NUCLEAR WASTE MANAGEMENT AND DECOMMISSIONING – REVENUE REQUIREMENT IMPACT OF NUCLEAR LIABILITIES

1.0 PURPOSE

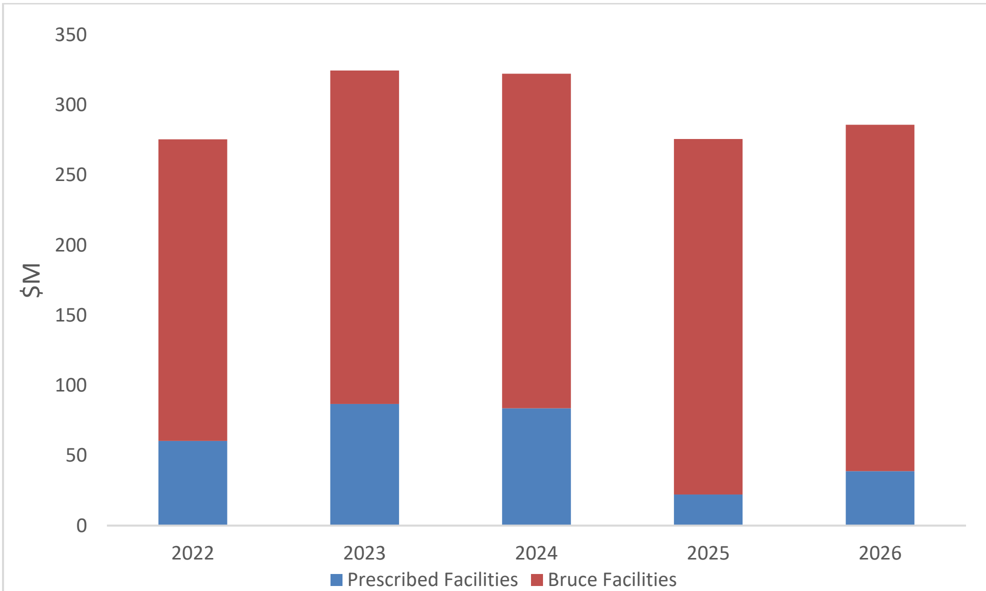
The purpose of this evidence is to outline the OEB-approved revenue requirement treatment of OPG's liabilities for nuclear waste management and decommissioning ("nuclear liabilities") and to present the forecast amounts of nuclear liabilities costs included in the proposed revenue requirements for the 2022-2026 IR term.

2.0 OVERVIEW

OPG is seeking recovery of $1,483.9M, after-tax, over the IR term in respect of nuclear liabilities, with $291.8M for the prescribed facilities and $1,192.1M for the Bruce facilities. These amounts were determined using the methodology approved by the OEB in EB-2007-0905, EB-2010-0008, EB-2013-0321, and EB-2016-0152, and reflect the approved 2017 to 2021 Ontario Nuclear Funds Agreement ("ONFA") Reference Plan effective January 1, 2017 (the "2017 ONFA Reference Plan") and its attendant contribution schedule approved by the Province of Ontario (the "2017 ONFA Contribution Schedule"). The relative contribution of the prescribed facilities and the Bruce facilities to the nuclear liabilities' revenue requirement impacts is illustrated in Figure 1 below.

For the prescribed facilities, OPG is seeking recovery of the following annual amounts: $60.3M in 2022, $86.8M in 2023, $83.6M in 2024, $22.2M in 2025 and $38.9M in 2026 (Ex. C2-1-1, Table 1, line 8). The significant reduction in the recovery amounts over the IR term primarily reflects the depreciation of asset retirement costs for the Pickering station in line with the current accounting end-of-life ("EOL") dates of December 31, 2022 for Units 1 and 4 and December 31, 2024 for Units 5 to 8.

Figure 1: Nuclear Liabilities Revenue Requirement Impact



For the Bruce facilities, the recovery amounts sought comprise (i) a reduction to Bruce Lease net revenues, and (ii) through the impact of Bruce Lease net revenues on regulatory earnings before tax for the prescribed facilities, associated regulatory income tax impacts. The annual Bruce Lease net revenues reductions are as follows: $161.4M in 2022, $178.3M in 2023, $179.0M in 2024, $190.2M in 2025 and $185.2M in 2026 (Ex. C2-1-1, Table 1, line 15). The associated annual regulatory income tax impacts are as follows: $53.8M in 2022, $59.4M in 2023, $59.7M in 2024, $63.4M in 2025 and $61.7M in 2026 (Ex. C2-1-1, Table 1, line 16).

The treatment of Pickering EOL dates is discussed in further detail in Ex. F4-1-1, Section 3.5 and Ex. H1-1-1, Section 6.2. As noted in those exhibits, OPG is applying for a deferral account related to future changes to Pickering station EOL dates for accounting purposes, including associated impacts on nuclear liabilities, as part of this application in line with the OEB's current accounting order requirements, effective January 1, 2021. This includes changes to the Pickering station EOL dates expected effective December 31, 2020, the impact of which cannot be determined pending finalization of the corresponding year-end

2020 adjustment to the nuclear liabilities and therefore has not been reflected in this application. This adjustment will be reflected in OPG's 2020 audited consolidated financial statements to be issued in March 2021.

The remainder of this evidence is structured as follows:

- Section 3.0 provides background on OPG's nuclear waste management and decommissioning obligations, an overview of ONFA, and financial accounting requirements for nuclear liabilities and ONFA segregated funds in accordance with US generally accepted accounting principles ("US GAAP').
- Section 4.0 describes the OEB-approved methodology for recovery of OPG's nuclear liabilities, for the prescribed facilities and the Bruce facilities, that was applied in all prior OPG payment amounts proceedings and has been applied by OPG in this application.
- Section 5.0 discusses main changes in the asset retirement obligation, the corresponding unamortized asset retirement costs and the segregated fund balances set aside for discharging the nuclear liabilities in accordance with the ONFA.
- Section 6.0 presents the impact of the year-end 2017 nuclear liabilities adjustment recorded in connection with the extension of EOL dates for the Pickering station subsequent to EB-2016-0152, for which the prescribed facilities' revenue requirement impact is being recorded in the Impact Resulting from Changes to Pickering End-of-Life Dates (December 31, 2017) Deferral Account established through the EB-2018-0002 accounting order proceeding.
- Section 7.0 provides the status of the 2022 ONFA Reference Plan update, which is under development and has not been reflected in the proposed IR term revenue requirement. Once finalized and implemented, the revenue requirement impact of the 2022 ONFA Reference Plan will be subject to the Nuclear Liability Deferral Account and the Bruce Lease Net Revenues Variance Account.
- Section 8.0 discusses the jurisdictional review of cost recovery methodologies for nuclear liabilities ("Jurisdictional Study") directed by the OEB's Decision and Order in EB-2016-

0152[1]. The Jurisdictional Study itself is provided in Attachment 3.

3.0 BACKGROUND

3.1 Obligations for Nuclear Waste Management and Decommissioning

OPG is responsible for the ongoing and long-term management of irradiated wastes, including used nuclear fuel and less radioactive material, categorized as low and intermediate level waste ("L&ILW"), generated over the life of its nuclear facilities, and for the decommissioning of its nuclear generating and waste management facilities at the end of their useful lives. These obligations are tracked by the following five programs:

- Decommissioning – OPG's nuclear station decommissioning plans consist of preparation and placement of stations into a safe state condition at the end of their useful lives, including removal of fuel and heavy water from the reactors, followed by an assumed 30-year safe store period and subsequent station dismantlement and site restoration.
- Used Fuel Storage – The program encompasses the interim storage of used nuclear fuel in dry storage containers at nuclear station sites prior to their ultimate long-term disposal.
- Used Fuel Disposal – The program encompasses the long-term management of used nuclear fuel, which is based on the Adaptive Phased Management ("APM") concept previously accepted by the Government of Canada on recommendation of the Nuclear Waste Management Organization ("NWMO") in response to the *Nuclear Fuel Waste Act*. The NWMO is responsible for the design and implementation of Canada's plan for the safe long-term management of used nuclear fuel. The APM approach includes the isolation and containment of used nuclear fuel in a proposed deep geologic repository. The NWMO is funded by nuclear fuel waste owners in Canada, including OPG.
- L&ILW Storage – The program includes the transportation, processing, and interim storage, at the OPG-owned and operated Western Waste Management Facility situated at the Bruce nuclear site, of the L&ILW generated at the sites during and following the operation of the nuclear stations, prior to its ultimate long-term disposal.

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[1] EB-2016-0152 Decision and Order, p. 97.

- L&ILW Disposal – The program encompasses the long-term management of the L&ILW generated at the nuclear sites. OPG's long-term disposal strategy previously entailed the permanent emplacement of L&ILW into a separate proposed deep geologic repository adjacent to the Western Waste Management Facility. As a result of the January 2020 vote of the Saugeen Ojibway Nation ("SON") not to support this proposal, OPG is exploring alternative solutions for the safe long-term management of L&ILW. Due to significant inherent uncertainties associated with potential alternative solutions, no adjustments to the estimate of OPG's nuclear liabilities have been made as a result of the SON vote in accordance with US GAAP and under the ONFA.

OPG's obligations include used fuel and L&ILW generated at the Bruce stations and the decommissioning of the Bruce stations.

OPG typically performs a comprehensive update of the cost estimates for the nuclear liabilities every five years, through the ONFA Reference Plan update process outlined in Section 3.2. Given the long-term duration of the nuclear liabilities programs and the evolving technology to handle nuclear waste, there is inherent uncertainty surrounding the cost estimates and economic indices underpinning the nuclear liabilities, which may increase or decrease materially over time as plans, assumptions, methods and technology evolve and economic conditions change.

In accordance with US GAAP, OPG recognizes an accounting obligation for its nuclear liabilities on the balance sheet, known as an asset retirement obligation ("ARO"). The ARO represents the present value of the committed portion of the costs for OPG's nuclear liabilities. The committed costs include the cost components of the above five nuclear waste management and decommissioning programs that are considered to be fixed, as well as the lifetime variable costs for irradiated waste generated to date. The baseline cost estimates underpinning the ARO are those developed through the ONFA Reference Plan update process.

The initial value and each subsequent adjustment to the ARO are known as tranches. In accordance with US GAAP, each tranche is calculated using a discount rate determined at the time of the adjustment, as discussed below, and is not revalued for subsequent changes in the discount rate.

The current ARO balance consists of nine different tranches. The tranches represent the initial ARO and each of the subsequent adjustments (in present value terms), with the latest tranche, recorded at December 31, 2017, related to the 2017 adjustment in connection with the extension of accounting EOL dates for the Pickering station (see Section 6.0).

Each of the ARO tranches increases over time due to accretion expense, which represents growth in the present value of the obligation at the discount rate used to establish each tranche, due to the passage of time. Accretion expense is recognized as a cost in OPG's income statement in accordance with US GAAP.

In accordance with US GAAP, the discount rate for each ARO tranche is determined using a credit adjusted risk-free rate[2] determined as of the date of the revision for each ARO adjustment underpinned by an upward revision in the amount of undiscounted estimated cash flows (for example, for the year-end 2017 ARO adjustment), or the weighted average discount rate of the existing tranches in the case of a downward revision in the amount of undiscounted cash flows (for example, for the 2017 ONFA Reference Plan ARO adjustment). The December 31, 2017 tranche, which was based on an upward revision, was calculated using a discount rate of 2.94% and the 2017 ONFA Reference Plan tranche, which was based on a downward revision, was calculated using a discount rate of 4.95%.

An overall objective of the financial accounting treatment of the ARO is to reflect costs in the periods they are incurred, by matching them to the benefits derived from the asset. ARO costs are typically capitalized as a component of property, plant and equipment ("PP&E") on

[2] The discount rate used by OPG is the Province of Ontario long-term bond yield rate.

the balance sheet and amortized over the useful life of the stations, in order to match the incurrence of these costs to the generation output of the station. The capitalized costs are known as asset retirement cost ("ARC"). As such, a change in the ARO as a result of changes in baseline cost estimates from an approved ONFA Reference Plan or from a change in the accounting estimate or assumptions typically result in an equal amount being recorded as an increase or decrease to the PP&E balances for the corresponding stations, to be amortized, like other capital costs, over their remaining useful lives. The amortization gives rise to depreciation expense. ARC is a component of the net book value of each of the Pickering, Darlington and Bruce nuclear stations.[3] Under the OEB-approved nuclear liabilities recovery methodology for the prescribed facilities discussed in Section 4.1, ARC is included in OPG's nuclear rate base, and associated depreciation expense is included in the total depreciation and amortization expense.

Quantities of used fuel and L&ILW produced over time give rise to incremental committed costs, which are recorded as increases to the ARO. These costs, expressed in present value terms, are known as used fuel variable and L&ILW variable expenses, and are charged to the income statement as incurred, in the period the additional used fuel and L&ILW is generated. The variable expenses are recorded as an increase to the ARO, either as an increase to the most recent tranche or as a separate tranche.[4] They are included in the revenue requirement, as incurred, under the OEB-approved nuclear liabilities recovery methodology for the prescribed facilities and the Bruce facilities.

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[3] For continuities of PP&E and accumulated depreciation and amortization balances for the prescribed facilities over the 2016-2026 period, including ARC, see Ex. B3-3-1 and Ex. B3-4-1.

[4] As incremental variable expenses represent, by definition, increases in undiscounted cash flows underlying the ARO, they are calculated using a credit-adjusted risk-free rate as of the date of the latest ARO adjustment. This approach is followed irrespective of whether the latest ARO adjustment was calculated using a credit-adjusted risk-free rate or a weighted average discount rate of the existing tranches (i.e. depending on the direction of change in the underlying undiscounted cash flows). Therefore, when an ARO adjustment is calculated using a credit-adjusted risk-free rate, variable expenses recorded following that date are added to the same ARO adjustment tranche. When the latest ARO adjustment is calculated using a weighted average discount rate, such variable expenses form a separate tranche, as was the case for the variable expenses recorded during 2017 that were calculated using a discount rate of 3.20%.

OPG maintains a station-level continuity of the ARO balances. The ARO is attributed at the station level for each of the five programs described above. For the Decommissioning and Used Fuel Storage programs, the underlying cost estimates are prepared directly at the station level, with individual estimates prepared for each station. The remaining programs involve central facilities, with cost estimates prepared at the program level and allocated to individual stations in proportion to the lifecycle waste volume estimates.[5]

Continuity schedules showing the opening, closing and average balances of the ARO and ARC are provided in Ex. C2-1-1, Table 2 (for the prescribed facilities) and Ex. C2-1-1, Table 3 (for the Bruce facilities).[6]

3.2 Ontario Nuclear Funds Agreement

The ONFA, a bilateral agreement between OPG and the Province of Ontario ("Province"), sets out OPG's funding obligations for the long-term programs of lifecycle nuclear liabilities, through contributions to two segregated funds, the Decommissioning Segregated Fund ("DF") and the Used Fuel Segregated Fund ("UFF") (collectively, "segregated funds").[7] These funds are set aside in segregated accounts for the express purpose of funding future expenditures on the underlying obligations. The Province established the ONFA as a funding mechanism for OPG's nuclear liabilities consistent with a growing trend in international jurisdictions at the time to place money aside for the long-term management of nuclear liabilities, in recognition of the fact that these liabilities will be discharged many years after the nuclear generating stations have closed. The ONFA was executed in 2003, but includes calculations and contributions effective as of OPG's inception in 1999.

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[5] The allocation of central program costs across the nuclear fleet based on lifecycle waste volume estimates gives rise to circumstances where a change in the assumed operating life of one nuclear station results in changes to the nuclear liabilities of all stations (i.e. both the prescribed facilities and the Bruce facilities).

[6] The average ARO and ARC balances are provided for the prescribed facilities but not the Bruce facilities as these values are required to determine rate base values and the return on rate base used only in the approved revenue requirement methodology for the prescribed facilities (see sections 4.1 and 4.2).

[7] In accordance with the ONFA, the DF is established to pay for costs associated with the Decommissioning program, the L&ILW Disposal program, certain costs of the Used Fuel Storage program incurred after the stations are shut down, and the costs of the L&ILW storage program incurred after the stations are shut down. The UFF funds the costs of the Used Fuel Disposal program and certain costs of the Used Fuel Storage program after the stations are shut down.

The costs for used fuel management and L&ILW storage costs incurred during the stations' operating lives are not funded under the ONFA, cannot be drawn from the segregated funds and therefore are not included in the ONFA funding liabilities. As these costs, referred to as "internally funded", are part of OPG's legal obligation for nuclear waste, they are included in the ARO and are funded from OPG's operating cash flow.

The ONFA funding liabilities reflect a lifecycle view of nuclear wastes forecast over the operating span of OPG's nuclear generating facilities, including wastes not yet generated. Conversely, as discussed above, the ARO considers the committed portion of the costs for OPG's nuclear liabilities, which includes lifetime variable costs associated with the wastes generated to date but excludes such costs for wastes yet to be generated.

OPG's station-level quarterly contributions to the segregated funds are determined periodically with reference to (i) the "ONFA Decommissioning Balance to Complete Cost Estimate" and "Used Fuel Balance to Complete Cost Estimate" (collectively, "funding liabilities") contained in the approved ONFA Reference Plan in effect, and (ii) corresponding segregated fund balances at that point in time. Prescribed funding formulae and rules set out in the ONFA are applied to calculate the contribution amounts based on the difference between the funding liabilities and segregated funds balance. The ONFA reference plan, including all underlying cost estimates and assumptions, is required to be updated every five years or whenever there is a significant change as determined under the ONFA. Station-level continuities of the funding liabilities and segregated funds balances are maintained in accordance with the ONFA. The funded status of the segregated funds at any point in time represents the difference between the funding liabilities per an approved ONFA reference plan then in effect and the value of the segregated funds.

The discount rate used to calculate the funding liabilities is determined in accordance with the ONFA, which prescribes that such rate be set at 3.25% real rate of return plus the long-term term change in the Ontario consumer price index ("CPI"). The resulting rate stands at 5.15% per the 2017 ONFA Reference Plan and establishes the long-term target rate of return on the segregated funds.

Cost estimates and underlying operational, economic and other planning assumptions reflected in the ONFA funding liabilities are determined through a comprehensive process that draws from a variety of sources, including the use of independent third party experts in different fields. Cost estimates and underlying assumptions are reviewed by the Province and their technical consultants prior to approval of an ONFA Reference Plan. In addition to the funding liabilities for the ONFA-eligible costs, an approved ONFA Reference Plan contains cost estimates for internally funded costs, which are also subject to review by the Province.

The ONFA contains several specific features designed to reduce risk for future generations of Ontarians, by ensuring that sufficient funds are available to pay for nuclear liabilities. First, the segregated funds are held in third-party custodial accounts, externally administered and subject to established reporting controls. Second, OPG cannot withdraw monies from the funds unless the withdrawal reimburses OPG for an eligible incurred expenditure related to nuclear waste management and decommissioning activities as specifically defined by the ONFA. These disbursements are subject to a detailed review and approval process by the Province. OPG does not have other rights to withdraw the funds, including on the agreement’s termination, as discussed below. Third, as also discussed below, specific funding formulae and rules contained in the ONFA have been structured such that OPG has been required to fund a substantial portion of the underlying used fuel liabilities in earlier years, effectively as a form of funding conservatism.

3.2.1 Funding of ONFA Segregated Funds

Prior to the current approved 2017 ONFA Reference Plan, OPG had been making overall quarterly contributions to the UFF since inception, as the fund was in an underfunded position. These contributions reflected ONFA requirements that result in about three-quarters of the long-term used fuel management costs being funded over the assumed remaining operating periods of the nuclear stations per the 1999 ONFA Reference Plan.[8] These operating periods did not contemplate subsequent station refurbishment or extended operation decisions and therefore are much shorter than the operating lives expected currently, including those used for accounting purposes. In addition to the overall quarterly contributions, ONFA also required OPG to make a special one-time payment of $334M into the UFF in 2007, which further accelerated the funding of the underlying liabilities.[9] These factors, together with the performance of the fund assets, led to the UFF becoming overall fully funded based on the approved 2017 ONFA Reference Plan.

In 2003, the Province made a substantial contribution to the DF, which, together with fund performance since that time, has been sufficient to ensure that the fund remained fully funded overall each time a new contribution schedule has been established.[10]

Contributions to either or both the UFF or DF may be required in the future should the funds be in an underfunded position relative to the funding requirements of a new approved ONFA Reference Plan, either as a result of changes in underlying cost estimates or due to below target fund investment performance.

Although each of the segregated funds was fully funded in aggregate when setting the 2017 ONFA Contribution Schedule, the portion of the 2017 ONFA Reference Plan funding obligations related to the prescribed facilities was underfunded, while the portion related to the Bruce facilities was overfunded. Specifically, the prescribed facilities' portion of the DF was underfunded and their portion of the UFF was overfunded, while for the Bruce facilities, the DF portion was overfunded and the UFF portion was underfunded. Accordingly, the 2017

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[8] This reflects ONFA requirements that the costs for the first 2.23 million fuel bundles, the estimated lifecycle quantity expected to be produced by the stations as of OPG's inception, be funded over the assumed remaining operating periods of the nuclear stations per the 1999 ONFA Reference Plan. As the estimated fixed costs of the used fuel long-term management program, which are expected to be incurred irrespective of the fuel bundle volume, make up a significant portion of the total used fuel funding liability, the majority of the used fuel liability is funded over the assumed 1999 remaining operating period applicable to the first 2.23 million bundles (or within 5 years of a new approved ONFA reference plan if these operating periods have elapsed).
[9] See EB-2007-0905 Ex. G2-2-1, p. 2, lines 11-20.
[10] The funded status of the DF was noted in EB-2007-0905 Decision with Reasons, p. 66.

ONFA Contribution Schedule included rebalancing of each of the funds via offsetting positive and negative station-level contribution amounts, consistent with the intent of the ONFA that, over time, the funds be fully funded at the station level. This results in overall positive prescribed facilities' contributions and overall negative Bruce facilities' contributions based on the 2017 ONFA Contribution Schedule. The approved contributions to the UFF and the DF are found in Attachments 1 and 2, and are reflected, as applicable, in the revenue requirement impacts proposed in this application under the OEB-approved recovery methodology.

3.2.2 Segregated Funds Assets and Earnings

In accordance with US GAAP, segregated funds are recognized as assets on OPG's balance sheet to the extent that OPG has a right to access the monies based on the terms of the ONFA. OPG does not have the right or access to any portion of the segregated funds that are not recorded on its balance sheet.

The difference between the ARO and the segregated fund assets recorded on OPG's balance sheet represents the unfunded nuclear liability ("UNL"), as defined under the OEB-approved revenue requirement methodology for the prescribed facilities, discussed in section 4.1.

Under the ONFA, the Province guarantees the rate of return earned for the portion of the UFF attributed to the first 2.23 million used fuel bundles at a prescribed real rate of return of 3.25% plus the change in the Ontario CPI as defined in the ONFA ("committed return"). The Province also limits OPG's financial exposure under the ONFA with respect to the lifecycle costs of long-term management of the first 2.23 million used fuel bundles. Any earnings above the guaranteed rate accrue to the Province. The Province has the right to access cumulative excess market earnings above the committed return when a new or amended ONFA reference plan becomes approved, but has not done so to date. If the market earnings are lower than the committed return, the Province is required to make a contribution to the UFF when a new or amended ONFA reference plan is approved.

The portion of the fund attributed to used fuel bundles above the 2.23 million threshold is not subject to the Province's guarantee and earns a return based on the market performance of the assets. This portion is intended to fund the incremental costs associated with fuel bundles in excess of 2.23 million, which currently represent about one-quarter of the used fuel funding liability.[11]

Upon termination of the ONFA, only the Province has a right to any surplus in the UFF. The ONFA does not allow inter-fund transfers from the UFF to the DF. If there is a surplus in the UFF such that the underlying used fuel funding liability, as defined by the most recently approved ONFA reference plan, is at least 110% funded based on the fair market value of the fund assets and after taking into account the committed return on the guaranteed portion, the Province has the right to access the surplus amount greater than 110% at any time.

There is no Provincial guarantee with respect to the DF, which earns a return based on the market performance of the assets. OPG has the right to direct, solely when a new or amended ONFA reference plan is approved, up to 50% of the surplus, if any, above 120% in the DF to the UFF, with the Province entitled to receive the other 50%. OPG has not directed any portion of the DF surplus to the UFF since the fund's inception. The Province does not have a right to withdraw, at its own discretion, any portion of the surplus amounts in the DF until the termination of the ONFA, at which time all such surplus amounts accrue to the Province.

As OPG does not have the right to any surplus funding in the UFF, in accordance with generally accepted accounting principles, it limits the portion of the UFF recognized as an asset to the underlying funding liability per the approved ONFA reference plan in effect. For the DF, OPG records, as an asset, an amount equal to the underlying funding liability plus the portion of DF surplus funding, if any, equal to 50% of the surplus above the 120% threshold, in recognition of the company's right to direct that portion to the UFF. The portion of the DF surplus recognized as an asset is further limited by the amount of underfunding in

[11] The incremental costs associated with fuel bundles in excess of the 2.23 million threshold do not include the fixed costs of the used fuel long-term management program.

the UFF, such that when the UFF is fully funded, none of the surplus in the DF is recorded as an asset. This additional limitation recognizes that a transfer from the DF to UFF when the UFF is fully funded would increase the surplus in the UFF that OPG cannot access. When the portion of the DF or UFF asset is limited to the underlying funding liability per above, fund earnings are recorded at the rate of growth of that liability (i.e. the discount rate) per the approved ONFA reference plan in effect.[12]

Continuity schedules showing the opening, closing and average balances of the segregated fund assets and UNL are provided in Ex. C2-1-1, Table 2 (for the prescribed facilities) and Ex. C2-1-1, Table 3 (for the Bruce facilities).[13]

4.0 APPROVED METHODOLOGY FOR RECOVERY OF NUCLEAR LIABILITIES

In accordance with section 6(2)8 of O. Reg. 53/05, the OEB is required to ensure that OPG recovers the revenue requirement impact of its nuclear waste management and decommissioning liabilities arising from the current approved ONFA reference plan. The OEB established the methodologies for recovery of OPG's nuclear liabilities costs in OPG's first payment amounts proceeding, EB-2007-0905. Different methodologies were established for prescribed facilities and the Bruce facilities, as discussed below. These methodologies have been applied in all subsequent OPG proceedings.

The revenue requirement methodologies established by the OEB were largely based on accounting values determined in accordance with generally accepted accounting principles. The main difference between the methodology for the prescribed facilities and the Bruce facilities is the application of a return on rate base, a regulatory construct, to the prescribed facilities, as opposed to including the net amount of ARO accretion expense and segregated fund earnings for the Bruce facilities.

4.1 Approved Revenue Requirement Methodology for Prescribed Facilities

[12] The portion of any surplus in the funds not recognized as an asset is recorded as Due to Province in OPG's financial statements. The OEB addressed the matter of the Due to Province amounts in EB-2013-0321 (see EB-2013-0321, 20 Decision with Reasons, p.110).

[13] The average UNL balances are provided for the prescribed facilities but not the Bruce facilities as these values are required to determine rate base values and the return on rate base used only in the approved revenue requirement methodology for the prescribed facilities.

Under the OEB-approved methodology for the prescribed facilities, OPG recovers:

- depreciation expense on the ARC balance;
- used fuel variable expenses;
- L&ILW variable expenses;
- return at the ARO weighted average accretion rate on the lesser of the average unamortized ARC and average UNL; and
- return at the approved weighted average cost of capital ("WACC") on the portion, if any, of average unamortized ARC in excess of average UNL.

Each of these components is discussed separately below. The associated income tax impacts are also summarized below and further discussed in Ex. F4-2-1. Accounting accretion expense on the ARO and earnings on the segregated funds do not directly form part of the revenue requirement for the prescribed facilities, with the return component of the methodology effectively replacing the net amount of accretion expense and segregated fund earnings recorded for financial accounting purposes. One of the implications of this approach is that ratepayers are not exposed to investment performance risk for the prescribed facilities' portion of the segregated funds.

Section 5.2(1) of O. Reg. 53/05 establishes the Nuclear Liability Deferral Account, which records the revenue requirement impact for the prescribed facilities of any change in nuclear liabilities arising from an approved ONFA reference plan. This account is discussed in Ex. H1-1-1, section 5.14.

4.1.1 Depreciation Expense

Depreciation on the unamortized ARC is treated in the same manner as depreciation associated with other capital assets; it is included in annual nuclear depreciation and amortization expense presented in Ex. F4-1-1, Table 2. The ARC is depreciated over the station life. Actual amounts of ARC depreciation expense for the 2016 to 2019 period and the forecast amounts for the 2020 to 2026 period are presented in Ex. C2-1-1, Table 1, line 1.
The OEB's decision for the inclusion of the ARC depreciation expense in the revenue

requirement was related to the following observations in the EB-2007-0905 Decision with Reasons:

> *The Board will accept inclusion in the revenue requirement of depreciation expense for the nuclear plants computed in accordance with GAAP, as proposed by OPG. Under GAAP, ARC included in the net book value of fixed assets is depreciated like any other fixed asset cost. It appears as an expense in OPG's income statement. The Board finds that this approach results in a rational allocation of cost.* (pp. 88-89).

4.1.2 Used Fuel Variable Expenses

The used fuel expense is calculated by reference to the difference between the lifecycle cost estimate and the amount of committed costs included in the nuclear liabilities for the corresponding nuclear waste management programs. This difference represents the variable costs of future fuel waste. The present value of this cost difference is then divided by the forecast number of future fuel bundles to calculate the per bundle cost rate. Used fuel variable expenses are calculated by applying the per bundle cost rate to the forecast used fuel volume. The actual used fuel expenses for the 2016 to 2019 period and the forecast amounts for the 2020 to 2026 period are presented in Ex. C2-1-1, Table 1, line 2, and form part of the nuclear fuel expense presented at Ex. F2-5-1, Table 1. The accounting discount rate of 2.94% associated with the latest ARO tranche was used to determine the forecast used fuel expenses for the 2020 to 2026 period.

4.1.3 Low and Intermediate Level Waste Variable Expenses

The L&ILW variable expenses are a component of the OM&A expenses reflected in Ex. F2-2-1, Table 1 and Ex. F2-7-1, Table 1. Similar to used fuel, the difference between the lifecycle cost estimate and the amount of committed costs included in the nuclear liabilities for the corresponding nuclear waste management programs represents the variable costs of future waste. The present value of this cost difference is then divided by the forecast future L&ILW volume estimates to calculate the dollar per cubic metre rate. L&ILW variable expenses are calculated by applying the dollar per cubic metre rate to the forecast waste volumes. The actual L&ILW expenses for the 2016 to 2019 period and the forecast amounts for the 2020 to 2026 period are presented in Ex. C2-1-1, Table 1, line 3. The accounting discount rate of 2.94% associated with the latest ARO tranche was used to determine the forecast L&ILW expenses for the 2020-2026 period.

4.1.4 Return on Rate Base

The OEB-approved nuclear liabilities recovery methodology requires that the return on a portion of the rate base be limited to the weighted average accretion rate. This portion is equal to the lesser of: (i) the average UNL related to the Pickering and Darlington facilities, and (ii) the average unamortized ARC included in the fixed asset balances for these facilities. The remainder of OPG's rate base, including the amount, if any, by which average ARC exceeds average UNL, earns the OEB-approved WACC. The average UNL and the average unamortized ARC, including the apportionment of the ARC between amounts subject to the weighted average accretion rate and the WACC rate, are provided for the 2016 to 2026 period in Ex. C2-1-1, Table 1a.

The OEB's decision for splitting the ARC return component between a portion attracting the weighted average accretion rate and a portion attracting the weighted average cost of capital was related to the following observations in the EB-2007-0905 Decision with Reasons:

> *At some point, the unamortized ARC that is included in fixed assets in effect will be funded by debt or equity because OPG is obligated by ONFA to make cash contributions to the segregated funds; however, until those contributions occur, the ARC component of fixed assets has not been funded with capital supplied by investors.* (p. 89)
>
> *Clearly, OPG incurs accretion expense (at an average rate of 5.6%) on its nuclear liabilities whether they are funded or not.* (p. 90)

The UNL balances for the 2020 to 2026 period are projected based on forecast ARO and segregated fund balances, taking into account forecast activity for future years. For the ARO, forecast activity includes accretion expense on the ARO balance, used fuel and L&ILW variable expenses, and expenditures against the ARO. For the segregated funds, forecast activity includes fund earnings at the target rate of 5.15% consistent with the discount rate per the approved 2017 ONFA Reference Plan, and fund disbursements. The forecast activity for the prescribed facilities' portion of the ARO and segregated funds is shown in Ex. C2-1-1, Table 2.

As seen in Ex. C2-1-1, Table 1a, Note 1, the amount of average unamortized ARC is projected to exceed the amount of average UNL in each year of the IR term. In 2022, the excess of the forecast average unamortized ARC over the forecast average UNL earns WACC of 5.98% and the remainder earns the current weighted average accretion rate of 4.89%. For the 2023-2026 period, the forecast of average UNL is negative and therefore has been set at $0 for the purposes of the revenue requirement calculation.[14] As such, the full amount of the forecast average ARC earns WACC of 5.93% in 2023, 5.99% in 2024 and 6.01% in each of 2025 and 2026. The resulting return on rate base amounts are shown in Ex. C2-1-1, Table 1, lines 4 and 5. The WACC is derived from the deemed capital structure, return on equity and cost of debt proposed by OPG in this application and as set out in Ex. C1-1-1, Tables 1-5 for the corresponding years.

4.1.5 Income Tax Effects

Through the calculation of regulatory income taxes for the prescribed facilities, the nuclear revenue requirement includes income tax impacts associated with the above cost elements for the nuclear liabilities, as well as the tax impacts of the prescribed facilities' contributions to the segregated funds, expenditures on nuclear liabilities and disbursements from the segregated funds.

As further described in Ex. F4-2-1, sections 3.2.1, 3.2.2 and 3.2.6, the cost components of the prescribed facilities' revenue requirement methodology (depreciation, nuclear waste management variable expenses and return components) are not tax deductible and therefore attract a tax gross-up cost. As described in Ex. F4-2-1, sections 3.2.3 and 3.2.4, contributions to the segregated funds and both ONFA-funded and internally funded expenditures on nuclear liabilities are deductible for income tax purposes in accordance with

[14] Setting the average UNL at $0 rather than applying a negative UNL results in a lower revenue requirement impact.

regulations under the *Electricity Act, 1998*, while the disbursements from the segregated funds to cover the ONFA-funded expenditures are correspondingly taxable. The income tax effects of these components are included in the nuclear liabilities' revenue requirement impact at Ex. C2-1-1 Table 1, line 7, as calculated in Ex. C2-1-1 Table 1a, Note 2.

4.2 Approved Revenue Requirement Methodology for the Bruce Facilities

For the Bruce facilities, the OEB determined, by reference to sections 6(2)9 and 6(2)10 of O. Reg. 53/05, that the costs of the nuclear liabilities (as well as other OPG revenues and costs related to the Bruce stations that form part of Bruce Lease net revenues) are to be calculated using generally accepted accounting principles applicable to unregulated entities. Section 6(2)9 requires that the OEB ensure that OPG recovers all the costs it incurs with respect to the Bruce nuclear generating stations. Section 6(2)10 requires that the excess of OPG's revenues over costs related to its lease of these stations be applied to reduce the payment amounts for the prescribed nuclear facilities.

On this matter, the OEB found the following in the EB-2007-0905 Decision with Reasons:

> *The Board finds that the appropriate method to calculate OPG's test period revenues and costs related to the Bruce stations is to use amounts calculated in accordance with GAAP. OPG's investment in Bruce is not rate regulated. In the Board's view, it would be not be a reasonable interpretation of Section 6(2)9 and 6(2)10 to find that OPG should use an accounting method to determine revenues and costs that an unregulated business would otherwise never use.* (p. 109)
>
> *OPG should base its calculation of costs on GAAP. The costs should include all items that would be recognized as expenses under GAAP, including accretion expense on the nuclear liabilities. Forecast earnings on the segregated funds related to the Bruce liabilities should be included as a reduction of costs.* (p. 110)

Under this approach, OPG recovers ARC depreciation expense, used fuel and L&ILW variable expenses and ARO accretion expense, less segregated fund earnings. Each of these components is discussed separately below, as is a summary of the associated income tax impacts.

To give effect to O. Reg. 53/05 requirements, in EB-2007-0905, the OEB established the Bruce Lease Net Revenues Variance Account, which captures the difference between forecast and actual Bruce Lease net revenues, including nuclear liabilities costs. The Bruce Lease Net Revenues Variance Account is discussed in Ex. H1-1-1, Section 5.16.

4.2.1 Depreciation Expense

Depreciation on the unamortized ARC for the Bruce facilities is treated in the same manner as the depreciation associated with other capital assets and the ARC for the prescribed facilities. Total depreciation expense for the Bruce facilities is presented in Ex. G2-2-1, Table 4. Included in these amounts are actual amounts of ARC depreciation expense for 2016 to 2019 and forecast amounts for the 2020 to 2026 period, as presented in Ex. C2-1-1, Table 1, line 9.

4.2.2 Used Fuel Variable Expenses

The used fuel variable expense for the Bruce facilities is determined in the same manner as described in Section 3.3.1.2 for the prescribed facilities. The used fuel expense for the Bruce facilities is presented in Ex. G2-2-1, Table 5. Actual amounts of the expense for the 2016 to 2019 period and forecast amounts for the 2020 to 2026 period are also presented in Ex. C2-1-1, Table 1, line 10.

4.2.3 Low and Intermediate Level Waste Variable Expense

L&ILW variable expenses for the Bruce facilities are determined in the same manner as described in Section 3.3.1.3 for prescribed facilities. The L&ILW expenses for the Bruce facilities are included in amounts shown in Ex. G2-2-1, Table 5. Actual amounts of the expenses for the 2016 to 2019 period and amounts forecast for the 2020 to 2026 period are also presented in Ex. C2-1-1, Table 1, line 11.

4.2.4 Accretion Expense

As discussed above, accretion expense represents the growth in the present value-based ARO due to the passage of time. The attribution of the ARO balances between prescribed facilities and Bruce facilities is discussed in Section 3.1 above. Forecast accretion expense for the Bruce facilities for the 2020 to 2026 period is derived by applying the corresponding accretion rates to the opening balances of each ARO tranche, using the same methodology as in prior payment amounts applications. The forecast amounts were derived by reference to the June 30, 2020 ARO balances from OPG's second quarter 2020 consolidated financial statements, using the half-year rule and based on projected changes in the Bruce stations' portion of the ARO due to additional used fuel and L&ILW variable expenses and expenditures against the ARO during the forecast period as shown in Ex. C2-1-1, Table 3. Actual amounts of the accretion expense for the 2016 to 2019 period and amounts forecast for the 2020 to 2026 period are presented in Ex. C2-1-1, Table 1, line 12 as well as Ex. G2-2-1, Table 5, line 3.

4.2.5 Earnings on the Segregated Funds

The station-level attribution of the segregated funds balances is discussed in Section 3.1 above. Actual segregated funds earnings for the 2016 to 2019 period and amounts forecast for the 2020 to 2026 period are presented in Ex. C2-1-1, Table 1, line 13 as well as Ex. G2-2-1, Table 5, line 4. Forecast segregated funds earnings were determined using the same methodology as in prior payment amounts applications. In particular, earnings were determined by applying the target rate of 5.15% consistent with the discount rate per the approved 2017 ONFA Reference Plan, to the opening balances of each fund. Such earnings take into account, using the half-year rule, contributions to the segregated funds pursuant to the approved 2017 ONFA Contribution Schedule and projected disbursements from the funds as shown in Ex. C2-1-1, Table 3. The forecast amounts were derived by reference to the June 30, 2020 segregated funds asset balances from OPG's second quarter 2020 consolidated financial statements.

4.2.6 Income Tax Effects

The calculation of Bruce Lease net revenues includes the income tax expense associated with the above cost elements for the nuclear liabilities.[15] As these items are not deductible for tax purposes, they attract a deferred income tax credit in accordance with generally accepted accounting principles. This credit is included in the nuclear liabilities' revenue requirement impact at Ex. C2-1-1, Table 1, line 14, as calculated in Ex. C2-1-1 Table 1a, Note 3. As part of Bruce Lease net revenues, segregated fund contributions and expenditures on nuclear liabilities (net of disbursements from the segregated funds), as tax deductible items, reduce the current income tax expense but also attract an equal and offsetting deferred income tax cost, with no net effect.[16]

Additionally, Bruce Lease net revenues amounts are subject to regulatory income tax treatment through their impact on regulatory earnings before tax for the prescribed facilities, as shown at Ex. C2-1-1, Table 1, line 16.

5.0 CHANGES IN ARO, UNAMORTIZED ARC AND SEGREGATED FUND BALANCES

With the exception of 2016 and 2017, which include a year-end ARO balance adjustment reflecting approved 2017 ONFA Reference Plan and changes in Pickering station EOL dates, respectively, the actual and forecast growth in the ARO for the period to 2026 is primarily the result of accretion expense. Similarly, with the exception of the year-end ARC balance adjustments in 2016 and 2017 corresponding to the above ARO adjustments, depreciation and, for the prescribed facilities, the planned Pickering shutdown are the drivers of the otherwise declining trend in the ARC balances over the period to 2026.

The 2017 ONFA Reference Plan adjustment to the ARO and ARC balances at the end of 2016 is the same as provided in EB-2016-0152 and reflected in the EB-2016-0152 approved nuclear revenue requirement and payment amounts.[17] The revenue requirement impact of the year-end 2017 ARO and ARC adjustment on the prescribed facilities and the Bruce

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[15] The calculation of the total income tax expense component of Bruce Lease net revenues is discussed further in Ex. G2-2-1, sections 4.8 and 4.9 and presented in Ex. G2-2-1, Tables 7 and 8.
[16] As the net tax effect is nil, these items are not identified in the calculation of the income tax component of Bruce Lease net revenues at Ex. C2-1-1 Tables 1 and 1a.
[17] EB-2016-0152 Decision and Order, pp. 91, 98.

facilities is discussed in Section 6.0.

The actual and forecasted growth in the segregated funds balance for the 2016 to 2026 period is mainly the result of actual and forecasted fund earnings and station-level contribution amounts in accordance with the 2017 ONFA Contribution Schedule.

The proposed IR term revenue requirement reflects the current accounting EOL dates for the Pickering station of December 31, 2022 for Units 1 and 4 and December 31, 2024 for Units 5 to 8. As the Pickering ARC balance fully depreciates by the end of 2024 based on these assumptions, there is significant decrease in the forecast ARC balance and associated depreciation expense for the prescribed facilities. As of the beginning of 2026, the ARC balance for the prescribed facilities is forecast at $96M, compared to $851M at the beginning of 2016 and $447M at the beginning of 2020.

The treatment of Pickering EOL dates is discussed in further detail in Ex. F4-1-1, Section 3.2 and Ex. H1-1-1, Section 6.2. As noted in those exhibits, OPG is applying for a deferral account related to future anticipated changes to Pickering station EOL dates for accounting purposes, including any associated impact on nuclear liabilities for the prescribed facilities, as part of this application in line with the OEB's accounting order requirements, effective January 1, 2021. Any associated impact on nuclear liabilities for the Bruce facilities, through allocation of central program costs across the nuclear fleet based on lifecycle waste volume estimates, will be recorded in the Bruce Lease Net Revenues Variance Account in the normal course.

6.0 YEAR-END 2017 NUCLEAR LIABILITIES ADJUSTMENT

As described in EB-2018-0002 and discussed in Ex. F4-1-1, Section 3.2, OPG implemented changes to accounting EOL date assumptions for the Pickering station, from December 31, 2020 for Pickering Units 1 and 4 and Units 5 to 8 to December 31, 2022 for Pickering Units 1 and 4 and December 31, 2024 for Units 5 to 8, effective December 31, 2017.

Effective December 31, 2017, in accordance with US GAAP, OPG recorded an increase in the carrying values of the ARO and ARC of $188.4 million, comprising $143.7 million for the prescribed facilities and, through allocation of central program costs across the nuclear fleet based on lifecycle waste volume estimates, $44.7 million for the Bruce facilities, to reflect the changes in the Pickering station EOL date assumptions. The net increase in the ARO was primarily due to the increase in the committed costs associated with used fuel disposal activities resulting from the extension of the Pickering units' operating period and related additional used fuel. The detail of the year-end 2017 ARO adjustment are provided in Ex. C2-1-1, Table 4.

The total revenue requirement impacts from the above change in the ARO and ARC balances over the 2018-2021 period are estimated at $186M for the prescribed facilities, including $47M in associated income tax impacts, as shown at Ex. H1-1-1, Table 13.[18] These impacts are recorded in the Impact Resulting from Changes to Pickering Station End-of-Life Dates (December 31, 2017) Deferral Account pursuant to the EB-2018-0002 Decision and Order and are nearly identical to the estimated impacts provided during that proceeding.[19] [20]

The prescribed facilities' impacts over the period reflect higher ARC depreciation due to the increase in the ARC balance, partially offset by the impact of extending the period over which ARC is being depreciated. The impacts also include a higher return on rate base, due to the increase in the ARC balance, and higher used fuel variable expenses, due to an increase in per bundle cost rates reflecting a lower discount rate of 2.94% (compared to 3.20%[21] in use prior to the year-end 2017 adjustment).

For the Bruce facilities, the above changes in the ARO and ARC balances are estimated to decrease Bruce Lease net revenues by approximately $20M in total over the 2018-2021

[18] These impacts have been determined by applying the revised Pickering station EOL dates, ARO/ARC adjustment and volumetric variable cost rates to recalculate the corresponding OEB-approved values (such as ARC depreciation and used fuel and L&ILW variable expenses) reflected in the EB-2016-0152 revenue requirement, holding other variables constant (such as forecast volumes of used fuel and L&ILW).
[19] EB-2018-0002, OPG's response to Board Staff Interrogatory #1, Attachment 1, Table 1.
[20] The Impact Resulting from Changes in Pickering Station End-of-Life Dates (December 31, 2017) Deferral Account is discussed in Ex. H1-1-1, Section 5.22.
[21] Footnote 3.

period. This is primarily due to higher used fuel variable expenses for the above noted reason. The impacts are recorded in the Bruce Lease Net Revenues Variance Account.

7.0 2022 ONFA REFERENCE PLAN STATUS

As discussed in Section 3.2, OPG reviews and updates the ONFA Reference Plan and associated lifecycle cost estimates and assumptions at least every five years, in line with the ONFA requirements. Updated ONFA Reference Plans are submitted to the Province for review and approval. The next Reference Plan update, effective for the 2022-2026 period, is under development and is expected to be finalized in 2021 for the Province's approval.

The proposed IR term revenue requirement reflects the approved 2017 ONFA Reference Plan. The corresponding revenue requirement impact of the approved 2022 Reference Plan will be recorded in the Nuclear Liability Deferral Account for the prescribed facilities and the Bruce Lease Net Revenues Variance Account for the Bruce facilities, as described in Ex. H1-1-1.[22]

7.0 JURISDICTIONAL STUDY OF COST RECOVERY METHODOLOGIES

In the EB-2016-0152 Decision and Order, the OEB directed OPG to "provide a jurisdictional study of cost recovery methodologies for nuclear liabilities with its next cost based nuclear payment amounts application".[23] OPG retained KPMG LLP to undertake this Jurisdictional Study, which is provided in Attachment 3.

The key findings of the Jurisdictional Study are as set out in the executive summary and Part IV of the Jurisdictional Study.

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[22] Any additions to the Nuclear Liability Deferral Account related to the 2022-2026 ONFA Reference Plan and to the proposed deferral account related to future changes to Pickering station EOL dates for accounting purposes (Ex. H1-1-1, section 6.2) would be calculated such that they do not duplicate impacts across the accounts.

[23] EB-2016-0152 Decision and Order, p. 97.

ATTACHMENT 1

Approved Used Fuel Fund Quarterly Contributions ($)						
	Pickering A (Units 1-4)	Pickering B (Units 5-8)	Bruce A	Bruce B	Darlington	Total
3/31/2017	(12,516,579)	(9,206,560)	(19,205,814)	54,670,578	(13,741,624)	0
6/30/2017	(12,516,579)	(9,206,560)	(19,205,814)	54,670,578	(13,741,624)	0
9/29/2017	(12,516,579)	(9,206,560)	(19,205,814)	54,670,578	(13,741,624)	0
12/29/2017	(12,516,579)	(9,206,560)	(19,205,814)	54,670,578	(13,741,624)	0
3/30/2018	(12,516,579)	(9,206,560)	(19,205,814)	54,670,578	(13,741,624)	0
6/29/2018	(12,516,579)	(9,206,560)	(19,205,814)	54,670,578	(13,741,624)	0
9/28/2018	(12,516,579)	(9,206,560)	(19,205,814)	54,670,578	(13,741,624)	0
12/31/2018	(12,516,579)	(9,206,560)	(19,205,814)	54,670,578	(13,741,624)	0
3/29/2019	(12,516,579)	(9,206,560)	(19,205,814)	54,670,578	(13,741,624)	0
6/28/2019	(12,516,579)	(9,206,560)	(19,205,814)	54,670,578	(13,741,624)	0
9/30/2019	(12,516,579)	(9,206,560)	(19,205,814)	54,670,578	(13,741,624)	0
12/31/2019	(12,516,579)	(9,206,560)	(19,205,814)	54,670,578	(13,741,624)	0
3/31/2020	(12,516,579)	(9,206,560)	(19,205,814)	54,670,578	(13,741,624)	0
6/30/2020	(12,516,579)	(9,206,560)	(19,205,814)	54,670,578	(13,741,624)	0
9/30/2020	(12,516,579)	(9,206,560)	(19,205,814)	54,670,578	(13,741,624)	0
12/31/2020	(12,516,579)	(9,206,560)	(19,205,814)	54,670,578	(13,741,624)	0
3/31/2021	(12,516,579)	(9,206,560)	(19,205,814)	54,670,578	(13,741,624)	0
6/30/2021	(12,516,579)	(9,206,560)	(19,205,814)	54,670,578	(13,741,624)	0
9/30/2021	(12,516,579)	(9,206,560)	(19,205,814)	54,670,578	(13,741,624)	0
12/31/2021	(12,516,579)	(9,206,560)	(19,205,814)	54,670,578	(13,741,624)	0

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Approved Decommissioning Fund Quarterly Contributions ($)						
	Pickering A (Units 1-4)	Pickering B (Units 5-8)	Bruce A	Bruce B	Darlington	Total
3/31/2017	38,377,991	26,864,182	(37,743,464)	(23,346,329)	(4,152,381)	0
6/30/2017	38,377,991	26,864,182	(37,743,464)	(23,346,329)	(4,152,381)	0
9/29/2017	38,377,991	26,864,182	(37,743,464)	(23,346,329)	(4,152,381)	0
12/29/2017	38,377,991	26,864,182	(37,743,464)	(23,346,329)	(4,152,381)	0
3/30/2018	38,377,991	26,864,182	(37,743,464)	(23,346,329)	(4,152,381)	0
6/29/2018	38,377,991	26,864,182	(37,743,464)	(23,346,329)	(4,152,381)	0
9/28/2018	38,377,991	26,864,182	(37,743,464)	(23,346,329)	(4,152,381)	0
12/31/2018	38,377,991	26,864,182	(37,743,464)	(23,346,329)	(4,152,381)	0
3/29/2019	38,377,991	26,864,182	(37,743,464)	(23,346,329)	(4,152,381)	0
6/28/2019	38,377,991	26,864,182	(37,743,464)	(23,346,329)	(4,152,381)	0
9/30/2019	38,377,991	26,864,182	(37,743,464)	(23,346,329)	(4,152,381)	0
12/31/2019	38,377,991	26,864,182	(37,743,464)	(23,346,329)	(4,152,381)	0
3/31/2020	38,377,991	26,864,182	(37,743,464)	(23,346,329)	(4,152,381)	0
6/30/2020	38,377,991	26,864,182	(37,743,464)	(23,346,329)	(4,152,381)	0
9/30/2020	38,377,991	26,864,182	(37,743,464)	(23,346,329)	(4,152,381)	0
12/31/2020	38,377,991	26,864,182	(37,743,464)	(23,346,329)	(4,152,381)	0
3/31/2021	38,377,991	26,864,182	(37,743,464)	(23,346,329)	(4,152,381)	0
6/30/2021	38,377,991	26,864,182	(37,743,464)	(23,346,329)	(4,152,381)	0
9/30/2021	38,377,991	26,864,182	(37,743,464)	(23,346,329)	(4,152,381)	0
12/31/2021	38,377,991	26,864,182	(37,743,464)	(23,346,329)	(4,152,381)	0
3/31/2022	38,377,991	26,864,182	(37,743,464)	(23,346,329)	(4,152,381)	0
6/30/2022	38,377,991	26,864,182	(37,743,464)	(23,346,329)	(4,152,381)	0
9/30/2022	38,377,991	26,864,182	(37,743,464)	(23,346,329)	(4,152,381)	0
12/30/2022	38,377,991	26,864,182	(37,743,464)	(23,346,329)	(4,152,381)	0
3/31/2023	0	26,864,182	(15,541,286)	(9,613,107)	(1,709,788)	0
6/30/2023	0	26,864,182	(15,541,286)	(9,613,107)	(1,709,788)	0
9/29/2023	0	26,864,182	(15,541,286)	(9,613,107)	(1,709,788)	0
12/29/2023	0	26,864,182	(15,541,286)	(9,613,107)	(1,709,788)	0
3/29/2024	0	26,864,182	(15,541,286)	(9,613,107)	(1,709,788)	0
6/28/2024	0	26,864,182	(15,541,286)	(9,613,107)	(1,709,788)	0
9/30/2024	0	26,864,182	(15,541,286)	(9,613,107)	(1,709,788)	0
12/31/2024	0	26,864,182	(15,541,286)	(9,613,107)	(1,709,788)	0

Ontario Power Generation

Nuclear Liability Cost Recovery Jurisdictional Study

KPMG LLP

December 2020

This report contains 181 pages

OPG_Report

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Ontario Power Generation
Nuclear Liability Cost Recovery Jurisdictional Study

Executive Summary

In its Decision and Order in proceeding EB-2016-0152, the Ontario Energy Board ("OEB") directed that OPG "should provide a jurisdictional study of cost recovery methodologies for nuclear liabilities with its next cost based nuclear payment amounts application".[1]

We prepared this Nuclear Liability Cost Recovery Jurisdictional Study at the request of OPG to support its response to the OEB directive to review nuclear decommissioning cost recovery methodologies used in jurisdictions outside of Ontario.

Our study included a sample of companies in Europe, Asia and North America. Canadian and the United States ("US") jurisdictions were most relevant to the review of cost recovery methods due to their regulatory regimes being the most consistent with those of Ontario.

In general, we have found that the relevant parties (governments, regulators and nuclear power plant owners) seek to collect costs associated with decommissioning over the operating life of power plants, with funds collected from users (i.e. consumers of power) rather than from taxpayers. External segregated funds are commonly used to provide financial assurance that funds will be available at the end of a nuclear plant's life to perform decommissioning activities. The definition of costs associated with decommissioning and the methods of recovery vary across jurisdictions. Further, the complexity of decommissioning activities and the substantial amount of time that passes before they will occur introduces significant estimation uncertainty.

Scope of obligation for decommissioning costs

The scope of the obligation of 'costs associated with decommissioning' to be recovered from users varies across jurisdictions. We identified four broad categories of costs:

1) **Plant decommissioning**. This involves the safe removal of a nuclear facility from service and the reduction of residual radioactivity to a level that permits release of the property and termination of its operating license.
2) **Site restoration**. This involves the removal of non-radioactive equipment at a site and its return to a greenfield or near-greenfield condition, where the site can be used for other purposes.
3) **Low-level and intermediate level waste**. This involves dealing with items that have been contaminated with radioactive material or exposed to radiation during the operation of the plant.
4) **Spent fuel long-term storage and processing.** This involves dealing with spent nuclear fuel, which remains highly radioactive and must be stored securely after its use for a very long period of time. The processing of spent fuel may involve packing it in specialized containers and the storage of these containers in some form of geologic repository.

In a few jurisdictions, most notably the US and Japan, the government has assumed responsibility for long-term spent fuel storage, underwriting a potentially large part of the associated cost risk. For example, the United States Department of Energy ("US DOE") is responsible for the disposal of spent nuclear fuel from commercial power reactors, levying fees on US utilities to fund building a central spent fuel storage facility. Since spent nuclear fuel tends to account for a significant percentage of overall nuclear decommissioning and waste management costs, this significantly reduces US utilities' direct cost responsibility and funding obligations.

[1] Ontario Energy Board, Decision and Order, EB-2016-0152, December 28, 2017, p. 97.

Additionally, some regulators excluded site restoration costs from the costs recoverable from users as there was not a legal requirement to complete restoration costs.

Rate recovery methods

We found a wide range of practices with respect to nuclear decommissioning cost recovery. We have organized the practices we identified into four broad methodologies, as follows:

1) **Forward looking funding requirements**. This method bases recoveries from consumers on the amounts that need to be contributed through financial assurance mechanisms to set-aside funds to pay for future in-scope obligations related to nuclear decommissioning and waste management.
2) **Accounting expense.** This method bases recoveries from consumers on the amount of expenses recognized in the company's financial statements related to asset retirement obligations for nuclear decommissioning and waste management; amounts collected may be offset by earnings from trust funds over the same period.
3) **Flow through cost**. This method "passes" through to consumers the fees or levies payable by utilities to other parties in exchange for these parties effectively discharging the utilities' obligations for nuclear decommissioning or, more often, for waste management and spent fuel management.
4) **Arbitrary rate.** This method bases recovery from consumers on an arbitrary or quasi-arbitrary rate that is not directly or clearly linked to the underlying costs or obligations of the utility or of the parties fulfilling functions on their behalf.

Rate recovery methods outside of North America

Many of the European Jurisdictions included in our study have developed competitive electricity markets as the primary electricity pricing setting mechanism. Accordingly, there is no clear link between decommissioning and waste management costs and the prices paid by consumers in these jurisdictions. As a consequence of the prevalence of competitive electricity markets, we had a lesser focus on European jurisdictions in our subsequent research. We did apply greater attention to three European jurisdictions, France, UK and Finland where there are exceptions from the general open-market approach.

In other jurisdictions it proved difficult to determine the link between decommissioning and waste management costs and the prices paid by users; therefore we undertook more limited research in these jurisdictions as they were not considered readily comparable or applicable to the regulatory structures in Ontario..

Rate recovery methods in the US and Canada

We found that the forward-looking funding approach is the dominate methodology used in the US to determine amounts collected from consumers for nuclear decommissioning costs. In the US, the Nuclear Regulatory Commission (US) ("NRC") establishes a legal requirement for nuclear operators to fund external segregated funds to cover decommissioning costs of nuclear plants. It is important to note that this methodology has largely been in place before any accounting based guidance on Asset Retirement Obligations was available in the U.S.

- The NRC defines the minimum costs that must be covered through funding plans with a standard formula that takes into account reactor type and capacity. In combination with prescribed escalation factors, this formula identifies the minimum value of projected costs in current dollars. These minimum amounts may not have a direct correlation to site specific decommissioning costs to be expected at individual locations.
- Utilities must prepare site-specific cost estimates as the reactor nears the end of its operating life (but can prepare such studies earlier if desired).

Based in the cost parameters identified above, utilities then prepare funding plans that show the accumulation of funds over time to meet expected decommissioning costs. These funds identify future contributions, taking into account current fund balances and expected earnings. Fund contributions generally become part of regulated a utility's revenue requirement. With respect to these funding plans:

- The NRC defers to state utility regulators on certain parameters and thus allows them to approve estimates of future cost escalation rates, rates of return on invested funds, and on the profile of trust fund contributions. The NRC, however, provides guidance in respect of these parameters.
- The Utilities must file updates on a biennial basis with the NRC on funding status, and funding shortfalls identified must be made up within a defined period. The identification of funding status in these updates will take into account the parameters accepted by utility regulators (such as with respect to projected fund earnings rates).

In Canada, the accounting expense methodology, or a variation of this methodology, is used by OPG and NB Power. The specific application of the accounting expense methodology is impacted by the nature of the regulatory mechanisms for recovery of costs in these two provinces. The only other company in Canada with nuclear operations was Hydro Quebec and based on their regulatory regime there was no observable link between retail prices and the recovery of nuclear decommissioning and waste management costs. Nuclear generation in Quebec has since been phased out.

NB power sets rates based on principles of making progress towards the achievement of a minimum capital structure of 20% over a reasonable timeframe. NB Power uses a 10-year plan to show progress towards this financial target, and the 10-year plan includes depreciation expense, accretion expense and earnings on sinking funds in the equity calculation.

OPG utilizes an accounting based approach to the Bruce facilities where they seek to recover depreciation expense, accretion expense, variable used fuel management and waste management expenses less segregated fund earnings. The recovery of costs for the Pickering and Darlington generation stations ("Regulated facilities") utilizes a modified approach where depreciation of the ARC and a rate of return on the lessor of the unfunded nuclear liabilities or undepreciated ARC and the variable used fuel management and waste management expenses. This method excludes accretion expense and return on the segregated funds.

Ultimate Commonality Between Methods

Regardless of the use of forward looking funding requirements or accounting expense methods, the ultimate end objective of each method is the same, that being to ensure the costs of executing decommissioning and nuclear waste management activities are adequately funded and expensed in a rational manner over a period of time such that all funds are used without surplus or deficit and that all liabilities are adequately reflected and charged to operations without a residual profit or loss. Any change in methodology mid-cycle or that does not cover the entire lifecycle would introduce transitional matters that would have to be evaluated to ensure the same ultimate objectives are met.

Impacts on Inter-generational Equity

As noted above, NRC requires specific site-specific estimates to be prepared as the reactor nears the end of its operating life. A "preliminary" decommissioning cost estimate must be prepared at or about 5 years from the projected end of operations. "Site specific" estimates must be prepared prior to or within 2 years of the end of operations.

A review of a sample of US rate proceedings suggests that many utilities may prepare site-specific estimates well before they are specifically required under NRC guidance.

The move to more precise estimates over time, and certainly as the decommissioning date approaches, may have inadvertent impacts on inter-generational equity. The preparation of site-specific estimates should theoretically address any shortfalls in the estimates of costs available as a result of using the NRC formula. We note, however, that to the extent that these site-specific estimates are prepared later in a reactor's life, and result in increases in estimated decommissioning costs, it might reasonably be assumed that these estimates would then result in increases in funds being set aside for decommissioning. Assuming that these funding increases late in the reactor's life are only then reflected in the rate-setting process, this would presumably tend to increase the back-end loading associated with the recovery of decommissioning costs. We have not done any research to confirm if this has been a widespread issue. However, we do note that this circumstance appears to have arisen in the case of PGE's Diablo plant, as reviewed in more detail in our Chapter on California.

Impacts of transitions in market structure

When utilities have transitioned from a regulated regime to one with a competitive electricity market, anomalies may arise as a result of the transition process. Transition processes typically complicate funding arrangements and introduce policy challenges. It may be easier to guarantee the recovery of decommissioning costs from regulated entities and from periods where rates are subject to regulation, and this may be reflected in arrangements for funding decommissioning costs when market structures change.

Examples of transition were found, for example, in many US jurisdictions. Many regional jurisdictions in the US have introduced a competitive spot market for electricity or some form of power pool at the wholesale level. In these jurisdictions, many states also restructured their electric utility sector to "unbundle" generation from transmission and distribution, and to provide consumers with retail open-access, in which individual consumers can choose their commodity supplier. Alternatively, vertically-integrated, regulated utilities may continue to operate. (In the latter case, the utility has access to an open spot market but individual retail customers are still dependent on their utility for commodity procurement.)

The process of market restructuring, and unbundling of generation, often created issues for vertically integrated utilities that had existing generation plants, particularly nuclear facilities. In these circumstances, shareholders were typically kept whole through some form of non-bypassable stranded asset charge, levied on all consumers going forward. These charges were a mechanism to compensate utility shareholders for the one-time losses in asset value associated with market opening. Decommissioning obligations were often a significant component of stranded cost estimates.

Regulatory Flexibility

Regulators' discretion in applying regulatory principles may be greater under some approaches for quantification than under others. For example, regulators likely have considerably more flexibility to adjust the allocation of decommissioning costs across time periods under a forward-looking funding approach than when rates are set based on accounting expenses. Accounting expenses are determined based on defined methodologies and there is limited scope to adjust calculated amounts in any given circumstance. In contrast, the primary focus of a forward-looking funding approach is simply on ensuring that there is funding adequacy at the time of decommissioning. This can theoretically be achieved using a wide variety of different funding scenarios. Notwithstanding this flexibility, however, regulators and utilities do in practice apply other regulatory objectives, such as achieving reasonable intergenerational equity or reducing the risk of underfunding, when setting up contribution profiles under forward looking approaches.

Screening level comparison to OPG methodology and transition consideration

As part of our scope of work, we prepared a screening level comparison between OPG's methodology and potentially applicable methodologies identified in our study. We determined that the forward looking funding requirement and the accounting expense methodologies would potentially be applicable based on the most prevalent rate recovery mechanisms identified and the jurisdictional characteristics that are most similar to OPG. These methods appear to be common in jurisdictions subject to economic regulation. The flow through method and the arbitrary rate methods are not broadly applicable rate recovery methods.

The comparison highlights similarities and differences between OPG's methodology for the Bruce facilities and Regulated facilities to the forward looking funding requirement methodology and the accounting expense methodology. This comparison was used to identify considerations for transitions. Some key transition considerations:

- Transition processes needs to adhere to established rate-making principles, including fairness, minimizing intergenerational inequities, transparency, minimizing rate volatility, appropriate allocation of risk, providing value to customers, consistency and simplicity, and alignment with required financial accounting and reporting principles.
- Recovery mechanism for Bruce facilities and Regulated facilities may not be aligned due to the different regulatory mechanism and legal agreements.
- Under the forward looking funding requirement methodology, the economic regulator's oversight would increase to include the determination of cost estimates, profile of recovery and expected rates of return. Consideration would need to be given to the role of ONFA in Ontario as those functions have been the purview of the Ministry of Finance as part of their oversight on nuclear liability cost estimates and their joint management of the segregated funds.

A detailed and specific analysis would be needed to identify all transition considerations to change from OPG's method to another potentially applicable methodology. Such a detailed and specific analysis is beyond the scope of this study.

Transitions between methodologies

We did not observe changes between recovery methods in the jurisdictions reviewed, for operations that remain under regulation. Looking at the US Jurisdictions, NRC requirements took effect in 1990, and the predominant method to meet funding assurance requirements thereafter was the external sinking fund. As noted earlier, the forward-looking funding approach is the most common rate recovery mechanism. This funding methodology has continued to be applied in the US jurisdictions we reviewed.

We note that the US jurisdictions adopted this approach prior to the implementation of accounting standards that mandated the recognition of asset retirement obligations for nuclear facilities and associated accounting expenses in their publicly available financial statements. In 2003, FAS 143 - Accounting for Asset Retirement Obligations ("ARO"), became effective for most US GAAP reporting issuers. Affected US utilities typically proposed, and their economic regulators accepted, that the new accounting standard would not impact the rate recovery of decommissioning costs and that rates would continue to be based on a forward looking funding approach. The US jurisdictions determined they could record the differences between amounts for rate setting purposes and accounting expenses in regulatory assets (or liabilities) in accordance with ASC 980, regulated operations, and therefore the adoption of FAS 143 was income neutral upon adoption.

The above timelines, in which current accounting standards followed NRC requirements for financial assurance, may conceivably have influenced the adoption of the funding approach in the US. In comparison, we note that OPG's Nuclear facilities entered regulation after the adoption of FAS 143. Hence, accounting methodologies were already in place and influenced the recovery method approved for use by OPG.

Part I – Introduction and Overview

1 Introduction

Ontario Power Generation ("OPG") retained KPMG LLP ("KPMG") to prepare a study of the cost recovery methodologies used in other jurisdictions with respect to short-term and long-term liabilities associated with nuclear decommissioning and nuclear waste (including used fuel). This report summarizes the results of our review.

1.1 Background

In its Decision and Order in proceeding EB-2016-0152, the Ontario Energy Board ("OEB") directed that OPG "should provide a jurisdictional study of cost recovery methodologies for nuclear liabilities with its next cost based nuclear payment amounts application".[2] This review is intended to support OPG's response to this directive.

1.2 Limitations

The findings of this review have been developed through a review of publicly available information, including company annual reports, regulatory filings and decisions, rating agency reports, government publications, news articles and academic papers. In some cases we have supplemented our research and confirmed findings through discussions with knowledgeable individuals in the nuclear industry. There are inherently limitations in undertaking research of this nature:

- We may not have identified the most recent or most relevant documents in respect of practices in any particular jurisdiction or utility.
- Practices may have changed in the period of time since any particular document that we have reviewed was published.
- We may not have interpreted the information collected properly as a result of limitations on the data that was publicly available.
- As per the Engagement Agreement, our study did not cover all jurisdictions, entities, or all time periods.

Further, as noted in the Notice of Reader, we have not independently verified the information provided in the materials that have been reviewed and summarized. As such, our report does not constitute an audit, examination or review in accordance with standards established by the Chartered Professional Accountants of Canada.

Given the limitations noted above, we do not warrant that our findings are complete and/or accurately capture all elements of cost recovery practices for nuclear decommissioning and waste management.

Nevertheless, we think that our review provides a useful overview of the range of practices that are used for the recovery of nuclear decommissioning and waste management costs from customers, and of the factors and considerations that have influenced their establishment. Accordingly, we believe it should provide useful information in the context of assessments that may need to be made regarding cost recovery for OPG's nuclear decommissioning and waste management liabilities.

[2] Ontario Energy Board, Decision and Order, EB-2016-0152, December 28, 2017, p. 97.

1.3 List of Acronyms and Terms

ACC:	Arizona Corporations Commission.
AERB:	Atomic Energy Regulatory Board (India).
AGR:	Advanced Gas-Cooled Reactors.
ARO:	Asset Retirement Obligations.
ARC:	Asset Retirement Cost.
BEIS:	Department of Business, Energy and Industrial Strategy (UK).
CANDU:	Canada Deuterium Uranium heavy-water reactor
CAG:	Comptroller and Auditor General of India.
ComEd:	Commonwealth Edison Company.
CPUC:	California Public Utilities Commission.
CCA:	Community Choice Aggregator (US).
CfD:	Contract for Differences.
CNP:	Commission for Nuclear Provisions (Belgium).
CNSC:	Canadian Nuclear Safety Commission (Canada).
CPUC:	California Public Utilities Commission.
CRE:	Energy regulator (France).
CR3:	Crystal River 3 Nuclear Plant (US)
DAE:	Department of Atomic Energy (India).
DEC:	Duke Energy Carolinas (US).
DEP:	Duke Energy Progress (US).
DECON:	A decommissioning approach in which a nuclear facility is dismantled immediately after closure, permitting release of the property and termination of the NRC license.
DSM:	Demand-Side Management.
FDP:	Funding Decommissioning Programme (UK).
FERC:	Federal Energy Regulatory Commission (US).
FPC:	Florida Power Corporation.
FPL:	Florida Power & Light.
GAAP:	Generally Accepted Accounting Principles.
GASB:	Government Accounting Standards Board.
HPC:	Hinkley Point C (UK).
ICC:	Illinois Commerce Commission.
IFRS:	International Financial Reporting Standards.

IOU:	Investor-Owned Utility.
IPA:	Illinois Power Agency.
IRP:	Integrated Resource Plan.
IRS:	Internal Revenue Service (US).
JNFL:	Japan Nuclear Fuel Limited.
JPEX:	Japan Electric Power Exchange.
LADWP:	Los Angeles Department of Water and Power.
MEAE:	Ministry of Economic Affairs and Employment (Finland).
MEC:	Minnesota Energy Consumers.
METI:	Ministry of Economy, Trade and Industry (Japan).
MFF:	Municipal Franchise Fee (US).
MISO:	Midcontinent Independent System Operator (US).
NAO:	National Audit Office (UK).
NCUC:	North Carolina Utilities Commission.
NDCA:	Nuclear Decommissioning Cost Adjustment (US).
NDT:	Nuclear Decommissioning Trust.
NEB:	National Energy Board (Canada).
NFWA:	Nuclear Fuel Waste Act (Canada).
NLF:	Nuclear Liabilities Fund (UK).
NRC:	Nuclear Regulatory Commission (US).
NSPC:	Northern States Power Company.
NWPA:	Nuclear Waste Policy Act of 1982 (US).
OCI:	Other Comprehensive Income.
OEB:	Ontario Energy Board.
OPG:	Ontario Power Generation.
ONDRAF:	Belgian Agency for Radioactive Waste and Enriched Fissle Materials.
ONFA:	Ontario Nuclear Funds Agreement (Canada).
ORS:	Office of Regulatory Staff (US).
PAPDUC:	Pennsylvania Public Utility Commission.
PEC:	Progress Energy Carolina.
PG&E:	Pacific Gas & Electric.
PPE:	Property Plant & Equipment.

PSC: Public Service Commission (US).

PSCSC: Public Service Commission of South Carolina.

PUC: Public Utilities Commission (US).

Palo Verde: Palo Verde Nuclear Generating Station (US).

PWR: Pressurized Water Reactor.

Rate RSE: Rate Stabilization and Equalization Factor (Alabama).

REC: Rural Electric Co-operative.

ROE: Return on Equity.

RPS: Renewable Portfolio Standard.

SAFSTOR: A decommissioning approach in which dismantling of a nuclear facility is deferred, allowing for the decay of radioactivity prior to the plant's removal.

SBC: System Benefits Charge.

SCE&G: Southern Carolina Electric & Gas Company.

SERI: System Energy Resources Inc.

SFAS: Statement of Financial Accounting Standards (US).

SONGS 1: San Onofre Nuclear Generating Station (US).

SRP: Salt River Project (US).

TVA: Tennessee Valley Authority.

TVO: Teollisuuden Voima (Finland).

US: United States of America

US DOE: United States Department of Energy.

US GAO: United States Government Accountability Office.

VYR: Finnish Nuclear Waste Management Fund.

2 Approach to Study

This Chapter summarizes our approach to the Nuclear Liability Cost Recovery Jurisdictional Study.

2.1 Countries with Operating Nuclear Reactors

As summarized in Exhibit 2-1, operating nuclear power plants are found in 30 countries. Countries have been listed in order of decreasing nuclear power production for 2019 (in TWh). Data are also shown for the number of operational reactors and the percentage of electricity production accounted for by nuclear power generation.

Exhibit 2-1[3]

List of Countries with Operating Nuclear Power Reactors (2019)					
Ranking 2019	**Country**	**Nuclear Generation (TWh)**	**Nuclear Share (%)**	**Operating Reactors**	**Reactors under construction**
1	USA	809.4	19.7%	94	2
2	France	382.4	70.6%	56	1
3	China (Mainland)	330.1	4.9%	48	15
4	Russia	195.5	19.7%	38	2
5	South Korea	138.8	26.2%	24	4
6	Canada	94.9	14.9%	19	0
7	Ukraine	78.1	53.9%	15	2
8	Germany	71.1	12.4%	6	0
9	Japan	65.7	7.5%	33	2
10	Sweden	64.4	34.0%	7	0
11	Spain	55.9	21.4%	7	0
12	United Kingdom	51.0	15.6%	15	2
13	Belgium	41.4	47.6%	7	0
14	India	40.7	3.2%	22	7
15	Czech Republic	28.6	35.2%	6	0
16	Switzerland	25.4	23.9%	4	0
17	Finland	22.9	34.7%	4	1
18	Bulgaria	15.9	37.5%	2	0
19	Hungary	15.4	49.2%	4	0
20	Brazil	15.2	2.7%	2	1
21	Slovakia	14.2	53.9%	4	2
22	South Africa	13.6	6.7%	2	0
23	Mexico	10.9	4.5%	2	0
24	Romania	10.4	18.5%	2	0
25	Pakistan	9.1	6.6%	5	2
26	Argentina	7.9	5.9%	3	1
27	Iran	5.9	1.8%	1	1
28	Slovenia	5.5	37.0%	1	0
29	Netherlands	3.7	3.2%	1	0
30	Armenia	2.0	27.8%	1	0
	TOTAL	**2,626.0**		**435**	**45**

2.2 Selection Criteria

We focused our research on countries and jurisdictions that met one or more of a number of section criteria designed to ensure that relevant jurisdictions were included in the study, subject to information availability. These criteria are discussed in more detail in Section 2.2.2 below.

In selecting our target sample group, we relied on both:

[3] World Nuclear Association, “World Nuclear Power Reactors & Uranium Requirements”, November 2020.

- Overall objectives for the sample group as a whole, and
- Criteria for inclusion of individual countries or jurisdictions in the sample group.

This is discussed further below.

2.2.1 Objectives for the Sample Group

Taken as a whole, our target sample group was developed to meet a number of objectives:

- **The sample group should include a number of countries with very large nuclear fleets (e.g. larger than Canada).** Countries with large fleets can reasonably be viewed as important precedents in understanding and evaluating cost recovery methodologies.
- **The sample group should cover a diverse range of experiences in order to be sufficiently representative of global practices**, while focusing more on those countries that are likely to be more relevant comparators for Ontario and OPG. The objective of having a diverse sample group is to ensure that the analysis considers jurisdictions with a range of characteristics, which should help illuminate how these characteristics have influenced the methods and processes for cost recovery. This approach increased the likelihood that we would identify the full range of practices applied globally. Thus:
- The sample group should include a range of ownership structures for nuclear plants (investor-owned, publicly-owned, and co-operative if applicable).
- **The sample group should include some countries from each of North America, Europe and Asia, to the extent possible.** Within Europe, the sample group should include a mix of countries, taking into account size, geographic location, and institutional conventions.
- In addition to rate regulated jurisdictions, the sample group should include other market structures for pricing the output from nuclear generating fleets (e.g., prices set under a long-term contract). While rate regulated jurisdictions provide a more immediate comparison, given the heterogeneous nature of the industry, other market structures can offer relevant insights into cost recovery considerations and provide additional context.

2.2.2 Criteria for Inclusion of Jurisdictions in the Sample Group

We used a number of criteria when considering the inclusion of any individual jurisdiction in the study sample group. The criteria were designed to identify and include jurisdictions that are comparable and relevant Ontario and OPG. Criteria were also used to prioritize our research effort, subject to information availability.

In applying the criteria, we used the following approach:

- In general, not all criteria needed to be met to proceed with the selection of an individual country.. However, a country should meet a number of the criteria. Further, consistent with our goal of having a reasonably diverse sample group, any given criterion should be demonstrated by at least some countries within the sample group.
- Some criteria are intended to be met by all sample members (for example, the jurisdiction needs to meet minimum standards for institutional quality and have a sufficiently large installed nuclear generation base).

The specific criteria used are outlined below.

- **There is a sufficiently large installed nuclear generation base.** A country should have a meaningful nuclear fleet (more than just one or two units) and this fleet should make up a sufficiently significant portion of total generation. The rationale for this criterion is that jurisdictions that rely on nuclear power for a large portion of their needs are more likely to place particular attention to the cost recovery methods.
- **Nuclear power has an ongoing role.** It is preferable that nuclear power play an important and ongoing role in the jurisdiction. We felt that countries committed to nuclear power would likely provide more relevant insights for Ontario, where nuclear is and will continue to be a critical component of the energy supply mix. Additionally, cost recovery considerations may be different for jurisdictions with ongoing operating nuclear plants compared to those in the wind down phase.
- **There has been recent new build or refurbishment.** We felt it was desirable to include jurisdictions where there has been notable recent investments in the nuclear fleet, whether through new build or through large refurbishment programs for existing facilities. This characteristic parallels Ontario where major nuclear refurbishment programs are ongoing.
- **The user-pay principle is in place.** The jurisdiction should have the general goal of recovering plant decommissioning and waste costs from electricity users over the operating lifespan of the associated facilities. It should not be intended that the costs be subsidized by the government, for example. The principle seeks to ensure that costs are allocated fairly to those benefiting from the output from the nuclear facilities, in line with the premise of cost-based rate regulation.
- **Institutional quality meets minimum standards.** The jurisdiction should meet minimum standards for the quality of its governmental and regulatory institutions. Ideally, terms for decommissioning and waste management cost recovery would be set by arm's-length institutions with sufficient resources to make informed decisions. This criterion is necessary to ensure the relevance and reliability of the jurisdictional information.
- **Transparency is high.** Information on approaches to recovery of decommissioning and waste management costs should be readily accessible. Ideally, information should also be available in English or French. The need to include a range of countries, however, would influence how strictly the language criterion is applied.
- **The country is developed.** Most of the jurisdictions should be developed countries with stable financial markets. The rationale for the criterion is that less developed countries and/or those with less stable financial markets may face additional challenges in funding decommissioning and waste management costs. These challenges may influence approaches to cost recovery in a manner that is less applicable to Ontario and OPG. Additionally, developing countries with potentially higher rates of growth may make different decisions on allocating costs between generations of consumers.

2.3 Selection of Jurisdictions

Based on the criteria above, we selected the countries to include in the study as set out in Exhibit 2-2 below.

Exhibit 2-2

Target List of Countries
Canada
United States
France
United Kingdom
Germany
Belgium
Sweden
Finland
Japan
South Korea
India

The rationale for inclusion of individual countries other than Canada is highlighted below:

- **United States (US).** The US is the largest nuclear operator, has well-developed regulatory frameworks, and its rate-setting processes share many features with those in Canada. There are also a number of markets within the US that have introduced retail open access and/or competitive electricity markets.
- **France.** France is the second largest nuclear operator and nuclear power has a very large share of total electricity generation in the country. There are some unique aspects to pricing arrangements for nuclear generation.
- **United Kingdom (UK).** The UK has recently made major new investments in nuclear generation through the Hinckley Point C plant, which receives revenues under a contractual arrangement. The UK also has a well-developed regulatory regime.
- **Germany.** Notwithstanding its planned phase-out of its nuclear power fleet, Germany still has a significant amount of nuclear power generation, operating in a competitive market.
- **Belgium.** Similar to Germany, Belgium remains an important nuclear power producer notwithstanding its plans for unit shut-down, and operates under a competitive electricity market.
- **Sweden.** Sweden represents a mid-tier European nuclear operator, where nuclear power is now seen as an important component of transition to carbon-free generation. Electricity is sold through a competitive market.
- **Finland.** Finland is committed to a growing role for nuclear power and has recently made large investments in new capacity. In addition, relative to other countries, it is well advanced in the implementation of plans for nuclear waste disposal, and has a number of utilities providing power “at cost” to its owners under the so-called Mankala principle.
- **South Korea.** South Korea is a major nuclear operator and provides representation from Asia. Some of the reactors use CANDU technology, similar to Canada. There are also several reactors under construction.

- **Japan.** In addition to providing representation from Asia, Japan was included to explore implications on cost recovery that may have arisen as a result of the shut-down of nuclear units following the Fukushima incident.
- **India.** Although nuclear generation represents a relatively small portion of the country's total energy output, India has a relatively large number of operating reactors and a number of reactors under construction, and provides representation from a developing market. Further, government materials are available in English, and the country provides additional representation from Asia.

Including Canada, the targeted selections represented 11 of the top 17 countries by nuclear output and by number of operating nuclear reactors, with the six excluded countries being Russia, China, Ukraine Czech Republic, Spain and Switzerland.

Additional observations with respect to some of the specific jurisdictions selected is provided below.

2.3.1 The United States is an Important Jurisdiction

The nature of the US electricity sector bears additional discussion, given that the US plays a major role in this jurisdictional review. Beyond having a large nuclear fleet and a well-developed regulatory regime, the US has a number of other key features that make it a very useful point of comparison. Some of these are as follows:

- The US features a broad range of ownership structures, including investor-owned utilities ("IOUs"), publicly-owned utilities, and electric membership co-operatives ("EMCs").
- The US includes a wide range of electricity market structures. Some states continue to rely on vertically-integrated utilities that are fully-regulated, whereas other states have introduced competitive electricity markets. Many states with competitive electricity markets have enforced the separation of generating activities from regulated transmission and distribution. In other cases vertically-integrated utilities continue to operate in competitive wholesale markets.
- Compared to other global jurisdictions, we have found the US to have the most instances of rate-regulated nuclear generators, which we expect to be of important interest to the OEB.
- The US has at least 30 states that have or have had operating nuclear reactors, some owned by multiple parties and some supplying customers across state boundaries. Since retail electric power rates are typically regulated at the state level, this may provide a wide range of potentially different regulatory approaches to cost recovery.

Given the above range of circumstances and study scope, we decided to conduct a review of the US by considering its component jurisdictions. Thus, within the US, we studied a number of individual state jurisdictions in more depth, in addition to understanding key elements that are common. In some instances, we further focused our state-level review on the prevalent industry participants, subject to information availability.

Because of the importance of the US to our review, and the many complexities associated with this country, we devote one section of our report (Part II) to this specific jurisdiction.

2.3.2 European Jurisdictions

The European Union has mandated the introduction of competitive electricity markets in its member states. As a consequence, most operators of nuclear power plants in Europe receive a market price for power and no longer have revenues determined through rate regulation. Among the jurisdictions selected, this is the case in at least Sweden, Belgium, and Germany.

Although operators must recover their overall costs over time if they are to remain solvent, there is no clear link between decommissioning and waste management obligations and costs and the prices paid by consumers in these jurisdictions.

As a consequence of the prevalence of competitive electricity markets, we had a lesser focus on European jurisdictions in our subsequent research. We did apply greater attention to three European jurisdictions where there are exceptions from the general open-market approach as follows:

- **France -**The government of France has set a fixed price of power for a portion of the output from Électricité de France's ("EDF") nuclear fleet.
- **United Kingdom -**The UK government has negotiated a fixed contract price for power produced by Hinkley Point C, a reactor that is currently under construction in order to help the country reach its targets for carbon reduction emissions.
- **Finland -**The main nuclear power plant operator in Finland, TVO, operates under the Mankala principle, providing power "at cost" to its constituent shareholders, which are either large industrial consumers or electricity distribution utilities.

Reviews for these three jurisdictions are presented in Chapters 22, 23 and 24.

2.3.3 Information from Some Countries Proved Difficult to Collect

As we began our research for the targeted jurisdictions, we encountered difficulties in collecting and/or evaluating information for some countries. In particular, while our target list included South Korea, we found it difficult to find documentation in English with respect to decommissioning arrangements. Additionally, we found disclosures in South Korean company financial reports to be less extensive than in other developed countries.

Japan also presented many of the same challenges with respect to understanding actual practices and interpreting relevant official documentation in a sufficiently clear manner.

For these reasons, our report does not present any findings with respect to South Korea.

Similar constraints exist with respect to information from Japan and therefore our study contains more limited and qualified discussion of practices in Japan.

2.3.4 Some Countries have Less Developed Decommissioning Funding Frameworks

India was included in our initial selections because of the substantial and growing role that nuclear power plays in the energy sector, and as a representation of a developing market It also has the advantage that government reports are readily available in English.

Nuclear power is India's fifth-largest source of electricity, supplying approximately 3% of Indian electricity in 2019, according to the International Energy Agency.[4] According to the International Atomic Energy Agency, India has 22 nuclear reactors in operation, providing for a total installed

[4] International Energy Agency, "Electricity mix in India, January – October 2020". Retrieved 16-11-2020.

capacity of 6,780 MW.[5] Seven more reactors are under construction with a combined generation capacity of 4,824 MW.[6]

As we advanced in our research, we found that practices in India are not likely to be a relevant comparator for Ontario and OPG. Based on the findings of a review by the Comptroller and Auditor General of India ("CAG"), it appears that India lags behind other countries in terms of the maturity of its nuclear decommissioning-related arrangements. As of 2012, specific challenges identified by the Comptroller and Auditor General included the following:

- None of the 20 plants that had entered operation had then prepared decommissioning plans, despite Atomic Energy Regulator Board ("AERB") guidance to do so. (This included one plant that had been shutdown as of 2004.)[7]
- Neither government legislation nor related regulations provide for the creation and calculation of decommissioning reserves by the utilities.[8]

The CAG drew attention to the lack of a legislative framework in India for the decommissioning of nuclear power plants, noting that the AERB's mandate is limited to prescribing codes, guides, and safety manuals on decommissioning.

We did note that India's Department of Atomic Energy ("DAE") has been levying a decommissioning charge per kWh of energy sold from nuclear power stations in the country since 1988. This was initially set at 1.25 paise per kWh but was raised to 2 paise (0.00035 $CAD)[9] per kWh in 1991.[10] Funds accumulated have been placed in a Decommissioning Fund, which is maintained by the Nuclear Power Corporation of India on behalf of the Government of India.

Rates charged by nuclear generators are regulated and are based on a recovery of relevant costs and a specified return on equity.[11]

As of 2012, the levy amount had remained unchanged since 1991 and an expert committee in 2009 had expressed concern over the inability to assess the adequacy of the levy given uncertainties in decommissioning costs.[12] It is not clear from the documentation found whether or not the amount is intended to cover the costs of handling spent fuel in addition to the costs of plant decommissioning.

In a 2015 review, the International Atomic Energy Agency ("IAEA") reviewed the Government of India's strategies for the safe disposal of radioactive wastes. It concluded that it was "not able to find clear evidences of the existence of high-level policies and strategies". It further noted that:

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[5] World Nuclear Association and IAEA PRIS, "Nuclear Reactors in India". Retrieved 16-11-2020.
[6] IAEA PRIS – Country Statistics – India. Retrieved 18-09-18.
[7] Report of the Comptroller and Auditor General of India on Activities of Atomic Energy Regulatory Board for the year ended March 2012, Union Government Department of Atomic Energy, Report No. 9 of 2012-13, p. 65.
[8] Report of the Comptroller and Auditor General of India on Activities of Atomic Energy Regulatory Board for the year ended March 2012, Union Government Department of Atomic Energy, Report No. 9 of 2012-13, p. 67.
[9] Based on exchange rates as of November 16, 2020. As of that date, there were 56.96 Indian rupees to the Canadian dollar, and there are 100 paise per Indian rupee.
[10] Report of the Comptroller and Auditor General of India on Activities of Atomic Energy Regulatory Board for the year ended March 2012, Union Government Department of Atomic Energy, Report No. 9 of 2012-13, p. 66.
[11] Government of India, Department of Atomic Energy. Response of Dr. Jitendra Singh, Minister of State to Unstarred Question No. 1231 to be Answered on 07.05.2015.
[12] Report of the Comptroller and Auditor General of India on Activities of Atomic Energy Regulatory Board for the year ended March 2012, Union Government Department of Atomic Energy, Report No. 9 of 2012-13, p. 65.

> "it would be beneficial for India to develop a RAW [*radioactive waste*] Management Strategy, which should cover short and long term plans and measures and include the Governmental policy and respective strategy for the lifetime of the facilities."[13]

As per the provisions of the Atomic Energy Rules, 2004, the responsibility for decommissioning rests with the plant operator. The DAE stated in 2015 that detailed procedures for decommissioning were best prepared at the time of need.**Error! Bookmark not defined.**

Based on the above findings, it appears that amounts being collected through the decommissioning levy are not reasonably linked to expected costs, contrary to the user-pay principle. Given this and the observations on the overall state of the decommissioning-related arrangements, we did not further investigate developments in India, although we expect that the decommissioning levy would be collected through the regulated rates.

2.4 Report Structure

In the course of our research, we prepared summary profiles of key aspects and developments for each of the applicable countries researched and these are included in this report as individual Chapters or, in the case of the US, a series of Chapters including those profiling certain states. Although we endeavoured to present the results of our research in a manner that facilitates overall observations across jurisdictions where possible. the profiles may differ in terms of their specific structure, focus areas and relative depth. This reflects the fact that:

- Although we found some common themes that we ultimately summarize in a later Chapter, many of the jurisdictional approaches to the nuclear power industry in general and decommissioning and waste management in particular had a number of unique characteristics, elements and background.
- We also found that the issues of potential relevance to this review for each jurisdiction were sometimes different, reflecting different circumstances and developments in each jurisdiction.
- Given the wide range of global practices surveyed, the availability of relevant information differed across jurisdictions.

The report is structured in four parts:

- Part I includes Chapters on introduction, approach to the study and selection of jurisdictions, and an overview of jurisdictional characteristics that we believe may be influential in the establishment of cost recovery practices.
- Part II comprises Chapters focusing on the US, including an overview and specific state profiles.
- Part III provides the summary profiles for jurisdictions studied in Europe, Asia and Canada, including OPG in Ontario.
- Part IV provides overall findings and observations from our work.

[13] International Atomic Energy Agency, Integrated Regulatory Review Service – Mission to India, March 2015, p. 12.

3 Jurisdictional Characteristics

This Chapter provides a summary description of some of the key jurisdictional characteristics that we have observed in an initial review of the selected jurisdictions. These characteristics may be influential in the establishment of cost recovery practices for nuclear decommissioning and waste management costs in a particular country, US state or Canadian province.

In general, we observed a wide range of circumstances faced by nuclear power plants and their operators across the jurisdictions. Variations in circumstances were most notable across the following characteristics:

- Pricing Regime.
- Ownership Structures.
- Industry Outlook.
- Scope of Obligations.
- Role of Regulators.
- Financial Assurance Mechanisms.

A discussion of each of these characteristics below is intended to provide a contextual framework for considering the findings from individual jurisdictional profiles presented in subsequent Chapters.

3.1 Pricing Regime

Revenues earned by a nuclear plant owner may be determined through a variety of mechanisms:

- **Revenues may be determined through participation in competitive electricity markets.** Utilities in such jurisdictions may either bid into an electricity power pool or sign bilateral contracts with major power users. In either case, the prices offered will be set by utility management within the market mechanism. In these jurisdictions, there is no clear link between decommissioning and waste management obligations and costs and the prices paid by power purchasers (although, as noted elsewhere, operators must recover their overall costs over time if they are to remain solvent). The majority of European jurisdictions as well as deregulated US states are under a market pricing regime.
- **Revenues may be set through long-term contractual relationships with major counterparties, including government procurement agencies**. Governments may enter long-term contracts to support the construction of new nuclear capacity or refurbishment of existing plants. These contracts can provide nuclear developers with the long-term revenue certainty needed to finance these major projects. However, the exact link between the contracted price and the decommissioning and waste management obligations and costs may not be clear because they are just one component of the plant's overall projected cost profile that would be expected to be considered in determining the contract price. How various individual costs factor into a developer's willingness to accept a particular off-take price is ultimately an internal management matter. The Hinkley Point C project is the major example of a new nuclear generator whose rates have been established by long-term contract.
- **Revenues may be determined by an independent, external regulator.** Where this is the case, rates will often be set through some form of rate of return regulation, based on the amount of invested capital and allowed operating expenses, including an allowance for decommissioning

and waste management cost recovery. Within this overall rate-setting framework, the specific approach to determining amounts for decommissioning and waste management costs that is applied by the economic regulator may vary. A number of US states as well as Ontario and other Canadian jurisdictions reviewed in this study provide the main examples of independent economic regulation.

- **Revenues may be determined through rates set by the government, perhaps arbitrarily.** Depending on a jurisdiction's industry structure, public policies and unique history, the government may prescribe rates for electricity production. The rates may be set with the intent to cover costs but there may be no firm or transparent link between decommissioning and waste management costs (or other costs) and rates. France is a major example of this approach, whereby consumers have access to a defined quantity of power from EDF at a fixed price set by government decree. Our research indicates that this price is intended to approximate EDF's cost base but has not been systematically updated to match the actual cost structure.
- **Revenues may be determined through rates set by the utility itself.** Certain utilities may have the authority to set their own rates and are not be subject to oversight by a separate economic regulator. In setting rates, a self-regulating utility may seek to follow principles similar to those that would be applied by an independent regulator or it may adhere to other requirements such as those of lenders or debt capital markets. The Tennessee Valley Authority ("TVA") in the US is an example of a major self-regulating utility.
- **Revenues may reflect a direct flow-through of costs.** The funding for certain utilities may be structured for the direct flow-through of costs to participating owners through some form of co-operative agreement or similar arrangement. The use of the Mankala principle in Finland is an example.

There are variations within these mechanisms, and any individual power plant may have revenues set through one or more of these mechanisms.

3.2 Ownership Structure

Nuclear power plants may be owned, variously, by:

- **Governments, including through arm's length but publicly owned business corporations.** Examples reviewed in this study include Vattenfall in Sweden, as well as OPG and NB Power in Canada.
- **Private-sector investors.** The vast majority of US and European jurisdictions included in the study derive nuclear power from investor-owned utilities, as does Japan.
- **Consumers themselves through co-operative structures.** This structure was encountered in the US, where electricity membership cooperatives are an important component of the industry base. The example that we reviewed in our research was Oglethorpe Power Corporation in Georgia.

In some cases, an individual plant may have multiple owners, and these owners could fall into more than one of the above categories.

3.3 Industry Outlook

Jurisdictions vary in the future outlook for the nuclear generation industry, with some facing a growing role and others facing a declining role for the sector. We observed the following range of circumstances for this characteristic:

- **Jurisdictions where nuclear power is being phased-out or is facing major curtailments.** These developments may be taking place for policy reasons related to the acceptability of nuclear power generally (e.g. Germany and Belgium) or because of specific concerns (e.g. Japan).
- **Jurisdictions where the nuclear power plant sector is growing.** These circumstances reflect a recognition that nuclear energy can play a substantial role in decarbonisation efforts, such as in Finland and the UK, and/or expectations of increased electricity demand through economic development, such as in India.
- **Jurisdictions where the nuclear power sector is generally stable.** These jurisdictions may have a number of existing plants, perhaps with life extensions, but relatively little or no major new current construction. Examples include such major nuclear power producing jurisdictions as the US, France and Canada.[14]

3.4 Scope of Obligations

The type of nuclear decommissioning and waste management costs for which nuclear operators are responsible can vary across jurisdictions. Major categories of the costs include:

- **Plant decommissioning.** This involves the safe removal of a nuclear facility from service and the reduction of residual radioactivity to a level that permits release of the property and termination of its operating license.
- **Site restoration.** This involves the removal of non-radioactive equipment at a site and its return to a greenfield or near-greenfield condition, where the site can be used for other purposes.
- **Low-level and intermediate level waste.** This involves dealing with items that have been contaminated with radioactive material or exposed to radiation during the operation of the plant.
- **Spent fuel long-term storage and processing.** This involves dealing with spent nuclear fuel, which remains highly radioactive and must be stored securely after its use for a very long period of time. The processing of spent fuel may involve packing it in specialized containers and the storage of these containers in some form of geologic repository.

In a few jurisdictions, most notably the US and Japan, the government has assumed responsibility for long-term spent fuel storage, underwriting a potentially large part of the associated cost risk. Fees may be charged to utilities (and in turn consumers) to help recover these costs. Where governments have assumed responsibility for spent fuel, this reduces the scope of utilities' set-aside funding activities for decommissioning and waste management and may change the nature of the associated cost recovery from consumers. Similarly, some jurisdictions do not require utilities to set aside funding for full site restoration, which can also impact the approach to recovery of these costs.

For example, the United States Department of Energy ("US DOE") is responsible for the disposal of spent nuclear fuel from commercial power reactors, levying fees on US utilities toward building a

[14] We note that OPG has recently announced resumption of planning activities for future nuclear power generation at its Darlington site, to host a small modular reactor, subject to regulatory approvals.

central spent fuel storage facility. Since spent nuclear fuel tends to account for a significant percentage of overall nuclear decommissioning and waste management costs, this significantly reduces US utilities' direct cost responsibility and funding obligations. Accordingly, financial assurance guidelines from the US Nuclear Regulatory Commission ("NRC"), as discussed in Chapter 6, do not require operators to address funding for the disposal of spent fuel. In addition, the NRC does not require operators to set aside funding (or provide other forms of financial assurance) for full site restoration. Thus, the scope of activities covered by financial assurance provisions for US nuclear utilities is narrower than in a number of other jurisdictions, including in Canada. OPG and other nuclear waste owners in Canada are responsible for set-aside funding and ultimate cost of disposal of nuclear spent fuel, as well as for full site restoration.[15]

3.5 Role of Regulators and Other Government Agencies

In comparing jurisdictions, it is important to understand how the role of various regulatory or other government agencies may affect decisions on how they secure financial assurance for the funding of future nuclear decommissioning and waste management costs, and how and when such costs are recovered from consumers.

The two layers of oversight are:

- **Oversight of funding and financial assurance.** This focuses on whether an organizational will have sufficient funds on hand to pay for decommissioning and waste management costs in the future. Most commonly, this involves a requirement that dedicated trust funds be established, with mandated funding levels.
- **Oversight over amounts included in consumer rates.** This focuses on the economic regulation of amounts in respect of decommissioning and waste management included in prices charged to consumers.

One or both layers of the oversight may apply to utilities in a given jurisdiction, depending on the prevailing regulatory framework and market structure. The two types of oversight may be integrated to different degrees, potentially influencing outcomes on cost recovery methodologies.

For example, the NRC's rules for financial assurance provide that US utilities' funding plans for decommissioning costs may be influenced, to a potentially significant degree, by rate case decisions made by state utility commissions or by the FERC. On the other hand, the Canadian Nuclear Safety Commission's ("CNSC") requirements for financial assurance by Canadian utilities, as well as OPG's funding requirements under the Ontario Nuclear Funds Agreement ("ONFA"), are independent of economic regulation. Cost recovery outcomes may potentially also be influenced by the regulator's mandate, jurisdiction and approach to rate setting.

Economic regulation does not typically apply to decisions regarding the recovery of decommissioning costs from consumers for utilities that operate in competitive electricity markets, have the authority to self-regulate, operate on a non-profit basis, or have rates governed by direct contract.

Through our review, we observed that the portion of consumer contributions that are intended to cover decommissioning and nuclear waste management costs are generally more transparent in jurisdictions with regulated rates.

[15] The Nuclear Waste Management Organization, as funded by the waste owners, is the entity responsible for implementing Canada's spent fuel disposal plan.

Regulatory Principles

Where economic regulators play a role in determining recoveries for decommissioning and nuclear waste management costs, they would typically be expected to follow proper cost allocation practices and other sound regulatory principles.

Regulatory principles typically considered include those listed below, to which we have added potential interpretations of their meaning in the context of nuclear decommissioning and waste management costs: [16]

- **Fairness.** Do consumers pay for all of the costs of decommissioning, including a share of associated overhead costs?
- **Minimizing intergenerational inequity.** Are costs fairly allocated amongst different generations of consumers, so that consumers in different periods pay similar costs per unit of electricity received, with 'similar' perhaps being defined in inflation-adjusted terms?
- **Transparency.** Are amounts collected for decommissioning based on clear assumptions and calculations? Can consumers and regulators clearly see how amounts have been derived?
- **Minimizing rate volatility.** Are amounts collected stable and predictable over time? Do methodologies minimize the variation from period to period as a result of changes in economic conditions or cost estimates?
- **Appropriate allocation of risk.** Do methodologies fairly apportion risks (for example in investment returns, cost estimates, or decommissioning performance) between consumers and utility owners?
- **Providing value to consumers.** Do methodologies ensure that costs to consumers are minimized?
- **Consistency and simplicity.** Are changes to methodologies limited such that transition impacts are minimized?
- **Alignment with required financial accounting and reporting.** Are methodologies aligned with well-established accounting principles?

[16] A number of these regulatory principles have been identified by the OEB, including in the consultation on the regulatory treatment of pension and other post-employment benefit costs (EB-2015-0040 Report of the Ontario Energy Board, p. 3).

4 Review of Accounting Principles

In this Chapter we review accounting issues associated with the recognition of decommissioning costs in utility financial statements.

4.1 Asset Retirement Obligations

Subtopic ASC-410-20, Asset Retirement Obligations, establishes US Generally Accepted Accounting Principles ("GAAP") accounting standards for recognition and measurement of a liability for an asset retirement obligation ("ARO") and associated asset retirement cost ("ARC"). Subtopic 410-20 requires entities in all industries to:

- Recognize a liability for all legal obligations, including conditional AROs, associated with the retirement of tangible long-lived assets;
- Recognize the liability at fair value, and capitalize an equal amount as a cost of the related long-lived asset, which is depreciated over its estimated remaining useful life;
- Increase the liability for the passage of time (accretion) and report the change as an operating expense (accretion expense);
- Adjust the liability for changes arising from a change in the timing or amount of the estimated undiscounted future cash flows, with a corresponding change to the carrying amount of the asset; and
- Recognize a gain or loss on the settlement of the obligation when the associated asset is retired. The extensive use of estimates may cause entities to record a gain or loss when they settle the ARO.

The ARO is initially measured at the fair value of the liability, in accordance with the following guidance:

Determination of a Reasonable Estimate of Fair Value

"30-1 An expected present value technique will usually be the only appropriate technique with which to estimate the fair value of a liability for an asset retirement obligation. An entity, when using that technique, shall discount the expected cash flows using a credit-adjusted risk-free rate. Thus, the effect of an entity's credit standing is reflected in the discount rate rather than in the expected cash flows. Proper application of a discount rate adjustment technique entails analysis of at least two liabilities—the liability that exists in the marketplace and has an observable interest rate and the liability being measured. The appropriate rate of interest for the cash flows being measured shall be inferred from the observable rate of interest of some other liability, and to draw that inference the characteristics of the cash flows shall be similar to those of the liability being measured. Rarely, if ever, would there be an observable rate of interest for a liability that has cash flows similar to an asset retirement obligation being measured. In addition, an asset retirement obligation usually will have uncertainties in both timing and amount. In that circumstance, employing a discount rate adjustment technique, where uncertainty is incorporated into the rate, will be difficult, if not impossible."

In the US, this is generally based on US Treasury bond yields with an uplift to reflect the credit risk associated with that company (i.e. the risk associated with the entity's non-performance due to default).

On recognition of the ARO, the entity recognizes the ARC and depreciates that cost over the remaining useful life of the asset on a systematic and rational basis; for utility companies this is typically on a straight-line basis over the period of plant operation.

Subsequent Measurement

Excerpts for ASC 410-20:

"35-1 A liability for an asset retirement obligation may be incurred over more than one reporting period if the events that create the obligation occur over more than one reporting period. Any incremental liability incurred in a subsequent reporting period shall be considered to be an additional layer of the original liability. Each layer shall be initially measured at fair value. For example, the liability for decommissioning a nuclear power plant is incurred as contamination occurs. Each period, as contamination increases, a separate layer shall be measured and recognized.

35-2 An entity shall subsequently allocate that asset retirement cost to expense using a systematic and rational method over its useful life"

35-3 In periods subsequent to initial measurement, an entity shall recognize period-to-period changes in the liability for an asset retirement obligation resulting from the following:

a The passage of time

b Revisions to either the timing or the amount of the original estimate of undiscounted cash flows.

- 35-4 An entity shall measure and incorporate changes due to the passage of time into the carrying amount of the liability before measuring changes resulting from a revision to either the timing or the amount of estimated cash flows.
- 35-5 An entity shall measure changes in the liability for an asset retirement obligation due to passage of time by applying an interest method of allocation to the amount of the liability at the beginning of the period. The interest rate used to measure that change shall be the credit-adjusted risk-free rate that existed when the liability, or portion thereof, was initially measured. That amount shall be recognized as an increase in the carrying amount of the liability and as an expense classified ass accretion expense."

The subsequent measurement due to the passage of time increases the ARO amount and the entities recognize accretion expense, which is the unwinding of the discounting at the same discount rate that was used when the ARO was initially recognized.

The subsequent measurement of the change in timing or in the amount of cash flows, if it represents an increase, is accounted for as another "layer" of liability and the associated ARO is measured at fair value, calculated in the same way as for initial recognition but utilizing a new discount rate for this new layer; the related ARC is added to the asset. If the subsequent measurement is a decrease, then there is a downward adjustment in ARO and to the ARC. The entity would recognize accretion expense, using the same discount rate for this new layer.

Effects of Funding and Assurance Provisions

Excerpts for ASC 410-20:

35-9 Methods of providing assurance include surety bonds, insurance policies, letters of credit, guarantees by other entities, and establishment of trust funds or identification of other assets *dedicated to satisfy the asset retirement obligation. The existence of funding and assurance provisions may affect the determination of the credit-adjusted risk-free rate. For a previously recognized asset retirement obligation, changes in funding and assurance provisions have no effect on the initial measurement or accretion of that liability, but may affect the credit-adjusted risk-free rate used to discount upward revisions in undiscounted cash flows for that obligation.*

KPMG interpretive guidance 410-20-35-9, Funding and Assurance Provisions (Dec. 2014):

"An entity may obtain surety bonds, insurance policies, letters of credit, guarantees by other entities, and dedicated trust funds to satisfy an ARO.

These funding and assurance provisions do not eliminate the requirement to recognize the ARO. However, these arrangements generally reduce the counterparty's exposure to the entity's non-performance risk and should be considered in determining the entity's credit-adjusted risk-free rate for new obligations or upward revisions.

An entity should not present the funding or assurance provision as an offset to the asset retirement liability. Additionally, an entity should account for the costs of the funding or assurance provisions separately from the ARO."

The above guidance, and interpretation, clarifies the relationship between funding arrangements and the requirements of US GAAP. Of most important, is the distinction between the funding basis and the ARO determined based on US GAAP requirements in accordance with ASC 410-20.

4.1.1 Factors Influencing Accounting Expenses

In practice, the recognition of accounting expenses is complicated by various factors that can arise as assumptions and cost estimates change. These could result from the following circumstances:

- Estimates of future decommissioning activities may change, either up or down.
- The lifespan of the plant may be adjusted, either becoming shorter or longer.
- The decommissioning date may be adjusted, either becoming shorter or longer.
- Prevailing discount rates may change, which would impact new layers of ARO.

The impacts of these changes are discussed further below.

Changes in Cost Estimates for Future Decommissioning Activities

When the estimated future cost of decommissioning activities increases, this is treated as an additional layer of liability that is recognized at the time that the cost estimate changes. The discount rate used to calculate the present value of the additional liability will be one based on the then-current market conditions. Accretion expense will then be calculated going forward on this new layer of liability. The new layer of the liability would increase the ARC that is added to the related asset.

In the event that the future cost of decommissioning activities decreases, then the associated liability should be reduced using the discount rate originally used to set up the liability. Thus, unlike for increases in the cost estimate, the current discount rate is not used. The reduction of the ARO would result in a consistent decrease to the ARC.

Changes in Plant Lifespan

If the plant lifespan is extended, which reduces the liability by extending the depreciation period of the ARC and the periodic depreciation rate would be lower. In contrast, if the lifespan is shortened then the depreciation period of the ARC would decrease, and the periodic depreciation rate would be higher.

Changes in Timing of Decommissioning

If the decommissioning date is extended, which reduces the liability by extending the discounting period, the adjustment should be calculated using the original discount rate. In contrast, if the decommissioning date is shortened, the increase in the liability should be calculated using the current discount rate.

Changes in Discount Rates

Changes in discount rates over time will have different implications depending on the accounting rules used.

Under US GAAP, a change in the discount rates as a result of changes in market conditions or entity risk profile will not affect the accounting of AROs that have already been set up on the balance sheet. Accretion expense will continue to be based on the discount rates used to set up the initial ARO. As noted above, however, increases in costs and the resulting new liability layer will be set up using current discount rates.

Under IFRS, the discount rate is adjusted at each reporting period.

4.2 Evolution of Accounting Practice

In June 2001, the Financial Accounting Standards Board ("FASB") in the US issued Standard No. 143, which requires that companies recognize a liability for the fair value of AROs. Under the standard, this liability is to be calculated on a net present value basis at the time an asset is constructed, acquired, or when a change in law creates a legal obligation to perform the retirement activities. Consistent with the accounting framework outlined earlier in this Chapter, this standard envisages the recognition in subsequent periods of accretion expense and of depreciation on the initial value of the asset created as a result of recognition of the liability.

4.2.1 Response By Regulators

In our US research we found in many instances that the accounting changes on adoption of FAS 143 were discussed in regulatory proceedings and that the utility commissions involved did not change how costs were recovered in rates. As an example, in South Carolina, at the request of utilities in the state, the utility commission issued a joint order confirming that adoption of FAS 143 by utilities under its jurisdiction would not lead to a change in the allowances in rates for decommissioning costs. The utility commission also thereby set up deferred accounts for regulatory accounting purposes. This is discussed in more detail in Section 18.2.2.1. We noted similar considerations in Florida (Section 12.3.1), Georgia (Section 13.2.2.1), Minnesota (Section 15.2.2.2), and North Carolina (Section 16.2.1.1).

4.3 Accounting considerations for entities applying ASC 980 (US GAAP)

4.3.1 General Guidance Applicable to Rate Regulated Entities

Under US GAAP, entities that have activities that are subject to rate regulation are required to follow special accounting provisions which are set out in ASC 980. These special accounting provisions require the economic effect of rate regulation to be reflected in general purpose financial statements prepared under US GAAP. It is important to note that if an entity falls within the scope of ASC 980, it is required to prepare its financial statements based on these special accounting provisions; it cannot choose to apply the accounting provisions that apply to entities that are not subject to rate regulation. In Canada and the US, many utilities are rate-regulated and apply the various sub-topics of ASC 980. Therefore, regulatory assets and liabilities are recognized in these entities.

It is, also important to note that a regulator cannot eliminate a liability that was not imposed by its actions. As such, although certain costs relating to obligations may be fully recoverable through the rates charged to customers in the future (for example, obligations relating to deferred taxes, P&OPEB and asset retirement obligations), a regulated entity still recognizes the obligations on its balance sheet.

By their very nature, AROs can remain outstanding for a very long time. For this reason, regulators establish various methods for including these costs in the rates charged to customers. The methods used can include forward looking funding requirements, accounting expense, flow through cost, and arbitrary rate as discussed in Section 5.1. If the amount determined by accounting expense is not used for setting rates, a difference will exist between the method used for rate-making purposes and the amount recognized in general purpose financial statements. In order to reflect the economic impact of rate regulation in general purpose financial statements, ASC 980 requires that regulated entities recognize the regulatory assets and liabilities as discussed below.

Regulatory Assets (ASC 980-340)

ASC 980 defines an ‘incurred cost’ as a cost arising from cash paid out or obligation to pay for an acquired asset or service, a loss from any cause that has been sustained and has been or must be paid for. As such, ‘incurred cost’ includes costs that have been paid already as well as those for which an obligation to make a payment in the future exists as at the reporting date. This is consistent with the accrual accounting principles used in preparing general purpose financial statements.

AROs that are recognized in an entity’s general purpose financial statements represent management’s best estimate of decommissioning costs that will occur at the end of the assets useful life.

Note also that the definition of ‘incurred costs’ that is used for accrual accounting may at times differ from the criteria that are used by regulators in assessing whether a cost is actually included in the rates charged to customers during a particular period. For example, in setting rates, a regulator may conclude that certain costs that have been recognized under accrual accounting do not yet meet its criteria for inclusion in the rates because the amounts are not due to be paid before the next rate application. Although such costs would meet the definition of ‘incurred costs’ for accrual accounting, they would not meet the definition that is used for setting rates. Under ASC 980, costs relating to such differences in treatment between accrual accounting and ratemaking are included in the definition of regulatory assets, and would be recognized (or capitalized) if the criteria discussed further below are met. In this section of the report, all further references to 'incurred costs' relate to the definition that is used for accrual accounting and not a different definition that may have been used for ratemaking.

Under the general provisions of ASC 980-340, Other Assets and Deferred Costs, an incurred cost that would otherwise be charged to expense is capitalized as a regulatory asset if:

a) It is probable that future revenue in an amount at least equal to the capitalized cost will result from inclusion of that cost in allowable costs for rate-making purposes; and

b) Based on available evidence, the future revenue will be provided to permit recovery of the previously incurred cost rather than to provide for expected levels of similar future costs. If the revenue will be provided through an automatic rate-adjustment clause, this criterion requires that the regulator's intent clearly be to permit recovery of the previously incurred cost.

Based on this requirement, a regulatory asset is only recognized if it is probable that the incurred cost will be recovered in future rates. ASC 450 states that an event is probable if it is "*likely to occur*". As such, in order for incurred costs to be capitalized as regulatory assets, there needs to be suitable evidence to support the judgmental criteria that recovery in future periods is reasonably assured. In assessing that probability, reporting entities consider (1) how the costs are being recovered in rates and on what basis they are being recovered; (2) any specific actions by the regulator with respect to similar deferred costs; (3) the regulator's historical approach to inclusion of such costs in rates; and, (4) whether there is significant uncertainty indicated by the regulator regarding the future rate recovery approach. If it is not probable that an incurred cost will be recovered in future rates, a regulatory asset is not recognized at the time that a cost is incurred. Instead, a regulatory asset is recognized when it does meet the criteria at a later date.

Regulatory assets are not measured at discounted present value if the related cost will be recovered over an extended period without a return on the unrecovered amount. After determining that an incurred cost is treated differently for ratemaking and that it is probable that the incurred cost will be included in future rates, the amount that is recognized as a regulatory asset is not further adjusted to reflect the time value of money. However, an entity discloses the remaining amounts of such regulatory assets and the remaining recovery period applicable to them.

Regulatory Liabilities (ASC 980-405)

Regulatory liabilities arise from rate actions of a regulator that impose obligations on a regulated entity to its customers. ASC 980-405, Liabilities, addresses the accounting requirements for regulatory liabilities.

Regulatory liabilities typically arise if a regulator provides current rates intended to recover costs that are expected to be incurred in the future with the understanding that, if those costs are not incurred, future rates will be reduced by corresponding amounts. The current rates are intended to recover such costs and the regulator requires the entity to remain accountable for any amounts charged pursuant to such rates and not yet expended for the intended purpose. The usual mechanism used by regulators for this purpose is to require the regulated entity to record the anticipated cost as a liability in its regulatory accounting records, and the amounts are taken to income only when the associated costs are actually incurred and recognized as expenses. Typically, all these requirements would be specified beforehand and included in the rate orders/decisions issued by the regulator.

4.3.2 The Implications of Regulatory Assets and Liabilities

As noted above in Section 4.1, irrespective of the rate setting methodology for recovery of decommissioning costs, all companies will recognize AROs, ARCs, the related depreciation expense of the ARC, and accretion expense of the ARO in their US GAAP financial statements. Where companies recover decommissioning costs on a methodology other than accounting (such as on an estimate of required funding contributions), there will then be a difference between decommissioning costs allowed for rate-making purposes (i.e. the amount recovered through rates) and the accounting expense recognized under accounting principles for financial reporting purposes.

In the event that the utility is allowed under applicable accounting standards to recognize the effects of rate regulation as noted in Section 4.3, this will often give rise to a regulatory liability or a regulatory asset on its balance sheet.

The regulatory assets or liabilities can be significant, as shown below in numbers provided for Florida Power & Light ("FPL"). FPL rates are set based on required fund contributions, rather than based on accounting expense recognized under accounting principles for financial reporting purposes. Amounts accrued for ratemaking purposes by FPL were $4.4 billion at the end of 2018, which included AROs of $2.0 billion and a regulatory liability for the ARO regulatory expense difference of $2.4 billion. Figures shown in Exhibit 4-1 below are as presented in the 2018 annual report for FPL's parent company, NextEra Energy.[17] .

Exhibit 4-1ARO Reconciliation

FPL - ARO Reconciliation - Nuclear ($Millions)	
	2018
AROs	2,045
Less capitalized ARO asset net of acumulated depreciation	(316)
Accrued asset removal costs	319
ARO regulatory expense difference	2,358
Total accrued for ratemaking purposes	4,406

FPL had some specific circumstances that may influence the size of the differential: its nuclear plants received license extensions in 2002 and 2003, reducing the present value of decommissioning costs. FPL does not currently make contributions to the decommissioning funds, other than the reinvestment of fund earnings. Therefore, no amounts are currently being recovered from ratepayers. In contrast to the amount included in rates (of zero), the annual accretion expense associated with FPL's ARO's was $101 million in 2018.[18]

The ARO regulatory expense difference of $2.358 billion noted above in Exhibit 4-1 appears as a regulatory liability on FPL's balance sheet. The ARO regulatory expense difference represents the difference between what has been recovered in rates and the sum of (1) accretion expense on ARO; (2) depreciation on ARC; (3) Fund earnings.

[17] NextEra Energy, 2018 Annual Report, p.53.
[18] *Ibid*, p. 107. A small amount of non-nuclear AROs is reflected in this expense amount, but a note in the annual report indicates that they are not significant.

5 Rate Recovery Methodologies

This Chapter is intended to briefly summarize the broad categories of methodologies for the determination of amounts for decommissioning and waste management costs for the purpose of price setting that we noted in our research. Within these categories, there are many variations in approach and application.

This brief overview is intended to assist the reader in comparing and contrasting the individual jurisdictional profiles in the subsequent Chapters. A more detailed discussion of our findings and observations related to the application and development of these methods is provided in Part IV of the report.

5.1 The Broad Categories of Methodology

Methodologies for the collection of decommissioning and waste management costs fall into four broad categories:

- Based on forward looking funding requirements.
- Based on accounting expense.
- Based on a flow through cost
- Based on an arbitrary rate.

There are more fully defined below.

Based on forward looking funding requirements.

This method bases recovery from consumers on amounts that are contributed to set-aside funds as part of financial assurance mechanisms for in-scope obligations related to nuclear decommissioning and waste management. The key elements of a forwarding funding structure discussed later in this chapter in Section 5.2 tend to play a key role in determining the amounts collected under this regime. The amounts collected are therefore reflective of funding arrangements in place for a particular utility,

Based on accounting expense.

This method bases recovery from consumers on expenses recognized in the company's financial statements related to asset retirement obligations for nuclear decommissioning and waste management. The recovery amount would be determined in reference to depreciation and accretion expense, offset by current trust fund earnings. The amounts collected are therefore reflective of prevailing accounting standards as determined by the relevant standard setting bodies, such as US GAAP discussed in Chapter 4.

Based on a flow through cost

This method "passes" through to consumers the fees or levies payable by utilities to other parties in exchange for these parties effectively discharging the utilities' obligations for nuclear decommissioning or, more often, for waste management. Such fees or levies may be treated as operating expenses and recovered as such in the normal course through cost-based price setting.

Based on an arbitrary rate.

This method bases recovery from consumers on an arbitrary or quasi-arbitrary rate that is not directly or clearly linked to the underlying costs or obligations of the utility. As such, either by design or application of policy, amounts for nuclear decommissioning and waste management cannot be observably traced through to electricity charges paid by consumers, even though these charges may be broadly intended to be based on a utility's overall cost levels.

5.2 Key Elements of a Forward-Looking Funding Approach

As noted in Section 3.5, regulators (or governments) generally seek to ensure that sufficient funds will be available to pay for decommissioning and waste management costs when needed in the future. This objective is typically achieved through the establishment of trusts (such as Nuclear Decommissioning Trusts in the US) or similar set-aside mechanisms, which allow for the accumulation and investment of funds by or from the nuclear operator.

At the time of decommissioning or waste management activities, the funds should provide a segregated pool of investments that can cover the required expenditures. To ensure that future fund balances are sufficient, while recognizing the inherent uncertainty in projecting future expenditures and economic conditions over long periods of time, regulators (or governments) may use more conservative methods and assumptions in determining the amount and timing of required trust contributions.

In determining the required contributions to a segregated fund, we have found the following to be the typical key parameters of relevance:

- Funding requirement target.
- Expected fund earnings.
- Contribution profile.
- Funding period, typically based on station lifespan.

These are discussed further below.

Funding Requirement

The starting point for any analysis of funding requirements is an estimate of in-scope future decommissioning and waste management costs. These estimates identify the targeted amount of funds to be accumulated in a trust or similar set-aside arrangement by a certain timeframe. Inherently, any such estimate will be subject to significant uncertainty, which may reflect:

- Uncertainty in the actual processes that will be used for decommissioning and waste management. For example, processes may change over time with evolution in the technologies for decommissioning and waste processing and disposal, and with changes in safety and environmental standards and public policies.
- Uncertainty in future rates of cost escalation for input goods and services, including labour and materials, used in the decommissioning and waste management processes. These goods and services may escalate in price at a rate that is different than general price inflation, including for industry-specific inputs.

- Uncertainty in the timing given such factors as the operating lifespan of the assets, post-shutdown strategy, development of permanent solutions to spent fuel and other waste, and changes in technology and public policies as noted above.

The fact that decommissioning and waste management activities may take place far in the future magnifies potential forecasting risks in respect of each of the elements above.

To address some of the uncertainty, cost estimates may explicitly acknowledge that actual outcomes will follow a probability distribution.

We also observed approaches to cost estimating that provide for more conservative (i.e. higher) funding requirements, increasing the likelihood that funding will be sufficient to pay for the actual expenditures when they occur.

Expected Investment Returns

Expected earnings on invested funds is a key parameter in determining set-aside contributions under a forward-looking funding approach. Contribution requirements over time may vary significantly depending on the expected returns on fund balances. This reflects the fact that the relatively long-time horizon for the investment process means that even small differences in the rate of return assumed may have a notable impact on estimates of required contributions levels.

Expected returns are generally a function of future inflation, market outlook (including interest rates) and views on risk tolerance, which typically manifest themselves in investment mix decisions.

Profile of Contributions

Within the fundamental requirement that fund balances be sufficient at the expected future dates of decommissioning and waste management, there is a mathematically wide range of potential contribution profiles that could provide the future balances required. Contributions profiles could range from back-end loaded to front-end loaded to even-pay; selection among and the implementation of these alternatives inherently involves judgement. We have observed that approaches to contribution profiles can vary significantly depending on jurisdictional characteristics and the circumstances of a particular utility, including any applicable regulatory, contractual or other requirements and government policy considerations.

An example of a more back-end loaded contribution approach is that for Hinkley Point C (within its initial contract period), whereas we noted more front-end loaded profiles in many US states, where sufficient funds where accumulated prior to facility license extensions, for OPG under the ONFA, and, as noted earlier, in Finland.

Funding Period

We have observed that funds for decommissioning and waste management activities are typically set aside over a station's operating life rather than, say, over the period until decommissioning starts. However, we noted one jurisdiction (Japan) where asset retirement costs were initially allocated to expense through depreciation over a period covering both a plant's operating life and a subsequent safe storage period, rather than over just its operating life. This approach was ultimately changed to correspond to the typical practice of recovering costs over the operating life.

5.2.1 Variability in Funding Contributions

The nature of the above elements influencing funding projections is such that contribution requirements will need to be updated over time to reflect:

- Changes in estimates of real (constant dollar) decommissioning and waste management costs, including through more detailed decommissioning plans and evolution of methods for spent fuel and waste disposal.
- Changes in the expected lifespan of the associated nuclear facilities.
- Variances in actual investment returns from expectations.
- Changes in expected future investment returns as a result of changes in market outlook, mix of investments, and/or expected inflation rates.

These changes can result in significant variability in contribution levels, sometimes over a very short period of time. For example,

- Contributions may drop significantly, and even to zero, in the event a facility's lifespan is extended. This reflects the additional earnings potential of funds that have already been contributed, as a result of a longer investment horizon. (This may be offset by the added cost of managing increased volume of spent fuel and other waste material, if within funding scope.)
- Conversely, contributions may escalate sharply in the event a facility's lifespan is reduced.
- Contributions may also decrease after a period of sustained strong investment returns, and increase in the event of a significant downturn in the financial markets. We also observed instances where updates to decommissioning plans drove material impacts on funding levels. For example. This was the case for Pacific Gas & Electric's Diablo Canyon plant in the United States. The plant was originally expected to operate beyond the current operating licencing period, but the cancellation of a planned license extension resulted in an updated review of decommissioning costs and significant increases in required decommissioning allowances in rates (see Chapter 11).

We also noted the very long-term nature and the importance of technical and other assumptions underpinning cost estimates for future spent fuel and waste disposal plans, many of which are in their early stages globally. The continued evolution of these plans and methods can lead to substantial changes in future funding requirements. As noted earlier, examples of uncertainties include:

- Expectations and standards with respect to decommissioning performance.
- The technologies used in the decommissioning process.
- The ultimate design and location of waste repositories.

In addition to uncertainties over future costs, there are uncertainties in terms of fund accumulation and implications for financial statement presentation. Thus:

- Regulatory assets or liabilities may arise as a result of the resulting mismatch between amounts recovered from consumers and costs recognized for financial statement purposes under applicable accounting standards. The regulatory assets and liabilities that are shown on utility financial statements may then become significant.
- Required contributions may vary significantly depending on expectations with respect to future inflation rates and forecast rates of return on trust fund balances. These inputs become points of contention in regulatory proceedings and may be subject to specific regulatory constraints.

Decisions on the allocation of funds among investment asset classes is also important, as they will influence actual and expected returns and the degree of volatility in fund balances.

Accordingly, decisions on expected future investment returns are often a major component of related regulatory deliberations. The regulatory process determines the parameter values that will be used, and this may allow more subjective views to influence these parameters, possibly creating inter-generational equity issues.

This gives decision-makers considerable discretion to alter these profiles to meet other objectives in parallel. In contrast, accounting methodologies give less discretion in how related costs are recognized.

5.3 Application to the Accounting Expense Method

When rates are based on accounting methodologies, the depreciation expense and accretion expense are typically allowable costs and recovered in rates charged to customers, which results in the collection of cash. The cash received may then be set aside in a segregated fund in order to help fund the future decommissioning cost.

In addition to the recovery of the depreciation and accretion expenses, there are other factors to consider in connection with the amounts to be recovered by rate-payers to fund the future obligation. Investment earnings on segregated fund balances would generally be treated as a reduction to the costs to be paid by rate-payers. Therefore decommissioning costs to be recovered by rate-payers in any period under an accounting approach would likely be calculated as follows:

- Depreciation of the ARC
- Plus: accretion expense
- Less: investment earnings on segregated fund balances in decommissioning trusts.

It should be noted that, from an accounting perspective, the accounting expense is simply the sum of depreciation expense and accretion. Investment earnings are not deducted as an offset.

If the future cost of decommissioning activities remain as initially measured, and if investment earnings on segregated funds collected through the recovery of depreciation and accretion expense earn the same return as the discount rate used to recognize the initial ARO, then funds accumulated over time in segregated funds will exactly match future decommissioning costs. Thus, the process will ensure funding adequacy.

Overall, the recovery of decommissioning costs will generally be somewhat front-end loaded. This reflects the impact of the following trends:

- The depreciation expense account is constant over time.
- Accretion expense is recognized using the effective interest rate method which results in accretion expense being lower earlier, and increasing closer to the decommissioning date.
- Investment fund earnings (which are an offset to the expense items above) also grows, and these earnings grow by more than the increase in accretion expense in each period.[19]

[19] In the last period, the accretion expense exactly offsets the investment earnings. In earlier periods, the accretion expense is actually greater than investment earnings but, as noted in the text, the increase in

In addition to factors influencing accounting expense, the following factor will influence the rate setting process:

5.4 General Issues in the Rate Setting Process

In the remainder of this Chapter, we provide additional discussion with respect to general issues related to some of these rate recovery mechanisms. In the sections below, we identify:

- The implications of uncertainty.
- Exceptions to the user-pay principle
- The impacts of transitions in market structure.
- Regulatory flexibility.

5.4.1 The Implications of Uncertainty

An inherent challenge in the evaluation of nuclear decommissioning costs is that decommissioning may take place far in the future, resulting in considerable uncertainty with respect to factors such as:

- Methodologies that will be applied for decommissioning, and their associated costs.
- Rates of cost escalation.

Given uncertainties, regulators and governments may therefore be naturally concerned about the potential for cost over-runs and hence shortages in the decommissioning funds that will be available.

Uncertainty may be addressed in a number of ways, including through:

- The use of scenario analysis
- The inclusion of cost-buffers in cost estimates.

These approaches are discussed further below.

Scenario Analyses

Analyses of decommissioning costs may explicitly acknowledge that actual outcomes will follow a probability distribution. We identified some cases where nuclear operators use scenario analyses to determine the value of decommissioning obligations. Estimates of decommissioning obligations for financial reporting purposes are thus based on a probabilistic analysis of various potential outcomes. The practices of one nuclear operator (Exelon) in this regard are discussed further in the profile for Pennsylvania in Chapter 17.

In Exelon's case, the scenario analysis is used to determine an "expected" value for decommissioning costs. It is not used to identify the contributions that would be needed to cover costs that would be higher than the expected value. In other cases, probabilistic analysis may be used to identify additional required contingency amounts, as discussed further below.

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investment earnings in each period is greater than the increase in accretion expense, so that the net difference between the two line items narrows over time. This assumes that the interest rate earned is equal to the discount rate.

Cost Buffers

Governments or regulators may require utilities to increase the decommissioning cost estimates used for rate setting purposes or to provide guarantee commitments to cover potential cost over-runs. These contingency amounts may be based on some form of probabilistic scenario analysis. Relevant examples include the following:

- For Hinkley Point C, the UK government requires that decommissioning cost estimates be designed to be “P80” estimates. In words, they are to be conservative estimates, where the probability that they be exceeded is only 20%. In addition, the operator is required to provide an additional buffer over the P80 estimate of 25%. (This is discussed further in our UK Case Study in Chapter 23.)
- In Sweden, security guarantees take into account the potential for cost increases above a median estimate. (This is noted in our study of other European jurisdictions in Chapter 25.)
- In Finland, nuclear operators’ obligations to fund the Finnish State Nuclear Waste Management Fund include a “risk marginal”, which we assume is an uplift on expected costs. (This is noted in our Finland Case Study in Chapter 24.)

5.4.2 Exceptions to the User-pay Principle

Amounts may be collected from companies towards decommissioning costs based on considerations that reflect an ability to pay. When costs collected are less than decommissioning amounts, governments will generally make up the shortfall.

As noted elsewhere, the user-pay principle suggests that decommissioning costs should be paid by the beneficiaries of nuclear power. Most governments and regulatory agencies have adopted the user-pay philosophy as key principle. Nevertheless, governments have picked up some costs under the following circumstances:

- Governments provided some initial seed funding because funds were not collected during the initial years of plant operation; this funding addressed the fact that some catch-up was required when expectations changed regarding the need to set up dedicated funding reserves.
- The structure and ownership of the industry changed, perhaps as a result of the privatization of publicly-owned utilities and/or the introduction of electricity market competition. Government funding thus facilitated the transition to a new market structure.
- Governments mandated the early shut-down or phase-out of nuclear power plant operations, which resulted in a need to compensate operators for increased decommissioning plant costs and to avoid undue rate impacts for consumers.

In the case of OPG, the Ontario government contributed some funding directly to nuclear decommissioning trusts. This occurred after the Ontario Hydro’s generation assets were transferred to a new corporatized entity, OPG, and prior to electricity market opening and OPG’s anticipated privatization. Thus, Ontario is one example (but not the only example) of a jurisdiction where governments have made direct contributions as a result of the first two circumstances noted above.

In respect of the second reason cited above, the UK government has provided funding support for decommissioning costs for the initial UK nuclear fleet, which was built prior to utility privatization and the introduction of market competition.

5.4.3 Impacts of Transitions in Market Structure

When utilities have transitioned from a regulated regime to one with a competitive electricity market, anomalies may arise as a result of the transition process. Transition processes typically complicate funding arrangements and introduce policy challenges. It may be easier to guarantee the recovery of decommissioning costs from regulated entities and from periods where rates are subjected to regulation, and this may be reflected in arrangements for funding decommissioning costs when market structures change.

Examples of transition were found, for example, in many US jurisdictions. In the US, many regional jurisdictions have introduced a competitive spot market for electricity or some form of power pool at the wholesale level. In these jurisdictions, many states also restructured their electric utility sector to “unbundle” generation from transmission and distribution, and to provide consumers with retail open-access, in which individual consumers can choose their commodity supplier. Alternatively, vertically-integrated, regulated utilities may continue to operate. (In the latter case, the utility has access to an open spot market but individual retail customers are still dependent on their utility for commodity procurement.)

The process of market restructuring, and unbundling of generation, often created issues for vertically integrated utilities that had existing generation plants, particularly nuclear facilities. With market opening, prices for the commodity were often expected to fall below the fully allocated costs of existing power plants, creating the possibility of “stranded assets” from the perspective of utility shareholders. In these circumstances, shareholders were typically kept whole through some form of non-bypassable stranded asset charge, levied on all consumers going forward. These charges were a mechanism to compensate utility shareholders for the one-time losses in asset value associated with market opening. In parallel with stranded asset charges, generators were often given contracts to supply retail customers during an initial transition period. Decommissioning obligations were often a significant component of stranded cost estimates.

Complications arising from market transition were observed in a number of specific jurisdictions, including Illinois, Pennsylvania and the UK.

5.4.4 Regulatory Flexibility

Regulators’ discretion in applying regulatory principles may be greater under some approaches for quantification than under others. For example, regulators likely have considerably more flexibility to adjust the allocation of decommissioning costs across time periods under a forward-looking funding approach than when rates are set based on accounting expenses. Accounting expenses are determined based on defined methodologies and there is limited scope to adjust calculated amounts in any given circumstance. In contrast, the primary focus of a forward-looking funding approach is simply on ensuring that there is funding adequacy at the time of decommissioning. This can theoretically be achieved using a wide variety of different funding scenarios. Notwithstanding this flexibility, however, regulators and utilities do in practice apply other regulatory objectives, such as achieving reasonable intergenerational equity or reducing the risk of underfunding, when setting up contribution profiles under forward looking approaches.

Part II – United States

6 United States Institutional Framework

In this Chapter we provide an overview of the institutional framework that governs the financial responsibility for nuclear decommissioning and waste management in the United States. A detailed review of individual US jurisdictions selected for study is provided in the Chapters following.

6.1 Nuclear Regulatory Commission

The Nuclear Regulatory Commission plays a key role in regulating nuclear power plant operators. Among other things, it issues plant operating licences and sets safety and performance standards. The NRC also oversees the decommissioning process and is responsible for ensuring that nuclear plant licensees provide reasonable assurance that they will have adequate funds for future decommissioning.

Key elements of the NRC oversight process related to decommissioning financial assurance are discussed below.

6.1.1 Funding Assurance Requirements

NRC requirements to provide assurance of decommissioning funding were introduced as part of rule amendments in 1988. These rule amendments indicated that a number of methods would be acceptable for providing assurance by commercial nuclear reactor, including the use of external sinking funds, also known as Nuclear Decommissioning Trusts ("NDTs"). Requirements to demonstrate financial assurance took effect in July 1990.[20]

Conditions imposed by the NRC on the use of external sinking funds were "intended to ensure that the integrity of decommissioning trust funds will be maintained, especially with respect to protection from creditors in bankruptcy situations".[21]

In addition to external sinking funds, NRC identifies other potential methods of providing financial assurance for the decommissioning of reactors. These are summarized below:[22]

- Prepayment, into a segregated account prior to the start of operations that would be sufficient to pay decommissioning costs at the time of expected permanent cessation of operations.
- Guarantee Method, which can take the form of surety bonds, letters of credit, or insurance; parent company guarantees may be used, subject to a number of a financial tests for guarantors.
- Statement of Intent, by a government agency indicating that funds for decommissioning will be obtained when necessary, available to licensees whose obligations are explicitly guaranteed by the US government.23

[20] US Government Accountability Office, "NRC's Oversight of Nuclear Power Reactors' Decommissioning Funds Could Be Further Strengthened", GAO-12-258, April 2012.
[21] US NRC, Assuring the Availability of Funds for Decommissioning Nuclear Reactors, Regulatory Guide 1.149, August 1990, p. 1.159-4. Rule 10 CFR 50.75(e)(1)
[22] NRC Regulatory Guide 1.159, "Assuring the Availability of Funds for Decommissioning Nuclear Reactors", October 2011, Revision 2, pp. 7-8.
[23] *Ibid*, p. 20.

- Contractual Obligations, on the part of a licensee's customers that will, over the duration of the contracts, provide the licensee's share of uncollected funds needed for decommissioning.
- Other Mechanisms, to provide assurance of decommissioning funding equivalent to that provided by the other acceptable mechanisms.

The NRC requires that:

> "Each of the methods of financial assurance should be adjustable to take into account variations in earnings and adjustments in the amount of funds being set aside for decommissioning both during operation and during storage periods, if any (see Regulatory Position 1.4)."[24]

For regulated utilities, the use of an external sinking fund (i.e. an NDT) is the dominant method.

The NRC provides guidance on the calculation of required contributions to an NDT based on the funding requirement:

> "Annual deposits in an external sinking fund, including projected earnings, should attempt to approximate the total amount remaining to be accumulated, divided by the remaining years of the license, as determined by the initial and updated certification amount specified in 10 CFR 50.75(c)(1) and (2)."[25]

With respect to the contribution profile, the NRC guidance cautions against back-end loaded contributions, stating that "licensees should avoid undue reliance on contributions weighted in constant dollars toward the end of projected facility operating life."[26]

The NRC's approach to the determination of the funding requirement, projected earnings and other inputs is described below in Section 6.1.2. The requirement to use external funds or one of the other acceptable methods represented a substantial departure from previous practice, where companies may or may not have set aside funds that were specifically dedicated to cover decommissioning costs and that were segregated from other utility assets.

6.1.2 NRC Decommissioning Funding

The NRC sets out minimum requirements for licensees to develop and submit decommissioning cost estimates and therefore minimum funding requirements to demonstrate reasonable assurance of funds for decommissioning.

For much of a nuclear reactor's life, the NRC accepts an estimate of decommissioning cost (and therefore funding) that is based on a prescribed formula. The formula is based on studies published in 1978 and 1980, taking into account information available at the time. Separate formulas are provided for Boiling Water Reactors ("BWRs") and for Pressurized Water Reactors ("PWRs"). The formulas assume a linear relationship between capacity and decommissioning cost, with minimums and maximums.[27] The NRC provides a prescribed calculation of a minimum factor for escalating the

[24] NRC Regulatory Guide 1.159, "Assuring the Availability of Funds for Decommissioning Nuclear Reactors", October 2011, Revision 2, p. 13.
[25] *Ibid*, p. 18.
[26] *Ibid*, p. 18.
[27] For example, the formula for PWR's is 75+0.0088P, to be applied with a minimum value of P of 1200 MWt and a maximum value of P of 3,400 MWt. As noted, values are in 1986 dollars.

formula-based funding values from 1986 dollars to current dollars, but not one to account for future inflation, as further discussed below.[28]

The purpose of the formula is to provide values for the minimum amounts required to demonstrate reasonable assurance of funds for decommissioning. According to NRC guidance, the formula "represents the bulk of the funds needed to decommission a specific reactor and is not an estimate of actual cost".[29] In this regard, the formula "is a reference level for licensees as a planning tool early in a reactor's life".[30] Thus, the formula amounts are not intended to be actual estimates of likely decommissioning costs.

Site-specific estimates are required by the NRC beginning about five years before the projected cessation of operations as noted below, although our review of a sample of US jurisdictions suggests that some utilities may prepare site-specific estimates well before they are required under NRC guidance. Cost estimates called for under NRC guidance include the following:

- Preliminary decommissioning cost estimates, which must be provided at or about five years before the projected end of operations;
- An estimate of expected costs as contained in the post-shutdown decommissioning activities report, which is a report that must be submitted prior to or within 2 years following the permanent cessation of operations;
- A site-specific decommissioning cost estimate, which is required within two years following permanent cessation of operations; and
- An updated site-specific estimate of remaining decommissioning costs contained in the license termination plan.

Nuclear power reactor licensees must report to the NRC on the status of their decommissioning funding for each reactor owned on a biennial basis, with any shortfalls made up within a prescribed time frame.

With respect to changes in the funded status of an NDT over time, the NRC indicates a true-up approach, as follows:

> "Arithmetic precision is not required for fund accumulation rates. If, during the course of collecting funds, a licensee has accumulated significantly greater decommissioning funds than anticipated, it may reduce its remaining contributions commensurately. Likewise, if a licensee is significantly behind in collections, increased contributions should be used to make up the deficit."[31]

Costs for Spent Fuel Storage and Site Restoration

The NRC formula does not account for the costs of storing spent fuel, an activity that has since become necessary as a result of delays by the US DOE in accepting such fuel. Sites-specific studies, which become mandatory once the decommissioning date approaches, may take into account such

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[28] Per NRC Regulation 50.75, the adjustment factor is "at least equal to" 0.65L + 0.13E + 0.22B, where L and E are escalation factors for labour and energy, taken from regional data of US Department of Labor Bureau of Labor Statistics, and B is an escalation factor for waste burial, to be taken from NRC report NUREG-1307.
[29] United States Government Accountability Office, "NRC's Oversight of Nuclear Power Reactors' Decommissioning Funds Could be Further Strengthened", April 2012, p. 6.
[30] *Ibid*, April 2012, p. 21.
[31] NRC Regulatory Guide 1.159, "Assuring the Availability of Funds for Decommissioning Nuclear Reactors", Revision 2, October 2011, Paragraph 2.2.8.1, p. 18.

storage costs. State utility commissions may also (but do not always) require utilities to provide funding assurance with respect to spent fuel storage.

Similarly, the NRC formula does not envisage full site restoration. Rather, it provides for removal of radioactive contamination. Utilities may also collect funding for full site restoration and, as with collections for spent fuel storage, this will tend to increase projected costs and hence required fund contributions.

Overall, NRC funding assurance requirements may be exceeded by utilities and state utility commissions at their discretion. To the extent that amounts contributed exceed minimum requirements, this may influence the proportion that can be contributed to "qualifying" NDTs, which receive favourable tax treatment, as discussed further in section 6.4 later in this Chapter.

Review by Government Accountability Office

The NRC formula was subject to some criticism in the 2012 Government Accountability Office ("GAO") review.[32] The GAO questioned the fact that the cost estimates that were the basis of the formula had not been updated to reflect more recent experience. Moreover, GAO noted that NRC has not required licensees to provide information on actual decommissioning costs; hence, NRC has not had ready access to a database of actual cost information. The GAO also noted that there was no definition of the term "bulk", making it unclear as to whether the formula is working as intended.[33]

The GAO also observed that estimates from the formula often varied widely from site specific estimates, with the formula often producing considerably lower numbers. In particular, the GAO compared estimates from 12 different reactors, noting that for five of the reactors, the NRC formula captured 57% to 76% of the costs reflected in each reactor's site-specific estimate; for the other seven reactors reviewed the formula captured from 84% to 103%.

The NRC agreed with several of GAO's recommendations, including for the revision of decommissioning funding assurance estimates (of which a review was implemented in 2010). The NRC disagreed that the definition of "bulk" is necessary to ensure adequate planning for decommissioning costs. Finally, the NRC agreed that its decommissioning funding formula should provide a credible basis for decommissioning cost, but it disagreed that a re-evaluation of the current formula was the best method to achieve credibility and accuracy.[34] At the time our research, the NRC formula continued to be in use as described above.

The GAO review, and NRC's response, highlights the fact that the NRC's funding formula is designed to be a high-level tool to assist in the evaluation of required funding amounts and is not intended to provide utilities with accurate cost estimates. As noted earlier, detailed site-specific estimates are required by NRC only once station shutdown dates approach.

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[32] US Government Accountability Office, "NRC's Oversight of Nuclear Power Reactors' Decommissioning Funds Could Be Further Strengthened", GAO-12-258, April 2012.
[33] As noted earlier, NRC guidance states that the formula is intended to provide an estimate of the "bulk" of the funds needed to decommission a reactor. It is not an estimate of the costs of decommissioning.
[34] NRC Commission Responses to GAO Reports - 2012, "Nuclear Regulation: NRC's Oversight of Nuclear Power Reactors' Decommissioning Funds Could Be Further Strengthened (GAO-12-258)", p.1.

6.1.3 Relationship with Economic Regulation

Through our research, we noted that the US regulatory framework appears to contemplate a relationship between the NRC's regulation of assurance requirements for decommissioning funding and the setting of rates for regulated utilities. In particular, the NRC provides guidance as to how funding plans should be integrated with a utility's rate setting process, serving as a framework within which the FERC and state utility commissions, as economic regulators, should operate in determining amounts to be recovered from customers. In turn, decisions by these economic regulators may influence the amount of funds that are set aside and the acceptability of these balances to NRC.

Overall, the NRC appears to defer to the economic regulators on a number of key elements of the funding assurance process within the NRC's framework. These elements include decommissioning cost estimates (subject to NRC's minimum requirements), future escalation rates, expected investment returns, asset mix for decommissioning trusts, and the timing of updates (subject to NRC's minimum requirements). Economic regulators have the authority to determine associated parameters by virtue of their determination of amounts for decommissioning to be recovered from consumers. During our research, we observed multiple examples where a utility's rate proceeding determined these inputs to the funding calculations; this is highlighted in the Chapters on selected states that follow.

The role of economic regulators in determining funding contributions is reflected in several examples of NRC guidance below:

- **On the requirement and timing of periodic updates to financial assurance amounts**: While non-rate regulated utilities must correct any shortfall in funding that is identified at a biennial review by the time of the next biennial review, regulated utilities that rely on an external sinking fund would generally be expected to make adjustments to the amount of funds being set aside through its rate setting process, with shortfalls being made up within five years. [35] The NRC guidance notes that:

  > "Adjustments to the annual amount of funds being set aside may be made to coincide with rate cases considered by a licensee's public utility commission (PUC) or by the Federal Energy Regulatory Commission (FERC)."[36]

- **Regarding expected investment returns for external sinking funds**: While NRC regulations allow a credit for projected earnings of up to a 2-percent annual real rate of return (i.e. nominal rate less inflation and taxes), the credit may be greater than 2 percent if a licensee "is subject to a rate-setting authority that will provide the total amount of funds necessary for decommissioning and the authority has specifically presumed a higher rate". [37]

- **Regarding allowed asset investments within the external funds for rate regulated utilities:** NRC guidance notes that "investments selected with the approval of, or guidance from, the state PUC with jurisdiction over the licensee, or from the FERC, would be acceptable to the NRC staff". [38]

- **In relation to forward-looking escalation assumptions:** NRC guidance notes that its minimum escalation factor does not provide for estimates of future inflation, but only of inflation that has

[35] NRC Regulatory Guide 1.159, "Assuring the Availability of Funds for Decommissioning Nuclear Reactors", October 2011, Revision 2, p. 14.
[36] *Ibid*, p. 13.
[37] *Ibid*, p. 17.
[38] *Ibid*, p. 18.

already occurred. Accordingly, the guidance states that: "this recalculation is for certification purposes only and does not affect estimated future inflation that a licensee may calculate to establish amortization or collection schedules for rate-making or other purposes".[39] In regard to future inflation rates, which will influence assumptions on future decommissioning cost escalation, the NRC notes that:

> "Estimates of future inflation should bear a reasonable relationship to recent (i.e., within 10 years) economic performance or other relevant economic conditions and factors. The licensee should document the bases for all estimates of past and future inflation."[40]

In addition to economic regulation, the NRC guidance also discusses how adjustments may be co-ordinated with Internal Revenue Service rulings with respect to qualified Nuclear Decommissioning Reserve Funds, which are discussed in Section 6.4.[41]

6.1.4 Impacts on Inter-generational Equity

As noted above, NRC requires specific site-specific estimates to be prepared as the reactor nears the end of its operating life. Thus, "preliminary" decommissioning cost estimates must be prepared at or about 5 years from the projected end of operations. "Site specific" estimates must be prepared prior to or within 2 years of the end of operations.

A review of a sample of US rate proceedings suggests that many utilities may prepare site-specific estimates well before they are specifically required under NRC guidance.

The move to more precise estimates over time, and certainly as the decommissioning date approaches, may have inadvertent impacts on inter-generational equity. The preparation of site-specific estimates should theoretically address any shortfalls in the estimates of costs available as a result of using the NRC formula. We note, however, that to the extent that these site-specific estimates are prepared later in a reactor's life, and result in increases in estimated decommissioning costs, it might reasonably be assumed that these estimates would then result in increases in funds being set aside for decommissioning. Assuming that these funding increases late in the reactor's life are only then reflected in the rate-setting process, this would presumably tend to increase the back-end loading associated with the recovery of decommissioning costs. We have not done any research to confirm if this has been a widespread issue. However, we do note that this circumstance appears to have arisen in the case of PGE's Diablo plant, as reviewed in more detail in our Chapter on California.

Conversely, extensions to facility life as a result of life extensions can result in a decrease in funding requirements in later years, as additional earnings on existing funds may then be sufficient to fund future decommissioning costs. This was observed in a number of US jurisdictions: required contributions fell to zero as a result of extension in facility life.

[39] NRC Regulatory Guide 1.159, "Assuring the Availability of Funds for Decommissioning Nuclear Reactors", October 2011, Revision 2, p. 10.
[40] *Ibid*, p. 12.
[41] Within the NRC Regulatory Guide 1.159 at page 12, the NRC states that "adjustments also may be made to reflect the schedule of "ruling amounts" established by the Internal Revenue Service under Section 468A of the Internal Revenue Code for a qualified Nuclear Decommissioning Reserve Fund. However, the sum of the adjusted ruling amount in a qualified account plus the target amount in a nonqualified account should at least equal the amount indicated in 10 CFR 50.75(c)." [*Note: the amount indicated in CFR 50.75 (c) is the formula amount as discussed earlier.*]

6.2 Economic Regulation

The Federal Energy Regulatory Commission ("FERC") has jurisdiction over inter-state commerce in the US, and it has used this jurisdiction to enforce standards with respect to the development and operation of wholesale electricity markets. In this regard, we found that the FERC has asserted authority over contracts for the sale of power from nuclear power plants in one state to utilities (sometimes related) in adjacent states.

State utility commissions retain authority over the retail rates of most investor-owned utilities, and it is therefore these commissions that will typically have authority over determining how nuclear decommissioning and waste management costs are recovered from consumers by regulated entities.

The FERC also plays an important role in the utility regulatory process generally. The FERC Chart of Accounts defines how costs are tracked and allocated within the US electricity utility sector. These accounts provide a common basis amongst utilities in how costs are reported, thus facilitating cost comparisons across utilities. State utility commissions typically enforce the use of these accounts, as they make the tracking of costs easier.

6.2.1 FERC Precedents

Our review identified a limited number of FERC precedents related to inter-state power transactions that involved the recovery of nuclear decommissioning costs. In both of the decisions reviewed, it was accepted that decommissioning costs would be recovered on a forward-looking NDT funding approach. In addition to these precedents, we also briefly review below a general FERC accounting order related to the introduction of the FAS 143 US GAAP accounting standard.

Opinion No. 446

First, we noted that in Opinion No. 446, which dealt with sales of power from System Energy Resources Inc. (SERI) to four utilities in Arkansas, Louisiana, and Mississippi, FERC showed a preference for the recovery of decommissioning costs through levelized-real payments over levelized-nominal payments. Each of the companies involved, including SERI, were owned by Entergy.[42] Power to the various utilities was being supplied from SERI's Grand Gulf Nuclear Station, Unit 1, which had been the subject of a sale / leaseback transaction. The terms of the power sales agreement had been the subject of a series of proceedings. In its 2000 decision, the FERC upheld an earlier judge's ruling that rejected a SERI proposal to change the method for calculating the decommissioning revenue requirement during the lease period from a levelized-real basis to a levelized nominal-basis.

In a levelized real payment approach, annual payments are escalated over time by inflation, resulting in even recovery of costs on an inflation-adjusted basis. Under a levelized-nominal payments approach, which we have found to be the dominant method adopted by state commissions, an even amount in nominal terms is recovered over time. Both approaches may be potentially supportable from an inter-generational equity perspective.

Opinion No. 446-A

Another FERC decision in 2001 dealt with a subsequent request by the Louisiana Public Service commission to reverse a related FERC decision to allow for accelerated recovery of decommissioning

[42] FERC, Opinion No. 446, Docket No. ER95-1042-000, p. 23.

costs (i.e. within the lease period related to the sale / leaseback agreement for the Great Gulf 1 reactor). SERI provided for the recovery of decommissioning costs over the life of the lease instead of over the life of the unit. The Louisiana Public Service Commission objected that allowing this accelerated recovery of decommissioning expenses violated the principle of intergenerational equity, because "today's customers may be paying for the decommissioning funding obligations of future customers".[43]

Given the particular circumstances of that case, the FERC allowed the accelerated recovery on the basis that the sale / leaseback transaction brought other benefits that justified the move away from the general practice of recovering costs over the full plant life. It noted:

> "Usually, the Commission [*FERC*] requires recovery of decommissioning expenses over the license life of the plant. However, in this case the sale/leaseback of a portion of Grand Gulf has resulted in a savings to SERI's ratepayers of over $27 million. And the sale/leaseback would not have taken place without SERI's agreeing to fully fund the decommissioning liability for the leased portion of Grand Gulf I by the end of the lease.
>
> "…While it is true that future ratepayers will also benefit (because they will not be subject to decommissioning expenses for the leased portion of Grand Gulf I) still, current ratepayers could not have obtained the millions of dollars of benefits that the sale/leaseback made (and still makes possible) without the condition that SERI fund decommissioning of the leased portion of the plant on an accelerated basis. We will thus allow accelerated recovery of decommissioning expenses for the leased portion of Grand Gulf I because, in this instance, the substantial benefits outweigh both the cost of accelerated recovery and any intergenerational inequity that may result from it."[44]

In summary, the FERC decision in the SERI case confirms the FERC's general preference for an even recovery of costs over time, even though this method was waived in this particular instance.

Opinion No. 350

One of the decisions cited as a precedent in the two FERC decisions reviewed above dealt with recovery of decommissioning costs for a nuclear plant (Pilgrim 1) owned by Boston Edison. In Opinion No. 359, issued in July 1990, the FERC ruled in favour of what it termed the "fund analysis" methodology to setting decommissioning charges. In FERC's view, the fund analysis methodology provided for a levelized real payment approach.

Based on a review of Opinion No. 350, we have concluded that the levelized real payment approach as envisaged by FERC in that Decision entails contributions that are fixed in nominal terms between review periods, but which escalate at each review period to account for inflation in the intervening period. Hence, it is not a "pure" levelized real payment approach, under which payments would escalate by each in each year. However, since review periods will occur at least every five years, there will be nevertheless relatively frequent adjustments to payment amounts. Further, the calculations of required payment amounts within any five-year period would also take into account expected inflationary increases at each subsequent review date. Thus, the FERC noted,

> "In practice, the fund analysis calculates the current monthly charge by assuming an inflation rate, an interest rate for earnings on fund balances, a tax rate on fund earnings, and administrative charges for the fund. The customer's charge is set at the level necessary to fund the customer's

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[43] FERC, Opinion No. 446-A, Order Denying Rehearing, Docket No. ER95-1042-003, July 30, 2001, p. 20.
[44] *Ibid*, pp. 21-22.

> total decommissioning cost responsibility, as escalated to plant retirement, under the stated parameters and assuming that the charges are adjusted at the time of each review to account for inflation, so as to keep the charges constant in inflation adjusted terms."[45]

The result of this process would be that:

> "Monthly charges are levelized between review periods and adjusted at the time of each review. Payments remain constant in real (inflation-adjusted) dollars, but increase in nominal dollars at the time of each review."[46]

The FERC rejected the "remaining life methodology" put forward by Boston Edison. Under this methodology, the charge would be based simply on the total decommissioning cost estimate, less prior collections and accumulated net income, divided by the remaining number of months over which the charge is to be collected.[47] The decommissioning cost estimate used in this calculation would not account for inflation between the rate-setting date and the decommissioning date. The FERC concluded that this remaining life methodology was "unreasonable", noting:

> "The remaining life method, as described by Boston Edison, appears to be fundamentally flawed as it fails to account for the impact of inflation upon the ultimate costs of decommissioning Pilgrim 1 [*the nuclear plant in question*]."[48]

Boston Edison argued that it would conduct updated decommissioning cost studies every several years and then adjust decommissioning charges on the basis of the updated studies. The FERC did not favour this approach, noting:

> "While Boston Edison's plan will permit the company to recoup over time the under recovery induced by inflation, it does not provide a systematic method of allocating decommissioning costs among generations of customers."[49]

The FERC found that the fund analysis approach was superior to the remaining life method:

> "On the other hand, the fund analysis does incorporate the effects of inflation, as well as the effects of fund earnings and administrative costs, in developing the monthly charges. Further, the fund analysis incorporates periodic revisions in the monthly charges to maintain a constant charge in real, inflation adjusted terms. Thus the fund analysis provides a systematic and fair method of allocating decommissioning costs, in constant dollars, among generations of customers. Of course, actual customer charges will fluctuate as estimates of decommissioning costs and assumptions concerning interest, tax and inflation rates are updated. However, the fund analysis method should minimize these fluctuations, and thus minimize misallocation of decommissioning expense responsibility among generations of customers."[50]

In summary, the FERC decisions noted contemplate that decommissioning charges will rise over time in nominal terms, to provide for decommissioning charges that remain roughly flat in inflation-adjusted terms.

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[45] FERC, Opinion No. 350, Opinion and Order Affirming in Part and Reversing in Part Initial Decision, Docket No. ER86-645-001 et al, 52FERC61,010, July 9, 1990, p. 23.
[46] *Ibid*, p. 23.
[47] *Ibid*, p. 22.
[48] *Ibid*, p. 23.
[49] *Ibid*, p. 25.
[50] *Ibid*, p. 25.

FERC Order 631

In 2003, FERC issued Order 631, which requires entities that report to it to adopt accounting practices similar to those provided for under FASB 143. Prior to FASB 143, many utilities recognized their expected future decommissioning costs as a component of the depreciable amount. The depreciable amount would include the cost of future decommissioning as a "negative net salvage value", and this amount would be depreciated over the life of the asset. This depreciation would be treated as an incurred and allowable cost for rate-making purposes. Some other utilities may not have had explicit provisions for decommissioning costs. Order 631 was designed to provide more consistency in utility financial reporting.[51]

Among other things, Order 631 provided for new account codes to accommodate the new accounting entries.[52]

Order 631 also stated that public utilities that have formula rate tariffs must not include any cost components related to asset retirement obligations in their formula rate billing tariffs for automatic recovery in the billing determinations without obtaining Commission approval.[53] (Under a formula rate plan, tariffs may be automatically adjusted based on filed financial statements.)

FERC further noted:

> "The Commission finds that the issue of whether, and to what extent, a particular asset retirement cost must be recovered through jurisdictional rates should be addressed on a case-by-case basis in the individual rate change filed by public utilities, licensees, and natural gas companies."[54]

FERC updated its rate change filing requirements to ensure that rate base amounts related to AROs can be identified and, if necessary, excluded from the rate base calculations. Thus:

> "If the public utility, licensee or natural gas company is seeking recovery of an asset retirement obligation in rates, it must also provide a detailed study supporting the amounts proposed to be collected in rates. If the public utility, licensee or natural gas company is not seeking recovery of the asset retirement obligation in rates, then it must remove all asset retirement obligation related cost components from its cost of service."[55]

Based on this Order and our research, it does not appear that FERC intended that the accounting presentation of AROs be determinative with respect to how costs are recovered in rates.

6.3 The United States Department of Energy

The US Department of Energy ("US DOE") is responsible for the disposal of spent nuclear fuel from commercial power reactors. US utilities previously paid a fee to the US DOE for spent fuel disposal, but they are not directly responsible for arranging for long-term disposal and thus do not directly bear the associated costs. The US DOE has, for its part, faced a number of challenges in meeting its responsibilities as outlined below.

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[51] William J. Harmon, "FERC Issues New Rules Governing the Accounting, Reporting and Rate Filing Requirements for Asset Retirement Obligations", Jones Day, 24 April 2003.
[52] FERC, Order No. 631, Docket No. RM02-7-000, April 9, 2003, Appendix B.
[53] *Ibid*, Paragraph 60.
[54] *Ibid*, Paragraph 62.
[55] *Ibid*, Paragraph 62.

The US DOE's role in the disposal of spent nuclear fuel is set out in the Nuclear Waste Policy Act of 1982 (NWPA), which directed the US DOE, among other things, to:[56]

- study sites for a nuclear waste repository, and
- contract with industry to begin taking title to and disposing of commercial spent nuclear fuel in 1998.

The NWPA also provided for the creation of the Nuclear Waste Fund, a trust fund established to collect fees for the industry's share of a nuclear waste repository. The US DOE is to determine how much industry should contribute to the fund, and annually review the established amount taking into consideration whether the fee will provide sufficient revenue. Up to 2014, the fee rate was set at one-tenth of a cent per kWh of electricity generated from nuclear plants.[57]

The US DOE investigated a number of possible sites for a nuclear waste depository and eventually focused on developing a geological repository site at Yucca Mountain in Nevada. The site was to handle both commercial and defense waste. Opposition to the site developed and the process for development and licensing for this site was suspended in 2010-2011.

Earlier, in 1998, the US DOE missed the deadline in the NWPA to begin taking title to and disposing of commercial spent nuclear fuel. As a consequence, nuclear power plant operators have had to retain spent nuclear fuel on-site, incurring additional costs for storage and oversight. The US Department of Justice has entered into settlement agreements with many facility owners to cover these additional costs and provide for the payment of damages.[58, 59] Funds received as a result of these settlement proceedings have been an issue in a number of regulatory proceedings, including in some of the states reviewed in this report.

Fees levied on nuclear power generation were suspended beginning in 2014 as a result of a lawsuit filed by the Nuclear Energy Institute and the National Association of Regulatory Utility Commissioners.[60] Nevertheless, it is still expected that the US DOE will ultimately accept spent fuel. Decommissioning cost estimates prepared by utilities continue to assume that DOE will ultimately accept spent fuel, although timelines remain uncertain.[61] A DOE strategy document issued in 2013 identified a target of 2048 for making a geologic repository available.[62]

The fees levied by the US DOE have been typically treated by utilities as an operating expense related to the costs of fuel rather than as an accrued asset retirement obligation, and, for rate regulated utilities, recovered from customers on a pass-through basis. In this regard, the recovery methodology for these costs is, by definition, aligned between the accounting basis and the funding / disbursements basis.

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[56] United States Government Accountability Office, "Nuclear Waste: Benefits and Costs Should Be Better Understood Before DOE Commits to a Separate Repository for Defense Waste", January 2017, p. 62.
[57] *Ibid*, p. 8.
[58] United States Government Accountability Office, "Spent Nuclear Fuel Management: Outreach Needed to Help Gain Public Acceptance for Federal Activities That Address Liability", October 2014, p. 49.
[59] As of 2014, the Federal government had paid out about $3.7 billion in damages
[60] United States Government Accountability Office, "Nuclear Waste: Benefits and Costs Should Be Better Understood Before DOE Commits to a Separate Repository for Defense Waste", January 2017, p. 9.
[61] For example, see Decommissioning Cost Analysis for the Grand Gulf Nuclear Station, prepared by TLG Services, Inc. May 2017, System Energy Resources, Inc. Docket No. ER17-, Document E11-1740-001.
[62] US DOE, "Strategy for the Management and Disposal of Used Nuclear Fuel and High-Level Radioactive Waste", January 11, 2013.

In the US, the federal government's commitment to process utilities' spent fuel, and subsequent failure to meet deadlines for accepting this fuel, have considerably complicated the landscape with respect to decommissioning cost recovery. The various developments (i.e. a levy on nuclear generation, followed by settlement agreements) have made it difficult to assess the actual pattern of cost recovery in the US for spent nuclear fuel. The role of the federal government in handling spent fuel has also diminished the role of state regulatory agencies, which control other elements of the cost recovery process.

6.4 Internal Revenue Service

An NDT set up to meet NRC requirements may, in certain circumstances, qualify as a "Nuclear Decommissioning Reserve Fund" under Section 468A of the Internal Revenue Code ("Qualifying NDT"). Qualifying an NDT means that contributions to the NDT will qualify as an expense when calculating income tax payable. Consistent with this treatment, when decommissioning expenses are paid with funds from a Qualifying NDT, the associated expenses will not be tax deductible.

In contrast, when an NDT is non-Qualifying, contributions to the NDT will not qualify as an expense when calculating income tax payable. Hence, allowances in rates that target a particular contribution level for the NDT will need to be grossed-up to account for the income tax payable on the revenues thereby collected. Decommissioning expenses that are paid with funds from a non-Qualifying NDT correspondingly qualify as a deductible expense when calculating income taxes in that year.

Utilities often have both Qualifying and non-Qualifying NDTs in parallel. Income taxes are payable on earnings by both types of funds.[63]

For the purposes of evaluating funding adequacy, NRC treats the two types of NDTs as equivalent: the amounts in Qualifying and non-Qualifying NDTs are simply added together when comparing to target funding amounts.

The intent of IRS rules appears to be to limit the contributions that can be deemed as "qualifying" to the minimum level required to provide funding for expected decommissioning costs.[64] Limits on contributions are specified for any taxpayer through a "ruling amount". Among other things, the quantum of any "ruling amount" is defined:

> "to prevent excessive funding of nuclear decommissioning costs or funding of these costs at a rate more rapid that level funding, taking into account such discount rates as the Secretary [*of the IRS*] deems appropriate." [65]

IRS regulations provide that it may rely on schedules provided by state utility commissions in defining ruling amounts.[66] In our review of utility commission proceedings, we found multiple instances where utilities requested schedules from the commission for IRS compliance purposes.

IRS rules have evolved over time and this has influenced decisions by utility commissions on funding approaches and the use of NDTs. This is highlighted in some utility commission decisions that we found in our state-level review. For example, because external NDTs did not receive favourable tax treatment prior to 1990, the Minnesota PUC approved the use of internal, rather than external, sinking

63 CFR, Title 26, Section 1.1468A-4.
64 Internal Revenue Service, Index No. 468A. 04-02, Number 199909006, Release date 4/5/1999, p. 3.
65 *Ibid*.
66 See Internal Revenue Service, Index No. 468A. 04-02, Number 199909006, Release date 4/5/1999, p. 6.

funds for decommissioning. With internal funds, decommissioning funds are invested in the utility's own property, plant and equipment rather than being used to purchase external investments.

7 Overview of the United States Nuclear Fleet

In this Chapter we provide an overview of the United States electricity market, its nuclear power generation fleet, and mechanisms for the recovery of nuclear decommissioning costs.

7.1 Overview of the US Electricity Sector

The US electricity sector is very diverse, encompassing utilities with a range of ownership structures and multiple models for the operation of electricity markets. Some states retain a fully regulated market structure, where regulated utilities provide generation, transmission and distribution on a vertically integrated basis. Other states and/or regional markets include competitive electricity markets and have enforced the unbundling of competitive generation from monopoly transmission and distribution activities. These markets or states typically also include competitive retail markets for the supply of electricity commodity to retail end-users.

Given that retail rates are generally regulated at the state level, the US market provides the opportunity to observe practices for the recovery of nuclear decommissioning and waste management costs in multiple jurisdictions in parallel.

To capture the full range of experience in the US, we looked at 11 jurisdictions or utilities in more detail, as further outlined below.

7.1.1 States Reviewed

In the US, 30 of the 50 state jurisdictions have or have had operating nuclear power plants, as summarized in Exhibit 7-1 based on data compiled by the NRC. As noted in Chapter 2, it was not within the scope of this study to look at developments in each of the 30 states. We therefore focused our research on 11 state jurisdictions for a more detailed review. These jurisdictions were selected based on the following considerations:

- Inclusion of a sufficient number of jurisdictions with rate regulated power producers.
- Inclusion of states where nuclear power plays a major role.
- Inclusion of sample states with retail open-access and competitive electricity markets.
- Inclusion of a range of ownership structures.
- Inclusion of states where nuclear power is being expanded, as well as where it is being phased out.
- Inclusion of regionally diverse jurisdictions.

Based on these criteria, the following states or utilities were selected for review:

- **Tennessee Valley Authority.** This was selected as it represents a major government-owned utility that is also an important nuclear operator. TVA provides power across a number of different states, including Tennessee, and has the power to set its own rates. This means that it has more flexibility in its rate setting process than investor-owned utilities, which are typically regulated by state utility commissions.

- **Alabama.** Alabama was studied because it is the fourth largest nuclear power producer in terms of energy output and fifth largest by number of reactors.[67] Nuclear power plants in Alabama are also owned by the same corporate entity that owns plants in Georgia, allowing a comparison of practices across different jurisdictions for the same corporation.
- **Arizona.** Arizona is included because it hosts the single largest nuclear generating facility in the country (Palo Verde) and this complex provides power to utilities with service territories covering four separate states, including California.
- **California.** California is of interest because one of the major utilities (Pacific Gas & Electric) is phasing out its nuclear generation as a result of the planned shut-down of the Diablo Canyon plant in the near future. California is also often a leading state with respect to regulatory practices.
- **Florida.** Florida is a state with a long history of nuclear power owned by investor-owned vertically-integrated utilities subject to rate regulation. It also offers fairly good disclosure of materials supporting the setting of rates going back a number of years.
- **Georgia.** Georgia is the site of a new reactor currently under construction (Vogtle Units 3 and 4), and thus is a jurisdiction that has made a commitment to an expanding role for nuclear generation. It is also an example of a state where the electricity sector remains vertically integrated with a fully regulated investor-owned utility. As it happens, ownership of the nuclear power plants in the state is shared among a number of utilities that have different ownership structures, including electric membership co-operatives; this provides additional points of comparison.
- **Illinois and Pennsylvania.** These states were included because they are the two top producers of nuclear power in the country.[68] They also happen to be representative of states with open electricity markets and retail open access for individual consumers following deregulation.
- **Minnesota.** Minnesota was of interest because the state retains vertically integrated utilities but is part of a competitive wholesale market. Regulatory proceedings with respect to Northern States Power also provide a helpful overview of the evolution of rate recovery mechanisms over time.
- **North Carolina and South Carolina.** These states are of interest because they are large nuclear power producers (both are in the top 5 states in terms of nuclear output) and, like Georgia, they retain vertically integrated market structures. Along with Alabama, these are also among the top three rate regulated nuclear energy producing jurisdictions in the US.

Of the 11 jurisdictions selected, eight contain vertically integrated utilities that are rate-regulated while two provide for full competition in retail commodity supply.[69] The remaining jurisdiction and entity (TVA) has the authority to set its own rates. The selected states include 10 of the top 15 states by nuclear output, for a total of approximately 59% of both US nuclear power production and total number of operating reactors as at December 2019.[70, 71] Four of the five excluded top 15 states (New York,

[67] US NRC, 2019-2020 Information Digest, NUREG-1350, Volume 31, August 2019, p. 28.
[68] NRC, "Information Digest, 2019-2020" (NUREG-1350, Volume 31), p. 28.
[69] We have treated California as a regulated state although it offers some element of retail choice to large industrial customers and through community choice aggregation programs. Despite these programs, commodity supply is provided to most customers on a regulated basis, and hence we have characterized this jurisdiction as regulated in this summary discussion.
[70] TVA has been taken into account in this calculation by including production for Tennessee, where 2 of TVA's 3 reactors are located. TVA's other nuclear power plant is located in Alabama, which was already the focus of our review in connection with Alabama Power.
[71] U.S. Energy Information Administration, U.S. Nuclear Generation and Generating Capacity, Data Released 2020-11-30.

Texas, Michigan and New Jersey) operate in competitive electricity markets and have provided for the deregulation of commodity supply.

Within each of the selected states, we looked at practices with respect to the recovery of nuclear decommissioning costs at one or more prevailing utilities within the state.

Exhibit 7-1 - Summary of Nuclear Electricity Production by State[72]

Nuclear Power Production By State					
State	**Nuclear Power Production**		**State**	**Nuclear Power Production**	
	GWh	*Included?*		*GWh*	*Included?*
Illinois	97,191	1	Ohio	17,687	
Pennsylvania	83,199	1	Connecticut	16,499	
South Carolina	54,344	1	Louisiana	15,409	
Alabama	42,651	1	Maryland	15,106	
North Carolina	42,374	1	Minnesota	13,904	1
New York	42,167		Arkansas	12,691	
Texas	38,581		Kansas	10,647	
New Jersey	34,032		New Hampshire	9,990	
Georgia	33,708	1	Wisconsin	9,648	
Michigan	32,381		Missouri	8,304	
Arizona	32,340	1	Washington	8,128	
Tennessee	31,817	1	Mississippi	7,364	
Virginia	30,533		Nebraska	6,912	
Florida	29,146	1	Iowa	5,213	
California	17,901	1	Massachusetts	5,047	
Total US				**804,914**	
Total - Case Studies				478,575	59.5%

States known to have some form of customer choice or retail open access for at least a portion of their customer base are shown with blue highlighting in Exhibit 7-1. These states are potentially less directly comparable to Ontario; hence our selection of jurisdictions focused more on those states that retain market structures where regulated utilities retain responsibility for commodity supply.

Additionally, we reviewed certain FERC precedents related to recovery of decommissioning costs in certain inter-state transactions involving nuclear utilities over which it as asserted authority. These were reviewed in Chapter 6.

7.2 Key Findings – US Jurisdictions

Overall, for the utilities and jurisdictions that we reviewed we found that the recovery of nuclear decommissioning costs for investor-owned utilities in the US is based on a forward-looking funding

[72] US NRC, 2019-2020 Information Digest, NUREG-1350, Volume 31, August 2019, p. 28.

approach. Thus, collections from consumers are based on the funding that the utility needs to contribute to Nuclear Decommissioning Trusts ("NDTs") to meet various regulators' expectations with respect to funding adequacy. Rates are therefore not directly linked to accounting measurements of cost. Because we did not review practices at all investor-owned utilities, we cannot definitively state that a forward-looking funding approach is universal in the US. However, there is no reason to believe that the sample of utilities we selected was not representative of the other investor-owned utilities, as this sample was developed in order to capture a broad range of utility circumstances.

For utilities that are self-regulated, including for TVA and some of the electric co-operatives that we reviewed, the basis of amounts for nuclear decommissioning included in rates is somewhat less clear. This reflects more limited disclosure with respect to how retail rates were derived.

The use of a forward-looking funding approach by US utilities is consistent with the approach used by NRC for evaluating the adequacy of decommissioning funding arrangements. The NRC expects utilities to maintain NDTs and it evaluates the adequacy of current NDT balances, and expected future balances, based on assessments of expected future contributions and future investment returns.

In this report, we will generally use the term "decommissioning expense" to mean amounts provided in rates in order to fund future nuclear decommissioning costs. These decommissioning expenses may not correspond to expenses recognized for accounting purposes, which comprise accretion of the ARO and depreciation of ARC.

8 Tennessee Valley Authority

The Tennessee Valley Authority ("TVA") is a "corporate agency and instrumentality" of the United States. It was created to, among others, improve navigation on the Tennessee River and to further the economic development of its service area. It is the largest public utility in the United States.[73]

TVA is primarily a wholesale power supplier, selling power to local municipal utilities or co-operatives that in turn supply retail consumers. Its service area covers parts of Tennessee, Alabama, Mississippi, Kentucky, Georgia, North Carolina and Virginia. TVA's contracts with local utilities require these utilities to purchase all of their power from TVA. TVA also serves a number of large end-use customers directly.

TVA operates a total of seven nuclear units across three sites, with total capacity of 7,723 MW: Browns Ferry, Sequoyah and Watts Bar. The Sequoyah and Watts Bar plants are located in Tennessee and the Browns Ferry plan is located in Alabama. TVA's most recent nuclear unit was placed in service in 2016 (at Watts Bar). TVA has made investments of approximately $475 million to add an estimated 465 MW of generating capacity at Browns Ferry in 2019.[74] Additionally, the NRC issued an Early Site Permit to TVA in December 2019 to license small modular reactors at TVA's Clinch River Site in Oak Ridge.[75] TVA's power plants account for the entire nuclear generation output in Tennessee, which is 8th out of 30 states in terms of the generation of nuclear power.[76]

As TVA has the authority to set its own rates without regulatory oversight, our review focused on information provided in TVA's publicly available annual report.

8.1 Regulatory Regime

TVA wholesale rates are established by the TVA Board, which has the sole responsibility for setting these rates. Rates are not subject to judicial review or approval by any state or federal regulatory body. Thus, neither the FERC nor state utility commissions provide oversight on rates charged.

Under the Tennessee Valley Authority Act, TVA is required to charge rates for power that will produce gross revenues sufficient to provide funds for:

- Operation, maintenance, and administration of its power system;
- Payments to states and counties in lieu of taxes;
- Debt service on outstanding indebtedness;
- Payments to the US Treasury in repayment of and as a return on the government's appropriation investment in TVA's power facilities (the "Power Program Appropriation Investment")[77]; and
- Such additional margin as the TVA Board may consider desirable for investment in power system assets, retirement of outstanding bonds, notes, or other evidences of indebtedness in advance of their maturity, additional reduction of the Power Program Appropriation Investment, and other

[73] Tennessee Valley Authority, Annual Report for Fiscal 2020, Form 10-K, pp. 8-12.
[74] *Ibid*, p. 68.
[75] *Ibid*, p. 13.
[76] U.S. Energy Information Administration, U.S. Nuclear Generation and Generating Capacity, Data Released 2020-11-30.
[77] TVA has fulfilled its requirement to repay the US Treasury in respect of the Power Program Appropriation Investment, and so this category of expenditure no longer applies.

> purposes connected with TVA's power business, having due regard for the primary objectives of the Tennessee Valley Authority Act, including the objective that power shall be sold at rates as low as are feasible.

TVA's annual report notes that it uses a debt-service coverage ("DSC") methodology "to derive annual revenue requirements in a manner similar to that used by other public power entities that also use the DSC rate methodology. Under the DSC methodology, rates are calculated so that an entity will be able to cover its operating costs and to satisfy its obligations to pay principal and interest on debt, plus an additional margin."[78]

8.2 Rate Recovery

While we were unable to identify publicly available information directly setting out how TVA's rates recover decommissioning costs, we believe, based on our review of TVA's annual report, that the rates consider amounts being contributed to the TVA NDT, in a similar way to that used by state-regulated utilities.

In particular, TVA's annual report indicate the following with respect to the regulatory asset related to nuclear decommissioning costs:

> "Nuclear decommissioning costs [*deferred in the regulatory asset*] include: (1) certain deferred charges related to the future closure and decommissioning of TVA's nuclear generating units under the Nuclear Regulatory Commission ("NRC") requirements, (2) recognition of changes in the liability, (3) recognition of changes in the value of TVA's NDT, and (4) certain other deferred charges under the accounting rules for AROs. These future costs will be funded through a combination of the NDT, future earnings on the NDT, future earnings thereon. Deferred charges will be recovered in rates based on the analysis of expected expenditures, contributions, and investment earnings required to recover the decommissioning costs. […] There is not a specified recovery period; therefore, the regulatory asset is classified as long-term consistent with the NDT investments and ARO liability."[79]

Consistent with the above, the annual report notes that while realized and unrealized gains and losses on trading securities, including those held in the NDT, are recognized in current earnings, the gains and losses of the NDT are subsequently reclassified to a regulatory asset or liability account "in accordance with TVA's regulatory accounting policy".[80]

The existence of a regulatory asset related to nuclear AROs and NDT suggest that TVA has collected less in rates to date for nuclear decommissioning than has been recognized, net of earnings of the NDT, for accounting purposes. Among other things, this may reflect both differences in the decommissioning cost estimates used for accounting versus rate-making purposes as well as differences between the discount rates used to calculate ARO values and the future rates of return assumed for investing funds collected through rates toward decommissioning. These differences appear to parallel those identified in the financial statements of state-regulated nuclear utility operators that recover decommissioning costs in line with NDT contributions and as such we believe it likely that a similar rate recovery method is followed by the TVA.

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[78] Tennessee Valley Authority, Annual Report for Fiscal 2020, Form 10-K, p. 11.
[79] *Ibid*, p. 105.
[80] *Ibid*, p. 122.

8.3 Other Observations

8.3.1 Decommissioning Cost Estimates

TVA recognizes decommissioning obligations, including for nuclear power plants, in its annual report as an ARO in accordance with US GAAP, including any changes in underlying estimates and assumptions resulting in ARO revisions. A note in the TVA's annual report indicates:

> "Revisions to the ARO estimates are made whenever factors indicate that the timing or amounts of estimated cash flows have changed. Any change to an ARO liability is recognized prospectively as an equivalent increase or decrease in the carrying value of the capitalized asset. Any accretion or depreciation expense related to these liabilities and assets is charged to a regulatory asset."[81]

Decommissioning cost estimates are updated for each nuclear unit at least every five years.

Some key assumptions with respect to TVA's estimates of nuclear decommissioning costs provided in their annual report include:

- TVA uses expected inflation rates over the remaining timeframe until costs will be incurred to estimate future cash flow requirements.
- The discount rate used to calculate resent value is TVA's "incremental borrowing rate over a period consistent with the remaining timeframe until costs are expected to be incurred".[82]
- Cost estimates are based on site-specific studies.

As at September 30, 2020, the ARO liability was valued at $3.3 billion and regulatory assets related to nuclear decommissioning ARO costs were $896 million. Thus, regulatory assets related to nuclear decommissioning were about one-quarter of nuclear AROs. The most recent update to the decommissioning cost estimates used for accounting purposes in September 2017 resulted in an increase of $250 million in nuclear AROs.[83]

The TVA annual report notes that decommissioning costs reported to the NRC may vary from the $3.3 billion ARO value, which we believe gives rise, in part, to the TVA's regulatory asset balance. It further explains:

> "Utilities that own and operate nuclear plants are required to use different procedures in calculating nuclear decommissioning costs under GAAP than those that are used in calculating nuclear decommissioning costs when reporting to the NRC. The two sets of procedures produce different estimates for the costs of decommissioning primarily because of differences in the underlying assumptions."[84]

Additionally, we noted that he TVA is currently assuming that the NDT will earn a real rate of return of 5%..[85] This assumed rate appears higher than that used by many other utilities, even those with multi-asset investment portfolios.[86] We note further that a 5% real rate of return is much higher than

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[81] Tennessee Valley Authority, Annual Report for Fiscal 2020, Form 10-K, p. 74.
[82] *Ibid*, p. 75.
[83] *Ibid*, p. 109.
[84] *Ibid*, p. 146.
[85] *Ibid*, p. 36.
[86] According to the TVA's financial statements, the TVA NDT has exposure to US equities, international equities, real estate investment trusts, high-yield debt, domestic debt, inflation-protected securities, commodities, and private real estate, private equity and absolute return strategies.

the 2% real rate of return generally allowed by NRC in the absence of approval for a higher rate by a utility regulatory authority. Since TVA regulates set its own rates, it is possible it is relying on its own regulatory authority in using a 5% real rate of return.

The 5% real rate of return would be higher than the discount rate (based on TVA's long-term borrowing costs) that TVA used to measure the value of its AROs. Differences in discount rate are likely a major contributing factor to the difference between the TVA's accounting ARO and decommissioning funding obligations and therefore to the derivation of regulatory assets related to nuclear decommissioning costs.

9 Alabama

9.1 Industry Structure

The electricity sector in Alabama remains regulated, with vertically integrated utilities that supply power to captive customer bases. Retail open-access is not available. We reviewed one utility, Alabama Power, which owns one nuclear power plant in the state. TVA, which was reviewed in the prior Chapter, owns the other nuclear plant in Alabama. As noted earlier, TVA is not regulated by either state commissions or the FERC.

Based on data from the Nuclear Energy Institute, nuclear electricity accounted for 31.4% of electricity generated in the state in 2019.[87] Alabama was 5th out of 30 states in terms of the generation of nuclear power.[88]

9.2 Alabama Power

Alabama Power is an operating public utility company that owns and operates the Plant Farley nuclear plant in Alabama. Alabama Power itself is wholly-owned by Southern Company, an investor-owned holding company that owns utilities in Georgia, Alabama and Mississippi. Alabama Power's sister company in Georgia (Georgia Power) also operates nuclear power plants and is discussed in Chapter 13.

9.2.1 Regulatory Regime

Alabama Power is the only electric utility in Alabama that is under the jurisdiction of the Alabama Public Service Commission ("Alabama PSC"). Alabama PSC has implemented a formula rate-setting methodology through a mechanism known as the "Rate Stabilization and Equalization Factor" (or "Rate RSE".) This provides for automatic rate adjustments for Alabama Power based on forward-looking information, certain rules and on projected returns relative to allowed returns. The approach, which to our understanding has been in place since at least the early 1990s[89], appears to be designed to reduce administrative effort associated with regulatory processes. In support of this approach, Alabama PSC has noted:

> "The Commission finds that the adoption of Rate RSE and the resulting reduction of the number of general retail rate increase requests filed by the Company, given the increased monitoring and auditing provisions of Rate RSE and these Rules, will increase the Commission's ability to fulfill its statutory duty to supervise the overall operation of the Company as provided in Title 37, Code of Alabama (1975) with appropriate representation of the consumer interest. The absence of lengthy and time-consuming hearings occasioned by major rate cases brought by this utility will provide a better opportunity for the Commission and its staff to effectively and closely monitor the Company's daily operations and to investigate regulatory matters which heretofore have remained unaddressed."

[87] Nuclear Energy Institute, State Electricity Generation Fuel Shares. Updated August 2020.
[88] Including TVA's production. U.S. Energy Information Administration, U.S. Nuclear Generation and Generating Capacity, Data Released 2020-11-30.
[89] See dates noted in paragraph 9 on page 5 of the Special Rules Governing Operation of Rates RSE and CNP, 6th Revision, September 20, 2013.

> "The Commission finds that this increased supervision is essential to the proper implementation of Rate RSE, is essential to the protection of the Company's retail customers, and is a proper and necessary exercise of the Commission's statutory responsibilities. The Commission expressly acknowledges that its function is to regulate the Company, not to substitute its judgment for that of the Company's management, subject to the demonstration that the Company is honestly, economically and efficiently managed."[90]

As a result of the application of the Rate RSE mechanisms, there appear to have been no recent full rate hearings. Instead, the Rate RSE requires Alabama Power to participate in "informal meetings" with Commission staff, occurring on a scheduled day in December in advance of any rate adjustments taking place in January of the following rate year. Supporting information for a proposed rate increase must be provided by December 1.[91] The RSE mechanism also provides for refunds to consumers if the company's actual returns are above the allowed range in the prior year. The Rate RSE requires the completion of a number of forms that rely on costs reported according to the FERC Charts of Accounts.

9.2.2 Rate Recovery

While the absence of full rate hearings has resulted in an absence of regulatory filings that could directly identify how certain costs are recovered in rates, based on information presented in Southern Company's annual report and regulations in respect of the Rate RSE, we conclude that Alabama Power uses a forward-looking NDT funding approach to determine amounts collected in rates for nuclear decommissioning (including spent fuel storage).

In particular, Southern Company's 2019 annual report notes, in the context of describing NRC funding requirements, that, for rate-making purposes, decommissioning costs for Alabama Power are based on the site specific study for the Farley plan (whereas costs for rate-making for Georgia Power, its sister company, are based on the NRC generic formula). It then goes on to make an explicit connection between rate-setting and NDT funding as follows:

> "For ratemaking purposes, Alabama Power's decommissioning costs are based on the site study and Georgia Power's decommissioning costs are based on the NRC generic estimate to decommission the radioactive portion of the facilities and the site study estimate for spent fuel management as of 2018.
>
> […]
>
> "Amounts previously contributed to the *[external trust]* Funds for Plant Farley are currently projected to be adequate to meet the decommissioning obligations. Alabama Power will continue to provide site-specific estimates of the decommissioning costs and related projections of funds in the external trust to the Alabama PSC and, if necessary, would seek the Alabama PSC's approval to address any changes in a manner consistent with NRC and other applicable requirements."[92]

In indirect support of our conclusion that Alabama Power uses an NDT forward-looking funding approach to rate recovery, we also noted that regulations in respect of the Rate RSE state the

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[90] Special Rules Governing Operation of Rates RSE and CNP, 6th Revision, September 20, 2013. p.1.
[91] Special Rules Governing Operation of Rates RSE and CNP, 6th Revision, September 20, 2013. p.2.
[92] Southern Company 2019 Annual Report, p. 151

following, which supports that accounting values related to nuclear decommissioning are not considered in ratemaking:

> "For purposes of Rate RSE, the capitalization of asset retirement costs shall be excluded from Account 101 (Electric Plant in Service) and the associated depreciation shall be excluded from Account 108 (Accumulated Provision for Depreciation of Electric Utility Plant) pursuant to Accounting for Asset Retirement Obligations."[93]

Also, a note in Southern Company's annual report indicates that the NDT for Alabama Power currently has no additional funding requirements.[94] Thus, no cash contributions are being made. Accordingly, given the removal noted above of ARO depreciation costs from RSE rate calculations, it appears that there is now no allowance in rates for decommissioning costs.[95]

9.2.3 Other Observations

9.2.3.1 Decommissioning Cost Estimates

Alabama Power recognizes decommissioning obligations, including for nuclear power plants, in the annual report as an ARO in accordance with US GAAP. However, the value of the AROs and related regulatory assets is not broken down between nuclear and non-nuclear facilities in Southern Company's annual report. According to the 2019 annual report, changes in cash flow estimates included, among others, an increase of about $300 million in the ARO as a result of an updated decommissioning cost site study for the Farley nuclear plant.

In discussing NDT funding requirements, Southern Company's annual report disclosures set out projected decommissioning costs for Alabama Power's Farley nuclear plant as at December 31, 2019. These are summarized in Exhibit 9-1 below. The annual report indicates that these represent site study costs from the most current studies, which were performed in 2018 and indicate that Alabama Power uses costs from these site studies for ratemaking purposes.[96]

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93 Alabama Power, "Rate RSE – Rate Stabilization and Equalization Factor – Appendix B", Seventh Revision, Effective Date June 1, 2018, Note (E): p. 5 of 5.
94 Southern Company 2019 Annual Report, p. 83.
95 The removal of accounting expenses related to AROs is consistent with FERC Order 631, as discussed earlier in Chapter 4. This Order indicated that public utilities that have formula rate tariffs must not include any cost components related to asset retirement obligations in their formula rate billing tariffs for automatic recovery without obtaining Commission approval.
96 Southern Company 2019 Annual Report, p. 151.

Exhibit 9-1[97] – Alabama Power Projected Decommissioning Costs

Projected Total Decommissioning Costs (2018$ Millions)	
Radiated structures	1,234
Spent fuel management	387
Non-radiated structures	99
Total Site Study Costs	1,720

With respect to Alabama Power's NDT rate of return assumption, we noted that although its NDT appears to have a relatively high proportion of investments in equities, as of 2018, Alabama Power uses a relatively conservative implied real rate of return of 2.39% to assess NDT contribution needs for ratemaking purposes,[98] This implied return is nevertheless somewhat higher than the 2% allowed by the NRC for non-regulated utilities.

9.2.3.2 Spent Fuel Disposal Costs

According to Southern Company's 2019 annual report, both Alabama Power and Georgia Power have filed lawsuits against the US government for the costs of continuing to store spent nuclear fuel as a result of US DOE failure to meet its 1998 target date for accepting such fuel. Unlike some other utilities examined, Southern had not received settlements in respect of these lawsuits as at the date of the annual report. The annual report indicates that any potential recoveries from these lawsuits are expected to be credited to customers and that no impact on net income is expected.[99]

[97] Southern Company 2019 Annual Report, p. 150.
[98] Southern Company 2019 Annual Report, p. 151.
[99] Southern Company 2019 Annual Report, p. 136.

10 Arizona

10.1 Industry Structure

The electricity power sector in Arizona is regulated by the Arizona Corporations Commission ("ACC"), which has jurisdiction over the rates charged by investor-owned utilities and by cooperatively owned utilities. Arizona Public Service ("APS") is the largest investor-owned utility in the state.

Customers in Arizona are also served by a variety of public power utilities, including the Salt River Project Agricultural Improvement and Power District ("SRP"). SRP is a self-governing public corporation established by the state.

There is currently no retail open access in Arizona, although ACC is currently exploring measures for its implementation.[100]

Arizona's sole nuclear generating station is the Palo Verde Nuclear Generating Station ("Palo Verde"), the largest in the United States. Palo Verde has an installed capacity of 3,900 MW and is operated by APS. Palo Verde's ownership is shared among seven utilities spanning four states, including APS and SRP, as more fully explored in Chapter 11 covering California. We review APS and SRP as part of this Chapter.

10.2 Arizona Public Service

APS is a vertically-integrated utility that has the largest ownership share in Palo Verde and, as noted above, is the plant operator. APS is the principal subsidiary of Pinnacle West Capital Corporation ("Pinnacle West"), an investor-owned utility holding company based in Arizona.

10.2.1 Regulatory Regime

As noted above, the ACC has jurisdiction over rates charged by investor-owned utilities. Rates are set on a cost-of-service basis.

10.2.2 Rate Recovery

Our research indicates that regulated customer charges for the recovery of nuclear decommissioning are based on a forward-looking NDT funding approach.

Nuclear decommissioning costs are recovered through a non-bypassable System Benefit Charge ("SBC") paid by all APS retail customers. ACC implemented the use of SBCs as part of its preparation in the late 1990s for restructuring of the electric industry and the introduction of retail competition. The ACC saw the SBC as a mechanism that would allow it to continue to support environmental protection, renewable resource development, increased energy efficiency, low-income customer

[100] Retail choice was initially made available for customers of public power utilities following legislative changes in 1998 but it garnered limited customer uptake and was subsequently suspended (SRP Combined Financial Statements – 2019 and 2020). In 2018, the ACC voted to re-examine the facilitation of a deregulated electric retail market; a process to explore this initiative is currently in progress.

assistance and safe nuclear power plant decommissioning in a competitive market environment.[101] Although the move to retail competition stalled prior to being recently re-examined, the SBC has remained in place.

While we were unable to definitively confirm this through our research, we believe that the nuclear decommissioning costs being recovered through the SBC are based on those amounts allowed for recovery in APS' rate proceedings with the ACC. As such, we reviewed APS' recent rate filings, in addition to Pinnacle West's publicly available annual report as part of our research. We conclude that the decommissioning costs are currently included in APS's rates on the basis of forward-looking NDT funding.

In particular, we reviewed information pertaining to the APS rate case filed with the ACC in October 2019, which requested a $184 million rate increase.[102] The majority of the rate increase (57%) includes the recovery of costs associated with the Four Corners coal plant.[103] We noted that the rate case refers to proposed funding levels for decommissioning of Palo Verde remaining unchanged, but with a different allocation of funding to each of the three units within the APS NDT.[104]

The filing by APS documents a number of assumptions associated with its projections of NDT funding status, including the following:[105]

- The assumed escalation rate for decommissioning costs is 4%.
- After-tax earnings assumptions (nominal rate of return) vary from 3.39% to 4.63% (with earnings rates falling as license expiration nears and the asset allocation changes to provide a lower-risk profile).
- An asset allocation of 60% stocks and 40% bonds in the period up to 5 years before license expiration, with an allocation of 100% bonds thereafter.

In line with the NDT funding approach to rate recovery, Pinnacle West's 2019 annual report notes the recognition of regulatory liabilities related to earnings on the trust balance:

> "Because of the ability of APS to recover decommissioning costs in rates, and in accordance with regulatory treatment, APS has deferred realized and unrealized gains and losses (including other-than-temporary impairments) in other regulatory liabilities."[106]

[101] National Renewable Energy Laboratory (NREL), State Approaches to the System Benefits Charge, July 1997, p. 2.
[102] Hearings began in December 2019 and a final decision by the ACC is expected during the first half of 2021.
[103] Fitch Rates Arizona Public Service Co.'s $400MM Sr. Unsecured Green Bonds 'A'; Outlook Negative, Fitch Ratings Inc., September 8, 2020.
[104] Direct Testimony of Elizabeth A. Blankenship On Behalf of Arizona Public Service Company, Docket No. E-01345A-19-0236
[105] *Ibid*, p. 23.
[106] Pinnacle West Capital Corporation 2019 Annual Report, p. 171.

10.2.3 Other Observations

10.2.3.1 Decommissioning Cost Estimates

Pinnacle West recognizes decommissioning obligations, including for Palo Verde, in the annual report as an ARO in accordance with US GAAP. In particular, the annual report notes that Pinnacle uses an expected cash flow approach to measure the amount recognized as an ARO, whereby it applies "probability weighting to discount red future cash flows scenarios that reflect a range of possible outcomes" considering the ultimate settlement of the ARO. The value of the AROs, and associated regulatory liabilities, however, is not broken down between nuclear and non-nuclear facilities.[107]

Exhibit 10-1 below shows the total value of the AROs as at December 31, 2019.[108] According to the 2019 annual report, changes in estimated cash flows included, among others, an updated site study for Palo Verde, which resulted in a decrease to the ARO of $89 million, a decrease in plant in service of $80 million and a reduction in the regulatory liability of $9 million.[109]

Exhibit 10-1 – ARO Values

Arizona Public Service - ARO - All Assets ($Millions)	
	2019
Opening Balance - Dec 31, 2018	726.5
Liabilities Settled	(12.6)
Accretion	39.7
Change in Cash Flow estimates	(96.5)
Ending Balance - Dec 31, 2019	657.2

APS relies on an external sinking fund mechanism to meet NRC requirements for decommissioning its interests in the Palo Verde plant, pursuant to a Participation Agreement amongst the facility's utility owners, as discussed in Chapter 11 on California. Pinnacle West's 2019 annual report noted that:

> "based on the current nuclear decommissioning trust asset balances, site specific decommissioning cost studies, anticipated future contributions to the decommissioning trusts, and return projects on the asset portfolios over the expected remaining operating life of the facility, we are on track to meet the current site specific decommissioning costs for Palo Verde at the time the units are expected to be decommissioned".[110]

10.2.3.2 Spent Fuel Disposal Costs

According to Pinnacle West's 2019 annual report, APS and the US DOE entered into a settlement agreement which provides APS a method for submitting claims and getting recovery of costs related to the DOE's failure to meet its statutory and contractual obligations regarding acceptance of spent

[107] Pinnacle West Capital Corporation 2019 Annual Report, p. 127.
[108] Pinnacle West Capital Corporation 2019 Annual Report, p. 153.
[109] Pinnacle West Capital Corporation 2019 Annual Report, p. 153.
[110] Pinnacle West Capital Corporation 2019 Annual Report, p. 8.

nuclear fuel and high level waste. The amounts recovered are recorded as a regulatory liability, which is consistent with the treatment observed in other jurisdictions whereby such refunds are flowed back to customers.

10.3 Salt River Project

SRP is a publicly-owned utility. It operates a federal reclamation project that provides hydro-electric power and water irrigation services.

SRP is one of the utilities with an ownership share in Palo Verde, which accounted for just under 15% of SRP's power supply in 2020.[111]

10.3.1 Regulatory Regime

The Board of Directors of SRP has the power to set SRP's electric rates, subject to some notice requirements. According to the SRP's financial statements, SRP's price plans include the following:

- a base component to recover costs for generation, transmission, distribution, customer services, metering, meter reading, billing and collection, and SBCs that are not otherwise recovered through another component; and
- a Fuel and Purchased Power Adjustment Mechanism implemented to adjust for increases or decreases in fuel costs.

Similar to APS, SRP levies an SBC on its transmission and distribution customers to recover the costs of programs "benefiting the general public, such as discounted rates for low-income customers, energy efficiency and nuclear decommissioning, including the cost of spent fuel storage."[112] It appears that it is anticipated that the SBC will be less subject to bypass relative to base tariffs in the event that retail competition is introduced. In particular, a statement accompanying SRP's recent bond issuance noted that SRP "anticipates being able to continue to collect decommissioning funds in a competitive generation market".[113]

10.3.2 Rate Recovery

Because its electricity rates are not subject to oversight by ACC, there appears to be limited disclosure as to how SRP's rates are established or of associated cost components. This conclusion is based on our research of SRP's financial statements and NRC filings made on its behalf, which did not yield sufficient insights to allow us to draw a definitive conclusion on the rate recovery treatment for decommissioning costs.

We did note that SRP financial statements for Fiscal 2020 (year ending April 30th) include regulatory liabilities of $270.2 million for nuclear decommissioning, which are described as follows:

> "The nuclear decommissioning regulatory liability is any difference between current fiscal year costs and revenues associated with nuclear decommissioning and earnings (losses) on the NDT.

[111] Salt River Project, New Issue Revenue Bonds, October 1, 2020., p. 20.
[112] Salt River Project, Combined Financial Statements – 2019 and 2020, p. 20.
[113] Salt River Project, New Issue Revenue Bonds, October 1, 2020., p. 53.

> Such amounts are deferred in accordingly in accordance with authoritative guidance for regulated enterprises and have no impact to SRP's earnings."[114]

The financial statements also note that SRP's base rates recover its share of on-site interim storage costs at the Palo Verde site as a component of the SBC.

10.3.3 Other Observations

10.3.3.1 Decommissioning Cost Estimates

SRP recognizes decommissioning obligations (including for spent fuel storage) for its share of obligations for the Palo Verde nuclear power plant, in the financial statements as an ARO in accordance with US GAAP. Similar to other utilities examined, SRP notes that:

> "Subsequent to the initial recognition, the liability is adjusted for any revisions to the estimated future cash flows associated with the ARO (with corresponding adjustments to utility plant), which can occur due to a number of factors, including but not limited to, cost escalation, changes in technology applicable to the assets to be retired, changes in federal, state and local regulations and changes to the estimated decommissioning dates the assets, as well as for the accretion of the liability due to the passage of time until the obligation is settled."

The value of the AROs is not broken out between nuclear and non-nuclear facilities.

A 2017 filing with NRC shows that, in 2016, SRP contributed $426 million to funds for the decommissioning of Palo Verde. The filing further noted that these contributions were not then required to meet NRC tests for minimum financial assurance (based on the NRC minimum formula). NRC tests would be met with existing fund balances and taking into account a 2% real rate of return on these balances until the expected decommissioning dates. Differences in decommissioning cost estimates between the minimum requirements and site specific estimates may have contributed to SRP's decision to continue contributions to NDTs in this year. The same NRC filing noted that site specific estimates for Palo Verde decommissioning costs were $1.963 billion (in 2013 dollars). Costs estimates based on the NRC formula, in comparison, were only $1.482 billion (in 2016 dollars).[115]

[114] Salt River Project, Combined Financial Statements – 2019 and 2020, p. 21.
[115] Arizona Public Service, Consolidated Decommissioning Funding Status Report, filed with US NRC, March 31, 2017, pp. 3-5.

11 California

11.1 Industry Structure

California went through a process to open its electricity generation sector to market competition in 1996. This process led to significant increased in wholesale electricity prices over 2000 and 2001, in part as a result of a drought in the US northwest that reduced the amount of hydroelectric power available. In parallel, a number of energy marketing companies engaged in aggressive trading practices that exacerbated supply shortages. As the market restructuring framework did not allow the monopoly transmission and distribution utilities to pass through higher electricity wholesale prices to their customers, these developments resulted in utility financial distress. This led to significant changes in market structure and the state government stepped in to sign power contracts directly.

At the current time, large customers in the state can chose to procure electricity directly from the market. In addition, local communities have the option of setting up a Community Choice Aggregator (“CCA”), which has the right to procure power for those residents or businesses that do not elect to continue to receive electricity that is generated or procured by their utility. For other customers, utilities need to arrange for electricity supplies.

The California Public Utility Commission (“CPUC”) regulates investor-owned utilities and, in this process, reviews and approves their arrangements for the supply of electricity to their retail customers, including from utility-owned generating assets.

California currently has one operating nuclear plant, Diablo Canyon, which is owned by Pacific Gas and Electric Company. Based on data from NRC, nuclear electricity from Diablo Canyon’s two units accounted for 9% of electricity generated in the state in 2017.[116] California was 17th out of 30 states in terms of the generation of nuclear power.[117]

In addition, a number of utilities in California have ownership interests in, and receive power from nuclear units at the Palo Verde plant in Arizona. As discussed in the prior Chapter, Palo Verde is operated by Arizona Public Service Company.

California also has a number of nuclear reactors that have been shut down and that have either been decommissioned or are awaiting decommissioning.[118]

The Chapter on California reviews PG&E and one of California-based utilities that holds interests in Palo Verde, the Los Angeles Water and Power Department (“LAWPD”). LAWPD is the largest municipal utility in the United States. Additionally, we have included a separate section that describes the NDT funding approach for the jointly-owned Palo Verde.

[116] NRC, “Information Digest, 2019-2020” (NUREG-1350, Volume 31), p. 28.
[117] U.S. Energy Information Administration, U.S. Nuclear Generation and Generating Capacity, Data Released 2020-11-30.
[118] These include: Humboldt Bay 3 – shut down in 1976, with decommissioning is in progress; Ranco Seco – shut down in 1989, with decommissioning completed in 2009; Sanofre Unit 1 – shut down in 1992 and currently in safe storage status; Sanofre Units 2 & 3 – shut down in 2013, with decommissioning in progress (NRC, “Information Digest, 2019-2020” (NUREG-1350, Volume 31), p. 116-118).

11.2 Pacific Gas and Electric Company

Pacific Gas and Electric Company is an electric utility that serves customers in northern and central California. PG&E filed for bankruptcy in January 2019 as a result of lawsuits stemming from the company's role in wildfires that occurred in 2017 and 2018. Bankruptcy proceedings are not directly related to the company's operation of its nuclear plants and we have not further reviewed these proceedings in the context of this report.

PG&E supplies its retail customers with power through a combination of own generating facilities and power purchased from other suppliers under contract.

In addition to Diablo Canyon, PG&E owns another nuclear plant, Humboldt Bay, which is no longer operating and is in the process of being decommissioned.

11.2.1 Regulatory Regime

The California Public Utilities Commission regulates PG&E's rates. This includes oversight over recoveries for decommissioning costs by PG&E and other investor-owned utilities in California. CPUC has relied on triennial joint proceedings to review and approve the annual revenue requirements for decommissioning of nuclear power plants owned by subject California utilities. Thus, for example, a 2010 decision approved in parallel the revenue requirements for decommissioning cost recovery for Southern California Edison Company ("SCE"), San Diego Gas & Electric (":SDG&E), and PG&E. [119] In addition to operating plants, the decision covered nuclear plants already out of service and California-based interests in Palo Verde. CPUC does not regulate municipally-owned utilities in California, some of which have ownership interests in Palo Verde.

11.2.2 Rate Recovery

Given the availability of data, our research focused on CPUC regulatory filings. Based on our research, we conclude that PG&E (and other investor-owned utilities in California) recover decommissioning costs based on a forward-looking NDT approach.

For example, a forward-looking view of funding requirements for associated NDTs was used to establish the decommissioning revenue requirements in the 2010 CPUC decision on the above noted triennial joint proceeding. Key issues in the proceeding were the presumed reasonableness of cost estimates and estimated future returns on invested funds.

In that proceeding, the CPUC refused to accept provisions of a settlement that would have created a presumption of reasonableness if actual decommissioning costs incurred were within the bounds of prior cost estimates. CPUC maintained that this provision would unduly restrict its ability to review the prudence of expenditures made.[120]

CPUC noted that a presumption of reasonableness introduced major policy concerns, in particular, because of the unreliability of cost estimates. It noted:

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[119] California Public Utility Commission, Decision 10-07-047, July 29, 2010.
[120] California Public Utility Commission, Decision 10-07-047, July 29, 2010., p. 49.

> "The fact there is wide agreement that cost estimates are opaque, inconsistent between utilities, and rely on disputed assumptions, underscores the limited reliability of an estimate even as decommissioning approaches."[121]

The CPUC therefore wanted to retain the ability to review decommissioning spending, even if actual costs were less than originally forecast. This reflected a view that cost estimates may have been overly generous. Underspending was therefore not in itself proof that spending was prudent. Since decommissioning funds were collected from ratepayers, these ratepayers would benefit if costs could be reduced further. Hence, CPUC wanted to retain the ability to review prudence.

In its 2010 decision, CPUC accepted settlement provisions related to assumed returns on trust funds for SCE and SDG&E (these provisions provided for a 8.75% pre-tax return for equity and a 4.2% post-tax return for debt.)[122] The utilities had initially applied for contribution amounts based on lower assumed returns.

11.2.3 Closure of Diablo Canyon

We further reviewed the specific circumstances of the PG&E's Diablo Canyon plant closure in the context of the rate recovery approach in place in California.

PG&E had originally submitted applications to NRC for extensions of the operating licenses for the units at Diablo Canyon beyond 2024 and 2025, their original operating end dates. In 2016, however, the company proposed the shut-down of these units at the date of their license expiration.[123]

The decision to close Diablo Canyon at the end of its existing license life has resulted in substantial increases in proposed rate allowances for decommissioning under the forward-looking NDT approach. Namely, in September 2019, PG&E proposed an increase in its annual revenue requirement related to decommissioning costs of $350.1 million, from $67.8 million to $417.9 million.[124] Circumstances related to this increase include the following:

- Prior amounts for recovery had been based on a "unit cost factor methodology", taking into account industry-wide assumptions intended only to provide estimates for financial planning purposes.[125] In contrast, the proposed amount was based on a site-specific decommissioning cost estimate triggered by the decision to forego the expected license renewal..
- PG&E had nearly $3.2 billion in its NDT but, as a result of the updated estimate and a shorter remaining lifespan for the facility, indicated that it needed approximately $1.6 billion more (in 2017 dollars) to fully fund decommissioning activities.
- Over the period 2003-2019, customer contributions to the NDT had been only $32.4 million in total.

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[121] California Public Utility Commission, Decision 10-07-047, July 29, 2010., p. 49.
[122] *Ibid*, p. 46.
[123] Pacific Gas and Electric, Prepared Testimony – Retirement of Diablo Canyon Power Plant, Implementation of the Joint Proposal, and Recovery of Associated Costs Through Proposed Ratemaking Mechanisms, Application 16-08- , August 11, 2016, p. 1-2.
[124] Pacific Gas and Electric, Prepared Testimony – Revised – Volume 1, 2018 Nuclear Decommissioning Cost Triennial Proceeding, Application 18-12-008, September 17, 2019, Exhibit No: PGE-1, p. 11-2.
[125] We assume this refers to use of the NRC formula amounts.

Given that contributions to the NDT in respect of the Diablo Canyon plants were then near zero, PG&E proposed that customer contributions restart in 2020 and conclude at the end of 2025. It noted: "This will ensure that those customers who benefit from the clean, reliable and affordable energy produced by DCPP [*Diablo Canyon Power Plant*] will be responsible for supporting its decommissioning."[126]

In January, 2020, PGE and a number of interveners filed a joint-motion seeking approval of a settlement agreement. This settlement provides for a revised decommissioning cost estimate of $3.0 billion, $0.9 billion less than originally requested by PG&E.[127] The revised revenue requirement of $112.5 million annually would then be collected over an 8-year period (2020-2027), a slightly longer timeframe, resulting in a substantial reduction in required annual contributions relative to those initially proposed above. The settlement agreement has been opposed by at least one other intervener and the CPUC, as of the date of writing, had not yet issued a decision in the proceeding.

This case study is an example of how a change in plant lifespan can significantly impact the rate recovery profile under the NDT funding approach and therefore impact intergenerational equity considerations. Additionally, it highlights the significant discretion that a state utility regulator has over the decommissioning cost estimates and therefore set-aside amounts to satisfy the NRC's requirements.

11.3 Los Angeles Department of Water and Power

The Los Angeles Department of Water and Power is a Department of the City of Los Angeles that provides water and electricity to customers in the City of Los Angeles. LADWP is the largest municipal utility in the US, and unlike many municipal utilities, owns generation interests in addition to transmission and distribution.

LADWP has a 5.7% ownership interest in the Palo Verde plant.

11.3.1 Regulatory Regime

LADWP self-regulates and has monopoly rights within its service territory and is not subject to CPUC oversight.[128] The LADWP's rates are determined by the Board of Water and Power Commissioners ("Board of Commissioners") and subject to review and approval by the Los Angeles City Council.

Like many public power utilities, LADWP's does not set rates based on a target equity return and approved capital structure. Instead, LADWP's sets rates to ensure that it can meet three financial targets:

- Minimum debt service coverage ratio.
- Days cash on hand.

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[126] Pacific Gas and Electric, Prepared Testimony – Revised – Volume 1, 2018 Nuclear Decommissioning Cost Triennial Proceeding, Application 18-12-008, September 17, 2019, Exhibit No: PGE-1, p. 1-6.
[127] Pacific Gas and Electric et al, Joint Motion for Adoption of Settlement Agreement, Application 18-07-013 and 18-12-008, Filed January 10, 2020, p. 8.
[128] Moody's, Rating Action: Moody's assigns Aa2 to Los Angeles Department of Water and Power, CA's Power System Revenue Bonds, 2020 Series B; outlook negative, 09 Jun 2020, p.1.

- Maximum debt to capitalization ratio.

LADWP sets rates on a five-year cycle. Base rates are set for each year within the period at the beginning of the cycle, with quarterly and annual adjustment factors subsequently applied to account for variations in variable energy costs during the period, in costs related to Renewable Portfolio Standard requirements, and to account for upgrades for reliability purposes. Beginning in 2020, LADWP was to move to a four-year rate setting cycle.[129]

11.3.2 Rate Recovery

As we were unable to identify publicly available information regarding LADWP's approach to recovery of decommissioning costs through its self-regulated rates, we researched LADWP's separately issued financial statements for its electric power operations. Based on this additional research, we believe that LADPW is using a forward-looking funding approach in setting its rates, as discussed below.

As a government-owned entity, LADWP prepares its financial statements using Government Accounting Standards Board ("GASB") standards, rather than FASB standards followed by investor-owned utilities. GASB standards (Standard 83) require recognition of AROs similar to FASB standards, but this requirement is relatively recent. GASB issued Statement 83 in 2016 mandating the adoption of the ARO requirements for periods beginning after June 15, 2018. LADPW's 2018-2019 financial statements included a restatement of its 2018 financial position upon adoption of Standard 83.[130]

Under GASB standards, when obligations for future expenditure are recognized as a liability, such as obligations for decommissioning, they are matched by the recognition of a "deferred outflow" on the asset side of the balance sheet. This is generally equivalent to asset retirement costs recorded as part of property, plant and equipment under FAS 143. As noted in the LADPW's financial statements, "deferred outflows are amortized using the straight-line method over the remaining useful life of the asset or lease term, if leased."[131]

It appears that LADWP does not currently contribute to its NDT and has not for some time. In respect of reserve funds designated to meet NRC funding requirements, its 2018 financial statements note:

> "During fiscal year 2000, the Power System suspended contributing additional amounts to the reserve funds, as management believes that contributions made, combined with reinvested earnings, will be sufficient to fully fund the Power System's share of decommissioning costs. The Power System will continue to reinvest its investment income into the decommissioning reserves."[132]

[129] LADWP, Presentation to Investors – Power System Revenue Bonds 2019 Series D, December 3, 2019, pp. 10-11.
[130] Under GASB 83, if a government entity has only a minority interest in a capital asset that is majority owned by another entity that reports under a different accounting standard, then the government entity should follow the other entity's approach. It would thereby take its proportionate share of AROs recognized under the alternative standard. The requirement to defer to an alternative standard also applies when none of the joint owners of the facility has a majority interest but a non-government owner has operational responsibility for the facility. For LADPW, this latter case applies to Palo Verde.
[131] LADWP, 2019-2020 Power System Financial Statements, p. 31.
[132] LADWP, 2017-2018 Power System Financial Statements, p. 26.

As at June 30, 2018, the value of its restricted investments to meet NRC funding requirements for Palo Verde was $134.0 million. Up to that date, LADWP had accrued $154 million in expenses related to decommissioning and these amounts were recorded in accumulated depreciation in the 2018 financial statements initially issued.

Under the previous accounting standards, LADWP used the “negative salvage value’ method to account for decommissioning costs in depreciation expense. Upon adoption of Standard 83, LADWP recognized AROs totalling $281.2 million under the new standard at the end of 2018 as an additional non-current liability on its statement of net position.[133] On the asset side of the balance sheet, the additional liability was matched by two adjustments:

- Accumulated depreciation was reduced by $153.6 million. (The reduction in accumulated depreciation thereby resulted in an increase in the net book value of PPE by the same amount.)
- A “deferred outflow” of $127.7 million was recognized in connection with the ARO. The deferred outflow will be amortized over the remaining operating life of the associated facilities. We believe this balance included any cumulative differences between amounts recovered through rates on a forward-looking funding basis and the net changes in the statement of net position related to the adoption of Standard 83.

The various changes in accounting presentation did not have an impact on costs recovered from consumers in that year.

This case study was instructive in that we were able to observe a recent case where, prior to adoption of ARO accounting requirements, the utility was recording decommissioning costs through depreciation expense and accumulated depreciation. This is consistent with the discussion in Chapter 4 on evolution of accounting practices, which highlighted that, just like LADPW did prior to adoption of Standard 83, many investor-owned regulated utilities reporting under FASB standard prior to FAS 143 were using the “negative salvage value” method to account forthese obligations.

11.4 Palo Verde Funding Plan

As noted above, a number of utilities in California have ownership interests in the Palo Verde plant. Ownership of the facility is shared across utilities in four states, as summarized in Exhibit 11-1 below.

[133] Statement of net position is equivalent to the balance sheet statement under FASB.

Exhibit 11-1[134] – Palo Verde Ownership Share

Palo Verde Ownership		
Utility Company	**Service Territory**	**Ownership Share**
Arizona Public Service Company	Arizona	19.1%
Salt River Power District	Arizona	17.5%
El Paso Electric	Texas/ New Mexico	15.8%
Southern California Edison	California	15.8%
Public Service Company of New Mexico	New Mexico	10.2%
Southern California Public Power Authority	California	5.9%
Los Angeles Department of Water and Power	California	5.7%

Each individual utility owner maintains its own NDT related to its ownership in Palo Verde. Contributions by utilities to these NDTs are, however, governed by a Participation Agreement (or “Agreement”), which dates back to the plant’s opening. The Participation Agreement laid out a “Funding Curve” for each owner that defines a pre-established percentage funding commitment for each year through to the end of the plant life. The 2004 Funding Status report submitted to NRC noted:

> “Each Participant’s percentage funding commitment was based upon an analysis which incorporated the Participant’s individual business judgments (subject to regulatory approvals, as applicable) with respect to expected rates of fund investment earnings and escalation in total decommissioning costs. Every three years a new site specific decommissioning cost estimate is performed, and each participant applies the new cost estimate to its pre-established Funding Curve.” [135]

The Agreement provides a Funding Floor in addition to a Funding Curve. In the initial years the Funding Floor is 80% of the Funding Curve, but this differential narrows in later years, reaching 100% in the last 10 years of facility operation.

The Agreement provides for minimum funding commitments. Utilities can decide to fund at a faster rate, perhaps because of a decision for a broader scope for its funding of the decommissioning process. For example, the utilities’ 2004 NRC submission notes:

> “Note that the cost estimates are in 2001 dollars and do not take into account the individual assumptions made by each Participant, which may result in the accumulation of funds based upon higher cost estimates (e.g., site-specific estimates that may include removal and disposal of spent nuclear fuel and non-radioactive structures).”[136]

In our review of the 2004 filing, we noted that each utility had separate assumptions with respect to rates of return, cost escalation, and the inclusion of a contingency factor. One utility (Southern California Edison) had assumed cost escalation rates that were higher than rates of return. Accordingly, its funding curve shows the required funding ratio exceeding 100% in the years leading

[134] U.S. Energy Information Administration, “Nuclear Reactor Ownership”. Released December 2019. Retrieved 2020-12-21
[135] Arizona Public Service Company et al, 2004 Decommissioning Funding Report – 10 CFR 50.75(f)(1), for the year ending December 31, 2004, p. 3.
[136] *Ibid*, p. 3.

up to decommissioning. (More funds need to be accumulated to offset decreases in each year in the real value of initial fund balances in any year.)

Overall, the Participation Agreement appears to be a structured way of ensuring that participating utilities meet the requirements of NRC funding assurance regulations, while allowing them to make individual decisions with respect to expected rates of cost escalation and fund returns.

12 Florida

12.1 Industry Structure

The electricity sector in Florida remains regulated, with vertically-integrated utilities that supply power to captive customer bases. Retail open-access is not available. We have reviewed developments at two utilities, Florida Power & Light ("FPL") and Duke Energy Florida.

FPL has two nuclear plants comprising all currently operating reactors in the state, each with two units: one at Turkey Point and another at St. Lucie. Duke Energy Florida operated a nuclear plant at Crystal River that has since been shut down.

FPL is a subsidiary of NextEra Energy Inc. Duke Energy Florida is a subsidiary of Duke Energy Corporation, a holding company that owns electricity utilities in North and South Carolina, Florida, Indiana, Kentucky and Ohio.

Based on data from NRC, nuclear electricity accounted for 12% of electricity generated in the state in 2017.[137] Florida was 13th out of 30 states in terms of the generation of nuclear power.[138]

In this Chapter, we address the regulatory regime and rate recovery of nuclear decommissioning costs on a state-wide basis as they are consistent across both of the utilities reviewed. Given the accessibility of data, our review of Florida provided a useful opportunity to observe the historical evolution of the regulator's approach to recovery of nuclear decommissioning costs, including the interaction with FAS 143 financial accounting requirements, in some detail.

12.2 Regulatory Regime

Electricity rates charged by Florida utilities are regulated by the Florida Public Service Commission ("Florida PSC"). Electricity rates are set through various rate-making mechanisms including base rates and cost recovery clauses. Base rates are based on cost-of-service methodologies which include a rate of return on rate base and are determined through rate proceedings or negotiated settlements of those proceedings. Cost recovery clauses are designed to permit recovery of certain costs and provide a return on certain assets allowed to be recovered through these clauses.

12.3 Rate Recovery

Based on our review of Florida PSC's regulatory precedents, we conclude that the forward-looking NDT funding approach is in place for recovery of nuclear decommissioning costs (including spent fuel storage) by regulated utilities.

We note in particular that, in 2001, Florida PSC adopted Rule 25-6.04365 that codified the Commission's policies with respect to utilities' recovery of nuclear decommissioning costs. The Rule requires that each utility file a site-specific nuclear decommissioning study at least once every five years and the study should provide:

[137] NRC, "Information Digest, 2019-2020" (NUREG-1350, Volume 31), p. 28.
[138] U.S. Energy Information Administration, U.S. Nuclear Generation and Generating Capacity, Data Released 2020-11-30.

> "sufficient information to update cost estimates based on new developments, additional information, technological improvements, and forecasts; to reevaluate alternative methodologies; and to revise the annual accrual needed to recover the costs."[139]

Information required to be included as part of the study includes:

- The assumed fund earnings rate, net of tax, used in the calculation of the decommissioning accrual and supporting documentation for the rate proposed.
- The methodology and escalation rate used in converting current estimated decommissioning costs to future estimated costs.
- Supporting "schedules, analyses, and data, including the contingency allowance, used in developing the decommissioning cost estimates and annual accruals proposed by the utility. Supporting schedules shall include the inflation and funding analyses."[140]

With respect to the assumed fund earnings rates in particular, a memorandum from Florida PSC staff in regard to FPL's 2015 filing noted:

> "The fundamental purpose of the Commission's review of the decommissioning study is to make sure there will be adequate funding on hand at the time the nuclear units are decommissioned. The assumed fund earnings rate should be conservative enough to avoid a situation whereby future customers are burdened by inadequate funding for decommissioning. However, an assumed fund earnings rate that is too conservative inappropriately burdens current customers with expenses to be incurred in the future. As such, a certain amount of judgment is necessary to determine a fair balance between generations of customers."[141]

12.3.1 Past Regulatory Orders – Treatment of FAS 143 and Other

The above noted Rule 25-6.04365 was intended to codify practices that had been set in a number of earlier Orders, including in 1982, 1989 and 1995. In addition to providing additional context that led to the establishment of the current rate recovery method, these earlier Orders highlight the significant role that the Florida PSC's rate recovery decisions have historically played in the determination of key elements impacting decommissioning funding levels. Highlights from these Orders are summarized below.

Order 10987 – 1982

Order No. 10987, issued in 1982, required the establishment of a funded reserve for the accumulation of the estimated costs of decommissioning for each nuclear unit operating in Florida. Prior to this Order, the costs of decommissioning were considered a component of the depreciation rate, consistent with how it was accounted for in the utilities' financial statements. As reported in a subsequent 1995 Florida PSC decision, establishment of a funded reserve was prompted primarily by concerns over the amount of money necessary to decommission nuclear facilities and thus the

[139] Florida Public Service Commission, Order No. PSC-01-0096-FOF-EI, January 11, 2001, p. 2.
[140] *Ibid*, p. 5-6.
[141] Florida Public Service Commission, Memorandum from Higgins et al, May 26, 2016, Docket No. 150265-IE, pp. 11-12 of 18.

need to ensure the availability of sufficient funds at the time of decommissioning. Public health and safety issues also factored into the 1982 decision.[142]

This Order also established the five-year cycle of review.

Order 21928 – 1989

In Order 21928, issued in 1989, Florida PSC deferred the policy decision of whether to include the costs of decommissioning "non-contaminated" items at a nuclear plant in the decommissioning allowance (although it allowed inclusion of these costs on a temporary basis pending further information).[143] The PSC agreed with staff that a site-specific economic cost study should be performed by the utilities for each of their plants to determine if it would be cost justified to retain the non-contaminated portions of these plants for use with a new generating station. The outcome of these studies would then determine the general pattern for preparation of these studies. A subsequent order showed that each utility did identify some station assets that could be reused.[144] However, we have not been able to identity the impact that this had on allowances in rates for decommissioning.

In the 1989 Order, the Florida PSC addressed two important determinants of decommissioning funding levels – contingency factor included in the decommissioning cost estimate being funded and the projected fund earnings assumption.

With respect to the decommissioning cost estimate, the Florida PSC accepted a contingency factor of 25% as a reasonable amount given the "complexity" of nuclear decommissioning activities.

On the funding earnings assumptions, Florida PSC accepted company arguments against setting a minimum prospective fund earnings rate. However, it also indicated that it would require companies "to maintain the purchasing power as well as the principal amount" of funds contributed by rates. Thus:

> "The companies' investment performance will be evaluated along with all other decommissioning activities every five years. If it is found that the companies' investment earnings, net of taxes and all other administrative costs charged to the trust fund, did not meet or exceed the CPI average for the period, then we will consider ordering the utility to recover this shortfall with additional monies to keep the trust fund whole with respect to inflation."[145]

The Florida PSC then set the assumed fund earnings rate, net of taxes and all other administrative costs charged to the fund, at 5.27%. This was based on forecasts of the long-term average CPI over the next 25 years. Thus, the fund earnings rate was assumed to just equal inflation.

Order 95-1531 – 1995

In Order 95-1531, issued in 1995, Florida PSC confirmed its decision in Order 21928 that companies would be required, at a minimum, to maintain the purchasing power of funds contributed to NDTs (i.e. earn a return at least as high as CPI). It also noted, however, that Congress had eliminated certain investment restrictions for NDTs qualifying under IRS rules for tax-exempt status. These restrictions

[142] Florida Public Service Commission, Order No. PSC-95-1531-FOF-EI, Docket 941350-EI and 941352-EI, December 12, 1995, pp. 3-4.
[143] Florida Public Service Commission, Order No. 21928, Docket 870098-EI, September 21, 1989, p. 3.
[144] Florida Public Service Commission, Final Order No. PSC-92-0573-FOF-EI, Docket 910981-EI, June 26, 1992, p. 1.
[145] Florida Public Service Commission, Order No. 21928, Docket 870098-EI, September 21, 1989, p. 5.

had previously limited investments for such NDTs to public debt securities and bank or credit union deposits. Florida PSC therefore accepted a proposal by Florida Power Corporation ("FPC"), now Duke Energy Florida, to use a forecast nominal fund earnings rate of 4.90%, which was the average of:

- Forecast CPI over the next 25 years.
- The expected long-term return, after expenses and taxes, of FPC's NDT, as forecast by FPC's trust fund consultant.[146]

Florida Power and Light ("FPL"), the other utility whose funding proposals were under review, had proposed instead to continue the use of forecast CPI as the basis for its nominal earnings assumptions. FPL was required to adopt the 4.90% assumption from FPC.

Other items addressed or noted in the Order included the following:

- Recovery amounts (and therefore NDT contributions) needed to include provisions for the dry storage of spent nuclear fuel, given likely delays in the acceptance by the US DOE of such fuel. The two utilities had initially made different assumptions as to whether they would need to provide for dry fuel storage following the five-year cooling period in spent fuel pools. The Florida PSC instead required that both include provisions for dry fuel storage in their cost estimates, as it was concerned that failure to do so would result in funds being recovered later from consumers who had not benefited from the "low-cost nuclear generation".[147] The Florida PSC also noted that it had joined a lawsuit with 20 other state commissions seeking a declaration that DOE is obligated to accept spent nuclear fuel and high level radioactive waste, and that the DOE should develop a program to meet the 1998 deadline.
- The Florida PSC accepted lower cost contingency allowances than in the 1989 decision, as these were based on specific factors applied to individual line items rather than on a global assumption applied to overall cost estimates. (The resulting weighted overall contingency factors were about 17.0%).
- Site-specific studies submitted in the proceeding had taken into account actual experience with decommissioning nuclear units and changes in methodologies for decommissioning.

12.3.1.1 Treatment of FAS 143

In 2003, the Florida PSC approved Rule 25-15.014, which addressed how utilities should account for asset retirement obligations under FAS 143. The provisions provided that "the application of FAS 143 shall be revenue neutral in the rate making process."[148] Differences between expense amounts allowed by the Commission and expense amounts recognized under FAS 143 would therefore be recorded as regulatory assets or liabilities, as applicable.

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[146] Florida Public Service Commission, Order No. PSC-95-1531-FOF-EI, Docket 941350-EI and 941352-EI, December 12, 1995, p. 13.
[147] *Ibid*, p. 10.
[148] Florida Public Service Commission, Order No. PSC-03-0906-FOF-PU, Docket 030304-PU, August 7th, 2003, p. 2.

In circumstances where utilities are not required to establish an ARO, the rule provides that they should continue to include costs of removal in the calculation of depreciation expense and accumulated depreciation.

A staff memorandum in support of the rule noted that it would ensure that the effect of FAS 143 on financial statements would be consistent for all companies and would "not alter earnings from what they would be without SFAS 143".[149]

We find this Rule indicative of the regulator's decision to continue with the existing NDT funding approach to rate recovery, rather than adopt the new ARO accounting standard for ratemaking purposes. We noted similar decisions that were reached by regulators in Georgia, Minnesota, North Carolina and South Carolina.

As discussed in Chapter 4, utilities who have been recovering decommissioning costs on this basis from the beginning are able to stay net income neutral upon recognition of AROs by recognizing the regulatory asset (or liability) in accordance with ASC 980 because, in the long run, they would be expected to recover the cost equivalent of the AROs on a funding basis.

[149] Florida Public Service Commission, Memorandum, Office of General Counsel, Docket 030304-PU, May 22nd, 2003, p. 2.

13 Georgia

13.1 Industry Structure

The electricity sector in Georgia remains regulated, with vertically-integrated utilities that supply power to captive customer bases. Retail open-access is not available. We have reviewed two utilities, Georgia Power and Oglethorpe Power Corporation ("Oglethorpe"), which each have large ownership stakes in the two nuclear power plants in the state, Hatch and Vogtle.

Georgia Power is the only investor-owned utility in the state and is fully regulated by the Georgia Public Service Commission ("Georgia PSC"). It serves 155 of 159 counties in Georgia. In addition to Georgia Power, there are 41 EMCs and 52 municipally-owned electric systems.[150] Oglethorpe is an EMC.

Based on data from NRC, nuclear electricity accounted for 42% of electricity generated in the state in 2017.[151] Georgia was 9th out of 30 states in terms of the generation of nuclear power in 2019.[152]

13.2 Georgia Power

Georgia Power is an investor-owned utility that operates and partly owns the Hatch and Vogtle nuclear plants. These plants are owned jointly with a number of other public utilities, including Oglethorpe.[153] Georgia Power is wholly-owned by Southern Company, which owns utilities in Georgia, Alabama and Mississippi. Georgia Power's sister company in Alabama (Alabama Power) also operates nuclear power plants and was reviewed in Chapter 9.

Georgia Power is in the process of constructing Vogtle Units 3 and 4, which are the first new nuclear plants to be built in the US in 30 years. Georgia Power's cost and schedule performance on the construction project has been the focus of investor and regulatory attention. We have not reviewed issues specific to Vogtle 3 and 4 as part of this study.

13.2.1 Regulatory Regime

As noted above, Georgia Power is fully regulated by the Georgia PSC. Georgia Power's revenues from regulated retail operations are collected through various rate mechanisms subject to the oversight of the Georgia PSC. Georgia Power currently recovers its costs from the regulated retail business through an alternate rate plan ("ARP"), which includes traditional base tariffs, Demand-Side Management ("DSM") tariffs, the ECCR tariff, and Municipal Franchise Fee ("MFF") tariffs. The ARP provides for the sharing of earnings above a cap with customers and for rate adjustments (subject to Georgia PSC approval) if projected earnings for a calendar year fall below a floor.[154]

[150] https://psc.ga.gov/utilities/electric/
[151] NRC, "Information Digest, 2019-2020" (NUREG-1350, Volume 31), p. 28.
[152] U.S. Energy Information Administration, U.S. Nuclear Generation and Generating Capacity, Data Released 2020-11-30.
[153] Smaller ownership stakes are held by the Municipal Electric Authority of Georgia (MEAG) and the City of Dalton.
[154] Southern Company's 2019 Annual Report, p. 42.

Georgia Power typically files rate cases every three years with Georgia PSC. These rate cases determine the parameters of the subsequent ARP.

13.2.2 Rate Recovery

Based on information presented in Southern Company's ("Southern") annual report and regulations in respect of the ARP, we conclude that Georgia Power uses a forward-looking NDT funding approach to determine amounts collected in rates for nuclear decommissioning (including spent fuel storage).

In the discussion that follows, we use information from Georgia Power's 2019 rate filing and Southern Company's annual report to illustrate key elements of a forward-looking funding structure in a ratemaking context, including the impact of site specific estimates versus NRC's formula.

Georgia Power's 2019 rate application included a request for recovery of annual decommissioning costs based on proposed NDT funding requirements.

The proposal was a reduction in the annual cost recovery compared to 2018 levels, as shown in Exhibit 13-1 below for each of the generating units (amounts are Georgia Power's share).

Exhibit 13-1 – 2019 ARP Proposed Decommissioning Expense[155]

Change in Decommissioning Expense ($ Millions)						
	Cost at License	Fund Balance		Annual Expense		
	Expiration	12/31/2018	Life (Yrs)	Proposed	Current	Change
Plant Hatch						
Unit 1	680	280	15	2.368	1.153	1.215
Unit 2	759	267	19	0.467	2.375	(1.908)
Total	1,439	547		2.835	3.528	(0.693)
Plant Vogtle						
Unit 1	763	153	28	1.502	1.001	0.501
Unit 2	811	172	30	-	0.8	(0.827)
Total	1,575	325		1.502	1.828	(0.326)
Total	**3,014**	**872**		**4.338**	**5.356**	**(1.018)**

The proposed recovery levels were based on projected decommissioning costs and current NDT fund balances. Decommissioning costs at license expiration were based on escalating a 2018 cost estimate that included:

- The NRC minimum funding values based on the NRC formula[156] (See Exhibit 13-2) and

[155] Figures taken from Exhibit DPP-SPA-MBR-5, Schedule 4, from Georgia Power's 2019 rate filing.
[156] As noted in Chapter 9, Alabama Power, Georgia Power's sister company, uses site-specific estimates for rate-setting. The use of site-specific estimates versus the NRC formula for rate-setting purposes was considered in Georgia Power's 2007 rate proceeding, discussed in a subsequent section.

- An additional amount for interim storage costs related to spent fuel. (The costs to be incurred reflect expected delays in the US DOE acceptance of this spent fuel).

In support of its proposal, Georgia Power's rate filing included reports on projected total decommissioning costs (in 2018 dollars) submitted to the NRC in 2019. The escalation of cost estimates from 2018 dollars was performed using a composite escalation rate of 2.75%. Amounts included for spent fuel were taken from the site-specific estimates.[157] Increase in minimum funding requirements over the 2017 NRC minimum values were due to the increase in escalation factors for 2018 over 2017.

The 2019 rate filing indicates that the proposed annual recovery amounts were calculated assuming a 4.75% nominal earnings rate and that they exclude provisions for site restoration. We note that the implied real rate of return of 2.00% is the maximum amount suggested under NRC guidelines.[158]

Exhibit 13-2 shows NRC minimum funding requirement for Georgia Power in respect of its nuclear plants. (Values have been adjusted to account for Georgia Power's ownership share.) As noted above, the values are produced using the NRC funding formula.

Exhibit 13-2: NRC Minimum Decommissioning Funding Values

Minimum Funding Requirement (2018$ Millions)			
	Vogtle	Hatch	Total
Unit 1	234	324	
Unit 2	234	324	
Total - Georgia Power Share	467	647	1,114

For financial statement purposes, we note that Georgia Power's AROs are based on site-specific estimates prepared by Georgia Power's engineering consultants. Exhibit 13-3 below shows total projected decommissioning costs for Georgia Power's nuclear plants, presented in 2018 dollars as at the date of decommissioning. (As Georgia Power shares ownership of the Vogtle and Hatch plants with a number of other utilities, the bottom portion of the Exhibit shows Georgia Power's share of decommissioning costs.)

[157] Southern Company 2018 Annual Report, p. 143.
[158] In this comparison, we have calculated the real rate of return by simply subtracting escalation assumptions from the nominal expected return, rather than using a geometric calculation.

Exhibit 13-3: Site-Specific Decommissioning Cost Estimates

Projected Total Decommissioning Costs (2018$ Millions)			
	Vogtle	**Hatch**	**Total**
Unit 1	889	926	
Unit 2	953	994	
Total - All Owners	1,843	1,920	3,763
Ownership Interest - Georgia Power	45.7%	50.1%	
Unit 1	406	464	
Unit 2	436	498	
Total - Georgia Power Share	842	962	1,804

The $1.8 billion cost compares to the figure of $3.0 billion shown in Exhibit 13-1 earlier (taking the figure from Exhibit 13-3 that accounts for Georgia Power's ownership share). Values differ because the figures in Exhibit 13-3 are in 2018 dollars, rather than nominal dollars at the time of decommissioning, and because Exhibit 13-3 does not include costs for spent fuel storage.

As can be seen from Exhibit 13-2 and Exhibit 13-3, the NRC funding formula produces lower estimates for Georgia Power's share: $1.114 billion across both plants compared to $1.8 billion based on more detailed site-specific analyses. As discussed in our review of US regulatory environment in Chapter 6, the NRC funding formula is not intended to be an estimate of actual decommissioning costs but, rather, a value that can be used as a "planning tool" in assessing the adequacy of funding amounts. This does illustrate, however, the substantial differences that can arise between the NDT funding requirement target (and therefore rate recovery) and the more representative site-specific cost estimates, which would be expected to, and in this case have informed the accounting AROs.

13.2.2.1 Past Regulatory Orders – Treatment of FAS 143 and Other

We have included a discussion with respect to Georgia Power's past rate proceedings to provide a further example of how rate setting processes for nuclear decommissioning costs and corresponding NDT contribution amounts have evolved in practice.

2004 Rate Filing – Treatment of FAS 143

Georgia Power's 2004 rate filing included the company's proposal to address expenses related to the introduction of FAS 143. The company proposed to base allowances for nuclear decommissioning in rates on its site specific study and "not the higher FAS 143 estimates". As a result:

> "The difference between amounts collected in rates for dismantlement and the FAS 143 dictated accretion/depreciation expense is deferred to a regulatory asset account in accordance with FAS, Accounting for the Effects of Certain Types of Regulation."[159]

This accounting treatment was not contested in the proceeding and was not over-turned in the final order.[160] This outcome is broadly consistent with similar outcomes in Florida, Minnesota, North

[159] Georgia Power Company, Direct Testimony of Ron Hinson, Docket No. 18300-U, p. 12 of 29.
[160] Georgia PSC, Order - Georgia Power Company's 2007 Rate Case, Docket 18300-U, December 11, 2004.

Carolina and South Carolina, as discussed in the corresponding chapters. As noted elsewhere, the recognition of regulatory assets (or liabilities) in these circumstances requires that utilities expect to recover their ultimate ARO costs over the long-term through the forward-looking funding approach.

2007 Rate Filing

Georgia Power filed an initial rate application in 2007 that called for an annual decommissioning expense of $11.6 million.[161] The allowed decommissioning expense was ultimately reduced to $3.5 million. The reductions reflected the following changes:

- Calculations were revised to cover only those activities required to meet minimum NRC decommissioning requirements. NRC does not require site restoration and, as a result, the Georgia PSC decided that allowances for Georgia Power should therefore exclude the costs for such restoration.
- Costs for plant decommissioning were revised to reflect NRC funding minimums, rather than higher site-specific estimates that had been prepared by Georgia Power. One justification for using the lower NRC values was the anticipated life extension of the Vogtle plant, which was expected shortly thereafter, and which was expected to (and ultimately did) reduce required funding contributions.[162]

Funding amounts did include provisions for spent nuclear fuel storage, which is not a cost that was covered by minimum NRC funding values.[163]

This precedent further illustrates the significant discretion that US economic regulators exercise in determining the use of decommissioning cost estimates in setting NDT contributions and therefore rates. As noted in the earlier section of this Chapter, the difference between the NRC funding minimum cost estimate and the site-specific estimate is notable for Georgia Power.

2013 Rate Filing

In 2013, the Georgia PSC approved a settlement agreement, for 2013 ARP, setting rates for the next three years.[164]

As part of the decision accepting the 2013 ARP, the Georgia PSC issued a Supplemental Order confirming a new level of annual decommissioning recovery amount for Georgia Power's nuclear facilities. Positioned as an accounting order, the Order was intended to assist the company in receiving revised schedules of ruling amounts from the IRS. The total annual approved amount was $5.356 million, as summarized below in Exhibit 13-4. Amounts for spent fuel shown are to address additional storage costs as a result of delays by the US DOE in accepting this fuel.

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[161] Georgia Power 2007 Rate Application, Docket 25060, Exhibit APD-8
[162] Will Jacobs, Direct Testimony on behalf of the Georgia Public Service Commission staff, Docket 25060-U, October 22, 2007, pp. 7-9.
[163] Georgia PSC, Order - Georgia Power Company's 2007 Rate Case, Docket 25060, filed December 31, 2007, p. 6.
[164] In 2016, the Georgia PSC approved another settlement agreement that provided for the extension of the 2013 ARP through to 2019.

Supporting assumptions included a nominal investment earnings rate (after taxes) of 4.41% and an escalation rate of 2.41%.[165]

Exhibit 13-4 – ARP Approved Decommissioning Expense

Approved Decommissioning Expense - 2013 ARP ($ Millions)					
	Hatch 1	Hatch 2	Vogtle 1	Vogtle 1	Total
Decommissioning	-	-	0.495	-	0.495
Spent Fuel	1.153	2.375	0.506	0.827	4.861
Total - Georgia Power	1.153	2.375	1.001	0.827	5.356

13.3 Oglethorpe Power Corporation

Oglethorpe is a Georgia EMC and is owned by 38 retail electric distribution cooperative members. Oglethorpe Power Corporation ("Oglethorpe") has a 30% ownership interest in both the Hatch and Vogtle nuclear power plants operated by Georgia Power.

As a cooperative, Oglethorpe is not subject to regulatory oversight of its rates. It has wholesale power contracts with its member owners and these contracts provide Oglethorpe with substantial discretion to pass costs through to its members.

Oglethorpe falls into the category of public utilities generally referred to as Generation and Transmission ("G&T") co-operatives. These typically provide wholesale power to groups of smaller rural electric co-operatives, which in turn provide power directly to retail consumers. G&T co-operatives are often highly leveraged, with this leverage achieved on the strength of very strong wholesale power contracts. Oglethorpe's 2018 annual report, for example, notes that its wholesale power contracts with members extend through to 2050 and have strong provisions with respect to cost pass-through.[166] Oglethorpe reported an equity to total capitalization ratio of 9.2% for 2018, indicating a high reliance on debt funding. Oglethorpe member utilities, in contrast, have an equity to total capitalization ratio of 52%.[167]

13.3.1 Regulatory Regime

As noted above, Oglethorpe's rates are not subject to oversight by the Georgia PSC. Instead, rate setting is governed by contractual arrangements, including with lenders. Rates are reviewed at least once a year.

Oglethorpe's 2019 annual report provides a description of its rate setting framework as follows:

> "We are required to revise our rates as necessary so that the revenues derived from our rates together with our revenues from all other sources, will be sufficient to pay all of the costs of our

[165] The Order indicates that the rate of after-tax earnings was estimated after taking into consideration the tax rate charged and the removal of investment restrictions as a result of the Energy Policy Act of 1992. (Georgia PSC, Supplemental Order, 23 December 2013, Docket 36989, Exhibit A)
[166] Oglethorpe Power Corporation, Form 10-K for the year ended December 31, 2018, p. 2.
[167] Oglethorpe Power Corporation, 4th Quarter and Year-End 2018 Investor Briefing, April 10, 2019, pp. 5 and 19.

> system, including the payment of principal and interest on our indebtedness, to provide for reasonable reserves and to meet all financial requirements."[168]

It also notes:

> "The formulary rate we established in the rate schedule to the wholesale power contracts employs a rate methodology under which all categories of costs are specifically separated as components of the formula to determine our revenue requirements."

Oglethorpe must provide notice of, and opportunity to object to, most changes to the formula rate made under its wholesale power contracts. This notice must be given to the Rural Utilities Service and the Department of Energy. Oglethorpe has loan agreements with each of these entities, in addition to other, private-sector lenders.[169] The Rural Utilities Service exercises control and supervision of the rates of those of Oglethorpe's member co-operatives that have loans with it. This requires these utilities to maintain minimum debt service and interest coverage ratios.

The 2019 annual report describes the specific approach to rate setting followed by Oglethorpe based on the contractual arrangements with the lenders:

> "Under the first mortgage indenture, we are required, subject to any necessary regulatory approval, to establish and collect rates which are reasonably expected, together with our other revenues, to yield a margin for interest ratio for each fiscal year equal to at least 1.10. The formulary rate is intended to provide for the collection of revenues which, together with revenues from all other sources, are equal to all costs and expenses we recorded, plus amounts necessary to achieve at least the minimum 1.10 margins for interest ratio."[170]

The margins for interest ratio is determined by dividing margins for interest by total interest charges on debt secured under Oglethorpe's first mortgage indenture, where margins for interest includes, among others:

- Net margins (after certain defined adjustments), plus
- Interest charges on all indebtedness secured under Oglethorpe's first mortgage indenture, plus
- Any amount included in net margins for accruals for federal or state income taxes.

Effectively, net margin is reported in Oglethorpe's financial statements as an equivalent to net income for investor owned utilities.

13.3.2 Rate Recovery

While we were unable to identify publicly available information directly setting out how Oglethorpe's rates recover decommissioning costs, we believe, based on Oglethorpe's 2018 and 2019 annuals report, it is likely rates are based on forward looking funding, however, Oglethorpe's funding target is not directly linked to funding requirements to comply with NRC regulations.

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168 Oglethorpe Power Corporation, Form 10-K for the year ended December 31, 2019, p. 3.
169 The Rural Utilities Service is an agency of the US Department of Agriculture, and was originally established to provide financing for electric co-operatives.
170 Oglethorpe Power Corporation, Form 10-K for the year ended December 31, 2019, p. 3.

We reviewed disclosures in the financial statements related to Oglethorpe's regulatory asset and liability balances and noted the following in Oglethorpe's annual report:

> "We apply the provision of regulated operations to nuclear decommissioning transactions such that collections and investment income (interest, dividends and realized gains and losses) of our nuclear decommissioning funds are compared to the associated decommissioning expenses with the difference deferred as regulatory asset or liability. As this difference is largely attributable to the timing of decommissioning fund earnings, the difference is recorded as an adjustment to investment income in our consolidated statements of revenues and expenses. Unrealized gains and losses of the decommissioning funds are recorded directly to the regulatory asset or liability for asset retirement obligations in accordance with our ratemaking treatment."[171]

Two of the three factors above are based on accounting definitions, namely, investment income on the nuclear decommissioning fund, and associated decommissioning expenses. The third factor, collections, would represent the cash received from rate payers. Collections would be determined from the rate-making process and we do not have clarity on how this amount is set. Although we note the following phrase:

> "Based on current funding and cost study estimates, we expect the current balances and anticipated investment earnings of our decommissioning fund assets to be sufficient to meet all of our future nuclear decommissioning costs. Notwithstanding the above assumption, our management believes that increases in cost estimates of decommissioning can be recovered in future rates."[172]

From this wording we understand that the collection amounts are likely derived from a forward looking funding requirement.

From the annual report, we identified that the funding target is not directly linked to external funding requirements (i.e. NRC regulations), other than setting a minimum amount. The annual report indicates that Oglethorpe's nuclear decommissioning fund balances are divided into external and internal:

- External funds have been established to comply with NRC regulations.
- Internal funds are unrestricted investments internally designated for nuclear decommissioning. They are available to be used to fund the external trust funds, should additional funding be required, as well as other decommissioning costs outside the scope of NRC funding regulations.

Total fund balances were $623.5 million at the end of 2019.

The annual report indicates that in 2018 and 2019, no additional amounts were contributed to the external trust funds.[173] In each of those years, $4.75 million was contributed into the internal funds. In comparison, accretion expense of $32.9 and $38.5 million was recognized in each of these year's respectively. [174]

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[171] Oglethorpe Power Corporation, Form 10-K for the year ended December 31, 2019, p. 74.
[172] *Ibid*, p. 76.
[173] *Ibid*, p. 73.
[174] *Ibid*, p. 72.

14 Illinois

14.1 Industry Structure

Similar to other states that have restructured their electricity sectors, consumers in Illinois have the ability to choose who supplies them with the electricity commodity. Transmission and distribution remain regulated monopolies, with rates set by the Illinois Commerce Commission ("ICC").

Distribution utilities have an obligation to supply electricity to those consumers who do not choose an alternative electricity supplier. This obligation is overseen by the Illinois Power Agency ("IPA"), an independent government agency established in 2007 to develop and manage a new electric supply procurement process for customers of regulated utilities. After overseeing the procurement of electricity supply, the IPA directs the utilities to enter into wholesale electric supply contracts of various duration to purchase electric supply from different sources.[175]

Based on data from NRC, nuclear electricity accounted for 53% of electricity generated in the state in 2017.[176] Illinois was the top state in terms of the generation of nuclear power in 2019.[177]

We have reviewed one electricity producer, Exelon Generation Company ("Exelon Generation" or "Genco"), which operates all of the 11 operating nuclear reactors in Illinois. As one of the sample states with deregulated generation, we focused our review on the transfer of responsibility for nuclear decommissioning costs from within a regulated model to a competitive market structure for electricity generation.

An additional discussion of Exelon Generation is also found in Chapter 16 on Pennsylvania, where the company also owns a number of nuclear reactors.

14.2 Exelon Generation

Exelon Generation is a subsidiary of Exelon Corporation ("Exelon") and is one of the largest competitive generators of electricity in the United States.[178]

In Illinois, Commonwealth Edison Company ("ComEd"), a subsidiary of Exelon, functions as an energy delivery company. ComEd is a regulated transmission and distribution utility that provides electric service to more than four million customers across northern Illinois, or 70 percent of the state's population.[179] Prior to deregulation, ComEd also owned and operated the regulated nuclear generating assets in the state.

ComEd's parent company, Unicom, merged with PECO Energy Company ("PECO"), a Pennsylvania-based utility, in October 2000.[180] All of these entities are now part of Exelon.

[175] Plug-In Illinois, "Understanding the Utility's Electric Supply Price". Retrieved 23-11-2020
[176] NRC, "Information Digest, 2019-2020" (NUREG-1350, Volume 31), p. 28.
[177] U.S. Energy Information Administration, U.S. Nuclear Generation and Generating Capacity, Data Released 2020-11-30.
[178] Exelon Corp, "About Exelon". Retrieved 23-11-2020
[179] ComEd, "About Us". Retrieved 23-11-2020
[180] Illinois Commerce Commission, Report to the General Assembly – as required by the Electric Service Customer Choice and Rate Relief Law of 1997, May 2004., p. 5.

14.3 Regulatory Regime

As noted above, Illinois went through a restructuring process to introduce competition to the electricity generating sector. This process began in 1999. As a result, generation of electricity is not rate regulated and is subject to market prices.

14.4 Rate Recovery

Based on our review of the regulatory record, we conclude that the restructuring process in Illinois resulted in a gradual transition from an NDT funding approach that involved recovery of all projected costs from consumers of a vertically integrated utility, to recovery of a defined amount from consumers of a successor transmission and distribution utility, and finally to the recovery of all remaining future costs by a competitive generation company. Hence, recovery mechanisms have moved over time to a purely market based approach.

As part of the restructuring process in Illinois, ComEd transferred all of its nuclear electric generating assets, comprising 13 units in total at that time, to an affiliate, ultimately Genco. As part of this transaction, ComEd also entered into an agreement with Genco to purchase all of the power produced by these stations through 2004 at a rate defined as part of the restructuring process. In 2005 and 2006, ComEd would be able to purchase power from Genco at market rates. After 2006, ComEd would obtain all of its supply from market sources.[181]

The schedule of energy prices through to 2004 protected ComEd from any increases in energy prices attributable to increases in nuclear station operating costs, additional investments in station improvements, increases in market prices and energy, and deterioration in nuclear plant performance.

On behalf of Genco, ComEd was permitted to recover $73 million in decommissioning costs (based on a forward-looking NTD funding approach) in each of the years 2001 to 2004 through its regulated rates charged to consumers. For each of 2005 and 2006, ComEd could recover an amount equal to $73 million times the percentage of actual energy production purchased by ComEd in each year. Beyond 2006, ComEd waived any right to seek recovery of decommissioning costs from its retail consumers. Exelon Generation would therefore need to fund any NDT decommissioning contributions beyond 2007 through its revenues from the market.

Other key elements of the agreement and associated ICC decision were as follows:

- ComEd's NDT funds were transferred to Genco.
- To the extent that a trust fund established for any given plant had surplus funds remaining after the decommissioning of that plant, these funds would be returned to consumers (notwithstanding that the availability of any surplus funds would only become apparent well into the future). The ICC rejected ComEd's initial request that surpluses only be returned to consumers after all 13 plants were decommissioned (which would have allowed surpluses from any one plant to first be used to offset deficits at other plants). The ICC referenced specific provisions in governing legislation in making this determination.[182]
- ComEd sought to include non-radiological decommissioning costs (i.e. site restoration costs) in amounts to be recovered from consumers. The ICC rejected this inclusion, on the grounds that

[181] Illinois Commerce Commission, Order, Docket 00-0361, p. 3.
[182] *Ibid*, pp. 38-39.

there is no NRC statutory requirement for site restoration. Also, while ComEd promised to perform non-radiological decommissioning activity, there was no guarantee that it would use trust fund amounts for that purpose.[183]

- The amount of $73 million to be collected annually from consumers through 2006, per above, reflected reductions to account for a possible life extension of some of the units. (Life extension would allow additional time for trust fund amounts to accumulate earnings.) At the time of the decision, an application for life extension of some of the units was before the NRC.

[183] Illinois Commerce Commission, Order, Docket 00-0361, p. 18.

15 Minnesota

15.1 Industry Structure

Minnesota falls within the territory of the Midcontinent Independent System Operator ("MISO"), which operates a competitive wholesale electricity market and offers open-access transmission service. Accordingly, utilities in Minnesota have access to a robust wholesale electricity market.

The state, however, has not mandated retail open access. Accordingly, the major utilities in the state continue to be responsible for providing commodity electricity to their customers and operate on a vertically-integrated basis. Hence, Minnesota represents a state that is a hybrid model in terms of the extent of open-market competition. The Minnesota Public Utilities Commission ("Minnesota PUC") is the state utility regulatory agency.

Based on data from NRC, nuclear electricity accounted for 24% of electricity generated in the state in 2017.[184] Minnesota was 18th out of 30 states in terms of the generation of nuclear power in 2019.[185]

We have reviewed developments at one major utility, Northern States Power Company ("NSPC"), which operates the three nuclear units in Minnesota – two at the Prairie Island generating station and one at the Monticello generating station.

Given the availability of information, similar to Florida, our review includes additional details on the historical context for the current recovery methodology, including the regulator's response to the introduction of FAS 143 requirements for AROs.

15.2 Northern States Power Company

NSPC is a vertically integrated utility that supplies power to consumers in Minnesota, North Dakota and South Dakota. It is a subsidiary of Xcel Energy ("Xcel"), a publicly traded utility holding company with operations across multiple states.

15.2.1 Regulatory Regime

As an investor-owned utility, NPSC's rates are established by the Minnesota PUC. The rates change either through a general rate case or a rate rider, typically on a cost of service basis. Rates are set to allow for recovery of prudently incurred operating expenses and a regulated return on the utility's rate base.

15.2.2 Rate Recovery

As part of our research, we reviewed NSPC's publicly available financial statements and its regulatory filings with the Minnesota PUC. Based on this, we conclude that, similar to other regulated investor owned utilities reviewed in the US, NSCP uses a forward-looking NDT funding approach to determine collections for nuclear decommissioning costs (including for spent fuel storage) in rates.

[184] NRC, "Information Digest, 2019-2020" (NUREG-1350, Volume 31), p. 28.
[185] U.S. Energy Information Administration, U.S. Nuclear Generation and Generating Capacity, Data Released 2020-11-30.

NSPC's Annual Report states specifically that:

> "For ratemaking purposes, NSP-Minnesota recovers regulator-approved decommissioning costs of its nuclear power plants over each facility's expected service life, typically based on the triennial decommissioning studies. The studies consider estimated future costs of decommissioning and the market value of investments in trust funds and recommend annual funding amounts. Amounts collected in rates are deposited in the trust funds. For financial reporting purposes, NSP-Minnesota accounts for nuclear decommissioning as an ARO."[186]

Subsection 15.2.3.1, later in this Chapter, summarizes the company's reconciliation between amounts determined for rate-making purposes and costs reported in accordance with US GAAP.

NSPC's most triennial review of decommissioning cost recovery with the Minnesota PUC covered the period 2019-2021. A review of the record for the proceeding confirmed the use of the forward-looking NDT funding approach as the basis for recovery. Some of the highlights of the proceeding are discussed below.

15.2.2.1 Recent Decommissioning Review

In the most recent triennial proceeding for decommissioning costs, the Minnesota Department of Commerce ("MDOC") had recommended an increase in the annual recovery amount from $14.0 million to $45.6 million based on the fact that many scenarios that had been presented by the utility in its application could lead to a requirement to increase contribution accrual amounts.[187]

- In its reply argument, however, Xcel noted a number of uncertainties in the amounts that would actually be required, which could result in required collections being lower than suggested by the MDOC:[188]Refunds from US DOE related to delays in accepting spent fuel may continue in the future, and this could offset additional spent fuel storage costs that had been provided for in the recommended decommissioning allowances.[189]
- Utilities are generally moving to the SAFSTOR decommissioning option, which defers decommissioning procedures and allows for additional investment returns on the trust funds. The recommended increases had assumed the use of the DECON method, consistent with past calculations.[190]

[186] Northern States Power, 2019 Annual Report (10-K), Page 29
[187] Xcel Energy, Reply Comments, 2019-2021 Triennial Nuclear Decommissioning Study and Assumptions, Docket No. E002/M-17-828, p. 4.
[188] *Ibid*, p. 4.
[189] In 2018, Xcel had received its ninth settlement payment from the US DOE in respect of damages associated with delays in accepting spent fuel, in the amount of $15.4 million, of which $11.3 million was allocated to consumers in NSPC's Minnesota jurisdiction. (The balance was allocated to consumers in other states.) The settlement payment was deposited in an external interest-bearing account. (Minnesota Public Utilities Commission, Order Approving Compliance Filing and Authorizing Ninth Department of Energy Settlement Refund in Conjunction with TCJA Refund, Dockets E-002/M-15-1089 and E-002/M-178-828, p. 2.)
[190] The DECON method assumes that decommissioning begins shortly after the end of operations, while SAFSTOR method involves putting the reactor in a shut-down state for a number of years before decommissioning activities begin. This reduces radiation levels, reducing real expenditures, and defers the timing of these expenditures.

- There is increased use of third-party contractors to undertake decommissioning tasks, and this has led to efficiencies that reduce the overall costs of decommissioning.

In recognition of these trends, Xcel proposed to continue the previously approved annual accrual of $14.0 million, rather than increase it per to the MDOC's recommendation, until its 2019 Integrated Resource Plan ("IRP") was resolved.

Xcel also proposed that the Minnesota PUC permit NSPC to hold its recent US DOE settlement payments in an interest bearing account until its 2019 IRP was resolved, at which time a decision could be made to apply the amount to the NDT or then issue a refund to consumers.[191] (Prior settlement amounts received from the US DOE had been distributed as refunds to consumers.)

Ultimately, the Minnesota PUC approved an increase in the annual decommissioning accrual to $44.4 million, thereby largely accepting the MDOC's initial recommendation. However, rather than accept a parallel recommendation from the MDOC to use settlement refunds to reduce the increase in the decommissioning recovery amounts, the Minnesota PUC ordered these funds to be refunded to consumers.[192]

In support of its decision to increase accrual amounts, the Minnesota PUC noted that this was the most "conservative and reasonable approach". It also noted that if the next decommissioning study did result in a lower accrual, this could then be used to offset the impact of any rate increases.

The 2019 NSPC annual report noted, however, that the Minnesota PUC "verbally approved" a delay in NSPC-Minnesota's increase in the annual funding requirement to 2021.[193]

The positions taken by the parties in this proceeding once again highlight the broad discretion and judgment that a state regulator such as the Minnesota PUC has in setting the decommissioning cost estimate for external funding requirements (and therefore recovery amounts) within the NRC's framework. The case also highlights the degree of conservatism that may be adopted by economic regulators on the issues of decommissioning.

15.2.2.2 Past Regulatory Orders Treatment of FAS 143 and Other

Policies in Minnesota for the recovery and funding of decommissioning costs have evolved over time. Similar to Florida, availability of information has allowed us to trace this evolution through a review of regulatory decisions for NSPC dating back to 1978. We believe that, given the inherently long timeframes for nuclear decommissioning impacts, the historical review is helpful to contextualizing the present day application of the recovery methodology.

Docket No. E-002/D-77-1086A

In 1978, the Minnesota PUC approved depreciation rates for NSPC, including for its nuclear plants. These rates took into account estimated costs of decommissioning equal to 10% of the plants' initial installation costs. The resulting decommissioning cost of $56 million was treated as a negative net salvage value and recovered through straight-line depreciation, consistent with financial accounting

[191] Xcel Energy, Reply Comments, 2019-2021 Triennial Nuclear Decommissioning Study and Assumptions, Docket No. E002/M-17-828, p. 12.
[192] Minnesota Public Utilities Commission, Order Approving Decommissioning Study, Decommissioning Accrual and Taking Other Action, Docket No. E-002/M-178-828, January 7, 2019, p. 3 and p. 11.
[193] Northern States Power Company, 2019 Annual Report (Form 10-K), p. 48.

treatment.[194] This cost recovery approach has been referred to as the use of a "straight line internal fund". We note that this approach parallels our historical findings on the early approach in use in Florida.

Subsequently, the Minnesota PUC ordered NSPC to review the issue of nuclear plant decommissioning costs, discuss alternatives for recovery, and to recommend a preferred approach. A contributing factor to this review was concern over the appropriateness of the proposed cost amounts.

Docket No. E-002/D-79-956

In Docket No. E-002/D-79-956, initiated in 1980, evidence prepared by an external consultant forecast nuclear decommissioning costs for NSPC's three nuclear units at $760 million, significantly higher than under the original simplified net salvage approach.[195]

In the proceeding, two alternatives to the net salvage value approach were proposed for the recovery of these costs: these were the use of either an internal or external sinking fund.

With an external sinking fund, annuity payments over time would be calculated such that, along with earnings generated, they would equal future estimated decommissioning costs at the time of decommissioning. The charge to customers would then be set at the annuity payment.

An internal sinking fund would be similar, but revenues generated are invested in the utility's plant assets, rather than marketable securities, thereby reducing the utility's need to secure outside capital funding.

Effectively, an internal sinking fund would entail determination of the annuity amounts to be recovered using a future earnings rate based on the utility's return on equity.

As noted by the Minnesota PUC in its findings:

> "If the internal fund has an assumed earnings rate equal to NSPC's after-tax rate of return, the annual revenue requirements would be levelized. These facilities and equipment could serve as collateral for mortgage bonds to generate the necessary funds at the time of decommissioning." [196]

To select between these alternatives, NSPC suggested four criteria:

- Assurance of fund availability. The degree of certainty that funds will be available when required.
- Economic cost. The present value of the associated revenue requirement over a facility's service life.
- Fairness of Customers. Whether costs are paid by those who benefit.
- Adaptability to Change. The ability of the approach to incorporate new and revised information without causing disruption in the costs to customers. (This criterion thus is "intertwining partially" with fairness.)

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[194] Minnesota PUC, Findings of Fact, Conclusions of Law and Order, Docket No. E-002/D-79-956, February 26, 1981, p. 1.
[195] *Ibid*, p. 4.
[196] *Ibid*, p. 4.

Some participants questioned the ability of an internal sinking fund to provide assurance of fund availability. An internal fund is dependent on the financial health of the utility at the time that decommissioning costs occur: the utility, for example, may be vulnerable to financial collapse in the event of a catastrophic accident.

- Based on our review of the record, the key benefit identified for an internal fund relative to an external fund was cost: which was lower, on a present value basis, for the internal fund.[197] This reflected the fact that internal funds had a high implied after-tax earnings rate and external fund earnings were then taxable.

In its Order on the proceeding, the Minnesota PUC ruled in favour of the internal sinking fund. The Order noted that:

> "the cost associated with an external sinking fund, due to the prevailing interpretation of present federal tax provisions, is of such a magnitude that it exceeds the benefit of greater fund assurance which might be provided by an external sinking fund."[198]

The Minnesota PUC also requested NSPC that seek an IRS ruling to obtain more favourable tax treatments for an external fund.[199]

Docket No. E-002/D-90-184

In July 1990, the NRC imposed the requirement for nuclear operators to invest specified percentages of anticipated decommissioning costs in external funds.[200,] The Order issued in Docket No. E-002/D-90-184 addressed, among other things, the implications of this new NRC requirement.

In the proceeding, NSPC provided a new cost estimate for decommissioning its nuclear plants of $630 million in then current dollars for the years 2010 through 2020. This was based on a site-specific estimate. In parallel, new NRC rules required NSPC to put in place external funds that would accumulate $351 million in funding based on the NRC minimum formula. Accordingly, NSPC applied to establish such external funding arrangements on a typical annuity basis. Although allocating funds to external trusts represented a shift from the internal funds that had previously been approved, there was no change in the general approach such that the decommissioning funding requirement would be recovered from ratepayers in equal installments over the facilities' lifespan.

Of interest, Minnesota Energy Consumers ("MEC"), an intervenor group proposed an alternate contribution profile to reach the ultimate decommissioning funding target. Instead of a traditional annuity approach that uses equal installments over the funding period (even-pay basis), MEC proposed to set the contribution based on estimated decommissioning costs in current dollars, excluding future assumed escalation and investment earnings. The annual accrual would be calculated by taking the current funding shortfall (equal to estimated costs in current dollars less funds accumulated to date) and dividing by the number of the remaining years of service life. The funding

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[197] Minnesota PUC, Findings of Fact, Conclusions of Law and Order, Docket No. E-002/D-79-956, February 26, 1981, p. 6.
[198] *Ibid*, p. 8.
[199] At the time, decommissioning accruals were treated as income when received but the external fund contributions were not deductible. Additional, external fund earnings were taxable.
[200] Minnesota PUC, Order Determining Decommissioning Costs, Approving Cost Recovery Procedures, and Establishing Future Filing Requirements, Docket No. E-002/D-90-184, February 25, 1991, p. 8.

target and therefore future contributions amount would then be subject to periodic adjustments for the inflation that had occurred since the prior review.[201]

The Minnesota PUC characterized differences in the approaches as follows:

> "The Company's method requires present ratepayers to pay rates including an allowance for future inflation. MEC's method requires future ratepayers to pay rates including an allowance for past inflation."[202]

The Minnesota PUC went on to support NSPC's proposed approach, noting:

> "The Commission finds that the Company's method is consistent with traditional regulatory practice, provides greater intergenerational equity, and constitutes sounder regulatory policy."
>
> "First of all, collecting total projected costs on an even-pay basis is standard regulatory treatment of depreciation expense, including the negative salvage component of depreciation of which nuclear decommissioning is an example. Regulatory bodies traditionally allow utilities to recover depreciation in equal installments, even though, given inflation, early ratepayers will pay more in real dollars than later ratepayers. This is acceptable in large part because the utility business is so capital intensive, utilities regularly make expensive, long term capital investments subject to recovery through depreciation. Therefore, the same ratepayers who are paying full freight for recent capital improvements are benefitting from similar payments made in the past for older plants still in use."[203]

The Minnesota PUC also noted:

> "The Commission does not believe nuclear decommissioning expenses are so unique as to justify a departure from standard regulatory practice. Neither the amount of money nor the time frame is extraordinary in the utility context. The unusual thing about these expenses is that they will be incurred in the future. There is therefore some uncertainty about their amount. There is no reason, however, for the burden of that uncertainty to fall more heavily on either present or future ratepayers. The most reasonable approach is to proceed with the best information available and to review cost projections regularly so that any necessary adjustments can be made promptly.
>
> Furthermore, it appears that MEC's proposal would provide less intergenerational equity than standard depreciation procedures. According to the Nuclear Regulatory Commission, inflation rates for nuclear decommissioning activities will exceed general inflation rates for the foreseeable future. This means that adjusting for inflation after the fact would quite likely shift a significant portion of the cost of inflation from present to future ratepayers."[204]

On balance, the Minnesota PUC decision appears to demonstrate a preference for cautious conservatism by a utility commission on issues related to decommissioning. Specifically, the case study highlights the regulator's aversion to back end loading of contributions, preferring an even-pay basis for recovery over a station's lifespan.

[201] Minnesota Energy Consumers, Comments, Docket No. E-002/D-90-184, December 7, 1990, pp. 5-6.
[202] Minnesota PUC, Order Determining Decommissioning Costs, Approving Cost Recovery Procedures, and Establishing Future Filing Requirements, Docket No. E-002/D-90-184, February 25, 1991, p. 5.
[203] *Ibid*, p. 5.
[204] *Ibid*, p. 6.

Docket E-002/M-02-1766 Treatment of FASB 143 and Other Matters

A 2002 filing by NSPC with the Minnesota PUC addressed the impact of the introduction of FAS 143 on the utility's financial statements.[205] This filing contained NSPC's triennial review of funding for nuclear decommissioning costs.

In that filing, NSPC proposed to continue to recover decommissioning costs on the existing NDT sinking funds basis, notwithstanding the change in financial accounting standards. NSPC submitted that this approach would, for the period in question, result in a lower amount to be recovered from customers and proposed to record the difference between the accounting expenses under FASB 143 and recovery amounts as a regulatory asset on its balance sheet.[206]

NSPC also identified that the implementation of FASB 143 would result in the following impacts on its financial statements:

- the reversal of costs related to decommissioning that had been charged to accumulated depreciation,
- the creation of a new ARO asset (i.e. asset retirement cost) and of an offsetting account for its depreciation, and
- the setting up an ARO liability for decommissioning.

The net opening impact on NSPC's balance sheet position of these various adjustments would be reported as a regulatory liability, rather than through a cumulative adjustment earnings, as NSPC expected the entire amount to be recoverable/refundable thorough future rates under the NDT funding approach.[207]

The various implementation adjustments on the financial statements are summarized in Exhibit 15-2.[208] As shown, the adjustments necessitated reversal of the "negative salvage value" accounting treatment applied prior to FAS 143.

Exhibit 15-2 – Implementation Impact[209]

Consolidated Entries - Implementation of FASB 143 ($ Millions)		
	Debit	**Credit**
ARO Asset - Decommissioning	49.9	
Accumulated Depreciation through Dec 31, 2002	499.5	
Regulatory Asset / Liability		7.8
ARO Liability - Decommissioning		506.6
Accumulated Depreciation - ARO Asset		34.9

[205] Northern States Power Company, Petition for Approval, E-002/M-02-1766, October 11, 2002.
[206] *Ibid*, pp. 25-26.
[207] *Ibid*, p. 24.
[208] These FAS 143 implementation adjustments are similar to those reflected in LADPW's 2018-2019 financial statements upon application of GASB Statement 83, as discussed in Chapter 11.
[209] Northern States Power Company, Petition for Approval, E-002/M-02-1766, October 11, 2002, Appendix H, p. 1.

Final Order

In its final order, the Minnesota PUC accepted the continuation of a forward-looking funding approach to calculating the recovery amount for decommissioning.

With respect to the regulatory assets that NSPC proposed to create to record differences between amounts for rate setting purposes and accounting expenses, the Minnesota PUC noted that it was not making any commitments with respect to the future rate treatment of these assets. Specifically, it stated:

> "The Commission also clarifies that it is not addressing, in this proceeding, the granting of regulatory assurance supporting the recording of the differences, as regulatory assets or liabilities, between the amounts recorded under the certified decommissioning rates and those recorded to FAS 143. The accounting for FAS 143 should not dictate the recovery for future decommissioning filings."[210]

The outcome of this proceeding is similar to that in Florida , Georgia, South Carolina and North Carolina, whereby the regulators decided to continue with the existing NDT funding approach to rate recovery rather than convert to the new accounting standard for ratemaking purposes.

Transfer of Internal Funds to External Funds

This proceeding also addressed the transfer of funds from internal to external funds.

As noted earlier in this chapter, internal funds had been accumulated in the initial years of plant operation, prior to the introduction of NRC requirements for external funding, which were adopted by the Minnesota PUC. Although these internal funds were gradually being transferred to external funds, the Minnesota PUC ordered a faster rate of transfer as an outcome of this proceeding. In doing so, it acknowledged that there would be a cost to this transfer, as the external fund attracted a lower rate of return assumption. A staff briefing paper from the Minnesota PUC noted the following in this regard:

> "Before the NRC required external funding, the Commission allowed internal funding because it provided to be considerably less costly to ratepayers. Also, the utility focused on providing quality utility service and maintained a strong financial position.
>
> "With the changes in the financial position of the Company [*i.e. an improvement*], the Commission may wish to transfer the funds to the external account at an accelerated rate. There is an element of stewardship at issue. The Commission has collected significant sums of money from ratepayers for the purpose of meeting the decommissioning of the nuclear facilities. It would not be looked upon favourably should those funds not be available when needed."[211]

[210] Minnesota PUC, Order Setting End of Life Dates and Other Guidelines for Nuclear Decommissioning Accrual and Requiring Compliance Filings, Docket E-002/M-02-1766, January 9, 2004, p. 6.
[211] Minnesota Public Utilities Commission, Staff Briefing Paper, Docket E-002/M-02-1766, December 11, 2003, p. 11.

15.2.3 Other Observations

15.2.3.1 Reconciliation of Decommissioning Cost Estimates

As noted above, NSPC recognizes AROs for nuclear decommissioning in accordance with FAS 143 (now ASC 410). Its accounting policy for AROs as stated in the 2019 annual report is as follows:

> "NSP-Minnesota accounts for AROs under accounting guidance that requires a liability for the fair value of an ARO to be recognized in the period in which it is incurred if it can be reasonably estimated, with the offsetting associated asset retirement costs capitalized as a long-lived asset. The liability is generally increased over time by applying the effective interest method of accretion, and the capitalized costs are depreciated over the useful life of the long-lived asset. Changes resulting from revisions to the timing or amount of expected asset retirement cash flows are recognized as an increase or a decrease in the ARO."[212]

The annual report for NSPC-Minnesota provides relatively detailed disclosure that enables analysis of movements and reconciliation between the decommissioning AROs and the obligation used for funding and cost recovery purposes. We have summarized these disclosures in reconciliation format in Exhibit 15-1 below for the years 2017 through 2019.

Notably, in NSPC's case, the funding obligation is significantly higher than the accounting ARO.

[212] Northern States Power Company, 2019 Annual Report (Form 10-K), p. 29.

Exhibit 15-1 – NSPC Financial Disclosure[213]

Northern States Power - Minnesota ($ Millions)	2017	2018	2019
Estimated Future Decommissioning Costs (undiscounted)	11,205.5	11,205.5	11,205.5
Discount Rate For Discounting	2.80%	3.33%	2.39%
Effect of Discounting	(6,398.1)	(6,911.5)	(5,562.2)
Discounted Decommissioning Obligation - Regulated Basis	4,807.4	4,294.0	5,643.3
Differences in discount rate and market risk premium	(1,402.8)	(1,446.4)	(2,295.2)
O&M costs not included for GAAP	(1,041.5)	(879.3)	(1,280.3)
ARO differences between 2017 and 2014 cost studies	(489.5)	-	-
Nuclear projection Decommissiong ARO - GAAP	1,873.6	1,968.3	2,067.8
Nuclear AROs			
Opening Balance	2,249.3	1,873.6	1,968.3
Accretion	113.8	94.7	99.5
Cash Flow Revisions	(489.5)	-	-
Ending Balance	1,873.6	1,968.3	2,067.8
Assets Held in NDT	2,143.3	2,054.7	2,439.6
Annual decommissioning recorded as depreciation expense	20.4	20.4	20.4

The first line of the Exhibit shows undiscounted decommissioning costs as estimated for the purposes of setting rates, based on the regulator approved 2014 study. The estimate of future estimated costs is then discounted to the date of the report using average risk-free interest rates. The discounted amounts vary over time, primarily because of changes in the discount rate used, as well as due to the decreases in the length of time until decommissioning with the passage of time. For example, the decommissioning obligation increased from $4.29 billion in 2018 to $5.64 billion in 2019, as the discount rate decreased from 3.33% to 2.89%.

The Exhibit provides a reconciliation between regulatory estimates of the decommissioning obligation and ARO values under GAAP. To bridge the difference in 2019, the following values are reported:

– A $2.30 billion reduction associated with differences in the discount rate and market risk premium, which means that the discount rate used to measure the accounting AROs must be greater than the funding assumption shown.

A $1.28 billion reduction associated with O&M costs that are not taken into account in GAAP estimates. While we were unable to identify disclosure as to the nature of these costs, an example may be costs associated with future wastes not yet generated that are included in the lifecycle decommissioning obligations but are not yet accrued for accounting purposes.

[213] Information presented in, or derived from, Northern States Power Company, 2019 Annual Report (Form 10-K), p.48. “Annual depreciation decommissioning recorded as depreciation expense line” refers to the amount of NTD contribution collected through rates.

For 2017, the reconciliation also includes differences between underlying cost estimate studies, likely due to timing of implementation.

For reference, the next section of the Exhibit shows the roll-forward of ARO amounts including associated accretion expenses. Amounts held in NDT's are also included for comparison. The last line of the Exhibit shows amounts of decommissioning expenses allowed for rate-setting purposes based on the funding contributions.[214]

[214] The $20.4 million amount shown differs from the $14.0 million annual recovery discussed earlier in this Chapter, as it also reflects amounts recovered from consumers in North Dakota and South Dakota, in addition to those under the jurisdiction of the Minnesota PUC.

16 North Carolina

16.1 Industry Structure

The electricity sector in North Carolina remains regulated, with vertically-integrated utilities that supply power to their respective retail customer bases. Retail electric service is provided to consumers in North Carolina IOUs and university-owned utilities, EMCs, and municipally-owned electric utilities.

Exhibit 16-1 below summarizes the reactors located in North Carolina and their years of license expiration, all of them owned and operated by subsidiaries of Duke Energy Corporation ("Duke Energy"). Duke Energy is one of the largest electric power holding companies in the United States, providing electricity to 7.7 million retail customers in six states.[215]

Exhibit 16-1 – North Carolina Nuclear Facilities

Nuclear Facility	Owner	Ownership Stake	Year of Expiration
Brunswick Unit 1	Duke Energy Progress	100%	2036
Brunswick Unit 2	Duke Energy Progress	100%	2034
McGuire Unit 1	Duke Energy Carolinas	100%	2041
McGuire Unit 2	Duke Energy Carolinas	100%	2043
Harris Unit 1	Duke Energy Progress	100%	2046

Based on data from NRC, nuclear electricity accounted for 33% of electricity generated in the state in 2017.[216] North Carolina was sixth of the 30 states in terms of the generation of nuclear power in 2019.[217]

We reviewed the rate recovery approach in the state in the context of both Duke Energy Progress ("DEP") and Duke Energy Carolinas ("DEC"), as applicable, as we found significant commonalities across the two utilities.

16.2 Duke Energy Carolinas and Duke Energy Progress

DEC and DEP are primarily engaged in the generation, transmission, distribution and sale of electricity in portions of North Carolina and South Carolina. Combined, the two utilities cover a service area of approximately 56,000 square miles and supply electricity service to approximately 4.1 million residential, commercial and industrial customers.[218] As DEC and DEP have operations in both states, their costs must be allocated between the two jurisdictions.

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[215] Duke Energy, "About Us". Retrieved 23-11-2020
[216] NRC, "Information Digest, 2019-2020" (NUREG-1350, Volume 31), p. 28.
[217] U.S. Energy Information Administration, U.S. Nuclear Generation and Generating Capacity, Data Released 2020-11-30.
[218] Duke Energy, "Regulated Utilities'. Retrieved 23-11-2020

DEC and DEP file separate rate applications and are treated as independent entities in the regulatory process.

16.2.1 Regulatory Regime

The North Carolina Utilities Commission ("NCUC") regulates the rates and services of investor-owned utilities in the state. NCUC also has jurisdiction over the licensing of new generating plants operated by all electric power providers. The NCUC regulates all aspects of service provided by the IOUs.[219]

Rates for investor-owned electricity utilities are based on a cost-of-service approach, with rates allowing for a recovery of prudently incurred operating expenses and a regulated return on the utilities' rate base.

16.2.1.1 Treatment of FAS 143

In August 2003, the NCUC issued a ruling that confirmed that allowances for decommissioning in rates would continue to be based on a forward-looking NDT funding approach and would not be affected by the implementation of FAS 143.[220] In this ruling, the NCUC ordered that Progress Energy Carolina ("PEC"), now Duke Energy Progress, be allowed to place certain ARO costs in deferred accounts. The ruling noted that:

- The "intent and outcome of the deferral process shall be to continue the Commission's currently existing accounting and ratemaking practices for nuclear decommissioning costs and other ARO costs."
- The net effect of the deferral accounting shall be "to reset PEC's North Carolina retail rate base, net operating income, and regulatory return on common equity to the same levels as would have existed had SAFS 143 not been implemented."
- The implementation of the deferrals should have "no impact on the ultimate amount of costs recovered from the North Carolina retail ratepayers for nuclear decommissioning or other AROs, subject to future orders of the Commission."[221]

In making this determination, NCUC noted the following:

- The NCUC's approach calculates costs based on a "levelized or uniform earnings rate" over the service life of the nuclear plants through decommissioning, whereas the FAS 143 methodology results, effectively, in a variable rate. Under FAS 143, the utility is "required to recognize, on a current basis, the earnings actually realized on the trust fund",[222]

[219] North Carolina Utilities Commission, "Electricity". Retrieved 23-11-2020
[220] The ruling modified an earlier ruling that year on the same Docket in which NCUC allowed only transition adjustments as a result of FASB 143 to be deferred
[221] North Carolina Utilities Commission, Docket No. E-2, Sub 826, Order Granting Motion for Reconsideration and Allowing Deferral of Costs, August 12, 2003, p. 12.
[222] *Ibid*, p. 9.

- Based on results over the most recent six-month period, PECs nuclear decommissioning costs, on an annualized basis, would be $20.4 million greater under FAS 143 as compared to the historical expense level contained in the NCUC's earlier order. [223]

This finding is similar to the orders issued in Florida. Georgia, Minnesota and South Carolina related to the implementation of FAS 143. As noted earlier, the recognition of a regulatory asset under US GAAP under a deferral accounting ruling such as this is thereby made possible for utilities who have been recovering decommissioning costs on the funding basis from the beginning. These utilities would be expected to recover the cost equivalent of the AROs over the long term if they remain on the funding basis.

16.2.2 Rate Recovery

Based on our review of regulatory precedents in the state, we conclude that the forward-looking NDT funding approach is in place for recovery of nuclear decommissioning costs by regulated utilities.

Specifically, the recovery of nuclear decommissioning costs in rates is governed by guidelines adopted by the NCUC in 1998. These guidelines were the outcome of a proceeding that had been initiated 10 years earlier, in 1988 (Docket No. E-100, Sub 56).[224] A cover letter to these guidelines noted that they had been the result of "extensive negotiations".

The guidelines provide for a five-year review cycle of decommissioning recovery amounts as follows:[225]

- At each cycle, a nuclear operator engages a third-party consultant to perform a site-specific study of the decommissioning costs for any facility. These are set out in a "Cost Report".
- Also at each cycle, the operator calculates projected NDT balances at the time of decommissioning, based upon financial assumptions provided by additional third-party consultants. These are laid out in a "Funding Report", in addition, to details of the total revenue requirement and annual expense needed to fund the decommissioning obligations.
- The portion of the revenue requirement to be collected from North Carolina retail consumers is based on the jurisdictional factor used to allocate nuclear production plant to the various user groups of the utility.
- Calculations are made available to Public Staff (the body representing consumer interests), the Attorney General and staff of the utility commission.
- If calculations show a change of more than 15% in annual expenses relative to those currently provided for in rates, then the parties noted above will submit reports outlining their view of the requested funding changes.

As an example of how the NCUC guidelines are applied, we reviewed DEC's recent regulatory history, below.

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[223] North Carolina Utilities Commission, Docket No. E-2, Sub 826, Order Granting Motion for Reconsideration and Allowing Deferral of Costs, August 12, 2003, p. 8.
[224] North Carolina Utilities Commission, Docket No. E-7, Sub 1146 et al, Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction, pp. 164-165.
[225] North Carolina Utilities Commission, Docket No. E-100, Sub 56 et al, Joint Stipulation of Public Staff, CP&L, Duke Power, and NC Power, Guidelines for Determination and Reporting of Nuclear Decommissioning Costs, filed on August 11, 1998, pp. 1-2.

16.2.2.1 Duke Energy Carolinas

DEC has not included any decommissioning costs in rates since January 1, 2015.

In 2014, DEC filed a Cost Report and Funding Report that showed that, based on current project decommissioning costs and NDT balances, the company's NDT was adequately funded. The company concluded that additional contributions were not required and, hence, customer contributions to the NDT were suspended on January 1, 2015. This was implemented through a "decrement rider" as of July 1, 2015.[226]

In a subsequent rate case in 2017, the company again concluded that the NDT was adequately funded and that it need not collect any nuclear decommissioning expense, under the NRC's guidelines, as part of its cost of service.[227]

In this 2017 proceeding, Public Staff took the position that the NDT was, in fact, overfunded and that this overfunding should be reflected in a refund to consumers. Given that NDT funds cannot be refunded under the rules that govern NDT operation, Public Staff suggested instead a mechanism whereby utility shareholders would "loan" the funds to consumers, with this loan to be repaid once decommissioning has been completed (when presumably excess funds would remain in the NDT). Public Staff's assertion of NDT overfunding was based on the fact that excess funds at the time of decommissioning were projected at $2.5 billion, with figures quoted taking into account the proportion of decommissioning costs payable by North Carolina retail consumers.[228]

In its Order, NCUC found that a conclusion of overfunding was "premature", recognizing the uncertainty of many elements in the projection process. Specifically, the NCUC noted: [229]

> "The record shows that the NDTF [*i.e. NDT*] has experienced higher than expected returns recently, and the escalation rate used to forecast decommissioning costs has remained modest compared to historical rates of inflation, both of which have contributed to favorable results. Changes in assumptions for variables, including investment returns, escalation rates and decommissioning start or completion dates, will all impact future NDTF funding levels, as will deviation of future experience from current forecasts. In the judgment of the Commission, while the NDTF is currently adequately funded, it is premature to find and conclude that the NDTF is overfunded, and therefore, it would not be prudent to return funds to customers at this time, and perhaps for several years, even if it were legally permissible to do so."

In its Order, the Commission noted the following evidence that had been put forward by various witnesses in the proceeding:

- The overfunding would be eliminated if the cost escalation rate was changed from 2.40% to 3.09%. The latter figure is less than average inflation rate (of 3.24%) that was observed during the period 1913-2017.[230]
- Current NDT balances (in 2016 dollars) were less than current projected decommissioning costs (also in 2016). Thus, the NDT was underfunded on a "current dollars" basis.

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[226] North Carolina Utilities Commission, Docket No. E-7, Sub 1146 et al, Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction, p. 165.
[227] *Ibid*, p. 166.
[228] *Ibid*, p. 166.
[229] *Ibid*, p. 169.
[230] *Ibid*, p. 168.

- A probabilistic analysis showed that the NDT has a probability of actually being underfunded of from 15% to 23%. This was based on running 5000 Monte Carlo simulations that provided for variation in actual market returns and in escalation factors over the projection horizon.

This proceeding highlights the significant impact that variability in underlying economic assumptions and fund return rates can have on the calculations of required recoveries for long-term decommissioning obligations in a US state regulatory process. It also serves as an example of a regulator's reluctance to react to an apparent over-funding position that may be present for a relatively short period of the obligation's overall lifecycle.

17 Pennsylvania

17.1 Industry Structure

The electricity sector in Pennsylvania provides for retail open access, allowing consumers to select the supplier and plan for commodity supply that best suits their needs. The Pennsylvania Public Utility Commission's ("PAPUC") focus includes ensuring that residents have proper access to power and promotes growth within the industry.[231]

Like many other jurisdictions, Pennsylvania restructured its electricity sector to allow for open market competition in the late 1990's. As part of the restructuring process, utilities that were formerly vertically-integrated were required to separate their generation business units from their transmission and distribution activities. Retail consumers were given the right to select their commodity supplier. Large consumers were given the right to purchase directly from an electricity spot-market operated by PJM, a regional transmission organization.

The introduction of an open market was expected to lead to decreases in the cost of electricity and hence a reduction in earnings for existing generators. As a consequence, incumbent utilities with in-house generation were compensated through the introduction of "competitive transition charges" ("CTCs"). These charges were collected from utilities' existing customer bases, offsetting some of the savings that consumers would see from the introduction of competition, in order to help keep utility shareholders "whole" with respect to their existing investments (which were expected to lose value in an open-market). Under legislation, such stranded cost payments could be continued for a period of up to 10 years.[232]

Within Pennsylvania there are currently four nuclear power plants operated by three energy providers. These are summarized in Exhibit 17-1 below

Exhibit 17-1– Pennsylvania Nuclear Facilities[233]

Nuclear Facility	Owner	Year of License Expiration
Beaver Valley 1	Energy Harbor Corp	2036
Beaver Valley 2	Energy Harbor Corp	2047
Limerick 1	Exelon	2044
Limerick 2	Exelon	2049
Peach Bottom 2	Exelon	2053
Peach Bottom 3	Exelon	2054
Susquehanna 1	Talen Energy Corp	2042
Susquehanna 2	Talen Energy Corp	2044

231 Direct Energy, "Who are Major Players in the Pennsylvania Electricity Market?". Retrieved 23-11-2020
232 The 10-year limit assumed the use of "transition" bonds. See Pennsylvania Public Utility Commission, Opinion and Order, Docket R-00973953 and P-00971265, December 29, 1997, p. 104.
233 NRC, "Facilities Locator – Operating Reactors by Location or Name". Retrieved 2020-12-21.

The providers sell electricity in bulk to retail energy providers that sell directly to consumers. Based on data from NRC, nuclear electricity accounted for 39% of electricity generated in the state in 2017.[234] Pennsylvania was 2nd out of 30 states in terms of the generation of nuclear power in 2019, after Illinois.[235]

We have reviewed one energy provider, Exelon Generation, which operates four of the eight reactors in Pennsylvania.

Similar to Illinois, as one of the sample states with deregulated generation, we focused our review on the transition of responsibility for nuclear decommissioning costs from a regulated model to a competitive market structure for electricity generation.

17.2 Exelon Generation

As noted in Chapter 14 on Illinois, Exelon Generation is a subsidiary of Exelon and is one of the largest competitive generators of electricity in the United States. The company provides physical delivery of power across multiple geographical regions through Constellation, a customer facing business unit of Exelon Generation.[236] PECO, a subsidiary of Exelon, is a regulated transmission and distribution utility with a service territory in Southeastern Pennsylvania. Prior to deregulation, PECO also owned and operated the regulated nuclear operating assets in the state.

17.2.1 Regulatory Regime

Following sector restructuring, Exelon Generation operates in a competitive electricity market in Pennsylvania. However, legislation governing the state's electricity market restructuring process provided that stranded cost payments to utilities would include recovery of the "unfunded" portion of a utility's projected nuclear plant decommissioning costs.[237]

17.2.2 Rate Recovery

As part of the restructuring process, parties agreed that utility consumers in Pennsylvania should only be responsible for funding that portion of nuclear decommissioning expense associated with the period in which the plants were in service to the public, through January 1, 1999. Thus, PAPUC noted:

> "We agree with PECO's basic proposal that consumers should be responsible to fund that portion of nuclear decommissioning expense associated with the period in which the plants were in service to the public, through January 1, 1999. Similarly, we agree with PECO's proposal that it, or its affiliate or future owners of each plant, should be responsible for that portion of the

[234] NRC, "Information Digest, 2019-2020" (NUREG-1350, Volume 31), p. 28.
[235] U.S. Energy Information Administration, U.S. Nuclear Generation and Generating Capacity, Data Released 2020-11-30.
[236] Exelon Corporation 2019 Annual Report, p.223.
[237] Pennsylvania Public Utility Commission, Opinion and Order, Docket R-00973953 and P-00971265, December 29, 1997, p. 67.

> decommissioning cost related to its remaining useful life. Post-1998 decommissioning expenses are properly reflected as a future operating expense that affects the market value of the plants."[238]

PECO initially claimed recovery of $233.8 million in respect of unfunded nuclear decommissioning costs, an amount which was to be included in the calculation of future stranded cost payments. Ultimately, however, PAPUC decided to recover decommissioning costs through an annuity that would be collected through PECO's regular rates for the distribution and transmission business, rather than as part of the stranded cost levy. It was believed that including nuclear decommissioning costs as a stranded cost could preclude favourable tax treatment.[239]

PECO agreed to accept an annuity payment of $22.7 million as part of its regulated cost of service rates in lieu of claiming a stranded cost amount of $233.8 million for nuclear decommissioning. The $22.7 million amount was found to be "almost identical" to the amounts that were included in PECO's vertically integrated rates prior to the deregulation, leading to no net effect on the rates.[240]

As part of the restructuring and merger settlements, PECO is required to file a Nuclear Decommissioning Cost Adjustment ("NDCA") every five years. The NDCA is to reflect updated cost studies and fund balances as well as license expenses.

Exelon's annual report summarizes the arrangements described above as follows:

> "PECO is authorized to collect funds, in revenues, for decommissioning the former PECO nuclear plants through regulated rates, and these collections are scheduled through the operating lives of the former PECO plants. The amounts collected from PECO customers are remitted to Generation and deposited into the NDT funds for the unit for which funds are collected." [241]

Through periodic rate adjustments, Exelon Generation, through PECO, may collect additional amounts from customers related to NDT shortfalls for the former PECO units, but these amounts are subject to thresholds stated by the PAPUC. Specifically, Exelon Generation must bear the first $50 million of any shortfall, as well as 5% of any additional shortfalls, on an aggregate basis for all former PECO units.[242]

Based on these findings, we conclude that PECO consumers continue to pay for decommissioning costs in rates, even though the nuclear units are no longer regulated. This includes true-ups to amounts recovered, which may arise due to changes in the estimates of decommissioning costs, changes in operating lifespan, variability in trust fund performance and other such factors discussed throughout this report.

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[238] Pennsylvania Public Utility Commission, Opinion and Order, Docket R-00973953 and P-00971265, December 29, 1997, p. 78.
[239] It was believed that stranded cost payments may not quality as contributions for direct deposit into an NDT and hence may not receive favourable tax treatment. If they did not qualify, trust fund earnings could then be taxed at a higher rate.
[240] Pennsylvania Public Utility Commission, Opinion and Order, Docket R-00973953 and P-00971265, December 29, 1997, p. 80.
[241] Exelon Corporation 2019 Annual Report, p.273
[242] The most recent PECO rate adjustment for nuclear decommissioning costs was in 2018. This adjustment resulted in a substantial reduction in amounts collected from PECO consumers for nuclear decommissioning, due to the extension of the operating licences for Limerick Units 1 and 2 for an additional 20 years. The decrease in annual recovery was from approximately $24 million to $4 million. (Exelon Corporation 2018 Annual Report, p.388)

We also observe that while the overall process for considering the impact on decommissioning cost recovery as a result of market de-regulation was similar for Exelon Generation in both Pennsylvania and Illinois (discussed in Chapter 14, there were important differences in the final outcome, as follows:

- In Illinois, the company's right to recover decommissioning costs post market opening did not extend beyond a defined period, unlike the ongoing right to such recovery in Pennsylvania. The company must fund NDT contributions through market revenues in Illinois beyond 2007.
- The company does not have the ability to seek recovery from utility consumers in Illinois in the event that NDT funds are insufficient. Shareholders will have to make up any shortfall. If surpluses do arise, however, the company will have to remit funds to consumers of the utilities supplied by the nuclear units prior to market restructuring.
- The company's obligations with respect to shortfalls or excesses are evaluated in Illinois on a unit-by-unit basis, whereas obligations in Pennsylvania are evaluated for the former PECO units in aggregate.

17.2.3 Other Observations

17.2.3.1 Decommissioning Cost Probabilistic Analysis

In our review of Exelon's annual report, we noted that Exelon Generation uses certain probabilistic analyses to determine its decommissioning cost estimate for ARO purposes.

As a general matter, Exelon Generation uses site-specific cost estimates to determine its decommissioning obligations and updates them every five years, as noted below:

> "[Exelon] Generation uses unit-by-unit decommissioning cost studies to provide a marketplace assessment of the expected costs (in current year dollars) and timing of decommissioning activities, which are validated by comparison to current decommissioning projects within the industry and other estimates. Decommissioning cost studies are updated, on a rotational basis, for each of Generation's nuclear units at least every five years, unless circumstances warrant more frequent updates."[243]

It also appears that Exelon Generation takes into account multiple scenarios in determining the cost estimate for financial accounting purposes:

> "To estimate its decommissioning obligation related to its nuclear generating stations for financial accounting and reporting purposes, Generation uses a probability-weighted, discounted cash flow model which, on a unit-by-unit basis, considers multiple outcome scenarios that include significant estimates and assumptions, and are based on decommissioning cost studies, cost escalation rates, probabilistic cash flow models and discount rates. Generation updates its ARO annually unless circumstances warrant more frequent updates, based on its review of updated cost studies and its annual evaluation of cost escalation factors and probabilities assigned to various scenarios."[244]

[243] Exelon Corporation 2019 Annual Report, p.74.
[244] Exelon Corporation 2019 Annual Report, p.272.

Examples of scenarios included are: costs that are 20% higher and 15% lower than the “base cost” scenario; different decommissioning approaches, including DECON and SAFSTOR; and different operating lives based on 20-year licence renewal periods.[245]

These probabilistic scenario analyses, however, appear to be used only for Exelon’s accounting provisions. Filings with the NRC, which are the basis of rate recoveries, have used point estimates for various factors.[246]

[245] Exelon Corporation 2019 Annual Report, p.74.
[246] Exelon Nuclear, Report on Status of Decommissioning Funding for Shutdown Reactors, Letter to U.S. Nuclear Regulatory Commission, March 30, 2012. Attachments 1, 2 and 3.

18 South Carolina

18.1 Industry Structure

The electricity sector in South Carolina remains regulated, with vertically-integrated utilities that supply power to their respective retail customer bases. The Public Service Commission of South Carolina ("PSCSC") is the body that regulates retail rates.

Duke Energy, through its subsidiaries DEC and DEP, has ownership stakes in six out of the seven reactors in South Carolina. As discussed in Chapter 15, DEC and DEP also operate the nuclear reactors in North Carolina.

In addition to the six reactors in the state owned by Duke Energy, there is a seventh reactor (Virgil C. Summer Unit 1 or "Summer Unit 1") that is owned jointly by Dominion Energy South Carolina (formerly South Carolina Electric and Gas Company or "SCE&G") and the South Carolina Public Service Authority ("Santee Cooper"). SCE&G has a two-thirds ownership share while Santee Cooper owns the remaining third in the reactor. SCE&G is an investor-owned utility while Santee Cooper is a "component unit" of the State of South Carolina.

The ownership breakdowns and years of license expiration for the seven reactors in South Carolina are summarized in Exhibit 18-1.

Exhibit 18-1[247, 248] – South Carolina Nuclear Facilities

Nuclear Facility	Owner	Ownership Stake	Year of Expiration
Oconee Nuclear Station, Unit 1	Duke Energy Carolinas	100%	2034
Oconee Nuclear Station, Unit 2	Duke Energy Carolinas	100%	2033
Oconee Nuclear Station, Unit 3	Duke Energy Carolinas	100%	2033
H.B. Robinson Nuclear Plant, Unit 2	Duke Energy Progress	100%	2030
Catawba Nuclear Station, Unit 1	Duke Energy Carolinas	19.25%	2043
	North Carolina Municipal Power Agency #1	37.50%	
	North Carolina El Member Corp	30.75%	
	Piedmont Municipal Power Agency	12.50%	
Catawba Nuclear Station, Unit 2	Duke Energy Carolinas	19.25%	2043
	North Carolina Municipal Power Agency #1	37.50%	
	North Carolina El Member Corp	30.75%	
	Piedmont Municipal Power Agency	12.50%	
Virgil C. Summer Nuclear Station, Unit 1	Dominion Energy South Carolina	67.67%	2042
	South Carolina Public Service Authority	33.33%	

247 NRC, "Facilities Locator – Operating Reactors by Location or Name". Retrieved 2020-12-21.
248 U.S. Energy Information Administration, "Nuclear Reactor Ownership". Retrieved 2020-12-21.

Based on data from NRC, nuclear electricity accounted for 58% of electricity generated in the state in 2017.[249] South Carolina was third out of 30 states in terms of the generation of nuclear power in 2019.[250]

As we reviewed regulatory mechanisms applicable to DEC and DEP in North Carolina, we focused our research on SCE&G and Santee Cooper as case studies for South Carolina.

18.2 Dominion Energy South Carolina

As noted earlier, SCE&G operates the Virgil C. Summer Unit 1 ("Summer Unit 1"), which entered commercial operations in 1984.

SCE&G has recently undergone significant financial turmoil as a result of the forced cancellation of its project to add two new additional reactors at the Virgil C. Summer site. Following bankruptcy of a key vendor and faced with the prospect of having to refund amounts already collected for the project in rates, SCE&G's parent company, SCANA Corporation ("SCANA"), was ultimately acquired by Dominion Energy in 2019, and the entity has been renamed Dominion Energy South Carolina, Inc.[251]

Given the scope of the study, we did not focus on developments related to the proposed new units and to subsequent regulatory proceedings relating to the recovery of the cancelled project's costs. Rather, we have summarized our findings related to the recovery of decommissioning costs for Summer Unit 1.

18.2.1 Regulatory Regime

Retail electric base rates in South Carolina are regulated on a cost-of-service/rate-of-return basis subject to South Carolina statutes and the rules and procedures of the PSCSC. South Carolina base rates are set by a process that allows SCE&G to recover its operating costs and a return on invested capital.

18.2.2 Rate Recovery

Based on our review of the regulatory record and SCE&G's publicly available financial statements, we have concluded that SCE&G is subject to a forward-looking NDT funding approach for recovery of nuclear decommissioning costs. Our review of regulatory record focused primarily on PSCSC's 2003 accounting order that addressed recovery methodology for nuclear decommissioning costs in light of the introduction of the FAS 143 accounting standard , as well as documentation in the NRC filings. The FAS 143 order is discussed in section 18.2.2.1 following.

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[249] NRC, "Information Digest, 2019-2020" (NUREG-1350, Volume 31), p. 28.
[250] U.S. Energy Information Administration, U.S. Nuclear Generation and Generating Capacity, Data Released 2020-11-30.
[251] SCE&G had a contract with Westinghouse Electric Company ("WEC") to build the new reactors. In 2017, WEC filed for bankruptcy protection under Chapter 11 of the US Bankruptcy Code and subsequently notified SCE&G that it would be unable to complete the units under the fixed price terms previously agreed. SCE&G ultimately decided to cancel the project, which left it with the prospect of having to refund amounts already collected for the projects in rates. These events resulted in the company's credit rating falling below investment grade. (SCANA Corporation, Form 10-K, December 31, 2017, p. 35, 44)

According to a filing with the NRC, SCE&G's allowance in rates for nuclear decommissioning costs has remained unchanged since 1993. In June 1993, PSCSC approved gross annual collections for decommissioning in the amount of $3.22 million based on cost estimates contained a 1991 site-specific study.[252] Of the $3.22 million, $2.86 million, relates to items included in the NRC's definition of radiological decommissioning.[253]

The balance of the cost estimates is considered to relate to non-radiological segments of the decommissioning process (e.g. site restoration), which are not within the scope of the NRC financial assurance process (and hence not required to be covered by trust fund balances).[254]

In the historical NRC filings reviewed going back a number of years, the amount of $2.86 million (before tax) has been used consistently as the basis of projected contributions to NDTs.[255,256] However, we note that these contributions are being treated in the NRC filings as if they are in real dollar terms, whereas the historical record is consistent with these contributions (and associated allowances in rates) being flat in nominal dollar terms (and hence declining in real dollar terms).

The ability to keep the same (before-tax) funding contributions over-time may have been influenced by the following factors:

- The operating license of Summer Unit 1 was extended by 20 years in 2004, extending the investment horizon.
- The original contributions were based on site-specific estimates while funding reports to the NRC are based on decommissioning cost estimates that are based on the NRC formula (and which may therefore result in lower costs).
- The filing with the NRC notes that financial assurance is demonstrated using cost estimates that assume the use of the DECON decommissioning, whereas SCE&G currently intends to utilize a deferred decommissioning methodology (SAFSTOR). [257,]

Overall, we find this case study to be an example of rate recovery that is ultimately not closely linked to the actual utility decommissioning plans and underlying cost estimates.

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[252] SCANA's 2017 annual report similarly noted that "SCE&G transfers to an external trust fund the amounts collected through rates ($3.2 million pre-tax in each period presented), less expenses." (SCANA Corporation 2017 Annual Report, p. 78)

[253] SCE&G, Report of Status of Decommissioning Funding, letter to NRC, March 28, 2018, RC-18-0041, Attachment II.

[254] The 1993 Order approving SCE&G rates is available on-line but it has relatively limited discussion of the basis for approval of rates for nuclear decommissioning. For example, it does not specifically reference the $3.22 million figure noted above nor does it provide details as to how the decommissioning allowance was established. This appears to be because the Order approved a settlement, or "stipulation", between PSCSC staff and the utility and hence the Order focused on issues where the parties had disagreed in the proceeding. Supporting documentation in the proceeding is not available on-line.

[255] For example: SCE&G, Report of Status of Decommissioning Funding, letter to NRC, March 31, 2011, RC-11-0049, Attachment II; SCE&G, Report of Status of Decommissioning Funding, letter to NRC, March 28, 2003, RC-03-0073, Attachment II.

[256] The contributions net of tax have varied over the years because of changes in income tax rates.

[257] SCE&G, Report of Status of Decommissioning Funding, letter to NRC, March 28, 2019, SN-19-145, page 8,

18.2.2.1 Treatment of FASB 143

In a 2003 proceeding, the PSCSC issued an accounting order allowing utilities in South Carolina to place costs associated with AROs in a "deferred account" for regulatory accounting purposes and affirming the continuation of the forward-looking NDT funding approach previously in place. The order followed the adoption of FASB 143, and is similar to those in Florida, Georgia, North Carolina and, in some regard, Minnesota.

Utilities with nuclear operations requested the order, arguing that the regulatory treatment then (and still) in place for decommissioning costs should not be altered due to the adoption of FASB 143. In their petition to the PSCSC, the utilities noted:[258]

- FASB 143 requires utilities to measure their liability at fair market value, if available, or to estimate fair market value using the expected present value method. An estimate of the fair value would include third-party profit and market risk premiums, even though the utility may have no intent of settling its liability with such a third party and there may be no market for such settlement.
- FASB 143 does not consider the effect of expected earnings on funds collected when calculating the ARO expense, whereas the Commission-approved methodology does.

The PSCSC accepted the utilities' petition and, in its order, noted:

> "We believe that the Joint Petitioner's have stated a great many reasons for the Proposition that the current regulatory treatment for AROs should not be altered at this time due [*to*] the Joint Petitioners' adoption of FASB Statement 143. First, this Commission did establish specific levels of decommissioning costs to be included in rates in the Joint Petitioners' rate cases. We agree with the Joint Petitioner's belief that Statement 143 is not more appropriate for ratemaking purposes than the current Commission-approved decommissioning cost levels. Further, Statement 143 does not consider the effect of expected earnings on funds collected when calculating the ARO expense, whereas the Commission-approved methodology currently included in the Joint Petitioners' South Carolina retail rates reflects this cost offset."[259]

As similar orders did in other states, this finding supported the ability of regulated nuclear utilities in South Carolina to record regulatory assets or liabilities for differences between FAS 143 expenses less NDT earnings and funding-based amounts recovered in rates. In addition to the order itself, it is the fact that utilities would expect to recover their ultimate ARO costs over the long-term by virtue of having been on a funding method from inception that allowed recognition of such regulatory balances under US GAAP.

18.3 South Carolina Public Service Authority

Santee Cooper owns a one-third share of Summer Unit 1 operated by SCG&E. It was also a participant in the planned construction of Units 2 and 3 and hence has also faced financial challenges associated with the projects' cancellation. As Santee Cooper is a state authority, the state government subsequently established an oversight committee to provide greater oversight of Santee Cooper and

[258] Public Service Commission of South Carolina, Order Approving Accounting Treatment, Docket 2003-84-E, Order No. 2003-283, April 28, 2003, p. 4.
[259] *Ibid*, pp. 6 – 7.

has called on the Office of Regulatory Staff ("ORS") to conduct monthly reviews of its operations.[260] ORS is the agency that represents the "public interest" in proceedings of the PSCSC.

18.3.1 Regulatory Regime

Unlike SCE&G, Santee Cooper's rates are not regulated by PSCSC. Historically, it has adjusted rates as necessary to meet certain financial targets and cover its costs. According to its annual report, its governing statue provides that:

> "the Authority will establish rates and charges so as to produce revenues sufficient to provide for payment of all expenses, the conservation, maintenance and operation of its facilities and properties and the payment of the principal and interest on its notes, bonds, or other obligations, specifically."[261]

Santee Cooper is required to give 60 days notice of its plans to raise rates.

As part of a reform plan introduced subsequent to cancellation of the nuclear plants, Santee Cooper has committed not to raise rates through to 2024.[262]

Our review focuses on the comparison to SCE&G of the funding of decommissioning costs. Since the entities have ownership interest, this comparison shows the variability in the use of assumptions in determining funding requirements.

18.3.2 Rate Recovery

We conclude that Santee Cooper recovers a provision for decommissioning costs on a forward-looking funding basis. Our conclusion was based on a review of Santee Cooper's 2019 annual report which describes the process as follows:

> "The NRC requires a licensee of a nuclear reactor to provide minimum financial assurance of its ability to decommission its nuclear facilities. In compliance with the applicable regulations, the Authority established an external trust fund and began making deposits into this fund in September 1990. In addition to providing for the minimum requirements imposed by the NRC, the Authority makes deposits into an internal fund in the amount necessary to fund the difference between a site-specific decommissioning study completed in 2016 and the NRC's imposed minimum requirement. Based on these estimates and assuming a SAFSTOR (delayed) decommissioning, the Authority's one-third share of the estimated decommissioning costs of Summer Nuclear Unit 1 equals approximately $415.1 million in 2016 dollars. As deposits are made, the Authority debits FERC account 532 – Maintenance of Nuclear Plant, an amount equal to the deposits made to the internal and external trust funds. These costs are recovered through the Authority's rates."[263]

[260] Santee Cooper, Investor Presentation – Revenue Obligations, October 20, 2020, p. 12.
[261] Santee Cooper, 2019 Annual Report, Management's Discussion and Analysis, p. 14.
[262] Santee Cooper, Investor Presentation – Revenue Obligations, October 20, 2020, p. 13.
[263] Santee Cooper, 2019 Annual Report, p. 63.

18.3.3 Other Observations

18.3.3.1 Funding Amounts for Jointly Owned Facility

As both SCE&G and Santee Cooper have ownership interest in the same nuclear plant, we were able to compare some of the assumptions used in determining funding requirements by both entities, which we found to be instructive. Below we compare reports submitted by each entity to NRC in 2013 (this is a year for which we were able to find reports for both entities).[264,265]

Observations from the comparison are as follows:

- Both reports start with a decommissioning cost estimate for the whole plant of $493.9 million (in 2012 dollars). Santee Cooper takes a one-third share, while SCE&G takes a two-thirds share, according to their respective ownership.
- Both reports provide schedules in constant dollars. Assumed real rates of return by Santee Cooper varied annually and were calculated by subtracting assumed cost escalation rates in each year from projected nominal yields. Generally, real rates of return were around 1.0%. In contrast, SGE&G used a constant real return of 2.0% (consistent with its recent 2018 report).
- Starting fund balances for Santee Cooper were $114.4 million, while those of SCE&G were $132.0 million. These amounts are not in proportion to the entities' ownership interests, likely reflecting historical contribution profiles and achieved investment earnings.
- Projected ending balances (in 2049) were $57.2 million (i.e. in surplus) for Santee Cooper while negative $92.8 million for SCE&G (i.e. in deficit). Interestingly, these figures also highlighted that the status reports do not necessarily need to project funding adequacy at any given point in time, although utilities showing an ending deficit may subsequently need to make adjustments to the funding plan or provide explanations for why funding will be adequate. (SCG&E noted that it would use a delayed approach to decommissioning that would allow greater earnings to accrue.)
- Santee Cooper showed annual deposits of $1.977 million (treated as a constant real dollar amount), while SCE&G showed annual deposits of $1.766 million. These projected contributions were not proportionate to the ownership interests, reflecting differences in other inputs into the funding calculation as summarized here.

This comparison highlights that, even for utilities that share ownership in one facility, funding projections and contributions in regulated rates may be widely different depending on underlying assumptions, approaches and possibly investment performance.

[264] Santee Cooper, Report of Status of Decommissioning Funding, March 28, 2013.
[265] SCE&G, Report of Status of Decommissioning Funding, letter to NRC, March 27, 2013, RC-13-0051.

Part II - Canada

19 NB Power

Electricity in the province of New Brunswick is supplied by NB Power, a provincial Crown corporation. NB Power is a vertically-integrated utility, providing generation, transmission and distribution services. A number of municipalities in the province operate their own distribution utilities and purchase power from NB Power on a wholesale basis.

New Brunswick originally intended to restructure its electricity sector to provide for an open electricity market, and which was to follow the model that had been adopted in Ontario. As a result, the operations of NB Power were separated in 2003 into individual operating companies covering generation, transmission, distribution and the system operator function. The restructuring process was suspended, however, and individual operating companies within NB Power were re-integrated into one corporate entity in 2013.

NB Power operates one nuclear unit of 660 MW capacity at Point Lepreau. This plant supplied approximately 27% of total New Brunswick's supply requirements in Fiscal 2019 (year ending March 31).[266] Point Lepreau went through a refurbishment process in 2008 through 2012.[267]

19.1.1 Regulatory Regime

NB Power is operating under a long-term plan to improve its financial position; this will include debt reduction in the near term. It has a legislated target to achieve at least a 20% equity level in its capital structure, compared to 7% as of Fiscal 2019.[268] Under legislation, NB Power must prepare annual 10-year plans that show its progress in meeting its financial target. The recent 10-year plan dated September 2019 ("10-Year Plan") projects that NB Power will reach its target capital structure by Fiscal 2027. The plan calls for average rate increases of 2.00% through to Fiscal 2021, 1.75% for Fiscal 2022 and 2023, and 1.50% thereafter through to Fiscal 2028.[269]

The New Brunswick Energy and Utility Board ("NBEUB") is the provincial agency with responsibility for regulating public utilities. The legislative requirements for setting NB Power's rates pursuant to the 10-year plans have reduced the effective scope of the NBEUB's reviews of NB Power activity..

The 10-year plans entail applying specified percentage rate increases during the forecast period. These increases are intended to ensure that NB Power's equity levels move toward the target level. Specifically, the 10-year Plan describes the rate-setting approach as follows:

> "The rate strategy is based on the principles of making steady progress towards the achievement of a minimum capital structure of 20% equity within a reasonable timeframe and maintaining the minimum equity target once achieved, while attempting to maintain rates as low as possible and reducing variability in rate changes from year to year."[270]

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[266] NB Power 2018/2019 Annual Report, p. 21.
[267] NB Power 2018/2019 Annual Report, p. 32.
[268] NB Power 2018/2019 Annual Report, p. 35.
[269] NB Power's 10-Year Plan: Fiscal Years 2021 to 2030, September 2019, p. 5.
[270] NB Power's 10-Year Plan: Fiscal Years 2021 to 2030, September 2019, p. 6.

19.1.2 Rate Recovery

In considering the basis upon which NB Power recovers its decommissioning and waste management costs under the above noted methodology, we considered the basis of measurement of equity and the achievement of equity targets that are the basis of the rates. Based on our review of the 10-Year Plan and NB Power's annual report discussed below, we concluded that the definition of equity uses NB Power's accounting measurements of income. Decommissioning and waste management costs are provided for in NB Power's financial results and are thus accounted for in the achievement of the financial targets. On this basis, the rates effectively provide for the recovery of decommissioning and waste management costs in the manner recorded in NB Power's financial statements (under IFRS).

With respect to decommissioning and used fuel management costs, the 10-Year Plan notes the following that outlines the inclusion of depreciation expense, accretion expense and earnings on sinking funds in the equity calculation:

- "Depreciation expense is driven by NB Power's investment in capital assets and is based on expected useful service lives and the straight-line method of depreciation. Depreciation expense also reflects a component of charges to income to account for the future decommissioning of generating stations and the management of used nuclear fuel."[271]
- "Other components of finance charges and other income partially offset interest expense and the debt portfolio management fee. These include earnings on investment and sinking funds, as well as interest during construction which capitalizes interest on funds expended on capital projects not yet in service (i.e. work-in-progress). Finance charges also include an expense that recognizes the time value of money on the estimated expenditures for decommissioning and used nuclear fuel management liabilities. This is referred to as accretion expense and essentially represents an annual interest charge on these forecasted liability balances."[272]

In our review of NB Power's annual report, we identified the corresponding AROs related to nuclear decommissioning and used fuel management that are recognized on the balance sheet as follows: [273]

- The costs of decommissioning stations at the end of their useful lives.
- The fixed-cost portion of used nuclear fuel management activities (i.e. that portion that will be required regardless of the volume of fuel consumed).
- The variable-cost portion of used nuclear fuel management activities to take into account actual fuel volumes used to-date.

The annual report also notes that the liability for used nuclear fuel management is increased for the cost of disposing the nuclear fuel bundles used each year, with the corresponding amounts charged to operations through fuel expenses.[274]

Accretion expense is calculated annually on the liabilities for nuclear decommissioning, including for spent fuel and waste management.[275] It is calculated using NB Power's credit adjusted risk-free rate and a duration spread to take into account the long-term nature of the associated liabilities.

[271] NB Power's 10-Year Plan: Fiscal Years 2021 to 2030, September 2019, p. 16.
[272] NB Power's 10-Year Plan: Fiscal Years 2021 to 2030, September 2019, p. 17.
[273] NB Power 2018/2019 Annual Report, p. 63.
[274] NB Power 2018/2019 Annual Report, p. 63.
[275] Under IFRS, NB Power classifies accretion expense as a finance cost in the financial statements.

Realized and unrealized investment income on NB Power's trust funds for decommissioning and used fuel management is primarily recognized through earnings.[276]

There are no regulatory accounts associated with nuclear decommissioning and waste management costs reported in the 10-Year Plan or the company's annual report.

19.1.3 Other Observations

Decommissioning Obligations and Segregated Funds

In this section, we set out, for reference purposes, information from NB Power's Fiscal 2019 annual report related to decommissioning and waste management liabilities and associated segregated funds.

Exhibit 19-1 provides details on the AROs for nuclear decommissioning and used fuel management reported in NB Power's Fiscal 2019 annual report, as rolled forward from Fiscal 2018.

Exhibit 19-1 – NB Power Nuclear Asset Retirement Obligation

Nuclear Decommissioning Liabilities ($ Millions)			
	Nuclear plant decommissioning liability	**Used fuel management liability**	**Total**
Balance, March 31, 2018	381	313	694
Add: Change in discount rate and cost estimate	30	32	62
Add: Accretion	17	15	32
Less: Expenditures	(2)	7	5
Balance, March 31, 2019	426	353	779

NB Power has established segregated trust funds in order to meet the CNSC's licence conditions for the Point Lepreau plant and to meet requirements under the Nuclear Fuel Waste Act. These are summarized in Exhibit 19-2 below:

[276] In accordance with IFRS 9, investments by these funds are either fair value through other comprehensive income, or fair value through profit or loss. The vast majority of the investments are disclosed as being under fair value through profit or loss. (NB Power 2018/2019 Annual Report, pp. 69, 93)

Exhibit 19-2 – NB Power Decommissioning Trust Funds[277]

Segregated Trust Funds				
Fund	**Purpose**	**Funding Requirement**	**Fiscal 2018 Contributions**	**Fiscal 2019 Contributions**
Decommissioning segregated fund & used nuclear fuel segregated fund	To meet licensing requirements set by the CNSC	Determined annually based on the current obligations and market value of the funds	nil	nil
Nuclear Waste Trust Fund	To meet the Nuclear Fuel Waste Act and CNSC requirements	Determined by funding formula in Nuclear Fuel Waste Act.	$11 million	$4 million

Balances in these funds totaled $766 million at the end of Fiscal 2019. [278]

[277] NB Power 2018/2019 Annual Report, p. 75
[278] NB Power 2018/2019 Annual Report, p. 44.

20 Hydro-Québec

Power in the province of Quebec is supplied by Hydro-Québec, a provincial Crown corporation. Hydro-Québec has separate business segments associated with generation, transmission and distribution. (The segments operate within a single corporate entity but have separate reporting.)

Under Hydro-Québec's governing legislation, the distribution segment has access to a base volume of power, referred to as the Heritage Pool, from the generation segment. Thus, the generation segment makes available up to 165 TWh of electricity at a fixed price indexed under the *Act respecting the Régie de l'énergie.* For requirements not supplied through the Heritage Pool, the distribution segment runs open market procurement processes, to which the generation segment can respond.

Hydro Québec operated one nuclear reactor, Gentilly-2, between 1983 and 2012.

The plant is set to be dismantled after a more than 40-year planned dormancy period.[279]

20.1 Regulatory Regime

The electricity market structure in place in Quebec means that there is no regulatory oversight of the recovery of nuclear decommissioning and waste management costs. Further, the Heritage Pool price is not directly linked to underlying costs within the generation segment, including for nuclear decommissioning. Hence, no link can be drawn between funding for nuclear decommissioning and rates paid by consumers.

The provincial economic regulator, the Régie de l'énergie, approves tariffs and makes associated decisions on capital structure only for the transmission and distribution segments of Hydro-Québec.

20.2 Rate Recovery

As Hydro-Québec's generation business receives revenues from a competitive electricity market or under a fixed price, there is no observable link between the prices and recovery of nuclear decommissioning and waste management costs.

[279]Hydro-Québec Decommissioning Plan, filed with the Canadian Nuclear Safety Commission in March 2020.

21 Ontario Power Generation

OPG is an Ontario-based electricity generation company that is wholly-owned by the Province of Ontario. OPG and its wholly-owned subsidiaries own and operate two nuclear generating stations (Pickering and Darlington), 66 hydroelectric generating stations, three thermal generating stations and one solar facility in Ontario. OPG also owns two nuclear generating stations in Ontario, the Bruce A and Bruce B stations ("Bruce stations"), which are leased on a long-term basis to Bruce Power L.P. (Bruce Power). [280]

OPG is Ontario's largest electricity producer. In 2019, it accounted for approximately 50 percent of the total energy generated on Ontario's electricity system.[281]

The Pickering and Darlington generating stations have a total in-service capacity of approximately 6,600 MW, when all units are in operation. [282] Pickering's operating licence allows for commercial operation of the station to December 31, 2024. [283]. Darlington's four generating units are undergoing refurbishment to extent its operating life for another 30 years. [284]

Prior to 1999, Ontario Hydro served as a vertically integrated electric utility in Ontario. Following the adoption of a restructuring plan for Ontario's electricity industry, several successor organizations to Ontario Hydro began operating as separate entities on April 1, 1999, including:

- OPG, which purchased the electricity generation and wholesale energy businesses of Ontario Hydro;
- Hydro One, which purchased and assumed the transmission, distribution and retail energy services businesses of Ontario Hydro;
- Independent Electricity Market Operator (now the Independent Electricity System Operator), which was formed to act as both the independent electricity system operator and the market operator.

Ontario's competitive electricity market was opened in 2002. The market is used to manage the purchase and sale of wholesale electricity in the province. [285]

Virtually all non-OPG generators in Ontario currently have energy supply contracts with the IESO that provide for payments that are different from the market price of electricity.

Effective April 1, 2008 onwards, the prices for OPG's Pickering and Darlington generation and most of its hydroelectric generation in the province are set by the OEB. OPG is the only regulated generator in Ontario. [286] For the period April 1, 2005 to March 31, 2008, the prices for OPG's regulated generation were set by Ontario Regulation 53/05.[287]

[280] Ontario Power Generation Inc. 2019 Annual Information Form, p. 3
[281] *Ibid*, p. 3
[282] *Ibid*, p.14
[283] *Ibid*, p.16
[284] *Ibid*, p.46
[285] *Ibid*, p. 6
[286] *Ibid*, p. 7
[287] O. Reg. 53/05, s. 4., Payments Under Section 78.1 of the Act. (*since revoked*)

21.1.1 Regulatory Regime

OPG's regulated rates are set by the OEB pursuant to the Ontario Energy Board Act, 1998 and Ontario Regulation 53/05. Ontario Regulation 53/05 sets out certain requirements for the OEB to follow in setting OPG's regulated rates. Among them is a requirement to ensure OPG recovers the revenue requirement impact of its nuclear decommissioning and waste management costs, and also that OPG recovers its costs associated with the leased Bruce stations.[288]

OPG's nuclear rates set by the OEB are generally designed to permit the company to recover, over a forecasted generation volume, an allowed level of operating costs and capital investment and to earn a formulaic rate of return on a deemed equity portion of the capital invested in the rate base. Rate base for OPG represents investment in regulated fixed and intangible assets in service and an allowance for working capital. Beginning with the 2017-2021 rate period, the OEB has transitioned OPG from a cost of service framework to a custom incentive regulation framework. This framework applies an efficiency stretch factor to certain elements of OPG's cost-based nuclear revenue requirement.[289]

21.1.2 Rate Recovery

As part of this report, we reviewed OPG's historical regulatory filings and OEB decisions related to the recovery of the company's decommissioning and waste management costs. In OPG's first rate-setting application before the OEB, EB-2007-0905, the OEB approved a methodology for the recovery of such costs for the regulated nuclear facilities and the Bruce facilities. The methodology has been followed ever since. There are some differences between the methodology for the regulated and Bruce stations, and therefore each methodology is discussed in turn below.

21.1.2.1 Regulated Nuclear Facilities

The approved regulatory treatment of the nuclear decommissioning and waste management costs is based on OPG's financial accounting values, with application of regulatory constructs. OPG's financial statements are prepared in accordance with US GAAP and therefore OPG recognizes the effects of decommissioning and nuclear waste management costs in accordance with ASC 410-20, Asset Retirement Obligations (formerly FAS 143).

The ratemaking approach takes into account the following:[290]

- Depreciation of the ARC on the basis reported in OPG's financial statements (ARC is considered to be a component of rate base);
- Return on the undepreciated ARC at the weighted average accretion rate of the ARO balance as reported in OPG's financial statements.[291] This accretion rate is applied to the lesser of the "unfunded nuclear liabilities" ("UNL") or undepreciated ARC. The portion of undepreciated ARC in excess of the average UNL, if any, receives a return on rate base at OPG's approved weighted average cost of capital. UNL is calculated as the difference between the ARO

[288] The regulation also requires that OPG's rates be reduced by the revenues the company earns with respect any lease of the Bruce stations.
[289] Ontario Power Generation Inc. 2019 Annual Information Form, p. 9
[290] EB-2016-0152, Exhibit C2, Tab 1, Schedule 1, May 27, 2016, P.8
[291] The weighted average accretion rate is the average of the discount rates used to establish each ARO tranche in accordance with US GAAP, weighted by the value of each tranche.

liability and segregated fund assets for decommissioning and waste management on the basis reported in the company's financial statements; and

- The variable used fuel management and waste management expenses related to incremental quantities of fuel and low and intermediate level waste generated in each period.

Accretion expense on the ARO and the earnings on segregated funds are excluded from the revenue requirement. In effect, it appears the OEB's approved methodology effectively replaced these elements of financial accounting income and expense with a regulatory construct that applied the 'lesser of' formula above.

In directing the use of this 'lesser of' approach in EB-2007-0905, the OEB recognized that accretion expense represents a incurred cost:

"The Board disagrees with CCC's submission that OPG should earn no return on unfunded amounts. Clearly, OPG incurs accretion expense (at an average rate of 5.6%) on its nuclear liabilities whether they are funded or not."[292]

It also appears that the OEB recognized that a portion of OPG's to-be-recovered ARC may already be funded (by virtue of amounts contributed to the segregated funds) when it set out the application of the 'lesser of' approach:

"When the average unfunded nuclear liabilities exceed the amount of unamortized ARC in fixed assets, then the portion of rate base that attracts the 5.6% return [i.e. weighted average accretion rate at the time] would be capped at the average amount of unamortized ARC; if the average unfunded liabilities are forecast to be lower than the average unamortized ARC, it is appropriate to limit the portion of rate base that attracts the 5.6% return to the unfunded amount. That approach recognizes that OPG has raised debt (or used its retained earnings) to fund part of the unamortized ARC."[293]

Consideration of FAS 143 Treatment in Other Jurisdictions

The discussion in the OEB's EB-2007-0905 decision highlighted the possibly unique position of the regulator with respect to OPG's nuclear facilities entering regulation after the adoption of FAS 143 (and its then-Canadian equivalent CICA Handbook Section 3110), compared to historically regulated US utilities. In effect, the OEB had to establish an initial method of recovery in different circumstances than its counterparts. Some of the OEB's observations in this regard included:

> "As noted by OPG and intervenors, there does not appear to be any consistent and generally accepted treatment of AROs and ARCs in other North American jurisdictions. The standards governing the financial accounting for AROs are relatively new. The FASB in the United States issued Statement No. 143 in 2001, and the CICA Handbook section 3110 in 2003. Whether North American regulators will ultimately modify their ratemaking approaches to be compatible with the accounting standards is not clear."[294]
>
> "With respect to rate regulated nuclear plants in the United States, OPG's expert on cost of capital provided her views on the impact of FASB Statement No. 143, Accounting for Asset Retirement Obligations, which is virtually identical to CICA Handbook Section 3110. She

[292] EB-2007-0905 Decision with Reason, November 3, 2008, p. 91.
[293] EB-2007-0905 Decision with Reason, November 3, 2008, p. 90.
[294] EB-2007-0905 Decision with Reason, November 3, 2008, p. 88.

> indicated that "FASB 143 has not resulted in material changes in regulatory practice with respect to rate base or capital structure for U.S. utilities with ARCs and AROs."" [295]
>
> "There was no evidence provided at this hearing that any regulator has yet permitted the inclusion of ARC in rate base." [296]

As described in this study, ultimately, the adoption of FAS 143 by the US entities did not result in changes to the rate recovery practices historically approved by the US economic regulators.

21.1.2.2 Bruce Nuclear Facilities

For the Bruce facilities, the OEB applies a financial accounting approach, in accordance with generally accepted accounting principles, for determining the revenue requirement impact of OPG's decommissioning and waste management obligations for the Bruce facilities. The OEB adopted this approach on concluding that it was not reasonable, under Ontario Regulation 53/05, to calculate OPG's costs related to an unregulated activity, being its lease of the Bruce stations, using an approach that an unregulated company would not be permitted to use.[297] Thus, OPG recovers the following as its costs of decommissioning and waste management:[298]

- Depreciation of the ARC for the Bruce facilities treated in the same manner as depreciation on the ARC for the Regulated facilities;
- Accretion expense of the ARO for the Bruce facilities;
- The variable used fuel management and waste management expenses related to incremental quantities of fuel and low and intermediate level waste generated in each period; and
- Segregated fund earnings attributed to the Bruce facilities.

21.1.3 Other Observations

21.1.3.1 Decommissioning Segregated Funds

OPG has established two segregated trust funds in order to meet the CNSC's financial assurance requirements related to the decommissioning and waste management for the Pickering, Darlington and Bruce plants. The funds are established, maintained and managed pursuant to the Ontario Nuclear Funds Agreement (ONFA), a bilateral agreement between OPG and the Province of Ontario.[299] The two segregated funds are the Decommissioning Segregated Fund ("DF") and the Used Fuel Segregated Fund ("UFF").

The UFF is intended to fund costs of long-term nuclear used fuel waste management, while the DFF is meant to pay for the cost of decommissioning plants and the cost of managing low and intermediate

[295] EB-2007-0905 Decision with Reason, November 3, 2008, p. 84.
[296] EB-2007-0905 Decision with Reason, November 3, 2008, p. 89.
[297] EB-2007-0905 Decision with Reason, November 3, 2008, p. 110.
[298] EB-2016-0152, Exhibit C2, Tab 1, Schedule 1, May 27, 2016, P.10-12
[299] Ontario Power Generation Inc. 2019 Annual Information Form, p. 29

level waste. A portion of the UFF is set aside in a separate trust to meet the requirements of the Nuclear Fuel Waste Act.[300]

The level of OPG's required payments to each of the funds is determined by comparing segregated fund balances at a point in time with a Provincially-approved reference plan that sets out the cost estimates for OPG's decommissioning and waste management obligations. The main parameters of this calculations are determined as follows:[301]

- The ONFA reference plan, including all cost estimates and assumptions, is required to be updated every five years (or whenever there is a significant change as determined under the ONFA).
- Cost estimates are prepared by OPG with the assistance of external experts and reviewed by the CNSC and the Province, with operating assumptions and cost escalation rates determined through the cost estimating process.
- The investment earnings assumption used to determine the contributions is prescribed at 3.25% real rate of return under the agreement.
- The ONFA also sets out certain rules for calculating contribution amounts, including prescribing that any deficit for a portion of the UFF is to be funded over the original expectation of operating lifespans of the nuclear stations in 1999 (or within five years if those dates have lapsed).

The above inputs and calculations under the ONFA and the resulting fund contribution amounts are not subject to approval by the OEB.

21.1.3.2 CNSC Nuclear Requirements

The Canadian Nuclear Safety Commission (the "CNSC") is the federal regulator of nuclear power and materials in Canada. The CNSC regulates the use of nuclear energy and materials to protect health, safety, security and the environment; to implement Canada's international commitments on the peaceful use of nuclear energy; and to disseminate objective scientific, technical and regulatory information to the public.[302]

The CNSC was established in 2000 under the Nuclear Safety and Control Act (the "NSCA") and reports to Parliament through the Minister of Natural Resources. Neither the Minister nor the Governor in Council has a role in the CNSC's decision-making or the power of appeal. Its decisions are reviewable only by the Federal Court of Canada. The CNSC's regulatory framework consists of laws passed by Parliament governing the regulation of Canada's nuclear industry, and regulations, licences and documents that the CNSC uses to regulate the nuclear industry.[303]

Under the NSCA, the CNSC regulates the entire life cycle of nuclear power plants. Decommissioning activities are the actions taken by a licensee at the end of the useful life of the reactor. The decision to stop operating and to decommission is taken solely by the licensee. The CNSC's role is to ensure that decommissioning activities are carried out in accordance with the CNSC regulatory requirements

[300] Ontario Power Generation Inc. 2019 Annual Information Form, p. 31
[301] EB-2007-0905, Exhibit H1, Tab 1, Section 3.0.
[302] The Commission - Canadian Nuclear Safety Commission, website nuclearsafety.gc.ca/eng/the-commission/index.cfm accessed on December 31, 2020
[303] *ibid*

to ensure protection of the workers, the public and the environment, and to implement Canada's international commitments.[304]

It was a policy-based decision to impose financial guarantee licence requirement to pay for decommissioning in nuclear facilities. Generally, financial guarantees are intended to ensure sufficient financial resources will be available for decommissioning, regulating the full lifecycle and ensuring sustainable development.

Preliminary Decommissioning Plans

Applicants and licensees are expected to provide preliminary decommissioning plans that adequately contemplate end of life and site remediation from the beginning. The CNSC Staff typically work with applicants and licensees prior to hearings to ensure decommissioning plans are realistic and feasible. Preliminary decommissioning plans are expected to demonstrate that:

- The planned decommissioning activities will remediate all significant impacts and hazards to persons and the environment in a technically feasible fashion,
- Such plans assure compliance with all applicable requirements under law, and
- Such plans enable credible estimates of the dollar amount of financial guarantees.

The CNSC generally requires a five-year review period of decommissioning plans.[305]

[304] Decommissioning of nuclear power plants – From website nuclearsafety.gc.ca/eng/resources/fact-sheets/decommissioning-of-nuclear-power-plants, accessed on December 31, 2020.
[305] The Financial Liability of Industry as Part of the Legal Framework – A Canadian Case Study – November 21-22, 2017

Part III – Other Jurisdictions

22 France

22.1 Industry and Market Structure

Électricité de France ("EDF") has historically been the dominant electricity supplier in France, where it provided service as a vertically integrated monopoly utility.

EDF is owned 83.7% by the French government.[306]

EDF owns nuclear generators in both France and the United Kingdom. This chapter focuses on the decommissioning cost related mechanisms in France. Mechanisms for recovery of decommissioning costs in the United Kingdom are covered separately in Chapter 23.

Like other European jurisdictions, France has been required by European Union policies to implement a competitive electricity market. In order to facilitate the opening up of the market and to allow for competitive entry by alternative commodity suppliers, the French government has provided access to a fixed amount of output from EDF's nuclear fleet at a regulated, fixed price. Thus, up to 100 TWh of electricity is currently made available annually at a fixed price of €42 to rival suppliers. This regulated access to fixed price supply is referred to as "ARENH".[307] It accounts for about 25% of the output of EDF's nuclear fleet.[308] An additional amount of output reflects sales at a price that is capped by the ARENH rate but that is subject to market price risks on the downside.

A consequence of the ARENH price mechanism is that EDF receives a regulated, fixed price for the associated portion of its output. The remainder of its output is subject to pricing risks in the electricity spot market. Moody's Investors Service characterizes EDF's electricity sales according to their market exposure as summarized in Exhibit 22-1 below.

Exhibit 22-1

Distribution of Electricity Sales by Market Exposure (2018)		
	TWh	**Percent**
At ARENH price	100	22%
At minimum of market price and ARENH	230	51%
At Market Price	80	18%
Long Term Contracts	40	9%
Total	**450**	**100%**

The rest of this Chapter discusses the relationship between ARENH and recovery of decommissioning and waste management costs, and provides our findings related to the financial assurance arrangements for these obligations.

[306] Moody's Investors Service, Electricité de France, Credit Opinion, 3 July 2019, p. 2.
[307] ARENH is an abbreviation of "Acces Regulé a l'Electricité Nucleaire Historique".
[308] S. Ambec and C. Crampes, "Regulated Access to Incumbent Nuclear Electricity", Florence School of Regulation, 16th January 2019.

ARENH Pricing Mechanism

The ARENH price was initially set at €40 per MWh by government legislation in 2011. In January 2012, the price was increased to €42 per MWh. The price was increased in order to account for increased investments in safety measures as a result of the Fukushima events.[309]

From 2014 forward, the price was to be set by the energy regulator ("CRE") according to a methodology to be defined by decree. According to a review of the initial governing legislation, the intention for this price-setting methodology was that the ARENH price should be cost based, taking into account operating costs, investment, and decommissioning and waste management provisions.

However, it appears that the principles outlined in the governing legislation are imprecise. For example, one research paper argues the following:

> "This description of the principles and terms on which the ARENH tariff is to be based is so vague that it is not possible to draw any conclusions about its level. The economic or accounting method that will be used to calculate the ARENH tariff will be set forth in a decree. It should be borne in mind, however, that the same data can yield different results depending on the method used." [310]

We further note that, as of June 2020, the government had still not issued the methodology for the calculation of the ARENH price. Accordingly, in subsequent decisions with respect to consumer retail prices, the CRE has left the ARENH price unchanged at the level of €42 per MWh value set in 2012.

Under governing legislation, the ARENH pricing mechanism is set to expire in 2025.

In January 2020 the French government launched a consultation process with regards to the plan to reform the economic regulations for nuclear facilities, and their construction and operating principles. The proposed regulations would replace the ARENH mechanism and take the form of a price corridor.[311] We understand that a stated aim of the revisions is to both protect consumers from rising market prices after 2025 and to provide EDF with the financial capacity to meet the PPE in low-price scenarios.[312]

The government has commissioned the CRE to carry out an assessment of the costs borne by the nuclear operator, and determine fair remuneration for its nuclear activities under the government's potential future regulation.[313]

Based on the foregoing, while a portion of nuclear output sold is a regulated fixed price, the relationship of this prices to the underlying costs for decommissioning and waste management is not clear. Although the price may have been broadly intended to be representative of actual costs, it was administratively set at what appears to be a somewhat arbitrary value and has not been updated since 2012.

Because changes in accounting costs do not appear to flow directly to consumers, changes in decommissioning costs may partly be borne by utility shareholders, the largest of which is the French government.

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[309] Julien Tognola, "Costs, prices and tariffs in EU electricity markets – The Case of France", General Directorate for Energy and Climate, Government of France, 9 July 2014. p. 14.
[310] Francois Leveque, "France's new Electricity Act: a barrier against the market and the European Union", University of Cambridge, EPRG Working Paper 1036, December 2010, p. 11.
[311] Fitch Ratings, "Consultation on French Nuclear Regulation a Positive Development for EDF", 4 February 2020.
[312] EDF 2019 Annual Report, p. 58.
[313] EDF Half-Year Financial Report at June 30, 2020, p. 26-27.

22.2 Financial Assurance Mechanism

In this section, we summarize some observations on EDF's financial assurance mechanism related to decommissioning and waste management.

According to the EDF 2019 annual report, Article L. 594 of France's Environment Code and associated regulations require dedicated assets to be set aside for the secure financing of nuclear plant decommissioning expenditures and long-term storage expenditures for radioactive waste.

Dedicated assets are identified and managed separately from the company's other financial assets and investments and are subject to specific monitoring and control by the Board of Directors and administrative authorities.[314]

The EDF annual report further notes:

> "The law requires the realisable value of dedicated assets to be higher than the value of the provisions corresponding to the present value of the long-term nuclear expenses defined above."[315]

It also notes:

> "the annual allocation to dedicated assets, net of any increases to provisions, must be positive or zero as long as their realisable value is below 110% of the amount of the provisions concerned;"[316]

It thus appears that withdrawals are not permitted when dedicated assets are less than 110% of the value of provisions but may be permitted when they are greater than 110%.

The EDF annual report also provides some disclosure of current and forecast contribution levels. It notes:

> "Because of changes (other than regulatory modifications) in the assumptions used to calculate long-term nuclear provisions, the required allocation to dedicated assets for 2018 amounted to €1,337 million. The administrative authorities authorised EDF to spread this allocation as follows: €540 million in 2019 and 2020, and €257 million in 2021. Allocations to dedicated assets in 2019 thus totalled €540 million in realisable value (€387 million in 2018) (see note 48.5), and took the form of shares rather than cash. At 1 January 2019, the outstanding required allocation for 2018 amounts to €797 million. In accordance with the letter received on 12 February 2020 (see note 32.1.5.1), this allocation must be made in 2020, but no allocation is required in respect of 2019."[317]

Based on the above excerpt, it appears that there is regulatory oversight in place directed to ensuring that there is sufficient funding for dedicated assets.

[314] EDF 2019 Annual Report, p. 147.
[315] EDF 2019 Annual Report, p. 148.
[316] EDF 2019 Annual Report, p. 148.
[317] EDF 2019 Annual Report, p. 151.

22.3 Other Observations

A.1.1 Determination of Discount Rates

In this section, we set out our observations on the determination of discount rates used in calculating EDF's liabilities for decommissioning and waste management in accordance with IFRS. Unlike US GAAP that maintains the discount rate used to establish the ARO at its inception, IFRS requires an ARO to be remeasured using a current discount rate each reporting period. The discount rate used by EDF appear to be determined using a multi-layered approach that may have a significant impact on the resulting obligation values.

The EDF annual report indicates that the provisions established for EDF's nuclear generation fleet in France result from the Law of 28 June 2006 on long-term management of radioactive materials and waste, and the associated implementing provisions concerning secure financing of nuclear expenses. EDF recognizes the value of these obligations in its financial statements in accordance with IFRS, on a present value basis.[318]

For the calculation of provisions relating to the NPV of nuclear liabilities, the discount rate is determined based on long-series data for a sample of bonds with maturities "as close as possible to that of the liability". [319]

The 2019 annual report further notes:

> "The benchmark used to determine the discount rate is the sliding 10-year average of the return on French OAT 2055 treasury bonds which have a similar duration to the obligations, plus the spread of corporate bonds rated A to AA, which include EDF.
>
> The methodology used to determine the discount rate, particularly the reference to sliding 10-year averages, is able to prioritise long-term trends in rates, in keeping with the long-term horizon for disbursements. The discount rate is therefore revised in response to structural developments in the economy leading to medium and long-term changes.
>
> …the assumed inflation rate is determined in line with the forecasts provided by consensus and expected inflation based on the returns on inflation-linked bonds."

Key figures are summarized in Exhibit 22-2 below.

Exhibit 22-2 – Discount Rate for Nuclear Provisions

Discount Rate (%)		
	Dec 31, 2018	Dec 31, 2019
Discount Rate	3.9	3.7
Assumed Inflation	1.5	1.4
Real Discount Rate	2.4	2.3

318 EDF 2019 Annual Report, p.101.
319 EDF 2019 Annual Report, p.109. At the same reference, the annual report also cautions that some related expenses will be dispersed over periods of duration significantly longer than the duration of instruments generally available on financial markets

The annual report also notes that the discount rate must comply with certain regulatory limits as set out by the French government. Based on these requirements, the discount rate must be lower than:

- a regulatory maximum, set until 31 December 2026 as the weighted average of two terms, the first set at 4.3%, and the second corresponding to the arithmetic average over the 48 most recent months of the TEC 30-year rate plus 100 points. The weighting given to the first constant term of 4.3% reduces on a straight-line basis from 100% at 31 December 2016 to 0% at 31 December 2026;
- and the expected rate of return on assets covering the liability (dedicated assets).[320]

The ceiling rate based on the TEC 30-year rate was 3.8% for 2019.

The annual report also references certain changes that were being made to the regulatory limit, as per a letter dated 12 February 2020, which is the same letter referenced above in the discussion of required allocations (contributions) to dedicated assets.

Overall, it appears that EDF may be using an atypical approach to set the discount rate for determining its obligation for nuclear asset retirement and waste management under IFRS. EDF's approach appears to use a historical rolling average bond yield, subject to an externally mandated maximum rate and the expected rate of return on the assets covering the liability. We have not investigated further the basis for this treatment in accordance with IFRS.

[320] EDF 2019 Annual Report, pp.109.

23 United Kingdom

23.1 Industry and Market Structure

The United Kingdom has a competitive electricity market, with an active retail market for end-consumers. Transmission and distribution companies with monopoly service territories operate independently of companies in the competitive generation sector.

Although generation is a competitive activity, the government has stepped in and offered fixed-price contracts for low-carbon generation, including renewable sources and new nuclear construction. The additional costs of these fixed price contracts will be flowed through to electricity consumers.

The nuclear reactors currently operating or under construction in the UK can be grouped into two broad categories:

- A group of eight reactors now owned by EDF, all of which were completed prior to 1996. These are referred to as “second generation” reactors, as distinct from an earlier group of reactors that are no longer operational.
- One new reactor at Hinkley Point (“Hinkley Point C” or “HPC”), which is currently under construction by EDF in partnership with China General Nuclear.

Of the eight reactors in the second generation, one reactor (Sizewell B) is the only PWR built in the UK. The remaining seven reactors are Advanced Gas-Cooled Reactors (“AGR”s).

The overall price for power for Hinkley Point C is set by contract and increases by CPI over the contract term. As noted in Chapter 3, this type of contractual pricing regime effectively breaks the direct link between rates paid by consumers and operating costs (where operating costs may include decommissioning and waste management provisions) that is associated with traditional rate regulation.[321] For added context, we review below the decommissioning funding structure in place for Hinkley Point C in the context of the overall contractual arrangement. The structure is meant to ensure that all costs of decommissioning are ultimately paid by the facility owner.

With respect to the second generation reactors that operate within a competitive market for generation, EDF must recover its various costs through the prices that it bids into the electricity pool and those it arranges in any bilaterally-negotiated contracts. As noted in Chapter 3, this means there is no observable link between decommissioning costs and revenues. For additional context, we provide below a summary of our research into the decommissioning cost sharing arrangement in place for the second generation reactors between EDF and the UK Government.

In addition to the two groups of operating reactors noted above, there are a number of reactors that have already been shut down. This is the so-called “first generation” reactors. For this first generation of reactors, the UK. government retains full responsibility for decommissioning costs and associated funds are paid by the UK Treasury. Hence, no consumer contributions are provided.

[321] Government sources estimated in 2013 that, for Hinkley Point C, provisions for decommissioning and a share of waste management costs would account for about £2 of the overall negotiated strike price (of about £90/MWh). (Statement by Edward Davey, as reported in Hansard 21 October 2013, Column 24-25.)

23.2 Second Generation Reactors

British Energy was the owner of the second-generation nuclear fleet in the UK and was privatized in 1996. It ran into financial challenges in 2002 as a result of decreases in wholesale energy prices and some operational issues that occurred in parallel at some of its nuclear reactors. The company then underwent a restructuring process that was followed by government investment in the restructured firm. In 2011, British Energy was acquired by EDF.

23.2.1 Financial Assurance Mechanism

Decommissioning of the second generation nuclear fleet will be funded by the Nuclear Liabilities Fund ("NLF"). Operation of the NLF is governed by the Nuclear Liabilities Funding Agreement ("NLFA")..[322] NLF was set up in 2005 as part of the restructuring led by the UK government in order to stabilize British Energy's financial position. British Energy was acquired in 2011 by EDF, which assumed British Energy's obligations under the NLFA.[323]

As noted by the UK National Audit Office ("NAO"), the UK government stepped in during the restructuring process because "unplanned closures of British Energy's nuclear power stations would have had safety implications and put electricity supplies at risk".[324] The government also recognized that, to ensure a viable company, it would need to take responsibility for a large proportion of the company's liabilities, including its liabilities for decommissioning and spent fuel management.

As noted by the NAO, the government's efforts focused on "securing the maximum ongoing contribution from the Company [*British Energy*] towards meeting the liabilities whilst reducing the risk that these contributions could put the company in jeopardy in the future. The mechanism put in place was a cash sweep plus a fixed annual contribution. The cash sweep requires the Company to make a bigger contribution to the Nuclear Liabilities Fund when it is doing well."[325] Thus, contributions are not based strictly on estimated costs, but take into account affordability from the company's perspective. This is an atypical approach to financial assurance mechanism based on our research.

A summary of certain key terms of the restructuring agreements includes:

- The NLF agreed to fund, to the extent of its assets, two categories of costs:
- Qualifying contingent and/or latent nuclear liabilities associated with the. Sizewell B reactor, including those liabilities associated with the management of spent fuel.
- Qualifying decommissioning costs for EDF's AGR reactors.
- The Secretary of State agreed to fund the above noted items to the extent that they exceed the assets of NLF. The Secretary of State will also fund, subject to a cap, qualifying known existing liabilities for spent fuel that was loaded in EDF's AGR reactors prior to January 15, 2005.
- EDF is responsible for funding certain excluded or disqualified liabilities and additional liabilities that could be created as a result of failure to meet minimum standards under applicable law.

EDF also made commitments to pay:

[322] Nuclear Liabilities Fund, 2019 Annual Report and Accounts, p. 2.
[323] EDF 2018 Annual Report, p. 105.
[324] National Audit Office, "The restructuring of British Energy", 17 March 2006, p. 2.
[325] National Audit Office, "The restructuring of British Energy", 17 March 2006, p. 2.

- Annual decommissioning contributions for a period limited to the useful life of the plants as of the date of the restructuring agreements; the corresponding provision amounts to €117 million at 31 December 2019.
- £150,000 (indexed to inflation) per tonne of uranium loaded in Sizewell B after the date of the restructuring agreements.[326]

EDF also entered into separate agreements with the Nuclear Decommissioning Authority for management of AGR spent fuel and associated radioactive waste resulting from operation of the AGR power plants after 15 January 2005. The fee paid is also £150,000 (indexed to inflation) per tonne of uranium, plus a rebate or surcharged dependent on market electricity prices and electricity generated in the year. The rebate and surcharge provides for contributions to adjust in response to EDF's actual market earnings.

EDF bears no responsibility for spent fuel and associated radioactive waste once it is transferred to the processing site at Sellafield, an intermediate processing facility.

23.3 Hinkley Point C

Hinkley Point C has been developed under the UK Government's current policy for the development of new nuclear plants. Under this policy, all new nuclear sites will have to put money aside from the start to pay for their eventual decommissioning. All of the money for decommissioning is therefore to be recovered from revenues from the sale of electricity. This differs from funding for the first and second generation reactors, where all or some monies are ultimately paid by the taxpayer.

To support the building of Hinkley Point C, the government has provided it with a stable revenue stream, as embedded in a Contract for Differences ("CfD"). The CfD provides Hinkley Point with a price per kWh of output that is effectively fixed in real terms over a 37-year period. This contract works as follows:

- The CfD provides a full top-up to facility owners if the market price is below the contract price.
- Facility owners must return to the government any additional revenue that results when the market price exceeds the contract price.

The facility is expected to be operational for 60 years. Beyond year 37, facility owners face full market price risk. Because there is a risk that the facility may no longer be economic to run, provisions for recovery of decommissioning costs have been designed to ensure the costs full recovery of these costs during the initial 37-year period.

23.3.1 Decommissioning Financial Assurance Framework

Under the UK Government's current framework, the plans for the decommissioning and waste management for new nuclear sites must be set out in a Funded Decommissioning Programme ("FDP"), with the onus on the generator to propose and negotiate the extent to which payments will be required. Such plans must be approved and put in place in advance of construction – the development of a plan and its negotiation with the Department of Business, Energy and Industrial Strategy ("BEIS") constitutes a key part of the planning and licensing process of UK new nuclear. The

[326] EDF 2019 Annual Report, p. 112.

most important principle for this FDP is prudence and Directors can be held criminally liable for not meeting decommissioning liabilities.

Legislation and FDP guidance anticipates that the FDP will take the form of two main documents:

- A Decommissioning and Waste Management Plan describing all the works and activities needed along with cost estimates, and
- A Funding Arrangements Plan, a legally binding contract that sets out how the operator will finance the estimated costs.

23.3.2 Decommissioning Funding Parameters for Hinkley Point C

For Hinkley Point C, the FDP provides that money for decommissioning will be set aside in a fund throughout operations. This fund is structured in a similar way to a pension fund –i.e. an actuarial approach is used to fund the future decommissioning liability estimate.

The funding approach incorporates a number of important features, many of which are designed to ensure that there is very limited risk that funds will be insufficient to pay for future decommissioning expenditures. These features are as follows:[327]

- The decommissioning cost estimates that are used to calculate required funding levels are designed to be "P80" estimates. In other words, they are conservative estimates, where the probability that they will be exceeded should only be 20%.
- The operator must provide funding that exceeds the P80 estimate noted above by 25%. This provides an additional "buffer" in funded amounts.
- The FDP must provide for 100% of the funds needed for decommissioning to be set aside by the end of year 37. This is the year in which the CfD that provides price certainty to the facility comes to an end.
- Between years 37 and 60, the facility must annually contribute additional funds to cover the incremental increases in decommissioning costs for spent fuel and intermediate level waste that are generated as a result of continued facility operation.
- A profile of base case contributions to the fund has been calculated assuming that funds will earn at 1.5% real return until year 33.
- An additional "correction" contribution will be added to the required base case contribution in years in which fund balances are below target balances. (In years in which actual balances exceed target, a deduction can be used to offset a portion of the base case contribution.) Correction adjustment percentages increase in later years of the contract.[328]
- Fund investments must be "de-risked" in the later years of the plan. Thus, by year 25, not more than 35% of fund assets may be invested directly or indirectly in equities. By the end of year 37, at least 50% of fund investments must thus be in the form of specified government securities, with the balance of investments limited to corporate bonds (i.e. no equities). By year 60, and until the

[327] Nuclear Liabilities Financing Assurance Board (NLFAB), Advice to the Secretary of State, Funding Arrangements Plan for Hinkley Point C.
[328] NLFAB, Advice to the Secretary of State, Funding Arrangements Plan for Hinkley Point C., p. 50.

site is fully decommissioned, funds must be invested fully in government securities and cash and cash equivalents and permitted derivatives.[329]

- Payments to the fund must be made before debt repayments and dividends. .[330]

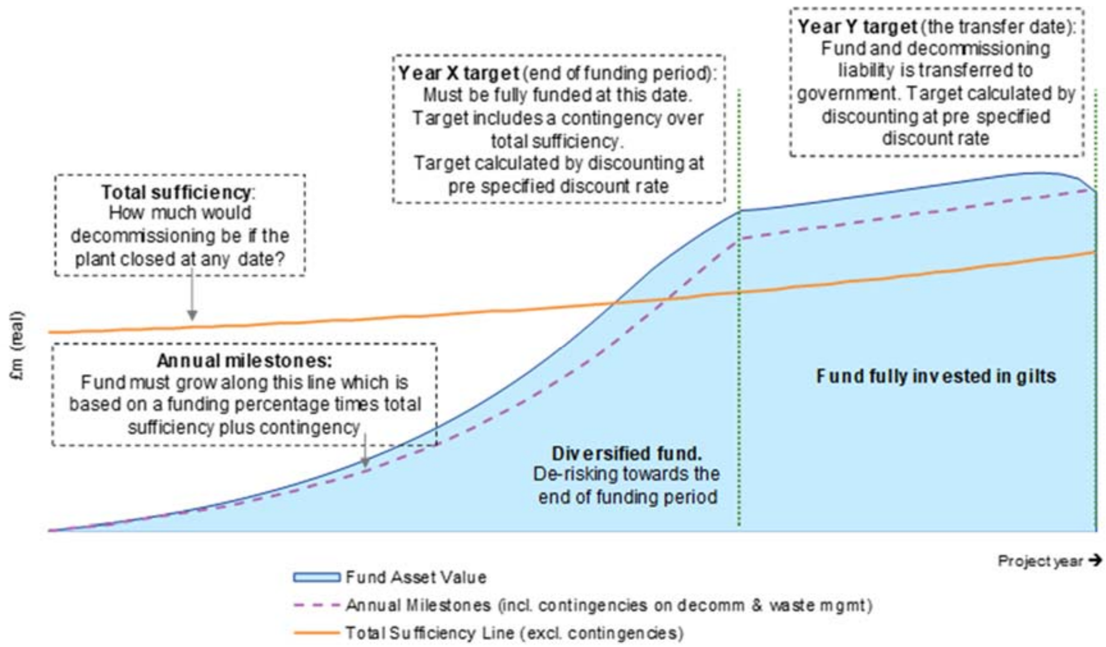
Notwithstanding the significant risk reducing features noted above, the funding profile itself is 'back ended,' providing for more contributions in later years of the CfD period.[331] In this regard, the Nuclear Liabilities Financing Assurance Board has observed the following:

> "The Board notes that the build-up of the fund is severely 'back-ended'. As an illustration of this, if the fund were to be build up evenly over the 37 year period rather than being back-ended, the fund would be 34 percent funded after 15 years rather than the 15 percent, and 77 percent. funded after 30 years rather than 61 percent (assuming a level annual contribution in real terms and that asset returns match the assumed long-term discount rate)."[332]

[329] NLFAB, Advice to the Secretary of State, Funding Arrangements Plan for Hinkley Point C., p. 54.
[330] In respect of the provision that fund payments take precedence over debt repayments and dividends, the NAO has noted that this made it more difficult for the Hinkley Point project to obtain project finance. This meant that it had to be funded through equity, with a corresponding increase in required returns. (National Audit Office, Hinkley Point C, June 2017, p. 57.)
[331] Contributions to decommissioning funds are somewhat back-end loaded *within the initial contract* period for Hinkley Point C. This is a characteristic of the specific funding schedule for such contributions that is outlined in the Hinkley Point C agreement. However, from the perspective of the *overall period of plant operation*, contributions are somewhat front-end loaded. This reflects the fact that all of the fixed costs of decommissioning are recovered during the initial contract period (thereby shifting costs forward from the subsequent period of open-market operation)
[332] NLFAB, Advice to the Secretary of State, Funding Arrangements Plan for Hinkley Point C., p. 16.

Exhibit 23-1 below provides a graphical representation of funding arrangements.

Exhibit 23-1 – Decommissioning Funding [333]



23.3.3 Spent Fuel and Intermediate Level Waste

As noted earlier, the UK government has agreed to accept radioactive waste (ILW and spent fuel) from Hinkley Point C. The waste will be handed in a future Geological Disposal Facility. which will also be used to house waste from other nuclear plants and from government defence sites.

The government will set the final price for handling Hinkley Point C's radioactive waste in 2050 but, to avoid an unquantifiable liability on the developer's balance sheet, it has capped the price at £5.9 billion (in 2016 prices). This value was well in excess of then current cost estimates of £2.9 billion (also in 2016 prices), which provides some buffer against potential cost increases. Nevertheless, the UK Government will be responsible for any shortfall if costs escalate beyond the cap of £5.9 billion.[334]

[333] Funding Arrangements Plan – Hinkley Point C, KPMG analysis
[334] National Audit Office, Hinkley Point C, June 2017, p. 57.

24 Finland

24.1 Industry and Market Structure

There are two operating nuclear plants in Finland, comprising a total of four reactors. Nuclear generation currently provides approximately 30% of Finland's electricity, however, that number may rise closer to 60% as a fifth reactor is under construction and a sixth is in the planning phase.[335]

In 2019 the Finnish government announced a new energy policy aimed at achieving carbon neutrality by 2035. The policy shift would see coal power phased-out completely by 2029, while the contribution from nuclear power will continue to grow. In addition to the two new nuclear power reactors to be commissioned, the country is considering an extension of the operating lifetime of existing reactors.[336, 337]

Under the Nuclear Energy Act 1987, Finland's Ministry of Economic Affairs and Employment ("MEAE") is responsible for supervision of nuclear power operation and waste disposal. The National Nuclear Waste Management Fund, further discussed below, is under the mandate of the MEAE.

Finland is part of the deregulated Nordic Power Pool, connected to the systems in Denmark, Norway and Sweden. Accordingly, there is a competitive electricity generation market.

There are four operating nuclear reactors in Finland, with operational control distributed as follows:

- Fortum, a conventional publicly-traded utility, operates two modified Russian pressurized water reactors with Western containment and control systems at the Lovissa facility. Fortum also operates in a number of other jurisdictions, including Sweden and Russia.
- Teollisuuden Voima Oyj ("TVO"), operating under the Mankala (cost-price) principle discussed below, operates two boiling water reactors at the Olkiluoto plant.

Exhibit 24-1 below summarizes the ownership and expected decommissioning dates for the operating nuclear plants.

Exhibit 24-1 – Finland's Operating Nuclear Power Reactors

Operating Nuclear Plants		
Reactor Name	**Owner**	**Expected Shutdown**
Loviisa 1	Fortum	2027
Loviisa 2	Fortum	2030
Olkiluoto 1	TVO	2038
Olkiluoto 2	TVO	2038

[335] World Nuclear Organization, "Nuclear Power in Finland – Country Profile", Updated April 2020.
[336] World Nuclear News, "Finland aims for carbon neutrality by 2035", 06 June 2019.
[337] World Nuclear Organization, "Nuclear Power in Finland – Country Profile" Updated April 2020.

In 2018, the Government of Finland extended the operating license for the Olkiluoto units for the next 20 years (to 2038). In 2018, Olkiluoto 1 had a major maintenance outage that included replacement and upgrade of a number of system and equipment components.[338]

There are two nuclear reactors currently under construction. Olkiluoto 3 was expected to begin operating in 2020.[339] The start date has since been delayed to 2022.[340] The country's sixth nuclear reactor, Fennovoima Hanhikivi 1, is expected to begin construction in 2021, with operations starting in 2028.[341] It will be built by Fennovoima Oy, which is a new nuclear power company that is organized under the Mankala principle, with 60 participating shareholding companies.[342]

TVO and Fortum have jointly established a private company Posiva Oy ("Posiva") to carry out all tasks related to the final disposal of spent nuclear fuel from the TVO and Fortum reactors. Plans for final disposal are approved by the Ministry of Employment and the Economy. [343] Posiva recovers its costs from the nuclear operators.

Our review of Finland has focused on TVO in order to investigate the recovery of decommissioning costs under the Mankala principle.

24.1.1 Mankala (Cost-Price) Principle

A unique feature of the Finnish electricity sector is the presence of a number of non-profit utilities that operate on the so-called "Mankala principle". These utilities developed after World War II as a means of facilitating the development of power generation plants in a country with limited financial market access. Under such as an arrangement, shareholders, who typically comprise large individual companies, retailers, and municipal distributors, commit to paying all of the costs of a utility, in return for getting access to the power produced. As a result, these "non-profit" utilities can provide power "at cost", bypassing the pricing set in the competitive power pool.[344] The model is viewed as particularly beneficial for industrial companies with large power needs that are looking for the supply of power at a stable price. Observers argue that the Mankala financing structure enables a more competitive electricity system, with a broader range of participants.[345]

24.2 Financial Assurance Mechanism

Nuclear operators cover their nuclear waste management obligations under the Nuclear Energy Act through payments to the Finnish Nuclear Waste Management Fund ("VYR"). The obligation covers

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338 TVO, 2018 Report of the Board of Directors and Financial Statements, p. 2.
339Fitch Ratings, Teollisuuden Voima Oyj (TVO) – Rating Report, 27 November 2019, p. 1.
340 https://yle.fi/uutiset/3-11516011
341 Fennovoima, 2019 Annual Report, p. 50.
342 International Atomic Energy Association, "Finland - Country Profile", Updated May 2019.
343 TVO, 2018 Report of the Board of Directors and Financial Statements, p. 47.
344 Pohjolan Voima, "The Mankala Cost Price Model", fact sheet available at https://www.pohjolanvoima.fi/filebank/24471-The_Mankala_cost-price_model.pdf
345 The model had been subject to a legal review related to whether or not the supply of electricity to shareholders constitutes the distribution of a dividend and therefore should be subject to taxation. Such taxation would undermine the viability of the business model. Ultimately, taxes have not been applied, although participating shareholders will pay taxes on any profits if they in turn sell the electricity delivered to the spot electricity market or to other parties. (Pirttila, M, Schroder, S., "Mankala energy production under threat?",International Law Office, 16 May 2011.)_

all the future expenditures for nuclear waste management, including the decommissioning of nuclear power plants, the disposal of spent fuel and a "risk marginal". [346]

The amount of the payment to the Fund is determined by assuming that decommissioning would start at the beginning of the year following the assessment year. As this funding obligation is therefore not discounted, it is much higher than the accounting based nuclear waste management obligation that is recognized on the operator's balance sheet. However, the financial impact of payments to VYR is minimized by the fact that operators can borrow back up to 75% of their required contribution.

In addition to funding VYR, nuclear operators must provide the Ministry of Employment and the Economy with guarantees to cover the difference between the legal nuclear waste management liability and the operator's share of VYR as well as for unforeseen expenses in nuclear waste management.

As part of our research, we reviewed a 2007 report for the European Commission on Finnish funding mechanisms that provided additional insight into the financial assurance mechanism. Among other things, the report that providing funding for the full, undiscounted decommissioning cost at the start of plant operation could result in an untimely allocation of these costs to the costs of electricity production. It further noted that, as mitigation, there is a provision that allows required fund holdings to be accumulated in roughly equal annual increments over the first 25 years of facility operation.[347] However, in any event, security must be provided to cover any unfunded amounts.[348] Finally, the report discussed that there are mechanisms in place to provide for the phasing-in of new funding targets, over a period of up to five years, when there have been substantial and sudden changes in forward-looking cost estimates, perhaps as a result of changes in decommissioning strategies. [349]

24.3 Teollisuuden Voima Oyj

TVO is a non-listed public limited liability company owned by Finnish industrial and energy companies. It generates about 17 percent of all electricity consumed in the country[350]

TVO is owned by six shareholders, some of which also operate on the Mankala principle. One of its shareholders is Fortum. There are 132 Finnish municipalities among the remaining shareholders, represented either directly or indirectly.

24.3.1 Cost-Price (Mankala) Principle

TVO delivers electricity it has produced or procured to its shareholders in proportion to their shareholdings in each of a series of shares. Each series of shares corresponds to one or two specific generating facilities.

[346] TVO, 2018 Report of the Board of Directors and Financial Statements, p. 40.
[347] Report for European Commission Directorate-General Energy and Transport, Comparison among different decommissioning funds methodologies for nuclear installations, Country Report Finland, Service Contract TREN/05/NUCL/S07.55436, 2007, p, 29-30.
[348] *Ibid*, p, 30-31.
[349] *Ibid*, p, 30-31.
[350] TVO, 2019 Report of the Board of Directors and Financial Statements, p. 5.

Each shareholder, irrespective of whether or not it has used its share of electricity, is responsible for the following annual fixed costs of the company, in proportion to the number of shares in each particular series that it holds: [351]

- Normal operating, maintenance and administrative costs.
- Taxes other than those that depend on power production.
- Insurance costs.
- Debt service costs.
- Depreciation.
- Costs set out in the Nuclear Energy Act incurred by the company's nuclear waste management activities.
- Other costs independent of power production related to the Company's normal business and included in the budget or approved by its board of directors.

The annual variable costs of the company are allocated to shareholders based on the volumes of electricity consumed. These variable costs include fuel costs, taxes that depend on power production, and other costs that vary directly with the volumes of power consumption.

24.3.2 Recovery of Nuclear Decommissioning Costs under the Mankala Principle

We reviewed TVO's annual report to determine the basis for cost recovery of nuclear decommissioning costs under the Mankala principle. However, as further discussed below, we were unable to draw a definitive conclusion on the recovery methodology.

As noted in the 2019 annual report, legal liabilities under the Nuclear Energy Act (and therefore the target funding obligation for VYR) are determined by the Ministry of Employment and the Economy according to methodologies outlined in the Act. [352] For financial accounting purposes, TVO recognizes a present value provision related to obligations for decommissioning and waste management as required by International Financial Reporting Standards.

Exhibit 24-2 summarizes TVO's provisions related to nuclear decommissioning and waste management as recognized in the 2019 financial statements. It shows provisions related to nuclear waste management equal to €1.040 billion, as compared to TVO's target funding obligation for to the YVR of €1.471 billion, significantly greater than the nuclear provisions.

[351] TVO, 2019 Report of the Board of Directors and Financial Statements, p. 28.
[352] TVO, 2019 Report of the Board of Directors and Financial Statements, p. 60.

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Exhibit 24-2 – TVO Nuclear Waste Management Provisions[353]

Nuclear waste management provisions (Euro millions)	2019	2018
Beginning of the year	952.0	953.1
Increase/Decrease in provision	205.7	(13.5)
Used provision	(37.5)	(32.1)
Changes due to discounting	(79.4)	44.5
End of the year	1,040.8	952.0
Discount rate	4.0%	5.5%
TVO's target funding obligation - Nuclear Waste Fund (2020 and 2019)	1,471.4	1,505.8

As under US GAAP, the provision has been capitalized as property, plant and equipment and is depreciated over the estimated operating time of the nuclear power plant.[354] TVO therefore recognizes, in its income statement, depreciation expense related to the nuclear decommissioning and waste management provisions, finance income from assets related to nuclear waste management and interest expense/recovery related to changes in discounting on the provision.[355]

The 2019 annual report notes that "[t]he main reason for the difference between the carrying value of the provision and the legal liability is the fact that the legal liability is not discounted to net present value".[356]

As noted earlier in this Chapter, the fixed costs that the company recovers from shareholders under the Mankala principle include costs set out in the Nuclear Energy Act. Our review of TVO's annual report did not further identify which specific costs as laid out in the Act are allocated to shareholders (and on what basis they are allocated). We do note, however, that the following individual expense items are identified in TVO's 2019 income statement, or are reported as part of component expense lines, and can thus reasonably be assumed to be reflected in revenues recovered:

- Depreciation related to decommissioning of €6.4 million (€2.5 million in 2018). [357]
- Nuclear Waste Management Services of negative €3.1 million (as a negative value this is an expense offset, or revenue, in that year). For 2018, the same expense item was (positive) €42.7 million.[358]
- Finance income and expenses as follows:
  - Interest income from assets related to nuclear waste management of €7.7 million (€9.2 million in 2018)
  - Interest expense/recovery of provision related to nuclear waste management of negative €79.4 million, representing a recovery, (€44.5 million expense in 2018).[359] This amount relates

[353] TVO, 2019 Report of the Board of Directors and Financial Statements, p. 95.
[354] *Ibid*, p. 35
[355] *Ibid*, pp.39-41.
[356] *Ibid*, p 60.
[357] *Ibid*, Note 8, p. 40.
[358] *Ibid*, Note 6, p. 39.
[359] *Ibid*, Note 10, p. 41.

to the “changes due to discounting” found in the change in the provision in Note 24 of the TVO Annual Report.

In total, these items sum to a negative expense (or expense offset) of €83.8 million in 2019. In 2018, the same items sum to an expense of €80.5 million. However, we have not been able to map these various items to the reported nuclear provisions on the balance sheet, which were summarized above in Exhibit 24-2.

In parallel, we also reviewed the 2007 report for the European Commission on Finnish funding mechanisms that was cited earlier. This report notes that impacts on power costs from the overall funding regime are difficult to assess. The report stated:

> “No obligation of balance-sheet-specifications in order to control the source of the money paid into the Fund has been set for the licence-holders. Consequently, on the basis of the funding system it is not possible to count precisely the effect of waste management costs on the cost of nuclear electricity.” [360]

While this report is dated, it also suggests that it may be difficult to identify linkages between the funding for decommissioning and consumer rates.

[360] Report for European Commission Directorate-General Energy and Transport, Comparison among different decommissioning funds methodologies for nuclear installations, Country Report Finland, Service Contract TREN/05/NUCL/S07.55436, 2007, p, 29.

25 Other European Jurisdictions

In this Chapter, we summarize some of our research on several other European jurisdictions, being:

- Belgium
- Germany, and
- Sweden

We did not research developments in these jurisdictions in greater depth as it became readily apparent that, like most other European jurisdictions, they have developed competitive electricity markets as the primary electricity price setting mechanism. Accordingly, as noted in Chapter 3, there is no clear link between decommissioning and waste management costs and the prices paid by consumers in these jurisdictions. In the section below, we have provided a contextual overview of institutional frameworks and financial assurance mechanisms in place for decommissioning-related arrangements in each of the three countries.

25.1 Belgium

25.1.1 Industry and Market Structure

Belgium has a competitive electricity generation market. There is a power exchange ("BELPEX") that operates both a day-ahead market and a real-time spot market.[361] Companies in the transmission and distribution sectors must be legally separate from companies involved in supply and production.[362]

Electrabel is the dominant electricity generator, which controlled over 75% of the country's generating capacity at the end of 2015.[363] Electrabel is a wholly-owned subsidiary of ENGIE, a holding company with diversified holdings in the utility sector across a range of jurisdictions.

There are seven nuclear reactors in Belgium, all of which are wholly or partly owned by Electrabel. Luminus the second largest electricity producer in the country, has ownership stakes in four of the reactors. EDF Belgium has a 50% stake in one of the remaining plants. Total capacity of the nuclear fleet is 5,931 MW.

Nuclear power is not part of the government's long-term plan, although the planned phase-out of nuclear generation has been somewhat delayed. On January 31, 2003, Belgium's federal Parliament passed a law prohibiting the construction of new nuclear units intended for the industrial production of electricity by nuclear fission. This law limited the operation of existing reactors to 40 years in total. According to this law, nuclear fission energy was to be phased out between 2015 and 2025. Successive governments have amended the law in order to ensure the security of supply of electricity, thus delaying the closure of some units past their original shut-down date. However, governments have remained firm on the decision to phase out all nuclear power reactors by 2025.[364]

[361] IEAE, Belgium Country Profile (Updated 2018), p.1 of 43.
[362] IEAE, Belgium Country Profile (Updated 2018), p.4 of 43.
[363] IEAE, Belgium Country Profile (Updated 2018), p.1 of 43.
[364] IEAE, Belgium Country Profile (Updated 2020), p.1 of 43.

25.1.2 Decommissioning and Waste Management

25.1.2.1 ONDRAF/NIRAS

The Belgian Agency for Radioactive Waste and Enriched Fissile Materials ("ONDRAF/NIRAS") is a national agency established to oversee the management of radioactive waste in the country and to undertake its final storage and disposal.[365] It is preparing plans for a geological storage facility, and will charge fees to nuclear operators to recover its costs. ONDRAF fees include margins for contingencies and other risks that may arise in connection with the disposal of waste. [366] ONDRAF also has role in ensuring that nuclear owners and operators create the necessary provisions for the financing of future dismantling programs.[367]

In 2018, ONDRAF proposed geological storage as a national policy for long-term management of high-level and/or long-lived waste. However, as of the date of Synatom's 2019 annual report, the regulatory framework had not yet confirmed adoption of this storage approach.[368] Synatom is discussed below.

25.1.2.2 Synatom

Synatom is a wholly-owned subsidiary of Electrabel that handles the upstream and downstream parts of the fuel cycle. Thus:

- It supplies enriched uranium to the production plant where the fuel assemblies used by nuclear reactors are fabricated.
- It accepts spent nuclear fuel and arranges for interim storage of spent fuel prior to its expected transfer to ONDRAF/NIRAS.

Additionally, Synatom is responsible for decommissioning nuclear plants and establishing nuclear provisions. Provisions measure the value of the nuclear liability, and are the basis of the funds set aside to cover the costs of decommissioning and spent fuel management.

On behalf of the Belgian government, Synatom collects a special contribution, also known as a nuclear tax, from four of the operating reactors. The other three reactors are subject to separate taxation as part of the agreement to extend their operating license for an additional 10 years. The special contribution is mainly based on the profit margin achieved by the plant owners.[369]

Although Synatom is responsible for managing the set-aside nuclear provisions, the Commission for Nuclear Provisions ("CNP") oversees the process of computing and managing these provisions. Synatom must submit a report on the constitution of these provisions for CNP's approval every three years. CNP takes into account opinions provided by ONDRAF with respect to Synatom submissions.[370]

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[365] ONDRAF stands for "Organisme national des déchets radioactifs et des matières fissiles enrichies" in French and NIRAS stands for "Nationale Instelling voor Radioactief Afval en verrijkte Splijtstoffen" in Dutch.
[366] Engie, 2019 Consolidated Financial Statements, p. 153.
[367] IEAE, Belgium Country Profile (Updated 2018), p.11 of 43.
[368] Synatom, 2019 Annual Report, p. 14.
[369] Synatom, 2018 Annual Report, p. 11.
[370] ENGIE, 2019 Consolidated Financial Statements, pp. 152 - 153.

Under governing legislation, Synatom can provide loans to nuclear operators for up to 75% of the value of nuclear provisions.

On its balance sheet, Synatom reports as a liability, provisions that cover expected costs relating to the definitive shutdown phase, including:

- The unloading and disposal of the plant's spent fuel.
- The decommissioning period itself, which results in site declassification and clean-up.

As the end of 2019, these provisions stood at €13.2 billion, with 43% related to decommissioning and 57% related to spent fuel management. Discount rates ranging from 3.20 to 3.25% in 2019 and 3.5% in 2018 were used to determine the provisions.[371] According to the Engie 2019 annual report, since that time, discount rates were further reduced to 2.5% for decommissioning, for which expenditures will begin as of 2020, and to 3.25% for spent nuclear fuel management.[372]

Although owned by Electrabel, a 2009 report noted that the Belgian government holds a "golden share" in Synatom that gives it power to veto the company's decisions. [373]

25.2 Germany

25.2.1 Industry and Market Structure

Germany has a competitive electricity generation market. Standardized futures products are bought and sold in a transparent process on the relevant exchanges, which for Germany are the European Energy Exchange ("EEX") in Leipzig, Germany and the European Energy Exchange ("EPEX SPOT") in Paris, France. However, companies continue to primarily conclude supply contracts with electricity producers directly in "over-the-counter" transactions. Trading on the electricity exchanges makes up only around 20% of the total trading volume.[374]

Although there is no regulation of retail electricity prices in Germany, retail electricity prices include regulated price components, such as network fees and surcharges. For example, the prices include the EEG surcharge, which is in place to finance the measures under the Renewable Energies Act.

Germany has some of the lowest wholesale electricity prices in Europe and some of the highest retail prices, due to its energy policies. Taxes and surcharges account for more than half the domestic electricity price.

Based on the report from the German Federal Ministry for Economic Affairs and Energy, as of December 31, 2017, only 7 of Germany's 23 nuclear power plants were still in active operation, with 11 power plants in the decommissioning and dismantling phase.[375] This reflected the 2011 decision by the German government to phase-out nuclear power, declaring the immediate shutdown of eight

[371] Synatom, 2019 Annual Report, p. 10-11.
[372] Engie, 2019 Consolidated Financial Statements, p. 153.
[373] Commission of the European Communities, "EU Decommissioning Funding Data", Commission Staff Working Document, SEC(2007) 1654 final/2, 22.12.2009, p. 31.
[374] Bundesnetzagentur (Federal Network Agency), "Wholesale prices", Updated: May 2020.
[375] TranspBericht, 29.11.2019, p. 8 and Appendix A (p. 36 and following).

of the 17 then active nuclear reactors. There are also Soviet-designed reactors in the east that are in various stages of being decommissioned. [376,377]

Nuclear power plants in Germany are owned and operated by companies that are consolidated in one of the following four entities:

- E.ON SE,
- RWE AG,
- Vattenfall GmbH, which is owned by the Swedish government, and
- EnBW AG, which is owned by the Baden-Wuerttemberg state government and a number of counties and municipalities.

25.2.2 Decommissioning and Waste Management

Nuclear operators are responsible for:

- The decommissioning and dismantling of nuclear plants[378], and
- The packing of radioactive waste.[379]

In 2017, the operators transferred the responsibilities for managing intermediate and final storage of radioactive waste to the federal government. Costs will be covered by a fund that plant operators pay into (the Entsorgungsfondgesetz). [380]

According to the law, the operators must pay a base amount (based on the decommissioning provisions made by the entities previously) plus a risk surcharge of 35.47 % on the base amount in return for being released from the liability for any possible future cost increases. In total, operators transferred €24.1 billion to the fund. According to the Federal Ministry for Economic Affairs and Energy the fund is expected to grow to about €70 billion by 2100 through investments.

Utilities are also required by German legislation (TransparenzG and RückBRTransparenzV) to report to the German Federal Ministry for Economic Affairs and Energy, on an annual basis, their expected costs[381] relating to asset retirement obligations for nuclear power plants as measured under local German GAAP.[382] In addition, they must report the liquid assets that they have set aside to cover those costs, present funding for the next three financial years from the reporting date by year, and explain the availability of liquid assets to meet future expenditures for asset retirement obligations.

[376] World Nuclear Association, “Nuclear Power in Germany”, Updated: December 2019.
[377] The dismantling and disposal of these nuclear facilities is being handled by a company that is 100% federally-owned. The financing of the activities is secured solely from the federal budget. No special tax or fee is explicitly charged to taxpayers for financing the entity’s activities.
[378], Atomgesetz [Atomic Energy Act], §7 (3).
[379] Entsorgungsübergangsgesetz [Waste Management Transfer Act], §2 (3, 5),
[380] Entsorgungsfondgesetz [Decommissioning fund legislation], §2 (2)
[381] Measured in accordance with German GAAP.
[382] According to §253 (2) of German GAAP, entities are required to discount their asset retirement obligations with a residual maturity of more than one year by using rates that are published monthly by the German Central Bank (Deutsche Bundesbank) and that represent a 7-year average risk-free rate. The requirement to report asset retirement obligations under German GAAP is in addition to the general financial reporting requirements under IFRS followed by the applicable entities.

Exhibit 25-1 summarizes funding plans filed by the utilities in response to these requirements. As shown, there is no universal set-aside funding mechanism for these utilities as part of Germany's financial assurance framework; it appears that at least of the funding needs will be met with other, less assured sources such as operating cash flow.

Exhibit 25-1 Short to medium term funding of asset retirement obligations in Germany[383]

Entity	Short-term funding	Medium-term funding
	(next 1-3 years)	**(approx. next 4-14 years)**
E.ON SE	– Funds from operative cash flows of active nuclear plants – Line of credit with banks	– Funds from operative cash flows – Investments – Line of credit with banks – Bonds
RWE AG	– Funds from operative cash flows of active nuclear plants – Line of credit with banks	– Funds from operative cash flows – Investments – Line of credit with banks – Bonds
Vattenfall GmbH	– Line of credit with banks – Cash and cash equivalents	– Funds from operative cash flows – Line of credit with banks – Bonds
EnBW AG	– Funds from operative cash flows of active nuclear plants – Cash and cash equivalents	– Cash-pooling within the EnBW group and profit transfer agreements – Line of credit with banks – Bonds

25.3 Sweden

25.3.1 Industry and Market Structure

Sweden is part of the Nordic Power Pool, which has a competitive spot market.

There are three operating nuclear plants in Sweden, comprising a total of 10 reactors. One other nuclear plant has been shut down (at Barseback). Two of the operating nuclear plants are owned by Vattenfall (Ringhals and Forsmark). The third plant (at Oskarshamm) is owned by German and Finnish energy companies.

Vattenfall is both the largest nuclear operator and the largest electricity generator in Sweden (accounting for more than 55% of total electricity generated). [384] Vattenfall's nuclear capacity in Sweden is 7,242 MW.[385] Vattenfall is owned 100% by the Government of Sweden.

Vattenfall's existing nuclear fleet consists of four reactors at the Ringhals plant and three reactors at the Forsmark plant. Ringhals 2 has been recently taken offline and Ringhals 1 is scheduled to be

383 TranspBericht. Data included in the TranspBericht has been gathered as of December 31, 2018.
384 Vattenfall AB Annual Report 2018, p. 36.
385 Including Ringhals 2 that has now been taken offline

taken offline in December 2020. Ringhals 3 and 4 and Forsmark 1, 2 and 3 are being upgraded to ensure long-term operation, scheduled into the 2040's.[386]

The Swedish government originally passed a law in 1980 requiring the phase-out of nuclear reactors. This law was ultimately rescinded in 2010 and current government policy envisages that the lifespan of existing reactors can be extended. Moreover, in 2016, the government decided to phase-out a nuclear capacity tax in order to support the country's transition to carbon-free electricity generation. Nuclear power plants are now seen as an important component of that transition.

25.3.2 Decommissioning and Waste Management

Swedish Nuclear Fuel and Waste Management Company (SKB)

In Sweden, there is a single entity that is responsible for the long-term, safe handling of radioactive waste. This is the Swedish Nuclear Fuel and Waste Management Company ("SKB"), which is owned by the nuclear power companies in Sweden. It is responsible for the development of a final repository for nuclear waste and for the ultimate encapsulation of nuclear waste at this site. In the interim, it also provides intermediate storage. Individual reactor operators, however, remain responsible for the decommissioning and dismantling of their facilities. For the total fleet, decommissioning costs represent an estimated 28% of remaining post-operational costs, while final repository, encapsulation, intermediate storage and other costs account for the remainder.[387]

Nuclear Waste Fund

Funds to pay for the expected costs of decommissioning and waste management are held by the Swedish Nuclear Waste Fund ("Karnavfallsfonden"), which is a fund established by the government to hold funds collected from nuclear operators to cover future decommissioning and waste management costs. The Nuclear Waste Fund collects fees from each holder of a license to own or operate a nuclear facility. The fee is calculated individually for each licensee and set so that the calculated future fees, together with assets already accumulated, will cover the total expected costs for that licensee. The National Debt Office is responsible for calculating fees and approving disbursements of Fund assets. Disbursements for waste processing and spent fuel management will ultimately flow largely to SKB, which, as noted above, is responsible for handing radioactive waste. Disbursements to cover reactor decommissioning and dismantling will generally offset costs incurred by the nuclear operators themselves. In summary, the Nuclear Waste Fund is a separate entity that holds funds for decommissioning and waste management activities, but ultimately returns these funds to the entities responsible when activities commence. For operating reactors, the fee for each licensee is established every three years as a fixed amount per kWh.

Nuclear Fund Guarantees

In addition to making payments to the Fund, nuclear operators currently need to provide guarantees (or security in the form of "guarantee commitments") to the Swedish government that sufficient funds will exist to cover the future costs of nuclear waste management. This is made up of two parts:

[386] IAEA Power Reactor Information System, Sweden. Retrieved 2020-12-23
[387] Vattenfall AB Annual Report 2018, p. 29.

- Financing Security, which is intended to cover the current deficit of the Nuclear Waste Fund assuming that no more nuclear waste fees are paid. This deficit is calculated as the difference between expected costs and existing funds.
- Supplementary Security, which pertains to future cost increases stemming from unforeseen events. [388] This amount accounts for costs above the median estimate.

The Vattenfall annual report describes the two types of security as follows:

> "The amounts for both of these types of security have been determined based on a probability-based risk analysis in which the former amount has been determined as such that there is a 50% probability that it, together with currently funded amounts (the median value), will provide full cost coverage for all waste produced to date. The latter amount consists essentially of the supplement that would be required if the corresponding probability was 90%."[389]

Thus, similar to the estimation process for the costs of decommissioning for Hinkley Point C in the UK, a P-value higher than 50% has been used to provide some buffer in the cost estimate relative to a median (or P-50 estimate).

Portfolio Allocation

The Nuclear Waste Fund has historically been allowed to invest only in low-risk bonds.

In 2018, however, the Swedish parliament passed a new law allowing the Fund to invest in corporate bonds and equities, subject to certain restrictions. This was prompted by concerns over declining returns from bond portfolios. In response, the Fund has initiated a new asset management strategy, with funds divided into two portfolios:

- A base portfolio with Swedish treasury and mortgage bonds, and
- A long-term portfolio with corporate bonds and equities.

The Fund notes:

> "This has made it possible to offer the different reactor owners and other fee-liable licensees an asset management strategy adapted to the particular reactor owner's investment horizon".[390]

Licensees will be required to allocate at least 60% of their funds to the base portfolio (of treasury and mortgage bonds).[391]

[388] Vattenfall AB Annual Report 2018, p. 145.
[389] Vattenfall AB Annual Report 2018, p. 145.
[390] Nuclear Waste Fund Annual Report 2018, p. 2.
[391] Nuclear Waste Fund Annual Report 2018, p. 6.

26 Japan

The Chapter summarizes our research on developments in Japan. As noted in Chapter 3, we encountered difficulties in collecting and interpreting some of the information related to decommissioning and nuclear waste management related arrangements in Japan. In particular, we have been unable to identify how decommissioning and waste management costs are reflected in consumer rates. For additional context, this Chapter sets out our general findings on the nuclear power sector, mechanisms for funding spent nuclear fuel costs and other related developments.

26.1 Industry and Market Structure

The Japanese electricity market is geographically divided into ten regions. Each region covers the service territory of a long-standing vertically integrated utility; collectively these utilities are known as the "general electricity utilities". The general electricity utilities have historically had monopolies in every aspect of the market, including generation, transmission, distribution and retailing. Nine of the 10 regional utilities in Japan currently operate nuclear plants.

Since 1995, Japan has gradually been liberalising its electricity sector, beginning with power generation. The electricity retail market was liberalized in April 2016 as part of a phased approach to electricity system reform, with the retail price for electricity and the conditions of retail sale becoming generally unregulated. However, as a transitional measure to protect customers during this phase of electricity system reform, the Electricity Business Act continued to provide for regulation of the retail prices offered to low voltage consumers. Together with this liberalisation, the regulatory framework of the electricity sector shifted from regulations that were differentiated by the type and historical origin of electricity companies to regulations differentiated by their function (generation, transmission, distribution, and supply).

In the next phase of reform, the ten general electricity utilities are required to unbundle their power generation and retail functions from their transmission and distribution functions, with the intent to fully liberalise the retail market.[392] This phase also enables the Ministry of Economy, Trade and Industry ("METI") to designate areas where retail price restriction will remain, and to decide the timing of when to lift the retail price restriction by area.[393]

The Japan Electric Power Exchange ("JEPX") is the current spot market and forward market for trading electricity. Generators and suppliers can also trade directly outside JEPX and are free to negotiate the terms and conditions of their power purchase agreements.

Japan needs to import approximately 90% of its energy requirements. Accordingly, concern over the security of supply for energy is an important policy consideration, with nuclear power historically playing an important role in addressing security concerns. Notwithstanding the Fukushima incident in 2011, nuclear energy remains a strategic priority for Japan.

In the Fukushima incident, a 15-metre tsunami followed a major earthquake. This tsunami disabled the power supply and cooling of three Fukushima Daiichi reactors, causing a nuclear accident on

[392] Takahashi, R; Takeuchi, N; Higuchi, W; Yokoi, K; Hayashi, K; and Takada, K, The Energy Regulation and Markets Review - Japan – Edition 9. Published July 2020.
[393] The METI Minister must make the decision after careful review of the status of competition from the perspective of consumer protection and consultation with the Electricity and Gas Market Surveillance Commission.

March 11, 2011. All nuclear units in Japan were subsequently shut down in order to undergo a re-assessment of their health and safety protocols and design features. Thirty-three commercial nuclear reactors in Japan were operational as at the end of May 2020, with two additional units under construction. However, many of the operational units were still not yet restarted. An additional 27 units have been permanently shut down.[394]

The government's fundamental energy policy, the Basic Energy Plan, is published by METI and describes nuclear power as "an important base-load power source contributing to the stability of the long-term energy supply-and-demand structure".[395] The July 2018 revision of the Plan reaffirms the 2015 target of 20-22% for the nuclear power's share of the energy mix by 2030. Up until 2011, Japan was generating about 30% of electricity from its reactors and this had been expected to increase to at least 40% by 2017.

26.2 Funding for Spent Nuclear Fuel

In May 2016 a new bill was implemented with the aim of "securing funds for expenses for the steady and efficient reprocessing operations of spent nuclear fuel" in Japan. The Spent Nuclear Fuel Reprocessing Fund Act ("Spent Nuclear Fuel Act") was established to introduce a new scheme in which an organization would be established to manage funds related to reprocessing of spent nuclear fuel.[396]

The Spent Nuclear Fuel Act aimed to ensure the efficient reprocessing and disposal of spent nuclear fuel in an environment in which the electricity retail market has been liberalized. The Act introduced a new funding system in which a new authorized fund management corporation, the Nuclear Reprocessing Organization of Japan ("NuRo"), has been established to administer such reprocessing and other work, and to which businesses contribute necessary funds. This replaced the prior funding system in which businesses accumulated funds in external organizations.

NuRo is responsible for collecting contributions from each nuclear power operator on an annual basis. The required contribution is based on the amount of electricity generated by each entity. The funds maintained by NuRo are used for the reprocessing of spent nuclear fuel. NuRo has commissioned Japan Nuclear Fuel Limited ("JNFL") to reprocess spent nuclear fuel at its Rokkasho complex.

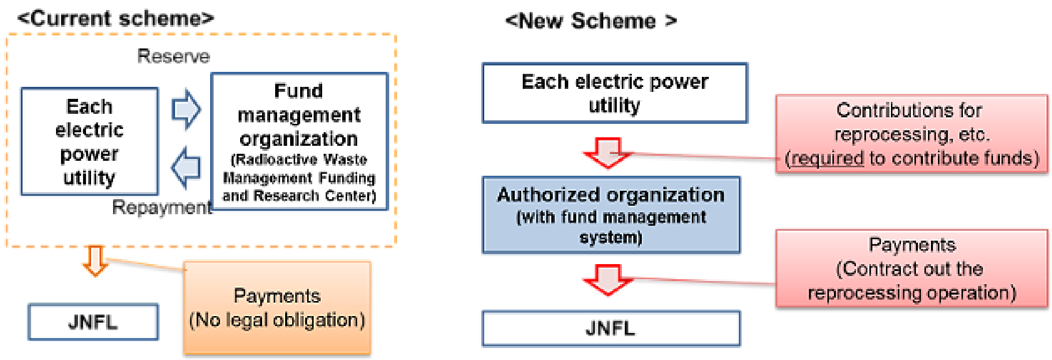
JNFL is a jointly owned entity with 91% of ownership being split amongst the ten general electricity utilities in Japan, and the remainder held by the Government of Japan. Under the new structure, NuRo will pay JNFL directly from the reserve fund, for reprocessing the spent nuclear fuel from the nuclear operators in Japan.[397]

According to NuRo's 2019 financial statements, of the 1.385 trillion JPY in investments held by NuRo, over 91% is invested in government bonds with the balance made up of government guaranteed bonds or local bonds.[398]

The above noted change in the structure for spent fuel funding is shown in Exhibit 26-1 below, with the new scheme shown on the right.

[394] International Atomic Energy Agency, Country Statistics, last updated May 28, 2020.
[395] World Nuclear News, "Japanese Cabinet approves new basic energy plan", July 3, 2018.
[396] "Spent Nuclear Fuel Reprocessing Implementation Act", Ministry of Economy, Trade and Industry. Retrieved 23-11-2020.
[397] World Nuclear Association, "Japan's Nuclear Fuel Cycle", (Updated April 2020). Retrieved 23-11-2020.
[398] "Nuclear Reprocessing Organization, March 31, 2019 Financial Statements"

Exhibit 26-1 – Changes in Funding Arrangements for Spent Fuel



26.3 Other Observations

26.3.1 Special Account for Nuclear Decommissioning

In our research, we came across information regarding a special account related to nuclear power decommissioning established by the METI. This was reflected in the revised Ordinance on Accounting at Electricity Utilities (Ordinance of the METI No. 77, 2017) issued in 2017.[399] This Ordinance provides that, in the event of the decommissioning of a nuclear reactor resulting from changes in energy policies, the following assets and costs may be posted or transferred to a special account related to nuclear power decommissioning with the approval of the METI:

- The carrying amount of fixed assets associated with the reactor, excluding a number of specific items. Specific items that are excluded relate to construction in progress and assets that correspond to AROs relating to items contaminated by nuclear fuel.
- The carrying value of nuclear fuel for said reactor (excludes projected disposal amounts); and
- (Cost of reprocessing of irradiated nuclear fuel generated in connection with the decommissioning of the nuclear reactor, and amounts corresponding to costs necessary to dismantle the components of the nuclear fuel.

We identified a reference that regulated fees will be applied to recover the costs transferred to the special account but were unable to identify further details on this mechanism.[400]

[399] Tohoku Electric Power Company Financial Data Book 2019, English Version, p, 17.
[400] Kyushu Electric Power Company Annual Report FY2019, English Version, p. 71.

Part IV – Summary of Findings

27 Key Findings

This Chapter summarizes some overall findings and observations, based on our review of practices across our sample group of jurisdictions with respect to the recovery of decommissioning costs.

In our jurisdictional review, we found a wide range of practices with respect to nuclear decommissioning cost recovery. As a consequence, it is difficult to identify an accepted or dominant methodology. Amounts collected from consumers, or put aside by company shareholders, may not be directly linked to accounting provisions. Amounts may sometimes not even be based on transparent cost analyses.

We observed that, in many cases, amounts collected for decommissioning are based on required contributions to segregated trust funds. Under this approach, amounts included in rates to consumers are based on forward-looking assessments of amounts that need to be set aside and invested in order to ensure that sufficient funds are available at the time of decommissioning. This can be referred to as a forward-looking funding approach. In particular, we found that the forward-looking funding approach is the dominate methodology used in the US to determine amounts collected from consumers for decommissioning costs.

Funding Approach Entails a Fair Degree of Subjectivity

A funding approach entails a fair degree of subjectivity, as a number of parameters must be defined when calculating required contribution amounts. These parameters include:

- Projected escalation rates for decommissioning costs.
- Estimated rates of return on invested funds.
- The period over which funding contributions will be made.
- The profile of contributions within the funding period.

Some similar parameters need to be defined when calculating ARO accounting expenses, but these parameters are generally fewer in number and subject to more constraints. Thus:

- The discount rate used to determine the present value of decommissioning costs and to calculate rates of accretion are generally constrained under accounting rules, with links to defined market benchmarks.
- The allocation of costs over time is defined by the mechanics of accounting procedures, with much more limited scope for subjective adjustment.

Timing of Recovery Decisions Are Different and May Have Influenced Decisions

The NRC funding approach was developed in 1990, thirteen years before the US GAAP standard on Asset Retirement Obligations came into force. U.S. utilities therefore adopted this forward-looking funding approach prior to the implementation of accounting standards that mandated the recognition of asset retirement obligations for nuclear facilities and associated accounting expenses. This timeline may conceivably have influenced the adoption of the funding approach as the dominant method in the U.S.

Key Features of the US Funding Approach

Notable elements of the US funding approach include the following:

- The NRC defines the minimum costs that must be covered through funding plans with a standard formula that takes into account reactor type and capacity. In combination with prescribed escalation factors, this formula identifies the minimum value of projected costs in current dollars. The formula is based on an analysis of observed decommissioning costs in the 1980s and is intended as a planning tool rather than an estimate of actual cost. The formula does not provide for full site-restoration nor does it cover costs of either interim or long-term spent fuel storage.
- Utilities must prepare site-specific cost estimates as the reactor nears the end of its operating life (but can prepare such studies earlier if desired). These site-specific estimates have sometimes resulted in significant increases in expected costs later in a facility life, relative to amounts determined through the NRC funding formula.
- The NRC defers to state utility regulators on certain parameters and thus allows them to approve estimates of future cost escalation rates, rates of return on invested funds, and on the profile of trust fund contributions. The NRC, however, provides guidance in respect of these parameters.
- Utilities must file updates on a biennial basis with the NRC on funding status, and funding shortfalls identified must be made up within a defined period. The identification of funding status in these updates will take into account the parameters accepted by utility regulators (such as with respect to projected fund earnings rates).

As indicated, the US regime provides for a major role by utility regulators within standards and guidelines provided by NRC. We thus observed significant discussion in US regulatory proceedings on fund investment policies, on expected rates of return on trust fund assets and on the scope of decommissioning activities. Different regulators have made quite different decisions in respect of these parameters.

The nature of a forward-looking funding approach is that annual funding amounts may fluctuate widely with changes in expected facility lifespan and in decommissioning cost estimates:

- Recoveries in rates for decommissioning have sometimes increased sharply when facility closures became imminent and/or costs are better understood.
- Conversely, there are many cases in the US in which required contributions to decommissioning trusts, and hence allowances in rates, have fallen to zero as a result of reactor life extensions. This reflects the extended period over which investment earnings can then accrue.

Changes in funding requirements as a result of unexpected developments can have significant implications for intergenerational equity. The development of more accurate decommissioning cost estimates late in the facilities life may result in an undue proportion of costs being borne by later generations of consumers. Conversely, life extension and the resulting increase in the investment horizon for initial contributions may result in later generations of consumers paying a relatively low share of decommissioning costs.

Responsibility for Spent Fuel is an Important Consideration

A very significant consideration in regard to US practice is the fact that the US DOE has accepted responsibility for the processing and long-term storage of spent fuel. In return, the US DOE collected fees from nuclear operators. These fees have been passed along to consumers and recovered through various mechanisms. The role of the US DOE significantly reduces the scope of activities that US nuclear operators need to provide for in their own recoveries for decommissioning. In particular, the scope of activities is much narrower than that covered by OPG through its own decommissioning provisions. OPG, through its membership in the Nuclear Waste Management Organization, must plan for the siting, technology development, licensing, construction and operation of facilities to manage spent nuclear fuel. This increases the risk and uncertainty over this significant element of the nuclear liability costs.

In must be noted, however, that the US DOE has failed to meet its commitments with respect to spent fuel collection and this has meant that US utilities have had to make additional provisions with respect to interim spent fuel storage. Uncertainty with respect to the timing of the US DOE's ultimate acceptance of spent fuel has been a major issue in US utility proceedings and continues to influence decisions on required funding amounts and how those amounts will be recovered from electricity consumers.

The Role of Conservatism in Funding Projections

Looking more broadly, and considering practices globally, governments and regulators have often adopted conservative policies with respect to decommissioning funding. Legislative and regulatory policies tend to favour approaches that reduce the risks of underfunding. This is reasonable given concerns that taxpayers may ultimately be liable for funding shortfalls if amounts collected from utilities and utility ratepayers are insufficient. Thus, governments or regulators have sometimes included large buffer amounts in decommissioning cost estimates to reduce the risk that funds collected will be insufficient. Such buffers have taken the following forms:

- The use of conservative cost estimates in calculation of required amounts.
- Additional contingency amounts above those associated with conservative cost estimates.

Although there is a general trend to conservatism by governments and regulatory agencies, we observed some instances in which US state regulators have made decisions that have reduced required consumer contributions from what they would otherwise be. This has included reductions as a result of:

- Ignoring costs for site restoration, which is not a requirement under NRC's funding guidelines.
- Basing recoveries on the NRC funding formula rather than on site-specific estimates that may be already available (the latter of which are generally higher).

Market Transition Can Complicate Funding Mechanisms

When utilities have transitioned from a regulated regime to one with a competitive electricity market, anomalies may arise as a result of the transition process. Transition processes typically complicate funding arrangements and introduce policy challenges. It may be easier to guarantee the recovery of decommissioning costs from regulated entities and from periods where rates are subjected to regulation, and this may be reflected in arrangements for funding decommissioning costs when market structures change.

Other Observations

Other key findings are as follows:

- In general, the relevant parties (governments, regulators and nuclear power plant owners) seek to collect costs associated with decommissioning over the operating life of power plants, with funds collected from users (i.e. consumers of power) rather than from taxpayers. There are, however, exceptions where this objective has not been lived up to in practice.
- Regulators often aim to recover decommissioning costs on a relatively uniform basis over the life of facility. Uniformity may be assessed in real dollar rather than nominal dollar terms.

28 Rate Recovery Methodologies Potentially Applicable to OPG

In this Chapter, we consider the potential applicability of the rate recovery mechanisms identified in the preceding chapters to the nuclear liabilities related to OPG's Regulated facilities and for the Bruce facilities nuclear assets.

28.1 Screening Analysis

As noted in Section 3.7, we identified four major categories of rate recovery methods: (1) forward looking funding requirement; (2) accounting expense; (3)flow through ; (4) arbitrary rate.

We have performed a screening analysis of these four methods considering the most prevalent rate recovery methods identified in the jurisdictions most similar to OPG using the jurisdictional characteristics (as discussed in Chapter 3). Although we have attempted to identify the aspects of each cost recovery method that may apply to OPG. In comparing OPG's nuclear liabilities cost recovery methodology to methodologies encountered in other jurisdictions, the unique circumstances of each entity must be considered.

Based on this screening analysis, the two recovery methods most likely to be applicable to OPG are the forward looking funding requirement and the accounting expense. These methods appear to be common in jurisdictions subject to economic regulation. The flow through method and the arbitrary rate methods are not broadly applicable rate recovery methods.

28.2 Comparisons between applicable rate recovery methods

We have organized this comparison to the following parameters:

- Scope of obligation
- Costs estimates for rate recovery
- Determination of cash contribution amounts:
- The period over which funding contributions will be made
- The period of rate recovery

28.3 Comparisons between US jurisdictions' Forward Looking Funding Requirement Methodology, Accounting Expense Methodology, and OPG's Methodology

	US Jurisdictions' Forward Looking Requirement Methodology	Accounting Expense Methodology	Ontario Power Generation's Methodology
Scope of obligation	NRC requirements are specific to decommissioning costs and specifically do not cover site restoration costs or spent fuel waste management (the latter being the responsibility of the DOE). However, entities' regulators have allowed for recovery beyond the NRC minimums.	Recognize all legal obligations which includes decommissioning, spent fuel and restoration of site costs.	Same as Accounting Expense Methodology
Cost estimates for rate recovery	The NRC defines the minimum costs that must be covered through funding plans with a standard formula that takes into account reactor type and capacity. In combination with prescribed escalation factors, this formula identifies the minimum value of projected costs in current dollars. The formula is intended as a planning tool rather than an estimate of actual cost. Utilities must prepare site-specific cost estimates as the reactor nears the end of its operating life (but can prepare such studies earlier if desired).	Cost estimates are determined in accordance with US GAAP, which requires a reasonable estimate of fair value of the decommissioning costs. In practice, a present value technique is used to estimate the fair value of the ARO which includes the estimated cost of the future decommissioning on a site-specific basis and then discounted back to the present period using a credit-adjusted risk-free rate.	Same as Accounting Expense Methodology. Through the ONFA Reference Plan process, OPG does a comprehensive revaluation of all cost estimates at minimum every five years and monitors for any changes that may require a more frequent update.

	US Jurisdictions' Forward Looking Requirement Methodology	Accounting Expense Methodology	Ontario Power Generation's Methodology
Determination of cash contribution amounts	The US jurisdiction provides for a major role by economic regulators within standards and guidelines provided by NRC. We observed significant discussion in US regulatory proceedings on fund investment policies, on expected rates of return on trust fund assets and on the scope of decommissioning activities.	Cash contributions to segregated funds do not directly impact the application of this methodology. However, these contributions have an indirect impact as the subsequent return on the segregated funds is an offset to the accretion expense of the ARO and the depreciation of the ARC. Fund contributions based on a third-party (i.e. ONFA/NRC) requirements would still need to be met in order to maintain compliance with legal obligations.	ONFA sets OPG's contribution amounts by comparing segregated fund balances at a point in time with a Provincially-approved reference plan that sets out the estimated costs to meet OPG's nuclear waste management and decommissioning obligations. The OEB does not have a direct role in determining fund investments, expected rate of return or scope of decommissioning costs.
The period over which funding contributions will be made	The overall funding profile of the segregated funds in the US is flat in nominal terms, if isolated for changes in key parameters. When parameters change, which occurs in practice, these costs may shift to be either front-end loaded (extension of license) or back-end loaded (unanticipated costs, or earlier decommissioning).	The overall funding profile may be front-end loaded in nominal terms, as depreciation is straight-line, earnings on segregated funds would be greater in future periods, somewhat offset by the gradual increase in accretion expense. Subsequent to the operating life of the plant, and assuming a SAFSTOR approach, may result in earnings in	ONFA, explicitly by design, required an up-front funding of the segregated funds. For clarity, the up-front funding of these segregated funds was not from amounts collected from rate payers, which is decoupled from amounts contributed to the segregated funds.

	US Jurisdictions' Forward Looking Requirement Methodology	Accounting Expense Methodology	Ontario Power Generation's Methodology
		excess of accretion expense.[401]	

[401] The accretion expense is based on the unwinding of the discounting at the same discount rate that was used when the ARO was initially recognized. The earnings would be based on the actual earnings of the segregated funds. It is unlikely these amounts would match exactly through the period subsequent to the operating life. We have not observed in our jurisdictional study how entities would manage this potential mismatch and whether it would impact funding contributions (or refunds) during this subsequent period.

	US Jurisdictions' Forward Looking Requirement Methodology	Accounting Expense Methodology	Ontario Power Generation's Methodology
The period of rate recovery	In general, utilities seek to collect amounts from rate payers for funding contributions over the operating life of the power plants. Utilities that are expecting to follow the SAFSTOR method and defer decommissioning activities until 30 years post operations cease would none-the-less plan to recover expected contributions over the rate period, but they would factor earnings of the segregated fund during the 30- year period.	It is relevant to disaggregate the components of the methodology. Depreciation expense is recognized over the operating life of the power plant, however, earnings on the segregated funds and the accretion of ARO would continue to the decommissioning date. Therefore the depreciation expense will be recovered over the operating life of the plant, and the accretion less segregated fund earnings are recovered until decommissioning date. It could also be possible that the segregated fund earnings may exceed the accretion during the SAFSTOR period.[402]	For the prescribed Regulated facilities, the recovery from rate payers would be over the operating life of the power plant. For the Bruce facilities, assuming the lease period aligns with the operating life of the plants, the recovery from rate payers may be over the operating life of the power plant.[403]

28.4 Considerations of transition to another methodology

Based on the above

- Transition processes needs to adhere to established rate-making principles, including fairness, minimizing intergenerational inequities, transparency, minimizing rate volatility, appropriate allocation of risk, providing value to customers, consistency and simplicity, and alignment with required financial accounting and reporting principles.
- Stability of the methodology through the time to decommissioning date should be considered as the decommissioning activities which are sought to be recovered over the operating life will occur a long time in the future. The methodology should not solely consider the implications to the next

[402] Following on the footnote related to the period over which funding contributions will be made, a regulatory mechanism may need to be considered to smooth these fluctuations during this time period.
[403] Based on documents reviewed in our study, we cannot be conclusive of the treatment post the operating life of the power plant. Similar issues may arise as noted in the Accounting Expense Methodology.

rate period, but should be robust throughout the lifecycle of a nuclear plant. This may be most relevant to changes in inputs that occur post the date of facility closure.

- The methodology should consider the implication of the recovery mechanisms for Bruce and Regulated facilities and the applicable legal obligations.
- Specific to Forward looking funding requirement methodology:
  - Increases the need for regulatory oversight with respect to the determination of cost estimates, profile of contributions, and expected rates of return. In OPG's case, that would include consideration of the ONFA and the role the Province currently plays in the oversight and decision making on funding matters.
  - In the US jurisdictions, we have noted the role of NRC, which is not currently consistent with either the role of the CNSC or the Province in Ontario. Consideration should be given to whether it is appropriate to use the funding principles of the ONFA reference plan for the purposes of determining rate recovery.
- Specific to accounting expense methodology:
  - The accounting expense (recovery) relating to the accretion expense and segregated fund earnings will continue past the operating life of the asset. From a rate-making perspective, to avoid inter-generational inequalities, the value from use and cost to rate payers should align. The accounting expense methodology therefore requires further consideration to avoid such inequities.

A detailed and specific analysis would be needed to identify all transition considerations to change from OPG's method to another potentially applicable methodology. Such a detailed and specific analysis is beyond the scope of this study.

Numbers may not add due to rounding.

Table 1
Revenue Requirement Impact of OPG's Nuclear Liabilities ($M)
Years Ending December 31, 2016 to 2026

Line No.	Description	Note or Reference	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Budget	2021 Budget	2022 Plan	2023 Plan	2024 Plan	2025 Plan	2026 Plan
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	PRESCRIBED FACILITIES												
1	**Depreciation of Asset Retirement Costs**	Ex. C2-1-1 Table 2	50.3	74.1	82.2	82.2	82.2	82.2	82.2	50.5	50.5	3.6	3.6
2	**Used Fuel Storage and Disposal Variable Expenses**	Ex. C2-1-1 Table 2	61.0	45.1	51.8	65.0	53.6	51.7	46.2	55.2	58.6	44.1	42.9
3	**Low & Intermediate Level Waste Management Variable Expenses**	Ex. C2-1-1 Table 2	3.2	11.3	8.9	5.9	8.3	11.3	11.1	13.7	13.7	8.0	4.2
	Return on ARC in Rate Base:												
4	**Return on Rate Base at Weighted Average Accretion Rate**	Ex. C1-1-1 Tables 1-9	42.2	25.0	28.1	23.9	19.9	15.9	3.6	0.0	0.0	0.0	0.0
5	**Return on Rate Base at Weighted Average Cost of Capital**	Note 1	0.0	0.0	0.0	0.0	0.0	0.0	10.1	10.4	7.5	5.9	5.7
6	**Pre-Tax Revenue Requirement Impact**		156.7	155.5	170.9	177.0	163.9	161.0	153.1	129.9	130.3	61.6	56.4
7	**Income Tax Impact**	Note 2	(36.8)	(25.3)	(11.0)	(9.1)	(43.4)	(46.0)	(92.8)	(43.1)	(46.7)	(39.4)	(17.5)
8	**Total Revenue Requirement Impact - Prescribed Facilities** (line 6 + line 7)		119.9	130.2	159.9	167.9	120.5	114.9	60.3	86.8	83.6	22.2	38.9
	BRUCE FACILITIES												
9	**Depreciation of Asset Retirement Costs**	Ex. C2-1-1 Table 3	100.2	68.0	69.2	69.2	69.2	69.2	69.2	69.2	69.2	69.2	69.2
10	**Used Fuel Storage and Disposal Variable Expenses**	Ex. C2-1-1 Table 3	66.9	57.3	63.6	64.7	59.0	59.0	57.9	69.5	63.3	72.0	59.7
11	**Low & Intermediate Level Waste Management Variable Expenses**	Ex. C2-1-1 Table 3	2.5	2.5	2.5	2.6	4.0	7.2	3.2	4.2	4.5	3.8	4.7
12	**Accretion Expense**	Ex. C2-1-1 Table 3	511.9	459.9	470.6	487.8	503.8	519.8	537.5	556.8	576.7	599.6	623.7
13	**Less: Segregated Fund Earnings (Losses)**	Ex. C2-1-1 Table 3	374.9	393.8	406.5	423.8	439.8	445.5	452.6	462.0	475.1	491.0	510.3
14	**Impact on Bruce Facilities' Income Taxes**	Note 3	(76.7)	(48.5)	(49.9)	(50.1)	(49.0)	(52.4)	(53.8)	(59.4)	(59.7)	(63.4)	(61.7)
15	**Pre-Tax Revenue Requirement Impact (Impact on Bruce Lease Net Revenues)**		230.0	145.4	149.6	150.4	147.1	157.3	161.4	178.3	179.0	190.2	185.2
16	**Income Tax Impact on Revenue Requirement** (line 15 x tax rate / (1-tax rate))	Note 4	76.7	48.5	49.9	50.1	49.0	52.4	53.8	59.4	59.7	63.4	61.7
17	**Total Revenue Requirement Impact - Bruce Facilities** (line 15 + line 16)		306.6	193.9	199.4	200.5	196.2	209.7	215.2	237.7	238.7	253.6	247.0
18	**Total Revenue Requirement Impact - Prescribed and Bruce Faciliites** (line 8 + line 17)		426.5	324.1	359.3	368.4	316.7	324.7	275.5	324.5	322.3	275.8	285.8

Notes:
See Ex. C2-1-1 Table 1a for notes

Table 1a
Revenue Requirement Impact of OPG's Nuclear Liabilities ($M)
Years Ending December 31, 2016 to 2026
Notes to Ex. C2-1-1, Table 1

Notes:
1 If average Unfunded Nuclear Liabilities (UNL) is less than average Asset Retirement Costs (ARC) for the prescribed facilities, the funded portion of average ARC (i.e. the amount by which average ARC exceeds average UNL) earns WACC as follows:

Table to Note 1

Line No.	Year	(from Ex. C2-1-1 Table 2, line 28) Average ARC ($M)	(from Ex. C2-1-1 Table 2, line 21) Average UNL ($M)	(a)-(b) ARC-UNL ($M)	Annual WACC	(c) x (d) if >0 Return on Rate Base ($M)	WACC Reference
		(a)	(b)	(c)	(d)	(e)	
1a	2016	825.7	1,063.1	(237.4)	6.85%	0.0	EB-2013-0321 Payment Amounts Order, App. A, Table 6b
2a	2017	505.1	703.9	(198.8)	6.65%	0.0	EB-2016-0152 Payment Amounts Order, App. A, Table 11
3a	2018	570.6	753.6	(183.0)	6.50%	0.0	EB-2016-0152 Payment Amounts Order, App. A, Table 12
4a	2019	488.5	672.1	(183.7)	6.46%	0.0	EB-2016-0152 Payment Amounts Order, App. A, Table 13
5a	2020	406.3	540.4	(134.1)	6.44%	0.0	EB-2016-0152 Payment Amounts Order, App. A, Table 14
6a	2021	324.1	349.5	(25.3)	6.43%	0.0	EB-2016-0152 Payment Amounts Order, App. A, Table 15
7a	2022	242.0	73.6	168.4	5.98%	10.1	Ex. C1-1-1 Table 5
8a	2023	175.7	0.0	175.7	5.93%	10.4	Ex. C1-1-1 Table 4
9a	2024	125.1	0.0	125.1	5.99%	7.5	Ex. C1-1-1 Table 3
10a	2025	98.1	0.0	98.1	6.01%	5.9	Ex. C1-1-1 Table 2
11a	2026	94.6	0.0	94.6	6.01%	5.7	Ex. C1-1-1 Table 1

2 The income tax impact for prescribed facilities is calculated as follows:

Table to Note 2 ($M)

Line No.	Item	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Budget	2021 Budget	2022 Plan	2023 Plan	2024 Plan	2025 Plan	2026 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1b	Regulatory Taxable Income Before Impact of Segregated Fund Contributions (Ex. C2-1-1, Table 1, line 6)	156.7	155.5	170.9	177.0	163.9	161.0	153.1	129.9	130.3	61.6	56.4
2b	Contributions to Nuclear Segregated Funds for Prescribed Facilities (Ex. C2-1-1 Table 2, line 15)	176.7	102.5	102.5	102.5	102.5	102.5	244.4	100.6	100.6	0.0	0.0
3b	Expenditures for Used Fuel, Waste Management & Decommissioning (Ex. C2-1-1 Table 2, line 5)	128.8	169.2	150.5	146.3	257.0	314.2	269.6	262.7	306.1	463.9	638.4
4b	Disbursements from Nuclear Segregated Funds (Ex. C2-1-1 Table 2, line 16)	(38.5)	(40.3)	(49.0)	(44.6)	(65.5)	(117.6)	(82.5)	(104.3)	(136.4)	(284.2)	(529.3)
5b	Net Increase in Regulatory Taxable Income (line 1b - line 2b - line 3b - line 4b)	(110.3)	(75.9)	(33.0)	(27.3)	(130.1)	(138.1)	(278.4)	(129.2)	(140.0)	(118.2)	(52.6)
6b	Income Tax Rate (Ex. F4-2-1 Table 3, line 31 and Ex. F4-2-1 Table 3a, line 29)	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
7b	Income Tax Impact (line 5b x line 6b / (1 - line 6b))	(36.8)	(25.3)	(11.0)	(9.1)	(43.4)	(46.0)	(92.8)	(43.1)	(46.7)	(39.4)	(17.5)

3 The impact on Bruce facilities' income taxes relates to higher deductible temporary differences associated with expenses not deductible for tax purposes, as follows:

Table to Note 3 ($M)

Line No.	Item	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Budget	2021 Budget	2022 Plan	2023 Plan	2024 Plan	2025 Plan	2026 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1c	Increase in Temporary Differences (Ex. C2-1-1 Table 1, lines 9 through 13)	306.6	193.9	199.4	200.5	196.2	209.7	215.2	237.7	238.7	253.6	247.0
2c	Income Tax Rate (Ex. G2-2-1 Table 7, line 19 and Ex. G2-2-1 Table 8, line 19)	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
3c	Impact on Bruce Facilities' Income Taxes (line 1c x line 2c)	(76.7)	(48.5)	(49.9)	(50.1)	(49.0)	(52.4)	(53.8)	(59.4)	(59.7)	(63.4)	(61.7)

4 Income tax rates are from Ex. F4-2-1 Table 3, line 32 (2016-2021), and Ex. F4-2-1 Table 3a, line 31 (2022-2026).

Numbers may not add due to rounding.

Table 2
Prescribed Facilities - Asset Retirement Obligation, Nuclear Segregated Funds, and Asset Retirement Costs ($M)
Years Ending December 31, 2016 to 2026

Line No.	Description	Note	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Budget	2021 Budget	2022 Plan	2023 Plan	2024 Plan	2025 Plan	2026 Plan
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	ASSET RETIREMENT OBLIGATION												
1	**Opening Balance**	1	8,836.3	9,009.9	9,535.8	9,956.1	10,412.2	10,767.3	11,083.1	11,451.7	11,854.3	12,235.5	12,455.9
2	**Used Fuel Storage and Disposal Variable Expenses**	2	61.0	45.1	51.8	65.0	53.6	51.7	46.2	55.2	58.6	44.1	42.9
3	**Low & Intermediate Level Waste Management Variable Expenses**	3	3.2	11.3	8.9	5.9	8.3	11.3	11.1	13.7	13.7	8.0	4.2
4	**Accretion Expense**		494.7	495.7	511.4	531.4	550.3	566.9	581.0	596.3	615.0	632.3	646.4
5	**Expenditures for Used Fuel, Waste Management & Decommissioning**		(128.8)	(169.2)	(150.5)	(146.3)	(257.0)	(314.2)	(269.6)	(262.7)	(306.1)	(463.9)	(638.4)
6	**Consolidation and Other Adjustments**		(0.4)	(0.6)	(1.3)	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	**Closing Balance Before Year-End Adjustments** (lines 1 through 6)		9,266.0	9,392.2	9,956.1	10,412.2	10,767.3	11,083.1	11,451.7	11,854.3	12,235.5	12,455.9	12,511.1
8	**2017 ONFA Reference Plan Adjustment - Ongoing Operations**	5	2.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	**2017 ONFA Reference Plan Adjustment - Legacy Facilities**	6	(258.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	**Year-End 2017 Adjustment Reflecting Nuclear Station End of Life Changes**	4.0	0.0	143.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	**Closing Balance** (line 7 through 10)		9,009.9	9,535.8	9,956.1	10,412.2	10,767.3	11,083.1	11,451.7	11,854.3	12,235.5	12,455.9	12,511.1
12	**Average Asset Retirement Obligation** ((line 1 + line 7)/2)		9,051.2	9,201.0	9,746.0	10,184.1	10,589.8	10,925.2	11,267.4	11,653.0	12,044.9	12,345.7	12,483.5
	NUCLEAR SEGREGATED FUNDS BALANCE												
13	**Opening Balance**	1	7,722.6	8,253.5	8,740.7	9,244.0	9,780.0	10,318.7	10,832.8	11,554.9	12,144.2	12,731.1	13,093.3
14	**Earnings (Losses)**		392.8	424.9	449.8	478.1	501.6	529.2	560.2	593.1	622.6	646.4	658.8
15	**Contributions**		176.7	102.5	102.5	102.5	102.5	102.5	244.4	100.6	100.6	0.0	0.0
16	**Disbursements**		(38.5)	(40.3)	(49.0)	(44.6)	(65.5)	(117.6)	(82.5)	(104.3)	(136.4)	(284.2)	(529.3)
17	**Closing Balance** (line 13 through 16)		8,253.5	8,740.7	9,244.0	9,780.0	10,318.7	10,832.8	11,554.9	12,144.2	12,731.1	13,093.3	13,222.8
18	**Average Nuclear Segregated Funds Balance** ((line 13 + line 17)/2)		7,988.1	8,497.1	8,992.3	9,512.0	10,049.3	10,575.7	11,193.8	11,849.5	12,437.6	12,912.2	13,158.0
	UNFUNDED NUCLEAR LIABILITY BALANCE (UNL)												
19	**Opening Balance** (line 1 - line 13)		1,113.7	756.3	795.1	712.1	632.1	448.7	250.3	(103.1)	(290.0)	(495.6)	(637.4)
20	**Closing Balance** (line 7 - line 17)		1,012.5	651.5	712.1	632.1	448.7	250.3	(103.1)	(290.0)	(495.6)	(637.4)	(711.6)
21	**Average Unfunded Nuclear Liability Balance** ((line 19 + line 20)/2)		1,063.1	703.9	753.6	672.1	540.4	349.5	73.6	(196.5)	(392.8)	(566.5)	(674.5)
	ASSET RETIREMENT COSTS (ARC)												
22	**Opening Balance**	1	850.8	542.2	611.7	529.5	447.4	365.2	283.1	200.9	150.4	99.9	96.3
23	**Depreciation Expense**		(50.3)	(74.1)	(82.2)	(82.2)	(82.2)	(82.2)	(82.2)	(50.5)	(50.5)	(3.6)	(3.6)
24	**Closing Balance Before Year-End Adjustments** (line 22 + line 23)	7	800.5	468.0	529.5	447.4	365.2	283.1	200.9	150.4	99.9	96.3	92.8
25	**2017 ONFA Reference Plan Adjustment - Ongoing Facilities**	6	(258.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
26	**Year-End 2017 Adjustment Reflecting Nuclear Station End of Life Changes**	4	0.0	143.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
27	**Closing Balance** (line 24 + line 25 + line 26)		542.2	611.7	529.5	447.4	365.2	283.1	200.9	150.4	99.9	96.3	92.8
28	**Average Asset Retirement Costs** ((line 22 + line 24)/2)		825.7	505.1	570.6	488.5	406.3	324.1	242.0	175.7	125.1	98.1	94.6
30	**LESSER OF AVERAGE UNL OR ARC** (lesser of line 21 or line 28, if >0)		825.7	505.1	570.6	488.5	406.3	324.1	73.6	0.0	0.0	0.0	0.0

Notes:
1 Opening balances in col. (a) from EB-2016-0152, Ex. C2-1-1 Table 2, col. (d).
2 Includes expenses associated with four one-time, full loads of new fuel into the reactors at Darlington for the refurbished units prior to start-up (discussed in Ex. F2-5-1 section 2.0).
3 Starting in 2016, a portion of expenses relates to OM&A costs charged to the Darlington Refurbishment Program for disposal of low and intermediate level waste (Ex. F2-7-1, Table 1).
4 Adjustment recorded on December 31, 2017 reflecting the changes to station end-of-life date assumptions underlying the ARO calculation, consistent with the accounting order application in EB-2018-0002. See Ex. C2-1-1 Table 4 for further details.
5 Adjustment recorded on December 31, 2016 associated with the current approved ONFA Reference Plan effective January 1, 2017 related to legacy facilities. In accordance with GAAP, this amount was expensed (i.e., not included in ARC) as legacy facilities are not used to support OPG's current operations.
6 As shown in EB-2016-0152 Ex. J21.1, Att. 2, Table 4, col. (b), line 27, adjustment recorded on December 31, 2016 associated with the current approved ONFA Reference Plan effective January 1, 2017 related to ongoing facilities. See Ex. C2-1-1 Table 4 for further details.
7 Col. (b), line 24 is as per EB-2018-0002 Schedule 1-Staff-1, Att. 1, Table 1a, col. (d), line 1a (difference due to rounding).

Numbers may not add due to rounding.

Table 3
Bruce Facilities - Asset Retirement Obligation, Nuclear Segregated Funds, and Asset Retirement Costs ($M)
Years Ending December 31, 2016 to 2026

Line No.	Description	Note	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Budget	2021 Budget	2022 Plan	2023 Plan	2024 Plan	2025 Plan	2026 Plan
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	ASSET RETIREMENT OBLIGATION												
1	**Opening Balance**	1	10,946.0	10,083.6	10,529.1	10,953.8	11,361.4	11,735.1	12,106.8	12,524.6	12,953.5	13,415.1	13,916.2
2	**Used Fuel Storage and Disposal Variable Expenses**		66.9	57.3	63.6	64.7	59.0	59.0	57.9	69.5	63.3	72.0	59.7
3	**Low & Intermediate Level Waste Management Variable Expenses**		2.5	2.5	2.5	2.6	4.0	7.2	3.2	4.2	4.5	3.8	4.7
4	**Accretion Expense**		511.9	459.9	470.6	487.8	503.8	519.8	537.5	556.8	576.7	599.6	623.7
5	**Expenditures for Used Fuel, Waste Management & Decommissioning**		(132.6)	(118.5)	(111.1)	(147.6)	(193.0)	(214.4)	(180.7)	(201.5)	(182.9)	(174.2)	(178.6)
6	**Consolidation and Other Adjustments**		(0.3)	(0.4)	(0.9)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	**Closing Balance Before Year-End Adjustments** (lines 1 through 6)		11,394.4	10,484.4	10,953.8	11,361.4	11,735.1	12,106.8	12,524.6	12,953.5	13,415.1	13,916.2	14,425.7
8	**2017 ONFA Reference Plan Adjustment - Legacy Facilities**	3	2.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	**2017 ONFA Reference Plan Adjustment - Ongoing Facilities**	4	(1,312.9)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	**Year-End 2017 Adjustment Reflecting Nuclear Station End of Life Changes**	2.0	0.0	44.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	**Closing Balance** (line 7 through 10)		10,083.6	10,529.1	10,953.8	11,361.4	11,735.1	12,106.8	12,524.6	12,953.5	13,415.1	13,916.2	14,425.7
12	**Average Asset Retirement Obligation** ((line 1 + line 7)/2)		11,170.2	10,284.0	10,741.5	11,157.6	11,548.2	11,921.0	12,315.7	12,739.0	13,184.3	13,665.7	14,170.9
	NUCLEAR SEGREGATED FUNDS BALANCE												
13	**Opening Balance**	1	7,413.8	7,730.1	7,983.7	8,238.9	8,512.6	8,774.9	8,994.3	9,115.3	9,370.2	9,634.2	10,003.9
14	**Earnings (Losses)**		374.9	393.8	406.5	423.8	439.8	445.5	452.6	462.0	475.1	491.0	510.3
15	**Contributions**		(26.9)	(102.5)	(102.5)	(102.5)	(102.5)	(102.5)	(244.4)	(100.6)	(100.6)	0.0	0.0
16	**Disbursements**		(31.6)	(37.7)	(48.8)	(47.6)	(75.1)	(123.6)	(87.3)	(106.5)	(110.4)	(121.3)	(108.7)
17	**Closing Balance** (line 13 through 16)		7,730.1	7,983.7	8,238.9	8,512.6	8,774.9	8,994.3	9,115.3	9,370.2	9,634.2	10,003.9	10,405.5
18	**Average Nuclear Segregated Funds Balance** ((line 13 + line 17)/2)		7,572.0	7,856.9	8,111.3	8,375.8	8,643.8	8,884.6	9,054.8	9,242.7	9,502.2	9,819.0	10,204.7
	ASSET RETIREMENT COSTS (ARC)												
19	**Opening Balance**	1	4,390.9	2,977.8	2,954.5	2,885.2	2,816.0	2,746.7	2,677.5	2,608.3	2,539.0	2,469.8	2,400.6
20	**Depreciation Expense**		(100.2)	(68.0)	(69.2)	(69.2)	(69.2)	(69.2)	(69.2)	(69.2)	(69.2)	(69.2)	(69.2)
21	**Closing Balance Before Year-End Adjustments** (line 19 + line 20)		4,290.7	2,909.7	2,885.2	2,816.0	2,746.7	2,677.5	2,608.3	2,539.0	2,469.8	2,400.6	2,331.3
22	**2017 ONFA Reference Plan Adjustment - Ongoing Facilities**	4	(1,312.9)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23	**Year-End 2017 Adjustment Reflecting Nuclear Station End of Life Changes**	2	0.0	44.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
24	**Closing Balance** (line 21 + line 22 + line 23)		2,977.8	2,954.5	2,885.2	2,816.0	2,746.7	2,677.5	2,608.3	2,539.0	2,469.8	2,400.6	2,331.3
25	**Average Asset Retirement Costs** ((line 19 + line 22)/2))		4,340.8	2,943.8	2,919.8	2,850.6	2,781.4	2,712.1	2,642.9	2,573.7	2,504.4	2,435.2	2,365.9

Notes:

1 Opening balances in col. (a) from EB-2016-0152, Ex. C2-1-1 Table 3, col. (d).

2 Adjustment recorded on December 31, 2017 reflecting the changes to station end-of-life date assumptions underlying the ARO calculation, consistent with the EB-2018-0002 accounting order application. See Ex. C2-1-1 Table 4 for further details.

3 See Ex. C2-1-1 Table 2, Note 5.

4 Adjustment recorded on December 31, 2016 associated with the current approved ONFA Reference Plan effective January 1, 2017. See Ex. C2-1-1 Table 4 for further details.

Table 4
Impact of 2017 ONFA Reference Plan and Year End 2017 Adustments for Ongoing Facilities - Assignment of ARO Adjustment and Allocation of ARC to Nuclear Stations ($M)

Line No.	Description	Pickering A	Pickering B	Darlington	Prescribed Facilities Total	Bruce A	Bruce B	Bruce Facilities Total	OPG Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	December 31, 2016 Actual:								
1	**Decommissioning Program**	226.7	278.1	71.2	576.0	(52.6)	(40.6)	(93.2)	482.8
2	**Low and Intermediate Level Waste Storage Program**	11.6	40.0	30.9	82.6	20.2	(6.3)	13.8	96.4
3	**Low and Intermediate Level Waste Disposal Program**	(1.2)	33.1	26.5	58.4	(29.4)	(46.4)	(75.9)	(17.5)
4	**Used Fuel Disposal Program**	(194.7)	(246.1)	(434.8)	(875.6)	(443.5)	(621.1)	(1,064.6)	(1,940.3)
5	**Used Fuel Storage Program**	(10.2)	2.3	(91.8)	(99.6)	(43.7)	(49.4)	(93.1)	(192.7)
6	**ARO Adjustment Assignment to Station Level**	32.2	107.4	(398.0)	(258.3)	(549.1)	(763.8)	(1,312.9)	(1,571.3)
7	**Asset Retirement Cost Adjustment**	32.2	107.4	(398.0)	(258.3)	(549.1)	(763.8)	(1,312.9)	(1,571.3)

Line No.	Description	Pickering A	Pickering B	Darlington	Prescribed Facilities Total	Bruce A	Bruce B	Bruce Facilities Total	OPG Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	December 31, 2017 Actual:[1]								
8	**Decommissioning Program**	(1.9)	(29.3)	(0.5)	(31.7)	2.1	1.4	3.5	(28.1)
9	**Low and Intermediate Level Waste Storage Program**	21.1	37.8	(31.3)	27.5	28.2	16.3	44.5	72.0
10	**Low and Intermediate Level Waste Disposal Program**	12.6	38.1	(78.3)	(27.7)	9.2	7.2	16.4	(11.2)
11	**Used Fuel Disposal Program**	28.4	145.7	(18.1)	155.9	(0.7)	(3.7)	(4.4)	151.5
12	**Used Fuel Storage Program**	15.8	19.3	(15.5)	19.6	(4.0)	(11.3)	(15.4)	4.2
13	**ARO Adjustment Assignment to Station Level**	75.9	211.5	(143.8)	143.7	34.8	9.9	44.7	188.4
14	**Asset Retirement Cost Adjustment**	75.9	211.5	(143.8)	143.7	34.8	9.9	44.7	188.4

Notes:
1 As shown in EB-2018-0002 Schedule 1-Staff-1, Chart 1.