# DEPRECIATION CONSIDERATIONS WHEN MANAGING POTENTIAL STRANDED COSTS

Prepared by:
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Concentric Advisors ULC, located in Calgary, Alberta, Canada, became a primary subsidiary of Concentric Energy Advisors, Inc. (collectively "Concentric") in 2017. The Concentric depreciation staff specializes in developing and supporting depreciation studies, including the increasingly strict requirements of regulators for support of depreciation studies. Concentric understands the importance of appropriate depreciation rates and the impact of the depreciation rates on the client's requested revenue requirement and long-term rate base implications.

Concentric Energy Advisors specializes in management consulting and financial advisory services with a focus on the North American energy and water industries. Extensive industry experience, combined with rigorous analytics and a highly collaborative approach to working with clients, enables Concentric to deliver strategic insights and innovative solutions that help ensure success.

Concentric's service areas include Regulation, Markets and Resource Planning, Financial Advisory, and Litigation. Through its subsidiaries, CE Capital, Concentric Advisors ULC, and Concentric Energy Publications, Concentric provides capital market advisory support, consulting services in Canada, and publishes The Foster Report.

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# Executive Summary

The prevalence of legislation targeting greenhouse gas emissions has become a significant risk factor for natural gas and electric generation utilities throughout North America. At the time of writing, 15 U.S. states have committed to reducing greenhouse gas emissions by various dates, often with targeted reductions occurring between 2030 and 2050.[1] These targeted deadlines are looming closely throughout the industry.

As of the time of this paper, there are few, if any, utilities currently collecting tolls that properly account for the upcoming expected wave of, and stranded costs related to, retirements due to climate change initiatives. Without immediate action, utilities may soon find themselves with large amounts of stranded costs.

Recently there have been a number of utilities beginning to look at the necessary toll impacts, indicating increases in tolls that would be potentially staggering. However, the longer utilities wait to prepare for this change, the larger the future impact on their customer base. Historically, stranded costs have been dealt with retroactively, which has placed an undue risk on the shareholders and led to generational inequity issues.

Proactive preparation to consider the use of depreciation-based solutions allows for the potential to mitigate stranded costs while maintaining utilities' ability to function appropriately through this period of profound change. It is in the best interest of all stakeholders, including utilities, toll payers, and shareholders, to begin preparing today for the future impacts of climate change legislation.

This paper will review and discuss the potential use of proactive solutions to address climate change tolling concerns, thus reducing the need and risk inherent in relying upon retroactive approaches.

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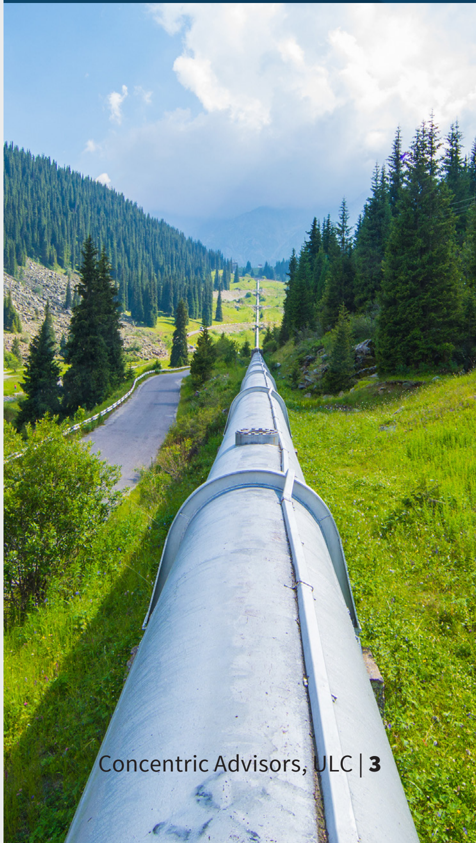
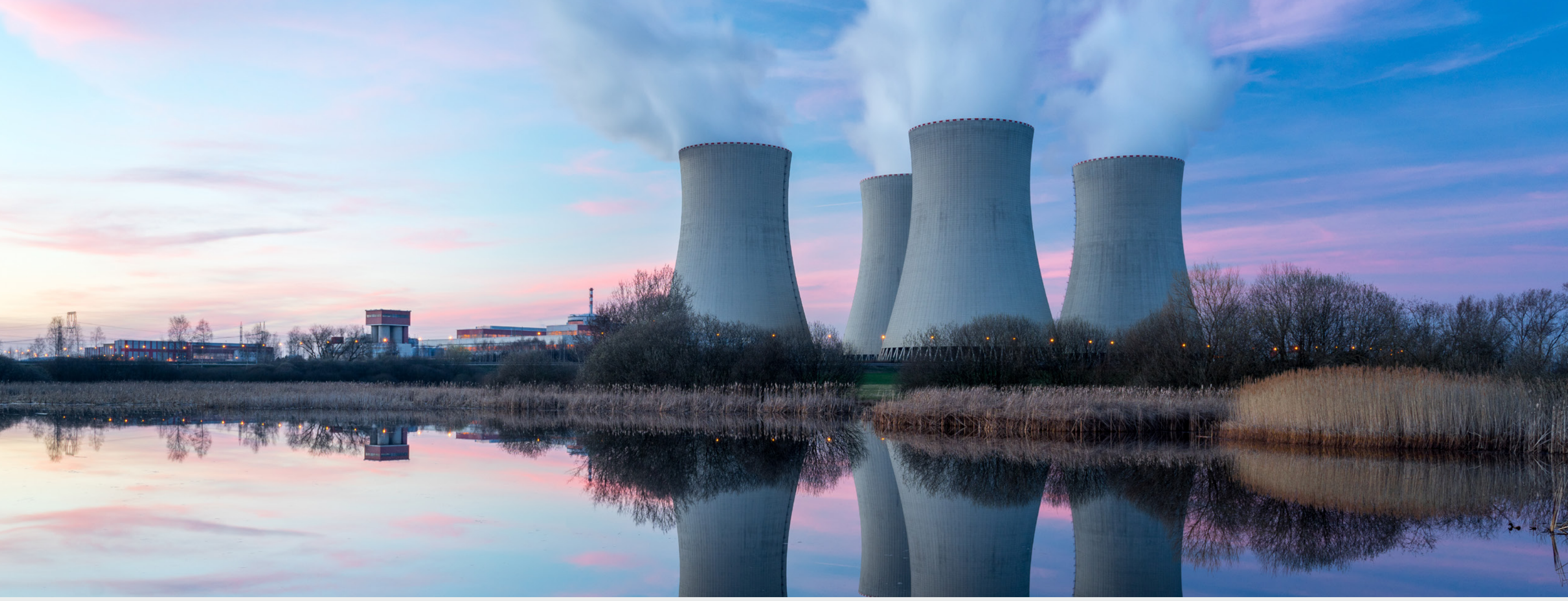




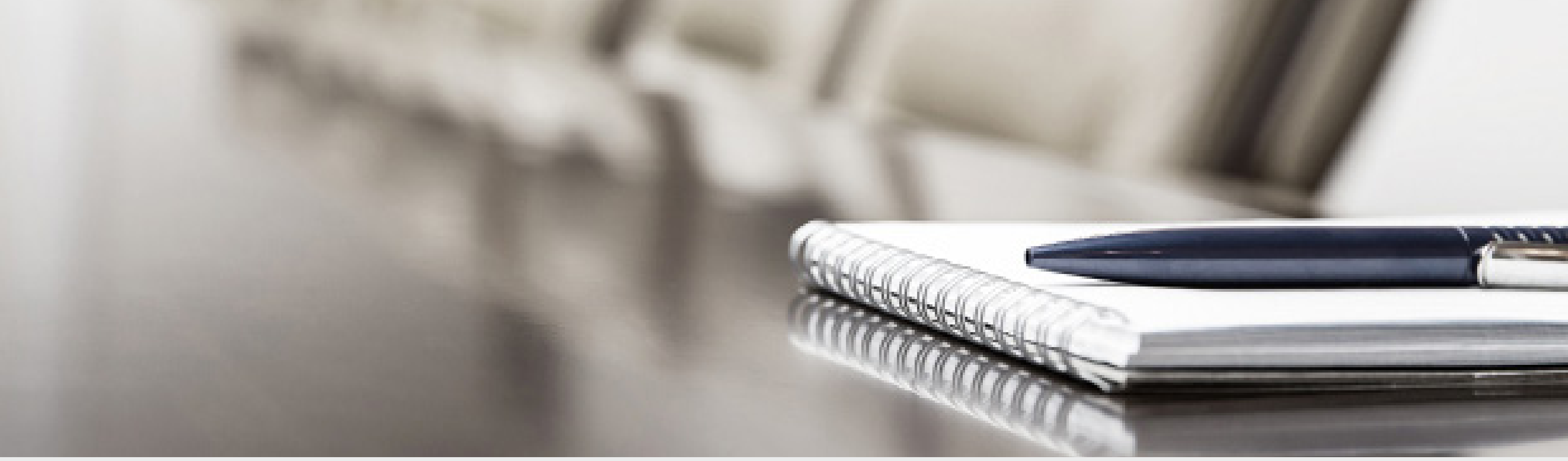
## Historic Approach to Stranded Costs

The concept of stranded costs is one that the regulated utility industry has long contemplated. Stranded costs can be thought of as costs that were prudently incurred and approved for inclusion in rate base but are required to be retired prior to the end of the expected useful life of the asset due to a change in governmental policy.[2]

Historically, utilities have reacted to stranded costs through a retroactive methodology. In the 1970s and 1980s, many nuclear generation facilities were canceled during construction, leaving billions of dollars in costs potentially stranded.[3] In the 1980s, natural gas pipelines were faced with stranded costs when transitioning to “take or pay” contracts to set rates. And in the 1990s, power generation facilities were faced with potential stranded costs due to the transition to competitive markets. Each of these instances of stranded costs was unforeseen, and consequently, the return of investment to shareholders had to be undertaken retroactively and had unintended consequences. In the case of the natural gas pipelines, there was a loss of investment that was not accounted for in the regulated rate of return for some utilities. This loss of investment for shareholders is a major risk[4] of collecting stranded costs after they occur.

In addition to the loss of value to shareholders in retroactively accruing for stranded costs, the above situations resulted in generational inequity. Shareholders were made whole by toll payers at a later date, and thus, the costs of using the system were born by toll payers in the future and not by the toll payers who actually received the value of the assets in used and useful service.[5]

***As of the time of this paper, there are few, if any, utilities currently collecting tolls that properly account for the upcoming expected wave of, and stranded costs related to, retirements due to climate change initiatives. Without immediate action, utilities may soon find themselves with large amounts of stranded costs.***



## Regulatory Compact and Stranded Costs

The concept of a regulatory compact is a well established principle that requires utilities to provide service as part of a natural monopoly in return for a reasonable opportunity for the return of and on investment. The regulatory compact requires that toll payers be responsible for all costs associated with using the utility system. Delaying the recovery of costs onto toll payers who receive no benefit is not permitted under the regulatory compact as currently understood in North America.

> *"Applied under an actual-cost philosophy of rate control, the rationale of the systemic transfer of capital costs originally charged to plant account into a series of smaller charges to operating costs is a corollary of the principle that the costs of supplying public utility service should be borne, as far as feasible, by those customers who derive a benefit from the particular outlays in question. It is for this reason that the burden of reimbursing a company for the acquisition of capital assets is distributed over the periods during which customers will enjoy the use of these assets. By the time when the assets have ceased to perform a useful service, their costs should already have been fully recovered."* [6]

The examples referenced previously were unable to ensure generational equity as the change in market forces was unforeseen at the time of the investment. Today, utilities benefit from planning for the upcoming wave of retirements due to climate change legislation in many jurisdictions, which will impact the retirement and use of utility assets for many years into the future.

Further, even utilities in jurisdictions without strict climate change legislation can prepare for potential changes to the market due to a lower reliance on greenhouse gas producing activities. There has been regulatory precedent that losses can be held against the shareholders in situations where a utility is able to plan for stranded costs but fails to take adequate measures to protect itself.

For example, the Alberta Utilities Commission ("AUC") released decision 2013-417 related to the Utility Asset Disposition Proceeding (Application No. 1566373), which stated:

> *"Under-recovery or over-recovery of capital investment on extraordinary retirements (as is the case with assets disposed of outside of the ordinary course of business or moved to a non-utility account) are for the account of the utility."*[7]

Further, the Canadian Energy Regulator ("CER"), acting as the National Energy Board ("NEB") at the time of this decision, has also affirmed the view that shareholders must proactively manage rate base to ensure proper recovery of their assets.

> *"A rule that imposes an obligation upon the Board to approve tolls that allow recovery of all costs in all circumstances is inconsistent with Parliament's grant of discretion to the Board and may not result in tolls that are just and reasonable. In this regard, we disagree with TransCanada's submission to the effect that the Board must approve tolls that allow recovery of all prudently incurred costs, even if the Board knew that those tolls could not be charged in the market. This would be an inefficient and non-sensical outcome.*
>
> *In our view,* ***a regulatory rule that compels the Board to set tolls that allow the return of and on investment, irrespective of whether assets associated with that investment are used and useful for providing service, erodes management's responsibility for its investment decisions and management's responsibility to keep depreciation rates current.*** *This situation, in our view, does not lend itself to creating efficient energy infrastructure and markets. It also provides no incentive for a pipeline company to find better or higher uses for its assets.*
>
> *Given the foregoing, the prudency standard should not be the only standard that determines the opportunity for cost recovery for NEB-regulated pipelines in all circumstances"*[8] *[Emphasis added]*

*"[A] regulatory rule that compels the Board to set tolls that allow the return of and on investment, irrespective of whether assets associated with that investment are used and useful for providing service, erodes management's responsibility for its investment decisions and management's responsibility to keep depreciation rates current."[8]*

Thus, it is in the best interest of current shareholders to begin to recover expenses for the forecasted potential stranded costs.

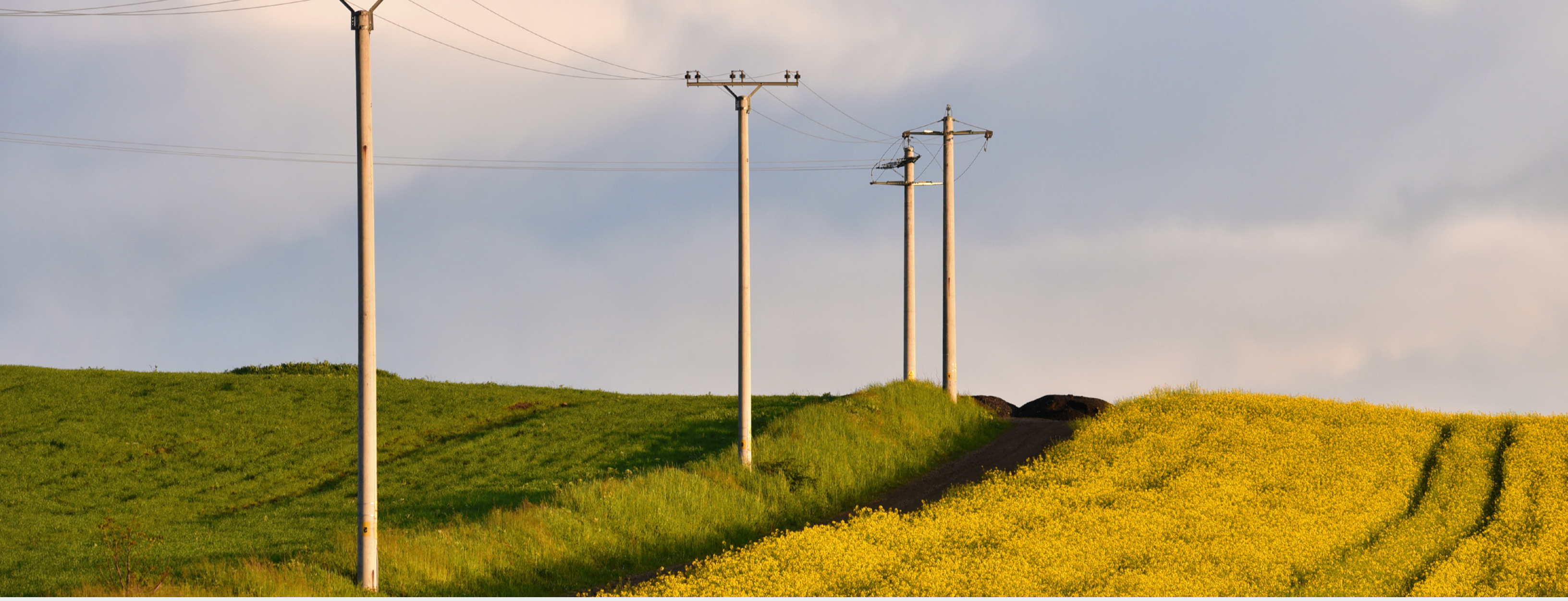
James Bonbright, in his influential text "Principles of Public Utility Rates," foresaw this tension between regulators and utilities regarding potentially stranded costs. He was of the view that utilities are best served by ensuring a faster recovery of investment in order to ensure that all investors are made whole.

> *"…the danger that an actual-cost rate may be difficult to sustain in the face of falling prices or of technological progress, can be reduced, even though not avoided, by rapid cost-recoupment in the form of liberal allowances for depreciation."[9]*
>
> *AND*
>
> *"…as between two proposed methods of cost amortization, one of which undertakes faster write offs than the other during the early years of useful service lives, any reasonable doubt may well be resolved in favor of the former…"[10]*

Rate regulated utilities have traditionally been provided with a reasonable opportunity for the recovery of investment through the use of depreciation.

Depreciation expense requires four variables—the average service life estimate, the estimated frequency of retirements around the average age as represented by an Iowa Curve,[11] the net proceeds or cost of retiring an asset, and an expected end of life date. There are mathematical formulas to calculate the average age, frequency curve, and traditional net salvage estimates, which have been widely accepted throughout the North American utility industry.

While the selection of these estimates is often contentious, the availability of these mathematical formulas provides public utility commissioners some guidance.[12] This mathematical guidance is not available for commissioners or utilities when selecting an expected end of life date.



# Depreciation Concepts

*Regulated depreciation concepts can generally be grouped into two categories:*

- *Prospective recovery of anticipated environmental and technology related retirement*
- *Retroactive recovery of the undepreciated original cost and costs of retirement after the retirement event.*

Many forces impact the useful life of a group of assets. The Federal Energy Regulatory Commission ("FERC") definition of depreciation states that:

> *"Depreciation in public utility regulation is the loss in service value, not restored by current maintenance, incurred with the consumption or prospective retirement of utility plant in service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authorities, and, in the case of natural gas companies, the exhaustion of natural resources."*[13]

The service life of a system is often limited to a much greater extent by the current and estimated economic realities of operating the system.

The availability of a fuel source, the market demand of the electric or gas supply, and the regulatory environment that the utility exists in are all economic reasons why a utility may face the economic need to retire assets before the end of the physical life. Through the careful selection of an Economic Planning Horizon ("EPH" also known as a "Truncation Date," "Economic Life," or "Life Span Date"), a utility is able to ensure the recovery of the full cost of investment.

### Depreciation Based Solutions

There has emerged a series of debates regarding the recovery of invested capital on early retirement of assets due to technological or environmental change. The issue includes a discussion of both the undepreciated original cost of investment and the cost of retirement expenditures required to deactivate, dismantle, and remediate sites upon early retirement. Regulated depreciation concepts can generally be grouped into two categories:

- Prospective recovery of anticipated environmental and technology related retirement
- Retroactive recovery of the undepreciated original cost and costs of retirement after the retirement event

### Prospective Methods

***Economic Planning Horizon***

The selection of an EPH provides an opportunity to estimate the selection of a date after which there is less certainty of the utility's ability to continue to utilize the asset. For example, an EPH on a nuclear generating station may be selected based on the end of the regulatory permits to continue to operate the site. As time goes on, the EPH is often pushed back to account for renewed permits or greater certainty of the future. Each depreciation study allows for the certainty of the assets' future operation to increase, which provides for the extension of the EPH. In this way, it is possible to ensure the return on investment for a shareholder while not unduly burdening the toll payer. The EPH concept has been consistently approved by the Canadian Energy Regulator (formerly the National Energy Board) and FERC for many decades in large diameter pipeline transmission systems such as TransCanada.[14]

The selection of the proper EPH can be controversial. An experienced depreciation expert may consider many factors when recommending the proper EPH. Among the most common factors cited in a number of CER, NEB, and FERC applications for large scale transmission pipelines is the following list:

- *"Availability of supply to the pipeline*
- *Availability of market demand*
- *Consumption of service value*
- *Engineering based retirement studies*
- *Competitiveness of the pipeline*
- *Opportunity for the recovery of the investment*
- *Projected long-term use of the pipeline*
- *Approved Economic Planning Horizons of peer pipelines*
- *Management discretion"*[15]

In the circumstances of a utility impacted by climate change legislation, a number of the above criteria will need to be considered when selecting the appropriate EPH. It is expected that a system will suffer from reduced market demand, a lack of competitiveness with renewable energy options, a lower long-term use of the system, and management discretion to ensure proper recovery of investment.

The use of an EPH is well accepted throughout the regulated utility industry. It is most commonly used in assets with a well-known life limiting factor, such as the regulatory approval date in electric generation sites. Typically, these are asset classes (also known as accounts[16]) made up of small numbers of large assets – electric generators, hydro-electric dams, structures, and improvements. In this manner, these accounts do not typically have a large number of interim or ongoing retirements.

| Prospective Methods | Retroactive Methods |
|---|---|
| • Economic Planning Horizon<br>• Securitization of Anticipated Stranded Costs<br>• Inclusion of Estimated Cost of Retirement in the Depreciation Rate<br>• Cost of Removal Trust Fund | • Inclusion of Cost of Removal to the Capital Cost of Replacement Assets<br>• Expensing Cost of Retirement in the Year of Asset Retirement<br>• Deferral of Stranded Costs and Seek Recovery Through Future Rate Surcharges |

There is a long precedent of utilities requesting EPH dates for large-scale transmission pipelines to deal with supply issues and the potential for environmental regulations that make natural gas and oil pipelines no longer financially feasible. However, even these assets are very different in nature from those used in a natural gas or electric distribution system.

The sheer number of individual assets managed by distribution systems and the potential financial impact of retiring these assets makes selecting an EPH for a distribution system difficult and risky.

Distribution systems, which are among the most impacted by state and provincial level climate change policies, have a number of complexities that make the return of investment more difficult than large scale transmission systems. It is far less common for mass asset accounts in distribution systems to have an approved EPH because climate change policies are the first large scale issue impacting a distribution system's ability to continue to operate.

As such, there has rarely been the need for regulatory approval of an EPH on a distribution mass asset account. Further, generation or transmission assets often have staggered EPH dates. Each individual generation location or transmission line will have the EPH related to the regulatory approvals for that unique location.

This leads to a situation where one generating plant nears retirement while others are being built or renovated and the rate base of the utility stays relatively consistent (or even grows) over time. If a single EPH is applied to an entire distribution system, the accrued depreciation account will become progressively larger until it eventually equals or exceeds the plant in service account. As such, the rate base of the utility is at risk as the date of retirement comes closer and can become negative.

Utilities with diverse markets, such as those that offer both transmission and distribution services or combined gas and electric utilities, are at lower risk of this outcome,[17] however, it is something that all utilities need to consider before adopting an EPH methodology.

***Securitization of the Anticipated Stranded Costs***

This approach was used in the 1990s to address the restructuring of the electric generation industry and introduction of competition through the issuance of Rate Reduction Bonds. Securitization requires:

a. Legislation that authorizes the establishment of a Special Purpose Entity (SPE) for a dedicated objective (e.g., recovery of stranded costs). The legislation typically includes language that protects bondholders from regulatory risk.
b. The regulator to issue an order with adequate protections to enable low-cost financing, after finding an Net Present Value benefit to customers.
c. The utility to issue bonds to finance the early retirement of assets. Further requiring:
    i. That undepreciated asset balances are removed from the utility rate base and no longer earn a return.
    ii. That customers pay a non-bypassable surcharge over the term of the bonds that is passed through the SPE to bondholders.
    iii. That the customer charge may be subject to periodic true-ups to ensure that it is sufficient to meet bond obligations.

Between December 1997 and August 2019, almost $55 billion of transition bonds (69 issuances) were issued to securitize the recovery of stranded costs. These bonds have been used to recover costs associated with electric industry restructuring in the late 1990s/early 2000s, funding of environmental control equipment, carbon reduction strategies, and disaster recovery (e.g., hurricanes and wildfires).[18]

***Inclusion of Estimated Cost of Retirement in the Depreciation Rate***

Another consideration for utilities facing end of life decisions is the role that the cost of retirement is expected to have. The cost of retirement is collected to offset the costs of activities such as removing service lines, capping and filling pipelines, and cleaning up any environmental contamination of sites.

Distribution assets are subject to particularly high cost of removal estimates due to the nature of these assets. They often tend to be located in busy metropolitan areas, which requires shutting down roadways and digging through developed areas to remove assets upon retirement. Further, due to the age of many distribution assets, inflation has taken a large toll on the original cost of investment. As many distribution systems were developed throughout the twentieth century, there have sometimes been more than 100 years elapsed since installation. As such, the costs to retire these assets relative to their initial installation price has greatly increased.

Consequently, it is not uncommon for distribution system assets to have approved cost of removal estimates of over 100 percent when taken as a percentage of the retired assets' original cost in some accounts such as Services and Mains. In other words, for every $100 collected of the initial investment, the utility must collect a further $100 to pay to remove the asset from service, totaling $200 of recovery for a $100 asset.

This method, known as the "Traditional Method," provides for the inclusion of the estimated future cost of removal in the depreciation rate calculation. With this method, cost of removal estimates must be updated to incorporate impacts of environmental legislation and inflation.

Cost of removal estimates, however, are not without controversy. The recovery of large amounts of future costs can cause large price increases for current customers. Generational equity requires that users fund costs of retirement along with a return of investment for all assets consumed in providing service. Price increases, needed to adequately fund the cost of removal, have proven difficult for regulators to approve. As the date of retirement approaches, price levels continue to grow.

While utilities have attempted to increase the cost of removal recovery included in the depreciation rate calculation, regulators have been hesitant due to the effect on current price levels. Moreover, increased funding can significantly reduce the rate base, resulting in lower returns to the shareholders. It is even feasible that the rate base could turn negative as the utility assets age, caused by the recovery of an estimated expenditure that is not made until the asset is retired and the recovery of the actual invested original cost. In the later years of an asset life, the accumulated depreciation can exceed the original cost of investment in some utility accounts.

***Cost of Removal Trust Fund***

The problem of increasing net salvage collection is one that has been addressed by many state, provincial, and federal regulators throughout North America. Costs relating to the retirement of long lived and potentially hazardous assets have moved to a trust fund model by both the CER and FERC in order to ensure both the proper collection of these costs and the proper disbursement of the funds collected.

In Canada, costs relating to the retirement of large diameter pipelines that cross provincial borders are subject to the Land Matters Consultative Initiative ("LMCI"). The LMCI requires that large diameter pipelines carry out in depth analyses of the upcoming costs of retirement and submit this analysis to the CER for approval and update the estimates every five years. Once the CER has approved the costs, funds are collected from toll payers and placed into a secure trust fund. The trust fund is invested conservatively and gains interest


*Given the upcoming wave of retirements this may be a good time for utilities to reconsider a trust fund for cost of retirements.*

throughout the life of the investment. In this manner, the role of inflation in the cost of removal estimate is reduced, and the cost estimate can be lowered for current toll payers. Further, because the CER controls the disbursement of the funds, there is certainty about the costs incurred in retirement, a point of contention in many regulatory proceedings.

In the United States, a similar process is carried out for the cost of removal and decommissioning of nuclear generation facilities.

At this time, the trust fund model for costs of retirement has not been widely utilized by transmission and distribution utilities. A similar methodology, referred to as Constant Dollar Net Salvage (“CDNS”), has previously been accepted by the Alberta Utilities Commission, however more recent proceedings have expressly disallowed it.[19] Enbridge Gas Distribution, operating under the Ontario Energy Board, has been using CDNS since approximately 2014.

This methodology does have some flaws – there can be disagreement about the proper interest and discount rates, it leads to a reduction in working capital through the life of the assets, and a lack of regulatory approval are all reasons why many utilities have been reluctant to consider a trust fund model. However, given the upcoming wave of retirements, this may be a good time for utilities to reconsider a trust fund for the cost of retirements.

### Retroactive Methods

Retroactive methods assume some costs cannot be estimated and should not be included in customer prices until the costs are reasonably known. Retroactive methods include:

***Inclusion of Cost of Removal to the Capital Cost of Replacement Assets.***

The estimated costs of removal of current assets are eliminated from the depreciation rate calculation, and such costs are capitalized in the replacement asset. This method is not generationally equitable, as future users of the replacement asset are burdened with a cost that should be borne by today’s users that gain a benefit from the asset being in used and useful service. However, this approach has gained some regulatory approval since current customers benefit from a lower price, albeit to the detriment of future customers.[20]

***Expensing Cost of Retirement in the year of asset retirement.***

With this approach, the costs of removal are directly charged to the income statement in the year of the actual cost of retirement expenditure.

***Deferral of Stranded Costs and Seek Recovery through Future Rate Surcharges.***

This approach is commonly used to provide recovery from retirements caused by storms and wildfire events that were unanticipated in prior depreciation studies. Most U.S. regulators provide a Storm and Wildfire Mitigation Recovery fund to be amortized over a set term following storm and wildfire events. In this manner, the average service life and cost of retirement estimates do not consider any historic storm and wildfire events.

This approach has also been used to recover the stranded costs related to the retirement of coal fired generation units caused by climate change legislation. Additionally, this approach was used to recover stranded costs of analog metering equipment related to smart metering technology installation. There have been some whole or partial disallowances of the stranded cost recovery associated with this method as regulators have indicated that this approach does not meet a used and useful test.

## Conclusion

Based on the issues discussed in this paper surrounding the regulatory compact, the changing nature of utility service, and the potential for large stranded costs, utilities are required to prospectively act in order to limit the amount of potential stranded costs.

The author's opinion is that the use of prospective methods allows the greatest flexibility and opportunity to reduce the risk to the largest extent possible. Because prospective methods rely on the estimated timing of retirements and costs to remove assets at retirement, small amounts of costs may still exist and be left stranded, which may be recovered through retrospective methods.

It is expected that prospective methods of limiting stranded costs combined with small amounts of retroactive post retirement solutions result in the best outcomes for all stakeholders. All utilities must begin to consider the potential for stranded costs at the earliest possible opportunity given the rapidly changing governmental legislation and social landscape.

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Amanda Nori is a versatile, highly analytical, and dedicated Certified Depreciation Professional with over ten years of experience completing depreciation studies.

Ms. Nori's areas of expertise include data processing, Iowa curve estimation, cost of removal, gross salvage estimation, statistical analysis depreciation expense analysis, testimony preparation, post filing services, business analysis, service life estimation, financial and actuarial analysis, simulated retirement analysis, and regulatory compliance. She routinely reviews and evaluates complex financial data to ensure regulatory compliance within jurisdictions throughout Canada, and has experience working with clients throughout the natural gas and electric utility, pipeline, transmission, and railway industries across North America. Most recently Ms. Nori has completed work on electric transmission cases for AltaLink, ATCO Electric Transmission, and Manitoba Hydro, along with natural gas transmission cases for Viking Pipelines.

Ms. Nori is a graduate of the University of Calgary, Alberta, and has been a member of the Society of Depreciation Professionals since 2010. Ms. Nori has completed the Public Utilities Management and Regulation Graduate Certificate through the University of Illinois at Springfield.

# Endnotes


1. National Conference of State Legislatures; “Greenhouse Gas Emissions Reduction Targets and Market-based Policies”; January 1, 2020
2. A commonly accepted definition of stranded costs can be found in Hammond, Emily and Rossi, Jim, “Stranded Costs and Grid Decarbonization”, September 2, 2016, Brooklyn Law Review, page 3 where it states “those investments that a utility has incurred to meet its obligations to serve customers with an expectation of cost recovery through rates, but which may no longer be recoverable due to a change in the rules or new market competition in the industry.”
3. For an in depth discussion of the historical treatment of stranded costs, please see Hammond, Emily and Rossi, Jim, “Stranded Costs and Grid Decarbonization”, September 2, 2016, Brooklyn Law Review
4. A discussion of the scale of potential losses due to decarbonization can be found in McKinsey & Company; Barth, Adam; Tai, Humayun; Wagner, Amy; “Decarbonization Policies Mean Utilities Must Change”
5. Environmental Defense Fund, “Managing the Transition: Proactive Solutions for Stranded Gas Asset Risk in California”, page 23
6. Bonbright, James C.; Principles of Public Utility Rates; 1961; pages 202-203
7. Alberta Utilities Commission, Decision 2013-417, Proceeding 1566373, Paragraph 304
8. NEB Decision RH-003-2011, In the Matter of TransCanada PipeLines Limited, NOVA Gas Transmission Ltd., and Foothills Pipe Lines Ltd. Business and Services Restructuring Proposal and Mainline Final Tolls for 2012 and 2013, dated March 2013
9. James Bonbright, Principles of Utility Rates, Columbia University Press, 10961, page 189
10. James Bonbright, Principles of Utility Rates, Columbia University Press, 10961, pages 208-209
11. Iowa Curves are a system of widely accepted smoothed survivor curves used to model the retirement dispersion of utility assets. A full description of the Iowa Curve methodology can be found at Wolf, Frank K. and Fitch, W. Chester “Depreciation Systems”, Iowa State University Press, 1994
12. For an in-depth discussion of the selection of life and net salvage parameters, please see Wolf, Frank K. and Fitch, W. Chester “Depreciation Systems”, Iowa State University Press, 1994
13. Federal Energy Regulatory Commission, Part 201, Uniform System of Accounts Prescribed for Natural Gas Companies Subject to the Provisions of the Natural Gas Act Definitions
14. For example, as approved in NEB decision RH-003-2011 and re-affirmed in CER decision RH-001-2019 and as considered by FERC in many negotiated settlement agreements.
15. As filed in Exhibit VGT-0012, Docket RP19-1340
16. For the purpose of depreciation studies, homogenous assets are grouped into asset classes and assigned a single depreciation rate for all assets within that account. American utilities typically follow the FERC guidance on grouping assets as detailed in the “Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act” or the “Uniform System of Accounts Prescribed for Natural Gas Companies Subject to the Provisions of the Natural Gas Act”
17. For a full discussion of tolling related solutions to stranded costs, please see Environmental Defense Fund, “Managing the Transition: Proactive Solutions for Stranded Gas Asset Risk in California”
18. Concentric Energy Advisors research.
19. CDNS was approved by the Alberta Utilities Commission (then operating as the Alberta Energy and Utilities Board) in EUB Decision U97065 and later disallowed in a 2002 EUB decision. CDNS was again disallowed by the Alberta Utilities Commission in AUC Decision 2011-453, pages 121 - 125
20. Utilities following the International Financial Reporting Standards (“IFRS”), which does not allow for the recovery of future costs of removal in depreciation rates, may find this approach attractive. As a result, it is more widely used by Canadian utilities.