, Sunset Public Utilities Commission, signed 5/30/2019.

https://leg.colorado.gov/sites/default/files/2019a_236_signed.pdf

to see a net reduction on their bills. This credit mechanism was used until the next rate case, when the asset was removed from the rate base.

Replacement assets may be added to the rate base in the same case as the retired assets were removed. In that case, the net rate impact from securitization, retirement and replacement can be evaluated in the same rate case. Most commonly, those activities do not happen at the same time; therefore, bill credits can be used to adjust the rates in the interim until all the impacts are reflected in the final rate case. Chart 7 below illustrates how a bill credit can help mitigate the rate fluctuation caused by securitization and rate case timing issues.

Chart 7. Illustrative Rate Adjustment Process



WEPCO and Duke Energy Florida had no need for bill credits because the relevant plants were already retired and the associated plant balances already shifted into regulatory asset accounts. Where regulatory assets exist, balances can be adjusted/eliminated when a securitization occurs without need to wait for a rate case.

Ultimately, the choice of rate adjustment mechanisms can—and we believe should—be defined by legislative requirement. As securitization legislation is not in place yet in Minnesota, the company should work with legislators to ensure that language is included in the bill to ensure that customers are not harmed by any rate fluctuation stemming from a timing mismatch between securitization and removal of the assets from rate base.

Key Insight 2: Implementing the securitization charge as a volumetric (per kWh) charge that is allocated across customer classes consistent with the basis of allocation in the most recent rate case is a simple and relatively non-controversial approach that has been commonly used historically. However, alternative allocation methods have also been considered. For instance, bond revenue certainty could be enhanced with minimal cost-shifting across customer classes by implementing securitization charges as fixed or demand charges, even for residential customers.

The cost allocation method is usually mentioned but not prescribed in securitization bills, with utilities left with considerable flexibility to adjust the method as they see fit. Table 12 below summarizes the language used in the bills.

Table 12. Securitization Bill Summary – Cost Allocation

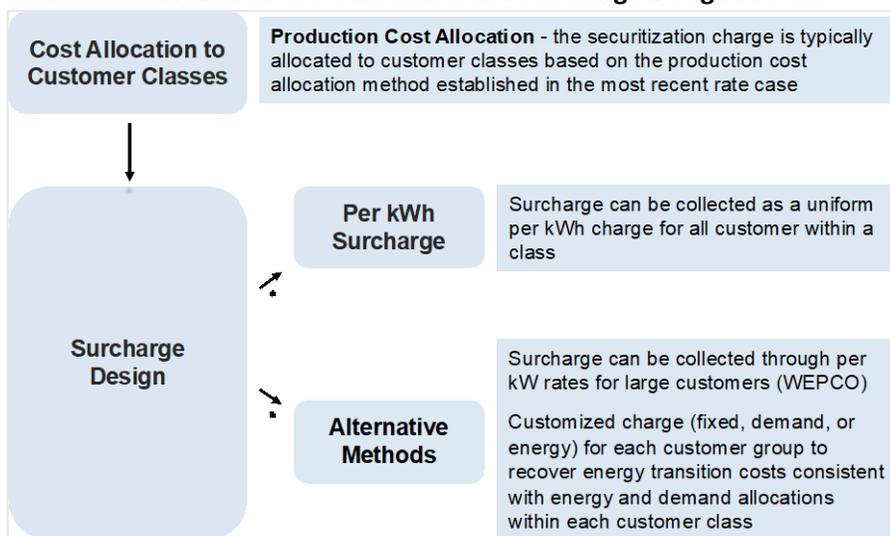
State	Cost Allocation
Michigan	Not specified in the securitization bill
New Mexico	“If the commission issues a financing order, the qualifying utility for which the order is issued may charge all of the qualifying utility’s customers an energy transition charge, which shall be allocated to customer classes consistent with the production cost allocation methodology established by the commission in the qualifying utility’s most recent general rate case . Energy transition charges shall be assessed consistent with the production cost allocation methodology and the determination of energy and demand costs within each customer class, both of which shall be subject to the adjustment mechanism.” ¹⁵
Wisconsin	Not specified in the securitization bill
Florida	“Require nuclear asset-recovery charges to be allocated to the customer classes using the criteria set out in s. 366.06(1), in the manner in which these costs or their equivalent was allocated in the cost-of-service study that was approved in connection with the electric utility’s last rate case and that is in effect during the nuclear asset-recovery charge annual billing period. If the electric utility’s last rate case was resolved by a settlement agreement, the cost-of-service methodology that was adopted in the settlement agreement in that case and that is in effect during the nuclear asset-recovery charge annual billing period shall be used” ¹⁶
Montana	Not specified in the securitization bill
Colorado	Not specified in the securitization bill

Cost allocation and surcharge design methods do vary across utilities. Chart 8 below summarizes the cost allocation and surcharge design process and basic options.

¹⁵ New Mexico, SB0489, Energy Transition Act, signed 3/22/2019.
<https://www.nmlegis.gov/Sessions/19%20Regular/final/SB0489.pdf>

¹⁶ Florida, Florida Statutes, Section 366.95.
http://www.leg.state.fl.us/Statutes/index.cfm?App_mode=Display_Statute&URL=0300-0399/0366/Sections/0366.95.html

Chart 8. Securitization Cost Allocation and Surcharge Design Process



In general, the securitization cost is allocated based on coincident peak demand and energy (either during peak hours or average energy use), though not necessarily using both factors for all customers. For instance, PNM uses the cost allocation method that is based purely on the coincident peak during the four highest peak months of the year (3 summer months and 1 winter month, “3S1W”). It is worth noting that even when utilities have been given authority in securitization legislation to modify allocations method, they have often chosen to stick with the method approved in the most recent rate case.

Once allocated to each customer class based on various weighting methods, securitization charges have most often been collected through volumetric (per kWh) surcharges. The volumetric surcharge design is typically chosen for its simplicity: it is easy for customers and other stakeholders to understand and is simple to administer.

In the recent cases, however, we have seen utilities exploring alternative rate designs, including Consumers, WEPCO, and PNM. In the 2020 Consumers case, some stakeholders advocated a demand-based (per kW) charge for the primary customer group. However, the Commission ultimately did not agree to use such a design, instead sticking with a volumetric surcharge. WEPCO proposed a complete shift to “demand charges” for its General Primary customers to adequately reflect cost allocation principle (75% demand, 25% energy), while avoiding the administrative burden of a split charge. PNM proposed a set of customized rates based on the metering requirements and the numbers/diversity of customers within each rate schedule, effectively implementing fixed charges for most customers and demand-based charges for large customers. This allowed the utility to meet the requirement of “non-bypassable” charges required by the Energy Transition Act and follow the principle of recovering energy transition costs consistent with energy and demand allocation within each customer class.¹⁷

¹⁷ New Mexico PRC, Case No. 19-00018-UT, Transcript of Proceedings 12-12-2019 Public Hearing Exhibits of ABCWUA 2-3, NEE 11-14, NM AREA 1 & PNM 16-22, filed 12/17/2019.

Overall, the final decision on the securitization surcharge cost allocation and rate design must balance the competing interests of utilities and consumer advocates. Advocates for large industrial customers tend to prefer demand-based surcharges or a combination of energy and demand rates to better reflect cost-causation principles. Utilities, though, tend to prefer the administrative and explanatory simplicity of volumetric charges.

Implementing a securitization surcharge through a demand-based or fixed charge could help Minnesota Power ensure better revenue certainty.

Key Insight 3: Utilities have balanced intergenerational equity and least-cost considerations by carefully structuring the securitization bond issuances through judicious choices of multiple tranches of bonds with different tenors.

As summarized in Table 13 below, legislation in Michigan and New Mexico provided guidance on the upper bound of the tenor (15 years for Michigan, and 25 years for New Mexico), whereas Wisconsin's law did not identify a number. The Montana and Colorado bills passed in 2019 both set the upper bound of the bond tenor as 32 years, leaving it to the financing order to specify how much flexibility the utility should have in setting bond terms.

Table 13. Securitization Bill Summary – Bond Tenor

State	Bond Tenor
Michigan	“The financing order shall detail the amount of qualified costs to be recovered and the period over which the securitization charges are to be recovered, not to exceed 15 years.” ¹⁸
New Mexico	“A financing order shall authorize the qualifying utility to issue one or more series of energy transition bonds for a scheduled final maturity of no more than twenty-five years for each series ; provided that a rated final maturity may exceed twenty-five years.” ¹⁹
Wisconsin	“In a financing order issued to an energy utility, the commission shall...specify the amount of environmental control costs and financing costs that may be recovered through environmental control charges and the period over which such costs may be recovered.” ²⁰
Florida	Not specified in the securitization bill
Montana	<p>“ ‘Montana energy impact assistance bonds’ means low-cost corporate securities... that have a scheduled maturity of no longer than 30 years and a final legal maturity date that is not later than 32 years from the issue date”</p> <p>The financing order must:</p> <p>“specify the degree of flexibility afforded to the electric utility in establishing the terms and conditions of the Montana energy impact assistance bonds, including but not limited to repayment schedules, expected interest rates, and other financing costs”²¹</p>
Colorado	<p>“ ‘CO-EI Bonds’ means Colorado energy impact bonds that...have a scheduled maturity date as determined reasonable by the commission but not later than thirty-two years following issuance”</p> <p>The financing order must:</p> <p>“specify the degree of flexibility afforded to the electric utility in establishing the terms and conditions of the CO-EI bonds, including, but not limited to, repayment schedules, expected interest rates, and other financing costs”²²</p>

Our deeper dive into recent securitization transactions revealed that utilities tend to set the bond tenor to coincide with the remaining accounting life of the retired plant prior to accelerated retirement. However, we also noticed that consumer advocates often advocated for longer bond tenors to maximize customer savings both in the short-term and on an NPV basis (often in spite of potential concerns with intergenerational cost shifting).

¹⁸ MCL 460.10i(3), [http://www.legislature.mi.gov/\(S\(2jft4gfuf0e2jqy1bwk3refu\)\)/mileg.aspx?page=getObject&objectName=mcl-460-10i](http://www.legislature.mi.gov/(S(2jft4gfuf0e2jqy1bwk3refu))/mileg.aspx?page=getObject&objectName=mcl-460-10i)

¹⁹ New Mexico, SB0489, Energy Transition Act, signed 3/22/2019. <https://www.nmlegis.gov/Sessions/19%20Regular/final/SB0489.pdf>

²⁰ Wis. Stat. § 196.027 (2)(b)2.a, <https://docs.legis.wisconsin.gov/statutes/statutes/196/027>

²¹ Montana, HB467, Montana Energy Impact Assistance Act, signed 5/10/2019. <https://leg.mt.gov/bills/2019/billpdf/HB0467.pdf>

²² Colorado, SB19-236, Sunset Public Utilities Commission, signed 5/30/2019. https://leg.colorado.gov/sites/default/files/2019a_236_signed.pdf

Parties to the Consumers Energy and WEPCO financing order proceedings had robust discussions around tenor, but both commissions deferred to the utility's preference for relatively short tenor bond issuances. In the Consumers case, advocates proposed a tenor that doubled the current remaining life. The Commission eventually supported the utility because of the lower interest rates received with a shorter tenor and the intergenerational equity consideration. In the WEPCO case, there was a similar conversation between the utility and the Citizens Utility Board (CUB), but CUB finally deferred to the utility in the question of tenor, accepting the validation of a financial expert.

Even though both cases ended up with the adoption of the shorter tenor, longer tenors will often lead to lower costs—both in the near term and on an NPV basis over the long-term. We see that potential benefit in our modeling of Boswell. The lower bound of the bond tenor should at least be the same as the previous remaining life of the retired plant. If the bond tenor is shorter than the remaining life, rates can increase in the near term, just as they would with accelerated depreciation using traditional utility finance. Longer tenors can help further mitigate rate increases. The common pushback that longer tenors are not fair to future customers (intergenerational equity) should be assessed in conjunction with analysis of the benefits that can be derived from an accelerated clean energy transition that makes optimal use of tax benefits and exploits attractive opportunities for low-cost long-term financing of capital (for new assets and securitization).

In the context of Minnesota Power, we would recommend that the legislation provide flexibility for the utilities to explore the trade-offs of different tenor options.

Key Insight 4: Utilities have been able to stagger the timing of securitization, retirement, and replacement while still minimizing risks to utility investors and providing customers with immediate bill savings.

As we discussed in the Phase 1 Report, securitization does not necessarily have to coincide with the retirement and replacement. In fact, securitization laws normally do not impose any restrictions on when securitization needs to happen relative to retirement and replacement. As shown in Table 14 below, New Mexico legislation requires the utility receive approval on the retirement before they can submit a securitization order but does not put restrictions on the sequence of the actual retirement and securitization. In the Montana and Colorado Bills passed in 2019, both states explicitly provide flexibility by permitting the timing of securitization bond issuance can be independent of the retirement schedule.

If these activities happen simultaneously, it can be easier for stakeholders to assess the costs and benefits of the entire package, which could facilitate the conversation addressing system transition challenges. However, there may also be advantages to separating the processes. This can allow the planning team sufficient time to ensure retirement and replacement schedules satisfy reliability requirements. In addition, utilities can work with legislators and financial experts to evaluate the market dynamics and choose the best timing for the bond issuance to maximize cost savings.

Table 14. Securitization Bill Summary – Timing and Process

State	Timing and Process
Michigan	Not specified in the securitization bill
New Mexico	<p>“A qualifying utility that is abandoning a qualifying generating facility may apply to the commission for a financing order pursuant to this section to recover all of its energy transition costs through the issuance of energy transition bonds. To obtain a financing order, a qualifying utility shall obtain approval to abandon a qualifying generating facility pursuant to Section 62-9-5 NMSA 1978. The application for the financing order may be filed as part of the application for approval to abandon a qualifying generating facility.”</p> <p>“For a qualifying utility that abandons a qualifying generating facility in New Mexico prior to January 1, 2023, the qualifying utility shall, no later than one year after approval of the abandonment, apply for commission approval of competitively procured replacement resources.”²³</p>
Wisconsin	Not specified in the securitization bill
Florida	Not specified in the securitization bill
Montana	<p>The financing order must: “specify the timing of actions required by the order so that... the Montana energy impact assistance bonds are issued as soon as feasible following the issuance of the financing order, independent of the schedule of closing and decommissioning of the electric infrastructure or facility”²⁴</p>
Colorado	<p>The financing order must: “specify the timing of actions required by the order, including... the timing of issuance of the CO-EI bonds, independent of the schedule of retirement of the electric generating facility”²⁵</p>

Across the five transactions reviewed, there was considerable variation in how utilities handled timing differences. In its earlier securitization, Consumers issued the bonds in 2014, in advance of the coal retirements, which took place in 2016. In contrast, Duke Florida securitized in 2016, after the retirement of the nuclear plants in 2013. This arrangement provided Duke with more time for the passage of securitization legislation and regulatory mechanism.

WEPCO and PNM are both organizing securitizations in connection with established regulatory assets. In addition, PNM’s securitization order is closely linked to the IRP order. Linking the securitization and the IRP enables a more integrated assessment of the costs and benefits of retirement, securitization, and replacement, making it easier for utilities to communicate the systematic cost implications to all stakeholders.

²³ New Mexico, SB0489, Energy Transition Act, signed 3/22/2019.
<https://www.nmlegis.gov/Sessions/19%20Regular/final/SB0489.pdf>

²⁴ Montana, HB467, Montana Energy Impact Assistance Act, signed 5/10/2019.
<https://leg.mt.gov/bills/2019/billpdf/HB0467.pdf>

²⁵ Colorado, SB19-236, Sunset Public Utilities Commission, signed 5/30/2019.
https://leg.colorado.gov/sites/default/files/2019a_236_signed.pdf

As our stress tests in Chapter 2 showed, closely aligning the timing of securitization with retirement and reinvestment can mitigate EPS risks stemming from unanticipated losses of revenue.

Key Insight 5: Recent securitization legislation (in particular, in New Mexico) allows the proceeds of securitization transactions to also be used to support the transition of coal plant workers and communities.

Transition assistance has only recently been considered for inclusion as an allowable use of proceeds in legislation, starting with legislation passed in Colorado in 2019, and also included in the New Mexico Energy Transition Act with specific details on the percentage allocation of transition assistance costs.

Table 15. Securitization Bill Summary – Allowable Use of Proceeds

State	Allowable Use of Proceeds
Michigan	“In a financing order, the commission shall ensure all of the following...that the proceeds of the securitization bonds are used solely for the purposes of the refinancing or retirement of debt or equity.” ²⁶
New Mexico	Recover, finance or refinance “energy transition cost”, including financing costs and the abandonment costs that include: <ul style="list-style-type: none"> - “Plant decommissioning and mine reclamation costs”; - “Severance and job training for employees losing their jobs as a result of an abandoned qualifying generating facility and any associated mine that only services the abandoned qualifying generating facility”; - “Undepreciated investments as of the date of abandonment.” Allocate the bond proceeds at the following percentages: <ul style="list-style-type: none"> - 1.5% to the Indian affairs department for deposit in the energy transition Indian affairs fund; - 1.65% to the economic development department for deposit in the energy transition economic development assistance fund; and - 3.35% to the workforce solutions department for deposit in the energy transition displaced worker assistance fund.²⁷
Wisconsin	“An energy utility may use the proceeds only for paying environmental control costs and financing costs that are prudent, reasonable, and appropriate, and only if the energy utility has applied for and obtained all approvals from the commission under this chapter that are required for the environmental control activities for which the environmental control costs are incurred or expected to be incurred.” ²⁸
Florida	Use of proceeds include: <ul style="list-style-type: none"> -Nuclear asset-recovery costs: “the capitalized cost of the retired or abandoned nuclear generating asset unit, other applicable capital and operating costs, accrued carrying charges, deferred expenses, reductions for applicable insurance and salvage proceeds and previously stipulated write-downs or write-offs, if any, and the costs of retiring any existing indebtedness, fees, costs, and expenses to modify existing debt agreements or for waivers or consents related to existing debt agreements.”²⁹ -Financing costs
Montana	Recover, finance or refinance “Montana energy impact assistance costs,” including: <ul style="list-style-type: none"> - “Unrecovered capitalized costs of retired or replaced electric infrastructure or facilities,” - “Costs of decommissioning and restoring the site of the electric infrastructure or facility,” - “Other applicable capital and operating costs, accrued carrying charges, deferred expenses, reductions for applicable insurance and salvage proceeds,” and

²⁶ MCL 460.10i(2),

[http://www.legislature.mi.gov/\(S\(2jft4gfufoe2jqy1bwk3refu\)\)/mileg.aspx?page=getObject&objectName=mcl-460-10i](http://www.legislature.mi.gov/(S(2jft4gfufoe2jqy1bwk3refu))/mileg.aspx?page=getObject&objectName=mcl-460-10i)

²⁷ New Mexico, SB0489, Energy Transition Act, signed 3/22/2019.

<https://www.nmlegis.gov/Sessions/19%20Regular/final/SB0489.pdf>

²⁸ Wis. Stat. § 196.027 (4)(a), <https://docs.legis.wisconsin.gov/statutes/statutes/196/027>

²⁹ Florida, Florida Statutes, Section 366.95.

http://www.leg.state.fl.us/Statutes/index.cfm?App_mode=Display_Statute&URL=0300-0399/0366/Sections/0366.95.html

	- “The costs of retiring any existing indebtedness, fees, costs, and expenses to modify existing debt agreements or for waivers or consents related to existing debt agreements.” ³⁰
Colorado	<p>Recover, finance or refinance “pretax cost,” including</p> <ul style="list-style-type: none"> - “The unrecovered capitalized cost of a retired electric generating facility,” - “Costs of decommissioning and restoring the site of the electric generating facility,” and - “Other applicable capital and operating costs, accrued carrying charges, deferred expenses, reductions for applicable insurance and salvage proceeds and the costs of retiring any existing indebtedness, fees, costs,” - “Expenses to modify existing debt agreements or for waivers or consents related to existing debt agreements,” and - “Amounts for assistance to affected workers and communities if approved by the commission.” <p>Community assistance is to be provided in “an amount equal to the costs of the voter-approved projects that were expected to be paid from the revenue sources directly impacted by the retirement.”³¹</p>

Consumers and Duke Energy Florida handled transition costs outside of the securitization. In the Consumers 2014 case, the transition plan was included in the IRP proceeding. In the Duke Energy Florida case, the company worked with the employees of the Crystal River Nuclear Plants to help them transition to positions in other Duke Energy organizations.³²

PNM is the only case we studied where transition assistance is explicitly included as an abandonment cost, and where those costs are included as permitted uses of the proceeds from securitization.

It is worth noting that Consumers, WEPCO and Duke Energy Florida opted to use existing legislation for the securitization transaction, rather than to pursue amendment to expand the use of proceeds to include transition assistance. Consumers used the securitization legislation from the early 2000s era of restructuring that limited use to recovering uneconomic assets. WEPCO used the Environment Trust Financing Law, which limited recovery of costs associated with an environmental control devices. Leveraging existing legislation simplifies the process and avoids lengthy stakeholder coordination efforts, but it can also limit the flexibility of the utility to address community transition costs.

In the context of Minnesota, where there currently is no securitization statute, we recommend that the utility work with the Commission and stakeholders to coordinate the development of legislation that allows for transition assistance costs to be included as an allowed use of the proceeds from securitization.

³⁰ Montana, HB467, Montana Energy Impact Assistance Act, signed 5/10/2019.
<https://leg.mt.gov/bills/2019/billpdf/HB0467.pdf>

³¹ Colorado, SB19-236, Sunset Public Utilities Commission, signed 5/30/2019.
https://leg.colorado.gov/sites/default/files/2019a_236_signed.pdf

³² <https://news.duke-energy.com/releases/crystal-river-nuclear-plant-to-be-retired;-company-evaluating-sites-for-potential-new-gas-fueled-generation>

Detailed Case Study Overviews

Case Study 1: Consumers Energy (2014 and 2020)

Overview

- Consumers Energy has used securitization multiple times. The two recent applications are the securitization transaction bond issued in 2014³³ and a 2020 transaction currently under plan.³⁴ Both transactions are connected to the early retirement of coal plants.
- The 2014 securitization was for 10 coal units at three facilities: BC Cobb Units 1-5, JC Weadock Units 7-8, and JR Whiting Units 1-3. Cobb Units 1-3 were deemed inoperable for safety reasons beginning in 2013, and the remaining 7, referred to as the “Classic 7” were slated for early retirement in 2016 due to the cost of compliance with EPA’s new Mercury Air Toxics Standards. Together, the units totaled \$361.2 million in unrecovered plant balances as of December 2013. Consumers sought an additional \$93.2 million in qualified costs, of which \$64.7 million in demolition costs were not allowed to be recovered through securitization. The Commission approved a total of \$389.6 million for securitization.
- The 2020 securitization is for two baseload coal-fired units, Karn Units 1 & 2. Together, they will account for \$691.2 million in unrecovered book costs as of their projected retirement date in April 2023. The Commission approved \$677.7 million in unrecovered book costs for the units in question. Consumers requested an additional \$11.6 million in qualified costs and was granted \$10.6 million, totaling \$689.8 million in costs approved for securitization.
- The securitization legislation was established in the 2000 for electricity market restructuring. Advocates made the case that the coal units were uneconomic and could not compete in the MISO market and that, therefore, the existing securitization legislation could be applied.³⁵

Timing of Securitization, Retirement and Replacement

After the December 2013 financing order, securitization bonds were issued in July 2014. The generation facilities stopped operating in 2014 and were kept on standby to meet MISO’s resource adequacy requirement until they were retired in 2016. In the 2019 rate case and IRP, Consumers’ confirmed the acquisition of the Jackson Gas Plant as partial replacement power for the “Classic 7” units retired and recovered in the 2014 securitization case.

The financing order from 2020 anticipates a simultaneous 2023 bond issuance and 2023 retirement. Consumers plans to replace this power by reducing demand through its waste energy reduction program and adding 550 MW of wind and 6,000MW of solar by 2040. These additions will also serve to replace Consumers’ remaining fossil assets scheduled for retirement in 2031 and 2040.

³³ Michigan PSC, Case Number U-17473, In the matter of the application of Consumers Energy Company for a Financing Order Approving the Securitization of Qualified Costs, filed 12/6/2013.

³⁴ Michigan PSC, Case Number U-20889, In the matter of the application of Consumers Energy Company for a Financing Order Approving the Securitization of Qualified Costs, filed 12/17/2020.

³⁵ Michigan PSC, Case No. U-17473, Direct Testimony of Douglas B. Jester on Behalf of the Sierra Club, In the Matter of the Application of Consumers Energy Company for a Financing Order Approving the Securitization of Qualified Costs, filed 10/21/2013.

Securitization Cost Allocation and Surcharge Design

Consumers Energy used the **production cost allocator** from its most recent rate case to calculate annual allotments of the 2014 securitization cost by customer class. The allocation method, known as 4CP 50/25/25, was based on 50% weighting of coincident peaks occurring from June through September, 25% weighting of on-peak use, and 25% weighting of total energy use. This allocator was preferred by stakeholders such as The Association of Businesses Advocating Tariff Equity (ABATE) over 12CP 50/25/25, an allocator based on peaks from all 12 months, because of the latter's tendency to understate the consequences of peak behavior and unnecessarily raise the rates of primary customers. The methodology for the selected 4CP allocator was frozen at the release of the financing order in 2014, preventing future changes to the allocator from impacting charge calculations during true-ups. Because the relevant securitization legislation does not specify an allocation method, this decision was left to the discretion of Consumers and the Commission.

Ultimately, the chosen **allocator was applied to all customers except those participating in the Retail Open Access (ROA) program**. This detail sparked controversy, as Act 147 characterizes securitization surcharges as non-bypassable, and therefore mandatory, for all utility customers. Michael Torrey, a representative from Consumers, testified in favor of including ROA customers on the basis that inclusion was lawful, conducive to good bond ratings, indicative of Consumers' obligation to serve all those in its service territory, and supportive of a retirement that benefitted all customers financially and environmentally. At the time of the order, Consumers' ROA program was capped at 90% of retail load; however, Consumers noted that changes to regulation could change or eliminate that cap and subject a different, potentially smaller, number of customers to the charge. Energy Michigan argued that ROA customers did not use Consumers' electricity and therefore bore no responsibility for its retired generation assets. Furthermore, Energy Michigan pointed to testimony highlighting the assets' lack of impact on reliability as determined by MISO. The Commission eventually settled on a compromise that exempted *existing* ROA customers from the charge.

Within each customer class, Consumers proposed a **volumetric (cents per kWh charge)** subject to **annual, semi-annual, and as-needed true-ups** to account for over or under collection. Using a volumetric (per kWh) charge was consistent with prior securitization case U-12505, compatible with Consumers' current billing system, and, by necessitating adjustments, would help the utility achieve a higher bond rating. ABATE favored a levelized charge and objected to the uniform volumetric (per kWh) option on the grounds that high load factor industrial customers would pay more than their cost-based share, pursuant to the MCL 460.11 statute mandating cost-based rates. The Commission sided with Consumers.

The surcharge design remained the same in the 2020 case, and the 4CP allocation method will be refrozen at the time of bond issuance.

Rate Base Adjustment

When the bonds were issued in July 2014, the retiring units remained in the rate base. To negate double counting of asset costs on customer bills, Consumers designed a **Power Plant Bill Credit**. The credit began the first billing cycle after the sale of the bonds and remained in effect until the utility self-updated its rates and removed the capital costs of the "Classic 7" in June 2015.

Consumers sought and received approval for another bill credit during its November 2015 rate case. This credit offset the cost of adding the replacement power, the Jackson Plant, to the revenue requirement before its official acquisition. The credit remained in effect until the utility closed on the sale, at which point the utility was authorized to recover the cost from rate payers. Upon the retirement of the “Classic 7” in April 2016, the utility adjusted its rates downward by \$38 million to reflect the decrease in O&M.

For the 2020 securitization, the utility intends to employ the same bill credit and removal of assets from the rate base in its upcoming rate case.

Transition Plan

Transition assistance and workforce training was not directly included in either the 2014 or 2020 securitization case because they are not considered a qualified cost. According to Michigan law, qualified costs include regulatory assets, costs that would be unlikely to collect in a competitive market, and costs related to the issuance of securitization bonds. Furthermore, savings from securitization are legally required to be used in refinancing or retiring existing debt and equity.

Consumers’ 2019 Climate Action Plan IRP highlights the utility’s intent to quickly redevelop the sites of Karn Units 1 & 2 (slated for securitization in the 2020 case) and implement a community transition plan to help with employee retention. In vague terms, Consumers proposed a “plan to support Hampton Township and the Bay region as they re-imagine the local economic landscape after the plant is retired, working closely with stakeholders to identify and meet challenges related to the plant closure through the economic transition.”³⁶ This is not directly tied to the securitization proceedings or financing order.

Securitization Bond Tenor

The tenor for the 2014 securitization bonds was capped at 15 years. This length and the use of multiple tranches were selected to minimize the securitization charges. While the 2014 case was not without controversies, bond tenor was not among them.

In 2020, bond lifespan was more contentious. Consumers proposed an 8-year maturity, ending the bonds at the coal plant’s originally scheduled retirement date; both ABATE and the Attorney General opposed. A representative of the Attorney General argued that 14 years would provide better NPV savings and lower rates for customers. Ultimately, the Commission backed the 8-year term in light of support by financial markets, customer savings of \$62.2 million in interest payments, and mitigation of intergenerational inequities.

³⁶ 2019 Clean Energy Plan, Consumers Energy <https://www.consumersenergy.com/-/media/CE/Documents/sustainability/integrated-resource-plan-summary.ashx?la=en&hash=9F602E19FE385367FA25C66B6779532142CBD374>

Case Study 2: Public Service Company of New Mexico (2020)

Overview

- Public Service Company of New Mexico (PNM) filed a financing order in February 2020 to use securitization for retiring PNM's share of two coal units, San Juan Units 1 and 4. Together, the two units totaled \$283 million in undepreciated investment.
- Aside from the undepreciated plant balance, PNM also proposed to include \$20 million of severance and job training costs for PNM and coal mine employees, \$19.8 million in payments to state administered energy transition funds for Indian affairs, economic development and displaced workers in the financing order. The Commission approved a total of \$361 million for securitization in April 2020.³⁷
- The Energy Transition Act enabling the securitization transactions was passed in 2019.

Timing of Securitization, Retirement and Replacement

The securitization bonds are expected to be issued shortly after July 1, 2022, the scheduled retirement date for the plant.

PNM's securitization order is a consolidated application that includes securitization, retirement and replacement of the coal units. In the IRP proceeding in 2017, PNM stated that retiring PNM's share of the San Juan coal plant in 2022 would result in cost savings for customers and planned to issue a request for proposals for energy storage, renewable energy, and flexible natural gas resources to further consider the combination of replacement resources.³⁸ Through an All-Resource Request for Proposal (All-Resource RFP) process, the Coalition for Clean Affordable Energy's (CCAEE) clean energy portfolio was approved in July 2020 as the replacement portfolio, consisting of 650 MW of solar, 300 MW of storage, and 24 MW of additional demand response.³⁹

PNM estimates that the 2022 retirement of the San Juan coal plant and the replacement by PNM's proposed replacement resources will lead to \$80 million in net annual savings in 2023, the net result of the decrease in coal plant costs (\$50 million fuel cost, \$94 million non-fuel O&M cost, \$8 million other) and the increase in financing and replacement cost (\$23 million in securitization surcharge and \$49 million in replacement resources costs).

In terms of the customer bill impact, PNM provided examples of the modeled impact on representative customer groups. Residential customers using 600 kWh per month will see \$1.90 per month securitization surcharge and \$6.87 per month savings on \$73.25 monthly bills. Residential customers

³⁷ New Mexico PRC, Case No. 19-00018-UT, Recommended Decision on PNM's Request for Issuance of a Financing Order, filed 2/21/2020.

³⁸ New Mexico, PNM 2017 IRP Final, filed 7/3/2017.

<https://www.pnm.com/documents/396023/396193/PNM+2017+IRP+Final.pdf/ea4efd7-3de5-47b4-b686-1ab37641b4ed>

³⁹ New Mexico PRC, Case No. 19-00195-UT, Order on Recommended Decision on Replacement Resources - Part II, filed 7/29/2020.

using 1,000 kWh per month will see a \$4.97 per month securitization surcharge and \$9.65 per month savings on \$129.03 monthly bills.

Securitization Cost Allocation and Surcharge Design

PNM's proposed financing order included a detailed methodology for allocating securitization costs to different customer classes and rate schedules. PNM also included detailed discussion of the trade-offs for using different rate design methodologies to collect the securitization surcharge and proposed a customized plan based on the characteristics of each customer class.⁴⁰

PNM's proposed securitization surcharge calculation involves a multi-step process. First the securitization cost is allocated to customer classes based on the production cost allocation methodology established in the most recent general rate case. The approved method is based on the coincident peaks during the four highest peak months of the year: 3 summer months (June, July, and August) and 1 winter month (December) ("3S1W"), which are used to calculate the allocation factors for each customer class. Then the cost is further allocated to each rate schedule based on the forecast energy usage. This approach applies to all customers to ensure consistent application of cost-causation.

Once the costs are allocated to each rate schedule, PNM's proposal for securitization surcharge design is to customize the type of rates based on the metering requirements and the numbers/diversity of customers within each rate schedule. The table below summarizes the list of options PNM considered and discussed in the order, with an assessment of advantages and disadvantages.

⁴⁰ New Mexico PRC, Case No. 19-00018-UT, Transcript of Proceedings 12-12-2019 Public Hearing Exhibits of ABCWUA 2-3, NEE 11-14, NM AREA 1 & PNM 16-22, filed 12/17/2019

Table 16. Summary of Securitization Surcharge Design Options

	Customer charge (\$/bill)	Individual customer charge (\$/bill)	Demand charge (\$/kW)	Energy charge (\$/kWh)
Definition	Flat monthly charge; same for all customer within rate schedule	Flat monthly charge; each customer in rate schedule gets different charge based on the forecast demand	Per kW charge based on the forecasted demand	Per kWh charge based on the forecasted energy
Applicability	Suited to rate schedules with very few, homogeneous customers	Suited to rated schedules with few customers	Suited to rate schedules with demand metering that have many customers	
Advantages	The charge cannot be effectively bypassed through changes in usage or demand; easier to understand; more accurate forecast of the number of customers than an energy or demand forecast	The charge cannot be effectively bypassed	Proportional to customers' demand; easy to understand	Easy to understand
Disadvantages	Not proportional to relative customer demand and energy in the rate schedule	Requires a forecast of each individual customer's demand within the rate schedules	Need to forecast the total customer demand; sensitivity of demand to weather; demand metering capability required	Requires forecast of energy demand that can be weather sensitive; customer with onsite generation can effectively bypass the charge

Note: Two options are excluded from this summary table as they only applied to special customer types: block customer charge for residential 1A customers, and light charge for street and area lighting customers.

Citing a desire to ensure that “energy transition charges are non-bypassable, and to recover energy transition costs consistent with energy and demand allocations within each customer class,”⁴¹ PNM did not opt for a volumetric (per kWh) surcharge. It also decided against hybrid charges, recognizing that these would lack transparency and would be hard for the customer to understand. Table 17 below summarized the final proposal from PNM—essentially demand-based rates for the large customers and flat rates for other customer groups.

Rate Base Adjustment

Upon the start date of the securitization surcharge, if PNM has not adjusted its base rates to reflect the retirement of the remaining San Juan plant, an immediate credit is to be implemented to eliminate the cost impact of the retired plant. This credit should include the full value of the revenue requirement of the retired plant and be applied until the first general rate case which reflects the impact of the retirement on the revenue requirement.

⁴¹ New Mexico PRC, Case No. 19-00018-UT, Transcript of Proceedings 12-12-2019 Public Hearing Exhibits of ABCWUA 2-3, NEE 11-14, NM AREA 1 & PNM 16-22, filed 12/17/2019

Table 17. Securitization Cost Allocation and Surcharge Design Process

line	Rate Schedule	Charge Type
1	3B - General Power	Demand (\$/kW)
2	3D - Pilot Municipalities and Counties General Power - TOU	Demand (\$/kW)
3	3C - General Power Low LF	Demand (\$/kW)
4	3E - Pilot Municipalities and Counties General Power Low LF - TOU	Demand (\$/kW)
5	4B - Large Power	Demand (\$/kW)
6	5B - Lg. Svc. (8 MW)	Individual Customer (\$/bill)
7	15B - Universities 115 kV	Individual Customer (\$/bill)
8	30B - Manuf. (30 MW)	Individual Customer (\$/bill)
9	33B - Lg. Svc. (Station Power)	Individual Customer (\$/bill)
10	35B - Lg. Svc. (3 MW)	Individual Customer (\$/bill)
11	36B - SSR - Renew. Energy Res.	Individual Customer (\$/bill)
12	6 - Private Lighting	Light (\$/bill)
13	20 - Streetlighting	Light (\$/bill)
14	1B - Residential - TOU	Customer (\$/bill)
15	2A - Small Power	Customer (\$/bill)
16	2B - Small Power - TOU	Customer (\$/bill)
17	10A - Irrigation	Customer (\$/bill)
18	10B - Irrigation - TOU	Customer (\$/bill)
19	11B - Water/Sewage Pumping	Customer (\$/bill)
20	1A - Residential	Customer Block (\$/bill)

Transition Plan

PNM will make an estimated \$19.8 million in “Section 16” payments, including:

- Energy Transition Indian Affairs fund: 0.50% of the bonds, or \$1.8 million;
- Energy Transition Economic Development Assistance fund: 1.65% of the bonds, or \$5.9 million; and
- Energy Transition Displaced Worker Assistance fund: 3.35% of the bonds, or \$12.1 million

PNM can use the securitization to recover a maximum of \$20 million of severance and job training costs for employees who lose their jobs because of the retirement of the San Juan coal plant and mine, to include:

- PNM/PNM Resources severance: \$10.4 million;
- PNM job training: \$1.3 million;
- Coal mine employees severance: \$7.4 million; and
- Coal mine employees job training: \$1.5 million.

Securitization Bond Tenor

The bond tenor is 25 years, as stipulated in the Energy Transition Act. PNM’s justification for the tenor is that “it parallels the 25-year period embodied in the Energy Transition Act,” while “the duration of the recovery period involves balancing factors of rate impact and intergenerational equity.”⁴²

⁴² New Mexico PRC, Case No. 19-00018-UT, Rebuttal Testimony of Ronald N. Darnell, filed 11/15/2019.

Case Study 3: WEPCO (2020)

Overview

- In January 2020, the Commission approved a Financing Order for WEPCO to recover \$100 million in qualifying environmental control costs associated with the Pleasant Prairie coal-fired Power Plant, already retired in 2018. This was on the tails of a Rate Case Settlement⁴³ a few months earlier that required WEPCO to file an application to recover these costs through securitization.
- The enabling legislation is the “Environmental Trust Financing” law that was established in 2003 to apply stranded costs securitization techniques to required pollution control technologies. It was created specifically for use by WEPCO as a part of Act 152 and not necessarily in the context of plant retirement.
- The “Environmental Trust Financing” law pertains exclusively to the financing of environmental control costs. Qualifying activities include “the construction, installation, or otherwise putting into place of environmental control equipment in connection with an energy utility plant that, before March 30, 2004, has been used to provide service to customers.”⁴⁴

Timing of Securitization, Retirement and Replacement

WEPCO retired the Pleasant Prairie Coal Plant in April 2018. The \$100 million of the plant’s remaining book value qualifying for securitization was removed from the utility’s rate base in December 2019. The Commission then approved the amount for refinancing in its November 2020 Financing Order, and the bonds are scheduled for issuance in April 2021.

Securitization Cost Allocation and Surcharge Design

WEPCO plans to allocate its securitization costs based on the methodology used for distributing plant-related costs included in its most recent rate case, 5-UR-109. The calculation entails a 75% demand, 25% transmission-level LMP-weighted energy split based on firm load 12 coincident-peaks (12CP). The Wisconsin Industrial Energy Group (WIEG) testified in favor of a 4CP allocator but did not directly oppose WEPCO’s methodology. The Citizens Utility Board (CUB) voiced support for a 12CP calculation based on firm and irregular loads but, like WIEG, did not oppose the chosen method.

The utility decided, and the Commission agreed, that **all retail customers obtaining distribution services will share the securitization cost**, regardless of customer class. The agreement binds customers to the charge even if WEPCO opts to sell the rights to its service territory or distribution assets.

The charge will be a **fixed per kWh** rate for all classes except the General Primary class which will incur a **fixed per kW** amount. All charges will be subject to **annual, mid-year, or as-needed true-ups** during which the fixed amount will be adjusted to account for over or under collection and the underlying calculation method will be updated, as necessary. Initially, WEPCO proposed a fixed per kWh rate for all classes. WEIG opposed, noting that the charge would not reflect the revenue requirement allocation method for the General Primary customer class which was based on a 75/25 split of demand and energy. WEPCO representative Richard Stasik explained that implementing a split charge would

⁴³ WI PSC, Docket No. 5-UR-109, “Final Decision” *Application of Wisconsin Electric Power Company and Wisconsin Gas LLC for Authority to Adjust Electric, Natural Gas, and Steam Rates*, filed 12/19/2019

⁴⁴ Wis. Stat. § 196.027 1(d)(1), <https://docs.legis.wisconsin.gov/statutes/statutes/196/027>

significantly increase the utility's administrative burden. WEIG and WEPCO settled on a purely demand-based charge for the General Primary class.

Rate Base Adjustment

WEPCO's previous rate case resulted in the removal of \$100 million associated with the Pleasant Prairie Coal Plant from its revenue requirement. This amount represents the remaining book value of the retired assets that are qualified for securitization under Wisconsin law. With the securitized amount already removed from the rate base, WEPCO plans to append the surcharge to customer bills beginning the first billing cycle after the bond issuance—scheduled for April 2021.

Transition Plan

The Wisconsin Environmental Trust statute defines qualified costs as those directly tied to the construction of installation of environmental control activities and limits the use securitization proceeds to environmental control costs and financing only. For this reason, the securitization proceedings and the rate cases did not include any specific transition assistance packages or workforce training.

Securitization Bond Tenor

The bonds will have an expected final maturity of 13 years and a legal final maturity of 15 years. Some stakeholders testified in favor of a longer tenor. CUB would have "preferred a longer term" but acknowledged the validity of WEPCO's attempts to balance rate impacts and savings with the overall cost. WEPCO responded with testimony from Barclay's in support of its proposed bond structure.

Case Study 4: Duke Energy Florida (2016)

Overview

- Duke Energy Florida (DEF) issued a securitization bond in 2016 to recover the cost of the unrecovered plant balance of a nuclear plant, Crystal River Unit 3.
- The plant was already retired in 2013 and the total unrecovered cost totaled \$1,283 million as of December 31, 2015.⁴⁵ Duke Energy Florida issued a securitization bond of \$1,294 million in 2016.
- The enabling legislation was established in 2015 as part of the Florida Statutes to allow the utilities to finance the nuclear generation asset retirement costs.⁴⁶

Timing of Securitization, Retirement and Replacement

The securitization bonds were issued in June 2016. Previously, DEF's 2013 Ten-Year Site Plan had announced the retirement of the Crystal River Unit 3 in 2013 and had three planned generation additions (two combined cycle units and one combustion turbine unit).⁴⁷ Replacement resources were included in rates in July 2018, with the inclusion of the revenue requirement for Citrus Combined Cycle Project.⁴⁸

According to DEF, retirement of Crystal River Unit 3 through the traditional method would have resulted in a Year 1 base rate increase of \$4.96 per 1000 kWh on a residential bill and a total revenue requirement over the 20-year recovery period of \$2,531 million. Using securitization, the Year 1 base rate increase declined to \$2.93 per 1000 kWh on a residential bill and a total revenue requirement over the 20-year recovery period of \$1,823 million, \$708 million lower than the traditional method.

Securitization Cost Allocation and Surcharge Design

The securitization surcharge was collected on a per kWh basis from all applicable customer rate classes, using an allocation method to customer rate classes consistent with the methodology approved in the Revised and Restated Settlement and Stipulation Agreement (RRSSA). This approved allocation method is the 12CP and 1/13 AD, which means twelve-thirteenths of the revenue requirement is allocated based on 12 monthly coincident peaks (or demand) and one-thirteenth is allocated based on average demand (or energy).

Rate Base Adjustment

DEF removed the Crystal River Unit 3 plant from the rate base as approved in the 2013 Settlement Agreement effective the first billing cycle for January 2013⁴⁹ and created a regulatory asset account for

⁴⁵ Florida PSC, Docket No. 150171-EI, Financing Order, filed 11/19/2015.

⁴⁶ Florida, Florida Statutes, Section 366.95.

http://www.leg.state.fl.us/Statutes/index.cfm?App_mode=Display_Statute&URL=0300-0399/0366/Sections/0366.95.html

⁴⁷ Florida PSC, 2013 Ten-Year Site Plans, filed October 2013.

⁴⁸ Florida PSC, Docket No. 20180084-EI, Order Approving Limited Proceeding to Include in Base Rates the Revenue Requirement for the Citrus Combined Cycle Project, filed 7/25/2018.

⁴⁹ Florida PSC, Docket No. 20170183-EI, Order Approving 2017 Second Revised and Restated Settlement Agreement, filed 11/20/2017.

the remaining balance. When the securitization bond was issued in 2016, surcharges were added to the customer bills, and regulatory assets were adjusted accordingly.

Transition Plan

DEF did not have transition assistance package and workforce training in the securitization. The securitizable balance includes only the regulatory asset, financing costs, and carrying charges.

Securitization Bond Tenor

The securitization bond tenor is 20 years. The 20-year recovery period proposed for the securitization surcharge is consistent with the Revised and Restated Settlement and Stipulation Agreement (RRSSA). In the RRSSA proceeding, the utility posited that the relatively long amortization period of the CR3 regulatory asset would mitigate rate increases.⁵⁰

⁵⁰ Florida PSC, Docket No. 130208-EI, Duke Energy Florida, Inc.'s Responses to Staff's First Data Request, filed 8/30/2013.

Chapter 4. Recommendations for the Use of Securitization by Minnesota Power

Quantitative modeling results in Chapter 2 indicate that the use of securitization could help achieve a “triple win” for utilities, ratepayers, and communities as they transition from Boswell 3 and 4 units to a cleaner portfolio of assets. Securitization can reduce—though not entirely eliminate—the initial rate increase occasioned by transition, lower total costs on an NPV basis, fund community transition assistance, and provide an opportunity for accretive investment in clean energy by Minnesota Power with minimal credit implications. Additional tools are likely needed to fully eliminate the potential rate increase. Given recent tax credits extensions and the emergence of tools such as market-indexing (the latter requiring legislative adoption by the state), there may be additional options that Minnesota Power, state regulators, and state policymakers could consider making available to fully mitigate these potential rate impacts and possibly accelerate the retirement and replacement process. However, these options require further analysis and careful consideration of tax capacity issues that are beyond the scope of this work.

Case study analysis in Chapter 3 suggests that rate adjustment mechanisms such as the use of a bill credit can stabilize customer rates throughout the transition. Numerous allocation methods are available to address concerns about cross-subsidization and enhance revenue stability.

Based on the research and analysis insights in this study, RMI offers the following recommendations as Minnesota Power considers designing a securitization plan to facilitate the retirement and replacement of Boswell 3 and 4.

Recommendation 1:

Securitization timed to coincide with utility reinvestment should be made available to Minnesota Power as an additional option to finance community transition assistance and help mitigate the near-term rate increase from accelerated retirement and replacement of Boswell.

Across all modeled scenarios, securitization provides ratepayer benefits, moderating near-term rate increases and delivering NPV savings relative to alternative scenarios with other transition options, such as accelerated depreciation and regulatory assets.

Recommendation 2:

Minnesota Power should work with regulators and policymakers to identify and analyze additional tools—such as market indexing policies and tax equity financing—as well as additional physical retirement and replacement options for Boswell that could help fully mitigate the residual near-term rate increase. In light of recent tax credit extensions through the end of 2025, this analysis should consider carefully the tax capacity constraints that Minnesota Power could face in utilizing those tax benefits.

In Chapter 2, we showed that securitization concurrent with retirement in 2030 mitigates—but cannot eliminate—the resulting near-term rate increase. Partial securitization in 2025 prior to retirement and replacement does not appear to be a more attractive option.

Securitization and retirement/replacement decisions could be coordinated differently to increase benefit. One scenario not quantitatively explored within the scope of this analysis is an early full securitization combined with deployment of clean generation around 2025, which would allow the utility to fully leverage the benefit from the recent tax credit extensions—particularly if supplemented by market-indexing policies.

Both the Investment Tax Credit (ITC) and the Production Tax Credit (PTC) were recently extended in the Taxpayer Certainty and Disaster Tax Relief Act of 2020 signed into law on 27 December 2020. Wind projects that begin construction in 2021 and enter service by the end of 2025 are now eligible for the PTC at 60% of the full value of the credit for 10 years of output, whereas previously such projects would not have received any credit. Solar projects that are placed in service in 2024 and 2025 are now eligible for as much as a 26% ITC, whereas previously any project entering service after 2023 could not receive more than a 10% ITC. As a result, Minnesota Power now has a meaningfully expanded window to deploy clean energy prior to the expiration of these tax credits at the end of 2025 and should do *so if the size of these tax benefits outweigh expected technology cost declines through the end of the decade and such deployment is technically feasible*.

Market-indexing policies coupled with securitization could enable Minnesota Power to unlock larger benefits. In anticipation of these opportunities, Minnesota Power could work with key stakeholders to develop legislative proposals for this complementary measure to take full advantage of the tax credit extension by the end of 2025.

However, a key potential barrier to this approach may be constraints that ALLETE faces in utilizing the tax credits that would be generated in a timely fashion. While analysis of these constraints is beyond the scope of this paper, quantifying those constraints and identifying options to address them (such as tax equity in the context of market indexing) could be critical to complement the benefits of securitization and unlock the benefits of the tax credit extension for Minnesota Power and its customers.

Recommendation 3:

Securitization legislation should provide regulators with the flexibility, means, and authority to work with utilities to adjust the timing of bond issuance relative to plant retirement, structure the bond issuances, and design the resulting surcharge to minimize bill impacts and risks for utility customers while also sufficiently mitigating risks for utility and securitization bond investors so as to minimize short and long-run financing costs.

As summarized in Chapter 3, recent securitization bills in Colorado and Montana set good examples of providing timing flexibility to the utilities and commissions, by explicitly stating that the timing of securitization can be independent of the plant retirement. Since securitization legislation is not in place yet in Minnesota, Minnesota Power can work closely with key stakeholders to make sure the legislation includes similar language that provides the flexibility needed.

- **Montana:** *“specify the timing of actions required by the order so that... the Montana energy impact assistance bonds are issued as soon as feasible following the issuance of the financing*

order, independent of the schedule of closing and decommissioning of the electric infrastructure or facility”,⁵¹ and

- **Colorado:** *“specify the timing of actions required by the order, including... the timing of issuance of the CO-EI bonds, independent of the schedule of retirement of the electric generating facility.”⁵²*

Recommendation 4:

Rate adjustment mechanisms, such as bill credits, should be used to help stabilize customer costs throughout the transition, while alternative surcharge rate designs should be considered to enhance revenue stability for the utility.

Temporal alignment of plant retirement and replacement is complicated—and indeed, Minnesota Power’s IRP assumes that such a shift will occur over three years. However, staggered retirement and replacement could create rate disruptions. Minnesota Power should consider rate adjustment mechanisms so that the changes in production costs, along with any potential savings from securitization—which might happen before the retirement and replacement—can be reflected on customer bills in a timely fashion.

RMI recommends that Minnesota Power conduct deeper analysis to explore alternative rate design choices for the securitization surcharges. As discussed in Chapter 3, we have seen utilities and stakeholders in other states switch from simplistic volumetric charges to demand charges to better reflect cost-causation principles or more complex designs that mirror the cost allocation methods used for electricity services. These alternative approaches (e.g., including demand-based or fixed charges) could increase revenue stability compared to the per kWh charges; this would be of particular value to a utility such as Minnesota Power that has concentrated load associated with a few large industrial customers. Minnesota Power should assess in greater detail through its cost-of-service study and revenue requirement model how these alternative mechanisms could achieve better cost-causation alignment while stabilizing the future revenue streams.

As discussed in both the Phase 1 Report and in the case studies in Chapter 3 of this report, the securitization statute plays a critical role in ensuring the success of securitization transactions by assuring investors of the reliability of future revenue streams. RMI encourages Minnesota Power to work with key stakeholders, including legislators, consumer advocates and industry experts to ensure that any future Minnesota statute provides flexibility for the utility to work with the Commission to customize rate design to achieve equitable allocation of costs and risks across customer classes.

⁵¹ Montana, HB467, Montana Energy Impact Assistance Act, signed 5/10/2019.
<https://leg.mt.gov/bills/2019/billpdf/HB0467.pdf>

⁵² Colorado, SB19-236, Sunset Public Utilities Commission, signed 5/30/2019.
https://leg.colorado.gov/sites/default/files/2019a_236_signed.pdf

Recommendation 5:

The structuring of a securitization transaction—the tenors and tranches of bonds issues—can have significant impacts on costs and benefits. Securitization legislation should provide the means and authority for regulators to engage financial sector experts to advise commissioners and their staff throughout the securitization process.

Minnesota Power should engage financial institutions and industry experts to better understand and communicate the implication of key securitization structuring choices. Arguably, the most important choice is bond tenor. As discussed in Chapter 3, previous utility transactions have tended to land on shorter tenors, while RMI’s modeling analysis and yield curve projection (based on current financial market dynamics) suggest that Minnesota Power could reduce costs by opting for an extended tenor. Minnesota Power should reach out to financial experts and gather inputs on the quantified impact of different tenor choices.

Recommendation 6:

Minnesota Power should work with key stakeholders to ensure securitization legislation includes transition assistance as an allowed use of proceeds.

Transition assistance has historically not been included in the securitization bills or financing orders but dealt with separately as part of the IRP or retirement settlements under regular cost-recovery methods. However, we have seen increasing attention paid through the more recent securitization legislation discussion. Both New Mexico and Colorado bills included transition assistance explicitly, though there are noticeable difference between two bills in the level of specificity regarding size and transfer of benefits to communities affected by the transition. We suggest Minnesota Power work with the City of Cohasset and surrounding communities to develop a comprehensive transition plan while working to include transition assistance as an allowable use of proceeds in securitization legislation.

STATE OF MINNESOTA)
) ss
COUNTY OF ST. LOUIS)

AFFIDAVIT OF SERVICE VIA
ELECTRONIC FILING

Tiana Heger of the City of Duluth, County of St. Louis, State of Minnesota, says that on the 5th day of February, 2021, she served Minnesota Power's Appendix Q: Securitization Plan in **Docket No. E015/RP-21-33** on the Minnesota Public Utilities Commission and the Energy Resources Division of the Minnesota Department of Commerce via electronic filing. The persons on E-Docket's Official Service List for this Docket were served as requested.



Tiana Heger