Harnessing Financial Tools to Transform the Electric Sector

November, 2018

SIERRA CLUB

AUTHORS & ACKNOWLEDGEMENTS

Authors
Uday Varadarajan[1]
David Posner[2]
Jeremy Fisher[3]

Contacts
Jeremy Fisher, *jeremy.fisher@sierraclub.org*
Uday Varadarajan, *uvaradarajan@rmi.org*

Suggested Citation
Varadarajan, Uday, David Posner, Jeremy Fisher.
Harnessing Financial Tools to Transform the Electric Sector. Sierra Club, 2018.

Acknowledgements
The authors thank the following individuals for their insights and perspectives:
Holly Bender, Sierra Club
Nachy Kanfer, Sierra Club
John Romankiewicz, Sierra Club

1. Rocky Mountain Institute; Stanford University, Sustainable Finance Initiative 2. Climate Policy Initiative 3. Sierra Club

CONTENTS

Executive Summary 1

1. Introduction 2

The Role of Finance: Catalyzing Electric Generation Transformation 3

2. Cost-of-Service Regulation Impacts on Retirement Decisions 3

Cost-of-Service Regulation 3

The Regulatory Conundrum of Early Retirement 4

Disallowance 4

Accelerated Depreciation 5

Regulatory Asset 5

Accelerated Retirement and Earnings Potentials 5

Accelerated Retirement and Rate Impacts 5

Early Retirement and Community Impacts 6

Early Retirement and Reliability 7

3. Overview of Utility Financing 7

4. Excess Collection in Rates 8

Excess Tax Collections from Federal Tax Reform—Direct Impacts 8

Excess Tax Collections from Federal Tax Reform—Indirect Impacts Through Excess ADIT 9

5. Ratepayer-Backed Bond Securitization 10

What is Securitization? 11

Enabling Legislation 12

The Securitization Process 12

Recent Utility Securitization Efforts 13

Mitigating Ratepayer Impacts With Securitization 13

Utility EarningsImpacts from Securitization 13

Funding Community Transition Through Securitization 14

Securitization and Credit Ratings 14

6. Financial Tool: Securitization + Capital Recycling 15

7. Green Bonds and Tariffs 17

Retirement-Linked Green Bonds 17

Retirement-Linked Green Bonds with Capital Recycling 18

Retirement-Linked Green Tariffs 18

8. In Closing 20

EXECUTIVE SUMMARY

In cost-of-service states, regulated utilities are continuing to operate generation units even though market signals show that the units should be replaced with more cost-effective alternatives. The reason for this behavior is that traditional regulatory mechanisms for dealing with the "stranded capital" of uneconomic generators suffer from significant drawbacks that render them unattractive to regulators, as each could cause harm to the utility, ratepayers, or both.

In this paper, we explore the merits of innovative financial tools that could help address these challenges and enable the transition to a more economically efficient electricity system. As we show, financial tools such as re-purposing excess collections in rates (such as the over-collection associated with tax reform), securitization, and green tariffs can provide funds to help smooth the elector-electric sector transition from fossil fuels to clean energy. We give particular attention to securitization with capital recycling as a key opportunity to advance the beneficial transition while minimizing harm to ratepayers and utilities, and providing a funding stream to impacted communities. Securitization allows ratepayers to directly raise low-cost debt to address near-term financing needs, while capital recycling helps the utility achieve reasonable profits for shareholders.

Each of these methods can be used to raise funds that help eliminate rate shock from accelerated depreciation and assist communities harmed by the closure of uneconomic generation plants. By relying on these tools, utilities, regulators, and other stakeholders can achieve the proverbial 'win-win' by which utilities are able to receive a reasonable return on their investments, expensive generation is retired, impacted communities have resources to smooth the transition, and customers benefit from lower costs.

1. INTRODUCTION

The United States electric sector is experiencing unprecedented change and opportunity. In 2017, unsubsidized wind passed economic parity with fossil-fired generation; it became the least-expensive option for new generation, and utility-scale solar is not far behind.[1] Combined with the depressed price of gas and a decade of investments in efficiency and demand response, operators of existing fossil and nuclear plants are realizing that they can no longer offer cost-competitive generation.

From 2008 to mid-2018, 65 gigawatts (GW) of coal-fired facilities retired in the U.S.[2] as owners determined alternative options were cheaper than continued operation. There is increasing evidence, both from national studies as well as recent utility actions, that clean energy options are increasingly competitive with both new[3] and existing[4] fossil generation, as well as increasing urgency to accelerate the pace of change.[5] The energy transition is the expected rapid shift from legacy fossil fuels to clean energy options that could occur over the next decade.

In March 2018, Bloomberg New Energy Finance (BNEF) issued a report titled with the conclusion that "Half of U.S. Coal Capacity on Shaky Economic Footing," because the long-run margins for those plants are negative;[6] i.e., they lose money by operating. In a competitive environment, owners of plants that are not currently profitable and have limited profitability prospects move to retire to avoid substantial ongoing losses. In fact, this thesis bears out in recent history: plants that relied on market-based revenues usually retired once profit projections sank below cost projections. For example, BNEF found that only 7% of the remaining merchant[7] fleet netted negative margins in the last six years. However, the BNEF report shows that a large majority of regulated[8] coal plants—both in organized market structures and vertically integrated states—have failed to retire even though their continued operation is uneconomic. BNEF notes that "regulated assets are stubborn; they are shielded by cost-of-service returns, and tend to linger longer after their economics sour."

Why do merchant and regulated owners act differently? By and large, merchant (or unregulated) owners of uneconomic power plants move to retire units that do not have a medium- or long-term prospect of a profit. With few exceptions, those merchant owners absorb any remaining or unpaid capital debt in the retired units, a loss which is passed onto investors. And while investors may not be pleased to absorb those capital losses, the alternative—absorbing both operating and capital losses through continued operation—is worse.

In contrast, regulated utilities are able to pass on costs to ratepayers, and unless a regulator specifically seeks to understand if an existing generator is competitive, those costs simply continue to be passed through. While regulators ideally demand that investor-owned utilities act as competitive enterprises, retirement decisions involve competing consequences that can cause a departure from market-optimal outcomes. Once a generating plant becomes uneconomic and a detriment to ratepayers, regulators usually face two unattractive options: either demand that investors absorb unrecovered capital costs, or pass those costs through to ratepayers who are no longer benefiting from the plant. The former is unattractive to the utility, which was authorized by regulators to invest in and operate the plant, and may not be able to absorb a loss without a credit rating impact. The latter is unattractive to ratepayers, who may either face rate increases to pay down debt, or are compelled to pay for power plants that are no longer in service. Because neither the utility nor the ratepayers, nor the regulators for that matter, are satisfied with the slate of unattractive options, they may reach an uneconomic, yet rational, impasse: choose to continue the operation of deeply uneconomic units simply to avoid an inevitable conversation about any unrecovered capital.

This is the impasse that we seek to overcome. The financial community has developed numerous tools to overcome analogous problems. Here, we explore three financial tools that would ease the transition away from uneconomic generation for investors, ratepayers, and regulators: 1) the diversion of over-collected earnings to depreciation, 2) securitization, and 3) green bonds and tariffs.

THE ROLE OF FINANCE: CATALYZING ELECTRIC GENERATION TRANSITION

The retirement of uneconomic generation plants, and their replacement with lower cost clean energy resources is a net benefit. Financing tools offer the opportunity to make sure that those benefits are realized by ratepayers and redound to the owners, reducing the barriers to retirement and resistance to the clean-energy transition.

The financial tools we explore here raise capital to cover near-term costs by compensating investors from a stream of well-characterized future benefits. Specifically, we seek to address the key barriers to transition—stranded assets,[9] an erosion of utility earnings, rate shock for consumers, and equity for communities and—using three future benefit streams: tax incentives, future electricity cost savings, and economic opportunities for reinvestment of utility capital.

How big is the problem? In 2017, the Carbon Tracker Initiative (CTI), an independent financial think tank, estimated that regulated utilities are carrying $185 billion of potentially stranded assets in non-economic coal units.[10] As the cost of alternatives, and thus the fair market value of those coal plants, continues to fall that number will only rise. As the discrepancy between the low market valuation and high remaining balance increases, the risks to utilities rise—the risk that regulators will simply demand a plant be taken out of rate base. This is the outcome we seek to circumvent, providing a pathway for both ratepayers and utility owners while leading to cleaner outcomes and just transitions for impacted communities.

2. COST-OF-SERVICE REGULATION IMPACTS ON RETIREMENT DECISIONS

To understand the core challenge of transitioning the remaining regulated utility generation fleet to clean energy, we first need to understand the key features of cost-of-service regulation. We begin by reviewing these key features and then turn to a more detailed discussion of the resulting financial incentives and barriers to transition faced by utilities, customers, and communities.

COST-OF-SERVICE REGULATION

Investor-owned utilities in many parts of the U.S. are subject to traditional cost-of-service regulation. Under the cost-of-service model, a utility makes capital investments in assets such as generation and transmission, and those investments are approved by a regulatory agency, a public utility commission. Ratepayers pay for the electricity service delivered by those assets much as they would for a mortgage: by paying back the utility's original investment plus a rate of return over time, and reimbursing the utility for other expenses as they are incurred (e.g., fuel and labor). This model of regulation predominates in states that do not have retail competition—i.e., in the Southeast, Midwest and Plains (except Texas, Illinois and Ohio), and West (except California).[11]

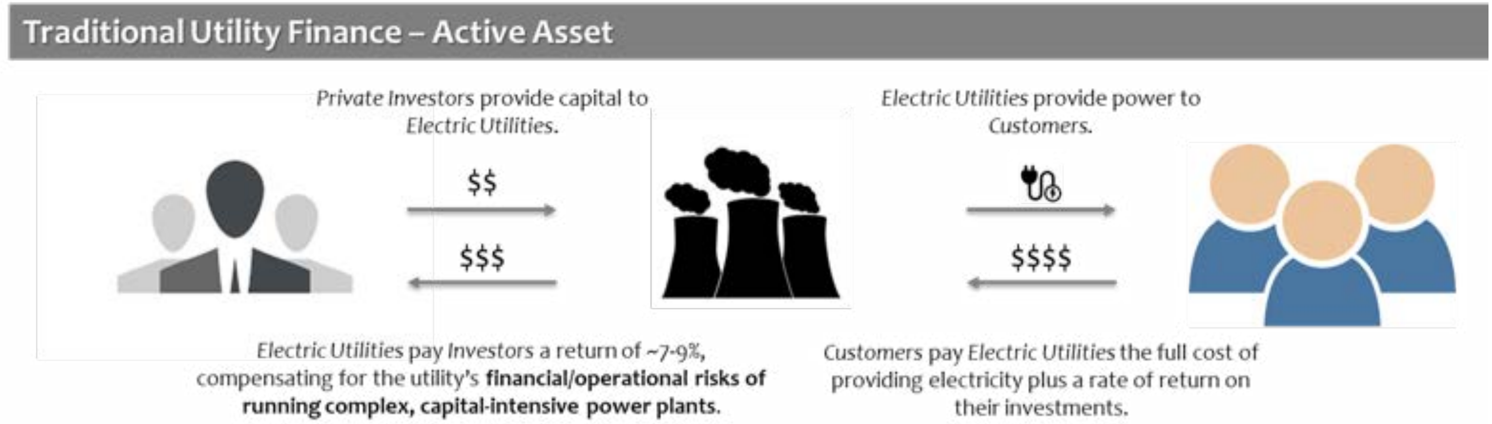
More formally, in cost-of-service regulation, the utility is authorized to charge customers rates sufficient to:

1. Recover the capital it invested in projects that are approved as used and useful for providing electricity service through steady depreciation charges (analogous to principal repayments made on a mortgage) spread over the project life;
2. Earn a rate of return (these are akin to interest payments on a mortgage) on the rate base—assets that continue to be "used and useful" but have not yet been fully paid for; and
3. Pay for the fuel and operations and maintenance (collectively termed "O&M") costs associated with running the system.

Collectively, these three elements constitute the revenue requirement—i.e., what the utility must recover from customers through rates. Utility monopolies are generally charged with providing reliable service at the least possible overall cost, and thus they should (at least in principle) prefer to minimize costs. The utility's expectation of full cost recovery—and a reasonable rate of return—for the assets it builds to serve customers is a core element of the "regulatory compact": the implicit agreement between the utility and the public utilities commission.

The rate of return is a set percentage applied to outstanding capital in the rate base—analogous to the interest charged on outstanding principal for a loan—and the primary way that the utility makes a profit. Because the utility "earns" this rate of return, it has a clear incentive to invest in capital assets. In contrast, utility owners are largely indifferent to O&M costs, which are passed through to customers without generating any profit.[12]

Capital investments made by utilities are typically recovered over a set period of time, called the "depreciable life" or "book life." At the outset, this period is typically set to coincide with an engineering-based estimate of how long the asset will be of use. Like a mortgage, the loan period is



typically decades. Unlike a home mortgage, the assumption is that as a plant's parts wear out, the plant becomes less useful. As a utility replaces worn-out parts of a large power plant, that asset life can be extended and the capital balance of the plant maintained. In the homeowner's analogy, the equivalent would be taking out additional loans to continue making home improvements. A conundrum arises when the theoretical engineering life of a power plant exceeds its expected economic life—i.e., when that plant has been priced out of the market—or in the home example, when that home's mortgage exceeds its sale value leaving the loan "stranded."

The graphic below shows the breakdown of the revenue requirements per megawatt -hour (MWh) of generation for a representative coal plant in 2016. The chart is divided into the three components: (a) the pass-through costs, including fuel and O&M expenses (Expenses), (b) capital depreciation and amortization (D&A), and (c) the capital rate of return (ROR). The ROR represents the earnings made by the utility owners on this asset.

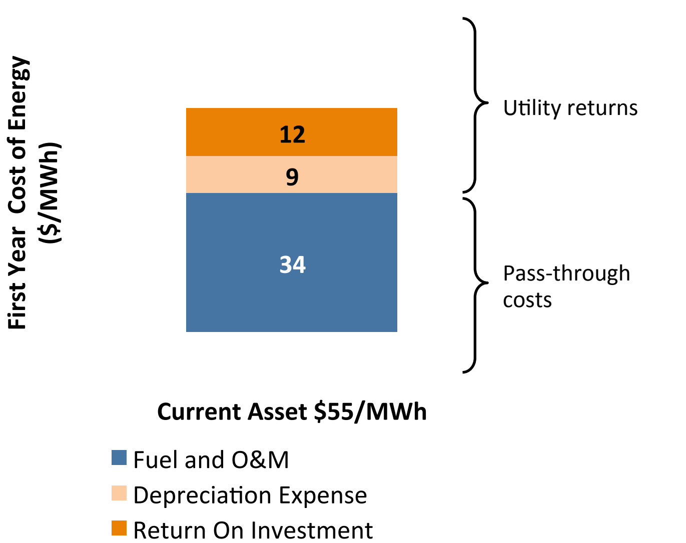


FIGURE 1. FIRST YEAR REV REQ FOR EXAMPLE PLANT UNDER BAU

In this case, our example plant's capital costs are based on a remaining plant balance (i.e., unpaid capital debt) in rate base of $433 million, with a remaining life of 20 years and an after-tax allowed rate of return of 7.35%. In this case, nearly two-thirds of every ratepayer dollar are just passed through to pay for fuel and operations. Only one-third of ratepayer revenues generate any returns—not a very attractive prospect from the utility's shareholders' perspective.

THE REGULATORY CONUNDRUM OF EARLY RETIREMENT

The fundamentals of cost-of-service regulation continue to apply even when assets are retired early. The utility still expects to recover its capital outlay in full and to see a return on any capital that has not yet been recovered. Because the utility expected to recover capital over the full life of an asset, an early retirement leaves a reservoir of undepreciated capital. In the parlance of cost-of-service regulation, an asset approved for early retirement with an associated capital balance is deemed a "stranded asset."

Under cost-of-service regulation, regulators traditionally have three core mechanisms for handling stranded assets: disallowance, accelerated depreciation, or the creation of a "regulatory asset"—an asset that exists only on paper. Each has its disadvantages.

Disallowance

In a disallowance, the regulator may determine that because a unit is retired and no longer provides service, it must be removed from rates. Under most circumstances, regulators are entitled to use this construct, but it is not without risk. While a disallowance can mean immediate rate relief for customers, it can have longer-term ramifications. A disallowance immediately reduces future cash flows and earnings without providing any funds for cost recovery that would allow the utility to pay off any outstanding debt. As a result, the company will have the same debt load but less cash to service that debt – potentially impacting its credit ratings and future behavior. A utility that receives a full or partial disallowance may be strongly inclined not to pursue additional retirements, even if they are cost effective. In addition, a lower credit score can impact the utility's cost of capital, making future projects more expensive. While there are certainly individual circumstances in which poor utility behavior may warrant disallowances, the prospect of a large disallowance incentivizes a utility to fight the retirement of an uneconomic asset, not support it.

Accelerated Depreciation

Under accelerated depreciation, a utility seeks to change its depreciation schedule to match the period until retirement, potentially shrinking the assumed remaining life from decades to years. From the utility perspective, accelerated depreciation ensures the rapid (and hence lower risk) recovery of capital. As a consequence, utilities can pay off their debt much faster—but ratepayers will see a much higher rate in those years as a result, even if the regulators decrease the utility's allowed return to reflect its lower risk. That is, ratepayers may be exposed to substantial rate shock under acceleration.

Regulatory Asset

Under the "regulatory asset" construct, the regulator authorizes a utility to retire a plant and remove it from service prior to achieving full cost recovery – but also authorizes the utility to continue collecting a return of and on investment after the plant itself no longer operates (hence a "regulatory asset", rather than a real asset). If the plant's pre-retirement depreciation schedule is used to set the amortization period of the regulatory asset, ratepayers are insulated from rate shock, but are left paying for an asset that no longer exists, which may be considered unfair by future ratepayers. In addition, a regulatory asset creates a risk exposure for the utility, as a future commission may choose to cease allowing such payments. As a result, utilities generally do not request—and regulators generally do not approve—amortization periods for regulatory assets that exceed five to seven years. If a plant is retired more than five to seven years early, utilities or regulators generally seek to combine acceleration and regulatory asset concepts, allowing a unit to be retired and recovered after-the-fact over a shorter period. However, this again results in ratepayers being exposed to a substantial rate shock.

Accelerated Retirement and Earnings Potentials

Retiring assets without replacing them lowers the future earnings potential of the utility. Because having generation units and other capital assets in its rate base is the key variable determining utility profits, accelerated depreciation of a regulatory asset decreases rate base more quickly than originally planned and eats into earnings. For our example coal plant, the utility would have expected to earn $3.30/MWh on a net present value basis of after-tax future earnings from continued operation of the plant. If the plant were now retired early and replaced in whole with a wind power purchase agreement ("PPA"), and the remaining plant balance recovered via an accelerated regulatory asset over five years, the earnings would drop by more than a half to $1.45/MWh.

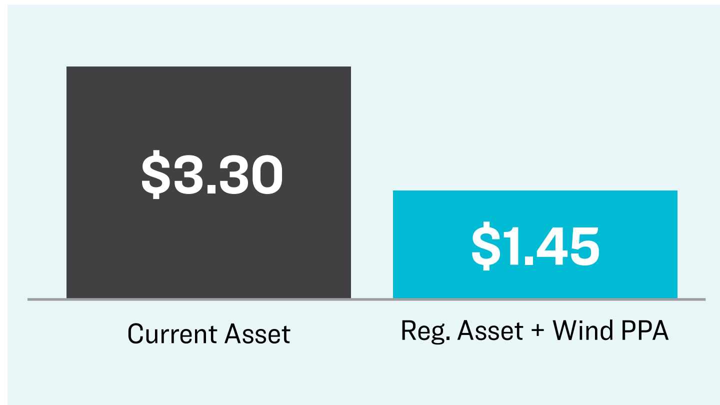
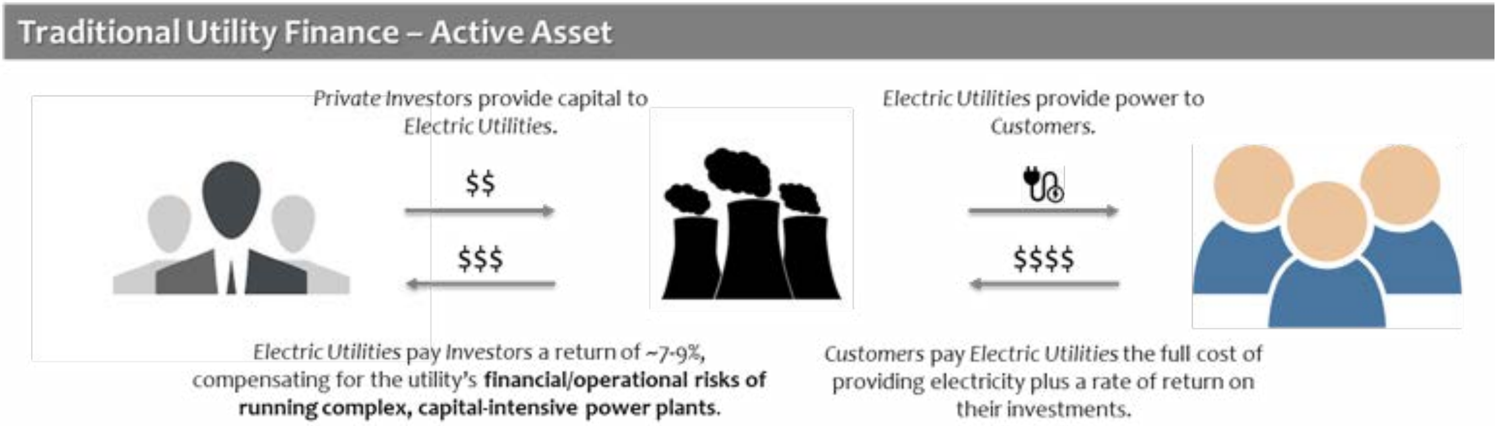


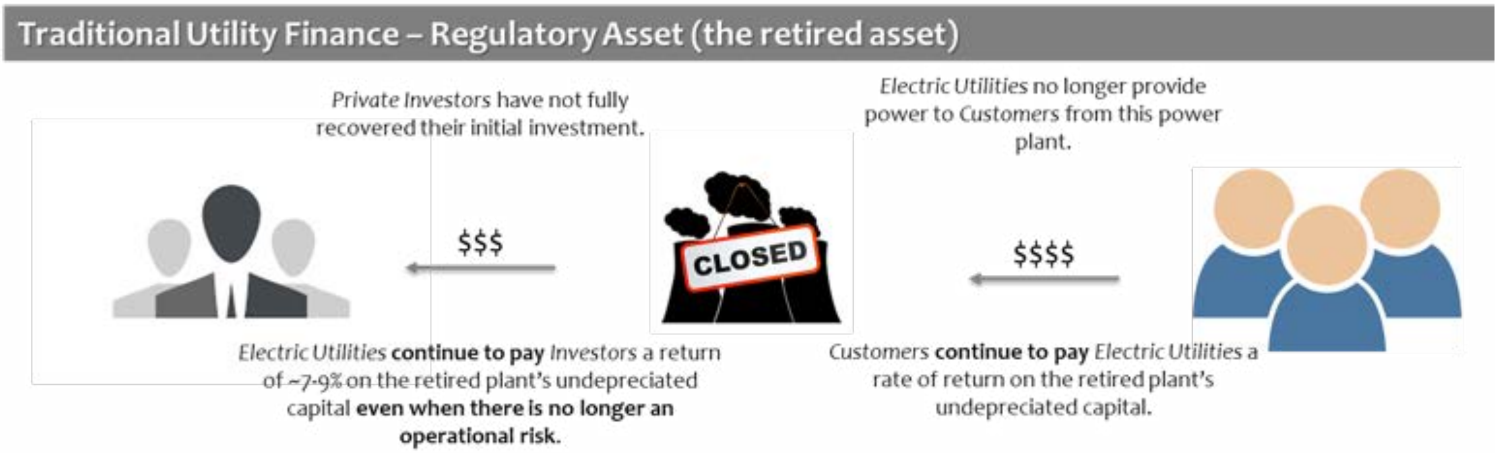
FIGURE 2. UTILITY EARNINGS

The company's future earnings depend on the ability to reinvest capital to continue accruing a regulated rate of return. Recalling that our example plant had an expected lifetime of 20 years, investors expected to earn a return on the remaining plant balance for the next two decades, not just for the next five years. Instead of a new capital investment however, the replacement power is a power purchase agreement, which operates as a pass-through cost (i.e. it offers no return to investors). If the utility cannot develop its rate base, its existing equity investors are likely to seek alternative opportunities. As such, the utility's shareholders are not incentivized to advocate for the retirement, even if it is cost effective, unless the utility has opportunities to replace (and preferably increase) the rate base.

ACCELERATED RETIREMENT AND RATE IMPACTS

An unavoidable consequence of *accelerated* depreciation is the shortened payback period, which in turn requires a short-term rate hike to cover the capital costs of the regulatory asset. Depending on the magnitude of the required recovery relative to the overall rate base, accelerated





depreciation could harm ratepayers—a consequence for which all stakeholders have a limited appetite. Even if the replacement resource is substantially less expensive than the retiring asset, a near-term rate hike is still a barrier. For example, if our example coal plant were retired early, the unrecovered plant balance transferred to a regulatory asset with an accelerated depreciation period, and replaced with inexpensive new wind generation, the near-term cost for that package of assets (e.g., the power plant and its replacement wind) would actually increase from the ratepayer perspective.[13] This happens primarily because the annual cost of amortizing the otherwise 20-year unrecovered plant balance over just five years quadruples the depreciation expenses of asset. In this case, even the significant savings in generation expenses associated with replacing the high operating and fuel costs at $34/MWh (dark blue bar in the first column) with the much lower price of a power purchase agreement (PPA) at $20/MWh (the dark blue bar in the second column) cannot overcome the first-year rate shock from accelerated depreciation.

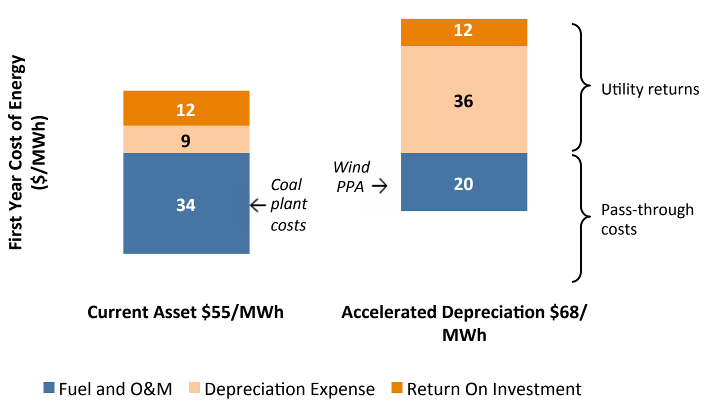


FIGURE 3. FIRST YEAR REVENUE REQUIREMENT FOR EXAMPLE PLANT BAU AND ACCELERATED DEPRECIATION

EARLY RETIREMENT AND COMMUNITY IMPACTS

The early retirement of a large generating asset can result in substantial impact to the local workforce and surrounding communities. There are direct economic impacts on workers at the plant and vendors who supply equipment, services, and raw materials. In rural or economically disadvantaged communities, the property taxes paid by the plant owner, as well as income and sales taxes paid by employees, can be a substantial component of municipal and county budgets. Finally, local employees re-spend locally, and thus retirements may have local multiplier effects and impacts on property values.

In many plant communities, the local power plant is a major provider of jobs and tax revenue; in areas where the coal is also locally sourced, this problem is compounded.

For instance, in Moffat County, Colorado, six of the top ten taxpayers are mine operators and utilities with interests in the local coal plant. These six taxpayers account for 42% of the county's tax base, providing roughly $5.3 million annually to the local school district.[14] And while replacement energy options may have very positive employment, tax and local revenue impacts, those impacts may not be in the same location or occur at the same time as the retirement, causing community stress.

EARLY RETIREMENT AND RELIABILITY

The physical constraints and reliability needs of the electricity grid itself may also act as a barrier to early retirement of specific plants, especially when variable renewable energy sources are foreseen as replacements for the retired generation. The retirement of some individual assets in specific grid topographies may significantly affect system operation, adding costs at a system level that were not captured in historical operating expenses of plants. The appropriate diagnosis of reliability challenges—as well as the potential range of solutions for addressing them—generally requires detailed system production cost and dispatch modeling. In general, at the levels of penetration of variable generation in balancing areas across the U.S. today, the cost of addressing any such challenges have has been estimated in renewable integration studies to be relatively small, less than $5/MWh.[15]

3. OVERVIEW OF UTILITY FINANCING

In traditional cost-of-service regulation, investor-owned utilities are allowed to charge customers a rate, set by regulators, to match the cost of providing service. The rate is typically set such that the utility has the opportunity to earn a reasonable rate of return on the capital it invests on behalf of ratepayers, or "rate base." Utilities typically finance their capital expenditures through a combination of corporate debt and equity, roughly in equal measure. Most vertically integrated electric utilities have an allowed rate of return on capital of between 7-9%, set by regulators.

What regulators actually adjust is the allowed return on equity, or the margin that can be earned by the equity investors. The return on equity, typically between 9-11% on an after-tax basis, is generally based on financial analysis of the historical cost of equity for comparable companies with similar risk profiles and engaged in activities that are similar in their complexity to generating and delivering power. In other words, a utility's return on equity is benchmarked to the historical returns demanded by equity investors as reflected in their share price, earnings, and dividend history. Regulators have the opportunity to adjust the equity return relative to the benchmark. The return rate on equity may be adjusted because the utility has equity costs and risks that differ from its peers, because current equity market conditions no longer match historical average conditions (i.e., regulatory lag), or because the regulators are seeking to signal the utility through a positive or negative adjustment.[16]

The remainder of utility financing is achieved through corporate bonds, or debt. Utilities always aim to achieve credit ratings for their debt issuance that are at or above the "investment grade" threshold (roughly, at or above a Moody's rating of Baa3 or S&P's BBB-).[17] Debt that is rated below investment grade generally faces a substantial increase in financing costs. Long-term, investment grade debt currently features interest rates between 3-6%. The interest rate depends crucially on the specific credit rating achieved (from Baa3 up to Aaa) as well as other characteristics of the debt such as its seniority (i.e., the specific priority of the claim of a given debt issuance on various streams of corporate cash flows) and its security (i.e., the type of lien on and value of any property pledged as collateral provided as security to debt-holders).

In addition, regulators have discretion over whether to allow utilities to recover various costs and can make decisions more generally that impact the timing, size, and certainty of the revenues the utility is allowed to collect from its customers. These decisions can significantly impact the cash flows available to the utility to service its debt, so regulatory risk is also a key determinant of the credit rating of utility debt.

The allowed rate of return—i.e. what the utility actually charges ratepayers for capital expenses—is a blend of the return on equity (9-11%) and debt rate (3-6%). The fraction of equity versus debt, or the capital structure of the utility, is also subject to oversight by regulators and is influenced by the choices they make. In general, utilities seek to balance the risks of debt and equity.

On a superficial level, regulators may desire that the utility borrow using lower-cost debt to drive down the cost of capital. However, as a company becomes more "leveraged," increasing its debt levels relative to equity, the risk to equity investors (i.e. shareholders) increases.[18] A utility might reasonably demand that its equity investors be compensated for this higher risk by increasing the return on equity, which may undo the desired lower cost of capital. Further, deeper leverage leaves less of a margin of error for debt repayment, leading to lower debt ratings and a higher cost of debt.[19] As a result, regulators seek to balance the reduced cost of capital from debt borrowing with the benefits of an equity buffer that mitigates the risk of unanticipated rate hikes.

Utility management may have a different view on the optimal capital structure. Investor-owned utilities have a fiduciary responsibility to achieve maximum value for shareholders while minimizing the risks they face. The value of a utility is most closely tied to the return on equity the utility can achieve (relative to the cost of equity it faces in capital markets) as well as to market perceptions regarding the level of growth in earnings per share that they can reliably expect. As discussed above, a utility's earnings are tied to the capital in rate base. As long as the allowed *return* on equity exceeds the utility's cost of equity (as is generally the case in low interest rate environments), utility management has the incentive to grow the rate base through incremental capital additions. Of course, they seek to do this while minimizing perceptions of risk that could raise their cost of debt. In general, the optimal capital structure that a utility would target will not necessarily be aligned with that desired by a regulator.

As a result, the actual capital structure that any given regulated utility employs will necessarily reflect a compromise that involves some give and take between utilities and regulators—and the customers that both serve. The possibility of electric generation transition—and the challenge of asset stranding in particular—can significantly shift this balance for both utilities and regulators. The possibility of future ratepayer savings from an energy transition *should* drive regulators to seek greater investments in clean energy—but only if current ratepayers' costs are not impacted. On the other hand, the specter of stranded assets affects investor expectations of debt risk and the potential of impaired earnings growth for equity investors. A critical question, then, is how this balance could be shifted to address the needs of all stakeholders—and whether new financial tools can help catalyze such a shift.

4. EXCESS COLLECTION IN RATES

Excess collection in rates can create opportunities to achieve rapid electric-sector transition. On occasion, utilities collect customer funds for some specific purpose authorized by their regulator but find later that those funds are no longer required for their originally intended purpose. Recent examples include collections for corporate tax that exceed actual tax due, or instances where forecasted incremental renewable costs exceed actual costs incurred. Regulated utilities typically have their rates adjusted to meet actual expenses incurred; in over-collecting, the utility incurs a regulatory liability and typically must return over-collected revenues to ratepayers. However, rather than simply returning excess revenues, over-collections can be repurposed to address asset retirement and community transition needs. For example, where a utility has collected excess revenues for a specific purpose there may be opportunity to re-purpose the excess monies towards mitigating customer rate shock from accelerated depreciation of an uneconomic plant. One such recent example is the excess collections realized from federal tax reform. While we describe the impact of this particular tax reform, the general principle is applicable to other excess collections.

EXCESS TAX COLLECTIONS FROM FEDERAL TAX REFORM—DIRECT IMPACTS

Recent federal tax reform has made excess collections of taxes a pressing issue. The 2017 tax reform lowered the corporate federal tax rate from 35% to 21%. Regulated utilities are compensated for their tax expenses through customer rates, which are adjusted in periodic regulatory proceedings ("rate cases"). Utility rates that were set before the passage of tax reform would over-collect tax expenses unless the rates were adjusted subsequently to the passage of the tax reform bill.

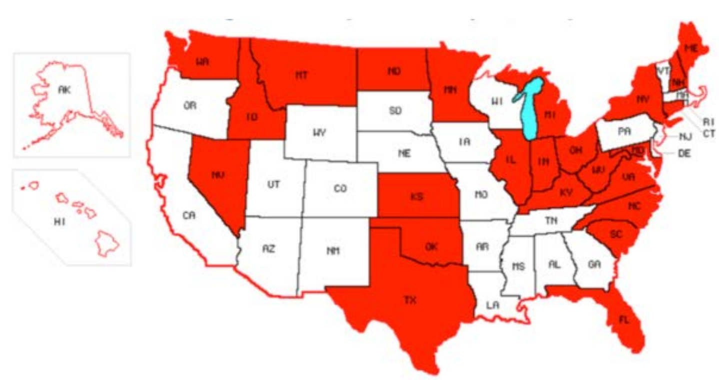


FIGURE 4. STATES WITH ANNOUNCED TAX REFORM

Within a month of the passage of tax reform in December 2017, more than half of the states had announced regulatory proceedings to address the consequences for utility customers.

Regulators have many options for how to address over-collection. If rates are not adjusted downwards, the utility's top-line revenues will remain as before tax change. If expenses do not increase correspondingly, the result will be higher utility net income and an inflated return on equity (see the second column in Table 1, below), a situation generally not acceptable to consumer advocates, large users, or regulators.

The simplest option a regulator may choose is to adjust ratepayer tariffs downward to reflect the reduced tax rate. This adjustment leaves the utility's after-tax net income unchanged (see the third column in Table 1, below). However, the loss of total revenues results in lower total pre-tax income, which can impact the perceived financial performance of the utility.

A utility can (correctly) argue that the downward adjustment to income from tax reform would negatively impact key cash-flow driven metrics (e.g., cash flow from operations, pre-working capital), and in turn harms its credit rating. In January 2018, Moody's credit rating agency, citing the tax reform as "credit negative for investor-owned utilities," changed the ratings outlook for twenty-four (24) utilities and holding companies from stable to negative.[21]

There are potential benefits to *both* the utility and customers to consider alternative uses of such over-collections. One option is to repurpose excess funds being collected to cover tax expenses to accelerate depreciation of uneconomic assets or pay for new clean generation or infrastructure. This could enable early retirement of those assets without an increase in ratepayer collections—but only if the savings are large enough, and as a one-time opportunity.

EXCESS TAX COLLECTIONS FROM FEDERAL TAX REFORM—INDIRECT IMPACTS THROUGH EXCESS ADIT

When utilities collect cash from ratepayers to compensate the utility for its tax expenses, those collections generally do not correspond to the tax due to the government in that specific year. The primary reason for this mismatch is that federal and state tax law often allow for tax deductions for depreciation expenses in a front-loaded manner, called "Modified Accelerated Cost Recovery System" (MACRS).

For example, a 30-year investment in a new wind asset is depreciated in just five years under MACRS (i.e. for the purposes of calculating federal taxes payable), significantly reducing the tax due to the federal government in those early years. The utility, however, still collects tax on the basis of a straight-line (i.e. 30-year) depreciation basis, resulting in an over-collection of tax expenses in those first five years of the asset's life. The utility records this excess collection as "Accumulated Deferred Income Taxes" (ADIT), another regulatory liability. In effect, ADIT acts as a loan the utility receives from ratepayers.

	35% Tax Rate *Original Customer Cost*	**21% Tax Rate** *No adjustment to rates*	**21% Tax Rate** *Adjusted rates*
Total Annual Ratepayer Costs	**$265.90**	**$265.90**	**$259.00**
Utility Revenues from Facility	$265.90	$265.90	$259.00
O&M Expense	$191.50	$191.50	$191.50
Utility EBITDA[20]	**$74.50**	**$74.50**	**$67.50**
Depreciation Expense	$25.70	$25.70	$25.70
Interest Expense	$11.40	$11.40	$11.40
Utility Pre-Tax Earnings	**$37.30**	**$37.30**	**$30.40**
Tax Expense	$14.50	$7.60	$7.60
Utility After-Tax Earnings	**$22.80**	**$29.80**	**$22.80**
Return on Equity	**9.80%**	**11.40%**	**9.80%**

TABLE 1. ILLUSTRATIVE EXAMPLE OF THE IMPACTS OF TAX REFORM ON UTILITY FINANCIAL METRICS WITH AND WITHOUT ADJUSTMENT TO RATES.

In most jurisdictions, ratepayers are compensated for this loan at the regulated rate of return—effectively the same way the utility would be compensated for incurring a capital expense on behalf of ratepayers. As a practical matter, the ADIT balance is deducted from the rate base when calculating the utility's allowed return. In later years, MACRS falls off and the actual federal taxes paid exceed the tax expense collected from ratepayers.[22] These under-collections are analogous to principal repayments, reducing the ADIT balance over time until that balance is fully exhausted.

If the tax rate is lowered after an ADIT balance has been created, then the accumulated ADIT will no longer be matched by cumulative future taxes due to government. This means that the ADIT balance will not be exhausted, and the utility will hold "excess" ADIT at the end of the asset's life unless corrective action is taken. In general, excess ADIT is returned in installments so that future ratepayers also benefit. However, there may be compelling reasons to allow utilities to repurpose excess ADIT rather than return it rapidly to ratepayers. ADIT effective acts as a cash balance that the utility can use as capital without the need to approach lenders or equity providers.

With a lower tax rate, future ADIT balances attained per dollar of utility capital investment will be smaller. As a consequence, utilities will need to raise additional capital from other sources, such as public debt or equity markets. That increased demand on debt/equity markets could potentially raise the utility's weighted average cost of capital. Repurposing excess ADIT from past investments, rather than simply returning it to ratepayers, can help provide a rapid and relatively low cost source of transition capital—i.e. capital to accelerate depreciation or build new renewable energy.

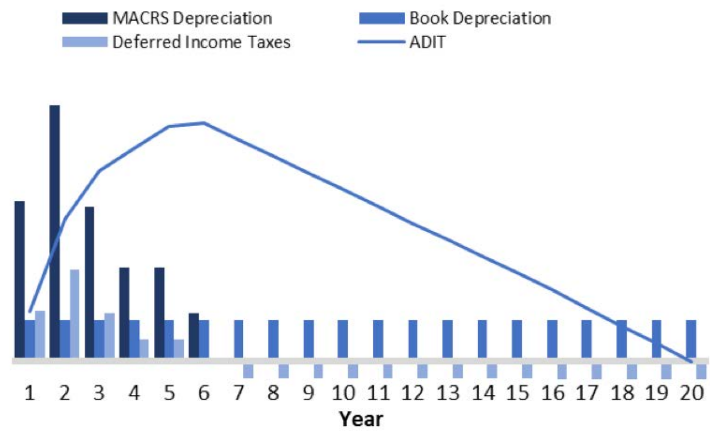


FIGURE 5. ADIT PROFILE

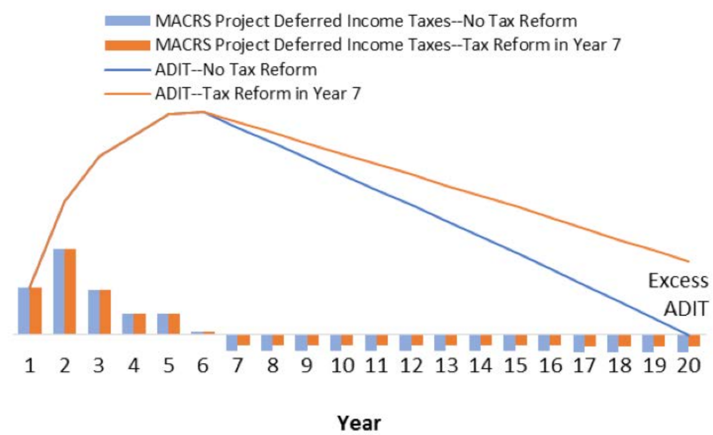


FIGURE 6. IMPACT OF TAX REFORM ON ADIT

While this is a promising near-term opportunity, **repurposing of excess collections is not a reliable long-term solution to refinancing uneconomic assets.** Opportunities associated with excess collections, such as federal tax reform, are unlikely to recur with any significant frequency.

5. RATEPAYER-BACKED BOND SECURITIZATION

Challenges associated with stranded assets due to electric generation transformation are not new—nor are the potential solutions. The falling cost of gas and advances in efficient combined-cycle gas generation technologies in the 1990s created an upswelling of support for breaking up electric generation monopolies to allow for rapid deployment of these cost-saving generators.

In states that opted for full competitive energy markets (in particular the states within PJM, New York, New England, Texas, and California), utilities were restructured—compelled to separate generation from transmission and distribution services. Investor-owned vertically-integrated utilities faced a similar challenge to today: the book value of generation facilities was often higher than the market cost, meaning that a utility could not recoup its historic investments when selling a generation asset. Utilities subsequently realized substantial stranded asset value. As a result, the regulatory and legislative process implementing restructuring in 21 states allowed for the use of a new financing mechanism—ratepayer-backed bond securitization—that provided utilities compensation for this stranded value.

WHAT IS SECURITIZATION?

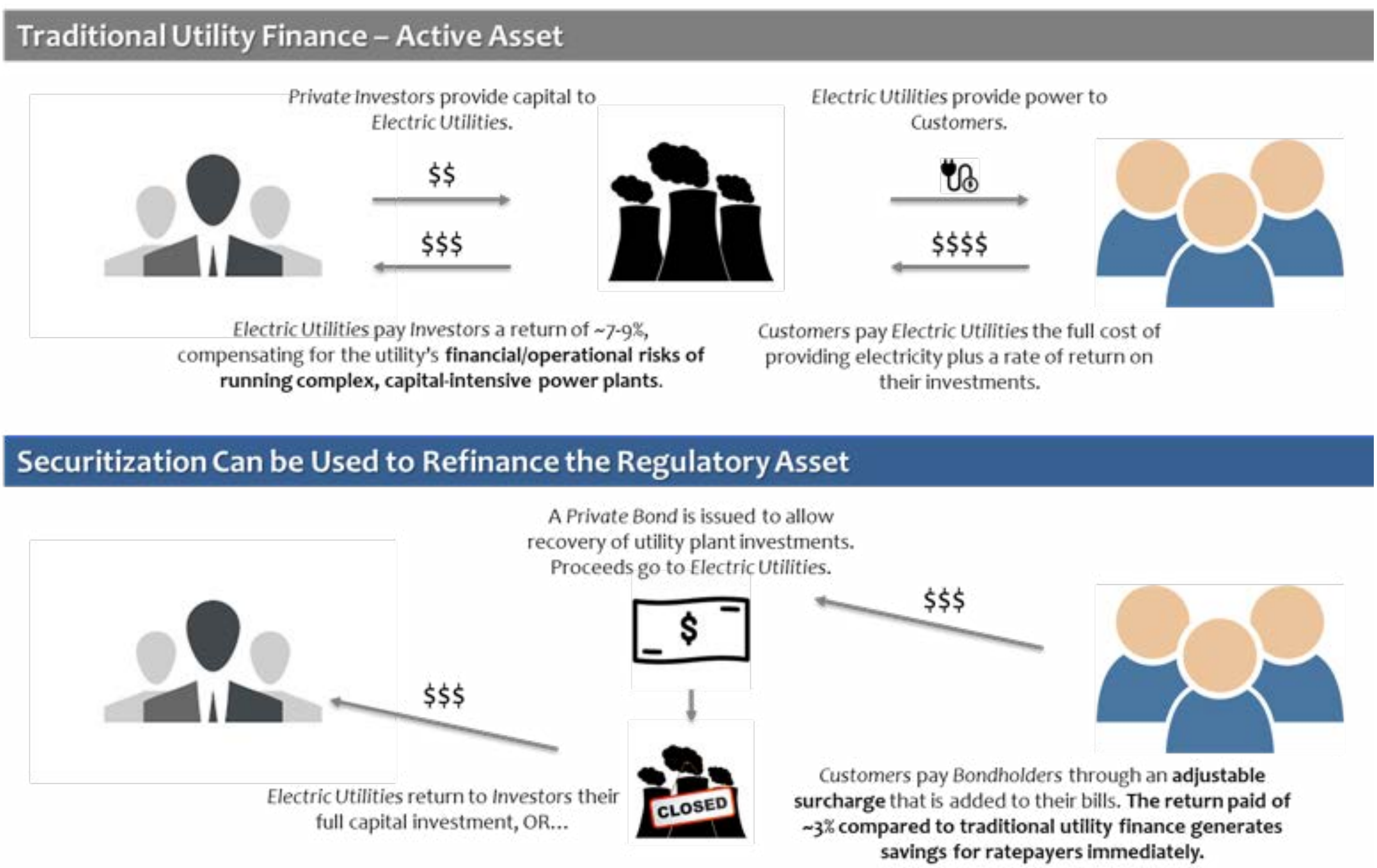
In a broader financial context, securitization is a financing mechanism that pools assets which are expected to generate future revenues and sells them as a private (i.e. not governmental) debt security. A financial institution can achieve very low interest rates on that debt when there is high confidence in future revenues—under four percent (4%) in the current yield environment. "Ratepayer-backed bond securitization" is the securitization of a stream of expected future ratepayer revenues. Securitization is an alternative way for ratepayers to directly raise low-cost debt to address near-term financing needs, cutting out utility's traditional financing role as the middleman between ratepayers and investors.

Securitization in the context of the energy transition is the opportunity to "make whole" (i.e. return the capital) the utility owners of non-economic generation, while also minimizing ratepayer impacts. In other words, the utility can ensure that it gets back the stranded asset value of non-economic fossil plants, without imposing higher rates on consumers. Used as part of a comprehensive transition package, securitization can free up funds for clean energy projects while keeping utilities financially viable and reducing ratepayer costs.

In this model, rather than ratepayers paying the utility the revenues required to raise capital from its investors to finance a given project, ratepayers raise the funds directly by issuing a bond to debt investors. Effectively, the ratepayers buy out the utility's debt on a non-economic asset. In normal circumstances, a utility would seek to raise its own funds to be able to build, service, and operate an asset. The utility's cost of capital, however, is relatively high. In ratepayer-backed securitization, the funds are raised through a bond issuance at a far lower rate. In addition, because the securitization mechanism operates through the ratepayers rather than the utility, the funds can also be directed towards assisting workers and communities negatively impacted by early plant retirement.

One critical component of ratepayer-backed bond securitization is that the payment on the bond must be collected from ratepayers, and must be non-bypassable—i.e. there must be zero risk that future ratepayers will not pay the bond. Such guarantees ensure a high bond rating, and low financing costs. This type of irrevocable charge typically requires enabling state legislation, as discussed below.

The graphic below provides an illustration of traditional utility finance and the securitization mechanism. Under



traditional finance, the customers pay electric utilities the full cost of providing service plus a rate of return on investments, which in turn are passed to private investors. In the ratepayer-backed securitization mechanism, the utility is authorized to issue a bond on behalf of ratepayers (through a special purpose vehicle), and the bond is used to cover the utility's stranded asset losses. In turn, the customers pay the bondholders through a bill surcharge, but at a lower overall cost than paying the utility directly.

ENABLING LEGISLATION

For a securitization to yield the lowest-possible cost of debt, state legislation is usually required that empowers regulators to:

1. Create predictable revenue streams for securitization via dedicated and non-bypassable ratepayer charges that are automatically adjusted in a timely fashion to make principal and interest payments to bond investors;
2. Create a special purpose vehicle (SPV) we refer to as "the securitization company" that is "bankruptcy remote" from the utility,[23] owns the future ratepayer charges, issues the securitization bond, and repays the bond with the proceeds from those charges,
3. Ensure that the collections from the ratepayer charge are the property of the securitization company under a "true sale;" and
4. Pledge not to alter this arrangement for as long as the bonds are outstanding.

Once a securitization mechanism is enabled and approved, the utility continues to play a role by collecting the ratepayer charge on its bills and transferring the proceeds monthly to the securitization company. To be clear, investors of a ratepayer-backed security are purchasing a claim on dedicated future ratepayer charges—and *not* a claim on any past, current, or future physical assets. Therefore, the securitized debt is *not* subject to any risks associated with the prudency of any previous or future utility investments or decisions. Those risks instead remain with the utility and its shareholders. If a future disallowance imperiled the financial viability of the utility, the ratepayer charges dedicated to securitization would not be available to satisfy the utility's creditors.

Securitization is not a municipal or state-backed bond. It does not rely on the bonding authority of any government entity, nor does it rely on any government funding or assistance.

Twenty-one states have legislation in place permitting securitization of utility assets, but most are states where prior restructuring required vertically-integrated utilities to sell generation assets. There are relatively few states where vertically-integrated utilities have access to existing securitization legislation, although a number are actively considering such legislation.

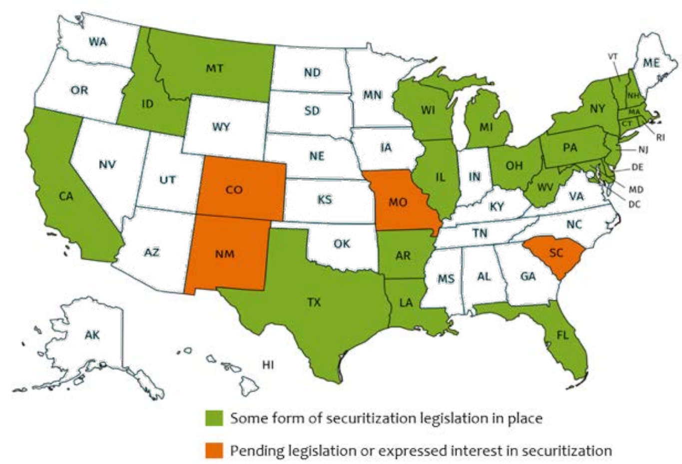


FIGURE 8. STATES WITH SECURITIZATION

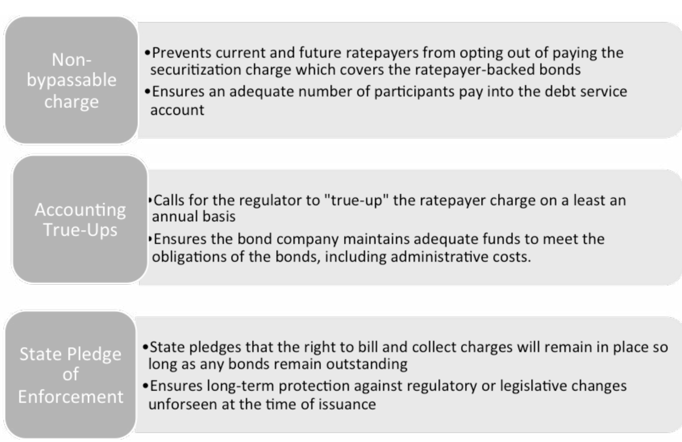


FIGURE 7. LEGISLATIVE REQUIREMENTS FOR RATEPAYER BACKED SECURITIZATION

THE SECURITIZATION PROCESS

In the securitization process, the utility files an application with the utility regulator to use securitization, and a financing docket is opened. If the application is approved, a financing order is issued which approves the true sale of the asset to the securitization company, the issuance of the bond, and the ratepayer charge. Then, each month a charge is included on ratepayers' bills. These funds are sent to the securitization SPV to make required payments to bondholders. These charges are subject to a true-up to ensure that they are adequate to satisfy bondholders. Once obligations to the bondholders are met, the line item is removed from customer bills and obligations to the SPV end.

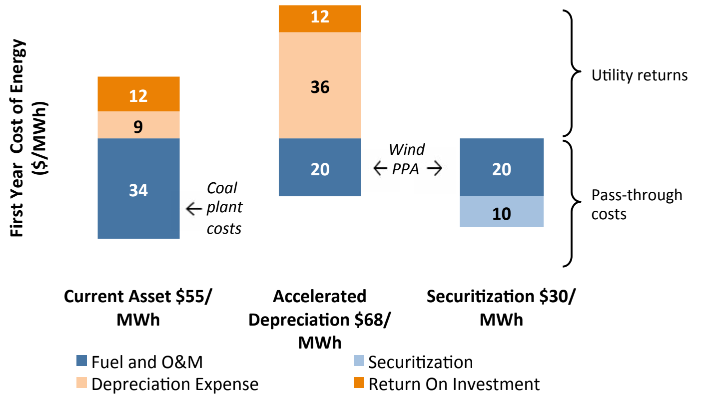


FIGURE 9. COMPLETE SECURITZATION PROCESS

RECENT UTILITY SECURITIZATION EFFORTS

Securitizations, in principle, can be used to finance any number of activities deemed by regulators to be in the interest of ratepayers. However, the legislative vehicle used to authorize the use of securitization will generally constrain the possible uses of the proceeds from securitization.

In recent years, securitization has been employed by:

- Duke Energy (FL) to finance $1.3 billion in assets of a closed nuclear plant in Florida. The bond interest rate is 2.72%, much lower than Duke's cost of capital. Duke calculates the deal saves customers $700 million over 20 years.
- Allegheny Energy (WV) used ratepayer-backed bonds to finance $460 million of pollution control upgrades. The bond was rated Aaa by Moody's, the agency's highest rating.
- Consumers Energy (MI) received PSC approval to sell $389.6 million in securitization bonds to capture the unrecovered net book value of 950 MW of coal-fired capacity retired in 2016.

MITIGATING RATEPAYER IMPACTS WITH SECURITIZATION

Securitization offers the opportunity to mitigate the rate shock of accelerated depreciation, harness lower cost clean energy projects, and reduce ratepayer costs.

Returning to our example early retirement plant: suppose that the utility files an application with its regulator to retire the plant now, and use securitization to address the $433 million in stranded investments. If the regulator approves the application, it would issue a financing order creating a ratepayer charge (in this case, over 20 years), and a bond would be issued to be repaid with those charges. In our example case, the plant also faces $58 million in near-term decommissioning costs, which are included in the bond. Because our example enabling legislation allows us to tap this low cost financing for other related costs, we also include a community transition fund. In this example, we assume that 15% of the savings from securitization, or $25 million, are channeled to addressing community and worker transition challenges. All told, the bond issuance is assumed to be sized at $515 million to cover all these needs.

So how does this hypothetical use of securitization address the rate shock for ratepayers? Figure 10 shows that securitization eliminates the immediate rate shock from accelerated amortization of a regulatory asset. In the accelerated depreciation case, ratepayers saw an overall first year rate increase, even though they replaced a high cost coal plant ($34/MWh) with a low cost wind PPA ($20/MWh). Annual depreciation expense increased to $36/MWh, increasing customer costs. In the securitization case, consumers still tap the lower cost wind PPA, but replace the depreciation and return on investment with a securitization charge ($10/MWh), drastically reducing the rate impact.

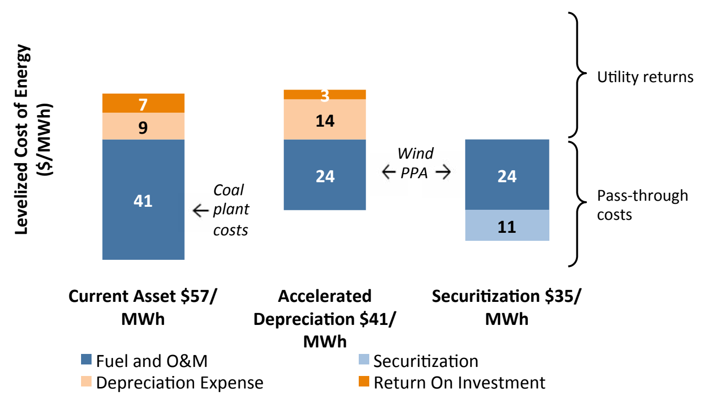


FIGURE 10. REVE REQ FOR EXAMPLE PLANT, BAU, ACCEL. DEP. AND SECURITIZATION (FIRST YEAR)

Over the long run, consumers remain better off in this example. Figure 11 shows the levelized[24] cost of energy for the asset and its replacement over a twenty-year period. Over the long run, accelerating depreciation and replacing a non-economic generating unit reduces ratepayer costs (from $57/MWh to $41/MWh). Securitization achieves the same end at a lower cost ($35/MWh). The levelized securitization charge in the third column ($11/MWh) replaces the existing unit's levelized depreciation ($9/MWh) and return ($7/MWh) expenses in the first column.

UTILITY EARNINGS IMPACTS FROM SECURITIZATION

Savings from securitization are largely achieved by eliminating the capital charges that cover utility return of and return on capital (represented in Figure 10, above, in the bars above the dividing line). In securitization, the utility gets all its outstanding capital back immediately, so the return of its

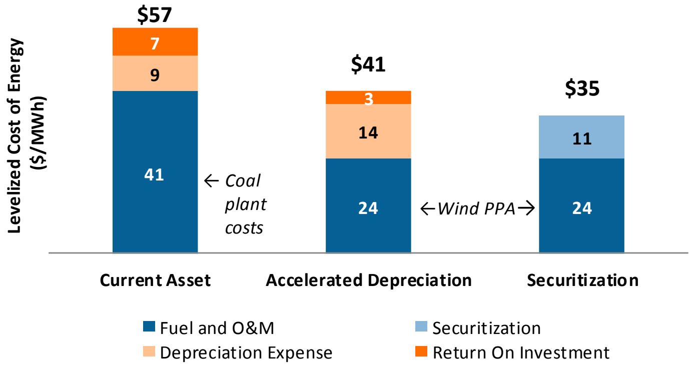


FIGURE 11. REVE REQ FOR EXAMPLE PLANT, BAU, ACCEL. DEP. AND SECURITIZATION (LEVELIZED COST)

capital is satisfied. However, the utility's earnings are largely dependent on its return on capital, which falls substantially.[25] Indeed, on a net present value basis (as shown in the utility earnings summary graph below), future utility earnings from securitization alone for the utility fall by over $4/MWh relative to earnings from continued operation of our example coal plant, and $2-3/MWh relative to the use of a regulatory asset via traditional utility financing.

This erosion in future earnings for the utility makes it highly unlikely that a utility would chose to securitize stranded asset balances on its own volition—unless there were other pressing issues or opportunities that could drive the utility to use this tool. One such pressing issue might be a challenge to the financial viability of the utility in the absence of mechanism for rapid recovery of stranded costs, or risk of disallowance for assets no longer considered economically viable. However, regulated utilities are buffered from this risk, in part, by regulators reluctant to risk the financial viability of utilities, or the resultant higher cost of capital. Few regulated utilities face near-term financial distress.

Therefore, securitization alone may not garner significant

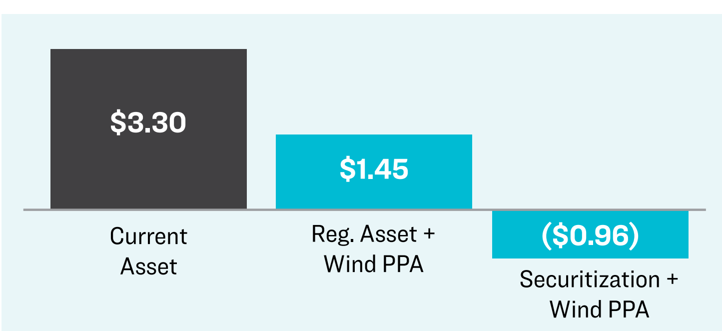


FIGURE 12. EXAMPLE OF UTILITY EARNINGS (NET PRESENT VALUE) WITH SECURITIZATION FOR STRANDED ASSETS AND A POWER PURCHASE AGREEMENT FOR REPLACEMENT POWER

interest from utilities. However, combining the release of capital funds through securitization with re-investment in low cost renewable energy, combined with attractive production tax credits offers an attractive, near term opportunity.

FUNDING COMMUNITY TRANSITION THROUGH SECURITIZATION

Thanks to a lower cost of capital and an extended repayment period, securitization generates savings on a net present value for ratepayers. While the value of savings are transaction-specific, we estimate that, on average, every $100 million in coal plant retired through securitization can unlock around $60 million in avoided capital costs. These savings can either be returned to consumers, or can be used for transition assistance for workers and communities adversely affected by plant retirements, or both.

Securitization can be structured in such a way that savings can be shared with workers and communities impacted by the plants' closure. For example, if 15% of the savings from securitization were set aside for transition assistance, on average, for every $100 million in net plant balances, on average $6 million could go to impacted workers or communities. The amount of transition assistance made available from securitization increases with the net plant balance and remaining life of the asset, so this approach can provide transition resources that are automatically scaled to the size of the shock that a given community faces from early retirement. This type of transition assistance can be substantial: in our example plant, harnessing $25 million towards transition assistance could provide the equivalent of a two-thirds salary for five years for over ninety employees.[26]

SECURITIZATION AND CREDIT RATINGS

For accounting purposes, utilities may consolidate the securitization bonds as long-term debt on balance sheet; under Internal Revenue Service Revenue Procedure 2002-4911 (Rev. Proc.02-49), this is necessary to avoid immediate recognition of income from the securitization of future ratepayer charges.[27] The increased debt load adversely impacts various metrics used by credit rating agencies to grade a utility's creditworthiness, including:

- Cash Flow from Operating Activities ("CFO") pre-Working Capital + Interest / Interest;
- CFO pre-Working Capital / Debt;
- CFO pre-Working Capital Minus Dividends / Debt; and
- Debt/Capitalization

On net, though, securitizations tend to be credit rating positive, because rating agencies treat the securitized debt as an obligation of the SPV,[28] and because securitization completely eliminates the risk of disallowance or incomplete recovery of a stranded asset.

6. FINANCIAL TOOL: SECURITIZATION + CAPITAL RECYCLING

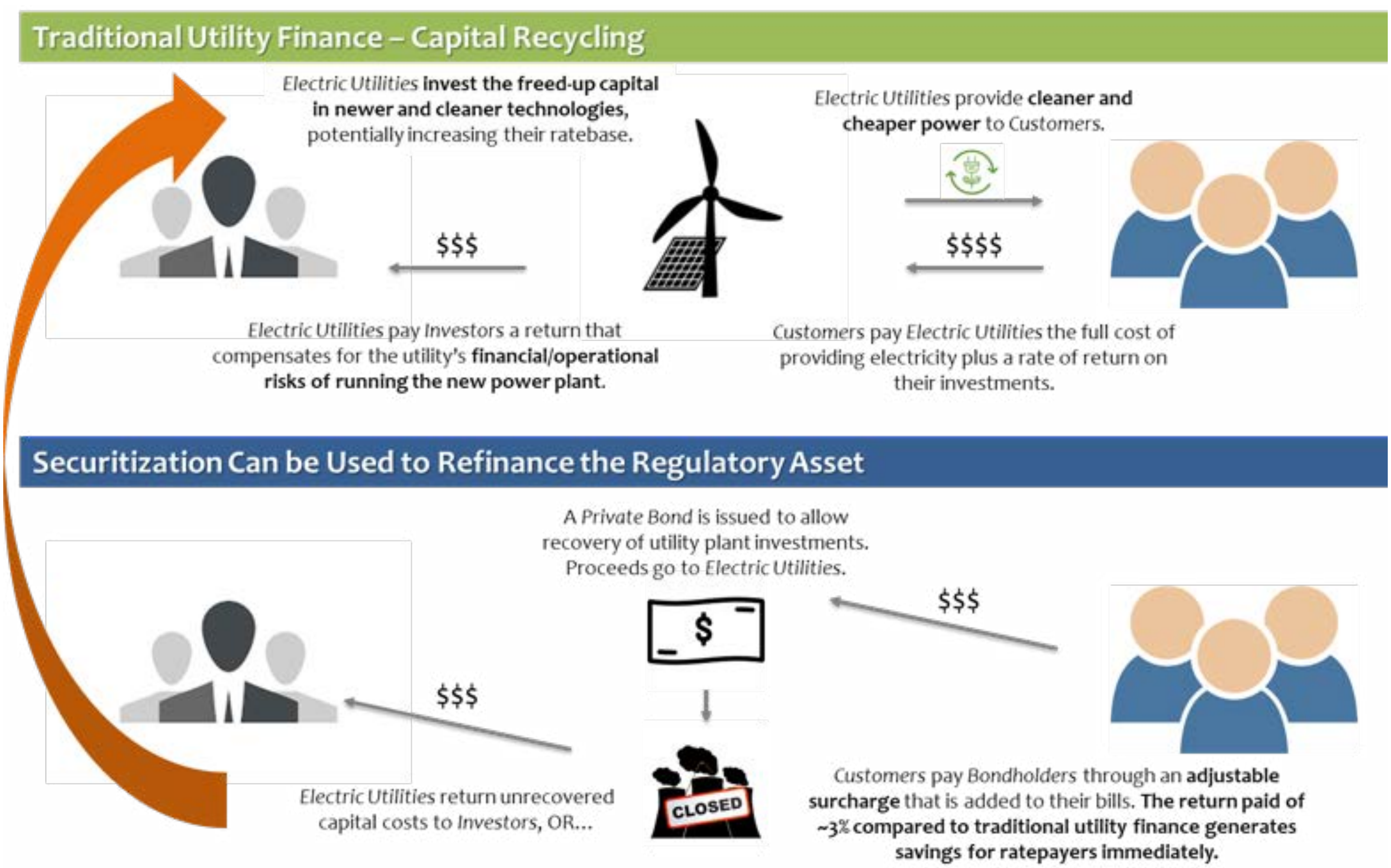
By definition, shuttering an uneconomic coal plant and replacing its marginal costs with a cheaper all-in PPA will provide benefits to ratepayers beyond the refinancing savings achieved through securitization. PPAs, however, are pass-through costs that do not provide profits to shareholders.

Better outcomes for shareholders—and ratepayers—are possible when a utility recycles bond proceeds into renewable assets on its balance sheet: a fuel-for-steel swap.

Renewable generation is far more capital intensive than fossil plants capable of equal output, but requires far less annual expense for fuel and operations. When we compare new renewable projects to substantially depreciated fossil plants, the potential to increase capital return is substantial. As discussed earlier, utility earnings are essentially the risk-adjusted return on the equity fraction of capital in rate base; therefore, deploying capital is generally a profit-enhancing strategy. A utility that is able to offer renewable energy and storage in place of existing fossil generation redirects dollars from pass-through fuel purchases towards capital projects. This swap aligns utility and ratepayer interests: ratepayers see lower energy costs, while utilities increase earnings potentials. In some cases, utilities may also be able to acquire lower cost financing than independent producers.

The expected phase-out of federal tax incentives for renewable energy justifies urgency in laying the foundations for securitization and subsequent capital recycling.

The graphic below provides a summary of how capital recycling can be paired with securitization. As before, the regulatory asset is refinanced through the ratepayer-backed securitization bond. However, in this case, the utility explicitly redeploys the recovered capital from the early retirement of uneconomic assets, and use the proceeds to finance the deployment of clean, cheap replacement power.



The replacement power is now placed in rate base, providing the opportunity for a return, while still meeting ratepayer needs.

Returning to our plant securitization example, we can demonstrate the impacts of capital recycling on utility earnings and ratepayers. Instead of procuring replacement generation through a 20-year PPA with a wind developer, this example allows the utility to own the wind asset as a cost-of-service regulated asset in rate base—a direct use of the dollars recovered through securitization.

In this example, we assume that a new $870 million wind asset is financed entirely through traditional utility financing mechanisms, and that it earns a return equal to the allowed rate of return for the utility. Due to early retirement and securitization, the utility lost $433 million in its rate base, and lost the associated future earnings. However, it recovered $433 million in cash from the proceeds of the securitization bond issuance.[29] The utility is able to turn around that capital to finance the new wind asset, effectively "recycling" its capital from the older fossil asset into a new, clean asset—and more. That is, the utility has been able to grow its rate base from $433 million to $870 million, an increase of $437 million using securitization and capital recycling. In this transaction, ratepayers realize substantial savings and the utility grows earnings, making a "fuel for steel" substitution (i.e. replacing high cost fuel-intensive resources with more capital intensive clean energy projects).

As shown in Figure 13, below, the pass-through costs associated with the wind PPA in the third column[30] is, in this case, replaced with the capital and operating costs for utility-owned wind in the fourth column. Relative to purchased power, this results in additional ratepayer savings both in the first year and over the long-term due to improved rate-of-return project financing.

This example assumes that the utility procures wind to own and operate at costs (i.e., capital and operating expenses) comparable to that of independent generators, but at a more attractive cost of capital. In this example, the securitization plus capital recycling option is also a least-cost option for ratepayers. In total, we transition from a first-year "business as usual" ratepayer cost of $55/MWh, largely driven by fuel and operational costs, to a securitization with capital recycling utility-owned wind at $24/MWh. In the later scenario, about half the revenue requirement is driven by the securitization bond, and the remainder is largely capital invested by the utility to meet customer needs.

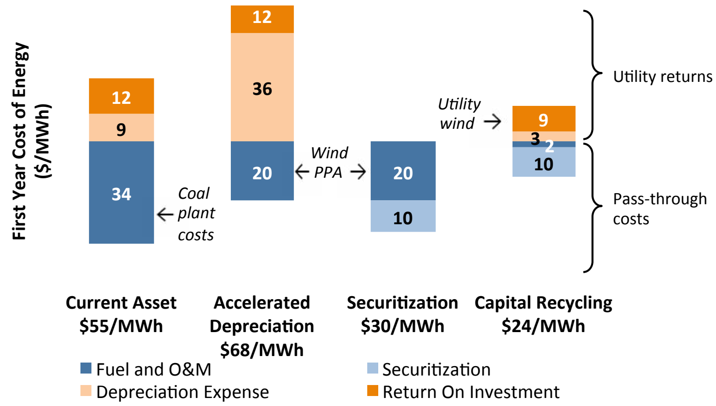


FIGURE 13. REVENUE REQUIREMENT FOR EXAMPLE PLANT UNDER BAU, ACCELERATED DEPRECIATION, SECURITIZATION, AND SECURITIZATION PLUS CAPITAL RECYCLING (FIRST YEAR)

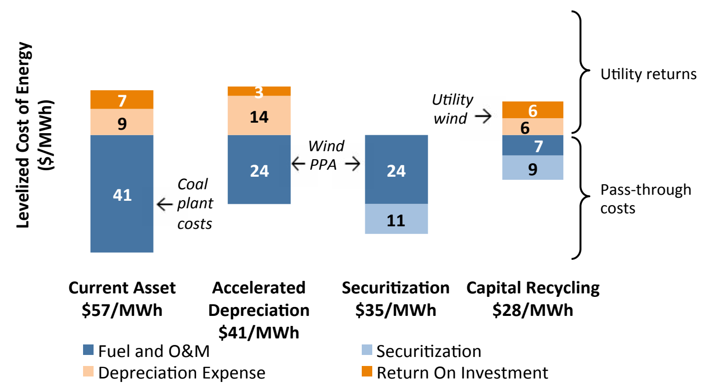


FIGURE 14: REVENUE REQUIREMENT FOR EXAMPLE PLANT UNDER BAU, ACCELERATED DEPRECIATION, SECURITIZATION, AND SECURITIZATION PLUS CAPITAL RECYCLING (LEVELIZED COST)

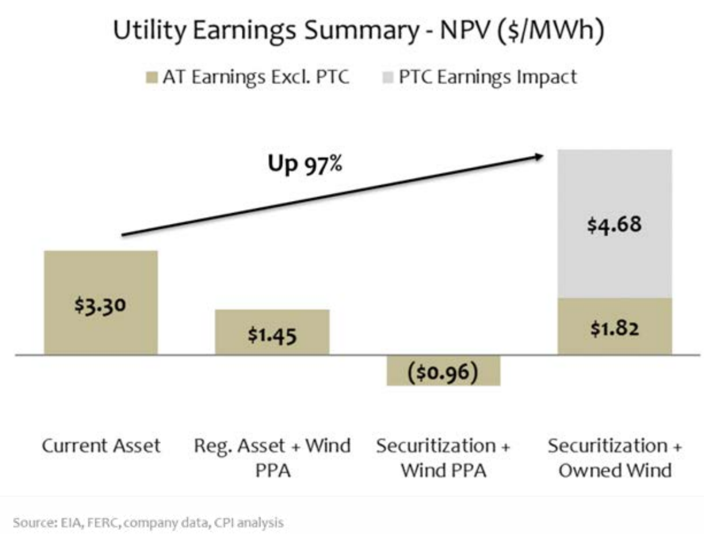


FIGURE 15. EXAMPLE OF UTILITY EARNINGS WITH SECURITIZATION FOR STRANDED ASSETS AND SELF-BUILT WIND FOR REPLACEMENT POWER. NET PRESENT VALUE ($/MWH) (AT = AFTER TAX)

This alternative financing scenario is particularly attractive in early years, but its benefits extend through the life of the instrument. As shown in Figure 14, the long-run costs of this scenario are, on net, about half of the costs of the business-as-usual scenario.

Recalling that the wind project is nearly $900 million, while our undepreciated plant was only $400 million, how do we yield these substantially lower ratepayer costs? Several factors are at play. First, the near zero marginal cost of wind avoids the substantial fuel expense of the current asset. Second, securitization shrinks the impact of the remaining capital balance at the fossil plant. And finally, the federal production tax credit ("PTC") in effect subsidizes consumers by lowering the revenue requirement.

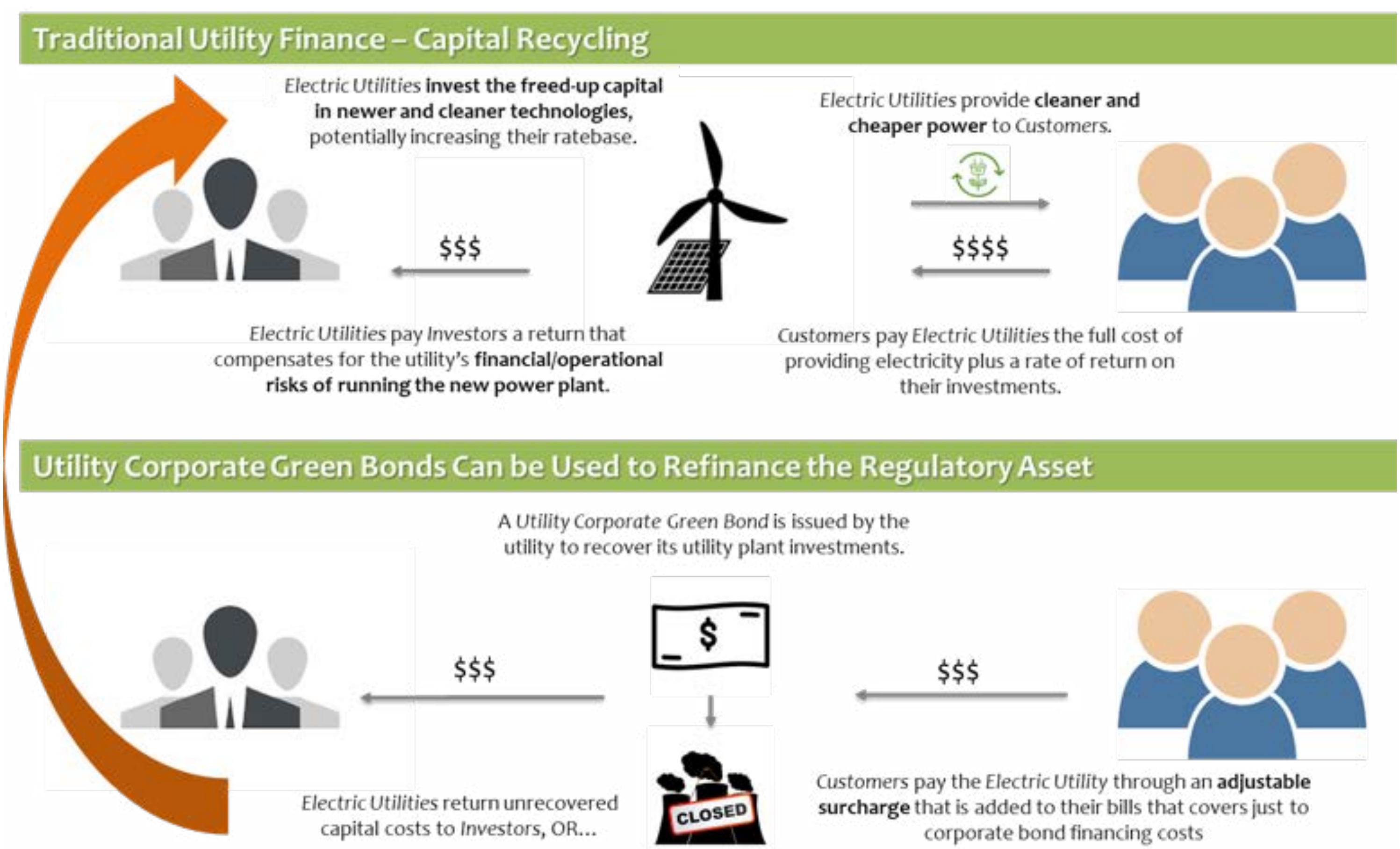
The PTC, when used by a utility to self-build wind, also provides utility earnings. Figure 15 reveals that, on an after-tax basis, Securitization + Owned Wind delivers the largest earning of all the scenarios, a total of $6.46/MWh on an NPV basis over 30 years, with more than 70% coming from ten years of monetization of the PTC.[31]

7. GREEN BONDS AND TARIFFS

One set of emerging financial tools available to utilities to lower the cost of retiring uneconomic coal plants is through green bonds and green tariffs. In both cases, the utility uses standard financial mechanisms linked to environmental attributes which may in turn attract lower cost financing. Neither of these mechanisms have a substantial history, but represent a new wave of harnessing finance to transform the energy sector.

RETIREMENT-LINKED GREEN BONDS

A green bond is a standard bond imbued with a specific environmental characteristic, for example a commitment to reduce emissions or other toxic pollutants to a verifiable extent. For example, a green bond issued for a wind project may carry a specific expectation to displace a certain tonnage of carbon dioxide emissions.[32] These bonds are potentially attractive to investors or corporate buyers with sustainability commitments. A green bond issued to support the retirement of a coal plant could effectively guarantee avoided coal-based emissions on par with either recent historic emissions or reasonably expected going-forward emissions. Investors looking to quantify investments in sustainable bonds, or looking to offset specific emissions



could find verifiable emissions reductions in a coal retirement bond.

In execution, a green retirement bond is similar to securitization, without the sale of assets or legislative protection on the ratepayer charge. The utility issues a bond to refinance the remaining asset balance on an uneconomic plant, plus any funds needed for transition assistance or physical dismantling of the plant net of any salvage value. The utility would still have to request regulatory relief to allow the bond to be paid through a ratepayer surcharge. Unlike securitization, however, the utility issues the bond, rather than the special purpose vehicle. As a result, the bond is not bankruptcy remote and is not immutable: future commissions could hypothetically reverse course on such a bond (an outcome precluded by legislation in securitization).

Because the green bond represents a utility debt, the price of the green bond is fundamentally determined by the credit rating of the utility. While a securitization bond retains guaranteed ratepayer recovery through legislation, a green bond does not, and will likely incur a lower credit rating and higher debt costs than securitization.

The utility would replace the old capacity with a new utility-owned facility, assuming wind for accounting purposes in this case. The replacement capacity would then be financed, in part, with the proceeds from the green retirement bond, minus amounts allocated for transition assistance and physical dismantling. The utility would raise the additional capital needed for the wind asset with further green bonds and stock issuance in line with the regulator-approved capital structure (e.g., 50% debt, 50% equity).

From a ratepayer perspective, the outcome is a net reduction in rates relative to accelerated depreciation or a regulatory asset, as the cost of debt is likely lower than the utility's cost of capital. However, in terms of leverage, the company has swapped out the equity component of the retired asset for low-cost debt and also borrowed additional funds to cover dismantling costs net of salvage and transition assistance. Thus, the overall capital structure will now reflect a higher fraction of debt than the regulator-approved structure. Credit metrics are affected, while none of the obligations or the cash flows for their repayment are bankruptcy remote. Accordingly, rating agencies are likely to treat green bonds as credit negative for the utility.

RETIREMENT-LINKED GREEN BONDS WITH CAPITAL RECYCLING

Pairing a green bond with capital recycling at our example coal plant results in a ratepayer cost approximately $1/MWh higher than securitization, both in the first year and over the levelized cost of energy. . In exchange, the utility, and its ratepayers, need not await the passage of securitization legislation where it is currently unavailable. Unless the approved rate of return changes, utility profits should be essentially unchanged when compared with the securitization approach.

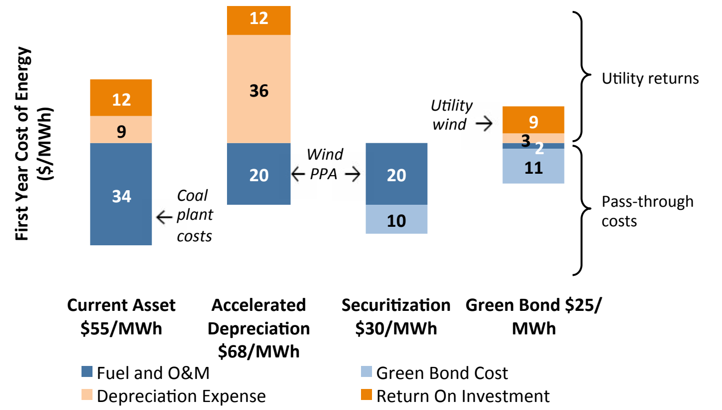


FIGURE 16: REVENUE REQUIREMENT FOR EXAMPLE PLANT UNDER BAU, ACCELERATED DEPRECIATION, SECURITIZATION, AND A GREEN BOND (FIRST YEAR)

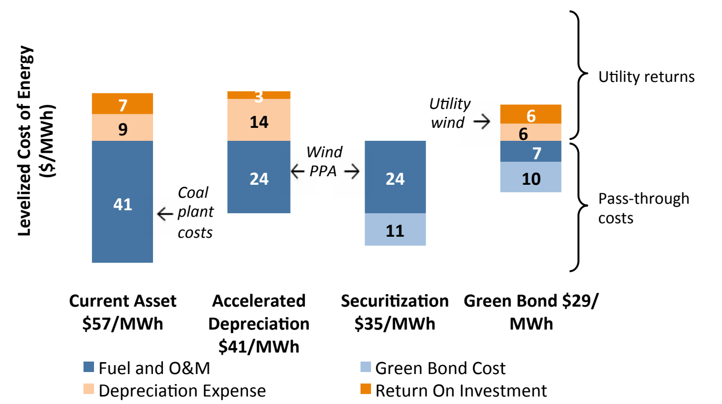


FIGURE 17: REVENUE REQUIREMENT FOR EXAMPLE PLANT UNDER BAU, ACCELERATED DEPRECIATION, SECURITIZATION, AND A GREEN BOND (LEVELIZED)

RETIREMENT-LINKED GREEN TARIFFS

A green tariff is a mechanism of creating a specialized rate class or energy delivery option for certain large corporate buyers, where the energy procured for and sold to those buyers has specific green characteristics. For instance, large corporate procurers may have self-imposed renewable energy targets that they cannot meet solely with onsite production or through direct purchase. How, and even if, they can satisfy these targets depends heavily on the structure of the markets in which they operate. Certain of these buyers may employ green tariffs, or purchasing specified green energy options directly from their utility suppliers through separate rate structures, usually authorized by the utility regulators.

In states with full retail choice, corporate (and individual) buyers can usually contract directly with renewables developers to purchase energy. However, in some states, retail choice is limited or non-existent, in which case corporate buyers may have to work directly with their regulated utilities to create tailored energy programs.

Green tariffs can enable cost-of-service utilities to deliver renewable energy to customers who may not otherwise be able to access products which satisfy their sustainability goals and cost predictability. Green tariffs take a number of forms, from “green choice” programs to specific rate structures where utilities negotiate and procure renewable energy on behalf of certain customers, and act as the delivery mechanism for that energy.[33] In some cases, green tariff customers pay certain fees to the utility to ensure that other customers are not exposed to higher rates.

In a retirement-focused green tariff, a large corporate buyer could hypothetically acquire a right to energy that specifically replaces a retiring asset. In doing so, the green tariff buyer would support the refinancing of the retired asset (i.e. help pay down the stranded asset cost) and yield the benefits of the low cost and/or potentially tax-advantaged renewable energy which replaces it. While specific green tariffs focused on retirement have not yet been widely introduced, we might term these to have “subtractionality” benefits.[34] Like green bonds, holders of green tariffs can unequivocally demonstrate emissions benefits linked to their actions.

In its purest variant, a green tariff structure combined with the retirement of an uneconomic asset using green bonds would provide corporate buyers with direct access to all the costs, benefits, and risks of a capital recycling strategy:

The green tariff would include the obligation to satisfy the retirement bond as well as the financing, integration, and O&M costs of the replacement generation.

In terms of benefits, participating customers would receive clean energy—and in all likelihood, along with the associated Renewable Energy Certificates (RECs)—at a lower cost than they had previously paid for uneconomic coal generation. Exposure to the capital costs of the retired asset would decline thanks to the replacement of rate of return financing with lower-cost, all debt green bond financing.

Green tariff customers would bear construction and operational risk related to the new assets, and they would also be expected to cover integration costs.

Green tariffs have their own share of challenges, including questions of equity and impact on non-participants. Once a green tariff customer exits, the remaining traditional “brown tariff” customers continue to pay for existing assets, and may not realize the same benefits – or any of the benefits – of the green tariff. Tariffs must be carefully designed to ensure that non-participants are not harmed by the actions of the corporate buyers of the green tariff, including any potential impacts on remaining system costs.

Green tariffs may require an “exit fee” to help the utility offset the costs of generation or power purchase agreements incurred prior to the exit of the corporate buyers (i.e. other stranded assets). Alternatively, some green tariffs are structured such that there is no exit fee, but the choice to acquire energy through alternative means is irreversible.

In light of equity concerns, regulators might object to a green tariff that narrowly channels to participants the full suite of benefits. Instead, green tariff customers and utilities may want to create a solution set where green tariff customers receive environmental or emissions benefits (and the subsequent right to claim a clean energy portfolio or “subtractionality”) while sharing the other system benefits—such as lower generation costs—with all ratepayers. Such a solution at worst causes no harm, and at best produces a lower cost of production.

As noted before, securitization and green bonds share a common feature in a separate ratepayer charge to pay back the bond. Because of the dedicated charge and/or the environmental attributes of the bond, respectively, the utility can command a lower rate than traditional regulated return leading to ratepayer savings. In contrast, a green tariff provides the utility the opportunity to solicit private financing from corporate buyers in helping the utility shed non-economic existing units.

Tariff	Securitization / Green Bond – No Green Tariff	Green Tariff with Exit Fees	Permanent Green Tariff
Type	Mandatory Charge	Opt-in	Opt-in
Securitization / Green Bond Charge	Paid by all customers	Paid only by green tariff customers	Paid only by green tariff customers
Exit Fees	None	Yes	No
Lock-In Period	Securitization / Green Bond Tenor (15-20 yrs)	None	No option to revert to prior tariff
Generation Costs Included in Tariff	All generation costs	Replacement clean generation costs + integration costs	Replacement clean generation costs + integration costs
Distribution of RECs	All customers	Green Tariff Customers	Green Tariff Customers
Transition Assistance Bond Repayment	All customers	Green Tariff Customers	Green Tariff Customers

FIGURE 18. COMPARING SECURITIZATION AND GREEN BONDS

8. IN CLOSING

The electric sector in the United States is in a state of nearly unprecedented change. While the electric sector has seen a number of rapid expansions, the emergence of new fuel choices, and the dramatic effects of restructuring, there has not been another period where so much of the existing fleet has been economically challenged from persistently low power prices, flat demand, and the emergence of new low cost energy sources.

Until recently, utilities and regulators have sought to navigate plant closures on a boutique basis, assessing the merits of each plant closure in meticulous detail, and optimizing for the closure of smaller, less efficient power plants. In the interim, the economics of coal have continued to decline dramatically and today's coal-owning traditionally regulated utilities face increasingly difficult questions: how to approach regulators and ratepayers with proposals to close without incurring rate spikes—and while supporting the communities that have grown up around these massive generating stations. Utilities are often loath to broach this question, particularly without significant capital triggers. In part, that hesitation extends from the concern that regulators or ratepayers will seek to disallow costs, leaving utility owners impaired. Regulators find themselves in a stalemate: seek to retire non-economic assets and incur credit risk, or allow non-economic assets to continue operating and punt until another opportunity is availed?

The financial sector may offer a unique opportunity to ease this transition and break the stalemate. Harnessing an assortment of financing tools, from tax incentives to securitization and green tariffs, the sector offers mechanisms to support the utility business model while protecting ratepayers and affected communities.

Ratepayers, utilities, regulators, and financial institutions can work to find creative tools to finance the transition, leading to both stronger corporate utilities, more engaged ratepayers and regulators, and better environmental outcomes.

ENDNOTES

1. Lazard's Levelized Cost of Energy Analysis 11.0. Note: Does not include federal tax incentives. With the federal tax incentives in place wind and solar are both lower cost than other generation options.
2. U.S. Energy Information Administration. Form 860, March 2018.
3. Rocky Mountain Institute, May 2018. The Economics of Clean Energy Portfolios. https://rmi.org/insight/the-economics-of-clean-energy-portfolios/.
4. Carbon Tracker Initiative. September 2017. No Country for Coal Gen. https://www.carbontracker.org/reports/no-country-for-coal-gen-below-2c-and-regulatory-risk-for-us-coal-power-owners/.
5. Intergovernmental Panel on Climate Change. October 2018. Global Warming of 1.5 °C: An IPCC Special Report. http://www.ipcc.ch/report/sr15/.
6. Bloomberg New Energy Finance. March 2017. Half of U.S. Coal Capacity on Shaky Economic Footing. https://www.bloomberg.com/news/articles/2018-03-26/half-of-all-u-s-coal-plants-would-lose-money-without-regulation.
7. "Merchant" owner means that an owner is not subject to cost-of-service regulation by a state utilities commission, and instead relies on market revenues for energy, capacity, and/or ancillary services.
8. "Regulated" owners are owners subject to cost-of-service regulation by a state utilities commission, wherein costs are recovered through rate case proceedings. Regulated utilities operating in a centralized market region still effectively have their costs covered, in full, by ratepayers.
9. Stranded asset value is the difference between the market value and the remaining capital, or plant balance, yet to be recovered by the utility from ratepayers.
10. Carbon Tracker Initiative. September 2017. No Country for Coal Gen.
11. In states with retail competition, generators and transmission lines are usually privately owned. In those states, the cost-of-service model is still used for the regulation of distribution assets.
12. The utility may have reasons to favor some O&M expense—for example, if they pay for goods or services sourced by a related entity such as a sister company, or if they pay for services provided by company workers. On the other hand, they also have reasons to avoid these expenses, particularly if they could crowd out capital expenditures that could otherwise increase their earnings per share.
13. In this example, replacement energy is purchased under a long-term power-purchase agreement (PPA) and the $433 million outstanding balance is placed into a regulatory asset with an amortization period of 5 years. As an outcome, ratepayers would see an increase for the cost of that procured energy in the first year from $55/MWh to $68/MWh. This type of impact would occur over the five year period.
14. https://www.colorado.gov/pacific/sites/default/files/2017%20Brochure.pdf.
15. See, for example, http://www.synapse-energy.com/project/renewable-energy-integration-costs
16. Such signaling adjustments may reflect a regulators response to poor management decisions or actions, or recognition of positive performance.
17. Moody's "investment grade" scale ranges from Aaa ("highest quality, with minimal risk") to Baa ("subject to moderate credit risk"). Non-investment grade debt ranges from Ba1 ("speculative elements and subject to substantial risk") to C ("poor standing" to default). S&P equivalencies range from AAA to BBB within the investment grade bonds, and BB to C in the non-investment grades.
18. In general, shareholders are last in line to get paid after bond-holders and other debt providers.
19. For example, with more leverage, there is a greater chance that unanticipated costs or investment needs (e.g., due to storm damage), or lower than expected revenues in a given year could lead to a downgrade in a utility's credit rating, thereby increasing the financing costs for any investments that might be required to provide services for future ratepayers.
20. EBITDA: Earnings before interest, tax, depreciation and amortization
21. Moody's. January 19, 2018. Rating Action: Moody's changes outlooks on 25 US regulated utilities primarily impacted by tax reform.
22. After the fifth year, federal taxes no longer include deductions for depreciation expenses, but utility tax expenses are calculated assuming such deductions continue.
23. Bankruptcy remote means that the company's resources would not be available to the utility's creditors in case of a utility bankruptcy.
24. Levelization: the average annual present value.
25. The utility earns profits through the capital it deploys on behalf of ratepayers. By recalling that capital through securitization, the utility reduces the amount of capital deployed, and hence its earnings.
26. Assumes a 75th percentile annual wage for power plant operators as assessed in May 2017 from Bureau of Labor Statistics (https://www.bls.gov/oes/current/oes518013.htm), endowment earns six percent per year.
27. J. Paul Forester, "Unstranding "Stranded Cost" Securitizations: New Applications for a Proven Technology," (2008), available at https://m.mayerbrown.com/Files/Publication/4cbbcd94-6fb6-42a5-b889-7f595fab14e1/Presentation/PublicationAttachment/be6fd304-233a-4031-b3dc-dfd9ea67b559/ART_STRANDEDCOST_FORRESTER.PDF.
28. Ibid.
29. The $58 million for decommissioning costs is assumed to be spent by the utility on decommissioning, while the $25 million transition fund is assumed to be passed to a transition assistance entity, trust, or non-profit.
30. Purchased wind (PPA) represented as the $20/MWh pass-through-cost in dark blue.
31. Profits slip below $0/MWh in the Securitization + Wind PPA scenario because ADIT from the retired coal plant must still be ratably returned to ratepayers.
32. See, for example, CarbonCount (https://cornerstonecapinc.com/carboncount-a-quantitative-impact-scoring-system-for-green-bonds/)
33. See https://wriorg.s3.amazonaws.com/s3fs-public/emerging-green-tariffs-in-us-regulated-electricity-markets_0.pdf.
34. "Subtractionality" is a notional counterpart to "additionality." Where "additionality" demands that any programs have benefits that are above and beyond those already realized through existing programs, "subtractionality" demands that a program produce a clear net reduction below that which would otherwise be achieved through other means. In this case, rather than increasing clean energy programs in anticipation of displacing pollution-emitting energy sources, a green retirement tariff would seek to unequivocally and directly reduce the use of the emitting energy source.

Sierra Club National
2101 Webster Street, Suite 1300
Oakland, CA 94612
(415) 977-5500

Sierra Club Legislative
50 F Street, NW, Eighth Floor
Washington, DC 20001
(202) 547-1141

facebook.com/sierraclub
instagram.com/sierraclub
twitter.com/sierraclub

EXPLORE, ENJOY, AND PROTECT THE PLANET. **SIERRACLUB.ORG**

SIERRA CLUB