

Appendix C. Cost Analysis – Inputs and Methodology

This technical appendix describes the methods and assumptions underpinning the cost analysis conducted to support the Advanced Nuclear Policy Options Paper (Options Paper). The analysis focuses on an assessment of relative expected costs to the public under a range of policy options and other scenarios and sensitivities. The results from the analysis, and findings and implications for the assessment of policy options in this paper, are provided in Appendix D (Cost Analysis – Results).

Quantification of the benefits provided by constructing and operating new nuclear generation is summarized in Section 2 (Nuclear Reliability Backbone Initiative) of the Advanced Nuclear Policy Options Paper, with reference to more detailed analysis of system benefits from New York's Coordinated Grid Planning Process and State Energy Plan, and preliminary economic benefits analysis provided in Appendix A (Preliminary Economic Impact Analysis) of this paper.

The technical and cost assumptions used in this paper's financial analysis were developed primarily based on The New York State Energy Research and Development Authority's (NYSERDA) and Electric Power Research Institute's (EPRI) Zero by 40 Technoeconomic Assessment (0x40 Assessment) and enhanced by industry expertise and additional research.¹ All cost estimates in this appendix are expressed in 2025 dollars unless stated otherwise. Across the analysis, an inflation rate assumption of 2.33% per year is used.² The below discussion focuses on the base case inputs used in each case. For many of these inputs, high/low sensitivities reflecting uncertainty around inputs are discussed and assessed in Appendix D.

NYSERDA and New York State Department of Public Service (DPS) acknowledge the contributions of The Brattle Group and its subcontractors, Dr. Koroush Shirvan and Sargent & Lundy, in conducting the analysis described in this appendix and Appendix D.

¹ NYSEDA & EPRI, "Zero by 40 Technoeconomic Assessment". September, 2025. ("0x40 Assessment"). <https://www.nyserda.ny.gov/-/media/Project/Nyserda/Files/Publications/Energy-Analysis/Zero-x-40-Technoeconomic-Assessment.pdf>.

² This reflects the inflation rate as established by the DPS Office of Accounting, Audits & Finance, revised February 23, 2026.

C.1 Analysis Methodology

Overview

The analysis represents a nuclear generation project using a project-level financial model, initially describing a single installation, and subsequently applied to pipeline scenarios. The analysis tracks cash flows, investor returns, and public support over the full lifecycle of the project, from development and construction through operations. Key modeling constructs—including ownership, financing structure, and the allocation of risks and returns across project phases—are used to enable transparent comparison across policy scenarios and related commercial and ownership arrangements.

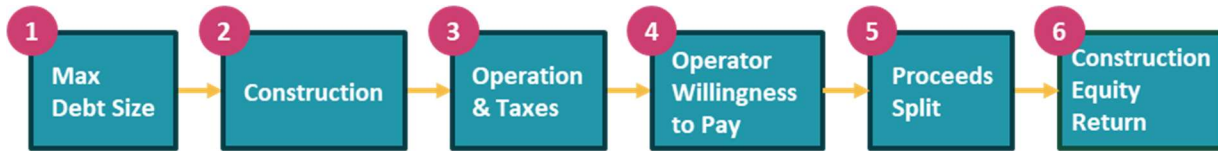
Large-scale energy generation projects are typically funded in one of two ways: corporate (or on-balance-sheet) finance and project finance. Reflecting the observations in Appendix B (Market Assessment) and the discussion in Section 4.3 (Ownership Structures), the analysis assumes that a project finance structure will be utilized. In project finance, equity investors do not commit their balance sheet to the project, meaning that debt can only be borrowed against the project's revenues rather than the equity investors' entire portfolio.

A nuclear project is modeled in two distinct phases: development/construction and operations. In project finance, the project's assets and debt obligations are held by a special purpose vehicle (SPV), typically a Limited Liability Company (LLC). This LLC is owned by the project's equity investors and borrows the debt needed to finance the project. Once the project's construction is complete, the SPV is assumed to be sold by the construction equity owner(s) to the operation equity owner(s) at a price that allows the construction equity to earn its target rate of return. This assumption reflects common project finance structures in which construction and operations are financed by different investors.

The analysis allows for a different finance approach during the initial pre-Final Investment Decision (FID) period (e.g., with bridge loan funding) compared to the financing approach that takes effect at FID for the remainder of the development and construction period.

The flowchart presented in Figure C-1 summarizes the cost analysis methodology.

Figure C-1. Cost Analysis flowchart



Using the inputs and assumptions described further below, the analysis applies a standard project finance framework to calculate the construction equity return (pre-tax levered IRR for the private equity (PE) constructor). The high-level methodology is summarized below, with numbering aligned to the flowchart in Figure C-1:

- (1) First, the maximum available debt is calculated based on the net present value of projected project cash flows and lender terms at the specified debt rate, subject to a minimum required debt service coverage ratio (DSCR) that ensures net revenues can cover expected debt service in each period of operation.
- (2) Next, capital spending during development and construction is quantified from total overnight cost and spending curve inputs, and each year's capital injections are split between debt, equity and, as applicable, grant sources, as described below in Section C.3 (Development and Construction Inputs).
- (3 & 4) Upon completion of construction, the project is assumed to be sold to an operator. To determine the operator's Willingness to Pay (WTP) — the price that allows it to earn its target equity return based on expected revenues net of operating costs, debt service, and taxes—the analysis determines the revenues, costs, and tax benefits and liabilities in each year of operation. The operator assumes the construction debt facility as part of the purchase. The federal Investment Tax Credit is claimed during the first year of operations, discussed in more detail below in Sections C.6 (Financing Inputs) and C.7 (Tax and Tax Credit Inputs).
- (5 & 6) Proceeds from the sale are split between the construction equity sponsors such that if realized costs align with expectations, they earn back their investment during construction plus capitalized returns at their respective hurdle rates. The payout amount to each construction equity owner is used to calculate their pre-tax levered IRR.

As needed, each scenario employs a combination of inputs for designated government interventions (revenue support, state equity, or support during development and construction) to enable the commercial requirements of the project to be met - i.e., effectively for the operator's WTP to match the return needs of the development and construction investors. Any

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public cost (ratepayer or taxpayer cost) associated with government interventions is extracted and made available in key output metrics from the analysis for the range of scenarios.

Key building blocks in the analysis are described in more detail below.

Debt

The analysis assumes that, at least for initial projects, U.S. Department of Energy Office of Energy Dominance Financing (DOE-EDF)/ Federal Financing Bank (FFB) debt finance will be available. Although finance literature provides evidence that a project's overall cost of capital is independent of capital structure (within a reasonable range), a nuclear project with access to DOE loan guarantees backing low-interest loans from the Federal Financing Bank can minimize its cost of capital by maximizing its utilization of such below market debt. The analysis assumes that the range of policy options considered in this Options Paper and ultimate adoption of a policy framework by New York will satisfy DOE's assessment in this regard.

DOE limits the amount it will back to no more than 80% of eligible capital expenditures in any given year. This analysis applies the 80% maximum for debt in each year of construction expenditure. In addition, the analysis limits total debt during construction (including capitalized interest) to an amount that project revenues will reasonably be able to support. To do so, forecasted operating expenses are subtracted from forecasted revenues in each period of operation to yield the project's Earnings before Interest Taxes Depreciation and Amortization (EBITDA). Revenue streams include energy and capacity, as well as any revenue adders (e.g., from Advanced Nuclear Zero Emission Credits (ANZECs) or Power Purchase Agreements (PPAs)). Operating expenses include all those listed below in Section C.4 (Operating Cost Inputs). Debt is capped such that the Cash Flow Available for Debt Service (CFADS) divided by the debt service in each year is no greater than a specified Debt Service Coverage Ratio (DSCR), representing a safety margin that the lender defines. In that calculation, the annual debt service depends on the amount of the debt as well as the assumed repayment structure. This analysis sizes debt using a mortgage style repayment (total of principal and interest equate to a constant payment).

Development and Construction

Development and construction costs and the associated timeline of spend are detailed in the analysis' assumed construction spend curves (commonly referred to as "S-Curves"). The S-Curve represents the portion of the project's overnight capital cost that is spent in each year on development and construction related activities, as discussed in greater detail in Section C.3

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(Development and Construction Inputs). The analysis uses the available debt, equity and, as applicable, grant funding sources in each period to meet that period's expected development and construction costs. Debt covers eligible expenses in each period up to the annual cap, and subject to a cumulative cap, as mentioned above. The analysis assumes that all project expenses as of FID are eligible for debt funding, subject to the 80% and DSCR constraints discussed above.

In the years before FID, 50% of funding is also assumed to be available from debt sources, which could be a combination of early availability of EDF debt, State bridge loans, or private sector bridge loans.

Project expenses not covered by available debt or grant funding are funded from equity investments.

Tax and Purchase

Total income taxes are calculated by considering the federal tax rate, eligibility for Investment Tax Credit (ITC) and tax credit adders, and eligible depreciable basis. Interest expenses and depreciation – using a 5-year Modified Accelerated Cost Recovery System (MACRS) mid-year convention – are subtracted from EBIDTA to determine the taxable income, which after being reduced by the federal tax rate is used in combination with ITC and qualifying tax credit adders to determine total tax benefits and liabilities. These are added or subtracted from the cash flow to equity before taxes to determine the after-tax cash distribution to equity investors. Since the project will be owned by a pass-through LLC, taxes are paid individually by the project's equity holders. The analysis assumes income taxes are only paid by the private equity owner during operations. Moreover, in the case of multiple owners, the ITC distribution is split to each owner, pro-rated by ownership share.

This analysis assumes the project will claim the ITC instead of the production tax credit (PTC) because the ITC provides a larger and more certain upfront benefit that is better aligned with the capital-intensive, front-loaded nature of nuclear development. The ITC enables a larger early return to owners during operation, lowering risk to investors and supporting a lower cost of financing. By contrast, the PTC would provide production-based support over the first 10 years of operations, meaning the benefit is smaller, delayed, and dependent on generation output.³

³ IRS/Treasury, "Section 45Y Clean Electricity Production Credit and Section 48E Clean Electricity Investment Credit," Final Regulations, 90 Fed. Reg. 4006, 4008–4009 Jan. 15, 2025. <https://www.irs.gov/credits-deductions/clean->

Tests conducted as part of this analysis confirmed these dynamics, and accordingly the analysis results presented in this appendix only consider the ITC.

The purchase price (or WTP) at Commercial Operation Date (COD) paid by the operator assumed to buy the project at COD is the net present value of after-tax cash distributions to equity discounted at the operator hurdle rate. If there are two operators, EBITDA, tax benefits/liabilities, and cash after debt service are split using the implied ownership share split from construction. Equity owners' WTP during operation are calculated using their individually defined hurdle rates.

Scenario Analysis

The feasibility of each scenario is determined by whether construction equity investors earn their assumed hurdle rate. This condition is satisfied when the operator(s)' WTP is greater than or equal to the cost to construct the plant, which consists of outstanding debt, including capitalized interest during construction, plus the construction equity principal and the required return on that equity. To achieve this for any given scenario, a specified input (e.g., PPA/ANZEC price, construction grant amount, etc.) is adjusted iteratively until the purchase price at COD equals the cost to construct the plant.

Pipeline Analysis

Pipeline analysis scenarios assess a portfolio of projects adding up to the goal of 5 GW. Each project is assessed individually, with relevant project parameters (in particular cost) adjusted from each installation to the next depending on a separate set of inputs (in particular around cost reduction and learning effects). Results from each install within a pipeline are then aggregated to each GW installed for comparison.

C.2 Technical and Operational Inputs

Reactor Type

The analysis includes inputs for two different reactor types: a Large Light Water Reactor (LLWR) and a Small Modular Reactor (SMR). Each reactor type corresponds to a specific set of technical and cost specifications.

electricity-investment-credit (discussing Section 45Y(b)(1)(B) and stating that a facility is treated as qualified only during the 10-year period beginning on the date it was originally placed in service).

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While several distinct reactor technologies fall within each category, technologies are grouped into LLWR and SMR categories for cost comparison purposes, consistent with the technology cost framework used in the 0x40 Assessment. The LLWR category represents reactor designs that are commercially mature and licensed or licensable under existing US regulatory frameworks, such as the AP1000.

The SMR category is broader and includes a range of smaller, modular reactor designs, including both water-cooled and non-water-cooled technologies. For the purposes of this analysis, the SMR category is intended to represent a generic modular reactor, with cost and operational assumptions selected to reflect the scale, construction approach, and risk profile common to this class of technologies, rather than any specific reactor design.

Capacity

A nuclear plant's capacity is the maximum electrical power it can produce and is measured in MW. Throughout, the analysis assumes a 1,000 MW capacity for the LLWR and a 250 MW capacity for the SMR to allow for simple comparison between the two technologies. All analysis inputs are quantified on a per-MW basis, so mismatch between these simplified capacity assumptions and actual reactor size does not affect the analysis findings.

Capacity Factor

A plant's capacity factor measures how much energy the plant produces annually as a percentage of the total amount it could produce if running constantly at maximum output. Nuclear plants generally aim for very high capacity factors, since their variable costs are typically lower than the value of their output; their capacity factors are limited by the need for occasional refueling and maintenance. This analysis assumes a 93% capacity factor for all units before major maintenance, which is consistent with the EIA's observed average nuclear capacity factor for existing plants in recent years.⁴ This assumption is used to determine the plant's electrical output in each year of operation. The output, in turn, is translated to revenues by multiplying the megawatt-hour (MWh) of output by assumed revenues per MWh.

⁴ U.S. Energy Information Administration (EIA), "Electric Power Monthly," Table 6.07.B ("Capacity Factors for Utility Scale Generators Primarily Using Non-Fossil Fuels"), December 23, 2025.
https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=table_6_07_b.

Economic Life

The plant's economic life in years represents the assumed operating life of the plant over which equity holders during operations must earn their target return. All technologies have an assumed operating life of 40 years, corresponding to the term of a Nuclear Regulatory Commission (NRC) license.⁵ While the 40-year economic life represents the baseline assumption for this analysis, it is common for reactors to receive license extensions and operate beyond 40 years; this prospect is not represented in the analysis.

Reactor Site

Construction costs and timing depend on the reactor siting assumptions made. This analysis distinguishes between reactors developed on greenfield sites and those developed on brownfield sites, consistent with the descriptions in the 0x40 Assessment.⁶

For the purposes of this analysis, greenfield sites refer to undeveloped locations that require more extensive site preparation and potentially longer permitting requirements. The construction timeline for the first reactor is assumed to be 12 years for both an LLWR or an SMR reactor. Brownfield sites refer to those with existing nuclear or non-nuclear generation and sites contiguous to nuclear generation (i.e., nuclear site expansion). Building a reactor at a brownfield site reduces the assumed construction timeline to 10 years for the first reactor unit of either an LLWR or an SMR.

C.3 Development and Construction Inputs

Overnight Capital Costs

A plant's overnight capital costs (OCC) are the total nominal costs to build a plant "overnight," excluding the carrying costs of debt and equity. This analysis maintains the same starting costs used in the 0x40 Assessment for LLWR and SMR, updated to 2025\$. Cost reductions through learning effects from pipeline deployment are discussed further below. It should be noted that the 0x40 Assessment recognizes a significant range of uncertainty around these OCC costs, both

⁵ NRC, "Reactor License Renewal Overview," August 28, 2020. "The Atomic Energy Act and NRC regulations limit commercial power reactor licenses to an initial 40 years but also permit such licenses to be renewed."

⁶ 0x40 Assessment, pp. 163-166. While there is no explicit quantification of the difference in construction timeline, the qualitative discussion leads to the assumptions used in this analysis.

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for LLWR but even more so for SMR. These uncertainties are reflected through sensitivity analysis.

Table C-1 displays the OCC assumptions for greenfield and brownfield LLWR and SMR deployments, including base, low, and high values used for sensitivity analysis.

Table C-1. Estimated OCC and Duration of the Next Deployment of Nuclear Power Generation in New York State

Tech	Site	Dev. + Constr. Duration	Base OCC	Low OCC	High OCC
		<i>Years</i>	<i>2025\$/kW</i>	<i>2025\$/kW</i>	<i>2025\$/kW</i>
LLWR	Greenfield	12	\$12,756	\$10,205	\$15,952
	Brownfield	10	\$11,385	\$7,395	\$14,790
SMR	Greenfield	12	\$18,655	\$12,125	\$30,780
	Brownfield	10	\$17,334	\$10,868	\$29,459

In the analysis, these OCC values are escalated at inflation (2.33%) from 2025 to the first year of project development and are spread across the development and construction period according to the defined construction spending schedule (or “S-Curve”, discussed in the next section). The OCC expenditure in each year is then escalated at inflation from the first year to the year in which that spend occurs, making cost input assumptions consistent with 0x40 Assessment estimates in real terms.

Nuclear construction costs are uncertain, both in an expected sense (i.e., uncertainty on the project cost level proposed or estimated by the project developer) and an unexpected sense (i.e., the possibility of cost overruns or possible under-budget deployment). The range of uncertainty presented in the 0x40 Assessment for OCC is significant, with -20% to +25% for LLWR and -38% to +65% for SMRs. The sensitivity analysis in this Cost Study illustrates the potential impact on cost when the range of uncertainty in OCC is considered.

Consistent with the 0x40 Assessment analysis, all cost inputs are applied for deployment anywhere in New York State, or, rather, the analysis does not make specific assumptions on where deployment takes place, other than assuming deployment Upstate (north and west of the Lower Hudson Valley).

The OCC is categorized into five cost components: equipment, materials, labor, indirect costs, and owner’s cost. These cost components are as follows:

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- **Equipment** costs include equipment manufacturing, transportation to site, taxes, decommissioning cost and profit for turbine and nuclear island equipment.
- **Materials** costs include concrete, steel (including pipes and rebar), and wires. This component excludes materials used in offsite work for equipment.
- **Labor** costs include the onsite labor to perform civil, mechanical and electrical work.
- **Indirect** costs include design services, project and construction management at the home office, field construction management and supervision at plant site, plant-specific commissioning service, and contingencies.
- **Owner’s Cost** includes costs related to site preparation (including utility access), cooling infrastructure (e.g., cooling water intake and heat rejection systems), additional transmission switchyard, site specific engineering, regulatory compliance, and startup.

While interconnection costs are assumed and included, transmission upgrade costs are outside the scope of this analysis. The needs for any transmission upgrades or new transmission and associated costs will be assessed further through appropriate proceedings, including the Coordinated Grid Planning Process.

Table C-2 shows the assumed contribution of each cost component to the total OCC for greenfield LLWR and SMR technologies. The breakdown of OCC into each of these cost components is derived from literature-based evidence and calibrated using expert judgment from the consultant team.⁷

Table C-2. Cost Component Contributions to OCC

Cost Component	Contribution to LLWR OCC	Contribution to SMR OCC
Equipment	21%	21%
Materials	5%	5%
Labor	16%	18%
Indirect	37%	32%
Owner’s Cost	21%	23%

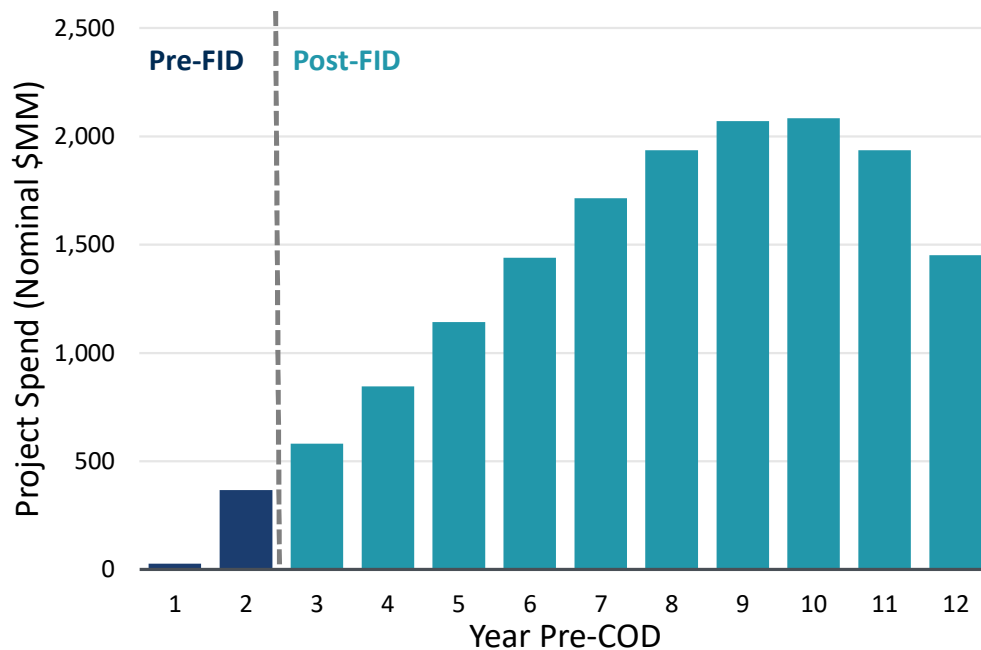
⁷ Component shares are based on consultant mapping of published nuclear cost-account information to the simplified OCC categories used in this analysis, informed by expert input and the MIT CANES AP1000 cost report. Final allocations reflect consultant judgment. See K. Shirvan, “2024 Total Cost Projection of Next AP1000,” MIT Center for Advanced Nuclear Energy Systems, MIT-ANP-TR-201. July 2024.

Project Spend Timeline (“S-Curve”)

The development and construction of a nuclear facility involve a multi-year sequence of activities with associated capital expenditures that vary significantly across the entire development and construction period. Each phase of construction and the cost components within it have specific timing considerations that must be accounted for in this analysis. The timing and size of spend on each component in each year of development and construction is combined into a project spend timeline, commonly referred to as an “S-Curve.”

The S-Curve allocates total overnight capital costs across the development and construction period by year, capturing the ramp-up of spending during early development, a peak period of expenditures during intensive construction and equipment installation, and a drop in costs as the project approaches commercial operation. Figure C-2 shows the assumed spend curve over time, shown for the 12-year development and construction period associated in the analysis with the first LLWR project in New York if developed at a greenfield site.⁸ The same normalized S-curve is used in the analysis for LLWR and SMR projects.

Figure C-2. Example Project S-Curve for First Greenfield LLWR install on a 12-year Timeline



⁸ The normalized S-curve assumed in this analysis is based on consultant input and generally agrees with the sinusoidal curve presented in Abdalla Abou-Jaoude et al., “Meta-Analysis of Advanced Nuclear Reactor Cost Estimations,” INL/RPT-24-77048, rev. 0, April 2024, pp. 78-79. <https://gain.inl.gov/content/uploads/4/2024/11/INL-RPT-24-77048-Meta-Analysis-of-Adv-Nuclear-Reactor-Cost-Estimations.pdf>.

The total development and construction timeline varies by the first reactor site. The first reactor in New York at a greenfield site is assumed to have 12 years of development and construction, as shown above in Figure C-2. This timeline is reduced to 10 years for development and construction at a brownfield site. Additionally, as discussed further below, total development and construction duration is assumed to reduce as pipeline deployment progresses. Whenever the timeline is reduced, the shape of the S-curve is assumed to stay the same but compressed into a shorter period of time.

An important distinction made in this analysis is when the project's FID occurs, being the point in time when the full range of project finance sources encompassing equity, debt and (as applicable) government support becomes available to the project. This analysis assumes that FID occurs at the beginning of year 3 of project development and construction.

C.4 Operating Cost Inputs

Unless indicated otherwise, cost assumptions discussed in this section are assumed to inflate over time by the inflation rate of 2.33% used in this analysis.

Fixed Operations and Maintenance Costs

Fixed operations and maintenance (O&M) costs represent the consistent costs of operating and maintaining the facility, including staff salaries, non-labor regular maintenance expenses, regulatory compliance costs, property taxes, annualized decommissioning costs, and ongoing capital plant expenditures. The cost of fixed O&M depends on the capacity or size of the plant, rather than its yearly output. Consistent with the 0x40 Assessment, this analysis assumes fixed operations and maintenance costs of \$201/kW-yr for an LLWR and \$155/kW-year for an SMR.

Variable Operations and Maintenance Costs

Variable O&M costs represent the cost of spent nuclear fuel management and disposal, along with other consumable materials. Unlike fixed O&M, variable O&M depends on the plant's yearly output. Consistent with the 0x40 Assessment, this analysis assumes variable operations and maintenance costs of \$3.32/MWh for an LLWR and \$3.08/MWh for an SMR.

Fuel

Nuclear fuel costs are expressed in \$/MWh of energy produced. The LLWR will require conventional low-enriched uranium (LEU) fuel, while SMRs could use LEU or high-assay low-

enriched uranium (HALEU) fuel depending on their design. In this analysis, SMRs are assumed to require LEU. A sensitivity on SMRs requiring HALEU is presented in the sensitivities in Appendix D (Cost Analysis – Results). Consistent with the estimates discussed in the 0x40 Assessment, this analysis assumes the costs of LEU and HALEU to be \$11.09/MWh and \$15.85/MWh, respectively.⁹

Major Maintenance

Every few years, the plant will require more substantive and costly maintenance than what is required in a normal operating year, including refueling. This “major maintenance” requires the plant to shut down for a period and thus decreases the plant’s availability for that year. In this analysis, major maintenance reduces annual generation by one month of downtime in the year in which it occurs.

Major maintenance also creates a periodic expense that would otherwise produce uneven cash flows across operating years. To smooth the expense impact, during the years when the plant runs at full availability, deposits are made from the project’s cash flows into an account. The reserve is then drawn down in years when major maintenance costs are incurred. This approach smooths the treatment of major maintenance expenses over time, while still reflecting the lower revenues associated with reduced plant availability during outage years.

This analysis assumes a major maintenance cost of \$50/kW-year incurred every four years. This estimate is slightly lower than the EIA’s latest estimate of the cost of capital additions for existing nuclear units from the 2025 Annual Energy Outlook, since existing older units will likely have larger major maintenance costs due to their age.¹⁰

Insurance

Nuclear reactors in the United States must comply with the Price-Anderson Act, which requires primary liability insurance for offsite damages with a minimum coverage of \$500 million per site.¹¹ The NRC also requires separate on-site property insurance for cleanup and decontamination costs of a nuclear accident with at least \$1.06 billion of coverage per site.¹² In

⁹ 0x40 Assessment, p. B-4.

¹⁰ EIA, “Assumptions to the Annual Energy Outlook 2025: Electricity Market Module,” April 2025, p. 17, https://www.eia.gov/outlooks/archive/aeo25/assumptions/pdf/EMM_Assumptions.pdf

¹¹ U.S. Nuclear Regulatory Commission (NRC), “Backgrounder on Nuclear Insurance and Disaster Relief,” August 6, 2025, <https://www.nrc.gov/reading-rm/doc-collections/fact-sheets/nuclear-insurance>.

¹² *Ibid.*

addition to legally required insurance, the plant will likely have purchased outage insurance to cover lost revenues in the event of an unexpected outage. In total, insurance is assumed to cost \$10,000/MW-year.¹³

C.5 Revenue Inputs

The value a nuclear plant can monetize is from commodity revenues (primarily energy and capacity) and, as applicable, revenue from other constructs (e.g., ANZEC revenue, above-market payments from PPAs). Together, these revenue streams determine the market value of the plant during operations and therefore an operating owner's WTP for the plant at COD. These revenue components are assumed to be hedged against market risk for at least part of the plant's operational life. Market risk is hedged either through a bundled long-term PPA or an ANZEC contract. After the assumed PPA or ANZEC period, the plant only earns energy and capacity value from the market.

The plant's energy and capacity revenues are projected using NYSERDA's blended long-term energy and capacity price forecasts. Energy revenues represent the value for the sale of electrical output of the plant and are measured on a \$/MWh basis. This analysis uses the load-weighted average of zones A-F for energy price forecasts. Capacity revenue compensates eligible resources for being available to supply electricity when needed and is measured on a \$/kW-month basis, averaging on an annual basis in the analysis. This analysis uses the forecasted capacity prices for the New York Control Area (NYCA) locality.

¹³ *Ibid.*

Figure C-3. Energy Revenue Forecasts

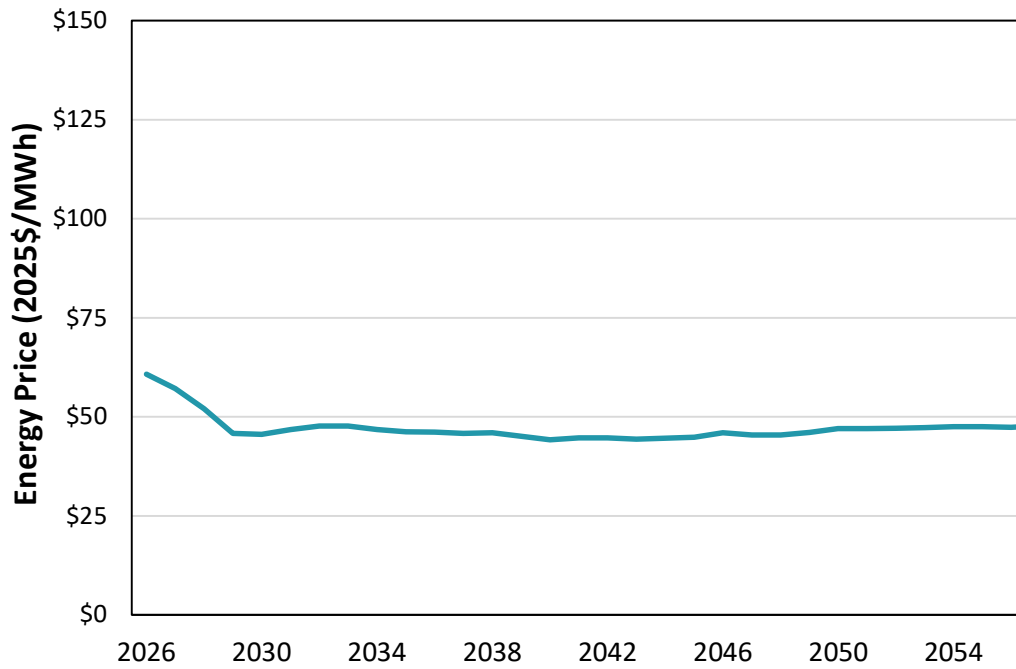
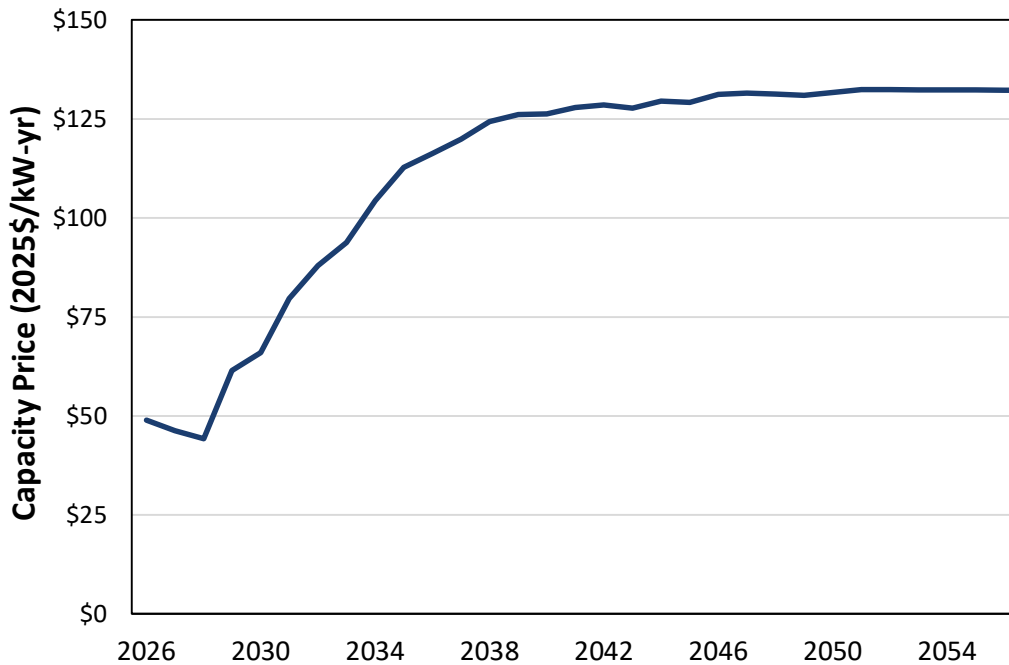


Figure C-4. Capacity Revenue Forecasts



Depending on the scenario in question, a higher amount of revenue than the commodity revenue is available to the project through ANZEC or PPA contracts, with the total revenue

amount per MWh set on a scenario basis. While either PPA or ANZEC contracts can employ a variety of mechanisms, in this analysis revenue under such contracts is assumed to be available as a fixed total revenue per MWh, escalating at the rate of inflation. In scenarios with an ANZEC arrangement, the component of such total revenue not covered by commodity revenue is accounted as the public cost of such government intervention, similar to the Index (O)REC approach used for renewables in the Clean Energy Standard (CES).

By default, the analysis assumes an ANZEC contract term of 25 years, consistent with the approach in New York in CES programs for other large projects, namely under the Offshore Wind Standard and the Tier 4 program.

C.6 Financing Inputs

The following subsections describe how debt and equity are represented in this analysis, including the assumed financing instruments, sizing constraints, and required returns. Note that Weighted Average Cost of Capital (WACC) or After-Tax Weighted Average Cost of Capital (ATWACC) is not used explicitly in the below financial assumptions. Instead, for construction, debt and equity investors' cash outlays are estimated directly and accrue their respective required returns, as described in the subsections below. The assumed debt-to-equity mix, ranging up to 80% debt, is determined based on projected cash flows and debt-service-coverage constraints during the operating stage.

Debt Structure and Cost

Since the project will need to draw debt to cover capital spend during construction but cannot generate revenues until operation, the interest accrued during construction is capitalized into the debt principal as interest during construction (IDC).

For the first or initial projects under assessment, the analysis assumes that, as of FID, debt financing is provided by the DOE-EDF and has an assumed tenor of 25 years from COD with repayment beginning at COD, matching the 25-year ANZEC/PPA project revenue period assumed throughout the analysis.¹⁴ Corresponding to DOE-EDF guidelines, the interest rate on an DOE-EDF loan is assumed to be equal to the sum of the U.S. Treasury rate corresponding to

¹⁴ If the term of EDF finance would not extend to the full 25 years, it is assumed that for the final years refinance into other debt sources is available at comparable price levels given the much lower project risk profile at that time.

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the loan tenor plus a 0.375% liquidity spread adder.¹⁵ Therefore, the cost of debt is assumed to be 5% based on the observed 20 and 30-year treasury rates plus the liquidity spread adder published by the DOE-EDF. In line with DOE-EDF financing terms, this analysis assumes the project pays closing fees at FID of 0.6% on the first \$2 billion of debt drawn and 0.1% on all additional principal.¹⁶ The amount of debt available to the project is dependent on its expected cash flows during operation. This analysis determines the debt facility size by dividing EBITDA by the lender's minimum acceptable DSCR, assumed as 1.1. Additionally, this analysis uses a mortgage-style repayment structure, which requires that the total debt service in each year, or the sum of principal and interest paid, is the same nominal amount over the life of the loan.

As a simplification in the analysis, it is assumed that these terms continue to be available also for later nuclear projects in any pipeline scenarios, either through a continued role for DOE-EDF, or on the basis of private sector debt finance becoming available at similar rates once project risk levels reduce over time.

During the pre-FID stage, it is assumed that an early development bridge loan is available to the project from private sector lenders. The early development loan is assumed to provide up to 50% of expenditures pre-FID, to charge 7.5% interest, and to be repaid at FID.

Separate reference scenarios explore a counterfactual situation where no DOE-EDF debt would be available and debt would need to be secured from private sector lenders. For that case, the debt-to-equity ratio is assumed to be 70/30 (i.e., debt would be 70% of the capital stack), and the interest rate is assumed to be 10%. These assumptions are simplifications used for illustrative analysis only.

Equity Structure and Hurdle Rates

As discussed in Section 4.3 (Ownership Structures) of this Options Paper, multiple ownership structures are under consideration, and this is reflected in the analysis. In all structures a minimum level of private sector equity ownership is assumed. The cost of private sector equity is represented by the equity investor's "hurdle rate," or the minimum expected return on their investment required for them to invest in the project. Equity is more expensive during

¹⁵ U.S. Department of Energy (DOE), "Pricing for LPO Financing by Program," March 15, 2024, <https://www.energy.gov/edf/articles/pricing-lpo-financing-program>;;
See also Georgia Power Company, "Form 8-K". (Feb. 20, 2014), GA DOE Loan 8-K.
<https://www.sec.gov/Archives/edgar/data/41091/000004109114000002/gadoeloan8-k.htm>.

¹⁶ *Ibid.*

development and construction, when risks to the project are highest. The equity hurdle rate during development and construction is the rate of return the equity should receive on the sale of the project at COD. Table C-3 presents the private sector equity investor hurdle rates used in this analysis.

Table C-3. Assumed Private Equity Hurdle Rates

Project Phase	Deployment Maturity and Support	LLWR	SMR
Development and Construction	First project; private sector bears full risk	35%	40%
	First project; state shares risk	22.5%	25%
	Later projects in 5 GW pipeline (4 th install and beyond for LLWR; 8 th install and beyond for SMR)	17.5%	17.5%
Operations	All	9%	9%

A PE hurdle rate of 35% for LLWR and 40% for SMR is assumed during construction in an approach where private sector project partners, including primarily the equity investors, fully bear the project risk. In the case of a (partial) state cost overrun guarantee, which provides some reduction in risk to the private sector equity investor, PE hurdle rates during construction are assumed to be 22.5% and 25%, respectively. These equity hurdle rates are gradually reduced in the analysis for each subsequent deployment unit until they reach a lower level of 17.5%. Equity hurdle rates are derived from industry research into what would be required for a risk of such nature, given that comparable projects are sparse. The equity hurdle rate during construction was benchmarked against three sources, while recognizing that none is truly comparable, so much uncertainty remains:

- First, Engineering, Procurement, and Construction (EPC) contractors that participate in the nuclear energy sector were examined to quantify the construction cost of capital, which was found to be 12%. However, the construction risk of this project is likely higher and an EPC contractor would not be the one to finance it, thus the 12% is likely a lower bound.
- Another group with a more comparable risk level is PE funds, which often demand returns at or above 20%, although their willingness to invest and their required returns will depend on the specific investments.
- Finally, discount rates for de-SPAC/Special Purpose Acquisition Company Transactions of SMR companies were considered to represent the expectation of

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return for the development and construction of the highest risk nuclear projects; discount rates for this last group ranged from 20%-35%.¹⁷

For LLWR construction, the risk level of PE funds is a useful proxy, understanding they are the most well-suited party to undertake such a high-risk investment that also demands large amounts of capital. The unique risk of this project therefore pushes the assumed hurdle rate above the average for PE funds. For SMR construction, de-SPAC transactions of SMR companies are the most fitting benchmark, and recognizing the significant uncertainty of the modeled project pushes the SMR hurdle to the higher end of the observed range.

It is assumed that PE funds are available during the entire development and construction period (both pre-FID and post-FID) to provide the funding not available from other sources.

In scenarios that include a portion of State equity ownership, the cost (hurdle rate) of such equity share is assumed at 5%, which could be based on either funding such equity share from State debt sources or through revenue-backed bonds with a level of State backing.¹⁸ The analysis does not explicitly consider funding sources. For more information, see Section 5 (Funding Sources) of the Options Paper. State equity is assumed to only be available to fund expenditures post-FID. This analysis captures the direct project-level cost of State equity through the assumed 5% return requirement, but does not quantify broader fiscal, credit, governance, or construction-risk implications associated with State equity participation.

During the operating phase, the cost of capital is lower since the project is already built and will generate revenue that is less risky than the construction costs themselves. Revenue is assumed to be secured by a PPA or Indexed ANZEC so that it is largely hedged against commodity fluctuation risk. In addition, since, at least for the initial projects, the analysis assumes the project receives a 40% investment tax credit paid in the first year of operations, equity during operations is relatively low cost since the front-loaded cash flow materially shortens the duration of capital at risk thereby reducing the equity exposure during operations. This means that equity investors during operation face even lower risks than they would without the tax credit, since a large portion of their required return is paid out early in the project's life. The cost of equity in operations is assumed to be below those of Independent Power Producers (IPPs) and slightly

¹⁷ "De-SPAC transactions" refer to the merger of a Special Purpose Acquisition Company (SPAC)—a publicly listed shell company formed to raise capital through an IPO—with a private operating company, thereby taking the private company public. In the context of SMR developers, these transactions provided public equity capital to pre-revenue, first-of-a-kind nuclear technology firms, and the implied discount rates reflect investors' required returns for assuming substantial technology, licensing, construction, and commercialization risk.

¹⁸ This reflects A to AAA-rated 10- to 30-year municipal bond yields as of April 6, 2026, per the Federal Reserve Bank.

below electric utilities in NY. IPPs are high-risk because of market revenue exposure and broader portfolio of highly leveraged assets, and utilities are lower risk because their returns are guaranteed by regulatory commissions.

C.7 Tax and Tax Credit Inputs

Tax Rate (Federal & State)

Equity owners during operations must pay corporate income taxes to the federal government and the state of New York. Corporate tax rates are set by federal and state governments and are expressed as a percentage of taxable income. The project's taxable income is equal to revenues less operating expenses, tax depreciation, interest payments on debt, and any tax credits. The analysis applies federal corporate tax at a rate of 21% and assumes that projects are exempt from New York State income tax. Stipulated target hurdle rates during operation (as indicated in Table C-3) are achieved in the analysis on a post-tax basis.¹⁹ Any State equity in the project is exempt from both state and federal income tax. The project is also assumed to be an efficient taxpayer which does not carry over net operating losses (NOLs) in the case that taxable income is negative (deductions exceed income).

For investors during the development and construction stage, questions may arise in respect of capital gains taxes, and whether the situation differs in this respect from a continuous single-owner model. Equity ownership during construction and the subsequent sale of the facility could involve complex and multilayered tax considerations including potential capital gains/losses elsewhere. These are not explored in the analysis, i.e., targeted development and construction hurdle rates as set out in Table C-3 are achieved without consideration of such possible tax implications.

Depreciation Schedule

United States tax law allows the project to deduct depreciation, an accounting measure of the plant's declining value, from taxable income. The tax depreciation schedules available to the project are set by the IRS, and this analysis assumes the project is depreciated over 5 years using the 5-year MACRS.²⁰ The depreciable basis, or the assessed value of the plant to be depreciated,

¹⁹ U.S. Internal Revenue Service (IRS), "Publication 542: Corporations," February 9, 2024, p. 15, <https://www.irs.gov/pub/irs-pdf/p542.pdf>.

²⁰ IRS, "Publication 946: How to Depreciate Property," March 17, 2025, p. 70, <https://www.irs.gov/pub/irs-pdf/p946.pdf>.

includes the cost of construction and installation works only. Moreover, the depreciable basis is additionally reduced by half of the total ITC claimed.

Investment Tax Credit and Monetization

Since the project will produce clean electricity, it is eligible for a Section 48E Clean Electricity ITC. The base amount of the ITC is 6% of the qualified investment, which increases to 30% of eligible project costs for facilities meeting prevailing wage and registered apprenticeship requirements. Additionally, there are two 10% adders for meeting certain domestic content requirements for steel, iron, and manufactured products and for siting in an energy community.²¹ This analysis assumes a total ITC of 40%, inclusive of a 10% adder for domestic content requirements.

The One Big Beautiful Bill Act, signed into law on July 4, 2025, changed the phase-out timeline of the Section 48E ITC to the following:²²

- 100% credit for facilities beginning construction during 2033
- 75% credit for facilities beginning construction in 2034
- 50% credit for facilities beginning construction during 2035
- 0% credit for facilities beginning construction after December 31, 2035

For all scenarios analyzed, the beginning of construction eligibility year is assumed to be when FID occurs, beginning in year 3 of project development and construction. For example, if the project starts development in 2031, then the project would be assumed eligible for the full 100% credit as FID occurs in 2033. For a project that starts development in 2032, it is only assumed to be eligible for 75% of the credit as FID occurs in 2034.

The project is assumed to claim its full ITC entitlement in the first year of operation regardless of ownership structure since, under IRS rules, the project company can sell the ITC to a third party in exchange for non-taxable cash income if its own tax appetite is not large enough to absorb the full credit. This analysis does not include a quantification of transaction costs in this respect.

Federal tax credits can be and, in the past, have been extended. The analysis includes sensitivities that assume that extension of the current tax credit levels would take place to cover

²¹ IRS, "Clean Electricity Investment Credit," last reviewed January 5, 2026, <https://www.irs.gov/credits-deductions/clean-electricity-investment-credit>.

²² Abramowitz, Laurie, et al., "From IRA to OBBBA: A New Era for Clean Energy Tax Credits," Arnold & Porter, July 22, 2025, <https://www.arnoldporter.com/en/perspectives/advisories/2025/07/from-ira-to-obbba-a-new-era-for-clean-energy-tax-credits>.

the full deployment horizon assessed in this analysis. The analysis also includes a reference case that tests project economics if current federal tax credits were not available.

C.8 Pipeline and Learning Inputs

In addition to evaluating the economics of a single nuclear reactor installation, this analysis examines scenarios with deployment of a pipeline of successive nuclear projects over time. The pipeline framework allows the analysis to reflect potential learning effects, improved project execution, and resulting capital cost reductions across multiple projects to assess how the magnitude and structure of required public support may change as deployment progresses. This analysis can inform how to minimize the cost of a pipeline of a given plant type. It can also inform the value of committing to a single standardized design vs. retaining optionality and waiting to develop subsequent plants after other jurisdictions' projects have discovered the cost and performance of other technologies.

Learning Rates and Cost Dynamics

Cost reduction through learning effects and economies of scale is a foundational concept across energy technologies. Repeated deployment enables project developers, manufacturers, and supply chains to reduce costs through standardization, process optimization, risk reduction, and improved construction and financing practices. This dynamic is often characterized using learning rates.

For advanced nuclear, learning effects are complex, uncertain, and path dependent. Prior analysis, including NYSERDA's 0x40 Assessment, demonstrates a wide range of potential learning outcomes depending on technology selection, deployment sequencing, contracting structures, and other project-specific and institutional factors. Historical evidence indicates that cost reductions in nuclear construction are not guaranteed. Observed costs and learning rates have varied significantly. A key observed difference between learning effects in nuclear energy and those in other clean energy technologies is that learning effects in the nuclear energy sector have generally remained limited to the technology design in question (e.g., within AP1000s or EPRs or APR1400s, not across technologies). Accordingly, while this is a simplification, the analysis in this options paper assumes that in scenarios where multiple different technologies are assumed to be deployed, learning occurs only within each distinct technology design.

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Learning rates are defined as the percentage reduction in cost associated with each doubling of cumulative installed capacity. In practice this relationship is captured by linking unit costs (or components thereof) to total cumulative deployment.

The learning rates used in this analysis build on those described in the 0x40 Assessment, but apply a more nuanced approach that identifies differences in learning by cost component. Specifically, each cost component is assigned: (1) a maximum learning rate, (2) an applicability factor based on the location of the prior deployment, and (3) an applicability factor based on the time between project starts, or the project “stagger.” This approach is captured in Tables C-4, C-5 and C-6:

- Table C-4 shows the maximum learning rate for each of the cost components described above in Section C.3 (Development and Construction Inputs), in optimal situations for learning, i.e., where deployment occurs on the same site and with ideal stagger timing between deployment of units.
- Table C-5 indicates in which situations only a portion of the full learning rate is applied, depending whether prior deployment occurred on the same site and in-state or out-of-state.
- Table C-6 indicates in which situations only a portion of the full learning rate is applied, depending whether deployment of the next unit occurs more quickly than optimal (meaning that only part of the learning can be transferred).

Table C-4. Learning Rates

Cost Component	Maximum Learning Rate
Equipment	16%
Materials	7%
Labor	5%
Indirect	18%
Owner’s Cost	30%

Table C-5. Fraction of Learning Rate Depending on Location

Cost Component	Same Site	Different Site but within NY	Different Jurisdiction
Equipment	100%	100%	100%
Materials	100%	100%	0%
Labor	100%	100%	0%
Indirect	100%	100%	100%
Owner’s Cost	100%	0%	0%

Table C-6. Fraction of Learning Rate Depending on Stagger

Cost Component	No Stagger	1 year	2-4 years
Equipment	100%	100%	100%
Materials	100%	100%	100%
Labor	0%	100%	100%
Indirect	0%	50%	100%
Owner’s Cost	50%	50%	100%

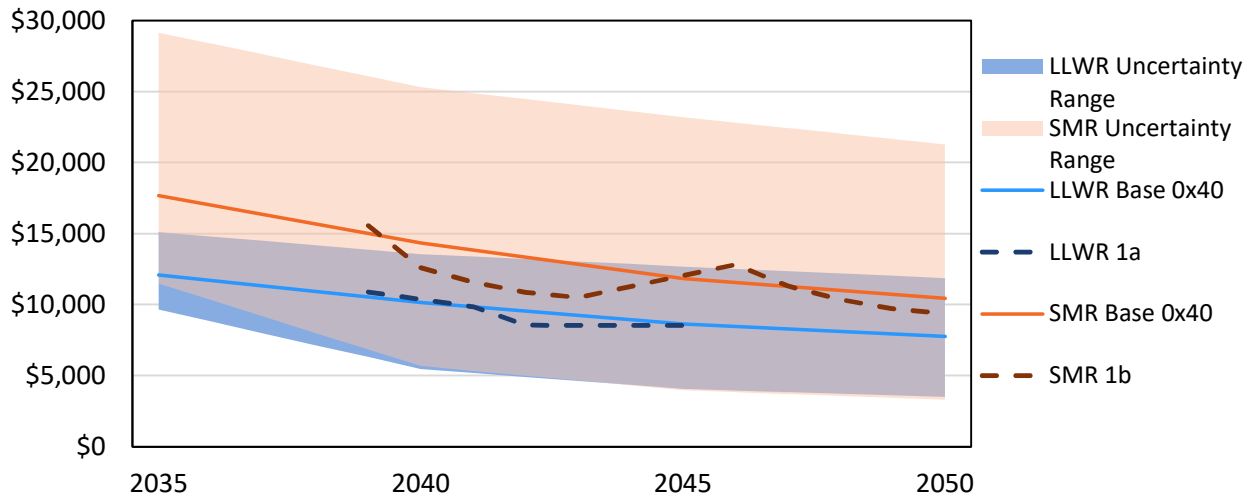
Note: A separate related effect not shown in this table occurs in pipeline scenario P-3, where specifically for materials and labor, a discount of 50% of accumulated learning in these areas is applied, to reflect attrition of such learning due to a longer gap in project development than in other scenarios.

The learning rates applied in this analysis are informed by a combination of empirical evidence and analysis team expert judgment. Prior work by Stewart and Shirvan develops a component-level learning framework that distinguishes between factory (equipment), on-site labor, and material cost reductions, with representative learning rates for each category.²³ The equipment and materials learning rates used in this analysis align with the ranges identified in that work, with adjustments to reflect differences in cost categorization and modeling structure. Availability of directly observable empirical data for labor, indirect cost and owner’s cost learning rates is limited, and the input assumptions used here reflect judgements relative to the data for other categories. Given the limited availability of disaggregated empirical data, all learning rates presented here should be interpreted as estimates that combine literature-based evidence with expert judgment. These uncertainties are further reflected through sensitivity analysis provided in Appendix D (Cost Analysis – Results).

The effective aggregate learning resulting from the differentiated approach outlined here was compared against the learning rates documented in the 0x40 Assessment. This comparison is shown in Figure C-5 and confirms the approach remains broadly consistent.

²³ Stewart, W.R., Shirvan, K., “Capital cost estimation for advanced nuclear power plants,” *Renewable and Sustainable Energy Reviews*, Vol. 155, March 2022, <https://www.sciencedirect.com/science/article/abs/pii/S1364032121011473?via%3Dihub>. This analysis uses the factory (equipment) and materials learning rate estimates from this paper.

Figure C-5. Comparison of Cost Reduction in Pipeline Scenario 1 to 0x40 Assessment



Note: Values for LLWR 1a and SMR 1b are from this analysis and are overlaid on Figure 41 from 0x40 Assessment p. 168.

The following discussion explains in more detail the basis for each cost component’s learning rate and the assumed applicability of learning across locations and stagger lengths.

Equipment

Equipment cost reductions are primarily driven by factory-based manufacturing, repeat procurement, standardization, and broader supply chain learning. As vendors produce additional units of the same reactor design or major components, they can improve manufacturing processes, reduce rework, refine quality control, and achieve purchasing efficiencies.

Because equipment learning is embedded primarily in the broader vendor and manufacturing supply chain, it is assumed to transfer across sites and states. As a result, the full equipment learning rate is available regardless of whether the subsequent unit is located at the same site, a different site in New York, or a different jurisdiction.

Equipment learning is also assumed to apply regardless of deployment stagger intervals. This reflects that equipment cost reductions are driven substantially by manufacturing repetition, volume ordering, and supply chain scale, rather than only by lessons learned from completed field construction.

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Materials

Materials cost reductions are driven by procurement strategies, supplier relationships, logistics efficiencies, and improved understanding of material quantities and specifications.

Materials learning is treated as more local than equipment learning. Projects within New York can benefit from similar regional supplier networks, transportation arrangements, procurement approaches, and construction practices. Accordingly, materials learning is assumed to transfer between sites within New York. However, materials learning is not assumed to transfer from projects in other jurisdictions, where supplier networks, logistics conditions, and regional market conditions may differ.

Materials learning is assumed to apply where such in-state deployment is subject to stagger periods of no more than four years. In these cases, procurement strategies, supplier relationships, and logistics planning can be maintained or replicated across units. For staggers greater than four years, materials-related learning is assumed to partially degrade. In this case, the analysis assumes that 50% of previously realized materials cost reductions are lost before the next unit begins. In practical terms, costs do not fully return to first-unit levels, but some benefit is lost due to reduced supplier readiness, weakened procurement continuity, and the need to re-establish project-specific logistics.

Labor

Labor cost reductions are driven by learning-by-doing in field construction. As construction crews repeat similar activities, productivity can improve through greater familiarity with the design, improved sequencing, reduced rework, and more efficient coordination across trades. This analysis applies a relatively low maximum labor learning rate of 5%, which is conservatively calibrated to reflect constraints on labor productivity improvements, including workforce turnover, site-specific conditions, and institutional factors.

Labor learning is assumed to transfer between sites within New York because the analysis assumes that the same core construction workforce can, to a significant extent, be retained and redeployed across the New York pipeline. However, labor learning is not assumed to transfer across states, because out-of-state projects are assumed to rely on different local workforces and labor markets.

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The timing between units is particularly important for labor learning. If units are deployed simultaneously with no stagger, labor learning is not assumed to apply between those units because the second unit cannot benefit from field experience that has not yet occurred. For one-year and two-to-four-year staggers, labor learning is assumed to be preserved because there is sufficient continuity in workers, construction management, and site execution practices to carry forward experience from one unit to the next. For staggers greater than four years, labor learning is assumed to partially degrade, with 50% of previously realized labor cost reductions lost before the next unit begins. This reflects workforce turnover, reduced continuity in construction teams, and diminished organizational memory.

Indirect Costs

Indirect cost learning is driven by organizational learning, standardization of project execution, improved project controls, and reduced uncertainty in construction planning.

Indirect learning is assumed to transfer across sites and states because these capabilities are often embedded in the developer, EPC contractor, engineering firms, and project management organizations rather than tied exclusively to specific projects. On this basis, this transferability depends on continuity in key project participants. Improvements in design packages, construction sequencing, project controls, and risk management are most likely to transfer where the same or similar EPC contractors, engineering teams, and project management organizations are involved.

Indirect learning is not assumed to apply between simultaneous units because project management and execution lessons from one unit cannot be incorporated into another unit that begins at the same time. For a one-year stagger, only 50% of indirect learning is assumed to apply, reflecting partial ability to incorporate lessons into the next project. For two-to-four-year staggers, the full indirect learning rate is assumed to apply, as this timing provides more opportunity to incorporate prior project experience into engineering, procurement, construction management, and oversight processes.

Owner's Cost

Meaningful reductions in owner's costs can be achieved when multiple units are deployed at the same site because infrastructure, permitting work, oversight functions, and site-specific engineering can be shared or repeated. This analysis applies a maximum owner's cost learning rate of 30%, based on Shirvan's prior work indicating that constructing successive units at the

same site can result in significant reductions in owner's costs due to shared infrastructure, reduced oversight requirements, and workforce continuity.²⁴

Owner's cost learning is assumed to apply only to repeated deployment at the same site. It does not transfer to other sites in New York or to other states because the relevant cost reductions are inherently location specific. A new site requires its own site preparation, engineering, permitting, utility access, interconnection-related work, and startup activities.

Owner's cost learning is partially available under no-stagger and one-year-stagger deployment because some owner's cost savings are tied to shared site infrastructure and common permitting rather than only sequential learning. However, the full owner's cost learning rate is assumed to apply only for two-to-four-year staggers, where there is enough time to incorporate site-level lessons while maintaining continuity.

Learning from Background Market Activity and Deployment

In addition to deployment within New York, the analysis assumes that when New York deploys a given technology, parallel deployments of that same technology occur elsewhere in North America in matching quantities. This background market activity contributes to learning only for equipment costs.²⁵ In scenarios where out-of-state deployment occurs during a period when New York is not deploying that technology, learning occurs for equipment and indirect costs.

Development and Construction Duration

Construction sequencing and timing are explicitly incorporated into the analysis to reflect both learning-driven efficiency gains and scenario-specific deployment assumptions. A learning rate equivalent to the indirect learning discussed previously (18%) is applied to construction duration, i.e., for each doubling of deployed reactors within a given pipeline, total development and construction timeline is reduced accordingly based on the initial duration set out further above in the discussion of S-curves.

²⁴ K. Shirvan, "Total Cost Projection of Next AP1000, MIT Center for Advanced Nuclear Energy Systems," MIT-ANP-TR-201, July 2024. While the cost reduction noted in this paper is not presented as a learning rate, this analysis assumes that it can be translated into a learning rate.

²⁵ While this analysis assumes that indirect costs also transfer between states, it does not assume the same EPC contractor or project management teams simultaneous to the New York pipeline; therefore, indirect learning from out-of-state deployment is only applicable where the deployment scenario allows time and continuity for those lessons to be transferred (i.e., Pipeline Options 3 and 4 in Appendix D).

Government Support

Pipeline scenarios quantify changes in the cost of deploying nuclear projects based on relevant pipeline deployment dynamics. Changes in cost translate to changes in the amount of government support quantified for each project in a pipeline. Where pipeline scenarios assess an integrated government support framework consisting of multiple support interventions, any changes in government support needs are implemented in the analysis as corresponding changes in the amount of ANZEC support, with other interventions (e.g., the percentage state equity investment) held constant.