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Revision 0

Meta-Analysis of Advanced Nuclear Reactor Cost Estimations

April 2024

Gateway for Accelerated Innovation in Nuclear (GAIN)

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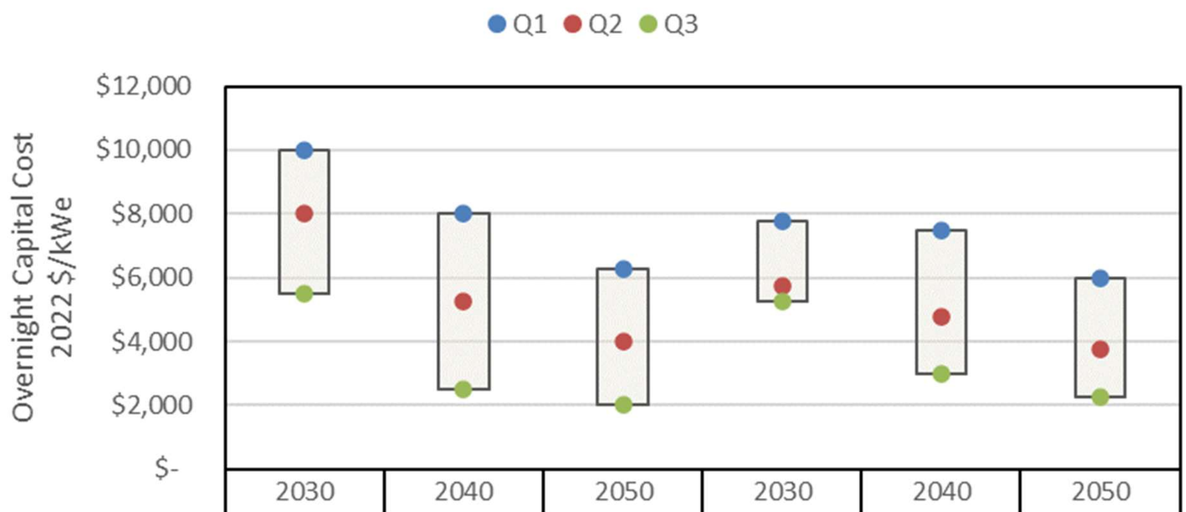
EXECUTIVE SUMMARY

Nuclear energy is a critical cornerstone of the current United States clean energy supply and may play a larger role in the future in support of a transition to a net-zero economy. The current fleet of nuclear reactors predominantly consists of large light-water reactors (LWRs), while many of the reactor designs under consideration are smaller and/or different technologies. Because these new designs have not yet been built, there is a high degree of uncertainty associated with their cost. This complicates energy-planning efforts because cost projections are not always standardized, consistent, and centralized in an easily accessible location. To help support energy planning in the US, this report provides advanced nuclear cost ranges using a transparent methodology along with other relevant information that can be used to help support decision making and energy planning.

The purpose of this work was to conduct a methodical process for cost evaluation using only public information that was vetted with the end-goal to provide reference cost projections for nuclear energy. To provide a solid basis for these values, the approach and assumptions are explicitly laid out throughout the report allowing any user of the data to challenge or reconsider them. Because future US nuclear-reactor costs are still unknown due to little recent observed data, the report opted to compile a comprehensive list of bottom-up estimates and evaluate averages/trends within the data to identify reference ranges. This was deemed preferable to opining on the robustness or validity of one cost estimation versus another. To that end, the work evaluated thousands of lines of cost subaccounts from several bottom-up cost estimates. A wide variety of different reactor types captured in the data are of various sizes and technologies. Some of these reactors will be representative of advanced reactors under development while others will not. Thus, the results here are dependent on the data that are available and the accuracy of the estimates that are used. Each bottom-up estimate was reviewed to determine whether it was complete. Incomplete data sets were corrected to ensure an adequate basis of cross-comparison. The report is not without limitations and should be interpreted as an initial step to develop cost ranges for nuclear technology. Ultimately, future work can build upon the methodology with refined cost estimates to reduce uncertainty.

US-based overnight capital cost (OCC) estimates were compiled from extensive data sets into ranges for both large and small reactor sizes. The resulting values are plotted in Figure A-1 for each reactor size. These ranges are independent of the actual reactor-technology type chosen which is consistent with the findings from (Abou-Jaoude 2023), which found significant overlap in cost estimates between different reactor types. The underlying assumption is that any reactor type that falls within this cost range is assumed to be of a relatively high technology readiness level, lower maturity technologies would need to be evaluated on a case-by-case basis. For a small modular reactor (SMR), the reactor is assumed to produce 300 MWe, and the large reactor is assumed to produce 1,000 MWe. Because the values consist of an average of data sets that cover first-of-a-kind (FOAK) and *Nth*-of-a-kind (NOAK) estimates, the resulting values are referred to as "between a first and *Nth* of a kind," or BOAK. In other words, this is equivalent to a 'next commercial offering', a reactor construction that occurs after the first demonstration. For instance, the upcoming X-energy plant in Seadrift, TX is considered a FOAK, while the subsequent deployment elsewhere would equate to a BOAK. These BOAK ranges are assumed to be applicable from 2030 onward, following currently planned commercial demonstrations in the late 2020s. Due to the high degree of uncertainty with estimating a BOAK cost, a range was provided to match varying levels of conservatism which avoids being overly prescriptive on selecting an exact cost for commercial deployment of advanced reactors. The upper end of the range can be assumed to be a pessimistic scenario for future nuclear deployments where prices are elevated and the benefits from learnings are only marginally realized. The factors for this could be poor project execution, lack of standardization with the initial demonstration design, supply-chain issues, inherent challenges with the technology, or a combination of these and other aspects. On the other end of the range, low BOAK numbers can be assumed to stem from efficient learning from the initial demonstration (or the initial demonstration consisting of a multiunit plant, as is the case with modular reactors), reducing deployment risk of the technology via government/private support, streamlined execution of the follow-on construction, or a combination of these and other aspects. The second-quartile, or median value, would correspond to a 'middle ground' case where some, but not all the initial cost reductions are captured. The cost estimates were grouped between large reactor and SMR to allow for differences in cost and specifications. All values reported in this report are in 2022 USD unless stated otherwise.

The Figure A-1 values are just OCC ranges and do not consider the construction duration and financing that would be included in the total plant cost. While there appears to be a notable difference between SMR and the large reactor OCC values, the differences will narrow when considering construction timelines and associated financing costs, so caution should be exercised with any direct OCC comparison. This is discussed in further detail within the report. The study then projected cost evolutions through 2050 by assessing potential deployment rates and associated learning which led to the trend observed for the 2040 and 2050 costs shown in the figure. Since SMRs are smaller, it takes more units/modules to reach the same electrical deployment. Thus, learning can occur faster with SMRs which allows for quicker and larger cost reductions than for the large reactors as shown in the figure. As a result, the combination of a shorter construction time (which reduces financing costs) and more learning per the same level of GWe deployment causes the cost projections to converge for both SMRs and large reactors.



	Small Modular Reactor 2030	Small Modular Reactor 2040	Small Modular Reactor 2050	Large Reactor 2030	Large Reactor 2040	Large Reactor 2050
Q1	$10,000	$8,000	$6,250	$7,750	$7,500	$6,000
Q2	$8,000	$5,250	$4,000	$5,750	$4,750	$3,750
Q3	$5,500	$2,500	$2,000	$5,250	$3,000	$2,250

Figure A-1. OCC range for large reactors and SMRs. Costs are in 2022 USD.

The OCC values are summarized in Table A-1 along with other key metrics that are expected to be useful for energy-planning, like capacity expansion models or utility integrated resource plans. One critical aspect of the costs is how to project learning and future cost reductions. After the first new nuclear power plants are demonstrated, project costs are expected to decrease on a yearly basis (provided good standardization can be achieved) as learning is accrued and supply chains are established. To project the cost declines over time, learning rates were sampled from literature sources. No SMRs were previously built; hence, learning rates based on bottom-up approaches (e.g., by quantifying the impact stemming from fabrication of different components, modular work, site construction, commissioning) were prioritized. For larger reactors, actual learning rates from deployments were used to project future costs (adjusted to account for standardization or lack thereof between designs). Table A-1 shows the initial BOAK and final 2050 OCCs after learning. Other factors included in the table are capacity factors and ramp rates. Capacity-factor values were taken from the current nuclear-fleet performance which will match well for large reactors. The same value was also applied for SMRs. While some concepts can be envisaged to have lower capacity factors at first during their lifetime and reach this threshold later, in the 60-year timeline of a reactor a fixed value was deemed acceptable. In future electrical grid scenarios, it can be expected that nuclear reactors will ramp their power outputs more significantly due to the variability in the grid energy mix. As a result, the capacity factor values should be interpreted as an upper end and may need to be adjusted depending on specific considerations (note that some upcoming designs intend to leverage thermal energy storage to ramp power while maintain the same nuclear capacity factor). Ramp rates were taken from technical documents for both current and future reactors to define the ramp rates for SMRs as well as large reactors.

While less-significant contributors to the levelized costs than the OCC, the operations and maintenance (O&M) costs of the reactors were considered as well. Table A-1 contains costs for different O&M subgroups, namely variable, fixed, and fuel. O&M costs for large reactors are derived from the operations of the current large LWRs and estimates for the advanced passive reactor (AP1000). The SMR O&M is based on the compiled data sets used for the OCC estimation.

The US government has also made subsidies available for energy technologies. To help planners understand how subsidies can affect costs, a detailed overview of potential cost reductions via subsidies is discussed later in the report. Simplified calculations are performed to adjust the identified cost ranges accounting for different cases. The report also provided insights on the applicability (and resulting cost) of nuclear energy for industrial heat. Cost ranges for heat-based systems with no power-conversion system are provided.

Overall, the report focused on aggregating data from various reactor estimates instead of focusing on a detailed cost estimate for any one specific reactor type. Therefore, this study should be treated as an initial, broad review of the reactor costs in general. Also, these costs are useful for more generic planning purposes. Utilities or companies looking for project specific costs need to carefully consider site specific factors that would not be captured in this information. Going forward, as detailed cost estimates are performed, real-word data are obtained, or reactors move towards construction, the new estimates can be used to represent the status of nuclear costs in the future.

The results are proposed to be used as inputs to the Annual Technology Baseline (ATB) database which offers consistent data on the costs and performance of various energy technologies publicly available. The ATB provides crucial insights and modeling inputs for assessing energy technologies annually, including diverse scenarios for electricity generation and technology deployment. It includes cost projections extending up to 2050 and offers a populated framework for informing strategic energy planning and decision-making processes.

Table A-1. Summary of key data outputs from this report. For National Renewable Energy Laboratory (NREL) Annual Technology Baseline (ATB) consideration.

		Advanced	Moderate	Conservative
Large Reactor	BOAK OCC ($/kWe)	5,250	5,750	7,750
	OCC 2050 ($/kWe)	2,250	3,750	6,000
	Fuel Costs ($/MWh)	9.1	10.3	11.3
	Fixed O&M ($/kW-yr)	126	175	204
	Variable O&M ($MWh)	1.9	2.8	3.4
	Power output (MWe)	1,000		
	Capacity Factor	0.93		
	Construction time (months)	60	82	125
	Ramp rate (%power/min)	5%		
	Learning Rate	8%		
SMR	BOAK OCC ($/kWe)	5,500	8,000	10,000
	OCC 2050 ($/kWe)	2,000	4,000	6,250
	Fuel Costs ($/MWh)	10.0	11.0	12.1
	Fixed O&M ($/kW-yr)	118	136	216
	Variable O&M ($MWh)	2.2	2.6	2.8
	Power output (MWe)	300		
	Capacity Factor	0.93		
	Construction time (months)	43	55	71
	Ramp rate (%power/min)	10%		
	Learning Rate	9.5%		

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ACRONYMS

ABTR	Advanced Burner Test Reactor
ACCERT	Algorithms for Comprehensive Cost Estimation of Reactor Technologies
AHTR	Advanced High-Temperature Reactor
ANL	Argonne National Laboratory
ARIS	Advanced Reactors Information System
ATB	Annual Technology Baseline
BLS	Bureau of Labor Statistics
BOAK	Between of a kind
BTU	British thermal unit
BWR	Boiling water reactor
CAPEX	Capital expenditure
CBR	Cost basis report
CCS	Carbon capture and sequestration
CF	Cost of fuel
CFPP	Carbon Free Power Project
COA	Code of account
CC	Combined cycle
CPI	Consumer Price Index
CPP	Coal power plant
CRF	Capital recovery factor
CT	Combustion turbine
D&D	Deactivation and Decommissioning
DMSR	Denatured molten salt reactor
DOE	U.S. Department of Energy
EEDB	Energy Economic Data Base
EIA	U.S. Energy Information Administration
EIRP	Energy Innovation Reform Project
EQ	Environmental qualification
FFE	Fossil Fuel Employment
FOAK	First of a kind
FRED	Federal Reserve Economic Database
GAIN	Gateway for Accelerated Innovation in Nuclear
GDP	Gross domestic product

GenIV	Generation IV
GIF	Generation IV International Forum
GNCOA	Generalize nuclear code of accounts
GW	Gigawatt
HALEU	High-assay low-enriched uranium
HTGR	High temperature gas reactor
IAEA	International atomic energy agency
IGCC	Integrated gasification combined cycle
INL	Idaho National Laboratory
IPD	Implicit price deflator
IRA	Inflation Reduction Act
IRP	Integrated resource planning
ITC	Investment Tax Credit
LCOE	Levelized cost of electricity
LLP	Limited liability partnership
LR	Learning rate
LWR	Light water reactor
MSR	Molten salt reactor
NEI	Nuclear energy institute
NOAK	Nth of a kind
NPP	Nuclear power plant
NPV	Net present value
NRC	Nuclear Regulatory Commission
NREL	National Renewable Energy Laboratory
NSSS	Nuclear Steam Supply System
O&M	Operations and Maintenance
OCC	Overnight Capital Cost
OPG	Ontario Power Generation
PC	Pulverized coal
PNNL	Pacific Northwest National Laboratory
PRIS	Power Reactor Information System
PRISM	Power reactor innovative small module
PTC	Production Tax Credit
PWR	Pressurized water reactors
R&D	Research and development

ROT	Reactor outlet temperature
SFR	Sodium fast reactor
SMR	Small modular reactor
SWU	Separative Work Units
TVA	Tennessee Valley Authority
TRISO	Tristructural isotropic
UAMPS	Utah Associated Municipal Power Systems
US	United States
VTR	Versatile Test Reactor
WACC	Weighted average cost of capital

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Meta-Analysis of Advanced Nuclear Reactor Cost Estimations

1. INTRODUCTION AND MOTIVATION

Interest in nuclear energy is growing in the United States, and a significant number of nuclear technology developers are working on various nuclear-energy technologies. The Department of Energy (DOE) noted that the United States has the potential for 200 GW of new nuclear deployment by 2050 (DOE 2023). The interest and potential are driven by initiatives to decarbonize the electricity sector as well as supporting decarbonization of other industries with nuclear energy for process heating. However, recent deployment of new nuclear technologies has been very limited, which has led to a scarcity of available cost information to support energy planning. Additionally, advanced reactors that are in development and scheduled for demonstration have different performance and cost characteristics than the current fleet of light-water reactors (LWRs) operating in the United States. Due to these issues, it can be challenging to model and plan for the role of nuclear energy in the future energy mix. This led the Nuclear Innovation Alliance to host workshops in 2022 to review limitations in cost and performance data and to recommend that updated cost and performance data for advanced nuclear be compiled to address this gap (NIA 2023a). NIA noted that without centralized cost and performance data, energy modelers are pulling in available public or other information that can be obtained to support modeling efforts. This creates variations in assumptions and data used by modelers, utilities, or others. Furthermore, these sources may not be representative of the nuclear technologies that are near demonstration and deployment.

The National Renewable Energy Laboratory (NREL) Annual Technology Baseline (ATB) currently hosts data for many electricity technologies to support energy modeling. For nuclear energy, the database contains data for two different reactors: an AP1000 and a small modular reactor (SMR) with a nameplate capacity of 600 MWe (NREL 2022). Currently, in the United States, no company or utility has announced the consideration of deploying these types of reactors, and this necessitates supporting development of information that is more representative of future deployment technologies. As a result, the Gateway for Accelerated Innovation in Nuclear (GAIN) led this study to compile existing information on nuclear costs to help centralize information that can be used to support energy planning in the US.

This report aggregates information that can be leveraged by energy planners wanting to consider advanced nuclear sources. It assembled a large quantity of publicly available detailed cost information for both large and small reactors and uses that information to develop cost ranges for nuclear technology. All estimates were analyzed, cross-compared, and adjusted where necessary to ensure each had the required detail. Estimates were escalated to a uniform dollar year. Subsequently, all values shown in this report are in terms of 2022 United States dollars (USD) unless stated otherwise. Along with the costs, performance characteristics are also included to support other input typically needed in energy models.

Section 2 provides additional background information on previous studies that have compiled nuclear cost estimates. Section 3 then provides an overview of the various sources and cost references available in the open literature that were leveraged as part of this study. Section 4 covers the detailed breakdown of the methodology leveraged in this study to map and escalate different costs to provide a common baseline for comparison. Section 5 analyzes the capital-cost trends, and Section 6 summarizes the operation and maintenance (O&M) costs for nuclear power plants. Section 7 summarizes the learning rates for nuclear power plants and the projection of nuclear costs over different deployment scenarios. Finally, Section 8 addresses additional considerations for nuclear reactor costs (including ramp rates, thermal applications, and the impact of subsidies).

2. BACKGROUND AND ASSUMPTIONS

2.1 Previous Work

Previous work in this space includes an array of top-down meta-studies where authors have taken high level overnight capital cost (OCC) estimates and aggregated the values to produce OCC ranges (Abou Jaoude 2023, Steigerwald et al 2023, Asuega, Limb, and Quinn 2023, Breakthrough Institute 2022, Vegel and Quinn 2017, EIRP 2021). Other existing studies have used a more bottoms-up approach, where authors look at specific costs of reactors and then aggregate them up to OCC (EIA 2022, Stewart and Shirvan 2022, SMR Start 2021, Petti 2018,). In this case OCC is defined as the cost of building the reactor without any financing included (assuming it was built overnight). This excludes the cost of interest during construction and other financing-related costs (referred to as Account 60 later in the report). In the National Renewable Energy Laboratory (NREL) ATB data set, the current values used come from an Energy Information Administration (EIA) Study (EIA 2022). The OCCs shown in that study are $7,468/kWe for a large reactor—specifically called out as an AP1000—and $8,017/kWe for a 600 MWe small modular reactor (SMR) which is not tied to a specific reactor design.

The EIA report used to populate current ATB nuclear cost values is useful because it provides a greater level of specificity over top-down estimates, but it is still limited in data granularity. Costs are not provided in a code-of-account (COA) format, and the estimates are for a single reactor type with no indication of how costs might change with different reactor designs or technology shifts. In this sense, the EIA numbers are useful to provide single-point estimates for nuclear costs, but less useful in providing the broader type of cost estimates needed for modeling, such as capacity expansion. Thus, a broader survey of existing literature is needed to update the current Advanced Technology Baseline (ATB) numbers and provide more context on nuclear costs, broadly. As already pointed out, this has been done to differing degrees by a variety of reports outside of EIA attempts. For example, Abou-Jaoude et al. (2023) surveyed existing top-down estimates and produces a meta-study of said top-down results. This report is useful to provide context for cost ranges, but it is limited in that it also does not provide granular COA breakdowns to these costs. Another report which does provide some level of granularity and breadth in its estimation is the Cost Basis Report (CBR, Dixon et al. 2017). The CBR mainly focused on observed costs for a variety of larger reactors but excluded SMRs which are under consideration currently. Furthermore, while the report does provide a cost range, it does not specify the maturity of the given reactor (FOAK vs. NOAK) nor indeed provide a projected temporal evolution in costs. Since both the CBR and this report are DOE-sponsored activities, future work should ideally work towards converging the two for consistent nuclear energy cost projections.

Overall, the approach leveraged within this report is useful even within the context of existing literature on nuclear cost estimation because it fills a key gap as a bottom-up meta-analysis. A comparison of the results found in this report and those found in other similar studies is found in Figure 1. Due to differing estimation methods, some studies only report a single cost value while others report high-low, or high-low-mid values. The figure helps visualize the wide variety of differing sources in the literature that are projecting future nuclear costs, and the need for a reference study dedicated to this purpose.

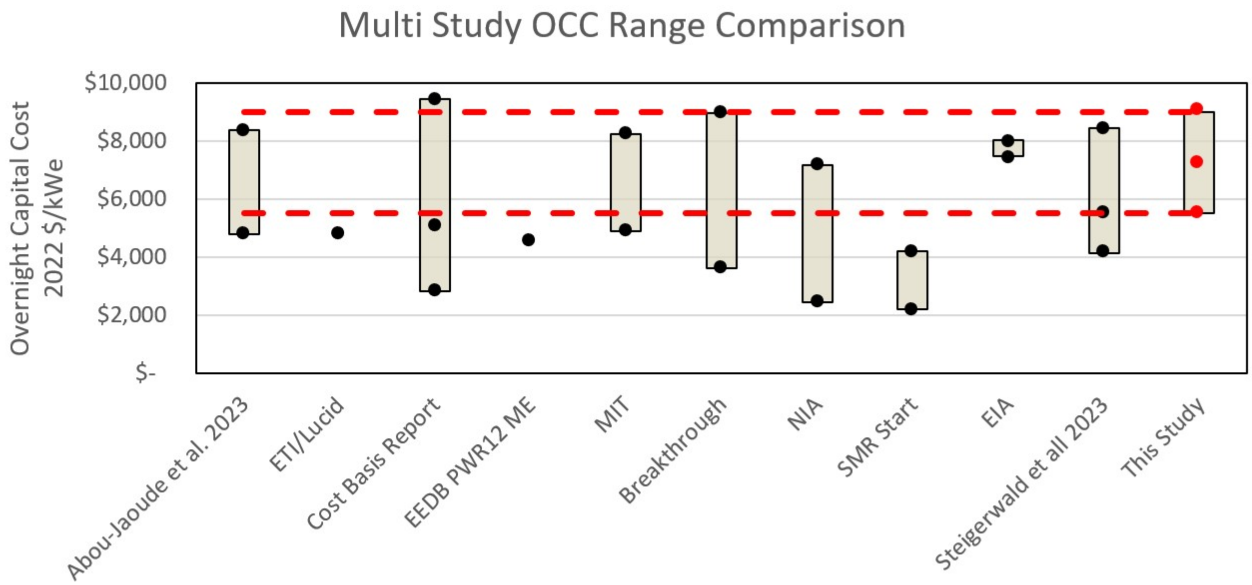

Figure 1. Comparison of US-based OCC estimates across different studies (values for the current study are for ‘all data’ not a particular subset). Note that the estimate types for each study may not be consistent.

It is worth noting that side by side comparisons of studies, as shown in Figure 1, are limited in their interpretation due to differences in data collection, cost escalation—this, in particular, can have major impacts to final numbers as different reports use different methodologies—technology and size focus, among others. It should be noted that while the cost basis report (CBR) suggests values that are lower than the between a first and *Nth* of a kind (BOAK) range for this report, 2050 projected numbers (representative of *Nth* of a kind) from this study are in line with those estimates. It should also be noted that these values only represent overnight capital costs, which are only one part of the overall cost of a plant. This does not include any of the associated financing costs and construction duration that can have significant impacts on overall costs. Ultimately, caution should be exercised when comparing such numbers without delving deeper into each study methodology and underlying data sets.

Lastly, it is also important to view this report as part of a broader longer-term effort to continuously refine nuclear cost estimations for energy-mix planning activities. Figure 2 showcases an illustrative vision of how future efforts can build upon this study as better data is generated and becomes available. As such, this report should be interpreted as a ‘best-effort’ within the context of currently available information. It is a first step with future efforts further refining the analysis and narrowing the cost uncertainties. Section 9 discusses potential future work to improve the analysis further in greater detail.

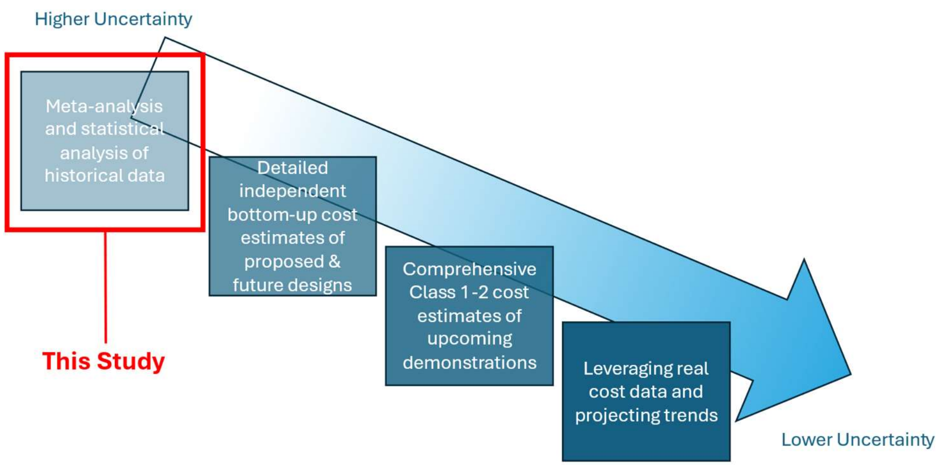

Figure 2. Illustration of the ideal path towards lower uncertainty in nuclear cost estimation.

2.2 Overview of Proposed Methodology and Limitations

The goal of this study was to compile a broad array of publicly available representative bottoms -up cost estimates to help define a cost range for advanced-reactor nuclear energy plants. As will be described in more detail later in this report, this includes both large- and small-reactor cost ranges, as well as varying technology types, including LWRs, sodium fast reactors, and gas reactors. This cost range is not specific to any one technology type or any specific size. Given the range of estimates used, efforts were made to ensure that numbers were comparable.

Because it is unclear at this stage which exact reactor type will ultimately prove to be successful, a lumped approach was deemed to be suitable. Further, while the effort compiled a broad variety of estimates from a wide range of sources, the total data set was still not large enough to derive statistically significant conclusions on subgroupings of the data.

To properly compare estimates across different technologies, time frames, COA methodologies, estimate completeness, and estimate types, a consistent, transparent, and justifiable methodology for normalizing data was undertaken. The following details the high-level steps taken to aggregate and normalize data. These are explained in more detail later in the report.

1. Estimates were mapped/binned to the same COA system, the generalized nuclear COA.
2. Estimates were escalated to the same dollar year, 2022 USD values.
3. Estimates were normalized and converted to $/kWe values to account for different sizes.
4. Missing data from specific estimates were populated, producing complete OCC estimates.
5. Data were aggregated and pulled into quartiles to produce cost ranges.

Because the data set grouped and processed both first-of-a-kind (FOAK) and *Nth*-of-a-kind (NOAK) estimates, the resulting figure of merit is termed a BOAK. This terminology was first introduced by Abou-Jaoude (2023) to delineate either a well-executed FOAK or the second/third deployment of a given design (sometimes also referred to as "next of a kind" or "next commercial offering"). In a sense, the BOAK identifies commercial advanced-reactor costs from 2030 onwards (demonstration are expected to occur in the late 2020s). The definition of the term is intentionally kept broad for several reasons:

- Significant uncertainty on the FOAK cost of advanced reactors as well as for the next commercial offering
- Substantial uncertainty of how many reactors (if any) will be built prior to the start of 2030 (to complicate things further, several vendors intend their demonstration to be a multiunit plant).

While other studies have defined an atemporal range of costs with the upper end representing FOAK values and the lower end NOAK ones (Dixon 2017), this study is setting out to project a time-based evolution of cost. Hence the initial starting point must be clearly defined (with an associated uncertainty band). For these reasons, the BOAK-approach was deemed to be suitable for the purposes of this study. It should be noted that all values in the data set were weighted to account for imbalance between NOAK and FOAK estimates within the data. This will be discussed in further detail in later sections.

The approach leveraged here allows for a more accurate comparison of estimates irrespective of the types of differences already discussed, but it is not without limitations. As is the case with any meta-study, the fidelity of the quartile ranges produced is dependent on the quantity and quality of data used. In this case, a total of 50 estimates were collected, but after excluding select values, only 35 could be used to produce the quartile ranges. More data always helps to improve fidelity, but in the case of bottom-up estimates, the number of available open-source data sets is relatively small. This limitation on the availability of data also makes it difficult to produce multiple groupings to compare cost ranges between technologies and designs. In an ideal world, this analysis would compare cost ranges between pressurized water reactors (PWRs), boiling-water reactors (BWRs), high-temperature gas reactors (HTGRs), sodium fast reactors (SFRs), and molten-salt reactors (MSRs), among others. However, the lack of available data made it impossible to produce justifiable ranges for each reactor type with high levels of certainty for each range. In that sense, this approach is most limited by the quantity of data leveraged. Another limitation to this approach is the inability to know what kind of cost estimate a given report has produced (Class 5, Class 4, etc.) and what kind of error band is associated with the reported numbers. It is common for estimates to have varying ranges of error and, ideally, this would be accounted for, and only similar class estimates would be compared. For example, a Class 5 estimate can have an expected cost variance up to 100% high while a Class 2 estimate would only expect to be up to 20% high (AACE 2005). Because of this, the underlying data set will be made available for future research to add upon this first attempt and improve the fidelity of results as more or higher-quality data become available. Note that most of the data used in this report are estimates and not observed cost data.

Starting with a goal to report information that can be used to support energy planning, it is important to compare how information for other technologies is reported such that what is provided here will be consistent with how other technologies are treated. This helps ensure that consistent comparisons are accomplished when considering a mix of energy resources. The 2023 Electricity ATB database (NREL 2022) offers consistent technology-specific information on cost and performance parameters for various research and development (R&D) scenarios, resource characteristics, and sites relevant to electricity -generating technologies. The performance parameters covered in the Electricity ATB encompass capital costs, O&M costs, capacity factors, fuel costs, other performance characteristics, and the levelized cost of electricity (LCOE) for different generating technologies. Table 1 contains a breakdown of costs that are included for various renewable generation technologies. The test shown in *italics* highlights those components that are specific to that technology and are not included in others. For the nuclear costs, comparisons were performed to determine that similar cost categories were included for nuclear technologies.

Table 1. Cost components for various renewable technologies. Items listed in *italics* are specific to the given technology in that column.

Description/ Technology	Land Based Wind	Utility-Scale PV	Concentrating Solar Power	Utility-Scale PV-Plus-Battery
Balance of System Category	Balance of System	Balance of System	Balance of System	Balance of System
Electrical infrastructure & interconnection (electrical interconnection, electronic, electrical infrastructure, electrical)	1. Internal and control connections 2. Onsite electrical equipment 3. Power electronics 4. Transmission substation upgrades	1. Internal and control connections 2. Onsite electrical equipment 3. Power electronics 4. Transmission substation upgrades *5. AC wiring and installation* *6. DC wiring and installation* *7. Distance-based spur line cost (GCC)* *8. Inverters*	1. Internal and control connections 2. Onsite electrical equipment 3. Power electronics 4. Transmission substation upgrades *5. Switchgear*	1. Internal and control connections 2. Onsite electrical equipment. 3. Power electronics 4. Transmission substation upgrades *5. AC wiring and installation* *6. DC wiring and installation* *7. Distance-based spur line cost (GCC)* *8. Inverters* *9. Switch Gear* *10. Transformers* *11. Energy Management System* *12. Monitors, Controls and Communications*

Description/ Technology	Land Based Wind	Utility-Scale PV	Concentrating Solar Power	Utility-Scale PV-Plus-Battery
Balance of System Category	Balance of System	Balance of System	Balance of System	Balance of System
Generation equipment & infrastructure (civil works, generation equipment, other equipment, support structure)	1. Plant construction 2. Power plant equipment *3. Wind turbine supply*	1. Plant construction 2. Power plant equipment *3. Foundation* *4. Hardware* *5. Module supply* *6. Racking*	1. Plant construction 2. Power plant equipment *3. Piping and heat-transfer fluid system* *4. Power block (heat exchangers, power turbine, generator, cooling system)* *5. Solar collectors* *6. Solar receiver* *7. Thermal energy storage system*	1. Plant construction 2. Power plant equipment *3. Foundation* *4. Hardware* *5. Module supply* *6. Racking* *7. Battery pack* *8. Battery container* *9. Battery management system* *10. Thermal management system* *11. Fire-suppression system* *12.Battery racking* *13. Foundation for battery and inverters* *14. Inverter housing*
Installation & indirect	1. Distributable labor and materials 2. Engineering 3. Startup and commissioning	1. Distributable labor and materials 2. Engineering 3 Startup and commissioning	1. Distributable labor and materials 2. Engineering 3. Start up and commissioning *4. Installation*	1. Distributable labor and materials 2. Engineering 3. Start up and commissioning

Description/ Technology	Land Based Wind	Utility-Scale PV	Concentrating Solar Power	Utility-Scale PV-Plus-Battery
Balance of System Category	Balance of System	Balance of System	Balance of System	Balance of System
Owner's costs	1. Development costs 2. Environmental studies and permitting 3. Insurance costs 4. Legal fees 5. Preliminary feasibility and engineering studies 6. Property taxes during construction	1. Development costs 2. Environmental studies and permitting 3. Insurance costs 4. Legal fees 5. Preliminary feasibility and engineering studies 6. Property taxes during construction	1. Development costs 2. Environmental studies and permitting 3. Insurance costs 4. Legal fees 5. Preliminary feasibility and engineering studies 6. Property taxes during construction	1. Development costs 2. Environmental studies and permitting 3. Insurance costs 4. Legal fees 5. Preliminary feasibility and engineering studies 6. Property taxes during construction
Site	1. Access roads 2. Buildings for operations and maintenance 3. Fencing 4. Land acquisition 5. Site preparation 6. Transformers 7. Underground utilities	1. Access roads 2. Buildings for operations and maintenance 3. Fencing 4. Land acquisition 5. Site preparation 6. Transformers 7. Underground utilities	1. Access roads 2. Buildings for operations and maintenance 3. Fencing 4. Land acquisition 5. Site preparation 6. Transformers 7. Underground utilities	1. Access roads 2. Buildings for operations and maintenance 3. Fencing 4. Land acquisition 5. Site preparation 6. Transformers 7. Underground utilities

3. OVERVIEW OF REFERENCE COST DATA

3.1 Overview of Sources

A wide variety of publicly available data sets featuring large and small reactors were analyzed for this study. While selecting the reactor cost-estimate sources for this study, three main selection criteria were considered.

1. Reliability of source. It was important to ensure that the incorporated data sets were selected from reputable and referenceable sources. Most sources were studies commissioned for DOE. The remainder were published research from experts in the field, including peer-reviewed articles.
2. Organization of data. The data sets that were selected prioritized a detailed bottom-up description of the reactor costs or, at the very least, included some breakdown in their cost estimate that allowed them to be baselined against other references. For example, it was preferable to have the total direct capitalized costs broken down into subcomponents, such as costs associated with structures, site improvements, reactor-system components, among others. These would be made more granular at one or more levels of detail. Table 3 provides an example of the bottom-up description of capitalized direct costs associated with a sample reactor of varying size (in MWe). Most sources use either Energy Economic Data Base (EEDB) code (EEDB 1987) of accounts or Generation IV International Forum (GIF) COAs (GIF 2007) to create a bottom-up organizational structure for representing cost data. Some sources also used a hybrid COA structure (a combination of EEDB, GIF, and additional subaccounts) to achieve data aggregation. Table 2 provides a comparative understanding of how the different COAs are organized into subaccounts for same main account (Account 21, which captures direct capital costs associated with structures and improvements).
3. Spread of data in the set. The goal of this study is to provide a range of detailed cost estimates, including the capitalized and annualized costs associated with building, operating, and managing nuclear reactors of different sizes and technology. As such, emphasis was placed on selecting sources that provided granularized costs estimates beyond direct capitalized costs.

Table 2. Hybrid, EEDB, and GIF code of accounts organization for Account 21.

Hybrid		EEDB		GIF	
Code of Account	Title	Code of Account	Title	Code of Account	Title
21	Structures + improvements	21	Structures + improvements	21	Structures and improvements
211	Yardwork	211	Yardwork	211	Site preparation/yardwork
212	Reactor-containment building	212	Reactor containment building	212	Reactor island civil structures
213	Turbine building	213	Turbine room and heater bay	213	Turbine generator building
214	Operation center	214	Security building	214	Security building and gatehouse
214A	Operation Center A	215	Prim. auxiliary building and tunnels	215	Reactor service (auxiliary) building
214B	Operation Center B	216	Waste-processing building	216	Radwaste building
215	Reactor service building	217	Fuel-storage building	217	Fuel service building
216	Radioactive waste management building	218A	Control room/D-G building	218A	Control building
217	(not used)	218B	Administration + service building	218B	Administration building
218A	Personnel services building	218D	Fire pump house including foundations	218C	O&M center
218B	(not used)	218E	Emergency feed-pump building	218E	Steam-generator storage building
218C	Makeup water treatment & auxiliary boiler building	218F	Manway tunnels (RCA tunnels)	218K	Pipe tunnels
218D	Fire pump house	218G	Electrical tunnels	218L	Electrical tunnels
218E	Helium-storage building	218H	Nonessential switchgear building	218N	Maintenance shop

Hybrid		EEDB		GIF	
Code of Account	Title	Code of Account	Title	Code of Account	Title
218G	Hydrogen-storage area	218J	Main steam and feedwater pipe enclave	218Q	Foundations for outside equipment and tanks
218H	Guard House	218K	Pipe Tunnels	218R	Balance of plant service building
218 I	Nuclear island warehouse	218L	Technical support center	218S	Wastewater treatment building
218J	ECA warehouse	218P	Containment EQ hatch missile shield	218T	Emergency power-generation building
218K	Maintenance building	218S	Wastewater treatment	218W	Warehouse
218U	Standby power building	218T	Ultimate heat-sink structure	218X	Railroad tracks
		218V	Control-room emergency air-intake structure	218Y	Roads and paved areas
				218Z	Reactor receiving and assembly building
				219A	Training center
				219K	Special-material unloading facility

Table 3. Example of bottom-up reactor costs description for capitalized direct costs associated with reactor of different size (in terms of electrical output).

	Parameter	Unit				
	Plant Block Nominal Power	[MWe]	165	311	622	1,244
	Reactor Nominal Power	[MWe]	165	311	311	311
	Reactor Blocks/Plant	[-]	1	1	2	4
COA	Titles					
20	Capitalized Direct Cost					
21	Structures and Improvements	$/reactor	$95,629,345.27	$116,911,260.17	$165,877,191.57	$269,737,393.18
22	Reactor Equipment	$/reactor	$103,339,439.52	$168,954,959.79	$301,181,473.66	$572,490,427.64
23	Turbine Generator Equipment	$/reactor	$114,790,006.41	$193,175,861.34	$360,385,781.71	$684,743,737.53
24	Electrical Equipment	$/reactor	$56,420,704.02	$93,718,631.00	$163,208,221.65	$284,231,233.86
25	Heat Rejection System	$/reactor	$17,362,219.46	$28,452,264.51	$52,390,708.54	$98,187,960.04
26	Miscellaneous Equipment	$/reactor	$47,811,287.48	$67,299,870.98	$102,139,004.08	$157,565,236.53
27	Special Materials	$/reactor	$0.00	$0.00	$0.00	$0.00
28	Simulator	$/reactor	$78,200.00	$78,200.00	$78,200.00	$156,400.00
29	Contingency on Direct Costs	$/reactor	$87,086,240.43	$133,718,209.56	$229,052,116.24	$413,422,477.76

3.2 Overview of Reactor Types in Data Set

Looking at the spread of reactor technologies in the selected data sets based on the criteria described in the previous section, it was found that selected data sets focused primarily on HTGRs, followed by PWRs and SFRs. This is not surprising considering the historic programs in these areas and the recent accelerated effort towards meeting global energy demands by harnessing the potential of advanced-reactor technologies. As such, this work relies on publicly available estimates for LWRs (i.e., PWRs and BWRs), SFRs, MSRs, and HTGRs. Figure 3 shows the breakdown of the reactor types with data in the data sets. These reactor types define the nuclear-reactor technology used for heat generation. For nuclear reactors, heat energy is extracted from the core (nuclear fuel) to run turbines for electricity production. Some of the sources clarified the type of power-conversion cycle (e.g., if Brayton or Rankine), but the majority did not (and are most likely Rankine-based). Depending on the reactor technology, turbines can be run directly by the primary coolant (coolant circulating between the fuel) or the secondary coolant (working fluid to which the heat energy from primary coolant has been transferred via a heat exchanger). The heat energy generated from fission in nuclear reactors can be extracted using a variety of coolants (leading to different reactor designs), such as water, liquid metal, molten salts, or gases such as helium. The reactor technologies are generally named based on the primary coolant type. As such, LWRs use regular water (as opposed to heavy water), HTGRs use gaseous helium, SFRs use liquid sodium, and MSRs use molten salt, as their primary coolants. Non-LWRs (such as HTGRs, SFRs, MSRs are under development while LWRs make up all the power-producing reactors in the United States (NEI 2023) and are a mix of PWRs and BWRs. PWRs, as the name suggests, consist of a pressurized primary system which maintains the coolant at a subcooled liquid state (preventing coolant boiling within the core). The primary coolant extracts heat energy from the core and subsequently passes through a steam generator to transfer the heat energy to the secondary coolant (water). Steam produced within the steam generator runs the turbine to produce electricity. Steam exiting from the turbine is directed through a condenser to create liquid water, which is then pumped back to the steam generator. Contrastingly, in BWRs, the turbine is run directly using the primary coolant. Regular water (primary coolant) moves through the core where fission heat is transferred from the core to the coolant, turning it into a mixture of steam and water. At the top of the core, the steam is directed to the turbine for power production. Unused steam is exhausted to a condenser to generate water, which is pumped back to reactor core from the bottom. The primary difference between PWRs and BWRs are the lack of secondary coolant loop in BWRs and coolant boiling inside the reactor vessel core in BWRs.

In SFRs and MSRs, liquid sodium or molten salts are used as the primary coolant. For some MSR variants, the nuclear fuel is circulated as part of the salt so, depending on the reactor type and goals, there may be one or two stages of heat exchangers to transfer heat to the power generation side of the power plant. First the fission-heat energy is transferred to the primary coolant circulating in the core (which may or may not be solid fuel). The hot coolant travels through a heat exchanger, where heat energy is transferred to an intermediate working fluid (which may be the same working fluid as the primary coolant). In the final stage, the intermediate fluid is directed to another heat exchanger to heat the power-cycle working fluid (which could be a gas [CO_2] or water) and produce electricity through the turbine.

The HTGR systems use an inert gas, such as helium, as the primary coolant to extract heat energy from the fuel core. Although it is possible to have helium-driven turbines in HTGR systems, the majority of the HTGR designs include a steam generator to transfer heat from the primary helium to water that runs through a turbine.

Figure 3 illustrates the split of the various reactor technologies included in the data sets. It should be noted that these data are before removing outliers, which is discussed in a later section. As shown in Figure 3, just over half of the data sets considered are HTGRs. The rest is almost evenly split between SFRs and LWRs (mostly PWRs). The mix of data is driven by what has been the focus of historical DOE programs as well as the technical maturity of the designs. MSRs are limited in their data sets as there has been more limited experience commercially with that reactor type.

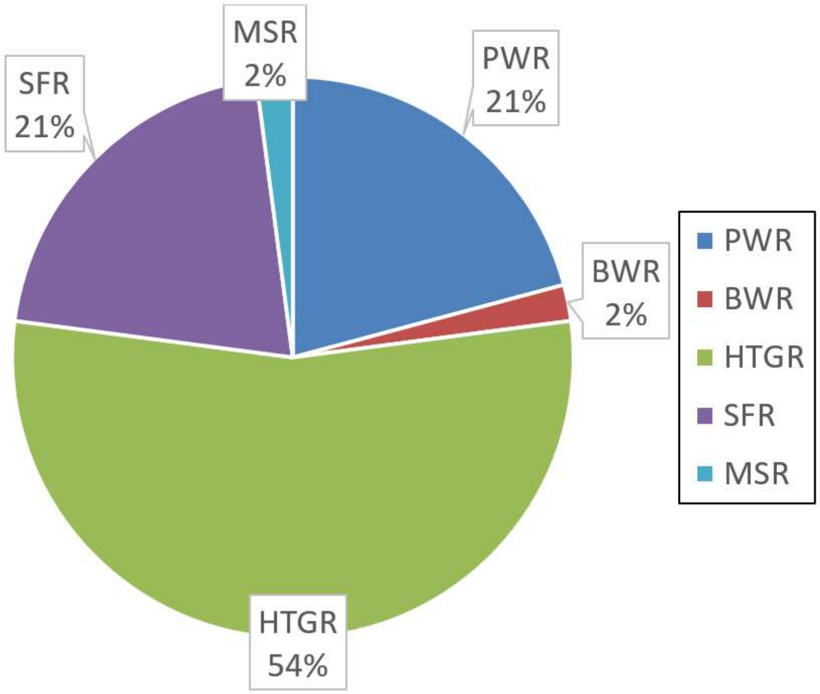

Figure 3. Split of reactor types within the entire data set (without removing outliers).

3.2.1 Reactor-Type Dependent Cost Estimates

Expanding on the spread of cost estimates discussed in the previous section, Table 4 shows a distribution of available input data sets included at different stages of reactor cost estimation. In Table 4, reactor technologies with significant operational history, such as PWRs, include a greater number of NOAK estimates compared to newer technology, such as SFRs or HTGRs, which have not been commercially deployed at scale.

Table 4. Distribution of FOAK, BOAK, and NOAK data sources by reactor type.

	Total Number of Data sets	Number FOAK Data sets	Number BOAK Data sets	Number NOAK Data sets
HTGR	28	13	1	14
PWR	10	3	1	6
BWR	1	1	—	—
SFR	10	5	1	4
MSR	1	1	—	—

It was found that most of the sources provided detailed estimates for capitalized direct and indirect costs. However, other costs pertaining to building, operating, managing, and financing reactor technology were sparse. Table 5 through Table 7 show the spread of input data included in this analysis, by different reactors for each reactor-technology type. For example, Table 5 shows the spread of all the HTGR data sets while Table 6 focuses on the PWR data sets. The green cells in Table 5 through Table 7 indicate which data sets were provided in the source while the white or blank cells show missing values. For example, since a cost estimate for the capitalized pre-construction costs (GNCOA number 10) was documented in the source, the cell marking GNCOA 10 under VHTGR column is colored green in Table 5. Similarly, since the VHTGR source did not document a cost estimate for plant licensing (GNCOA number 13), the subsequent cell for GNCOA 13 under the VHTGR column is not colored or left blank in Table 5.

For most estimates, Accounts 10 (preconstruction) and 20 (direct) were well-populated. However, many data sets do not include data for higher-number accounts, which include items like onsite construction costs, onsite staffing, owner's costs, O&M, and financing costs. Given that many of these reactor estimates originated from DOE programs, it is unsurprising that these costs were included as certain reactors were intended to be demonstration units and not necessarily support commercial operations. Details of the various data sets available for each reactor name in Table 5 through Table 7 are listed in Table 8. Table 8 is a compilation of all data sets that includes all the various technologies considered in this assessment. All the data sets are structured according to the Generalized Nuclear Code of Account (GN-COA) format (Moneghan et al. 2024) that will be explained in greater detail in the following sections.

Table 5. Spread of input data GN-COA for HTGRs. Green cells mark the account where data was available.

		Reactor Name						
COA	GNCOA Description	Very High-Temperature Gas-Cooled Reactor (VHTGR)	Traditional HTGR	Modular Integrated Gas-cooled High Temperature Reactor (MIGHTR)	General Atomics (GA)/ Modular HTGR (MHTGR)	Advanced High Temperature Reactor (AHTR)	MHTGR	MHTGR-Steam Cycle (SC)/Gas Turbine (GT)
10	Capitalized Pre-Construction Costs							
11	Land and Land Rights							
12	Site Permits							
13	Plant Licensing							
14	Plant Permits							
15	Plant Studies							
16	Plant Reports							
17	Community Outreach and Education							
18	Other Pre-Construction Costs							
19	Contingency on Pre-Construction Costs							
20	Capitalized Direct Costs							
21	Structures and Improvements							
22	Reactor System							
23	Energy Conversion System							
24	Electrical Equipment							
25	Initial Fuel Inventory							
26	Miscellaneous Equipment							

COA	GNCOA Description	Reactor Name						
		Very High-Temperature Gas-Cooled Reactor (VHTGR)	Traditional HTGR	Modular Integrated Gas-cooled High Temperature Reactor (MIGHTR)	General Atomics (GA)/ Modular HTGR (MHTGR)	Advanced High Temperature Reactor (AHTR)	MHTGR	MHTGR-Steam Cycle (SC)/Gas Turbine (GT)
27	Material Requiring Special Consideration							
28	Simulator							
29	Contingency on Direct Costs							
30	Capitalized Indirect Services Cost							
31	Factory & Field Indirect Costs							
32	Factory & Construction Supervision							
33	Startup Costs							
34	Shipping and Transportation Costs							
35	Engineering Services							
36	PM/CM Services							
39	Contingency on Indirect Services Cost							
40	Capitalized Pre-COD Personnel Costs							
41	Staff Recruitment and Training							
42	Staff Housing							
49	Contingency on Training Costs							
50	Capitalized Supplementary Costs							
51	Taxes							
52	Insurance							
53	Spent Fuel Storage							
54	Decommissioning							
55	Other Owners' Costs							
56	Fees							
57	Management Reserve							
59	Supplementary Contingencies							
60	Capitalized Financial Costs							
61	Escalation							
62	Interest							
63	Depreciation							
69	Contingency on Financial Costs							
70	Annualized O&M Cost							
71	O&M Staff							
72	Variable Non-Fuel Costs							
73	Regulatory Costs							
74	Fixed O&M Utilities and Materials							
75	Capital Plant Expenditures							
76	Taxes and Insurance							
77	Outage Expenses							
78	Annualized Decommissioning Cost							

COA	GNCOA Description	Reactor Name						
		Very High-Temperature Gas-Cooled Reactor (VHTGR)	Traditional HTGR	Modular Integrated Gas-cooled High Temperature Reactor (MIGHTR)	General Atomics (GA)/ Modular HTGR (MHTGR)	Advanced High Temperature Reactor (AHTR)	MHTGR	MHTGR-Steam Cycle (SC)/Gas Turbine (GT)
79	Contingency on Annualized O&M Costs							
80	Annualized Fuel Cost							
81	Refueling Operations							
82	Additional Nuclear Fuel							
83	Spent Fuel Management							
89	Contingency on Annualized Fuel Costs							
90	Annualized Financial Cost							
91	Escalation							
92	Fees							
93	Cost of Money							
99	Contingency on Annualized Financial Costs							

Table 6. Spread of input data GNCOA (highlighted in green) for PWRs. Green cells mark the account where data was available.

COA	GNCOA Description	Reactor Name						
		AP1000	PWR-12	Improved PWR-06	Improved PWR-12	Advanced PWR-06	Multi-Module Natural Circula-tion (MMNC)	NuScale SMR
10	Capitalized Pre-Construction Costs							
11	Land and Land Rights							
12	Site Permits							
13	Plant Licensing							
14	Plant Permits							
15	Plant Studies							
16	Plant Reports							
17	Community Outreach and Education							
18	Other Pre-Construction Costs							
19	Contingency on Pre-Construction Costs							
20	Capitalized Direct Costs							
21	Structures and Improvements							
22	Reactor System							
23	Energy Conversion System							
24	Electrical Equipment							
25	Initial Fuel Inventory							
26	Miscellaneous Equipment							
27	Material Requiring Special Consideration							
28	Simulator							
29	Contingency on Direct Costs							
30	Capitalized Indirect Services Cost							
31	Factory & Field Indirect Costs							

COA	GNCOA Description	Reactor Name						
		AP1000	PWR-12	Improved PWR-06	Improved PWR-12	Advanced PWR-06	Multi-Module Natural Circula-tion (MMNC)	NuScale SMR
32	Factory & Construction Supervision							
33	Startup Costs							
34	Shipping and Transportation Costs							
35	Engineering Services							
36	PM/CM Services							
39	Contingency on Indirect Services Cost							
40	Capitalized Pre-COD Personnel Costs							
41	Staff Recruitment and Training							
42	Staff Housing							
49	Contingency on Training Costs							
50	Capitalized Supplementary Costs							
51	Taxes							
52	Insurance							
53	Spent Fuel Storage							
54	Decommissioning							
55	Other Owners' Costs							
56	Fees							
57	Management Reserve							
59	Supplementary Contingencies							
60	Capitalized Financial Costs							
61	Escalation							
62	Interest							
63	Depreciation							
69	Contingency on Financial Costs							
70	Annualized O&M Cost							
71	O&M Staff							
72	Variable Non-Fuel Costs							
73	Regulatory Costs							
74	Fixed O&M Utilities and Materials							
75	Capital Plant Expenditures							
76	Taxes and Insurance							
77	Outage Expenses							
78	Annualized Decommissioning Cost							
79	Contingency on Annualized O&M Costs							
80	Annualized Fuel Cost							
81	Refueling Operations							
82	Additional Nuclear Fuel							
83	Spent Fuel Management							
89	Contingency on Annualized Fuel Costs							
90	Annualized Financial Cost							
91	Escalation							
92	Fees							
93	Cost of Money							
99	Contingency on Annualized Financial Costs							

Table 7. Spread of input data GNCOA (highlighted in green) for SFRs, BWR and MSR. Green cells mark the account where data was available.

Reactor Type		SFR					BWR	MSR
		Reactor Name						
COA	GNCOA Description	Sodium Advanced Fast Reactor (SAFR)	Power Reactor Innovative Small Module (PRISM)	SFR Strategic Analysis Incorporated (SFR SIANC)	Versatile Test Reactor (VTR)	Advanced Burner Reactor (ABR)1000	Small Modular BWR (SMBWR)	Denatured SMR (DSMR)
10	Capitalized Pre-Construction Costs							
11	Land and Land Rights							
12	Site Permits							
13	Plant Licensing							
14	Plant Permits							
15	Plant Studies							
16	Plant Reports							
17	Community Outreach and Education							
18	Other Pre-Construction Costs							
19	Contingency on Pre-Construction Costs							
20	Capitalized Direct Costs							
21	Structures and Improvements							
22	Reactor System							
23	Energy Conversion System							
24	Electrical Equipment							
25	Initial Fuel Inventory							
26	Miscellaneous Equipment							
27	Material Requiring Special Consideration							
28	Simulator							
29	Contingency on Direct Costs							
30	Capitalized Indirect Services Cost							
31	Factory & Field Indirect Costs							
32	Factory & Construction Supervision							
33	Startup Costs							
34	Shipping and Transportation Costs							
35	Engineering Services							
36	PM/CM Services							
39	Contingency on Indirect Services Cost							
40	Capitalized Pre-COD Personnel Costs							
41	Staff Recruitment and Training							
42	Staff Housing							
49	Contingency on Training Costs							
50	Capitalized Supplementary Costs							
51	Taxes							
52	Insurance							
53	Spent Fuel Storage							
54	Decommissioning							
55	Other Owners' Costs							
56	Fees							
57	Management Reserve							

Reactor Type		SFR					BWR	MSR
		Reactor Name						
COA	GNCOA Description	Sodium Advanced Fast Reactor (SAFR)	Power Reactor Innovative Small Module (PRISM)	SFR Strategic Analysis Incorporated (SFR SIANC)	Versatile Test Reactor (VTR)	Advanced Burner Reactor (ABR)1000	Small Modular BWR (SMBWR)	Denatured SMR (DSMR)
59	Supplementary Contingencies							
60	Capitalized Financial Costs							
61	Escalation							
62	Interest							
63	Depreciation							
69	Contingency on Financial Costs							
70	Annualized O&M Cost							
71	O&M Staff							
72	Variable Non-Fuel Costs							
73	Regulatory Costs							
74	Fixed O&M Utilities and Materials							
75	Capital Plant Expenditures							
76	Taxes and Insurance							
77	Outage Expenses							
78	Annualized Decommissioning Cost							
79	Contingency on Annualized O&M Costs							
80	Annualized Fuel Cost							
81	Refueling Operations							
82	Additional Nuclear Fuel							
83	Spent Fuel Management							
89	Contingency on Annualized Fuel Costs							
90	Annualized Financial Cost							
91	Escalation							
92	Fees							
93	Cost of Money							
99	Contingency on Annualized Financial Costs							

Table 8. Data availability by reactor type.

Reactor Type	Reactor Name	FOAK/ NOAK/ BOAK	Reactor Size Per Unit (MWe)	Quantity of Reactors	Source
BWR	Small Modular Boiling Water Reactor (SMBWR)	NOAK	290	1	Stewart and Shirvan 2023
HTGR	VHTGR	NOAK	281	1	INL 2010
		NOAK	281	4	
		FOAK	281	1	
		FOAK	281	4	
		NOAK	164	1	
		NOAK	164	4	
		FOAK	164	1	
		FOAK	164	4	

Reactor Type	Reactor Name	FOAK/ NOAK/ BOAK	Reactor Size Per Unit (MWe)	Quantity of Reactors	Source
HTGR	Traditional HTGR	FOAK	275	1	Stewart et al. 2020
		NOAK	275	4	
HTGR	MIGHTR	BOAK	154	1	Stewart et al. 2020
		NOAK	154	4	
HTGR	GA/MHTGR	FOAK	133	8	ORNL 1988
HTGR	AHTR (Two sets of input estimates based on initial enrichments of 9% and 19.7%)	NOAK	1500	1	Holcomb, Peretz, and Qualls 2011
		NOAK	1500	1	
HTGR	MHTGR (Lead Plant)	NOAK	540	4	DOE 1987
	MHTGR (Replica Plant)	BOAK	540	4	
	MHTGR (Plant)	NOAK	540	4	
	MHTGR (Large Plant)	NOAK	540	8	
HTGR	MHTGR-Steam Cycle (SC)/ Gas Turbine (GT) (SC-Prototype)	FOAK	173.25	4	DOE 1993
	MHTGR SC/GT (SC - Replica)	FOAK	173.25	4	
	MHTGR-SC/GT (SC - Target)	NOAK	173.25	4	
	MHTGR-SC/GT (GT/ Indirect Cycle (IC) - Prototype)	FOAK	201.5	4	
	MHTGR-SC/GT (GT/IC - Replica)	FOAK	201.5	4	
	MHTGR-SC/GT (GT/IC -Target)	NOAK	201.5	4	
	MHTGR-SC/GT (GT/DC - Prototype)	FOAK	217.25	4	
	MHTGR-SC/GT (GT/DC - Replica)	FOAK	217.25	4	
	MHTGR-SC/GT (GT/DC - Target)	NOAK	217.25	4	
MSR	DSMR	FOAK	1000	1	Engel et al. 1980
PWR	AP1000	FOAK	1100	2	Stewart et al. 2020
		NOAK	1100	2	
PWR	PWR-12	BOAK	1144	1	EEDB 1987
		NOAK	1144	1	
PWR	Improved PWR-06	NOAK	587	1	
PWR	Improved PWR-12	NOAK	1144	1	
PWR	Advanced PWR-06	NOAK	587	1	
PWR	MMNC	NOAK	77	6	Stewart, Gregory, and Shirvan 2022
PWR	NuScale SMR	NOAK	60	12	Black, Aydogan, and Koerner 2019
SFR	SAFR	FOAK	300	2	ORNL 1988

Reactor Type	Reactor Name	FOAK/ NOAK/ BOAK	Reactor Size Per Unit (MWe)	Quantity of Reactors	Source
SFR	PRISM	FOAK	104	6	ORNL 1988
SFR	SFR SAINC	FOAK	165	1	Prosser et al. 2023
		BOAK	311	1	
		NOAK	311	2	
		NOAK	311	4	
		NOAK	311	8	
		NOAK	311	10	
SFR	VTR	FOAK	-	1	Roglans-Ribas 2020
SFR	ABR1000	FOAK	380	1	Ganda, Taiwo, and Kim 2018

While reactor technologies are different, so are reactor sizes. For energy-planning and capacity-expansion models, the size of the reactor chosen is important; thus, the data are divided between small and large rectors. A commonly used term to define small reactors is SMR which, according to the International Atomic Energy Agency (IAEA) is an advanced nuclear reactor that has a power capacity of up to 300 MWe (IAEA 2023). One issue with this definition of SMR is that it can exclude certain reactors that are just above 300 MWe. Therefore, for this work, the split between small and large is taken at 400 MWe, which will include a few additional reactors as small that are over 300 MWe. Figure 4 and Figure 5 contain histograms of the reactor unit size and the total plant nameplate capacity, respectively. As shown in Figure 4, there are many SMR reactors considered in the data and several large reactors as well. Figure 4 is a histogram of reactor sizes, so this is for each reactor module, which means there could be more than one reactor module at each plant site. Figure 5 shows the histogram of each plant site, which may include one or more modules at the same site. This data set can help elucidate how multiple deployments at one site can change the cost profile of total site costs.

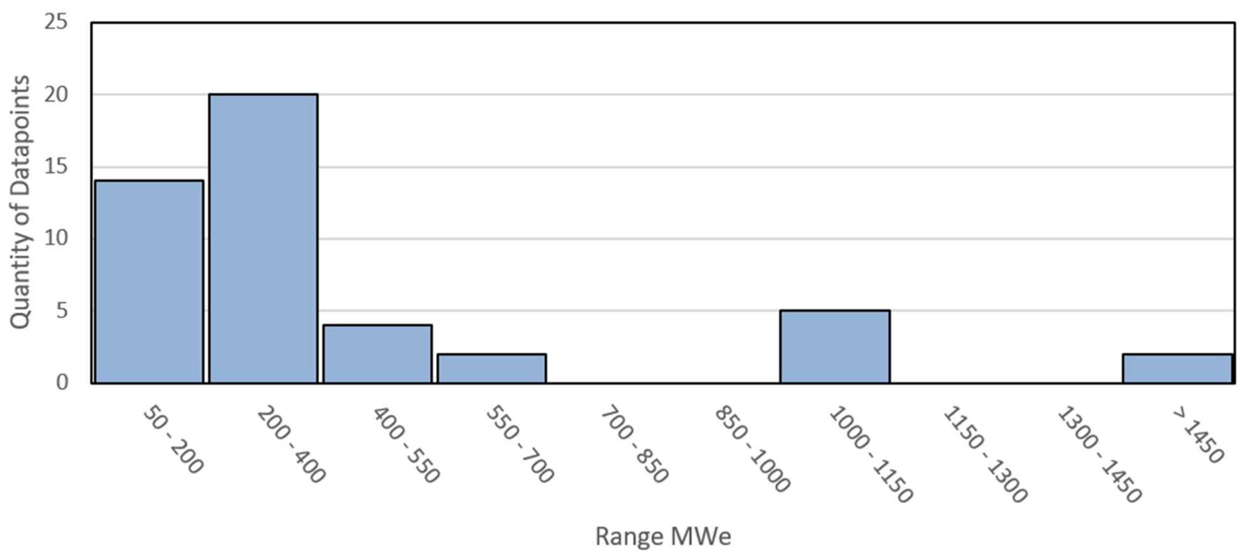

Figure 4. Distribution of individual reactor sizes within the entire data set (without removing outliers).

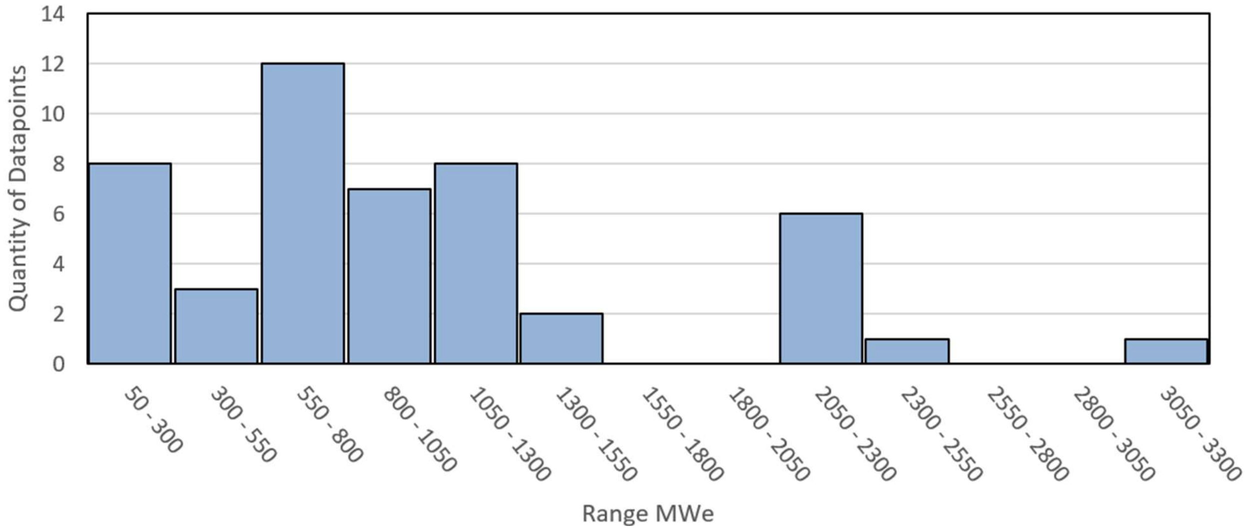

Figure 5. Distributions of plant nameplate capacity (may include one or more reactor modules per plant) within the entire data set (without removing outliers).

Figure 6 contains the counts of the estimate types as defined by the estimate. Several estimates are already considered BOAK estimates, which align well with the intended type of estimate produced in this report. Figure 7 contains all the OCC numbers for each estimate in the data considered. This figure is based on the plant nameplate capacity, so it would include multiple units for plants that are deployed with multiple reactors at one site. Given that this figure includes both NOAK, BOAK, and FOAK numbers all in one, not a lot can be concluded from the figure until the data are processed and turned into the various quartiles later in the report.

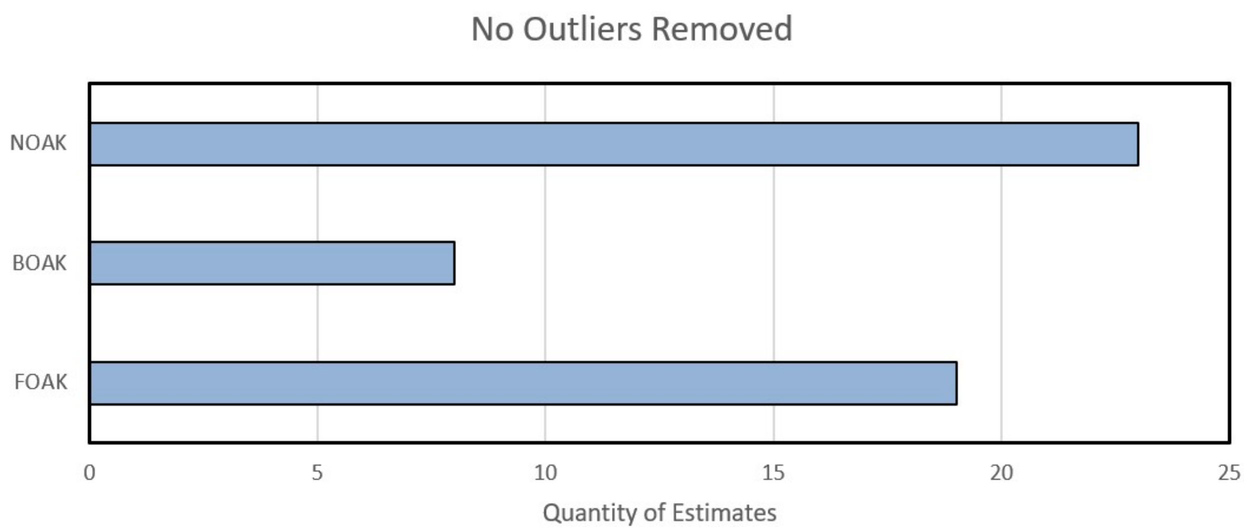

Figure 6. Quantity of estimates by type (without removing outliers).

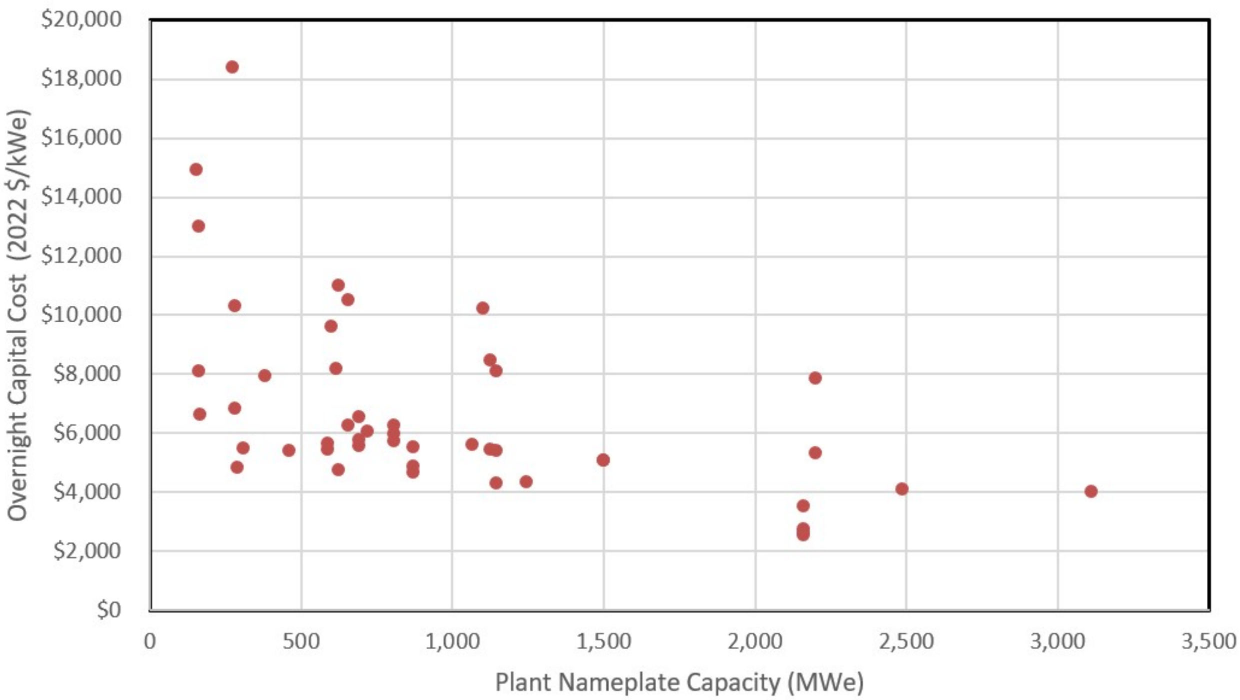

Figure 7. Plotted cost and plant nameplate capacity (without removing outliers).

3.3 Additional Considerations

Data sets included within this report span a large period (~1980 to present), with sporadic groupings of the cost estimate by reactor type. Figure 8 shows a drought in data sets in the early 1980s and from mid-1990s to around 2008. These gaps are likely due to major changes in the nuclear industry that were brought about by both nuclear and political events that impacted the nuclear industry at the time. The nuclear events that impacted the nuclear industry tremendously were the accident at Three Mile Island and, later, the event at Chernobyl. This led to changes in the US focus on research and development of nuclear energy which would limit the funding that might have supported advanced nuclear reactors. The cost estimates obtained in the 2000s were more detailed because increased funding was available to support a growing interest in a potentially growing nuclear industry. The original reactor-cost data estimation timeline (in Figure 8) ranges from late 1970s to 2023. Therefore, the reactor cost estimates from one specific year, referred to as "source-dollar year," cannot be consistently compared with another reactor cost estimated in a different year. This inconsistency originates from the dynamic nature of the dollar's value, which can be influenced by several political, economic, and other factors. Thus, an escalation methodology, described in Section 4, was applied to each reactor-cost estimate for consistent interpretation of the dollar value of each estimate, regardless of the year in which they were originally calculated. However, this methodology is only applicable to data sets extending as far back as 1985. Therefore, of the fifty data sets that were collected for the purpose of this study, data sets prior to 1985 were removed. Overall, fifteen data sets were excluded from the analysis for various reasons, as documented in Table 9. The remaining thirty-five data sets were appropriately escalated according to the methodology described in Section 4 for further analysis.

Table 9. Data outliers that were removed from this study.

[1]Outlier Data Set	Reason For Exclusion
Traditional HTGR	[2]The cost estimate was excluded as a single unit FOAK estimate.
MIG HTGR	[2]The cost estimate was excluded as a single unit FOAK estimate.
Next-Generation Nuclear Plant (NGNP) VHTGR	[2]The cost estimate was excluded as a single unit FOAK estimate.
VTR	The VTR is a non-electric research reactor. The focus of this study is on power producing reactors. As such, the VTR was excluded.
DMSR	The DMSR cost estimates were obtained prior to 1985. Since the escalation method is applicable to data sets after 1985, this source was excluded as an outlier.
AHTR 19.7% enrichment	[3]Multiple cost estimates were included in the same source. Only 1 of the 2 estimates (estimate for 9% initial enrichment) was included.
HTGR SC	[2,3]Multiple cost estimates were included in the same source. Only 1 of the 3 estimates was included. HTGR SC NOAK estimate was included.
HTGR GT/internal combustion (IC)	[2,3]Multiple cost estimates were included in the same source. Only 1 of the 3 estimates was included. HTGR GT/IC NOAK estimate was included.
HTGR GT/DC	[2,3]Multiple cost estimates were included in the same source. Only 1 of the 3 estimates was included. HTGR GT/DC NOAK estimate was included.
MHTGR	[2,3]Multiple cost estimates were included in the same source. Only 1 of the 4 estimates was included. MHTGR NOAK estimate was included.

1 For reference to the actual reactor, see Table 8 that contains all data sets.

2 The cost estimate was provided for a single unit FOAK. Upon discussions with experts in the field, it was determined that FOAK single unit plants are too expensive and not being considered by industry for construction. These estimates were excluded to avoid skewing the data set.

3 These sources included multiple cost estimates for the same reactor type which led to repetitions in the costs. As such only one of the data sets was included to avoid overestimations.

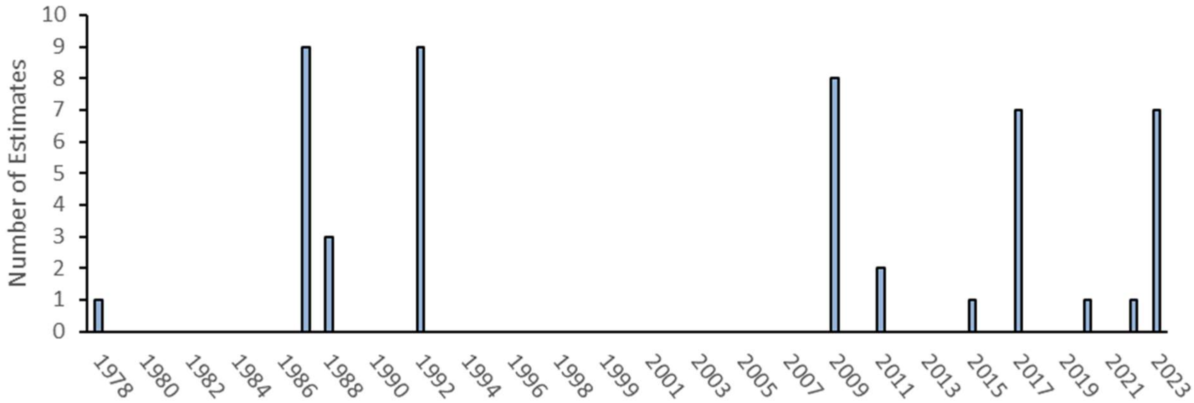

Figure 8. Timeline for original date of estimates.

4. MAPPING AND ESCLATION OF DATA SETS

4.1 Mapping Data to Generalized Nuclear Code of Accounts

4.1.1 Original Data Set Accounting Structure

Most of the cost-estimate sources were organized using existing COA structures, such as the EEDB (EEDB 1987) or the GIF COA (GIF 2007). Although both EEDB and GIF COAs follow a bottom-up structure, the breakdown of the costs included in the estimate were different. For instance, as shown in Table 2, account 218T in EEDB describes capital costs associated with the ultimate heat-sink structure while 218T in GIF captures the costs associated with the emergency power-generation building. Thus, costs in EEDB structure cannot be directly mapped to the GIF structure or vice versa.

Additionally, certain sources use a hybrid COA structure to organize reactor costs. These hybrid structures allow for individualized estimates capturing reactor specific costs, such as helium -storage building costs, associated with HTGRs. Costs documented in different COA structures can be difficult to interpret and cross-compare against other estimates for analysis. Therefore, a need for mapping cost accounts into a standardized structure was identified. Efforts described in Moneghan (2024). have been working towards an updated generalized nuclear code of accounts (GN-COA) structure. The intent of the new structure is to be reactor agnostic and provide enough flexibility to capture costs associated with a broader set of reactor technologies (Moneghan et al. 2024). Additional key features of the GN-COA structure included cost titles described by the functionality of a system, rather than technology -specific terms. For example, reactivity control system instead of control rods or drums because different reactor types use different features to achieve reactivity control. The GN-COA also provides a consistent logical method of distinguishing higher accounts from lower accounts for standardizing cross-reactor cost comparisons. Finally, it provides increased dimensionality on accounts (beyond labor, material, and equipment) to capture costs associated with work locations, learning rates, and confidence level.

4.1.2 Background on Generalized Nuclear Codes of Accounts

The GN-COA structure shown in Table 10 was developed to facilitate compilation of costs associated with different reactor technologies. The GN-COA structure follows a bottom-up approach (like EEDB and GIF) with four levels of granularity to provide applicability to a broad range of reactor technologies. On the highest level, the account titles (also referred to as “Level 1” estimates with account numbers 10, 20, 30, 40, 50, 60, 70, 80, and 90) capture any capital and annual costs associated with constructing, operating, financing, and maintaining a reactor technology. Each Level 1 is subsequently broken into sub accounts to capture a multitude of functionalities. It is important to distinguish Accounts 10–60, which relate to capital expenses, from accounts 70–90, which relate to annualized recurring costs.

Table 10. The joint INL-EPRI GN-COA with the account numbers and titles (Moneghan et al. 2024).

Levels				
1	2	3	4+	Account Title
10				Capitalized Pre-Construction Costs
	11			Land and Land Rights
	12			Site Permits
		121		Federal
		122		State
		123		Local
	13			Plant Licensing
		131		Preapplication
		132		Preparation
		133		Regulatory Review
	14			Plant Permits
	15			Plant Studies
	16			Plant Reports
	17			Community Outreach and Education
	18			Other Pre-Construction Costs
	19			Contingency on Pre-Construction Costs
20				**Capitalized Direct Costs**
	21			Structures and Improvements
		211		Site Preparation/Yard Work
		212		Reactor Island Civil Structures
		213		Main Function Buildings
			213.1	Energy Conversion Building
			213.2	Control Building
			213.3	Pipe Tunnels
			213.4	Electrical Tunnels
		214		Buildings to Support Main Function
			214.1	Spent Fuel Management Building
			214.2	Balance of Plant Service Building
			214.3	Wastewater Treatment Building
			214.4	Maintenance Shops
			214.5	Fire Protection Building
			214.6	Non-essential Switchgear Building
			214.7	Emergency and Start-up Power Systems
		215		Supply Chain Buildings
			215.1	Storage and Warehouse Buildings
			215.2	Unloading Facility for Material Requiring Special Consideration
			215.3	Reactor Receiving and Assembly Building
			215.4	Radwaste Building
			215.5	Fuel Service Building
		216		Human Resources Buildings
			216.1	Administration Building
			216.2	Security Building and Gatehouse
			216.3	Training Center
			216.4	Operation and Maintenance (O&M) Center
		217		Miscellaneous Other Structures

Levels				
1	2	3	4+	Account Title
			217.1	Foundations for Outside Equipment and Tanks
			217.2	Railroad Tracks
			217.3	Roads and Paved Areas
			217.4	Beyond Design-Basis Building
	22			Reactor System
		221		Reactor Components
			221.1	Reactor vessel and accessories
			221.11	Reactor support
			221.12	Outer vessel structure
			221.13	Inner vessel structure
			221.2	Reactor control devices
			221.21	Reactivity control system
			221.3	Non-fuel core internals
			221.31	Reflector
			221.32	Shield
			221.33	Moderator
		222		Main Heat Transport System
			222.1	Fluid circulation drive system
			222.2	Reactor heat transfer piping system
			222.3	Heat exchangers
			222.4	Pressurizer system
			222.5	Initial heat transfer fluid inventory
		223		Safety Systems
			223.1	Internal Residual Heat Removal System
			223.2	Reactor Cavity Cooling System
			223.3	Reactivity Safety Injection System
			223.4	Containment Spray System
			223.5	Combustible Gas Control System
		224		Radioactive Byproduct Processing Systems
		225		Fuel Handling Systems
			225.1	Core Refueling Equipment
			225.2	Ex-Core Operational Fuel Handling Equipment
		226		Other Reactor Plant Equipment
		227		Reactor Instrumentation and Control (I&C)
		228		Reactor Plant Miscellaneous Items
	23			Energy Conversion System
		231		Reactor-Application Interface Systems
			231.1	Thermal Energy Piping Systems
			231.2	Thermal Energy Storage Systems
		232		Energy Applications
			232.1	Electricity Generation Systems
			232.2	Process Heat Export Equipment
			232.3	Hydrogen Production Systems
			232.4	Ammonia Production Systems
			232.5	Other Synfuel Production Systems
			232.6	Water Desalination Equipment
			232.7	Carbon Storage and Sequestration Equipment

Levels				
1	2	3	4+	Account Title
			232.8	Isotope Production Equipment
			232.9	Battery Storage Systems
		233		Ultimate Heat Sink
			233.1	Water Condensing Systems
			233.2	Air-based Cooling Systems
		234		Feed Heating Systems
		235		Common Plant Equipment
		236		Common Instrumentation & Controls
		237		Miscellaneous Energy System Equipment
	24			Electrical Equipment
		241		Switchgear
		242		Station Service Equipment
		243		Switchboards
		244		Protective Systems Equipment
		245		Electrical Raceway Systems
		246		Power and Control Cables and Wiring
	25			Initial Fuel Inventory
		251		First Core Mining
		252		First Core Conversion
		253		First Core Enrichment
		254		First Core Fuel Assembly Fabrication
		255		First Core Supply of Other Fissionable Materials (e.g., Pu)
	26			Miscellaneous Equipment
		261		Transportation and Lift Equipment
		262		Air, Water, Plant Fuel Oil, and Steam Systems
		263		Communications Equipment
		264		Furnishing and Fixtures
		265		Robotic and/or Remotely Operated Inspection and Maintenance Equipment
	27			Material Requiring Special Consideration
	28			Simulator
	29			Contingency on Direct Costs
30				**Capitalized Indirect Services Cost**
	31			Factory & Field Indirect Costs
		311		Construction Tools and Equipment
		312		Construction Vehicles
		313		Construction Supplies, Consumables, and Utilities
		314		Temporary Roads and Railroads
		315		Module Receiving and Assembly Building(s)
		316		Laydown Areas
		317		Field Shops
		318		Other Construction Support Structures
		319		Construction Insurance
	32			Factory & Construction Supervision
	33			Startup Costs
		331		Commissioning and Trial Test Runs
			331.1	Initial Fuel Inventory Services

Levels				
1	2	3	4+	Account Title
			331.2	Other Commissioning Procedure Development
			331.3	Initial Fuel Loading Operations
			331.4	Heat Transfer Fluid Loading Operations
			331.5	Test Runs
		332		Demonstration Test Run
	34			Shipping and Transportation Costs
		341		Fuel Shipping and Transportation
		342		Reactor System Modules Shipping and Transportation
		343		Energy Conversion System Module Shipping and Transportation
		344		Construction Module Shipping and Transportation
		345		Other Shipping and Transportation Costs
	35			Engineering Services
		351		Off-Site
		352		On-Site
		353		Owner's Engineering Oversight
	36			PM/CM Services
		361		Off-Site
		362		On-Site
		363		Owner's Engineering Oversight
	37			Regulatory Inspection Support
	38			Spare Parts
	39			Contingency on Indirect Services Cost
40				**Capitalized Training Costs**
	41			Staff Recruitment and Training
	42			Staff Housing
	49			Contingency on Training Costs
50				**Capitalized Supplementary Costs**
	51			Taxes
	52			Insurance
	53			Spent Fuel Storage
	54			Decommissioning
	55			Other Owners' Costs
	56			Fees
	57			Management Reserve
	59			Supplementary Contingencies
60				**Capitalized Financial Costs**
	61			Escalation
	62			Interest
	63			Depreciation
	69			Contingency on Financial Costs
70				**Annualized O&M Cost**
	71			O&M Staff
		711		Operators
		712		Remote Monitoring Technicians
		713		Security Staff
		714		Maintenance Staff

Levels				
1	2	3	4+	Account Title
		715		Engineering Staff
		716		Continuing Education and Staff Retraining
		717		Management Staff
		718		Salary-Related Costs
	72			Variable Non-Fuel Costs
	73			Regulatory Costs
	74			Fixed O&M Utilities and Materials
		741		Operating Chemicals and Lubricants
		742		Spare Parts
		743		Utilities, Supplies, and Consumables
		744		Material Requiring Special Consideration
		745		Final Disposal of Non-Fuel Waste
	75			Capital Plant Expenditures
	76			Taxes and Insurance
	77			Outage Expenses
	78			Annualized Decommissioning Cost
	79			Contingency on Annualized O&M Costs
80				**Annualized Fuel Cost**
	81			Refueling Operations
		811		Fuel Management
		812		Fuel Management, Schedule
		813		Licensing Assistance
		814		Preparation of Computer Programs
		815		Quality Assurance
		816		Fuel Inspection
		817		Fuel Assembly Intermediate Storage
		818		Information for the Use of Third-Party Fuel
	82			Additional Nuclear Fuel
		821		Mining Cost for Reloads
		822		Conversion Cost for Reloads
		823		Enrichment Cost for Reloads
		824		Fuel Assembly Fabrication Cost for Reloads
		825		Supply of Other Fissionable Materials for Reloads
		826		Tails Disposal Cost for Reloads
	83			Spent Fuel Management
		831		Interim Storage
		832		Fuel Reprocessing
			832.1	Credits for Uranium, Plutonium and Other Materials
		833		Final Disposal of Fuel
	89			Contingency on Annualized Fuel Costs
90				**Annualized Financial Cost**
	91			Escalation
	92			Fees
	93			Cost of Money
	99			Contingency on Annualized Financial Costs

4.1.3 Mapping Older Data sets to the Generalized Nuclear Codes of Accounts

To effectively compare reactor costs across a broad range of COA methods, input data from each source were mapped from their specific COA structures to the GN-COA using consistent logic. Table 11 and Table 12 show mapping from EEDB and GIF to GN-COA. These mappings facilitate translation of existing cost estimates in EEDB or GIF COA structures to GNCOA. Some cost estimates input data, such as that for the ABR1000, used hybrid COA structures for documenting reactor specific costs. Since the hybrid structures are modifications of either EEDB or GIF, mapping from Table 11 and Table 12 were utilized for converting the hybrid COA to GNCOA. The original EEDB, hybrid COA for ABR1000 can be found in Appendix A, "Original Reference Cost Data."

Table 11. Mapping of EEDB COA structures to GNCOA.

EEDB Account ID	EEDB Account Title	Mapped GN-COA Account ID	Mapped GN-COA Title
	*Capitalized Preconstruction Costs	10	Capitalized Preconstruction Costs
	*Capitalized Direct Costs	20	Capitalized Direct Costs
21	Structures and Improvements	21	Structures and Improvements
211	Yardwork	211	Site Preparation/Yard Work
212	Reactor Containment Building	212	Reactor Island Civil Structures
213	Turbine Room and Heater Bay	213.1	Energy Conversion Building
214	Security Building	216.2	Security Building and Gatehouse
215	Primary Auxiliary Building and Tunnels	214	Buildings to Support Main Function
216	Waste Process Building	215.4	Radwaste Building
217	Fuel Storage Building	214.1	Spent Fuel Management Building
218A	Control Room/D-G Building	213.2	Control Building
218B	Administration and Service Building	216.1	Administration Building
218D	Fire Pump House, Including Foundations	214.5	Fire Protection Building
218E	Emergency Feed Pump Building	214	Buildings to Support Main Function
218F	Manway Tunnels (RCA Tunnels)	212	Reactor Island Civil Structures
218G	Electrical Tunnels	213.4	Electrical Tunnels
218H	Non-Essential Switchgear Building	214.6	Non-Essential Switchgear Building
218J	Main Steam and Feedwater Pipe Enclave	213.3	Pipe Tunnels
218K	Pipe Tunnels	213.3	Pipe Tunnels
218L	Technical Support Center	216.4	O&M Center
218P	Containment EQ[1] Hatch Missile Shield	212	Reactor Island Civil Structures
218S	Waste Water Treatment	214.3	Wastewater Treatment Building
218T	Ultimate Heat Sink Structure	233	Ultimate Heat Sink
218V	Control Room Emergency Air Intake Structure	213.2	Control Building
22	Reactor Plant Equipment	22	Reactor System
220A	Nuclear Steam Supply System (NSSS)	221	Reactor Components
220B	NSSS Options	222	Main Heat Transport System
221	Reactor Equipment	221	Reactor Components

EEDB Account ID	EEDB Account Title	Mapped GN-COA Account ID	Mapped GN-COA Title
222	Main Heat Transfer Export System	222	Main Heat Transport System
223	Safeguards System	223	Safety Systems
224	Radwaste Processing	224	Radioactive Byproduct Processing Systems
225	Fuel Handling and Storage	225	Fuel Handling Systems
226	Other Reactor Plant Equipment	226	Other Reactor Plant Equipment
227	Reactor Instrumentation and Control	227	Reactor Instrumentation and Control (I&C)
228	Reactor Plant Miscellaneous Items	228	Reactor Plant Miscellaneous Items
23	Turbine Plant Equipment	232.1	Electricity Generation Systems
231	Turbine Generator	232.1	Electricity Generation Systems
233	Condensing Systems	233	Ultimate Heat Sink
234	Feed Heating System	234	Feed Heating Systems
235	Other Turbine Plant Equipment	232.1	Electricity Generation Systems
236	Instrumentation and Control	236	Common Instrumentation and Controls
237	Turbine Plant Miscellaneous Items	232.1	Electricity Generation Systems
24	Electric Plant Equipment	24	Electrical Equipment
241	Switchgear	241	Switchgear
242	Station Service Equipment	242	Station Service Equipment
243	Switchboards	243	Switchboards
244	Protective Equipment	244	Protective Systems Equipment
245	Electrical Structure and Wiring Construction	245	Electrical Raceway Systems
246	Power and Control Wiring	246	Power and Control Cables and Wiring
25	Miscellaneous Plant Equipment	26	Miscellaneous Equipment
251	Transportation and Lift Equipment	261	Transportation and Lift Equipment
252	Air, Water, and Steam Service System	262	Air, Water, Plant Fuel Oil, and Steam Systems
253	Communication Equipment	263	Communications Equipment
254	Furnishings and Fixtures	264	Furnishing and Fixtures
255	Waste Water Treatment Equipment	262	Air, Water, Plant Fuel Oil, and Steam Systems
26	Main Condenser Heat Rejection System	233	Ultimate Heat Sink
261	Structures	233.1	Water Condensing Systems
262	Mechanical Equipment	233.1	Water Condensing Systems
	Total Indirect Costs	30	Capitalized Indirect Services Cost
	Plant Capital Costs	60	Capitalized Financial Costs
90	-	-	-
91	Construction Services	318	Other Construction Support Structures
911	Temporary Construction Facility	318	Other Construction Support Structures
912	Construction Tools and Equipment	311	Construction Tools and Equipment
913	Payroll Insurance and Taxes	-	See note[2]
914	Permits, Insurance and Local Taxes	12	Site Permits

EEDB Account ID	EEDB Account Title	Mapped GN-COA Account ID	Mapped GN-COA Title
915	Transportation	34	Shipping and Transportation Costs
92	Engineering and Home Office Service	351,352	See note[3]
921	Home Office Service	351,361	See note[3]
922	Home Office Q/A	353,363	See note[3]
923	Home Office Construction Management	361	Offsite
93	Field Supervision and Field Office Service	32	Factory and Construction Supervision
931	Field Office Expenses		#N/A
932	Field Job Supervision	362	Onsite
933	Field QA/QC	362	Onsite
934	Plant Startup Tests	33	Startup Costs
94	Contingencies on Owner's Costs	59	Supplementary Contingencies

* No COA number was used for these COA titles in the EEDB input sources

1 Equipment

2 GN-COA titles only track fully burdened staff salary before any deductibles.

3 The capitalized indirect service costs between EEDB and GN-COA are not broken down in the same way. EEDB groups engineering and services as Level 2 costs based on the location of offices—home office (EEDB code 92) or field office (EEDB code 93)—which is broken down further based on the type of service such as quality assurance, supervision, and other expenses. GN-COA categorizes these costs based on the type of services, whereas GN-COA codes 35 and 36 document engineering and management services, respectively. Subaccount of GN-COA codes 35 and 36 note whether the service was provided onsite or offsite among other expenses. Due to this mismatch in grouping, these EEDB accounts were mapped to multiple GN-COA accounts.

Table 12. Mapping of GIF COA structures to GNCOA.

GIF Account ID	GIF Account Title	Mapped GN-COA Account ID	Mapped GN-COA Title
10	Capitalized Preconstruction Costs	10	Capitalized Pre-Construction Costs
11	Land and Land Rights	11	Land and Land Rights
12	Site Permits	12	Site Permits
13	Plant Licensing	13	Plant Licensing
14	Plant Permits	14	Plant Permits
15	Plant Studies	15	Plant Studies
16	Plant Reports	16	Plant Reports
17	Other Preconstruction Costs	18	Other Pre-Construction Costs
19	Contingency on Preconstruction Costs	19	Contingency on Pre-Construction Costs
20	Capitalized Direct Costs	20	Capitalized Direct Costs
21	Structures and Improvements	21	Structures and Improvements
211	Site Preparation/Yard Work	211	Site Preparation/Yard Work
212	Reactor Island Civil Structures	212	Reactor Island Civil Structures

GIF Account ID	GIF Account Title	Mapped GN-COA Account ID	Mapped GN-COA Title
213	Turbine Generator Building	232.1	Electricity Generation Systems
214	Security Building and Gatehouse	216.2	Security Building and Gatehouse
215	Reactor Service (Auxiliary) Building	214	Buildings to Support Main Function
216	Radwaste Building	215.4	Radwaste Building
217	Fuel Service Building	215.5	Fuel Service Building
218A	Control Building	213.2	Control Building
218B	Administration Building	216.1	Administration Building
218C	Operation and Maintenance (O&M) Center	216.4	Operation and Maintenance (O&M) Center
218E	Steam Generator Storage Building	213.1	Energy Conversion Building
218K	Pipe Tunnels	213.3	Pipe Tunnels
218L	Electrical Tunnels	213.4	Electrical Tunnels
218N	Maintenance Shop	214.4	Maintenance Shops
218Q	Foundations for Outside Equipment and Tanks	217.1	Foundations for Outside Equipment and Tanks
218R	Balance of Plant Service Building	214.2	Balance of Plant Service Building
218S	Wastewater Treatment Building	214.3	Wastewater Treatment Building
218T	Emergency Power Generation Building	214.7	Emergency and Start-up Power Systems
218W	Warehouse	215.1	Storage and Warehouse Buildings
218X	Railroad Tracks	217.2	Railroad Tracks
218Y	Roads and Paved Areas	217.3	Roads and Paved Areas
219A	Training Center	216.3	Training Center
219K	Special Material Unloading Facility	215.2	Unloading Facility for Material Requiring Special Consideration
22	Reactor Equipment	22	Reactor System
221	Reactor Equipment	221	Reactor Components
222	Main Heat Transport System	222	Main Heat Transport System
223	Safety Systems	223	Safety Systems
224	Radioactive Waste Processing Systems	224	Radioactive Byproduct Processing Systems
225	Fuel Handling Systems	225	Fuel Handling Systems
226	Other Reactor Plant Equipment	226	Other Reactor Plant Equipment
227	Reactor Instrumentation and Control (I&C)	226	Other Reactor Plant Equipment
228	Reactor Plant Miscellaneous Items	228	Reactor Plant Miscellaneous Items
23	Turbine Generator Equipment	232.1	Electricity Generation Systems
231	Turbine Generator(s)	232.1	Electricity Generation Systems

GIF Account ID	GIF Account Title	Mapped GN-COA Account ID	Mapped GN-COA Title
233	Condensing Systems	233	Ultimate Heat Sink
234	Feed Heating Systems	234	Feed Heating Systems
235	Other Turbine Plant Equipment	232.1	Electricity Generation Systems
236	Instrumentation and Control (I&C)	236	Common Instrumentation & Controls
237	Turbine Plant Miscellaneous Items	232.1	Electricity Generation Systems
24	Electrical Equipment	24	Electrical Equipment
241	Switchgear	241	Switchgear
242	Station Service Equipment	242	Station Service Equipment
243	Switchboards	243	Switchboards
244	Protective Systems Equipment	244	Protective Systems Equipment
245	Electrical Raceway Systems	245	Electrical Raceway Systems
246	Power and Control Cables and Wiring	246	Power and Control Cables and Wiring
25	Heat Rejection System	233	Ultimate Heat Sink
251	Structures	233.1	Water Condensing Systems
252	Mechanical Equipment	233.1	Water Condensing Systems
26	Miscellaneous Equipment	26	Miscellaneous Equipment
261	Transportation and Lift Equipment	261	Transportation and Lift Equipment
262	Air, Water, Plant Fuel Oil, and Steam Systems	262	Air, Water, Plant Fuel Oil, and Steam Systems
263	Communications Equipment	263	Communications Equipment
264	Furnishing and Fixtures	264	Furnishing and Fixtures
27	Special Materials	27	Material Requiring Special Consideration
28	Simulator	28	Simulator
29	Contingency on Direct Costs	29	Contingency on Direct Costs
30	Capitalized Indirect Services Cost	30	Capitalized Indirect Services Cost
31	Field Indirect Costs	31	Factory & Field Indirect Costs
32	Construction Supervision	32	Factory & Construction Supervision
33	Commissioning and Startup Costs	33	Startup Costs
34	Demonstration Test Run	332	Demonstration Test Run
35	Design Services Offsite	351	Off-Site
36	PM/CM Services Offsite	361	Off-Site
37	Design Services Onsite	352	On-Site
38	PM/CM Services Onsite	362	On-Site
39	Contingency on Indirect Services Cost	39	Contingency on Indirect Services Cost

GIF Account ID	GIF Account Title	Mapped GN-COA Account ID	Mapped GN-COA Title
40	Capitalized Owner’s Costs	40	Capitalized Training Costs
41	Staff Recruitment and Training	41	Staff Recruitment and Training
42	Staff Housing	42	Staff Housing
43	Staff Salary-Related Costs	-	(not considered in GN-COA)
44	Other Owners Costs	55	Other Owner's Costs
49	Contingency on Owner's Costs	49	Contingency on Training Costs
50	Capitalized Supplementary Costs	50	Capitalized Supplementary Owner’s Costs
51	Shipping and Transportation Costs	34	Shipping and Transportation Costs
52	Spare Parts	38	Spare Parts
53	Taxes	51	Taxes
54	Insurance	52	Insurance
55	Initial Fuel Core Load	25	Initial Fuel Inventory
551	Fuel Assembly Supply, First Core	251	First Core Mining
512	First Core Conversion	252	First Core Conversion
513	First Core Enrichment	253	First Core Enrichment
514	First Core Fuel Assembly Fabrication	254	First Core Fuel Assembly Fabrication
515	First Core Supply of Other Fissionable Materials (e.g., Pu)	255	First Core Supply of Other Fissionable Materials (e.g., Pu)
552	Services, First Core	331.1	Initial Fuel Inventory Services
521	Fuel Management (U, Pu, Th)	331.1	Initial Fuel Inventory Services
522	Fuel Management Schedule	331.1	Initial Fuel Inventory Services
523	Licensing Assistance	331.1	Initial Fuel Inventory Services
524	Preparation of Computer Programs	331.1	Initial Fuel Inventory Services
525	Quality Assurance	331.1	Initial Fuel Inventory Services
526	Fuel Assembly Inspection	331.1	Initial Fuel Inventory Services
527	Fuel Assembly Intermediate Storage	331.1	Initial Fuel Inventory Services
528	Information for the Use of Third-Party Fuel	331.1	Initial Fuel Inventory Services
58	Decommissioning Costs	54	Decommissioning
59	Contingency on Supplementary Costs	59	Supplementary Contingencies
60	Capitalized Financial Costs	60	Capitalized Financial Costs
61	Escalation	61	Escalation
62	Fees	56	Fees
63	Interest During Construction	62	Interest
69	Contingency on Financial Costs	69	Contingency on Financial Costs
70	Annualized O&M Cost	70	Annualized O&M Cost

GIF Account ID	GIF Account Title	Mapped GN-COA Account ID	Mapped GN-COA Title
71	O&M Staff	71	O&M Staff
72	Management Staff	717	Management Staff
73	Salary-Related Costs	718	Salary-Related Costs
74	Operating Chemicals and Lubricants	741	Operating Chemicals and Lubricants
75	Spare Parts	38	Spare Parts
76	Utilities, Supplies, and Consumables	743	Utilities, Supplies, and Consumables
77	Capital Plant Upgrades	75	Capital Plant Expenditures
78	Taxes and Insurance	76	Taxes and Insurance
79	Contingency on Annualized O&M Costs	79	Contingency on Annualized O&M Costs
80	Annualized Fuel Cost	80	Annualized Fuel Cost
81	Refueling Operations	81	Refueling Operations
811	Fuel Management	811	Fuel Management
812	Fuel Management, Schedule	812	Fuel Management Schedule
813	Licensing Assistance	813	Licensing Assistance
814	Preparation of Computer Programs	814	Preparation of Computer Programs
815	Quality Assurance	815	Quality Assurance
816	Fuel Assembly Inspection	816	Fuel Inspection
817	Fuel Assembly Intermediate Storage	817	Fuel Assembly Intermediate Storage
818	Information for the Use of Third-Party Fuel	818	Information for the Use of Third-Party Fuel
84	Nuclear Fuel	82	Additional Nuclear Fuel
841	Uranium Supply for Reloads	821	Mining Cost for Reloads
842	Conversion for Reloads	822	Conversion Cost for Reloads
843	Enrichment for Reloads	823	Enrichment Cost for Reloads
844	Fuel Assembly Fabrication for Reloads	824	Fuel Assembly Fabrication Cost for Reloads
845	Supply of Other Fissionable Materials for Reloads	825	Supply of Other Fissionable Materials for Reloads
86	Fuel Reprocessing Charges	832	Fuel Reprocessing
861	Credits for Uranium, Plutonium and Other Materials	832.1	Credit for Uranium, Plutonium, and Other Materials
862	Final Disposal of Fuel Assemblies	833	Final Disposal of Fuel
863	Final Waste Disposal	745	Final Disposal of Non-Fuel Waste
87	Special Nuclear Materials	744	Material Requiring Special Consideration

GIF Account ID	GIF Account Title	Mapped GN-COA Account ID	Mapped GN-COA Title
89	Contingency on Annualized Fuel Costs	89	Contingency on Annualized Fuel Costs
90	Annualized Financial Cost	90	Annualized Financial Cost
91	Escalation	91	Escalation
92	Fees	92	Fees
93	Cost of Money	93	Cost of Money
99	Contingency on Annualized Financial Costs	99	Contingency on Annualized Financial Costs

4.2 Cost Escalation Methodology

4.2.1 Overview of Proposed Escalation Approaches in Literature

The consideration of escalation is crucial in nuclear-cost estimation due to the lack of a detailed publicly available breakdown of recent construction costs. This study primarily focuses on leveraging detailed estimates from the past, which necessitates normalization to a reference time. Escalation, in this context, means multiplying costs from a given date by an adjustment factor or index that is representative of that product (not simply adjusting for the inflationary evolution of currency). Also, escalation is crucial to comprehend the dynamic nature of prices and cost structures. It is important to note that these changes reflect multiple factors, including changes in productivity, technological advancements, and market dynamics, such as shifts in demand and labor shortages, profit margins, external markets, geopolitics, etc.

Estimating escalation is a specialized task that requires a deep understanding of macroeconomic conditions and multiple economic dimensions and factors that affect a specific variable at the same time with back-and-forth effects among them. In other words, escalation is a multidimensional concept vital for project planning and cost management, to make it possible to recognize and anticipate how underlying economic conditions impact pricing and cost dynamics, allowing sound economic decisions and cost management over time. To further this point, the following sections will discuss different cost -escalation approaches used by different publications before describing the methodology that was selected for this report.

4.2.1.1 Cost-Basis Report

The cost-escalation methodology employed in the 2017 CBR expresses cost data in constant 2017 dollars (Dixon et al. 2017). The report uses historical escalation indices specific to the power industry, considering factors like commodity-price escalation and labor costs affected by regulatory standards. Different escalation indexes are used over time to build the factors of adjustment for each particular year, from 1965 to 2017. For instance, the Handy Whitman-North America index is used from 1965 to 1995, the Department of Energy index from 1995 to 2000, the Information Handling Service (IHS) North American Power Capital Costs Index with nuclear from 2000 to 2015, and the Gross Domestic Product (GDP) Implicit Price Deflator (IPD) from 2015 to 2017. It is important to note that each method aims to represent specific time spans, reflecting the industry's evolving cost dynamics. The report provides an index concatenation derived from these sources, obtaining a long index for the escalation from any year between 1965 and 2017 for cost comparisons.

The CBR method is less focused specifically on nuclear construction because it was intended to cover additional nuclear fuel-cycle considerations, including mining, uranium enrichment, and other processing costs. This index has additional inherent limitations because (1) it tries to tie several different indices together, (2) none of which are nuclear-construction specific, and (3) it is a very broad high -level number without much nuance to the type of activity taking place.

4.2.1.2 Utilizing the CPI and GDP-IPD in Escalation

The Consumer Price Index (CPI) is one of the most used price indices for escalation, but it is important to consider some caveats if it is used. The CPI represents an average cost of a bundle of consumption goods rather than capital goods, and the use of CPI could be biased because it does not represent capital goods or inputs specifically for nuclear energy.

According to the Bureau of Labor Statistics (BLS), the CPI is calculated for two primary population groups, the all-urban consumers (CPI-U) and urban wage earners and clerical workers (CPI-W). The CPI-U covers over 90% of the total US population, reflecting the expenditures of all urban families. On the other hand, the CPI-W is a subset of the CPI-U, focusing on urban families whose income predominantly derives from clerical or hourly wage occupations. This group represents approximately 30% of the US population (US Department of Labor 2023). In this sense, CPI is a useful metric to escalate consumer products, such as milk, rent, and eggs, that are everyday products people buy. Where its use becomes limited is when it is applied to non-consumer goods. Subsequently, using CPI to escalate costs for industrial assets or commodities such as steel and concrete becomes fraught with error because the index does very little, if anything, to measure the impacts to these goods.

Another important metric of high-level inflation in the US is the GDP-IPD. The GDP-IPD does not measure the same basket of goods as the CPI. It measures the changes in the prices of goods and services produced in the US, including exports, but excluding prices of imports. The CPI measures the evolution of prices of consumer goods, in other words it measures a specific basket of goods. While both CPI and the GDP-IPD are indicators of inflation, CPI focuses on the cost of living for consumers, and the GDP deflator considers the prices of all goods and services produced in the economy, providing a broader measure of inflation that affects all sectors. While it is not applicable for all aspects of nuclear construction, the GDP-IPD was found to be a useful index for escalating some specific components of a nuclear power plant costs.

4.2.1.3 Stewart and Shirvan

Stewart and Shirvan (Stewart and Shirvan 2020) based their bottom -up advanced nuclear power plant cost estimation tool on the work done by Ganda though their scaling methodology escalates component costs building on additional sources (Ganda et al. 2019, Towler et al. 2013, and GIF 2007). Stewart and Shirvan (Stewart and Shirvan 2020) escalated the EEDB[a] from 1987 to 2018, scaling each component cost, accounting for modularization and learning to achieve NOAK cost, making design-specific adjustments, and estimating indirect costs. Also, Stewart and Shirvan (2020) include an implicit contingency cost, narrowly defined as allocated risk in the predicted overnight construction cost, based on median-experience plants.

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[a] In their methods, the EEDB is the reference point for cost estimation. It is important to note that each cost item in the EEDB includes factory cost, site labor cost, site labor hours, material quantity, and material cost. The costs are structured into a COA system, with one-digit accounts aggregating their respective two-digit accounts, and so on, providing detailed ten-digit cost breakdowns. The EEDB database encompasses costs for median-experience plant builds (PWR12-ME) and better-experience plant builds (PWR12-BE). In this analysis, PWR12-ME is considered representative of FOAK costs.

The authors developed a cost-estimate tool that uses five methods for scaling and estimating 209 cost components from the EEDB PWR12-ME, which includes escalation of each labor and material cost using indexes from the Bureau of Labor Statistics (BLS 2019). The cost-estimation process is represented in Figure 9. In general, the methodology is comprehensive and relatively complete; however, it can be challenging to implement considering the broad variety of data sets, often with incomplete information.

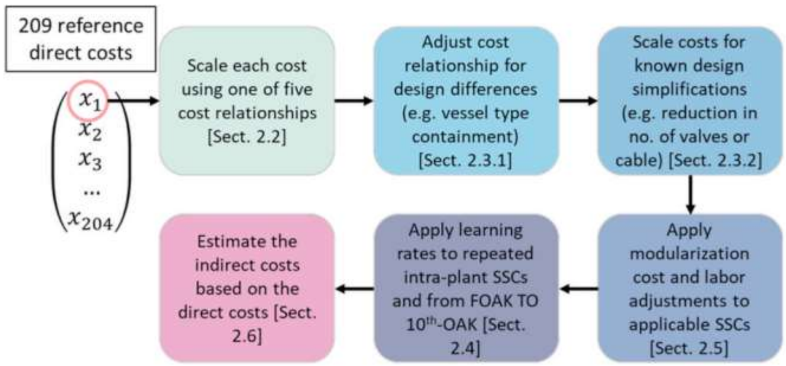

Figure 9. Escalation methodology of Stewart and Shirvan (2022).

4.2.2 Methodology Selected for Cost Escalation

This report opted for a middle ground between the approaches discussed. Here, each of the Level 2 accounts (i.e., Accounts 10, 20, 30, 40, and 50) were escalated differently. Account 20, which includes capitalized direct costs associated with the reactor and supporting systems, is perhaps one of the most -difficult accounts to escalate due to the unique split among different cost types. To account for this, a new cost index was created by using a weighted average between three indices, as shown in Equation 1.

$$Cost_t = Cost_x[(\beta)LaborIndex_x + (\alpha)MaterialsIndex_x + (\theta)EquipmentIndex_x] \quad (1)$$

where

t = represents the year costs to be escalated toward

x = represents the base year of the original costs

β, α, and θ = represent the labor, material, and equipment costs as a percent of total costs.

These weights were calculated using the EEDB database values reported for each cost category. The labor index selected was the “Employment Cost Index: Total compensation for Private Industry Workers in Construction” (BLS 2024). The material index selected is “Producer Price Index: Special Indexes: Construction Materials” (BLS 2024b). The equipment index selected is “Machinery and Equipment: Other Industrial Valves, Including Nuclear” (BLS 2024c). All these indices are published in the Federal Reserve Economic Database (FRED) database and updated regularly. Figure 10 shows a visual comparison of the new weighted-average nuclear-cost factor used to escalate Account 20 and the GDP-IPD. It is worth noting that here a cost factor is shown instead of an index. The difference is that a cost factor acts as a direct multiplier for costs while indexes must be applied using a specific equation. This transformation does nothing to the relative difference in the values themselves, it simply makes interpretation and application more straightforward.

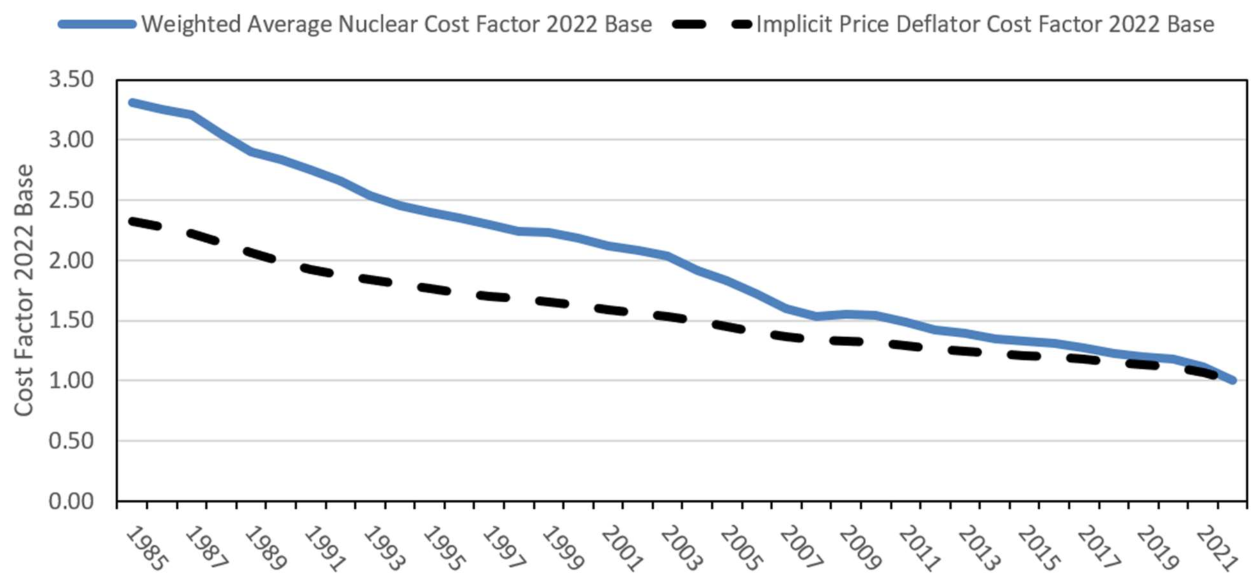

Figure 10. Weighted average nuclear cost factor 2022 base verse GDP IPD.

Selecting the specified indexes (above) was also a complex process. There is a clear difference between non-nuclear construction costs and nuclear construction costs. For example, welders at nuclear construction sites usually require more-specific qualifications and training than welders building a warehouse. However, very few indices exist that separate nuclear-related costs from non-nuclear costs. Additionally, some indexes include varying levels of specificity. For example, a general-construction labor index might look different depending on the weight of electricians, laborers, welders, and concrete workers assumed in the underlying data. The same potential concerns would hold true for material indexes. In an ideal world, the escalation method would account for exact weights of different works, material types, and cost-premium changes with nuclear-specific construction costs. However, because these data are not widely available, it was determined that using general-construction labor and material indices would be a viable option.

In the case of equipment costs, select indices do include nuclear costs in the data. Three different equipment-index methods were tested to determine how costs evolved relative to the GDP-IPD, and these tests were used to inform the final index selection called out above. The three indices tested included the following:

1. A high-level machinery and equipment index.
2. A valve-specific index that included nuclear costs.
3. An average of group of indices for various types of equipment.[b]

[b] A total of seven indices were averaged together that included turbine generators, heat exchanges and condensers, industrial valves, cranes and draglines, HVAC equipment, and power boilers.

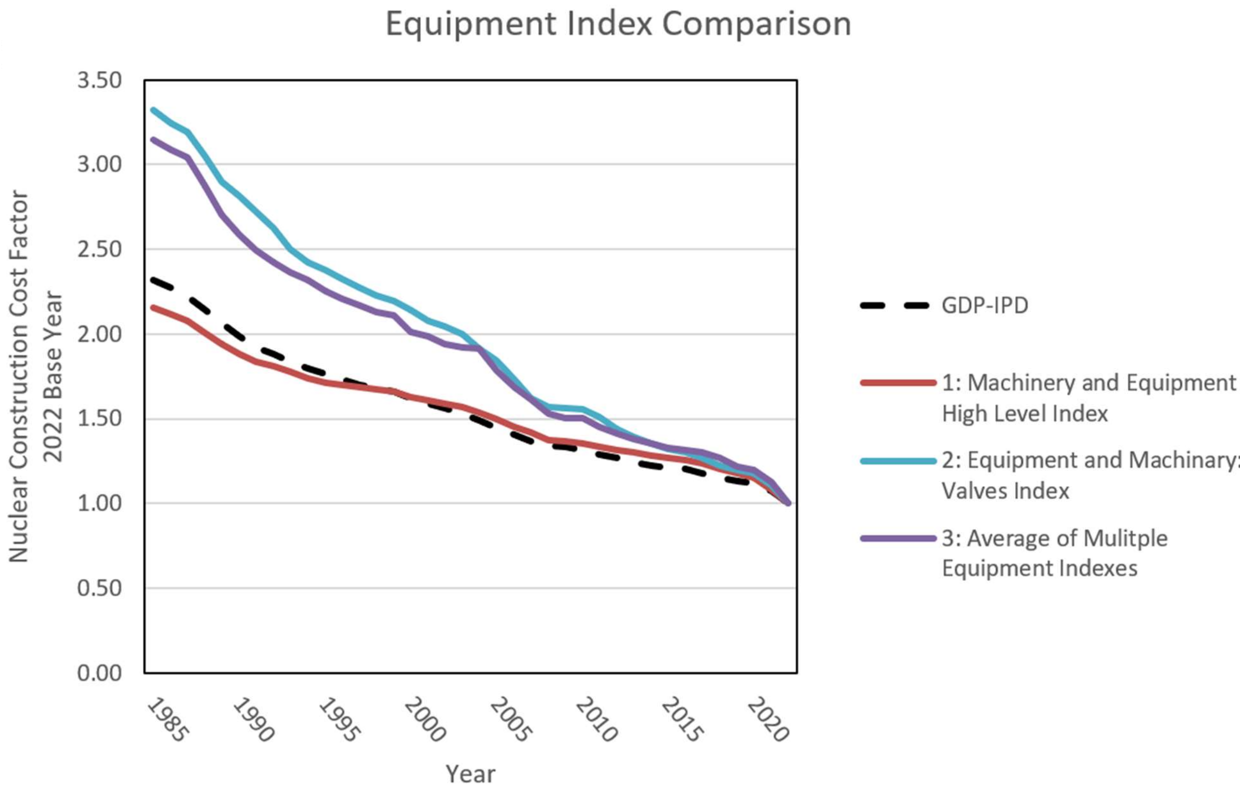

Figure 11. Equipment-index testing relative to GDP-IPD.

Figure 11 highlights the comparison of these three indices. The first index tracks at a rate at or below GDP-IPD through almost the entire timeline while the second and third remain tightly grouped through the timeline. The first index was disqualified because it seemed counterintuitive for nuclear costs to escalate more slowly than the GDP-IPD. Ultimately, the second index was selected due to its inclusion of nuclear costs.

The methodology to escalate accounts outside of the 20s is more straightforward. For accounts that were predominately labor based, Accounts 30 and 40, the labor index mentioned above was used. For Accounts 10 and 50, with less-traditional costs (such as shipping, land, insurance, taxes, and regulatory fees) the GDP-IPD was leveraged. Table 13 provides a breakout of which indices were used for which account groupings.

Table 13. Account-specific escalation method and indices used.

Account	Index Used
10 (Capitalized Preconstruction Costs)	GDP-IPD
20 (Capitalized Direct Costs)	See Equation 1
30 (Capitalized Indirect Services Costs)	Labor Index
40 (Capitalized Pre-COD Personnel Costs)	Labor Index
50 (Capitalized Supplementary Costs)	GDP-IPD

To further illustrate this process, an example of the escalation process for the Level 1 and Level 2 accounts in both the 20s and 30s is shown below for the PWR12-ME data set in Table 14.

Table 14. Escalation example using PWR12-ME data.

	Account Title	Total Costs 1987 USD	Total Cost 2022 USD
20	**Capitalized Direct Costs**	**$ 1,187,089,509**	**$ 3,788,142,768**
21	Structures and Improvements	$ 297,157,634	$ 948,265,092
22	Reactor System	$ 370,640,594	$ 1,182,757,892
23	Energy Conversion System	$ 329,398,512	$ 1,051,149,540
24	Electrical Equipment	$ 119,236,515	$ 380,497,796
25	Initial Fuel Inventory	$ –	$ –
26	Miscellaneous Equipment	$ 70,656,254	$ 225,472,448
27	Material Requiring Special Consideration	$ –	$ –
28	Simulator	$ –	$ –
29	Contingency on Direct Costs	$ –	$ –
30	**Capitalized Indirect Services Cost**	**$ 1,218,008,000**	**$ 3,393,590,917**
31	Factory & Field Indirect Costs	$ 299,853,000	$ 835,444,773
32	Factory & Construction Supervision	$ 374,574,000	$ 1,043,631,014
33	Startup Costs	$ 17,701,000	$ 49,318,192
34	Shipping and Transportation Costs	$ –	$ –
35	Engineering Services	$ 480,433,000	$ 1,338,573,363
36	PM/CM Services	$ 45,447,000	$ 126,623,574
39	Contingency on Indirect Services Cost	$ –	$ –

Last, a granular approach was also followed for O&M costs. The metric used for each type of annualized costs is summarized in Table 15. Variable O&M costs are mainly in the form of consumables and component replacement; hence, an equipment-based index was deemed most appropriate. Fixed O&M costs are predominantly staff-salary related; hence, a labor-index was used. Decommissioning fees and property taxes were escalated based on GDP-IPD. The same was used for fuel costs because these are commoditized.

Table 15. Escalation indices selected for nuclear reactor O&M costs.

O&M Cost Type	Index Used
Variable O&M	Equipment
Fixed O&M	Labor
Annualized decommissioning	GDP-IPD
Property taxes	GDP-IPD
Fuel	GDP-IPD

5. CAPITAL COST DATA ANALYSIS AND PROCESSING

5.1 Data Analysis and Treatment

Once all data were mapped to the same reference COA structure and the values escalated to a reference dollar-year, the next step was to normalize capital-cost values to electrical capacity. Here, values are normalized per the total plant output (for the entire site, which may include multiple reactors). At this stage, the values correspond to overnight capital cost (OCC); no financing cost is included yet.

As previously noted, however, data set granularity varied greatly between references. To perform statistical analysis, it is important to ensure that all data sets are complete. As a result, missing data points need to be added when specific cost estimates do not include them. This was conducted by either leveraging completed data from other data sets or providing an independent basis for estimating a given value. Overall, a methodology was developed for each of the cost categories listed below; a more-detailed breakdown of the approach followed in each case is provided in the next subsections:

1. Preconstruction costs (Account 10).
2. Direct costs (Account 20).
3. Indirect-service costs (Account 30).
4. Initial-fuel core-loading costs (Account 25).
5. Decommissioning costs (Account 54 and 78).
6. Other supplementary costs (Account 50).

Last, it should be noted that Account 40s (predominantly training costs) were excluded from further analysis. They relate to staff training costs for operations of the reactor, which are not typically considered in cost breakdown for grid modelers and are, therefore, not considered here. Costs associated with other labor to construct the reactor are included in Accounts 20 and 30.

5.1.1 Preconstruction Costs

Missing preconstruction costs were populated using two methods depending on the account. First, in the data set where estimates did include costs for a given account, an average $/kWe value was calculated. This average was then used to populate the missing values in incomplete estimates. The second method was to calculate the costs for a given account using characteristics from a built plant with generalized cost info. This approach was only used when calculating land and land-rights costs. The calculation involves taking the average cost per acre for rural land in 2022 from the US Department of Agriculture ($3,800 per acre) and multiplying it by the total acreage of a referenced plant, in this case Vogtle, to get total land cost. From there, the value was normalized to the total power for Vogtle to provide a value in $/kWe ($2.38/kWe) that could be substituted into estimates for which no land cost existed. The resulting $/kWe value is such a small contributor to overall costs that varying assumptions here are not expected to have major implications for the final OCC values. Using this number for a large or small reactor was concluded to be acceptable as a result. For all preconstruction costs, Table 16 details the method by which missing data were supplied.

Table 16. Account 10 subaccounts methods for populating missing data.

Account	Missing Data Population Method	Values Used ($/kWe)
11: Land and Land Rights	Calculated Using Vogtle Reference Case	2.38
12: Site Permits	Average $/kWe From Data set	10.03
13: Plant Licensing	Average $/kWe From Data set	98.86
14: Plant Permits	Average $/kWe From Data set	17.76
15: Plant Studies	Average $/kWe From Data set	25.37

Account	Missing Data Population Method	Values Used ($/kWe)
16: Plant Reports	Average $/kWe From Data set	12.35
17: Community Outreach and Education	Not Populated if Missing	0.00
18: Other Preconstruction Costs	Average $/kWe From Data set	55.43
19: Contingency on Preconstruction Costs	Average $/kWe From Data set	38.05

Account 17 is left as zero because none of the data sets considered reported any projected values for community outreach and education costs.

5.1.2 Direct Costs

Missing direct costs were only populated for select accounts. It was assumed that for Accounts 21, 22, and 23 that if data were excluded, it would be captured in other accounts because of differences in the accounting structures/tabulations. For Account 27, the only sources that included costs were for the AHTR estimate, which was a lithium fluoride and beryllium fluoride (FLiBe)-specific expense. Given this cost would not be incurred for other reactor types, this was also not populated when missing in other estimates. All other subaccounts of 20 were populated using an average $/kWe from the data set, as was done the preconstruction costs. Table 17 provides a summary of missing-data population methods and the values used.

Table 17. Account 20 subaccounts missing-data population methods.

Account	Missing-Data Population Method	Values Used ($/kWe)
21: Structures and Improvements	Always contained in data sets	N/A
22: Reactor System	Always contained in data sets	N/A
23: Energy Conversion System	Always contained in data sets	N/A
24: Electrical Equipment	Average $/kWe From Data set	261.80
25: Initial Fuel Inventory	Calculated, see Section 5.1.4	Variable
26: Miscellaneous Equipment	Average $/kWe From Data set	194.73
27: Material Requiring Special Consideration	Not Populated if Missing	0.00
28: Simulator	Average $/kWe From Data set	0.18
29: Contingency on Direct Costs	Average $/kWe From Data set	720.26

It is worth noting that within the entire data set, the average ratio of Account 29 (contingency costs), relative to Account 20, was 18%. This falls in line with feedback from industry leaders that suggests the contingency value should range from 10% to 30%. In this case, because Account 29 was populated for all data sets where these costs were missing (irrespective of size and technology), it is likely this is a conservative estimate for smaller reactors. This was also done across all cost estimates, so it is a combination of both FOAK and NOAK. Further discussion of the impact of contingencies in cost estimates are provided in Section 5.4.4. Accounts 21, 22, and 23 were already pre-populated in all the data sets and no further modifications were conducted.

5.1.3 Indirect Service Costs

Indirect costs (Account 30) were frequently found to be estimated differently between data sets. When only a handful of Level 2 indirect cost subaccounts were found to be missing in the dataset, the assumption was made that they were likely lumped into other Level 2 accounts due to differences in accounting structure. Hence, no further modifications were deemed necessary. This meant that if a source was encountered with at least one value for indirect services of any kind, it was assumed to be complete, and no additional data were populated. If the estimate contained no value for any indirect service costs, the Level 1 account (Account 30) was populated instead of its subaccounts by ratioing Account 30 to Account 20. Given that these two cost categories are closely correlated (i.e., when direct costs increase, indirect ones usually follow), this assumption should mirror real-world outcomes. To determine an adequate ratio to populate missing data, the average was calculated in the entire data set for which costs were available. This ratio was then multiplied by the total cost of Account 20 for a given estimate to populate data when missing. In other words, the implicit assumption made here is that indirect costs are tied to direct costs.

Table 18. Account 30 subaccounts missing-data population methods.

Account	Missing-Data Population Method	Values Used (Ratio of 20)
30: Capitalized Indirect Services Cost	Ratio of Account 20	0.34
31: Factory & Field Indirect Costs	Not Populated if Missing	—
32: Factory & Construction Supervision	Not Populated if Missing	—
33: Startup Costs	Not Populated if Missing	—
34: Shipping and Transportation Costs	Not Populated if Missing	—
35: Engineering Services	Not Populated if Missing	—
36: PM/CM Services	Not Populated if Missing	—
39: Contingency on Indirect Services Cost	Not Populated if Missing	—

5.1.4 Initial Core Loading Costs

The initial core load is a significant part of the initial capital investment in a nuclear power plant. Rough estimates of this cost can be made from a relatively small set of information about the reactor core, along with estimates of the unit cost (included in Table 35) for the various contributions (e.g., natural uranium, separative work unit [SWU], fabrication) to the cost of nuclear fuel. The core information needed is the specific power of the fuel (kW/kg of heavy metal [kgHM]), thermal efficiency, and power level. From these three pieces of information, the amount of heavy metal in the initial core for a power plant can be determined. To assess the number of units of the various contributors, fuel enrichment is also required. Ideally, this would be for each different batch in the core, so a more-accurate estimate can be made, but the approximate core-average enrichment is sufficient for estimating future reactor costs. Detailed designs of the initial core and transition to the equilibrium cycle are often not done until the project has progressed beyond conceptual design, so it is often necessary to make estimates of initial core enrichment from the equilibrium core composition. Initial core cost (ICC) is calculated by:

$$ICC[\$M] = \frac{\sum Comp_i\left[\frac{units}{kg\ HM}\right] Cost_i\left[\frac{\$}{unit}\right]}{SP\left[\frac{kW_{th}}{kg\ HM}\right] \eta \left[\frac{W_e}{W_{th}}\right]} P[GW_e] \qquad (2)$$

where

$Comp_i$ = kg of heavy metal of a given fuel unit (e.g., a fuel assembly or pebble)

$Cost_i$ = cost of each fuel unit

SP = specific power of the fuel

η = thermal efficiency

P = overall electric power output of the reactor.

Estimation of the units required for a given fuel enrichment is the same as for refueling, which is discussed in more detail in Section 6.1. The cost of the initial core should include all costs associated with the fuel, from the natural uranium through enrichment and fabrication to the disposal of all waste streams, including both depleted uranium and the spent nuclear fuel. This estimate is for once-through fuel cycles, but a similar approach could be used for initial cores utilizing recycled material.

For reactors operating on relatively short cycle lengths, the first refueling costs will be incurred near the start of operation and continue nearly continuously over the life of the reactor. That is what is evaluated in this report. However, for long-lived cores, the approximation of the initial core load followed by an approximately continuous refueling cost is inappropriate. For example, a 10-year core would likely have no refueling costs for nearly a decade after start of operations, then would incur a large cost for refueling over a relatively short duration, followed by another nearly decade-long period with no refueling costs. This would require proper amortization of costs. That is not the case for the reactors estimated here.

The values included in Table 19 are based on the assumptions in the Systems Analysis and Integration system datasheets (Dixon et al. 2017). The reference specification for each reactor types were obtained for an example PWR (Wigeland et al. 2014), HTGR (Pope et al. 2012), and SFR (T. K. Kim 2022). Variations in designs that impact the specific power, thermal efficiency, or the assumed initial enrichment will impact these values and can easily be adjusted in the future. As a result, the mean initial core-loading costs were added to incomplete data sets based on the reactor type. The initial core costs were estimated by using Monte Carlo sampling using the cost information in Table 19.

Table 19. Assumed parameters for example reactors used to estimate initial core costs. Fuel cycle inputs to the calculation were obtained from (Dixon et al. 2017).

	PWR	HTGR	SFR
Reactor Power (GWe)	1	1	1
Net Thermal Efficiency (We/Wt)	33%	40%	41%
Specific Power (kW / kg HM)	34	106	40
Average Enrichment (kg U-235 / kg U)	2.5%	5%	15%
Initial Core Cost ($/kWe) 25%/Mean/75%	300 / 320 / 340	220 / 260 / 290	890 / 990 / 1090
Natural Uranium (kg NU / kWe)	0.439	0.244	1.976
NU Conversion (kg NU / kWe)	0.439	0.244	1.976
Total SWU (SWU / kWe)	0.713	0.187	1.861
HALEU SWU (SWU+ / kWe)	–	–	0.231
HALEU Deconversion (kg HALEU / kWe)	–	–	0.062

Fuel Fabrication (kWe / kWe)	0.090	0.024	0.062
DU Deconversion (kg DU / kWe)	0.349	0.220	1.914
DU Disposal (kg DU / kWe)	0.349	0.220	1.914
SNF Packaging (kg iHM / kWe)	0.090	0.024	0.062

5.1.5 Decommissioning Costs

Nuclear power plants are legally required to establish decommissioning funds ahead of time. This ensures that, as a plant is retired at the end of its operating life, sufficient funds are available to bring the land back to the agreed-upon end state (e.g., brownfield, greenfield). This may differ from other technologies that do not have a legal requirement to fully transition the land back to a previous state and, thus, may not include the costs to support full disposal and decommissioning at the end of life. For nuclear plants, Larsen et. al. (2024) collected data on the decommissioning costs of US reactors from the Nuclear Regulatory Commission (NRC), Dominion (2004), and US utilities (Callan Institute 2019), to obtain the escalated decommissioning costs in the United States. The normalized yearly decommissioning costs are presented in Figure 12.

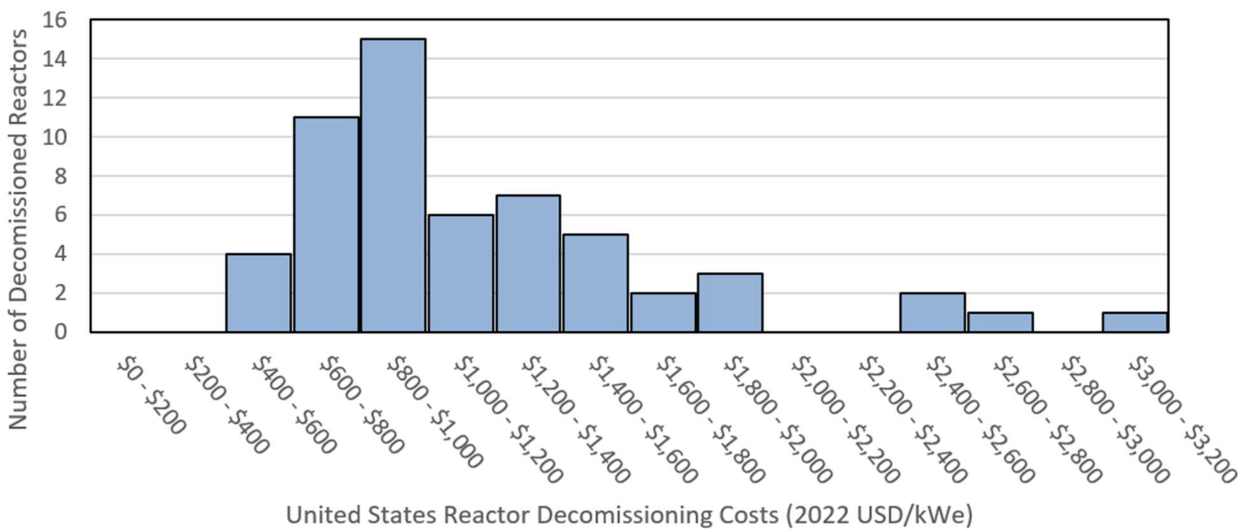

Figure 12. Decommissioning cost histogram data. Taken from (Larsen 2024).

Given that decommissioning costs are incurred over the life of the reactor it is important to represent them not as lump sum costs, but rather annual payments that are placed into a trust and earn a base return on the investments. For each of the 52 decommissioning funds called out in Callan Institute (2019), an annual payment was calculated using the following equation:

$$AnnualPayment = \frac{FinalCost * AR}{1-(1+AR)^n} \quad (3)$$

where

AR = represents an expected annual return of 4.75%

n = represents the number of years a payment will be put into the trust, in this case 41 years (1 payment upon completion of construction followed by payments for another 40 years of operation).

The resulting cost data resulted in an average cost of $7.7/kWe per year, which was rounded to $10/kWe-y to be conservative. It is worth noting that the NRC requires funds to be fully funded by the end of the initial license (40 years). Thus, it is possible that reactors will fully fund the decommissioning trust and then enter a license renewal period past 40 years.

5.1.6 Supplementary Costs

For missing supplementary costs, a variety of methods were leveraged. For Account 59, a data-set average was used as previously detailed. Account 53, 55, 56, and 57 were left unpopulated if missing. Account 54 was calculated using the method detailed in Section 5.1.5. For Account 51, property taxes, the average industrial property tax, was used and multiplied by the cost of land and land rights. For Account 52, insurance during construction was calculated by multiplying the total OCC by an assumed value of 0.45%.

Table 20. Account 50 subaccounts missing data population methods.

Account	Missing-Data Population Method	Values Used ($/kWe)
51: Taxes	Calculated Using Average Industrial Property Tax	0.03
52: Insurance	Calculated Using Assumed Insurance Ratio	Variable
53: Spent Fuel Storage	Not Populated if Missing	0.00
54: Decommissioning	Calculated, see Section 5.1.5	10.00
55: Other Owners' Costs	Not Populated if Missing	0.00
56: Fees	Not Populated if Missing	0.00
57: Management Reserve	Not Populated if Missing	0.00
59: Supplementary Contingencies	Average $/kWe From Data set	199.44

5.2 Observed Trends

A high-level look at the data helps contextualize reactor-cost trends without any sort of grouping. Figure 13 shows a mapping of the data based on plant nameplate capacity and OCC. Generally, it appears that as nameplate capacity increases, OCC appears to trend downward. This would support the claim that larger reactors experience economies of scale. It is worth noting that, while this may be the case in these data, much of it stems from paper-reactor estimates, not observations from real reactor builds. Real-world trends may differ depending on additional outside factors, such as regulatory changes, project-management ability, and other external factors. Figure 13 also shows the quartiles for the data set that are ~$9,000/kWe for the third quartile, ~$7,250/kWe for the second quartile, and ~$5,500/kWe for the first quartile. To correct for imbalances in the number of FOAK and NOAK estimates in the data set, a weighted-percentile method was applied that is explained further in the following section. This section will further investigate observed trends in the cost data based on several considerations.

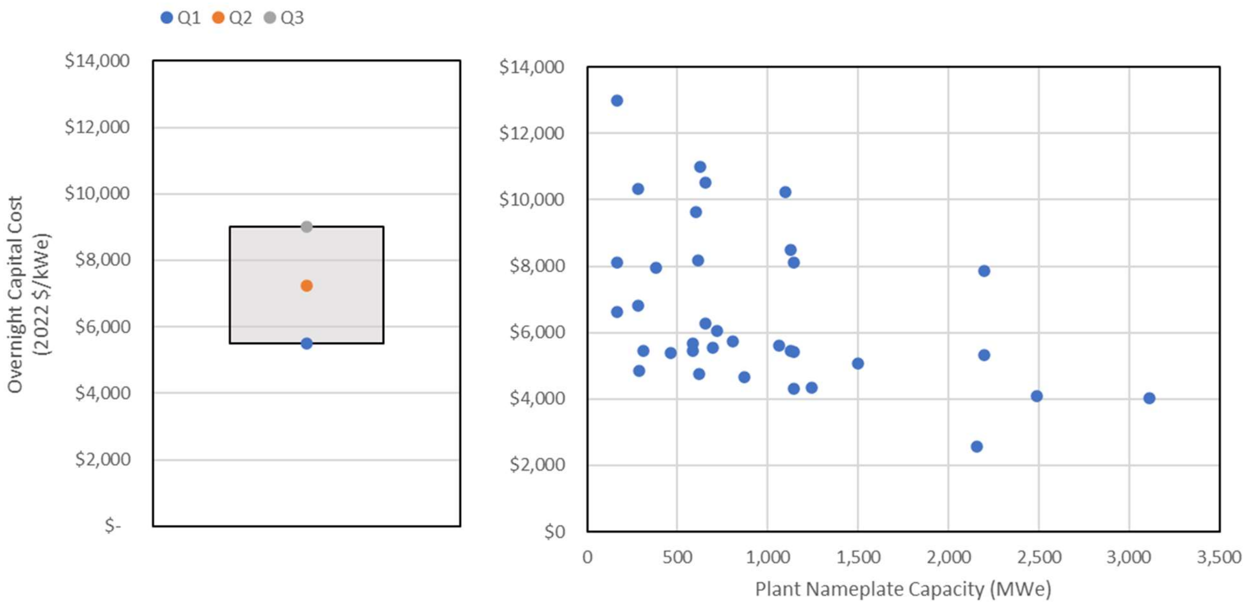

Figure 13. Overall data quartiles (weighted) with plotted data (outliers excluded).

5.2.1 Regression-Analysis Results

A regression analysis was conducted between the adjusted overnight capital costs and the reactor size:

$$\ln\left(OCC_{adjusted,i}\right) = \beta_0 + \beta_1 \ln(ReactorSize_i) + \beta_2 Dummy_1 + \beta_3 Dummy_2 + \mu_i \qquad (6)$$

where:

$\ln\left(OCC_{adjusted,i}\right)$	=	is the natural logarithm of the adjusted overnight capital cost
$\ln(ReactorSize)$	=	natural logarithm of the reactor size (MWe)
$Dummy_1$	=	equal to 1 if it is a NOAK and 0 if it is a FOAK
$Dummy_2$	=	equal to 1 if it is a GenIV reactor and 0 if it is an LWR.

It is important to note that this is a log-log regression, which means that all the variables are in natural logarithmic. In this way, the beta parameters obtained measure how many percentage points the OCC varies when there is a 1% variation in the reactor size.

Additionally, two binary variables were created to control NOAK reactors (Dummy1), and Gen IV reactors (Dummy2). These dummy variables were found to be non-statistically significant, relatively. Despite this, it was still decided to adjust data for the NOAK and FOAK proportions because this is intuitively expected to have an impact on the costs. Table 21 shows the results when all the variables are included (Model 1) and when only the reactor size is included (Model 2).

Table 21. Regression-analysis results.

Dependent Variable: ln (Overnight Capital Costs)				
	Model 1		Model 2	
	Coefficient	p-value	Coefficient	p-value
Intercept	9.59***	0.000	9.44***	0.000
	(0.48)	—	(0.40)	—
Reactor Size (Logged Variable)	-0.11	0.136	-0.11	0.11
	(0.07)	—	(0.07)	—
Estimate Type (Dummy Variable, NOAK = 1, 0 = otherwise)	-0.22**	0.056	—	—
	(.11)	—	—	—
Reactor Technology (Dummy Variable, GEN IV = 1, 0 = otherwise)	-0.04	0.782	—	—
	(.14)	—	—	—
R-squared	0.18	—	0.07	—
Adjusted R-squared	0.10	—	0.05	—
Number of observations	35	—	35	—
Standard errors are in parentheses.				
*** significant at 1%; ** significant at 5%; * significant at 10%				

The results show an absence effect of economies of scale, where a bigger production reaches lower costs thanks to learning by doing and better production knowledge. Note that economies of scale in these regressions means increasing the reactor size as opposed to increasing the quantity of rectors produced, which is the pure economies of scale effect as understood by Kaldor (1961, 1968). This can be noted through the Reactor Size coefficient which is not statistically significant. This result goes in line with the previous study from Zimmerman (1982).

Note that the low R-square shows that a small variation in the overnight capital costs is explained by the reactor size; however, this does not mean that the regression model does not fit well. The reasons for this could differ. First, it is vital to note that the data sources used are based not on physical observations but theoretical cost estimations. Second, the OCCs are unpredictable at the very beginning, and they can be more certain at the end of the project, after construction, in other words, *post factum*. At the very beginning, when only the reactor size is known, other factors that are not captured through this equation—such as the regulatory process and design issues—can lead to variations in the OCC. Furthermore, they produce a low R-square.

5.2.2 Weighted-Quartiles Adjustment based on Maturity

By dividing the data into quartiles, four equal parts (called quantiles) are obtained. The method to build quartiles is through arranging the data in ascending order to obtain the three primary quartiles. The first quartile (Q1) or lower quartile (that means that the 25% of the data lies below it) is identified as the midpoint between the smallest number (minimum) and the value that falls between the 25th and 75th percentiles of the sample, which means that the data set is divided into its initial quarter. Additionally, the second quartile (Q2) corresponds to the median of the data set, signaling the point where 50% of the data resides below it. Finally, the third quartile (Q3) stands as the middle value between the one that separates the last quarter of samples and the highest value (maximum) in the data set–known as the upper quartile—where 75% of the data lies below this point. The decision to use a range between first and third quartiles instead of picking a single value was deliberate. When analyzing a variety of data points with different levels of fidelity, estimation, and methodology, it becomes pertinent to avoid deterministic statements that peg expected costs to a single value. In this case, the Q1-Q3 range helps to describe the distribution of the middle 50% of the analyzed data and therefore provides an estimation of cost in the "middle" of potential outcomes. It also avoids over emphasizing minimum or maximum values that may be tied to specific edge cases (such as projects impacted by significant regulatory or other delays). It is important to re-emphasize that the quartile values should not be interpreted as project-specific costs, but rather the expected range of anticipated costs for energy planning modeling purposes. Care must be taken to select a specific value within the data set and include additional specific expenses (or subtract unapplicable expenses) as appropriate.

When the data are separated by design maturity, a clear difference is seen in ranges between FOAK and NOAK estimates, as shown in Figure 14. Specifically, the median of the NOAK estimates is ~34% less than the FOAK estimates. This is to be expected; the maturing and experience associated with NOAK builds is meant to drive the cost down.

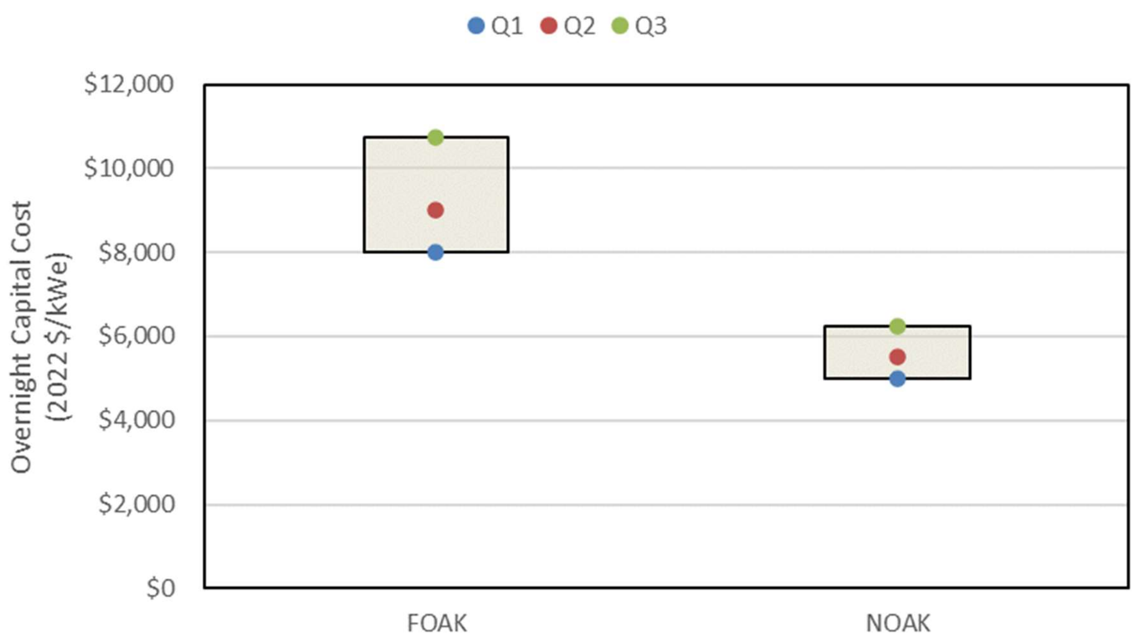

Figure 14. Quartiles ranges (weighted) for estimate types.

When using data that have both FOAK and NOAK estimates, a bias can therefore be introduced if there is an imbalance between the number of NOAK or FOAK estimates within a given data set. For example, in the large-reactor data set, there were only 2 FOAK estimates while there were 7 NOAK estimates. Even though this parameter was not found to be statically significant in previous sections, this imbalance can lead to the calculated BOAK quartile range leaning more heavily toward NOAK values; therefore, it must be corrected with weighting. This imbalance is different depending on how data are grouped; therefore, they must be handled on a case-by-case basis.

After the data are ordered to correct the bias of data imbalances, such as the 7:2 NOAK to FOAK ratio in the large-reactor data set, FOAK estimates must be weighted more when determining the quartile range. To do so within the quartiles, the method of weighted percentiles was used. This method is characterized by considering the percentage contribution to the total weight, rather than the total count. It is critical to note that there is no universally recognized function for a weighted percentile, but a common way to perform it is described below. Note that the following equations apply for a given data set that has been ordered in an ascending way.

$$TotalDatasetWeight = \sum_{n}^{N} X_n \tag{4}$$

where

X = represents the weight of a given datapoint n

N = total number of data points in each data set.

From Equation 4, the following can be performed to calculate a given quartile weight.

$$QuartileWeight_y = TotalDatsetWeight * y \tag{5}$$

where

y = represents a given quartile (Q1=25%, Q2=50%, Q3=75%, Q4=100%.)

The quartile weight is then matched to the OCC value associated with that cumulative weight. If no specific OCC value has the cumulative weight, an interpolation is done to determine what the weight could be between the two closest values.

To correct the bias described above one must assign more weight to FOAK estimates than NOAK estimates as there are more NOAK reactors in the data set. This approach requires the weights to change depending on how data are grouped and the respective amount of NOAK and FOAK estimates in each data grouping. The weight for a given FOAK estimate is therefore equal to the number of NOAK estimates in that grouping, and vice versa. This results in an equal cumulative weighting between both groupings[c]. The results of applying this method are shown below in Table 22. In the case of large reactors and the overall data set, because there were fewer FOAK than NOAK estimates, this weighted method resulted in the quartile range increasing. Note that in the case of SMR grouping, the amount of FOAK and NOAK estimates were equal; therefore, the weighted method yielded the same results as the unweighted method.

Table 22. Weighted verses unweighted quartiles, by different groupings.

Unweighted Values			
	Overall	Large Reactor	Small Modular
Q1	$5,000	$4,750	$5,250
Q2	$5,750	$5,500	$6,250
Q3	$8,250	$6,750	$8,750
Weighted Values			
Q1	$5,500	$5,250	$5,500
Q2	$7,250	$5,750	$8,000
Q3	$9,000	$7,750	$10,000

[c] For example, as mentioned previously, in the Large Reactor data set there were two FOAK and seven NOAK estimates. Thus, the value of the weight for the FOAK estimates would be seven while the value of the NOAK estimates would be two.

Because the quartile values take an aggregate of both FOAK and NOAK data, it seems fitting to label the values as BOAK. The different quartiles can be interpreted as follows in terms of costs:

- Q1: This value is mapped to the 'advanced' scenario under ATB definitions. This quartile corresponds to data points with very little cost overruns. In other words, this quartile is closest to a very well-executed BOAK. This could occur if lessons learned from a previous demonstration are well internalized or if substantial government investment is made in de-risking the technology before execution, ensuring cost overruns are avoided.
- Q2: This value is mapped to the 'moderate' scenario. The quartile corresponds to data points that are firmly between the range of data set estimates compiled. In a sense, this is the baseline scenario that is most likely. Significant overruns and inefficiencies do still occur here but are not as pronounced as in Q3.
- Q3: This value is mapped to the 'conservative' scenario. The quartile corresponds to datapoints with substantial cost overruns. As such, very limited learning has been accrued between the first demonstration and this BOAK estimate. It can be inferred here that many of the challenges faced with the FOAK have still not been resolved before building the next commercial offering.

5.2.3 Reactor Size and Type Considerations

The data were then divided into reactor size, where reactors up to 400 MWe were classified as SMRs, and anything above 400 MWe was classified as a large reactor. Figure 15 shows that SMRs have a much-wider quartile range than large reactors, but lower quartiles are relatively close. This is expected to be a function of two effects: First, the data set contained relatively fewer large-reactor data points. Therefore, they may not capture as much price volatility as the SMR data set. Large reactor data sets were particularly sparse in terms of FOAK estimates. Second, the SMR data contained more higher-priced estimates, most likely associated with the uncertainty behind the cost of SMRs since no SMRs have been deployed commercially, so only paper estimates are available whereas larger reactors have actual cost figures. Furthermore, SMR data sets are primarily non-LWR which also have higher uncertainty associated with them but have other benefits (e.g., new industrial applications or ability to recycle spent fuel). It should also be noted that all these data sets are estimated by different people/organizations and may have different levels of rigor in the evaluations which can lead to higher estimates and larger ranges. As a result, it is likely that as the quantity of data increases, these ranges will continue to be refined.

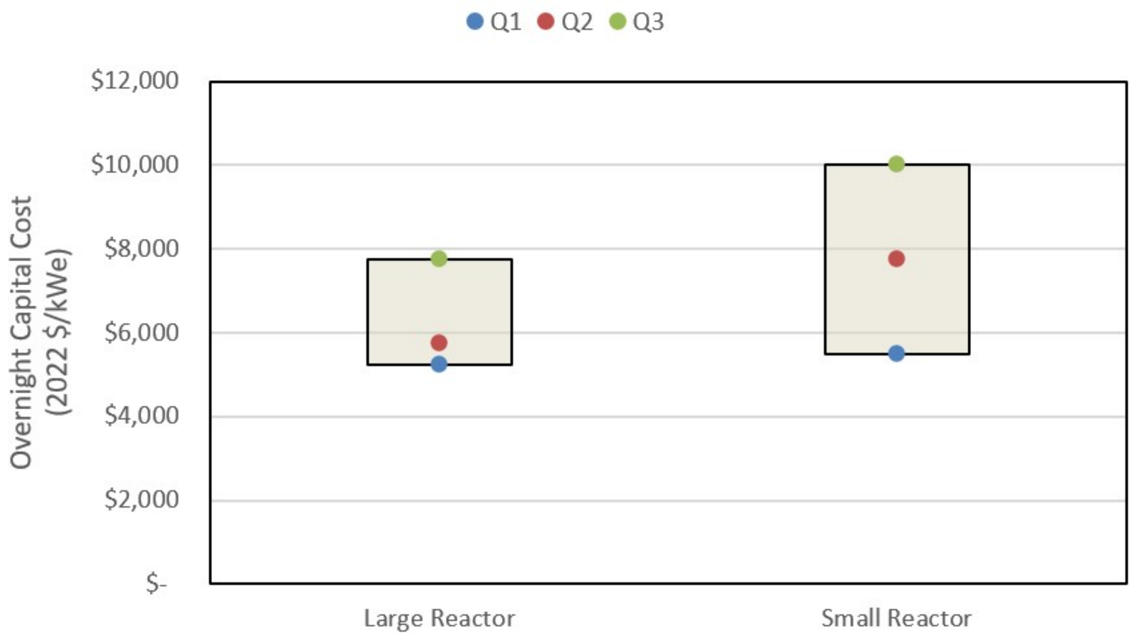

Figure 15. Quartiles ranges (weighted) for reactor size. Note SMR data did not require weighting.

Upon further inspection, the difference between the two reactor types appears minimal for Q1 and roughly ~25% for Q2 and Q3 as shown in. These economies of scale for OCC in large reactors are in-line with observations from the literature (Stewart and Shirvan 2022). Caution should be used to avoid inferring that SMRs are less competitive than large reactors. If the expected construction time (Section 5.3.1) and financing costs are factored (see Section 8.4), then the resulting differences are lower as shown in Table 23. Furthermore, SMRs are expected to have lower risks of cost overruns by virtue of smaller plant sizes and will require less capital to build. Lastly, Section 7 will highlight how faster learning rates for SMRs can provide a significant advantage over their larger counterparts. Overall, this study does not attempt to draw conclusion about inferred cost differences between the two reactor classes. Rather the intent was to simply follow a systematic methodology and leverage available data to project cost ranges for the two cases for energy-planning purposes.

Table 23. Percentage difference between the large and small modular reactor quartile without and with the financing impact during construction (assuming a 7.5% discount rate).

	OCC Difference	Difference accounting for financing during construction
Q1	-5%	1%
Q2	-28%	-22%
Q3	-23%	-8%

When data sets were grouped based on reactor technology type, it quickly became apparent that grouping at the lowest level, between HTGR, SFR, MSR, etc. was not feasible due to insufficient data for some reactor classes (e.g., 1 estimate obtained for FHR or MSR). Even larger groupings were considered based on LWR or GenIV designations as shown in Figure 16, but based on the regression analysis shown previously, the differences between Gen IV and LWR groupings are not statistically significant. LWR data had a much-tighter quartile range while the Gen IV data spanned a larger range. Upon further inspection, it was determined that much of this was a function of the data in the various data sets. Because of the high degree of uncertainty and lack of consistency within each reactor type grouping, no significant conclusions can be drawn from this comparison from the compiled sources.

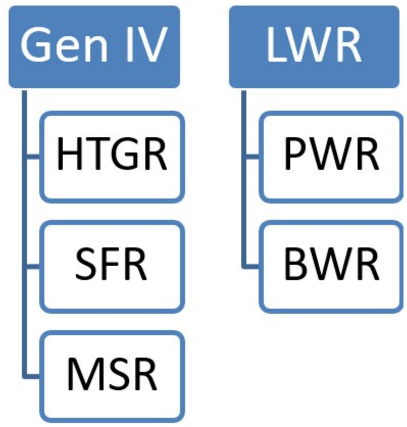

Figure 16. Reactor-technology groupings and subgroupings.

5.2.4 Multiunit Plant Impact on OCC

Hosting several reactor plants at the same site is a well-known approach for reducing the costs of nuclear reactors. Most existing plants in the US host more than one reactor. Cohosting several plants in the same location enables synergies both on the capital and the operational side. This section discusses the impact from a capital-cost perspective.

In general, multiunit plants can pool several resources together to achieve synergies and cut costs. For instance, the PRISM power module has one single turbine, fed steam from more than one reactor (Triplette et al. 2010). Other concepts, such as NuScale, use the same overall concrete structure for four, six, or twelve of their reactor modules (NuScale 2021). However, even in more-separated arrangements, where structures and turbomachinery are not shared, co-locating reactors can bring cost savings. For instance, land rights and permits can be split between the number of reactors, auxiliary buildings (for storage of equipment, administrative functions, etc.) and control building can be pooled among several units as well. This leads to notable cost savings among plants. This phenomenon is observed in the evaluated data in this report. As can be seen in Figure 17, the average normalized costs for multiunit plants are about ~10% cheaper than their single-unit counterparts. The upper and lower quartile overlap substantially due to the noise in the data and the inconsistent set of assumptions in each data set (for instance, many multiunit plant costs correspond to FOAKs, which have higher cost ranges).

Figure 17. Variation in OCC between multiunit and single-unit nuclear power plant in the data set analyzed.

Looking more closely at several consistent data sets that compare single-unit plant costs to multiunit ones, the trend can be more clearly visualized. Table 24 summarizes the evolution in costs from several sources, with the values normalized to the single-unit plant variant. On average, a two-unit plant could result in ~10% cost savings relative to a single-unit plant whereas a four-unit plant could achieve savings of the order of ~20%. This is, of course, design dependent, with some pooling more infrastructure than others, as previously explained. Nevertheless, this provides a useful reference for readers considering large-scale deployment regarding the benefits of co-locating power plants. It is also important to note that the concept of a 'unit' may, in fact, be nuanced in several designs. For instance, some vendors only offer reactors in four- or six-packs. Therefore, in the case of a four-pack concept, multi-unit cost reductions could differ within the pack and between the first four-pack and the second. For simplicity in the analysis, it is recommended to apply the cost reductions below by treating each multi-unit pack as a single unit.

Table 24. Normalized costs of multiunit plants against single-unit variants.

Number of units	VHTR, NOAK, 281 MWe (INL 2010)	VHTR, FOAK, 281 MWe (INL 2010)	VHTR, NOAK, 164 MWe (INL 2010)	VHTR, FOAK, 164 MWe (INL 2010)	PRISM, BOAK, 311MWe (Prosser 2023)	MIGHTR (Stewart et al. 2020)	**Average**
1	1.0	1.0	1.0	1.0	1.0	1.0	**Ref.**
2	–	–	–	–	0.9	–	**0.9**
4	0.8	0.9	0.8	0.8	0.8	0.6	**0.8**
8		–	–	–	0.7	–	**0.7**
10	–	–	–	–	0.7	–	**0.7**

5.3 Non-Cost Considerations

5.3.1 Construction Time

Construction timelines affect the overall cost of a project because longer durations increase financial burdens on the project. The construction timelines of nuclear power plants vary greatly depending on the type of reactor, system complexity, as well as how modular the construction is and the amount of onsite fabrication. Other external factors, such as political decisions, load growth, and the economic conditions of a country or operator, can also affect the construction timeline. This work will rely on observed data to assess realistic timelines for large reactors. Limited information exists about SMR construction because they have never been built before. As a result, the study estimated construction durations from sources in the literature that evaluated SMR construction timelines in a detailed fashion, as well as projection from utility resource-planning projections.

5.3.1.1 Large-reactor Timeline

The US has built many large reactors, and construction timelines were well documented. It needs to be noted that many factors influenced the large buildout of the current nuclear capacity. The data from historical construction includes durations that were likely affected by changing regulations as well as a changing political climate and electricity and energy markets.

A histogram of the LWR builds in the United States throughout history is captured in Figure 18. Following previous sections, quartiles from the data were extracted and summarized in Table 25. As shown in the table, the median is 82 months for construction of large LWRs.

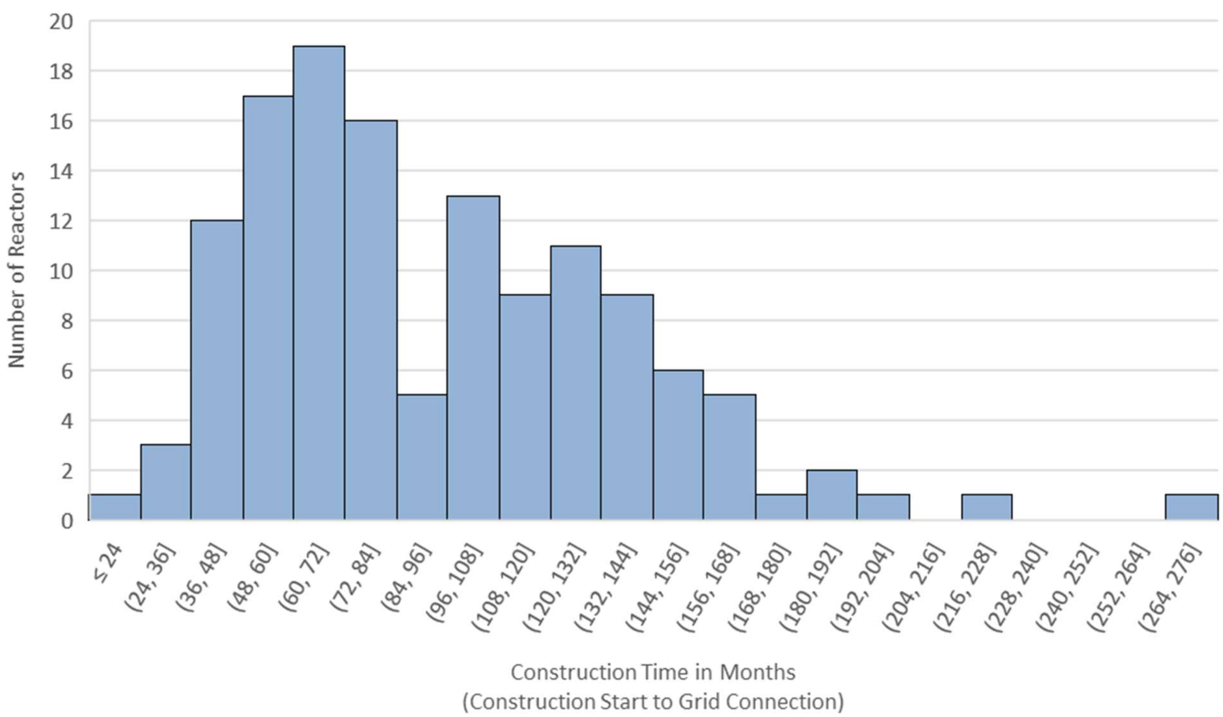

Figure 18. Construction duration (months) for US reactors. Taken from PRIS database (IAEA 2023b).

Table 25. US large-reactor construction-duration quartiles. Calculated from PRIS data (IAEA 2023b).

Quartile	Values (Months)
Q1	60
Q2	82
Q3	125

5.3.1.2 Small-Modular-Reactors Timeline

Utilities considering SMRs have looked at reactor-deployment timelines. Duke Energy recently updated their Carolina resource plan and is projecting buildout of nuclear energy starting in the 2030s (Duke Energy 2023). In that resource plan, the projected construction duration for an SMR is between 36 and 48 months. Ontario Power Generation (OPG) is under contract to build the first SMR in North America, and in their license application, they also have a 36–48-month construction timeline (OPG 2022).

Separately, studies have developed detailed bottom-up models of SMR construction timelines and conducted sensitivity analysis to evaluate potential construction ranges (Stewart and Shirvan 2023). Figure 19 showcase the statistical distributions of those models for different labor conditions where the quantity of labor was plentiful (upper bound) and one where the quantity of labor growth is constrained for the project (lower bound). In each scenario there is a difference in the reference, median, and 97.5% construction duration. Note that the values in the paper are just for the construction and do not include the timeframe it takes to get to commercial operations (testing before putting power on the grid), so a timeframe of 10 months was added to account for that portion of the schedule. The Stewart and Shirvan (2023) study durations were broken up into quartiles to determine the distribution of construction times for use in this work. Table 26 summarizes the ranges observed. The Q1 and Q2 values line up reasonably well with the utility resource plans' values. It would be expected that a utility plan probably does not line up with the Q3 value because that would reflect a project that was not well executed.

Table 26. SMR quartiles from considered data sets.

Quartile	Values (Months)
Q1	43
Q2	55
Q3	71

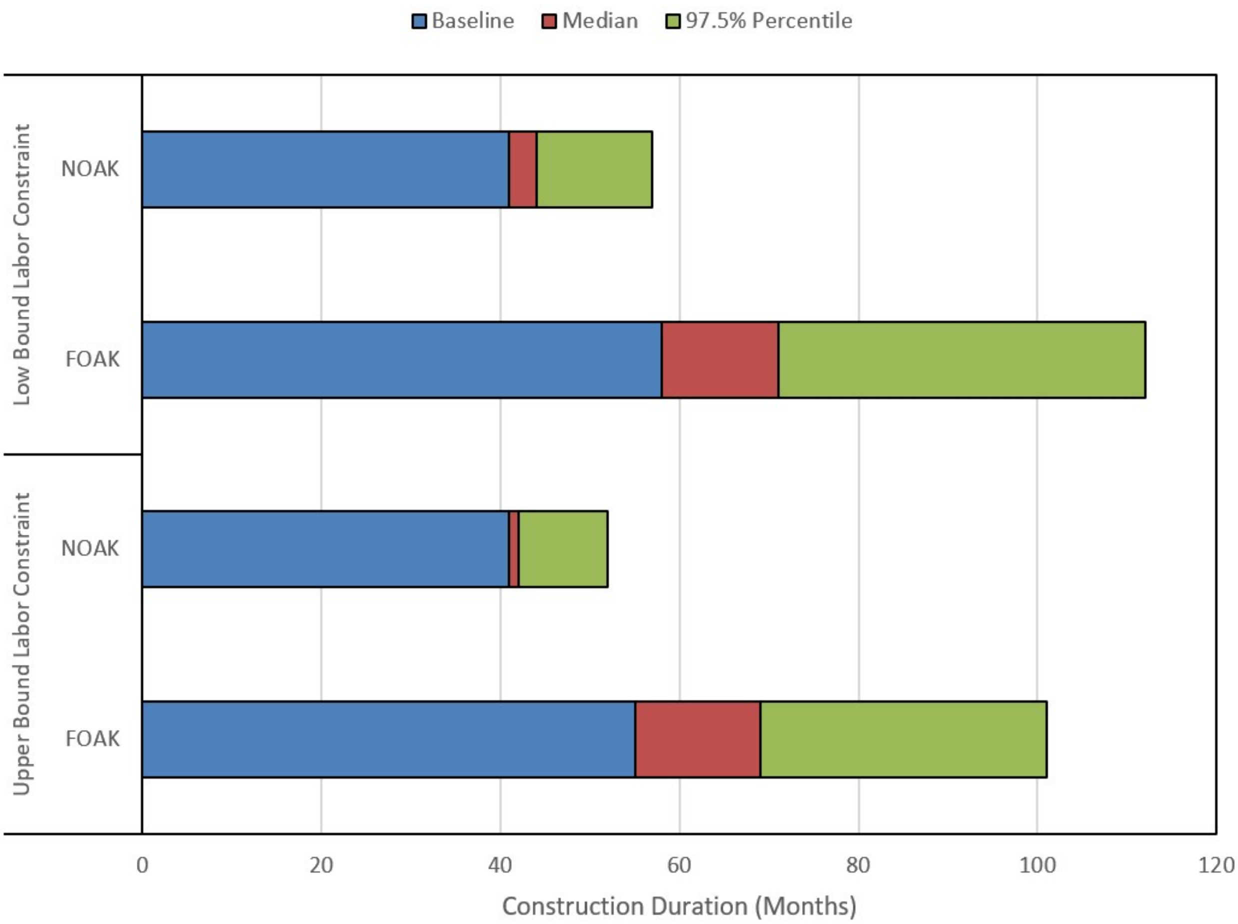

Figure 19. Construction duration for reference SMR. (Stewart and Shirvan 2023).

5.3.1.3 Spending Curve

As discussed, nuclear-plant construction does take some time, and the cost of the technology is affected by the money spent over time. For short construction periods or limited construction times, an assumption that all capital is spent up front may not affect the total cost; however, for a longer-build timeline, the spend curve will affect the interest that is accumulated on debt. For calculations on total cost (like levelized cost of electricity [LCOE]), a sinusoidal spending curve is assumed. This sinusoidal curve matches well with the manpower assumptions required during the large construction projects (IAEA 1980) and provides a reasonable estimate of capital cost spent versus time. An example of a sinusoidal curve used for the calculation of spend vs. time is shown in Figure 20.

Figure 20. Example construction spend curve.

5.3.2 Reactor Lifetime

Technically, nuclear reactors can operate for many years. However, because nuclear reactors are licensed by the NRC, there are some durations that are fixed for licensing nuclear technologies. The NRC can issue an initial license for up to 40 years. After the initial license period, follow on license renewals can be obtained in 20-year increments (NRC 2024). Many of today's LWRs already have licenses that will keep them operating for 60-year lifetimes and others are applying for operations for 80 years with a potential for operation beyond in the future (DOE 2020). For the technologies here, the technical life is considered 60 years, but there is potential for longer operations in the future.

5.3.3 Capacity Factor

Capacity factor is an important metric for energy modeling because it describes, on average, how available an energy resource is to the grid. The current LWR fleet of reactors in the US operates at a very high-capacity factor, an average of 92.7% (EIA 2020). The American Nuclear Society (ANS) also tracks the US capacity factors and noted that between 2020 and 2022, they show a median capacity factor of 91.13% (ANS 2023). The ARIS database tracks all nuclear reactors over the world, and a histogram of the capacity factors in Figure 21 shows a very large number of reactors over the 90% level (IAEA 2023).

Note that most of these data are centered on the current LWRs in operation. These reactors operate on standard 18- or 24-month fuel cycles. The advanced reactors that will be deployed include both LWR technology as well as non-LWR technologies. For LWR technologies it is reasonable to assume that they will continue to operate at or near the same capacity factors as current LWR technologies. Other non-LWR technologies do have a risk that they may not operate at high-capacity factors early in their deployments. It should be noted that many advanced reactors (non-LWRs) under consideration are looking at longer fuel cycles where many of these plants could operate longer without refueling, and this could push capacity factors up higher, to the range of 95%. It may also be likely that many nuclear utilities will first deploy LWR technology given the similarity to currently operating reactors which means non-LWR technologies could be deployed later (maybe late 2030s). Given the variety of designs and the potential deployment timelines, the current US average of 0.93 is selected as a reasonable capacity factor for use in modeling efforts.

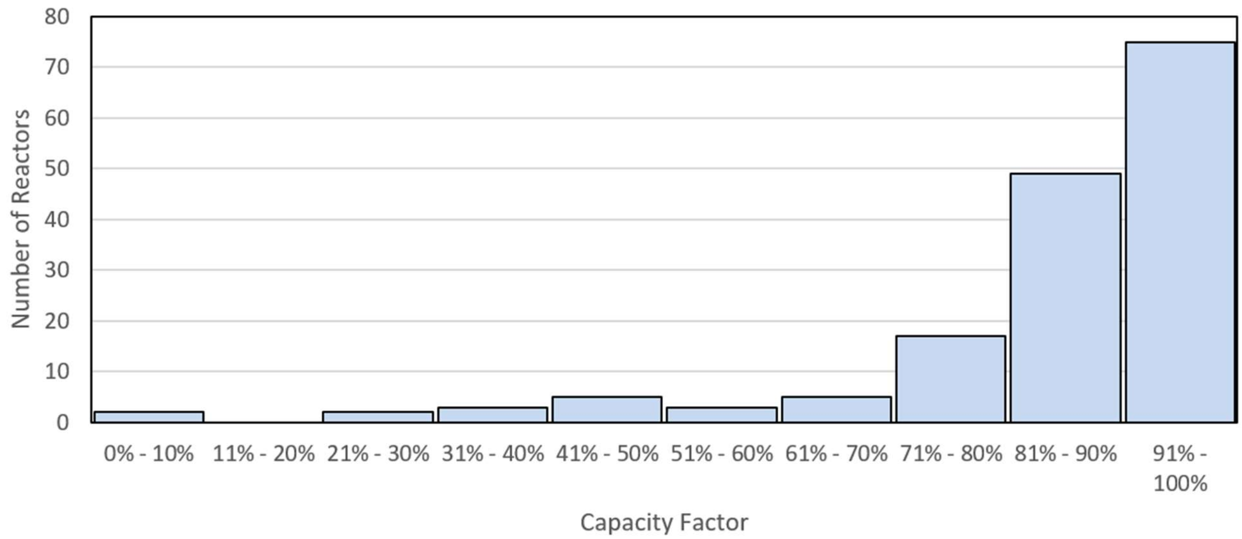

Figure 21. Worldwide nuclear capacity-factor distribution. Taken from PRIS database (IAEA 2023b).

5.3.4 Ramp Rate

The current nuclear reactors in the US are large nuclear reactors that mainly operate as baseload units in the current environment, with limited daily power ramping; however, there are not necessarily any inherent technological limitations with ramping existing reactor powers within an established range. Many of the advanced reactors are designed to more-effectively ramp their power to support a grid with increased variable power generation and thus have faster ramp rates than current LWRs. It should be noted that nuclear reactors are capable of other power changes to deal with frequency or emergency operations, so this is just a review of the load following capabilities of nuclear reactors. One area being considered by at least one reactor developer is to combine the reactor with a thermal energy storage system which would allow for certain advantages as explained later.

Table 27. Electricity ramp rates for various nuclear-reactor designs.

Developer	Reactor	Unit Capacity (MWe)	Ramp Rate (%power/min)	Notes	Reference
X-energy	Xe-100	80	5%	Rate per module, typically deployed for plant capacity of 320 MWe	X-energy 2023
GEH	BWRX-300	300	1%	Typical ramp rate. Higher rate possible by steam dumping.	GE Hitachi 2023

Developer	Reactor	Unit Capacity (MWe)	Ramp Rate (%power/min)	Notes	Reference
NuScale	VOYGR SMR	77	10%	Rate obtained by using turbine bypass and is per module.	ANS 2023
Terrestrial	IMSR	195	10%	Rate per module, typically deployed for plant capacity of 390 MWe	Terrestrial Energy USA 2020
TerraPower	Natrium	345	12%	Rate obtained using molten salt storage system	PacifiCorp 2023
Westinghouse	AP1000	1110	5%	–	Westinghouse 2023

Each reactor technology will be capable of different ramping based on the reactor or module size, as well as the reactor technology and whether it is combined with a thermal-energy storage capability. Table 27 contains ramp rates that are normalized to the reactor size and reported by reactor developers. These ramp rates are applicable both to increasing and decreasing the electric power for the unit. For energy-modeling flexibility, an upper-end ramp rate of 10% power/min is used for the SMR case as shown in Table 28. For larger units, like an AP1000, a ramp rate of 5% power/min is used.

Table 28. Reference ramp-rate values used for large and small modular reactors.

Reactor Type	Ramp Rate (% power/min)
Large Reactors	5%
SMRs	10%

The Natrium Reactor, being developed by TerraPower, is being combined with a molten-salt storage system. This combination allows for faster ramping of the power output as the reactor does not need to ramp or change power levels to support the change in power generation thus supporting a high-capacity factor and better operating economics. The molten-salt storage system ramps to help adapt to changing power demand. As shown in Table 27, the molten-salt storage system is capable of ramping at 12% power/min which is larger than the SMR rate of 10% power/min.

5.4 Resulting Groupings

This section summarizes the key cost parameters relating to OCCs in their respective groupings. These values are centered on US groupings; to project these costs to other countries, the methodology proposed in Larsen (2024) is recommended to be followed. The reader is also reminded that these cost ranges are for a BOAK which can be taken to represent the next commercial offering. Based on the current timeline for advanced-reactor demonstrations in the US—the end of the decade for the two DOE-sponsored demonstrations (X-energy 2023b) (Natrium 2023)—these costs can be considered valid from 2030 onwards. For the use of energy modeling, the nominal power levels (MWe) were chosen. For the large reactor, a 1,000 MWe power level was chosen, which lines up reasonably with large reactors that are commercially available and would be considered for large -reactor deployments. For the SMR, a value of 300 MWe was chosen which lines up with the traditional definition of an SMR and fits well with the plants that are being considered for commercial deployments. The actual MWe values of different reactor designs might vary a bit, but for modeling or planning purposes, these values should be sufficient.

5.4.1 Large Reactor

Table 29 contains the range of capital cost as well as the various construction, capacity factor, and ramp rates for a large reactor. As noted earlier, some economies of scale favor the large reactor on a capital basis. However, none of these values include the financing cost, which will add to the total cost because it will consider the construction time, which increases total project cost.

Table 29. Summary of reference values for large-reactor costs.

	Advanced	Moderate	Conservative
Reference output power (MWe)	1,000	1,000	1,000
Overnight CAPEX (w/o financing, w/ preconstruction costs, initial fuel load, etc.)	5,250	5,750	7,750
Capacity Factor (%)	0.93	0.93	0.93
Construction duration (months)	60	82	125
Ramp rate (% power/min)	5%	5%	5%

A more-detailed breakdown of cost fractions is provided in Table 30. The fraction was estimated by averaging all contributions from accounts across all large reactors in the data set. The table provides a more granular overview of the cost drivers in large systems. Unsurprisingly, Account 22 (reactor systems) is the highest contributor, closely followed by Account 23 (energy-conversion system).

Table 30. Breakdown of large-reactor cost contributors by L1 and L2 accounts.

Account	Fraction	Advanced ($/kWe)	Moderate ($/kWe)	Conservative ($/kWe)
10: Capitalized Pre-Construction Costs	**6.76%**	**$372**	**$524**	**$676**
11: Land and Land Rights	0.05%	$3	$4	$5
12: Site Permits	0.35%	$19	$27	$35
13: Plant Licensing	3.34%	$184	$259	$334
14: Plant Permits	0.36%	$20	$28	$36
15: Plant Studies	0.51%	$28	$40	$51
16: Plant Reports	0.25%	$14	$19	$25
17: Community Outreach and Education	0.00%	$0	$0	$0
18: Other Pre-Construction Costs	1.12%	$62	$87	$112
19: Contingency on Pre-Construction Costs	0.77%	$42	$60	$77
20: Capitalized Direct Costs	**63.07%**	**$3,469**	**$4,888**	**$6,307**
21: Structures and Improvements	15.56%	$856	$1,206	$1,556
22: Reactor System	12.74%	$701	$987	$1,274
23: Energy Conversion System	3.78%	$208	$293	$378
24: Electrical Equipment	6.09%	$335	$472	$609
25: Initial Fuel Inventory	2.17%	$119	$168	$217
26: Miscellaneous Equipment	2.17%	$119	$168	$217
27: Material Requiring Special Consideration	5.95%	$327	$461	$595
28: Simulator	0.00%	$0	$0	$0
29: Contingency on Direct Costs	14.61%	$803	$1,132	$1,461
30: Capitalized Indirect Services Cost	**20.67%**	**$1,137**	**$1,602**	**$2,067**
31: Factory & Field Indirect Costs	7.10%	$390	$550	$710
32: Factory & Construction Supervision	5.07%	$279	$393	$507

Account	Fraction	Advanced ($/kWe)	Moderate ($/kWe)	Conservative ($/kWe)
33: Startup Costs	0.41%	$23	$32	$41
34: Shipping and Transportation Costs	0.00%	$0	$0	$0
35: Engineering Services	7.20%	$396	$558	$720
36: PM/CM Services	0.89%	$49	$69	$89
39: Contingency on Indirect Services Cost	0.00%	$0	$0	$0
50: Capitalized Supplementary Costs	**5.71%**	**$314**	**$443**	**$571**
51: Taxes	0.00%	$0	$0	$0
52: Insurance	0.00%	$0	$0	$0
53: Spent Fuel Storage	0.00%	$0	$0	$0
54: Decommissioning	0.16%	$9	$13	$16
55: Other Owners' Costs	0.00%	$0	$0	$0
56: Fees	0.00%	$0	$0	$0
57: Management Reserve	0.00%	$0	$0	$0
59: Supplementary Contingencies	4.05%	$222	$313	$405

5.4.2 Small Modular Reactor

Table 31 contains the range of capital costs, as well as the various construction, capacity factor, and ramp rates for the SMR. Compared to a large reactor, the normalized capital cost of an SMR is a bit higher on a MWe basis. However, the shorter construction timeline for an SMR will normalize project costs and bring costs closer in line between the large and small reactor. A LCOE comparison is performed in a later section that shows the comparison for 2030 numbers.

Table 31. Summary of reference values for SMR costs.

	Conservative	Moderate	Advanced
Reference output power (MWe)	300	300	300
Overnight CAPEX (w/o financing, w/ preconstruction costs, initial fuel load, etc.)	5,500	7,750	10,000
Capacity Factor (%)	0.93	0.93	0.93
Construction duration (months)	43	55	71
Ramp rate (% power/min)	10%	10%	10%

Again, a more detailed breakdown of cost fractions is provided in Table 32. Similar to large reactors, the biggest two contributors are the reactor and the energy-conversion systems. Overall, similar trends are observed between large reactors and SMRs. These will be discussed in further detail in the next subsection.

Table 32. Breakdown of SMR cost contributors by L1 and L2 accounts.

Account	Fraction	Advanced ($/kWe)	Moderate ($/kWe)	Conservative ($/kWe)
10: Capitalized Pre-Construction Costs	**4.89%**	**$269**	**$391**	**$489**

Account	Fraction	Advanced ($/kWe)	Moderate ($/kWe)	Conservative ($/kWe)
11: Land and Land Rights	0.20%	$11	$16	$20
12: Site Permits	0.11%	$6	$9	$11
13: Plant Licensing	2.35%	$129	$188	$235
14: Plant Permits	0.27%	$15	$22	$27
15: Plant Studies	0.39%	$21	$31	$39
16: Plant Reports	0.20%	$11	$16	$20
17: Community Outreach and Education	0.00%	$0	$0	$0
18: Other Pre-Construction Costs	0.78%	$43	$62	$78
19: Contingency on Pre-Construction Costs	0.59%	$33	$47	$59
20: Capitalized Direct Costs	**62.15%**	**$3,418**	**$4,972**	**$6,215**
21: Structures and Improvements	19.23%	$1,058	$1,539	$1,923
22: Reactor System	13.93%	$766	$1,114	$1,393
23: Energy Conversion System	3.71%	$204	$297	$371
24: Electrical Equipment	9.10%	$500	$728	$910
25: Initial Fuel Inventory	2.88%	$159	$231	$288
26: Miscellaneous Equipment	2.88%	$159	$231	$288
27: Material Requiring Special Consideration	0.00%	$0	$0	$0
28: Simulator	0.00%	$0	$0	$0
29: Contingency on Direct Costs	10.41%	$573	$833	$1,041
30: Capitalized Indirect Services Cost	**25.01%**	**$1,376**	**$2,001**	**$2,501**
31: Factory & Field Indirect Costs	7.63%	$419	$610	$763
32: Factory & Construction Supervision	2.91%	$160	$233	$291
33: Startup Costs	0.75%	$41	$60	$75

Account	Fraction	Advanced ($/kWe)	Moderate ($/kWe)	Conservative ($/kWe)
34: Shipping and Transportation Costs	0.72%	$39	$57	$72
35: Engineering Services	3.87%	$213	$310	$387
36: PM/CM Services	2.85%	$157	$228	$285
39: Contingency on Indirect Services Cost	6.29%	$346	$503	$629
50: Capitalized Supplementary Costs	**4.37%**	**$240**	**$349**	**$437**
51: Taxes	0.00%	$0	$0	$0
52: Insurance	0.00%	$0	$0	$0
53: Spent Fuel Storage	0.00%	$0	$0	$0
54: Decommissioning	0.45%	$25	$36	$45
55: Other Owners' Costs	0.00%	$0	$0	$0
56: Fees	0.00%	$0	$0	$0
57: Management Reserve	0.00%	$0	$0	$0
59: Supplementary Contingencies	4.37%	$240	$349	$437

5.4.3 Comparison of Cost Components

The Level 1 breakdown of large reactor and SMRs is plotted in Figure 22. Slight variations are observed, with the direct-cost fraction being slightly smaller in the case of SMRs. Nevertheless, little variation can be detected between the two reactor types in this high-level assessment.

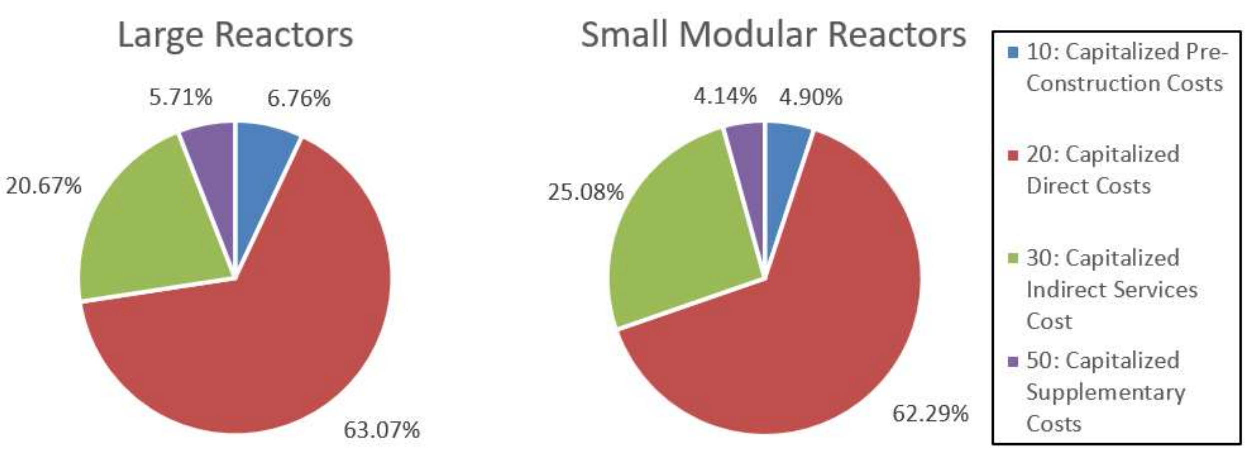

Figure 22. Comparison of the average L1 cost breakdown fraction in the SMRs and large reactors in the data set considered.

Looking more closely at Level 2 contributions in Figure 23, larger variations can be observed between reactor types. While still substantial, the contribution of structure-related costs (Account 21) is smaller for SMR than the reactor-system contribution (Account 22). This is expected because SMRs shift activities from the site to the factory where most of the reactor parts are fabricated and assembled. Constructions are generally smaller and less complex overall since many features can be internalized within fabricated modules (e.g., the containment structure in the NuScale design is integrated within the metallic power module). Similarly, indirect costs associated with site supervision are also comparatively lower for SMRs than their larger counterparts. Some additional variations can be seen in other accounts, but this is primarily attributed to variations within different estimations.

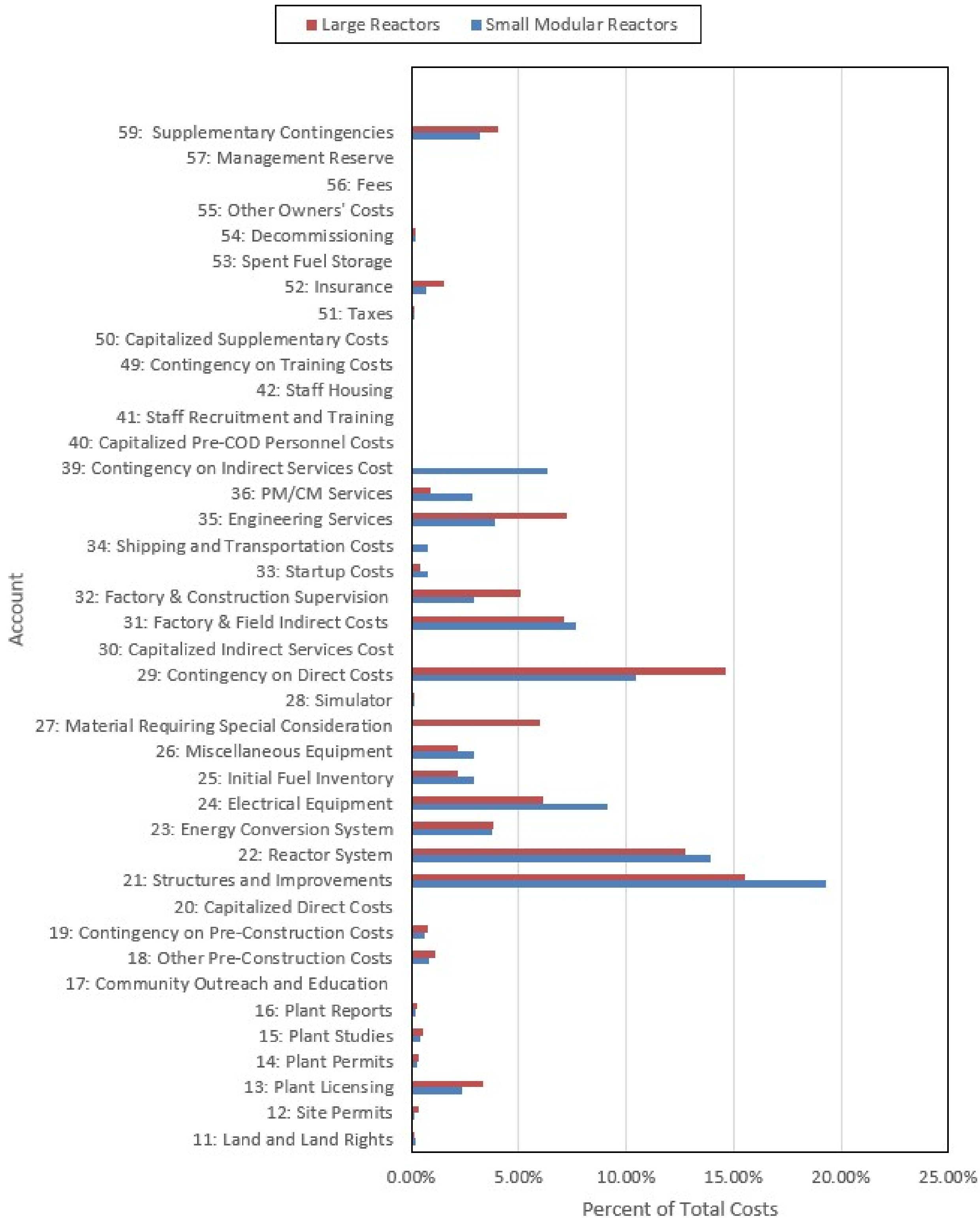

Figure 23. Comparison of Level 2 costs between the large and small modular reactors.

5.4.4 Overruns and Contingency Costs

Construction projects forecast contingency costs which represent the unforeseen challenges or problems that may arise during the construction process. These costs are typically included in the initial budget to decrease the financial risks associated with such uncertainties. Contingency costs serve as a partial warranty against budget overruns and delays by providing a financial buffer, as a portion of total costs, to attend any unexpected issues encountered during construction.

This section shows reactor costs without these planned potential issues, and furthermore it excludes contingency costs from the OCC for transparency reasons. Given this, stakeholders can gain a clearer understanding of the baseline expenses involved in constructing reactors, without the additional provisions made for potential problems that are subject to a big uncertainty and are difficult to predict.

Figure 24 highlights the contingency excluded OCC values for large reactor and small modular reactors while Table 33 provides additional context for these values by showing a comparison of the continency included and excluded costs. The cost difference between quartiles ranges between $750 to $2,250/kWe and constitutes an average cost difference of 17%.

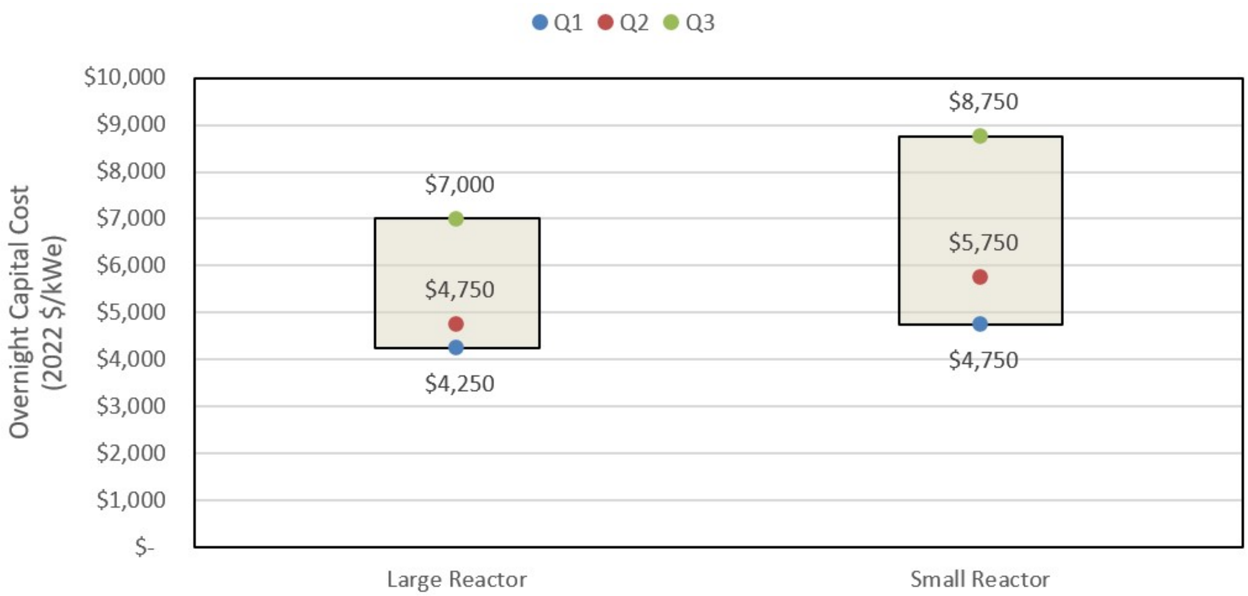

Figure 24. Large reactor and small modular reactor overnight capital costs with contingency removed.

Table 33. Reactor cost groupings with and without contingency costs included.

Contingency Costs Included			
	Overall	Large Reactor	Small Reactor
Q1	$ 5,500	$ 5,250	$ 5,500
Q2	$ 7,250	$ 5,750	$ 8,000
Q3	$ 9,000	$ 7,750	$ 10,000
Contingency Costs Excluded			
	Overall	Large Reactor	Small Reactor
Q1	$ 4,500	$ 4,250	$ 4,750
Q2	$ 5,750	$ 4,750	$ 5,750
Q3	$ 8,000	$ 7,000	$ 8,750

5.4.5 Comparison against Historical Costs

To better ground the resulting cost ranges against reality, the large and small modular reactor cost ranges were super-imposed over the historically observed cost data in the US (escalated to 2022$) in Figure 25 (EIA 1986). The overlap shows that historical costs landed above and below the ranges estimated in this report. It should be noted that anytime historical costs are shown, context should be added on the impacts of the Three Mile Island accident. Here, a distinct grouping is shown in the leftmost side of the distribution. These plants were completed prior to the Three Mile Island accident and their costs reflect that. Costs on the right side of the distribution represent those projects that were completed after, so there were significant impacts in their projects due to shifting regulatory pressures as well as a changing public perception of nuclear energy following the Three Mile Island accident. Overall, it does appear that the cost range developed in this report is within the bounds of historical observation of nuclear power plant costs in the US.

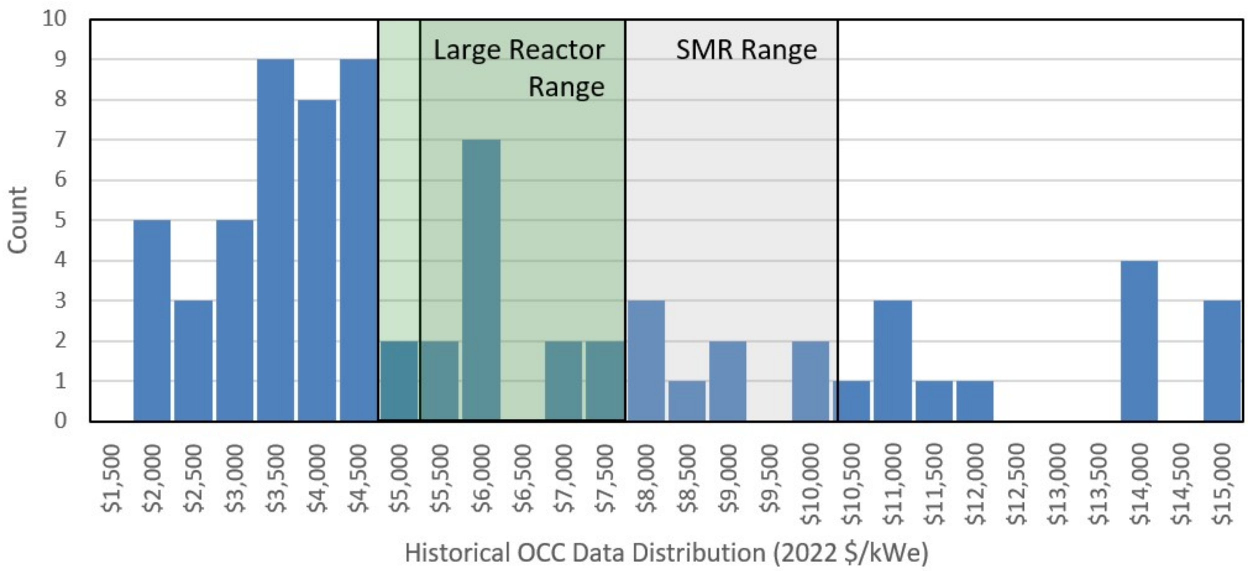

Figure 25. Historical US OCC cost distribution with SMR and large reactor cost ranges overlayed from this study.

6. Operation and Maintenance Costs

The O&M costs for a nuclear power plant are broken into two categories: fuel (refueling costs) and non-fuel O&M costs. Initial fuel costs required for the start of operations are included as capital costs. Estimation of the aggregate fuel and non-fuel O&M costs for existing power plants are publicly available (NEI 2022). These detail the current costs incurred by the power plants and lack some of the back-end costs associated with the disposal of nuclear fuel and some small contributors to the non-fuel O&M cost that would apply to newly deployed reactors with one exception. The future D&D costs must be assured which are modeled as fixed costs paid into a D&D fund. Since many operating reactors have been operating beyond their original 40-year license, the D&D funds are well funded and costs are in many cases less than would be when initially deployed.

For use in different models, it is desirable to have both fixed and variable O&M contributions. The variable O&M representing the marginal cost of producing power and, presumably, the bid price for determining which power plants clear the market. This variable cost is much more challenging than a conventional power plant because of how different nuclear fuels are produced and consumed. Nuclear fuel costs consist of natural uranium, often purchased well in advance, enrichment that occurs with a significant lead time, fabrication costs, and a few other front-end costs that occur from years to months prior to loading the fuel in the reactor. Then fuel is not consumed immediately but typically remains in the reactor for years. Once the nuclear fuel reaches the end of its useful life, then there are significant back-end costs associated with management of the spent nuclear fuel which, for this analysis, is assumed to be direct disposal. Recycling would add some additional complexity and is not considered here. The result is a very different expenditure profile for nuclear fuel than coal or natural gas for example. A more complex relationship exists between the costs incurred and any short-term variations in energy generation. On the day or week of variation in generation, there is going to be no change in the amount of fuel purchased.

For this study, the focus is on existing LWRs that have a refueling interval, typically every 18 months, but in some cases 24. Applying a simple marginal cost to nuclear fuel does not seem likely to accurately represent the marginal cost to the power station. The actual costs the power stations bid their costs are business-proprietary, and a reference was not found for this information. For very short refueling intervals, such as the online refueling of the CANDU reactor or a pebble-bed reactor, this seems like a reasonable approximation. For a very long-lived reactor, such as a reactor designed to operate for a decade or longer between refueling, this would seem to be a poor approximation. For the 18–24-month cycles, this assumption seems likely to overestimate the average bid price, but by how much is far from clear. The common modeling assumption is to treat nuclear fuel costs as purely variable and, at this point, no recommendation is made to change this. However, it would be valuable in studies where the clearing price falls below the combined cost of the variable O&M and the levelized fuel cost to perform parametric studies where the fuel costs are treated as fixed costs. If important differences are observed, more-detailed analysis of how nuclear-fuel costs are treated would be required.

6.1 Fuel-Cost Considerations

As discussed for the initial core load, estimation of the nuclear fuel costs only requires a small set of information about the nuclear reactor, along with estimates of the unit costs for those components that are important contributors to the cost of nuclear fuel. For existing power plants these costs are well known as most of costs are for the front end (i.e., natural uranium, enrichment, UOX fuel fabrication). There is some uncertainty in the back-end costs (i.e., spent-fuel disposal). There are some significant market fluctuations that impact on the front-end costs and that does add a significant amount of uncertainty about what these future costs will be under different scenarios. For example, a rapid expansion of nuclear power to meet net-zero goals would likely put a strong upward pressure on prices as the supply will need to grow to keep up with demand. For new technologies, the cost of those items specific to the technology (e.g., fabrication of TRISO fuel), are large, especially the near-term costs where market development costs may result in very high costs that would decline rapidly as the market grows, technology matures, and development and deployment costs are no longer impacting costs.

The refueling costs involve expenditure over time to purchase the fuel, which is then used over several years. Exact calculations would account for the cost of money and amortization over the life of the fuel, but for fuel cycles of 18–24 months and purchases made typically within about once cycle or fewer before the fuel is placed in the reactor, a simple uniform spending profile without interest is sufficiently accurate to estimate average refueling costs, given the uncertainty in the individual cost components. Calculation of the annual fuel cost is then approximated by the average fuel cost in $/MWh, which is the sum of the cost components (natural uranium, enrichment, fabrication, and so on) per kg HM. This is then divided by the average energy generated annually. The average annual energy generated is determined by nameplate power and average capacity factor.

Table 34 shows the units required for production of the example nuclear fuels. This was done for three reactor types. The first is a representative PWR. The second was for a pebble-bed HTGR with performance expected to be like the X-energy (XE)100 design. The third was for a once-through sodium-cooled fast reactor with performance expected to be like the first commercial Natrium reactors.

Refueling cost:

$$C_{fuel}\left[{}^{\$M}/_{yr}\right] = \frac{\sum Comp_i\left[\frac{units}{kg\ HM}\right] Cost_i\left[\frac{\$}{unit}\right]}{BU\left[\frac{MW_{th}-da}{kg\ HM}\right]\eta\left[\frac{W_e}{W_{th}}\right] 24\left[\frac{hr}{day}\right]} \frac{P[MW_e]\ CF\ 8766\left[\frac{hr}{yr}\right]}{10^6} \tag{7}$$

Table 34. Assumed parameters for example reactors used to estimate refueling costs.

		PWR	HTGR	SFR
Average Burnup	MWd/kg	50	165	147.3
Net Thermal Efficiency	We/Wth	33%	40%	41%
Fuel Requirements	kg U fuel / MWh	0.00250	0.00063	0.00069
Natural Uranium	kg NU / kg U fuel	8.6	33.1	37.7
NU Conversion	kg NU / kg U fuel	8.6	33.1	37.7
Total SWU	SWU / kg U fuel	6.3	31.3	36.2
HALEU SWU	SWU+ / kg U fuel	–	4.0	4.9
HALEU Deconversion	kg HALEU / kg U fuel	–	1.0	1.0
Fuel Fabrication	kg U fuel / kg U fuel	1.0	1.0	1.0
DU Deconversion	kg DU / kg U fuel	7.6	32.1	36.7
DU Disposal	kg DU / kg U fuel	7.6	32.1	36.7
SNF Packaging	kg iHM / kg U fuel	1.0	1.0	1.0
SNF Disposal	kg iHM / kg U fuel	1.0	1.0	1.0

* For fuel enriched above currently available commercial enrichments (~5%), there will be a premium cost on SWUs. This is the quantity of SWU subject to that premium, based on assumptions on the configuration of the enrichment system.

Data on unit costs were taken from the Advanced Fuel Cycle Cost Basis Report (Dixon et al. 2017), which estimates the what-it-takes costs that are representative of large commercial facilities operated relatively efficiently with an upside (lowest cost), downside (highest cost). It then typically assumes a triangular distribution of costs which has a specified mean or mode to define the distribution. Key assumptions for this estimate are that disposal costs are the same across all fuel types in terms of $/kg initial HM. For advanced fuels, this may be a poor assumption. TRISO fuel has a potentially robust fuel form for disposal, but the low density of HM in the fuel (if not separated from the graphite pebbles or blocks) will have a much-higher volume, which could impact cost. The example fast-reactor fuel is for a sodium cooled fast reactor but uses an advanced fuel that is not sodium-bonded. This avoids the likely significant processing costs to remove the sodium bond to produce an acceptable waste form. Even so, high burnup metallic fuel may have a significantly different cost from the current LWR spent nuclear fuel that has been studied in most detail. Previously power plants were paying $1/MW-hr for their spent fuel disposal costs which did not escalate over time.

Table 35 shows the unit cost information used in the calculation of the refueling costs and the initial fuel costs. This table also uses the mean value of the unit cost distribution to calculation the cost estimate for the mean value in terms of $/kg U of fuel using the units required per kg U of fuel in Table 34. This shows the contribution of each element. As expected, the higher enrichment fuel is more expensive per kg U of fuel. The HTGR and SFR being many times more expensive. However, these fuels produce many times more electricity because of the higher burnup and thermal efficiency. The last row of the table converts that value to $/MWh showing that fuel costs are much closer in levelized cost.

Table 35. Cost distribution data from the Cost Basis Report along with mean costs (2020 USD). Values were later escalated to 2022 USD using GDP-IPD.

	Cost Distribution Information					Mean Cost Estimate ($/kg U fuel)		
	Low	Mean	High	Units	Distribution	PWR	HTGR	SFR
Natural Uranium	35.8	145.2	310.2	$/kgU	Tri	1,247	4,803	5,477
NU Conversion	6	11.9	17.9	$/kg	Uni	102	394	449
Enrichment	126	145	164	$/SWU	Tri	909	4,535	5,243
SWU Premium Multiplier	0.03	0.15	0.27		Uni	0	86	106
HALEU Deconversion to non-metal	5	7	9	$/kgDU	Tri	53	225	257
HALEU Deconversion to metal	5	21	45	$/kgDU	Tri	159	674	771
UOX Fabrication	242	423	605	$/kgU	Tri	423		
Metallic HALEU Fabrication	1000	2000	3000	$/kgU	Uni			2,000
TRISO Fabrication	500	1250	2000	$/kgU	Uni		1,250	
DU Deconversion	1110	1310	1520	$/kgHM	Tri			1,310
DU Disposal	1000	4667	9000	$/kgU	Tri		4,667	
SNF Packaging	60	120	160	$/kgHM	Tri	120	120	120
SNF Disposal	300	611	908	$/kgHM	Tri	611	611	611
Total ($/kg U fuel)						**3,625**	**17,364**	**16,345**
Total ($/MWh)						**9.2**	**11.0**	**11.3**

NOTE: *Total SWU required is subject to the enrichment costs and the SWU above 10% is subjected to a multiplier of the SWU cost. For HALEU where 10% of the SWU is in a Cat II facility, the mean SWU cost would be 145*(1+.1*0.15) = 147.175 $/SWU with the SWU in the Cat II facility costing an average of $166.75/SWU. This is for a large commercial facility operating near capacity. Demo and first commercial plants may have costs far higher because of limited capacity and greater economic risk on the enricher until the HALEU market grows a steady demand. The same is true for other costs associated with as yet deployed services and products.*

Despite the many uncertainties in the components of the nuclear fuel costs that are not currently commercially available, a large fraction of the costs for advanced fuels will be in those front-end costs that are currently commercially available. The combination of natural uranium, conversion, and enrichment represent between 60 and 70% of the refueling costs which gives confidence that, for future, fully deployed commercial systems, these costs are reasonable order of magnitude estimates even for advanced reactors.

The results of Monte Carlo sampling of the unit costs were applied to estimate the 25%, mean, and 75% fuel-cost levels. The costs are summarized in Table 36. For the large reactors, the PWR values were used. The conservative cost being the 75th percentile costs (11.3 \$/MWh in 2022 USD). The moderate cost being the mean cost (10.2 \$/MWh). The advanced cost being the 25th percentile cost (9.1 \$/MWh).

Table 36. Estimated refueling costs by component (2020 USD). Values were later escalated in the analysis to 2022 USD using GDP-IPD.

		PWR	HTGR	SFR
Natural Uranium	\$/MW-hr	2.1 / 3.2 / 4.1	2.0 / 3.0 / 3.9	2.5 / 3.8 / 4.9
NU Conversion	\$/MW-hr	0.2 / 0.3 / 0.3	0.2 / 0.2 / 0.3	0.2 / 0.3 / 0.4
Total SWU	\$/MW-hr	2.2 / 2.3 / 2.4	2.8 / 2.9 / 3.0	3.5 / 3.6 / 3.8
SWU Premium	\$/MW-hr	—	0.0 / 0.1 / 0.1	0.1 / 0.1 / 0.1
HALEU Deconversion	\$/MW-hr	—	0.6 / 0.8 / 1.0	1.0 / 1.4 / 1.7
Fuel Fabrication	\$/MW-hr	0.9 / 1.1 / 1.2	2.2 / 2.9 / 3.7	0.9 / 0.9 / 0.9
DU Deconversion	\$/MW-hr	0.1 / 0.1 / 0.1	0.1 / 0.1 / 0.2	0.2 / 0.2 / 0.2
DU Disposal	\$/MW-hr	0.3 / 0.4 / 0.5	0.3 / 0.4 / 0.6	0.4 / 0.5 / 0.7
SNF Packaging	\$/MW-hr	0.3 / 0.3 / 0.3	0.1 / 0.1 / 0.1	0.1 / 0.1 / 0.1
SNF Disposal	\$/MW-hr	1.3 / 1.5 / 1.8	0.3 / 0.4 / 0.4	0.4 / 0.4 / 0.5
Total	\$/MW-hr	8.1 / 9.2 / 10.1	9.8 / 11.0 / 12.1	10.0 / 11.3 / 12.4

NOTE: Values are calculated by sampling assumed unit-cost distributions and represent the 25%, mean, and 75% costs. Each \$1.0/MW-hr represents approximately \$8M/yr in annual fuel costs per GWe of nuclear capacity.

This simple approach provides an estimate for the NOAK or near-NOAK fuel costs. For thermal reactors, physics requires increased enrichment to increase burnup under the same operating conditions. This limits the benefits of innovation, but some reductions would be plausible. On the other hand, the relationship between burnup and enrichment is not constrained in this way for fast reactors. The ability to achieve net reactivity breeding produces a very design-specific relationship and the potential to develop advanced fuel that requires no enrichment at all (i.e., breed and burn). This has the potential to greatly reduce the cost of fast-reactor fuel compared to designs that are based on current experience operating on a once-through cycle.

Recycling is also a potential factor in future fuel costs. In thermal reactors, most of the fissile content of enriched uranium fuel is consumed to keep fuel costs down. Therefore, recycling of enriched uranium thermal-reactor fuel requires a large amount of fuel to be recycled to produce one additional unit of recycled fuel. For thermal reactors using enriched uranium fuel, recycling will not eliminate the need for the enriched uranium fuel, but only reduces the amount required. So average fuel costs will not be impacted significantly by recycling in thermal reactors, except possibly in thorium-breeding reactors, which were not considered here.

The dynamic is very different for fast reactors because higher enrichment is needed for reactor operations. Therefore, less fissile material can be consumed and, as noted, the system can be designed to be a net breeder (i.e., increase fissile content). This has the effect that much-smaller quantities of fast reactor fuel need to be recycled to make one additional unit of fuel, and no additional enrichment may be required. This has the potential to greatly reduce future fuel costs because the high cost of the initial enrichment required is maintained by *in situ* breeding and not by additional enrichment (or recycling of thermal-reactor fuel). Elimination of the need for enrichment and achieving similar or higher burnups could potentially reduce the nuclear-fuel costs for fast reactors very significantly. If breed and burn (utilization of unenriched fuel by *in situ* breeding) were achieved, and fuel-fabrication or other costs would not rise dramatically (which is not anticipated), the nuclear fuel costs would be relatively low.

6.2 Observed Non-Fuel O&M Data for Existing Fleet

The Nuclear Energy Institute (NEI) puts out regular reports on the costs of the current nuclear fleet. The information in the 2022 report (NEI 2022) was reviewed. This report provides some useful information and insight into the O&M costs of nuclear plants. Figure 26 shows the nuclear generating costs by year in 2021 dollars. This shows that, even for the existing fleet, there is significant uncertainty and variability in these costs. It is also important to note that these costs do not represent the full O&M costs. NEI writes:

> *The total generating costs presented in this paper do not represent the full costs of operations, as it does not include market and operational risk management, property taxes, depreciation and interest costs, spent fuel storage costs or returns on investment that would be key factors in decision making about continued operation of a nuclear plant.*

Much of the cost not included are the amortization of capital, but taxes, spent-fuel management, and some others are part of the costs not included in the capital costs that would be included in the complete fuel and non-fuel O&M costs. To adjust for this, an estimate for property tax and D&D costs for newly deployed reactors relative to the estimated average was added to the estimate for non-fuel O&M.

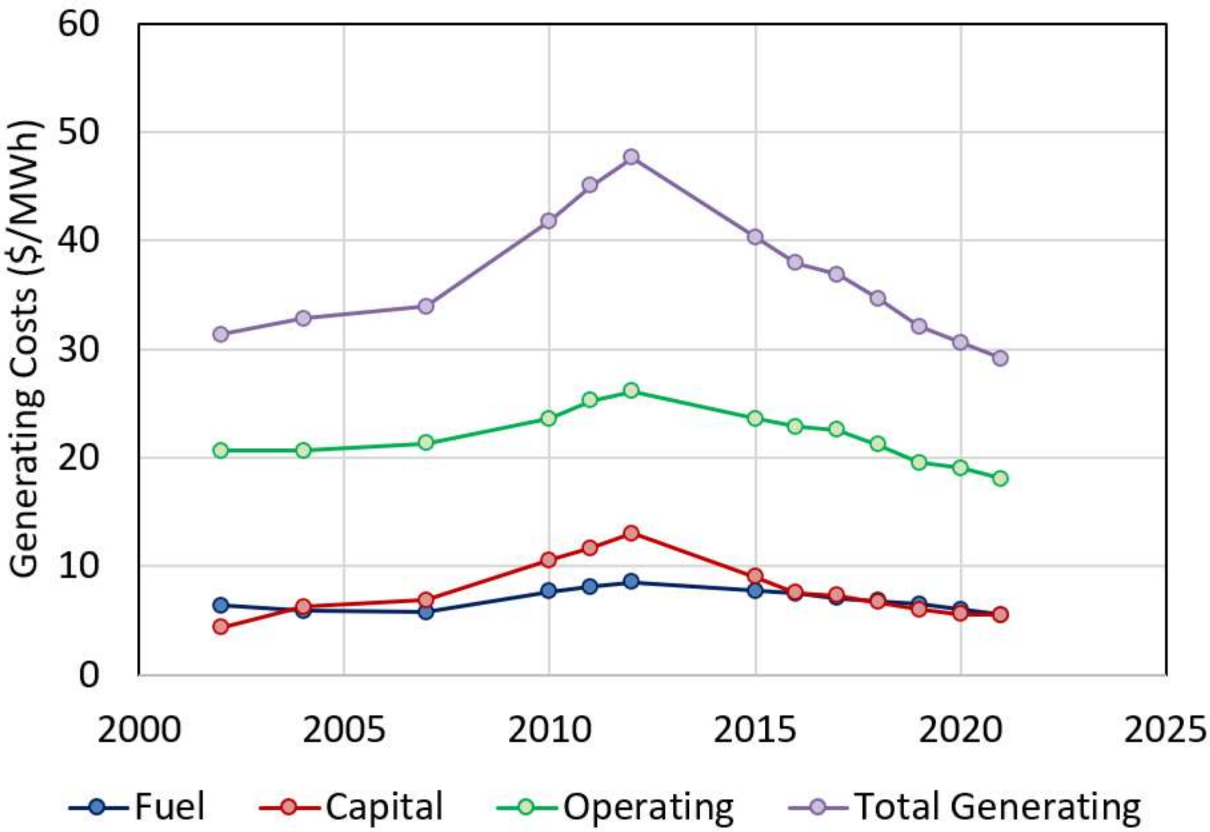

Figure 26. Nuclear generating costs by year (2021 USD).

The fuel costs vary from $5.51 to $8.52/MWh. The range estimated in the previous section for PWR fuel was from $8.1 to $10.1/MWh. When including the additional costs associated with spent -fuel management, the two sets of costs seem to be consistent, bringing confidence that the above estimate for the total fuel costs is representative of actual costs.

While part of the year-to-year O&M cost variability is associated with variability in the underlying components (e.g., variability in natural uranium market price, etc.), a significant variability in the investments made in equipment upgrades and maintenance and regulatory requirements also affects costs. NEI writes,

> *Capital investment saw a step-change increase around 2003 followed by another step-change increase in 2009 before peaking in 2012. These trends are the result of a few major investment categories: upgrades related to license extensions of plants, uprates, and completed safety-related investments post-September 11th and post-Fukushima.*

The significance is that, even for existing plants operating for decades where the costs should be expected to be NOAK, significant uncertainty is still driven by external and cyclical factors (e.g., plant license extensions). The O&M costs show a steady decline since their peak around 2012 and are near their previous lows. If this is an overall 20-year cycle driven by applications for license renewals, this would seem to be near the bottom, with the long -term average falling between the current costs and previous highs.

The non-fuel O&M costs for technology that is different from the existing fleet may not be directly related. The NEI aggregates costs at a high level, which does not align with the COA. This makes it challenging to infer O&M costs for advanced reactors from the costs of the existing fleet. Advanced reactors have the potential to greatly simplify designs (through greater passive safety and fewer system components). This could lead to the non-fuel O&M costs far less than that of the existing fleet. Conversely, the opposite could be true when normalized to energy generated because many advanced reactors are envisioned as much-smaller reactors which could result in higher O&M if proportional reductions in staff and other O&M costs are not as great as the reduction in size, even with the benefits of simplification. For reactors like the existing fleet (large PWR and BWR), these costs are probably near NOAK, but could still see some benefits of design evolution and technology benefits in reducing O&M below the current fleet. For advanced reactors with major changes in technology and/or scale, the O&M costs of existing reactors probably provide little insight. If a greater breakdown of the costs were available, it could probably be used to extrapolate costs with appropriate assumptions for each technology.

For the variable component of the non-fuel O&M, EIA (EIA 2020) estimated the O&M costs for an AP1000, which is an advanced PWR: "Variable O&M costs include water, water discharge treatment cost, chemicals, and consumables." These may vary with location but should be similar to water reactors. The estimate was $2.37/MWh, or about 13% of the total O&M costs.

6.3 Aggregating All Data Sets

This report focused more heavily on reactor capital cost, but both fuel and non-fuel O&M costs are required. Reviewing the existing O&M estimates, neither the level of detail was available, nor was the detail that was available organized in similar accounts. For future revisions of this report, an improved level of detail and a more thorough analysis of O&M costs will likely be an important focus. However, to have a complete set of costs, some assumptions were made in the data to provide the O&M costs as a function of time for existing LWRs and for potential future SMRs.

The overall spread of O&M cost data within the sources considered is shown in Figure 27. Note that there may be intercorrelation among cost estimates. Quartiles should not be summed across categories at this stage. This section will only discuss trends within the data to determine adequate groupings for the annualized cost ranges for nuclear reactors.

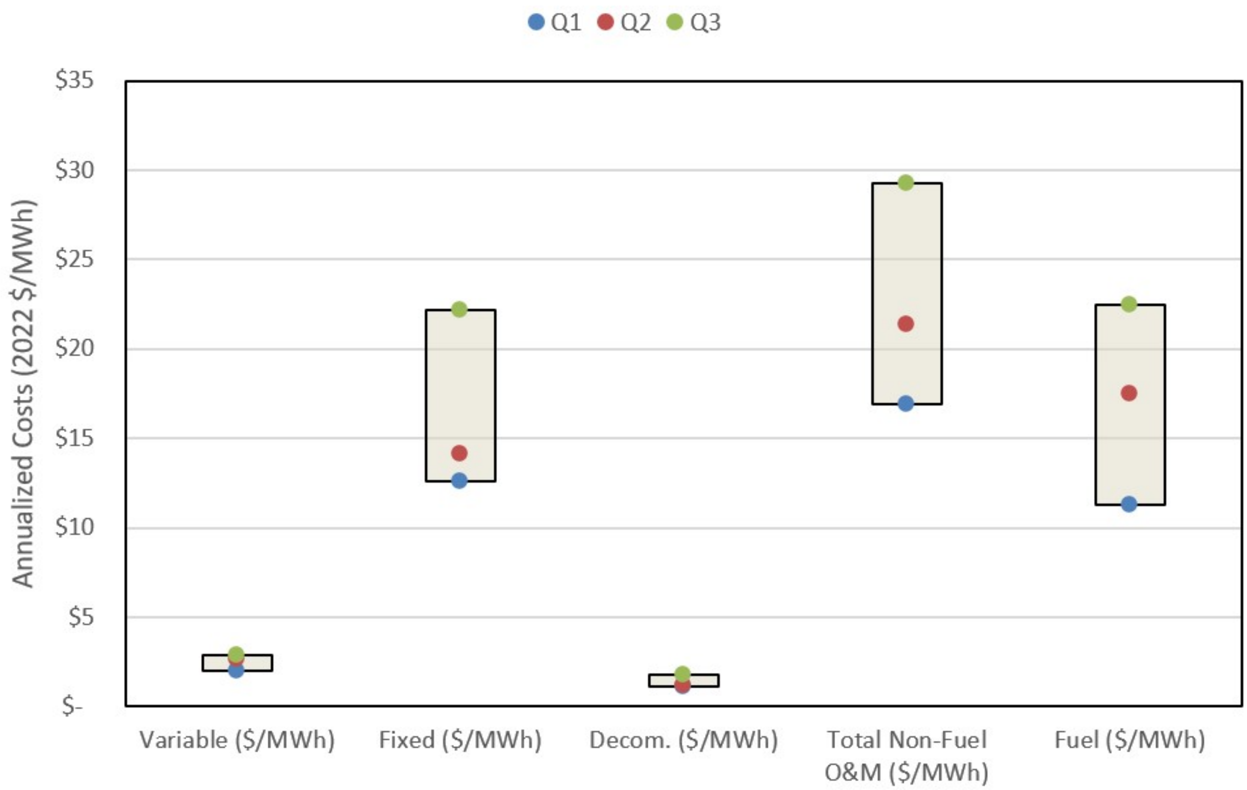

Figure 27. Overview of the O&M range in the entire data set considered.

There are several sub-cost categories of interest. Table 37 provides the estimates for decommissioning costs, property taxes, and the spent fuel disposal fee. The decommissioning costs will occur after operations permanently cease. This is a large cost after revenue has ceased. To cover this future expense, a sinking-fund payment was assumed to be included as part of the fixed nonfuel O&M costs. These payments would be sufficient that when the end of life is reached, sufficient resources would be available to cover the full cost of decommissioning. This is a small but significant part of the fixed O&M costs and is included in the fixed non-fuel O&M costs.

Note that it is possible to observe the sinking-fund in many of the existing reactors which have exceeded their initial operating licenses. As a result of decades of operations, they have accumulated large D&D funds that are nearly fully funded. Some payments continue to account for escalation and other changes, but on average, these D&D annualized payments are far below the average cost for a newly deployed facility with no initial D&D fund. For instance, a study in the literature estimates that the payments for a combination of 94 operating and 14 non-operating reactors was $248M in 2020 (Callan 2019). This was assumed to be spread over 94 GWe of generation which would equate to $2.64/kWe-yr based on these assumptions. To normalize the costs for new reactors, the $2.64/kWe-yr value is subtracted from the estimated D&D cost in Table 37 to provide the net additional cost for a newly deployed reactor. The additional $10/kWe-yr D&D fee (estimated in section 5.1.5) was then re-added to the final fixed O&M cost quoted. The purpose here is to avoid ‘double counting’ D&D fees in the existing fleet and tacking on another estimated yearly payment for new reactors.

One important cost category not included in the NEI operating costs is property taxes. This is likely to vary significantly between plant locations. One publicly available estimate of property taxes was for Byron Nuclear Power Station. Byron will pay about $33 million per year in property taxes (Rockford Register Star 2023). With a combined generation capacity of 2,347 MW for the two units, this corresponds to a fixed O&M cost of $14/kWe-yr. This will be added to the estimates based on the NEI costs for existing reactors.

The final sub-cost category is the spent-fuel disposal fee. This was set at $1/MWh (1 mil/kWhr) by contract in the US. Collection of the fee has been suspended. This was estimated to be adequate for disposal costs and did not increase with time. Future reactors will not necessarily automatically be covered by this value, and this is particularly true for advanced reactors that may have very different spent-fuel properties.

Table 37. O&M sub-cost categories.

Annualized decommissioning costs ($/kWe-yr)	10.0
Levelized decommissioning costs ($/MWh)	1.23
Property taxes ($/kWe-yr)	14.06
Spent fuel disposal fee ($/MWh)	1.0

6.3.1 Large Reactor O&M Costs

The recommendation for LWR fuel costs are the ranges estimated in Table 36, based on the PWR estimate. This is consistent with the NEI and other sources of data when all front- and back-end costs are included in the estimate. This should be treated as a variable cost, as is typically modeled for fuel costs, but parametric studies should be conducted that treat the fuel cost as fixed when the clear price falls between the total of the variable non-fuel O&M and fuel costs and just the variable non-fuel O&M.

For 33% thermal efficiency, this corresponds to 10.3 million BTU per MWh of electricity generated. This is used to convert the fuel costs from $/MWh to $/MBTU.

For the non-fuel O&M, a significant variation is seen in the O&M costs, even in the annual costs included in the NEI costs. One significant contributor to the generation cost included in the NEI costs is ongoing capital projects for the reactors. These capital costs occur after the start of operations and would not be included in capital expenditures (CAPEX). These include such things as power uprates that would be included in the CAPEX of future reactors and reduce the capital costs on a per kW basis. They also include significant investment for plant-life extension to extend the operating license from the original 40 to 60 and possibly again to 80 years. There are also capital costs associated with regulatory compliance in case of regulatory changes. The costs estimated for the AP1000 (EIA 2020) include an estimate of the non-fuel O&M costs, which is near the lowest annual value in the NEI cost for operating reactors. It is slightly above the multiunit only costs. The recommendation is to use the lowest experience costs as the most-optimistic future costs. This would include some overall improvement in cost, assuming more cost-efficient multiunit plants and more cost-efficient designs, like AP1000, are deployed to improve costs over current experience. Additionally, because this NEI data does not include property taxes, they were added to the fixed non-fuel O&M costs.

Based on the last 20 years of operating, operational experience is recommended as the current costs for all scenarios and either remains constant (at NOAK) or declines to the lower value (more cost-efficient plants). The high value included in the table represents the 75th percentile costs and should only be used as the current costs for parametric study. It is included to represent the variability that is seen in the operating costs. Variable non-fuel O&M costs were assumed to be 13% of total non-fuel O&M, excluding property taxes, which was the ratio for AP1000 (EIA 2020). The fixed O&M was then converted from \$/MWh to \$/yr per kW by using the current fleet capacity factory of 92.7%, which is 8.13 MWh/yr of electricity generated per kW of capacity. The 8.13 is multiplied by the fixed O&M in \$/MWh to the corresponding \$/yr per kW.

Table 38. Large LWR O&M costs.

	Advanced	Moderate	Conservative
Nuclear Fuel Costs (\$/MWh)	9.1	10.3	11.3
Nuclear Fuel Costs (\$/MBTU)	0.88	0.99	1.09
Fixed non-fuel O&M (\$/kWe-yr)	126	175	204
Fixed O&M (\$/MWh) @ 93% capacity factor	15.5	21.5	25.1
Variable non-fuel O&M (\$/MWh)	1.9	2.8	3.4
Total O&M (\$/MWh)	26	35	40

6.3.2 SMR O&M Costs

The SMR has no current operating experience to draw from, and the estimates from literature are limited. The EIA estimates (EIA 2020) the fixed O&M for the SMR to be 78% lower than that of a larger reactor. Estimates within the data set for non-fuel O&M costs in SMRs of various reactor types are plotted in Figure 28. As can be seen, there is substantial overlap within the estimates. This indicates that an overarching SMR grouping is adequate. As such, quartiles across the entire range of reactor types were used.

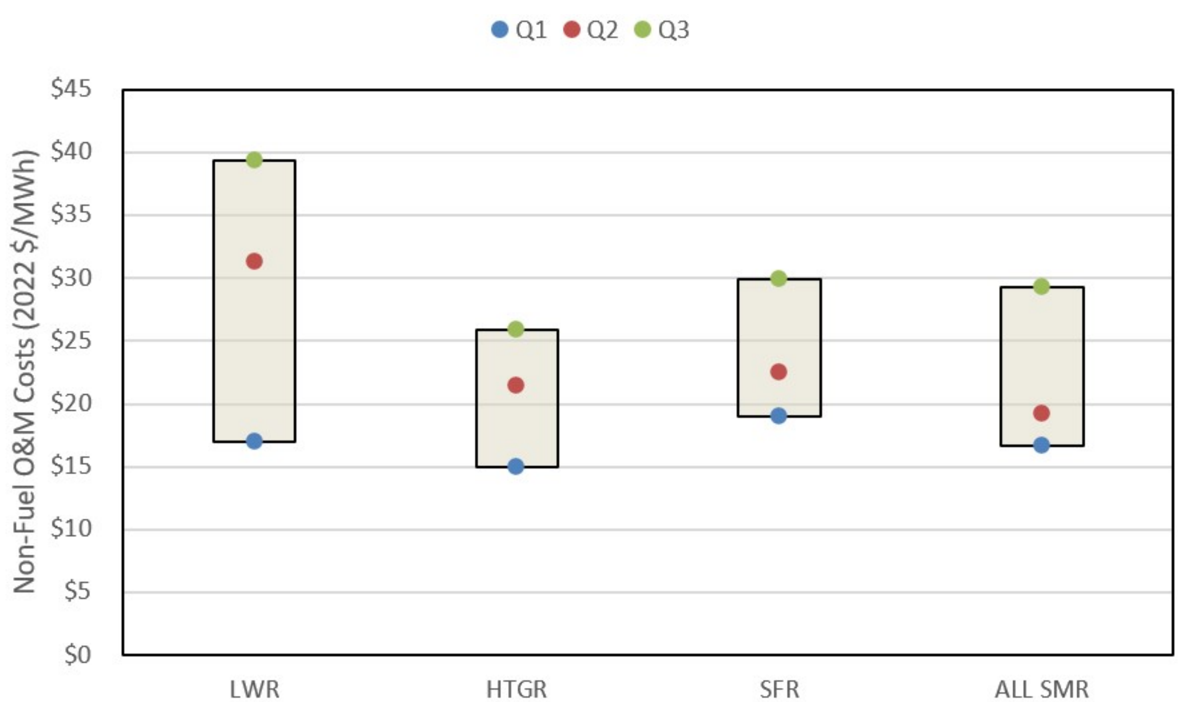

Figure 28. Comparison of non-fuel O&M costs across reactor types.

The fuel costs in Table 36 were also roughly in line across reactor types. Therefore, an overarching category for all SMR O&M appears to be suitable. The resulting values are slightly higher than for larger reactors. This is expected as small reactor cores will have more neutron leakage, requiring slightly higher enrichments to produce the same burnup under the same batch-refueling scheme. The summarized values for SMR O&M costs are highlighted in Table 39.

Table 39. SMR O&M cost ranges.

	Advanced	Moderate	Conservative
Nuclear Fuel Costs ($/MWh)	10.0	11.0	12.1
Nuclear Fuel Costs ($/MBTU)	0.97	1.06	1.17
Fixed non-fuel O&M ($/kWe-yr)	118	136	216
Fixed O&M ($/MWh) @ 93% capacity factor	14.5	16.6	26.5
Variable non-fuel O&M ($/MWh)	2.2	2.6	2.8
Total O&M ($/MWh)	27	30	41
NOTE: Capacity factor for all cases is 0.93.			

6.4 Multiunit Plant Impact on O&M Costs

Another very interesting part of the NEI data (NEI 2022) on the existing plants is that O&M costs are broken down by single- and multiple-unit sites. Single-unit sites have costs that are more than $10/MWh higher than multiunit sites. Table 40 shows the relative O&M costs for multiunit sites relative to single-unit sites and shows O&M declines by approximately one third.

Another smaller factor is the number of plants operated by the operator. O&M costs are about 10% higher for those operating a single plant than multiple plants. There is a wide range of reactor size in the existing fleet, and costs are not provided as a function of reactor size, which could play into the differences. The operating reactors range from under 700 to over 1200 MWe. The site power generation varies even more widely, with single-unit sites generating less than 800 MWe, and multiple-unit sites generating over 2500 MWe. The O&M cost as a function of reactor and plant size were not provided. How the fleet evolves in terms of units per site, operators, and other factors such as size, this could have some effect, but about 80% of energy is generated on multiple-unit sites as a result of many of the smaller, older single unit sites shutting down. This does not seem likely to be a major factor for fleet-average future O&M costs of large PWR and BWR reactors. However, looking at individual sites, the number of units would be a major factor for large LWRs. For SMRs, the relationship would be different and was not evaluated.

Table 40. O&M cost reductions in multiunit plants.

Number of Units	O&M Cost Reduction
1	1.0
2 or more	0.67

6.5 Projected Evolution of O&M Costs

The evolution of O&M costs could occur over several dimensions and be driven by the many different types of nuclear technology that could be deployed in the future.

The focus of the report and the basis of the data are primarily large LWRs. The current fleet average O&M costs are driven by experience and should be near NOAK. Future LWRs, such as the AP1000, will likely include experience and design improvements that will reduce O&M costs. This is the case for the projected non-fuel O&M costs of the AP1000. Also, a large benefit accrues from multiunit sites in the current fleet. Overall, this is likely to lead to small evolutions in costs of maybe 10–20% for the advanced costs and possibly a little more for the moderate costs. Moderate costs are recommended as the highest values of O&M, except for parametric studies for which the conservative value is provided to capture future uncertainties.

Reactor types that have not been built in significant numbers, or at all, may have higher O&M for several reasons, including taking a step back down the learning curve for new technology that will then flatten significantly with experience. Small reactors, while not estimated to have higher O&M costs, are not demonstrated, which could lead to higher O&M than estimated if the projected reduction in staff and other O&M costs are not as large as estimated.

For fuel costs, the behavior will likely be driven by the fuel/reactor technology. For solid fuel limited to near-current experience for radiation damage and other life-limiting factors, minimal future changes are likely. One area in which a large reduction in fuel costs could be possible is in fast reactors. If fuel can be developed that can withstand large increases in radiation damage relative to current experience, the fuel costs will decline substantially. At the extreme would be breed-and-burn reactors using unenriched uranium feed. Molten-salt fast reactors would also use unenriched uranium as their feed if very long lifetimes can be achieved. Reprocessing in breeder reactors also has the potential to greatly reduce fuel costs. These are all reactor types not considered here. For the LWRs, whether large or small, the evolution in fuel costs is expected to be very small unless some unforeseen reductions occur in natural uranium or enrichment costs, which are the largest contributors.

7. COST-EVOLUTION SCENARIOS

Nuclear-power-plant costs are inherently linked to the number of deployments. As more units are deployed, learning is accrued, leading to efficiency and, ultimately, cost reductions. However, this leads to a circular problem in certain capacity-expansion models because the projected number of reactors deployed is inherently linked to the projected cost as well. This section therefore sets out to (1) identify reasonable learning-rate assumptions for nuclear reactors and (2) apply these learning rates to different deployment scenarios to project how costs evolve over time. Users of these data that can account for learning rates inherently in their models are encouraged to directly leverage those values. Others that need an explicit temporal evolution in cost estimates can revert to the values in Section 7.3 or project their own cost reductions based on their expected deployment values.

7.1 Overview of Existing Literature on Learning Rate

Learning plays a crucial role in driving down the cost from a FOAK demonstration. As more units are built and brought online, experience is gained, mistakes addressed, and overruns avoided. This is a well-documented phenomena (Stewart and Shirvan 2020) that stems across any technology or construction project. To better quantify this impact on costs, modelers typically make use of a learning rate (LR) estimated using the equation:

$$\text{Cost } (\textit{Nth} \text{ unit installed}) = \text{Cost (FOAK unit installed)} \times (1\text{-LR})^{\log_2 N} \qquad (8)$$

In essence, the equation expresses the learning rate as the percent cost reduction for every doubling of cumulative production. With *N* representing the number of units installed. As an example, for a learning rate of 5% or 0.05, the second unit would cost 5% less, the fourth unit would cost 5% less than the second unit and so on.

This formula blurs a broad range of contributing factors to cost reductions, including streamlined delivery, more-experienced staff and supply chains, better overall project execution, etc. It is nevertheless still a useful formulation to integrate combined effects and project likely cost evolutions over time. It is important to note, however, that learning rates are not a guarantee on their own. Several countries have experienced little to no learning as more nuclear was deployed (e.g., the US) while others experienced accelerated learning rates (e.g., Korea and Japan) (Lovering, Yip, and Nordhaus 2016). To materialize, learning needs to occur with a standardized design (with little or no variation between units), a consistent regulatory environment, and a robust supply chain and workforce (Lovering, Yip, and Nordhaus 2016).

Typically, LRs are developed from the analysis of data related to installation and construction experience. However, to estimate cost reductions for SMRs and advanced nuclear reactors, LRs need to be estimated by other means due to the lack of data on advanced-reactor power-plant implementation and construction in the US. Several sources of information, including literature, similar industry, and similar size reactor-related information were researched to develop an average LR for cost-estimation purposes. This will be discussed in further detail in this section.

A review of the LRs from various sources is summarized in this section. The review found a wide range of discrepancies in LRs for both SMRs and large reactors. To obtain usable values to be leveraged in building cost-evolution scenarios, single reference values for each of these reactor types were sought. Alternative approaches that considered low, medium, and high LR values were not considered here due to the inherent challenge with matching high/low LRs with high/low initial cost values (BOAK). While matching low learning to high costs would be most conservative, it is very unlikely because high starting-point costs have the strongest potential for further cost reductions.

7.1.1 Learning Rates Outside of the Nuclear Industry

The LRs of other industries and technologies were examined. As shown in Table 41, the technology learnings range from 0.5 to 47% due to maturity level, complexity, and degree of market penetration. This variance and range support the decision to focus the report on the learning rates specific to nuclear technologies with common components and supporting structures.

Table 41. LRs of other technologies (Rubin 2015, Breakthrough Institute 2022).

LRs	Technology
5%, 10%, 15%	Natural Gas CT
1%, 5%, 9%	Natural Gas CC
18%, 20%, 22%	Solar
10%, 12%, 14%	Wind
5%	Coal fired power plant
6%, 8%, 12%	Coal PC
1% and 10%	Coal PC+CCS
2.5% and 16%	Coal IGCC
11%, 14%, 34%	Nat Gas CC
10%, 15%, 22%	Gas Turbine
2% and 7%	Natural Gas CC + CCS

LRs	Technology
11%, 12%,32%	Onshore Wind
5%, 12%, 19%	Offshore wind
10%, 23%, 47%	Solar
23% and 24%	Biomass
0.5%, 6%, 11.4%	Hydro

7.1.2 Review of Literature on Large Reactor Learning

The existing literature was surveyed for nuclear-specific technologies and divided between learning rates for large reactors versus SMRs. Estimates on LRs varied significantly within the literature. The approach followed to determine LRs and account for the impact of other variables (e.g., change in regulatory regime) varied greatly among sources. For instance, several studies leveraged a top-down approach that used information from past- and new-build nuclear reactors and other renewable technologies on costs and experience. These reports analyzed the data and developed a range of LRs. Others relied solely on observed data without any further manipulation. For instance, South Korea pursued a deployment schedule of roughly two reactors every 2 years between 1995 and 2011. As a result of this deployment rate, reductions in construction cost of 63% relative to FOAK were observed (NEI 2017). Construction durations also dropped from 64 months for FOAK reactors to 47 months for their twelfth reactor. Based on these factors, the LR for Korean reactor installation is calculated to be ~12%, using Equation 8, the generic LR equation. Other LRs are shown in Table 42.

Table 42. LRs for large reactors.

LR	Study Method	Methodology Detail	Source
6%	Top down	Used cost reductions for several technologies Developed learning rates of collected technology learning rates and literature information	McDonald and Schrattenholzer 2001
7%	Top down (info from data base	Used a data base of completed reactor projects Adjusted the capital costs for inflation Historic capital costs increased after 3 Mile Island Increased capital costs with expansion of nuclear power generating sector Reactor size was a proxy for regulatory change The sector size was used to project costs	Komanoff 1981

LR	Study Method	Methodology Detail	Source
11%	Top down (info from data base	Statistical analysis of nuclear power constructed capital costs Based on time and cost data from US nuclear power plants Plant size was a determinant of capital costs Data regression was used to project capital costs Nuclear power plant data adjusted to constant dollars used for the learning curve analysis	Mooz 1979
12%	Observed	Observed learning rate in South Korea from 1995 to 2011 Learning from other countries where standardization was not adequately achieved were not considered here.	NEI 2017
2 and 11%	Top down	Based on existing nuclear plant construction. Cost estimation was based on project performance factors and management. Learning and cost estimation compared 2 classes of steam-electric generation: nuclear and super critical coal. Incorporated buyer preferences and agent contracting history. Cost estimation included impact of project management, procurement, and incentives.	McCabe 1996

As can be seen from the data, the projected LR estimates varied greatly. It can be challenging to weigh these selected references against one another or determine which should be discarded (references that were not deemed to be of sufficient rigor were already excluded from the analysis). Hence, to account for differences in biases among sources, a simple average is used in this study. This provides a useful way to generate a reference value. In the case of large reactors, the corresponding LR value is 8%, as shown in Table 43. Note that the value was rounded to not infer a higher degree of accuracy.

Table 43. Large-reactor LR spread.

	Max.	Average	Min.
Large Reactor	12%	8%	3%

7.1.3 Review of Literature on SMR Learning

In the case of SMRs, no observed data could be relied upon because there is no existing demonstration of these concepts. As a result, the literature survey here focused exclusively on estimates and projected learning rates. However, these types of reactors are expected to be more conducive to learning than their larger counterparts due to their smaller size, modularization, and higher proportion of activities shifted to the factory rather than the site.

Proposed LRs for SMRs can be grouped into one of three categories: (1) top-down estimates that are based on nuclear or other technologies, (2) bottom-up estimates that estimate an equivalent LR by evaluating contributing factors from subcomponents, and (3) projecting equivalent learning from the observed experience for reactors that are roughly similar in size to proposed SMRs.

Table 44. LRs for small modular reactors.

LRs	Study Method	Study Methodology Details	Sources
5%	Top Down	—	VCE 2022
5%	Top down	Used capital costs of large nuclear reactor data Developed costs reductions of FOAK that reflect SMR savings such as modular design, layout, and multiple units Developed LR for SMR to match the cost savings.	Boldon and Sabharwall 2014
3%, 6% and 7%	Top down	Based on existing nuclear plant construction SMR cost estimation is based on conventional reactor technology Used supply-chain configuration to adjust conventional plant costs OCCs derived from reference-cost data set for 1 GW PWR Cost data converted to 250 MW SMR by applying top-down estimation with power scaling Cost-reduction approaches of standardization, modularization, and schedule reduction to get to SMR costs	Lyons 2019
10% and 15%	Top down	Used capital costs of large nuclear reactor data Developed costs reductions of FOAK that reflect SMR savings, such as modular design, layout, and multiple units Developed LR for SMR to match the cost savings.	Peres 2017

LRs	Study Method	Study Methodology Details	Sources
3% and 16%	Bottoms up	Used information from 200 structures, systems, and components Considered two LWR reactors Two SMR designs NuScale and SMR 160 Used a tool to estimate the capital costs based on AP1000, APR1400, and SMR NuScale and SMR160 plant designs Bottom up for factory production, learning rates, electrical and piping Did a component cost breakdown Used Westinghouse PWR12-MR as representative for FOAK Made design-specific adjustments For nuclear components, used learning for components from gas turbines, wind turbines, small airplanes to get 16% for initial units and then bounded the cost reduction	Stewart and Shirvan 2020
5% and 10%	Bottom up	Based on vendor supplied cost data Modified costs for standardization and modularization	Atkins 2016
13%	Top down	Based on observed experience from reactors of similar size to SMRs	Nichol and Desai 2019

While a top-down approach may hold some merit, it was not incorporated as part of the analysis due to lack of certainty—in a sense, they are weighted at a lower tier than the other two types of LR estimates. Bottom-up estimates were considered more robust because they are based on engineering judgement and practices. Costs and LRs were developed for SMR designs that captured component-production rates, piping and electrical installations, modular-construction impacts, and other cost-reduction features. In addition, observed experience for reactors of similar size range to SMRs and are also factory-built in a modular fashion was also considered (Nichol and Desai 2019). The study considered data in terms of manhour reductions with learning to infer cost reductions. Because labor costs are the predominant type of costs in nuclear reactors, this was a suitable proxy. The reference explains that the execution of these reductions was achieved by leveraging a modular approach for more-efficient production, improved fabrication processes to shorten timespan, and having large order books that allowed for longer-term planning. An LR of ~13% was based on the estimates provided for construction time.

Based on the bottom-up estimates in the literature and the observed experience for the SMR-like reactors, an average learning rate of 9.5% was used, as shown in Table 45. This value is slightly higher than that of larger reactors, as expected. Again, an average value was chosen here to account for potential biases in the various estimates and provide a representative value based on the curated data set.

Table 45. SMR LR spread.

	Max.	Average	Min.
SMR	16%	9.5%	3%

7.2 Nuclear Deployment Scenarios

As previously explained, while the specific learning rate assumption forms one pillar of cost evolution for nuclear reactors, the second is the projected number of deployments. It is therefore critical to attempt to quantify possible scenarios for nuclear deployments. While capacity expansion models provide a useful tool for predicting future energy mixes, estimated ranges for nuclear energy deployment rates vary greatly within the literature. Therefore, it is necessary to contextualize the current landscape for nuclear energy in North America, before discussing results from capacity expansion simulations, and then progressing towards the possible scenarios to consider as part of the nuclear reactor cost evolution.

7.2.1 Background on Nuclear Deployment Projections

From one perspective, the nuclear industry appears to be at an inflection point. In the last few years there has been an influx of factors at both the local and global levels influencing an increased interest in nuclear energy. First, the invasion of Ukraine by Russia has highlighted the need for energy independence, resulting in many countries shifting their thinking on energy transitions by emphasizing more diversity in their energy portfolios. One pillar of this diversity in many countries is nuclear energy. Several Eastern European countries are looking at US nuclear technology options to support decarbonization and add energy diversity for reduced reliance on potential adversarial countries. For instance, Poland is considering deploying the BWRX-300 as their first reactor by 2030 with a target of up to 79 SMRs by the late 2030s (World Nuclear News 2023a). Estonia is also considering a BWRX-300 near the 2030 timeframe to support their energy transition (Euractiv 2024). Romania is considering including NuScale reactors in their grid (World Nuclear News 2023b). These are just some examples of the geopolitical changes that are driving a new focus on nuclear energy in Europe due to the renewed focus on energy security. Beyond global factors, there are also local movements (states and regions) that are driving the discussion on new nuclear energy.

While the US grid is mostly interconnected, energy decisions are still mostly handled at the local level through the electric utilities, generators, and utility commissions/regulators. Utilities must therefore take into consideration state and local laws around pollution, decarbonization, etc. At the local level, many regions and communities that have been fossil energy exporters are starting to consider nuclear energy as part of their transition. This has fueled interest in the so-called ‘Coal-to-Nuclear’ transition (Hansen 2022). The state of Wyoming, which produces 40% of US coal (EIA 2023), is a notable example. The state has put a focus on nuclear energy as part of their future planning and is already funding studies on how to use nuclear energy for Trona production (BWX Technologies 2023) and will be the site of the first coal-to-nuclear transition at Kemmer, Wyoming. Another heavy energy state, Kentucky, recently passed a bill to investigate and support nuclear development in the state (ANS 2024). Texas recently stood up an advanced nuclear working group to understand ways they can bring nuclear power and the nuclear supply chain to their state (Public Utility Commission of Texas 2023). These are just some examples of the regional shifts trying to incentivize nuclear energy to help transition local/regional economies. Many state legislatures have worked to include legislation to help study, support, or remove barriers for nuclear deployment. In 2021 there were 31 bills introduced in state legislatures that had something to do with nuclear energy. In 2022, this number increased to 43 bills and in 2023 this number jumped to 118 bills introduced into the state legislatures. Currently, in 2024 there are 73 bills that have been introduced. This is a huge increase in interest at the state level around nuclear energy. Some of these bills introduced were to perform feasibility assessments or to study nuclear energy for their state/region. Ultimately, eleven states have established a committee or performed a feasibility study for advanced nuclear in their state. These activities highlight the nascent interest at the local level in leveraging advanced nuclear energy to potentially support energy transitions. It is difficult to help model or quantify these local/regional actions in energy modeling exercises, especially since many of them are recent and the true impact is still to be quantified. Decisions on technology options are now discussing factors like local job creation and regional economic drivers like supply chain development for fabrication of components and construction of the facilities. Nuclear energy (SMRs or large reactors) is well suited for some of these aspects (DOE 2023).

It is therefore important to place capacity expansion modeling into the right context. There are many models run that project zero nuclear deployment using business as usual or reference scenarios. These models often do not account for local economic development considerations or regional demands for broader energy diversity. Therefore, the energy models may not be able to specifically capture localized drivers like coal transitions where incentives are higher (for retired/retiring coal generating stations) than a traditional greenfield site. For new nuclear energy, there are significant shifts in the landscape, with several utilities showing new nuclear needs in their integrated resource planning (IRP).

When evaluating potential deployment of US new nuclear capacity, it is important to consider external developments that may influence decisions in the US. Deployments outside the US can have significant impacts on costs in the country especially when US-based designs are being considered. These early projects can help establish a supply chain for further deployments, help address early project design risks, and build a larger order book for standardized designs. While there are undoubtedly localized construction and labor challenges, it is important to recognize that early nuclear costs are likely to be driven by overruns, lack of experience, and incomplete designs. Taken from this perspective, a standardized reactor built in the US following deployments in other countries can be expected to see cost reductions. The full extent of benefits gained from non-US deployments will vary depending on how much of the supply chain can be used, similarity of project management, and whether the design is standardized in different countries.

The most significant external learning for US costs will likely occur from deployments in Canada. Currently, one of the first SMR projects is being deployed at the Darlington site for OPG (GE Vernova 2023), with the possibility of four total units at that site with the first unit projected to come online in 2029. OPG and Tennessee Valley Authority (TVA) have a joint agreement to collaborate on deployment which links the organizations together and allows for learnings to be realized. Therefore, the first deployment in Canada, will likely to be closely followed by deployment of the same standardized reactor in Tennessee (TVA 2023). As a result, both US and Canadian deployment projections are considered as part of this study for development of the cost reduction due to learning.

While many critics of nuclear energy point to the demise of the UAMPS SMR project (NuScale 2023a), it is important to highlight that this canceled plant is just one of many new nuclear project announcements:

- **ARDP** – the advanced reactor demonstration program (ARDP) is currently expected to be the flagship project for advanced reactor deployment in the US. The joint public-private partnership is expected to bring online a 345 MWe Natrium reactor as well as a 4-pack of Xe-100's (320 MWe) (US DOE ARDP 2023). The second demonstration is notable as it is intended for industrial application rather than typical electricity generation. This highlights the potential for further learning in the nuclear industry by tapping non-traditional markets that are looking into nuclear energy.
- **OPG** – As previously mentioned, OPG is committing to a 300 MWe BWRX-300 by 2029 with up to 1,200 MWe total of capacity (assumed by 2035) (GE Vernova 2023).
- **TVA** – As mentioned above, the TVA has signed an agreement with OPG and Synthos Green Energy (Poland) to quickly follow from the Canadian BWRX-300 deployment with a similar deployment at its Clinch River site. This is part of a cross-country consortium aiming to accelerate the learning curve for this design.
- **Duke Energy** – the utility IRP is accounting for 600 MWe by 2035 (unspecified design) in their Carolinas plan (Duke Energy 2023) and up to 15 GWe by 2050 (Energy Intelligence 2023).

- **Dominion Energy** – the utility IRP was recently updated to include up to 8 SMRs (2,400 MWe) (Virginia Mercury 2023).
- **Energy Northwest** – the utility has put in place agreements with X-energy to work on deployment of up to 960 MWe of new nuclear plants (Energy Northwest 2023).
- **Standard Power** – the infrastructure and project developer selected NuScale technology to develop up to ~2 GWe of power for data centers (NuScale 2023b).
- **Holtec** – the company is planning to deploy two of its 300 MWe reactors at the Palisades plant in Michigan (Holtec International 2023).
- **PacifiCorp** – the utility is part of the ARDP for the first Natrium reactor demonstration. As part of its IRP update, two more Natrium reactors (1,000 MWe advanced nuclear) were included to meet future energy demands (PacifiCorp 2023).

The list above is not intended to be exhaustive, but rather to showcase the shift that has started to occur in long-term planning within the energy community. Indeed, a recent Wood Mackenzie report attempted to do just that by compiling the broad range of nuclear-related project announcements (Wood Mackenzie 2024). As shown in Figure 29, the report tallied a total of 22 GW of nuclear announcements between the US, Poland, Canada, UK, and South Korea – often with US-based designs. Total US/Canadian announcements total 8.5 GW thus far.

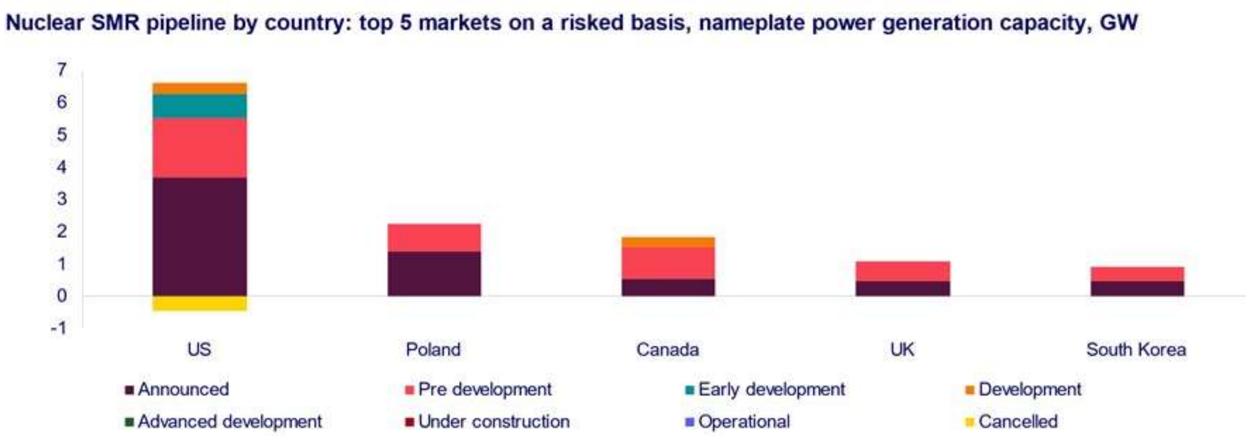

Figure 29. Wood Mackenzie tally of nuclear SMR deployment announcements across five western nations. Taken from (Wood Mackenzie 2024).

It is also important to contextualize future nuclear deployments with the projected closure of the existing nuclear fleet. Many capacity expansion models assume that the current nuclear fleet will continue to run for 80 years. While this is technically possible, it is not a guarantee that every plant will run for 80 years of operation. Figure 30 shows the potential range of net nuclear retirement in the US. By 2055 between 94 and 26 GW of capacity can be expected to come offline. Even if all currently announced extensions are granted, ~80 GW of capacity would come offline by that point. This represents a significant impetus for building additional firm, carbon free, baseload power generation prior to that date.

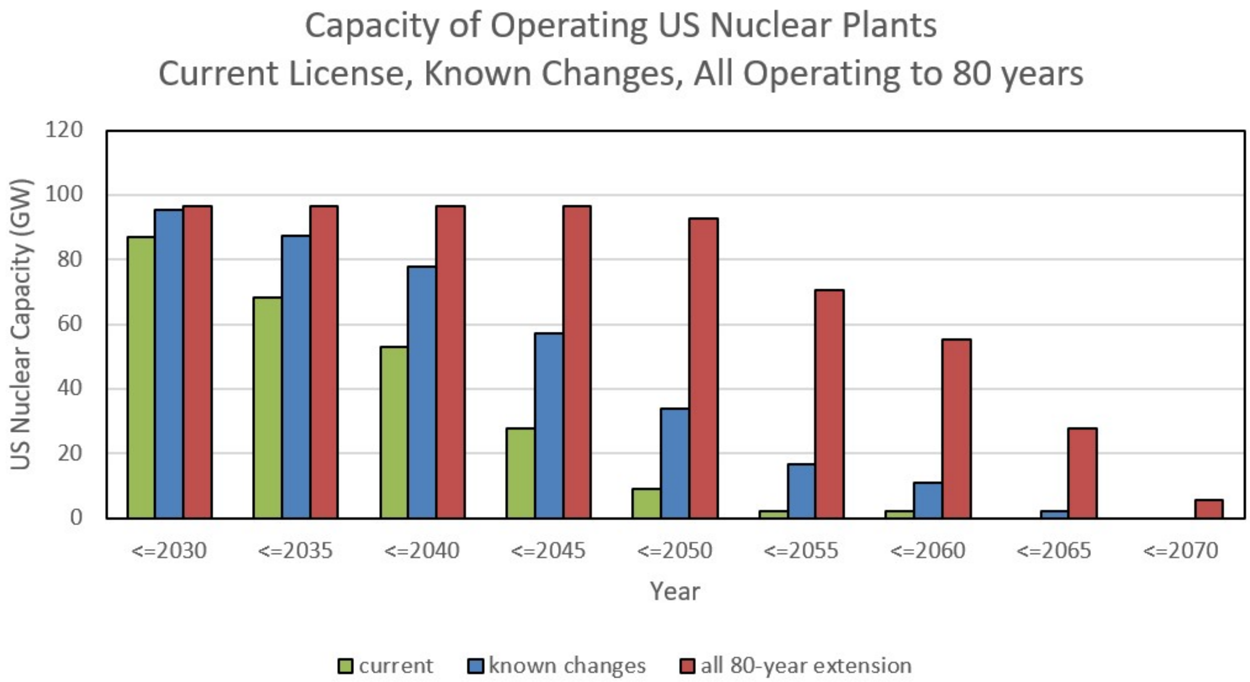

Figure 30. Projected retirement of US nuclear fleet based on currently licensed lifetime, submitted lifetime extensions, and assuming an 80-year license extension for all reactors. Data obtained from (NRC 2024b)

In summary, there are three different factors that are pointing towards more nuclear deployments in the future than observed in the past:

1. International deployments are moving ahead and, in some cases, even faster than US deployments. Given that many of the considered designs are US-based, this will likely drive learning and cost reductions within the US. While several countries in Europe are considering US designs, only Canadian projections are included in this report as a conservative assumption.
2. Local and regional factors are driving utilities to include nuclear energy within their IRPs. Overall, a recent report tallied ~8.5 GWe of new nuclear deployment announcements within the US and Canada. The OPG-TVA consortium is particularly illustrative of cross-border standardization of designs to drive nuclear cost reductions. While it is possible that some of these announcements do not move forward, there are many other stakeholders who are known to be considering nuclear energy (particularly beyond electrical markets) but have yet to make public statements to that effect.
3. The retirement of the current fleet is likely to result in added pressure to replace baseload carbon free power generating stations with new nuclear reactors. The significant infrastructure already at these sites along with the existing licensed sites makes these locations ideal for hosting new reactors.

Given these factors, nuclear projections should be expected to have a more positive outlook which are difficult to quantify in capacity expansion models. Therefore, this study utilized capacity expansion models only to provide an initial guide of projections that are later adjusted based on expert judgement and to align with scenario definitions (both to correct for near term over-optimism and for longer-term pessimism). These deployment projections were ultimately used to derive cost evolution of nuclear reactors based on expected learning curves.

7.2.2 Capacity Expansion Models with Sensitivity on Nuclear Costs

Capacity expansion models vary widely in terms of their projected deployments for nuclear. Overall, two key factors appear to drive deployment rates: (1) low nuclear capital costs (the exact threshold values are often disputed), and (2) policies to incentivize deep decarbonization. While a substantial number of capacity expansion models are projecting zero nuclear deployment (Bistline et al. 2023) (Browning et al. 2023), a large array of models concludes much greater potential for large-scale deployment rates. The DOE Liftoff report (DOE 2023) surveyed six models with a wide range of projected nuclear deployments. Figure 31 shows the broad range of projected deployments based on varying assumptions and constraints. On average, low cases projected 89 GW of nuclear deployments while more ambitious scenarios averaged 300 GW. While it is beyond the scope of this study to opine on the relative merit of optimistic/pessimistic modeling of capacity expansion models and their underlying assumptions, a select few models were investigated further here to provide a basis for the nuclear cost evolution.

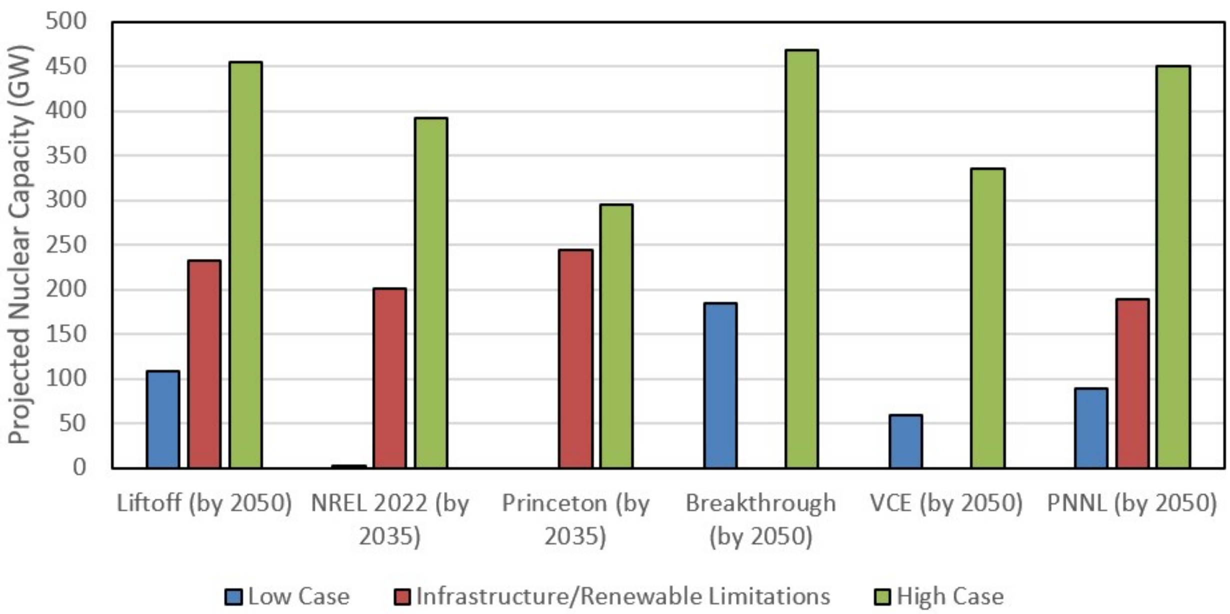

Figure 31. Projected nuclear capacity deployment from various capacity expansion models under different conditions. Reproduced from (DOE 2023).

Four publications were particularly leveraged for this study: (1) Pacific Northwest National Laboratory's (PNNL's) "Scenarios of Nuclear Energy Use in the United States for the 21st Century" (Kim, S. H. 2022), (2) Breakthrough Institute's "Advancing Nuclear Energy" (Breakthrough Institute 2022), (3) the Energy Information Administration's (EIA) 2022 Annual Energy Outlook (EIA 2022), and (4) the DOE "Pathways to Commercial Liftoff: Advanced Nuclear" (DOE 2023). These were particularly down selected because they conducted sensitivity analyses on potential nuclear cost ranges and considered varying scenarios to achieve decarbonization. A brief overview of the projected deployments in these reports is discussed here. It should be noted however, that this study does not rely entirely on capacity expansion models but adjusts them based on existing public statements as described in the previous section (this is particularly the case for the so-called 'moderate' scenario as described in later sections).

One notable adjustment conducted is with the start date for deployment projections. In all analyses, the market penetration of advanced nuclear reactors is not expected to begin prior to 2030. This projection is based on the completion of the X-energy/Dow and TerraPower Natrium projects, which will be funded through the US DOE ARDP. Also, several other SMRs, including Oklo, USNC, GE Hitachi, Kairos Power and NuScale, are expected to startup first reactors before 2030 (NIA 2023b).

The PNNL study explored several scenarios to reach net-zero-carbon emissions by 2050, 2060, and 2070, designated as NZ50, NZ60, and NZ70, respectively. The analysis developed a base reference scenario to estimate the nuclear energy buildout associated without any net-zero constraint. In each scenario, cases were developed for cost reduction from the initial cost of $6,600/kW. These cases assume achieved OCC reductions from the FOAK to $2,600, $3,600, $4,600 and $5,600/kW by 2050 and were labeled NUC26, NUC36, NUC46 and NUC56, respectively. Other sources of nuclear reactor deployment were utilized in the study reference case development. The PNNL scenarios were modeled to determine market penetration with nuclear power to achieve net-zero carbon emissions by the specified year. The reference case was developed to exhibit the nuclear buildout without any net zero restriction and is exhibited in Figure 32. The NZ50 scenario was also considered for the advanced scenario in this study.

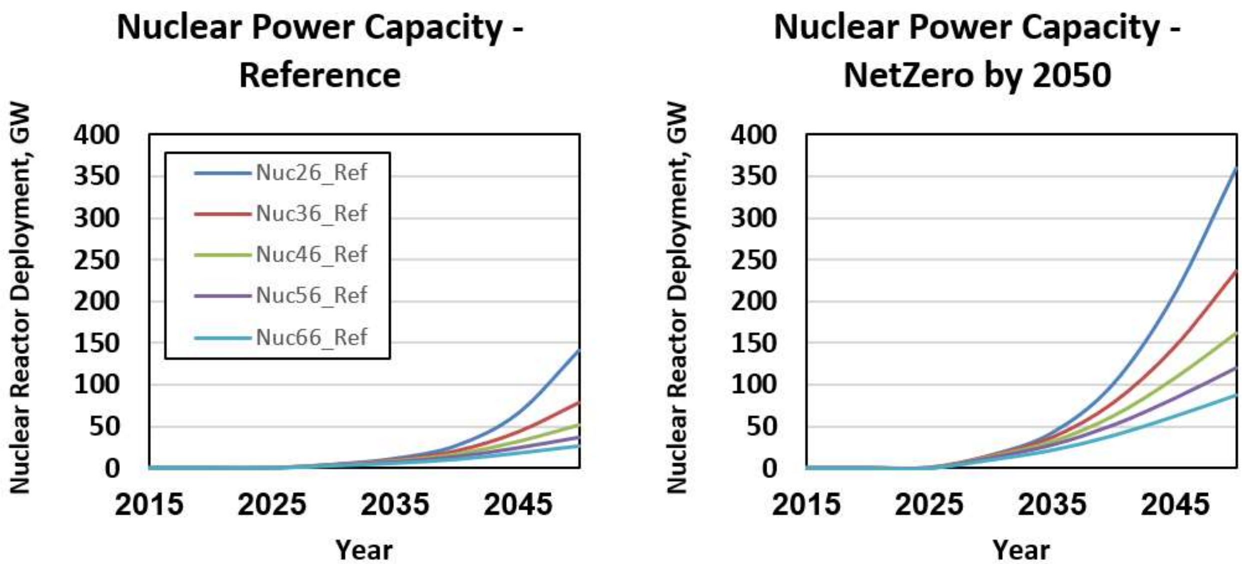

Figure 32. Nuclear power capacity with varying nuclear 2050 costs—reference and NZ50 cases. Taken from (Kim, S. H. 2022).

The Breakthrough Institute report modeled FOAK costs for light water SMRs and advanced nuclear reactor studies to establish the starting point for their study. In addition, a range of LRs, from 5 to 12%, was used to estimate the potential reactor-cost reduction to a floor value of $1,800/kWe. The parametrization of these variables led to the four scenarios described below:

- Low reactor cost, low LR (5%)
- Low reactor cost, high LR (12%)
- High reactor cost, low LR (5%)
- High reactor cost, high LR (12%).

The range of the LRs was used to bound the uncertainty of future reactor costs and were obtained from a review of relevant literature and comparative technologies. The developed reactor costs were employed to model market penetration, reactor deployment, and power generation for the grid. The highest deployment occurs with the scenario of low reactor cost combined with a high LR because of a competitive cost and higher rate of reactor-cost reduction. A net-zero by 2050 constraint was imposed on the simulation. The resulting decarbonization scenarios are exhibited in Figure 33.

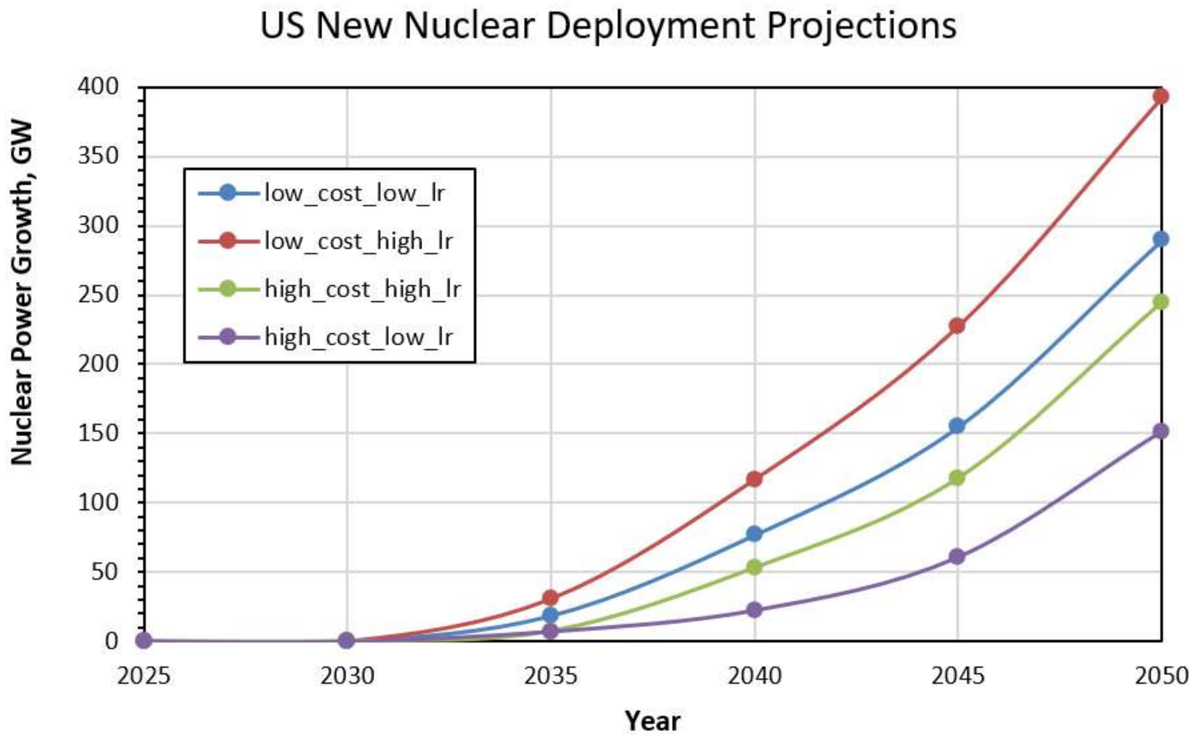

Figure 33. US nuclear power, total growth projections with a Net Zero by 2050 target. Taken from (Breakthrough 2022).

The remaining two capacity expansion models were from EIA and DOE. EIA conducted a separate capacity expansion simulation for their Annual Energy Outlook with a baseline ‘business as usual’ or reference case in which no additional investment or government policy are made towards decarbonization. In their modeling, effectively no nuclear deployment whatsoever is projected throughout 2050 (EIA 2022). On the other hand, the DOE Liftoff study evaluated a range of scenarios with varying degrees of nuclear deployment rates (DOE 2023). Ultimately the report settled on a peak target value of 200 GW of new nuclear capacity by 2050 as part of its assessment.

7.2.3 Projections for the Scenarios Considered

The NREL ATB considers three scenarios for cost projections (NREL 2022). This allows for the inclusion of learning or significant changes to the technology that may affect costs in future years. The following sections discuss the various scenarios and the deployment projections that are used for each case.

The starting point for each scenario was based on the corresponding quartile from Section 5. The first, second, and third quartiles were matched to the advanced, moderate, and conservative scenarios respectively. These BOAK values were assumed to be applicable from 2030 onward, with cost evolutions projected beyond that point based on the learning from the number of units deployed. In each scenario, a basis is detailed here to justify the considered GW deployment rate. O&M costs are assumed to be constant in this study with no projected evolution over time.

7.2.3.1 *Conservative Scenario*

The ATB conservative scenario is defined as follows (NREL 2022):

> *Historical investments come to market with continued industrial learning.*
> *Technology looks similar to today, with few changes from technology* innovation.
> *Public and private R&D investment decreases.*

Within the methodology of this report, 'continued industrial learning' is taken to mean that LR values are held constant here and no changes are made to these technology-specific values. Since the technology looks similar to first deployments, then the third quartile starting point for the BOAK was taken to be representative. Similarly, the third quartile values for all other parameters are used (O&M, construction time, etc.). The last point, regarding public and private R&D decreasing is what drives the deployment scenario projection. It is assumed that the drive towards decarbonizations stalls, no new policies favoring nuclear are implemented, and no goals towards Net Zero emissions are set.

In this conservative case, nuclear capacity deployment is only sustained by existing momentum. While several studies project zero deployment of nuclear in those conditions, others still project some new builds. Following the overarching methodology of this study, rather than opining on different contradicting estimates, statical averages (with some adjustments) were used. Two scenarios were taken to be representative of the two camps. The first scenario is the previously outlined EIA 'business as usual' case with zero nuclear deployment. The second was the PNNL 'reference' case. In that model, it is assumed that government subsidies and incentives will expire in 2032, which limits private investment due to the high technology costs and high market penetration of nuclear power. As a result, the PNNL base reference case was taken to be a suitable fit for the conservative scenario estimation.

Because the PNNL scenarios included variabilities in cost evolutions for nuclear energy, a differential analysis was conducted to determine the best fit under the current BOAK starting point values and LR assumptions. The scenario with the lowest cumulative difference for the large reactor and SMR costs was deemed to be 'Nuc56'. However, some additional adjustments were undertaken to better align with the assumptions of this report. Since no nuclear deployment is expected before 2030, and under a conservative scenario, R&D investment in nuclear energy decreases, this is expected to delay the first demonstrations (namely the ARDP projects) back to 2035. Because the PNNL projections observed deployments from 2030 onwards, the deployment rate is shifted back by a five-year increment. As a result, the deployment rate for 2050 corresponds to the original 2045 data.

The results were then averaged with the EIA projections (effectively halving the PNNL values) to obtain a combined estimate for a conservative scenario. The resulting starting deployment rate in 2035 was 2 GW of new nuclear capacity. This was further adjusted to 1 GW to represent the first three demonstrations that are expected (two from ARDP and the OPG plant). The resulting projected deployment scenario for new nuclear capacity is shown in Table 46.

Table 46. Projected deployment of new nuclear capacity in the conservative scenario.

Year	(Kim, S. H. 2022) Nuc56_Ref	(EIA 2022)	Projected New Nuclear Deployment for Conservative Scenario
2025	0 GW	0 GW	0 GW
2030	3 GW	0 GW	0 GW
2035	7 GW	0 GW	1 GW

Year	(Kim, S. H. 2022) Nuc56_Ref	(EIA 2022)	Projected New Nuclear Deployment for Conservative Scenario
2040	13 GW	0 GW	3 GW
2045	24 GW	0 GW	6 GW
2050	37 GW	0 GW	12 GW

For context, this scenario projects a net *decrease* in total nuclear capacity in the US. Even if 80-year plant lifetime extensions are granted, ~26 GW of nuclear capacity would come offline around the 2050–2055 timeline which exceeds the maximum deployment value considered here. As a result, the projected deployments are taken to be adequate for a conservative case.

7.2.3.2 Moderate Scenario

The ATB moderate scenario is defined as follows (NREL 2022):

> *Innovations observed in today's market become more widespread, and innovations that are nearly market-ready today come into the market. Current levels of public and private R&D investment continue. This scenario may be considered the expected level of technology innovation.*

Based on the language specified here, as new technology comes to market and R&D investment continues, the 2nd BOAK quartile is deemed to be a valid starting point for the OCC in this scenario (and other variables such as O&M). Similar to the conservative case, the LR is assumed to be specific to the technology itself and better practices in deployment (no technological innovation are explicitly assumed in this study). The same values were therefore used.

In searching for deployment scenarios that best fit the description above, no capacity expansion model was deemed to be a perfect fit. As a result, an explicit step-by-step approach was taken here to identify a realistic deployment rate, based on the background provided in Section 7.2.1. Table 47 provides a more detailed breakdown of the GW deployment rate and the basis at each 5-year interval.

Table 47. Generation capacity (GWe) for the moderate scenario.

Year	New Nuclear Capacity Deployment	Basis
2025	0.0 GW	No new deployments prior to 2030 assumed
2030	1.0 GW	ARDP projects + OPG
2035	3.0 GW	Similar build-out to last 15 years in US (2 GW at Vogtle and 1 GW at Watts Bar)
2040	8.5 GW	Wood Mackinzie tally of US + Canada new nuclear announcements (Wood Mackenzie 2024)
2045	17.0 GW	Doubling of 2040 capacity
2050	34.0 GW	Doubling of 2045 capacity

As explained previously no nuclear deployment is projected currently prior to 2030, with the first deployments at that point being the two ARDP demonstrations (0.32 and 0.35 GW) and the OPG reactor (0.3 GW). This leads to the 1 GW in 2030 starting point. The next main anchor in the model was the 8.5 GW of announced deployments in the US and Canada that was tallied in (Wood Mackenzie 2024). While some of these announcements may not turn into actual deployments, it is important to recognize that many other energy users are currently considering nuclear deployments but have yet to make public announcements to that effect. Overall, the tallied value was deemed to be a good fit with the ATB scenario definition of ‘technologies come to market’. To be conservative, 8.5 GW was assumed to come online in 2040 and a deployment rate 3 GW was then assumed for 2035. This is equivalent to the recently observed deployments in the US (~2 GW at Vogtle Unit 3 & 4 (Southern Company 2024) and ~1 GW at Watts Bar Unit 2 (TVA 2016).

Beyond 2040, a 5-year doubling of nuclear plant capacity was assumed. This results in 17 GW deployed by 2045 and 34 GW of deployments by 2050. This is in-line with the average of four 2040 deployment projections for nuclear in a broad capacity expansion model (Bistline 2022). It is worth noting that the resulting number of deployments was found to be lower than the most optimistic PNNL reference case (‘Nuc26’) (Kim, S. H. 2022). For additional context, this corresponds to 1.7 and 3.4 GW/year in 2040-2045 and 2045-2050. For perspective, at its peak, historical US nuclear deployment rates averaged at 4.5 GW/year with peaks above 10 GW/year in the 1970s (MPR 2018). A yearly deployment maximum in 2045 below the average during that era was deemed to be realistic and conservative for a moderate scenario. Lastly, it is important to highlight these deployment projections within the context of the existing US nuclear fleet. Assuming all existing plants licenses are extended to 80 years, approximately 26 GW of capacity would go offline by 2050-2055. A 34 GW deployment by that timeframe would only constitute a net increase in nuclear power generation of approximately +8% which is most likely a reduction of nuclear energy if total electricity loads start to increase. As a result, the deployment projections for nuclear capacity are deemed suitable for a moderate scenario.

7.2.3.3 Advanced Scenario

The next case considered was the advanced scenario. The ATB definition for this case is described as (NREL 2022):

> *Innovations that are far from market-ready today are successful and become widespread in the market. New technology architectures could look different from those observed today. Public and private R&D investment increases.*

Based on the language specified here, technology deployments are assumed to be successful and cost overruns are avoided. Hence, first quartile value for the BOAK (and other parameters) were deemed appropriate as a starting point. The timeline for first demonstrations is not brought forward however, nor is the starting capacity assumption of 1 GW altered. Similarly to the other cases, the LR values remain unchanged.

The deployment rates of the Breakthrough Institute, the PNNL NZ50, and the DOE Liftoff report were leveraged. The first two studies evaluated deployment projections under an imposed net-zero decarbonization by 2050 constraint. Similarly to the conservative case, a statistical average from the two cases was selected rather than opining on the relative merits of each study. In essence, these cases all assume that government support and incentives in nuclear will continue, and private investment will be encouraged to achieve technological improvements. The result is reduced long-term cost for new nuclear technologies with broader market penetration achieved. Thus, the scenarios were deemed to be a good fit for the ATB definition of an advanced scenario.

Each report parametrized nuclear cost evolutions. To map the best fits for the assumptions of this report, a differential analysis was conducted on the projected cost evolutions. Again, the cases with smallest percentage deviances over the timeline considered were first considered. In the case of the PNNL case it was the most ambitious ‘Nuc26 NZ50’ with 300 GW of nuclear deployment by 2050. For added conservatism, the following case was selected ‘Nuc36 NZ50’ with 237 GW of nuclear deployment by 2050. Similarly for the Breakthrough Institute cases, the projected costs and learning rates are closest to an average of all the cases considered. While an overall average would lead to 270 GW of nuclear deployment by 2050, the ‘high cost & high learning’ case was selected instead (with 245 GW of nuclear by 2050). The average between the PNNL ‘Nuc36 NZ50’ and the Breakthrough Institute ‘high cost and high learning’ was used as an initial starting point for the projection in this study.

This average was further adjusted to reflect the constraints discussed previously. Namely, a 1 GW deployment value is set for 2030. Additionally, considering the DOE Liftoff target of 200 GW, this was imposed as an upper limit for 2050. While it is possible to expect nuclear deployment rates to exceed this value by 2050, the industry is likely to encounter supply chain and other constraints in reaching that point. Hence a 200 GW cap was deemed suitable here. Lastly, this value should be considered within the context of approaching the target of ‘tripling nuclear capacity by 2050’ that was announced by several nations including the US at the 28th Conference of Parties (COP28) (Nuclear Energy Agency 2023).

Table 48. Projected deployment of new nuclear capacity in the advanced scenario.

Year	(Kim S. H. 2022) Nuc36_Ref	(Breakthrough 2022) High Cost & High LR	Projected New Nuclear Deployment for Advanced Scenario
2025	0 GW	0 GW	0 GW
2030	15 GW	0 GW	1 GW
2035	36 GW	7 GW	14 GW
2040	78 GW	53 GW	58 GW
2045	145 GW	118 GW	124 GW
2050	237 GW	245 GW	200 GW

7.3 Nuclear-Cost Evolution

With the LR values and deployment rates for new nuclear defined, this section will project nuclear cost evolutions. As a reminder, users able to model learning endogenously in their models are encouraged to directly do so. For others, this section can provide a useful reference for likely cost evolutions of nuclear technology. For anyone looking to utilize different cost evolutions based on other deployment projections, Figure 34 is included to allow for creation of additional cost evolutions not specifically created in this report.

7.3.1 Scaling Methodology

When mapping LRs to different BOAK OCC starting points, three options are possible:

1. Match the highest LR to the highest OCC and vice versa. In effect, this option would recognize that the highest starting point OCC has the highest potential for cost reductions because most of the learning benefits have not yet been internalized. However, this option would not be conservative because it is also possible that, in a worst-case scenario, high costs remain high.
2. Match the highest LR to the lowest OCC starting point and vice versa. This option would provide the broadest range of resulting results. The high OCC values would remain relatively high while the low OCC value would observe steep reductions. In effect, this would lead to both the most pessimistic and optimistic configurations being achieved within the specified bounds.
3. Use an average LR value for all OCC starting points. This constitutes something of a middle ground between the other two options. This option recognizes that the LR is a somewhat intrinsic feature of the technology and applies a middle-ground value consistently for each BOAK range.

As explained in previous sections, option 3 was ultimately selected in this analysis. This is because it avoids the contradictions of the other two while offering a more-consistent methodology to evaluate scenarios. A constant LR across the three scenarios was still deemed consistent with the ATB definitions. Despite the LR being consistent in all cases, the resulting cost evolution will likely not be. This is because each case will be matched to a different nuclear-deployment scenario, as was previously discussed.

The number of reactors deployed was determined from the projected deployment values for the conservative, moderate and advanced scenarios. The nuclear capacity for each time period of the scenarios was divided by the assumed operating capacity of a large reactor and an SMR. The assumed capacity for a large reactor is 1 GWe per reactor; for SMRs, it is 300 MWe per reactor. The other assumptions used in the analysis include the following:

- Specific reactor-type market share capture of 25% for each technology (Dixon et al. 2021)
- Spillover learning of 1/3 for remaining deployed units (Irwin and Klenow 1994).

Note that the market-share assumption may need to be revisited in future work. At this stage, it was taken to be a more realistic value than assuming a single reactor vendor dominates the entirety of the market. Incorporating these two assumptions leads to a modified LR equation shown below:

Starting point: generic LR equation:

$$NOAK = FOAK(1 - LR)^{Log_2(N)}. \tag{9}$$

Solving for FOAK costs with BOAK costs, and assuming here that BOAK = 2OAK:

$$BOAK = FOAK(1 - LR)^{Log_2(2)}. \tag{10}$$

Adjusted LR equation using BOAK costs in place of FOAK costs:

$$NOAK = \frac{BOAK}{1-LR}(1 - LR)^{Log_2(N)}. \tag{11}$$

The new LR equation accounting for split market (i.e., four equally split developers) and (33%) learning spillovers:

$$NOAK = \frac{BOAK}{1-LR}\left[(1 - LR)^{Log_2\left(\frac{1}{4}N\right)}\right] \times \left[(1 - \frac{LR}{3})^{Log_2(\frac{3}{4}N)}\right]. \tag{12}$$

Based on this formulation, for a given GW of projected nuclear capacity, the number of SMR and large reactor units deployed (assuming 25% market share and the 0.3/1 GW per unit) can be calculated. With these parameters set, the resulting cost reductions for a given GW deployment rate can be estimated. Figure 34 shows how total nuclear deployment levels in GW result in different cost reduction levels relative to a given starting point. The GW values selected in the x-axis are arbitrary and solely used for illustrative purposes. From the plot it can be observed that SMRs see faster cost reductions than large reactors with the same nuclear deployment rates. This is due to both higher learning rates (9.5% for SMRs vs. 8% for large) and a larger number of units deployed to reach a given GW value. Another interesting observation is how cost evolutions tend to plateau after around 100 GW of deployment. For instance, the evolution in reactor costs between a 200 GW scenario and a 300 GW scenario is only ~3 percentage points. The largest impact is observed at earlier rates of deployments: going from 5 GW of new nuclear deployed to 10 GW can contribute to nearly 10 percentage point difference. As noted earlier, this plot can be utilized to help define other cost evolutions for difference deployment projections if other scenarios are desired.

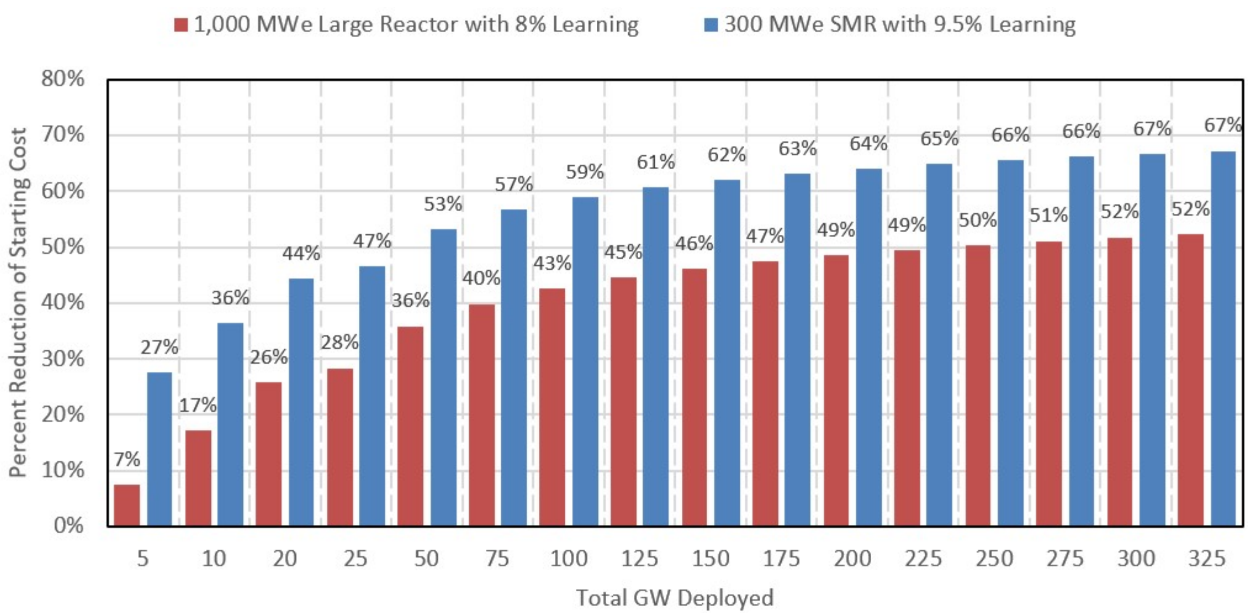

Figure 34. Illustration of cost reductions relative to an initial reference value at various deployment levels. Note that deployment values in the x-axis do not necessarily correspond to any given scenario previously described.

7.3.2 Conservative Scenario Resulting Cost Evolution

The results of the cost evolution with the outlined process for the conservative scenario yielded the generation capacity for the large reactors and SMRs for each step of deployment. The generation capacity for each period of the deployment is shown in Table 49. As observed, the power generation buildout is slow in this scenario prior to 2040. Even then, the ramp up is relatively slow compared to other scenarios. After applying Equation 11, the percentage decrease in cost reduction can be quantified. A maximum drop in costs of 39% over 20 years is projected under these conditions.

Table 49. Generation capacity (GWe) and cost declines for the conservative scenario.

	New Nuclear Deployment	Large Reactor Cost Declines from Initial	SMR Cost Declines from Initial
2030	0 GW	Ref	Ref

	New Nuclear Deployment	Large Reactor Cost Declines from Initial	SMR Cost Declines from Initial
2035	1 GW	0%	4%
2040	3 GW	4%	20%
2045	6 GW	12%	30%
2050	12 GW	23%	39%

The resulting cost evolution is summarized in Table 50. Due to lag in deployments, prices do not begin to significantly decrease until 2045. The ultimate 2050 prices are within the original BOAK Q1 and Q2 values. Hence under these conditions, it takes 20 years to reach the starting point of the moderate/advanced scenarios.

Table 50. Reactor-cost evolution (conservative scenario).

Year	Large Reactor OCC	SMR OCC
2030	$7,750	$10,000
2035	$7,750	$9,500
2040	$7,500	$8,000
2045	$6,750	$7,000
2050	$6,000	$6,250

7.3.3 Moderate Scenario Resulting Cost Evolution

The results of the cost evolution with the outlined process for the moderate scenario yielded an estimate deployed power generation of large reactors and SMRs and is shown in Table 51. In this case, deployment is also slow until the 2040s, but ramps up more quickly afterwards. Ultimate cost reduction ranges from 37% to 50% for large and small modular reactors.

Table 51. Generation capacity (GWe) and cost declines for the moderate scenario.

	New Nuclear Deployment	Large Reactor Cost Declines from Initial	SMR Cost Declines from Initial
2030	1.0 GW	Ref	Ref
2035	3.0 GW	4%	19%
2040	8.5 GW	18%	34%
2045	17.0 GW	28%	44%
2050	34.0 GW	37%	50%

The resulting cost evolution is summarized in Table 52. The ultimate cost drop in 2050 is now much more pronounced. Values appear to drop below BOAK Q1 ranges by 2040 under these conditions. The 2050 costs approach the targeted nuclear cost ranges highlighted in the DOE Liftoff study (DOE 2023).

Table 52. Reactor-cost reduction for the moderate scenario.

Year	Large Reactor OCC	SMR OCC
2030	$5,750	$8,000
2035	$5,500	$6,500
2040	$4,750	$5,250
2045	$4,250	$4,500
2050	$3,750	$4,000

7.3.4 Advanced Scenario Resulting Cost Evolution

The results of the cost evolution with the outlined process for the advanced scenario yielded an estimate of the generation deployment for large reactors and SMRs. The power generation for each period is shown in Table 53. The deployment by 2040 now matches the 2050 values in the conservative scenario. The ramp rate past that point accelerates quickly. This rapid scale of deployment will undoubtedly require significant investment to quickly ramp up the supply chain. Still, the majority of cost declines are obtained within the 2030-2040 timeline.

Table 53. Generation capacity (GWe) and cost declines for the advanced scenario.

	New Nuclear Deployment	Large Reactor Cost Declines from Initial	SMR Cost Declines from Initial
2030	1 GW	Ref	Ref
2035	14 GW	41%	25%
2040	58 GW	55%	43%
2045	124 GW	61%	51%
2050	200 GW	64%	55%

The resulting cost evolution is summarized in Table 54. The ultimate 2050 OCC ranges are exceedingly low but are not considered to have reached the theoretical floor. Costs even below this range have been observed in the US in the past (accounting for escalation to 2022 USD) (Dixon et al. 2017).

Table 54. Reactor-cost reduction for the advanced scenario.

Year	Large Reactor OCC	SMR OCC
2030	$5,500	$5,250
2035	$3,250	$4,000
2040	$2,500	$3,000
2045	$2,250	$2,500
2050	$2,000	$2,250

7.3.5 Overall Result Discussion

A side-by-side cost evolution of SMR and large reactor types is shown in Figure 35. The cost reductions for each technology exhibit similar trends. While SMR OCC costs start higher than larger reactors, they end up matching or even dropping below large-reactor costs. This is a result of slightly higher LR but namely due to the larger number of reactors per GW deployed, which allows for more learning per GW. This highlights the value of SMRs and why they are being actively pursued by the industry (beyond the lower total initial investment). Even in the conservative scenario, the SMR cost curve quickly approaches that of larger reactors. This is because the technology starts at a high cost and sees larger relative numbers of units deployed.

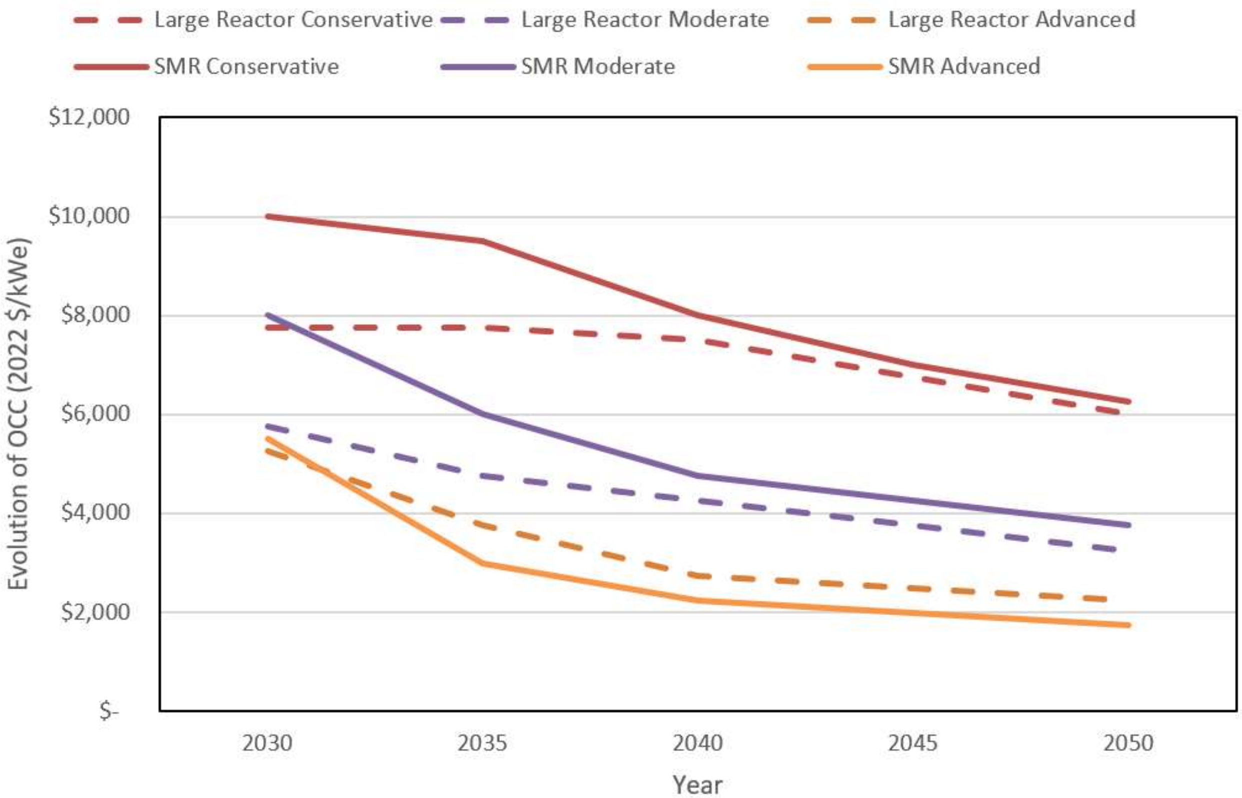

Figure 35. Small modular and large reactor OCC comparison over time.

The slowest cost reductions were unsurprisingly observed in the conservative large reactor case. Values remain almost flat through 2050. The narrowing of the cost window in 2050 is an interesting phenomenon as well. Within that timeline, costs under all scenarios end up between ~6,000 and ~2,000/kWe. Lastly, it is interesting to note the speed at which SMR costs drop below their large reactors in the advanced scenario. Within less than five years, SMRs already appear more competitive from an OCC standpoint. Care should be taken from drawing substantial comparative conclusions between the two reactor types from this study, however. Limitations in the initial data set primarily render the comparison challenging. Overall, the plot does show that while SMR costs may start higher costs per kW than their larger counterparts, the differences quickly narrow. Given that this figure only shows OCC values, it does not consider total cost. Even if SMRs have higher OCC values, when construction time and financing costs are included, total cost for a SMR can be cheaper than a large reactor.

8. ADDITIONAL CONSIDERATIONS

8.1 Impact of Subsidies

8.1.1 Inflation Reduction Act

- Over the past two decades, federal tax credits have been integral in driving the deployment of renewable energy (RE) in the US (Mai 2016). The production tax credit (PTC) was initially introduced in the Energy Policy Act of 1992 (US House 1992), primarily supporting wind energy projects. The PTC is calculated based on the electricity produced by a system and it is received every year the PTC is available as an amount depending on the total megawatt hour produced. On the other side, the ITC is calculated based on the CAPEX of building the system, and it is received only once as a proportion of the total given CAPEX. For instance, a 30% investment tax credit (ITC) for solar projects was established in the Energy Policy Act of 2005 (US House 2005). Since their inception, these federal tax credits have undergone cycles of expiration, extension, modification, and renewal. These fluctuations in federal tax policies have closely correlated with year-to-year variations in annual RE installations, notably in the wind sector, which has experienced boom-and-bust cycles tied to PTC expirations and renewals (Wiser 2015). Before the passage of the Consolidated Appropriations Act of 2016 in December 2015, the PTC had expired, and the ITC was slated to decrease by the end of 2016.
- The new Inflation Reduction Act (IRA) extends and modifies the PTC and ITC for renewable energy, making them technology-neutral, emissions-based credits. Some of them can be applied to advanced nuclear energy and the IRA allows a taxpayer to choose the PTC for ten years after the facility is built between 2025 or later, or to receive the ITC once. The new tax credits are set to be available from 2025 until the later of: 2032 or when the annual GHG emissions from production of electricity are equal or less than 25% of GHG emissions in 2022 (US House 2022). Note that the taxpayer must choose between the PTC or ITC, and it cannot have both. Also, credits could be extended further if the carbon emissions from the electric sector do not meet the 2022 threshold (US DOE Solar Energy Technology Office 2023). For a more detailed description of the different credits that apply to nuclear energy, see (Guaita and Hansen 2023).

The Act structures these incentives to promote investments in disadvantaged communities, with bonus credits available for projects meeting specific criteria, including wage and apprenticeship requirements, domestic content standards, and locations in energy communities.

The IRA recognizes a need to address the climate crisis, particularly in the electric power sector, where the United States aims to achieve 100% carbon pollution-free electricity by 2035 (IRA Guidebook 2023). To meet these climate goals, substantial investments are required to accelerate the deployment of existing clean energy technologies and to foster innovation in new technologies that can reverse the trend of CO_2 emissions.

The IRA provides a vast set of supporting financial mechanisms to incentivize investment in clean energy technologies and decarbonize energy production. The IRA introduced over 20 new or revised tax incentives and allocates substantial funding towards grants and loans. These financial mechanisms aim to stimulate investments in clean energy technology and accelerate the transition towards a cleaner, and more sustainable energy economy. Finally, the IRA also includes funding, in the form of grants and loans, dedicated to financing and deploying clean energy projects that reduce greenhouse gas emissions and other pollutants. It is important to note that the IRA gives bonuses to projects located in disadvantaged and energy communities, and to those projects that meet labor requirements (US House 2022).

Also, the IRA has expanded the Loan Authority for Innovative Clean Energy Projects: The Inflation Reduction Act grants the DOE Loan Programs Office $40 billion in loan authority, supported by $3.6 billion in credit subsidies. The purpose of this funding is loan guarantees under Section 1703 of the

Energy Policy Act and targets innovative clean energy technologies, including renewable energy systems, carbon capture, nuclear energy, and critical minerals processing, manufacturing, and recycling (US DOE 2023b).

In addition to these provisions, the Act introduces measures to ensure accessibility to these tax incentives for a broader range of entities, including state, local, and tribal governments, and tax-exempt organizations. These entities have the option to receive certain tax credits as direct payments or to transfer certain credits to unrelated parties in exchange for cash (IRS 2023).

8.1.2 Modelling Tax Credits

To better understand how taxes are included in modelling, refer to Guaita and Hansen (2023). The report shows how applying tax credits during an analysis is essential. This section describes briefly how models have addressed tax credits (such as the PTC and ITC) historically. It is important to note that the impacts of these policy credits have financial and accounting issues that need to be considered. For instance, certain situations may arise where the taxes owed fall short of the tax credited, thereby disqualifying an applicant from receiving the tax credit—a circumstance that the current IRA addresses through its monetization provision.

It is important to note that IRA tax credits exert no influence on the gross, or complete, costs associated with SMR construction and operation. Rather, these tax credits serve as financial incentives that increase the income after taxes for SMR developers or proprietors. The gross costs remain unaffected by IRA tax credits because the monetary value of the physical inputs to build a reactor do not change. For instance, when a construction firm purchases materials and equipment for constructing a nuclear reactor, it incurs the full expenses up front. The recovery of a portion of these expenditures in the form of tax credits occurs at a later point, typically when the company realizes profits—in other words, when the product is sold. Consequently, analysts should refrain from reporting reduced costs for SMRs due to tax credits. Instead, a clear distinction between gross costs (pre-tax credit) and net costs (post-tax credit) needs to be made when presenting findings.

Given this, there is an additional caveat that should be considered. The ITC reduces the flow of annual streams needed to recover capital. In other words, the ITC affects the capital-recovery factor of an investment project, and not the capital expenditure directly:

$$Discounted\ Capital\ Expenditure = \mathrm{CRF} * \mathrm{CAPEX} \qquad (13)$$

where

CRF = capital recovery factor, which is a function of the ITC.

CAPEX = capital expenditure.

The CRF includes the discount factor, and given this, the CAPEX is discounted when it is multiplied by the CRF.

On the other hand, the PTC decreases the present value of the variable O&M cost. The PTC, expressed in dollars per megawatt-hour, directly impacts the current assessment of variable operating expenses. In essence, a higher PTC leads to a proportionally lower operating cost. Moreover, this tax credit effectively diminishes the total expense associated with electricity generation from these technologies.

$$O\&M_{w/PTC} = \mathrm{O\&M} - \frac{PTC}{(1-TR)} \qquad (14)$$

where

O&M w/PTC = is the O&M costs after the PTC adjustment

O&M = O&M costs

TR = tax rate.

8.1.3 Domestic-Content Bonus

The IRA adds a bonus that increases the amount of the credit (45U, 45Y, and 48E) depending on domestic content of the materials used in the project:

> *A taxpayer establishes that the Domestic Content Requirement is satisfied with respect to an Applicable Project by certifying to the Secretary of the Treasury or her delegate (Secretary) (at such time, and in such form and manner, as the Secretary may prescribe) that "any steel, iron, or manufactured product which is a component of [the Applicable Project] (upon completion of construction) was produced in the United States (as determined under section [sic] 661 of title 49, Code of Federal Regulations).*

The bonus provision boosts the PTC by 10% and increases the ITC by 10 percentage points for projects meeting specific domestic-content requirements related to iron, steel, and manufactured goods. All iron and steel components of a facility must be entirely produced within the US. Additionally, 40% of the overall costs of manufactured products and their components integrated into a facility (20% for offshore wind) must be domestically produced, with this requirement rising to 55% by 2027 (or 2028 for offshore wind) (US DOE 2023b). Finally, to qualify for the complete bonus value, projects must additionally adhere to the prevailing-wage and apprenticeship prerequisites stipulated in the IRA.

8.1.4 Energy Community Bonus

In accordance with the IRA, the Energy Community Tax Credit Bonus offers an additional benefit of either up to 10% in the case of PTCs or an increase of 10 percentage points for ITCs. This bonus is specifically applicable to projects, facilities, and technologies situated within designated energy communities. Eligible taxpayers who meet specific energy-community criteria outlined in Sections 45, 48, 45Y, or 48E of the Internal Revenue Code may access enhanced credit amounts or rates (IRS 2023).

The IRA outlines the criteria for energy communities, defining them as follows:

- A brownfield site, identified in designated sections of the Comprehensive Environmental Response, Compensation, and Liability Act of 1980 (CERCLA).
- A metropolitan statistical area (MSA) or non-MSA that has demonstrated, at any point since 2009, a direct employment level of 0.17% or higher, or local tax revenues constituting 25% or more of the total, related to the extraction, processing, transport, or storage of coal, oil, or natural gas. Additionally, the area must have an unemployment rate equal to or exceeding the national average for the preceding year.
- A census tract, or one directly adjacent, where a coal mine has halted operations after 1999 or a coal-fired electric generating unit has been retired post-2009.
- The following map shows census tract directly adjoining a census tract with a coal closure (light orange), census tract with a coal closure (dark orange), and in dark purple the areas MSAs/non-MSAs that meet both the Fossil Fuel Employment (FFE) threshold and the unemployment rate requirement (IRS 2023b).

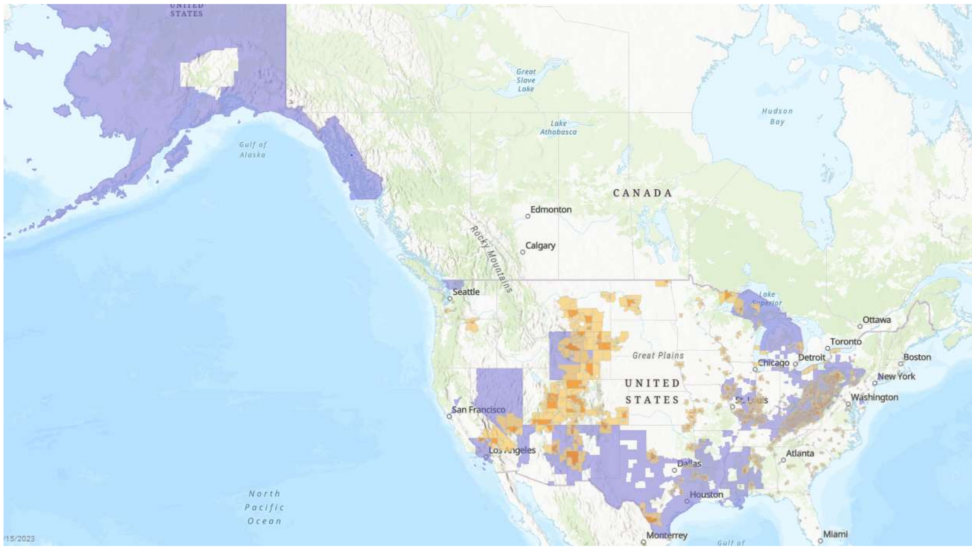

Figure 36. Areas that meet the requirements to receive the Energy Community Tax Credit Bonus.

8.1.5 Impact of Investment Tax Credits

ITCs have different levels depending on the bonus a project/taxpayer can access. The base rates and potential bonuses are shown in Table 55.

Table 55. ITC base rate and adders.

Base Rate		Bonus Domestic Content		Bonus Energy Communities	
Without Labor Requirements	With Labor Requirements	Does not meet Labor Requirements	Meets Labor Requirements	Does not meet Labor Requirements	Meets Labor Requirements
6%	30%	+2%	+10%	+2%	+10%

To meet the domestic-content requirement for an applicable project, a taxpayer should prove that any steel, iron, or manufactured product integral to the project under consideration, upon its construction completion, was produced in the US (US DOT 2023).

Also, the Energy Community Tax Credit Bonus provides up to 10% for PTCs or 10 percentage points for ITCs for projects, facilities, and technologies located in energy communities. To access this credit, taxpayers need to meet specific requirements related to energy communities (see IRA). It is important to mention that an energy community means a brownfield-site requirement under certain provisions of CERCLA, an MSA or non-MSA meeting requirements related to employment, local tax revenues, and unemployment rates, or sits within a census tract where a coal mine was closed after 1999 or a coal-fired electric generating unit was retired after 2009 (US House 2022).

The effect of the investment tax credit on the OCC is significant. There is a 46% OCC reduction when the ITC reaches 50%, as is presented in Figure 37. This means that the CAPEX of a project could be reduced almost by a half when the project receives a 40% ITC.

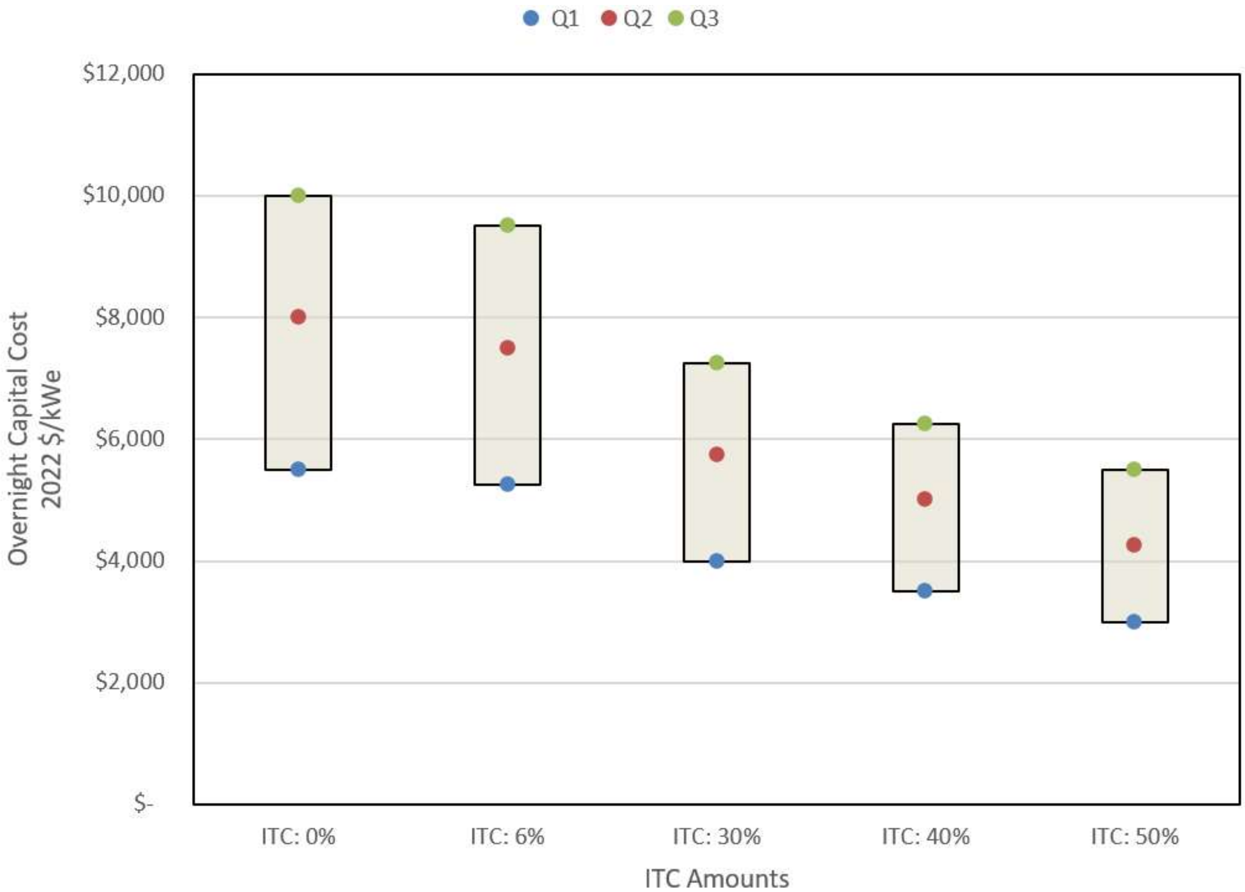

Figure 37. Sensitivity analysis of ITC on SMR OCC values.

Applying these ITC percentages to the BOAK estimates can result in drastic cost reductions, as shown in Table 56. In the case of a 40% ITC, large-reactor and SMR OCCs can drop by as much as 37%. This illustrates the impact of ITCs on overall nuclear-power-plant competitiveness.

Table 56. Impact of ITC on the BOAK OCC values.

	ITC	Conservative ($/kWe)	Moderate ($/kWe)	Advanced ($/kWe)
Large	0%	$7,750	$5,750	$5,250
	6%	$7,250	$5,500	$5,000
	30%	$5,750	$4,250	$3,750
	40%	$5,000	$3,750	$3,250
	50%	$4,250	$3,000	$2,750
SMR	0%	$10,000	$8,000	$5,500
	6%	$9,500	$7,500	$5,250
	30%	$7,250	$5,750	$4,000
	40%	$6,250	$5,000	$3,500
	50%	$5,500	$4,250	$3,000

8.1.6 Impact of Production Tax Credits

The PTC, which is only applicable for 10 years after the facility is built, has two different adders that increase the base rate, depending on the domestic-content and energy-community bonuses. Table 57 provides an overview of these bonus credits and their applicability.

Table 57. PTC base rates and adders.

Base Rate		Bonus Domestic Content		Bonus Energy Communities	
Base Rate w/o Labor Requirements	Base Rate with Labor Requirements	Does not meet Labor Requirements	Meets Labor Requirements	Does not meet Labor Requirements	Meets Labor Requirements
$5.50	$27.50	+$0.55	+$2.75	+$0.55	+$2.75

The relative impacts of the PTC on the O&M costs for large reactors with and without labor requirements being met are shown in Figure 38 and Figure 39, respectively. Figure 40 and Figure 41 show the PTC impact on the O&M for SMRs with and without labor requirements. The impact on the operating expenses of a reactor can be substantial—so much so that negative prices can be reached where an operator may be paid to run the power plant on top of the revenues from electricity sales. These negative prices have been encountered with subsidized renewables as well.

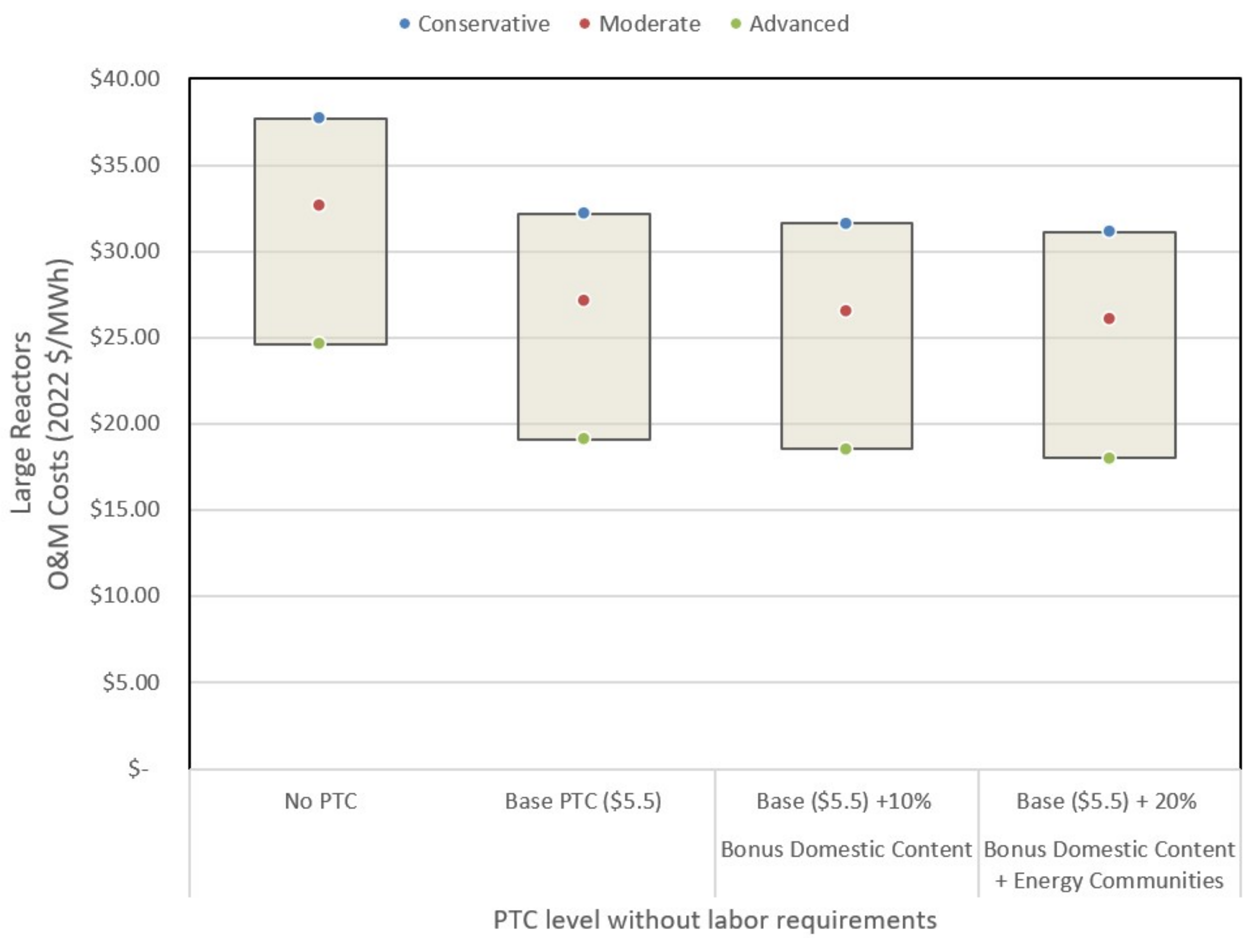

Figure 38. Large-reactors total O&M levels ($/MWh) on different levels of PTC without labor requirements.

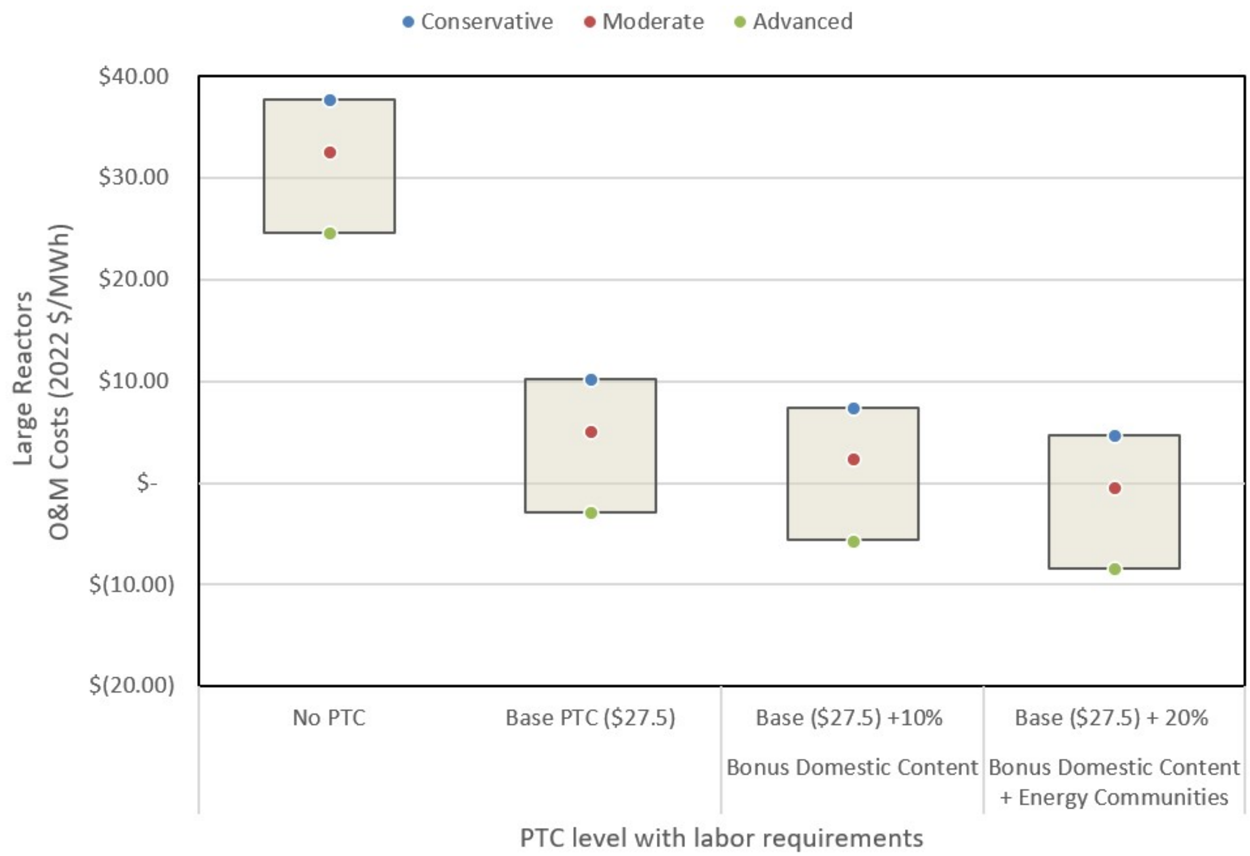

Figure 39. Large-reactors total O&M levels ($/MWh) on different levels of PTC with labor requirements.

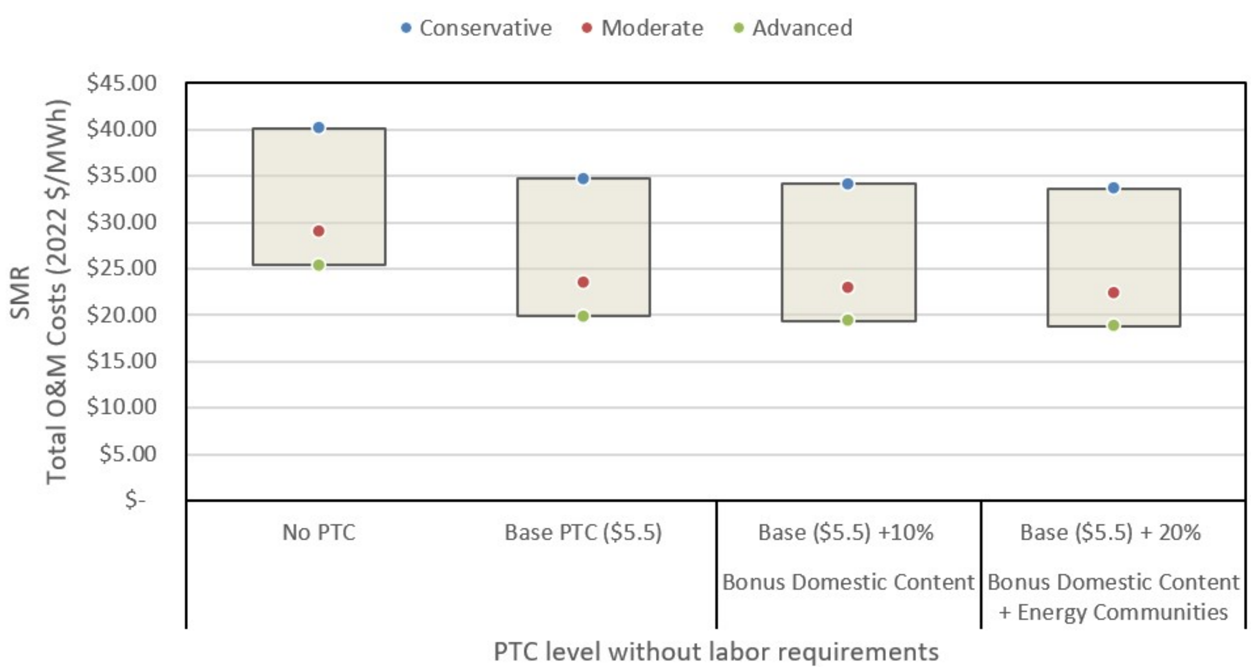

Figure 40. SMRs total O&M levels ($/MWh) on different levels of PTC without labor requirements.

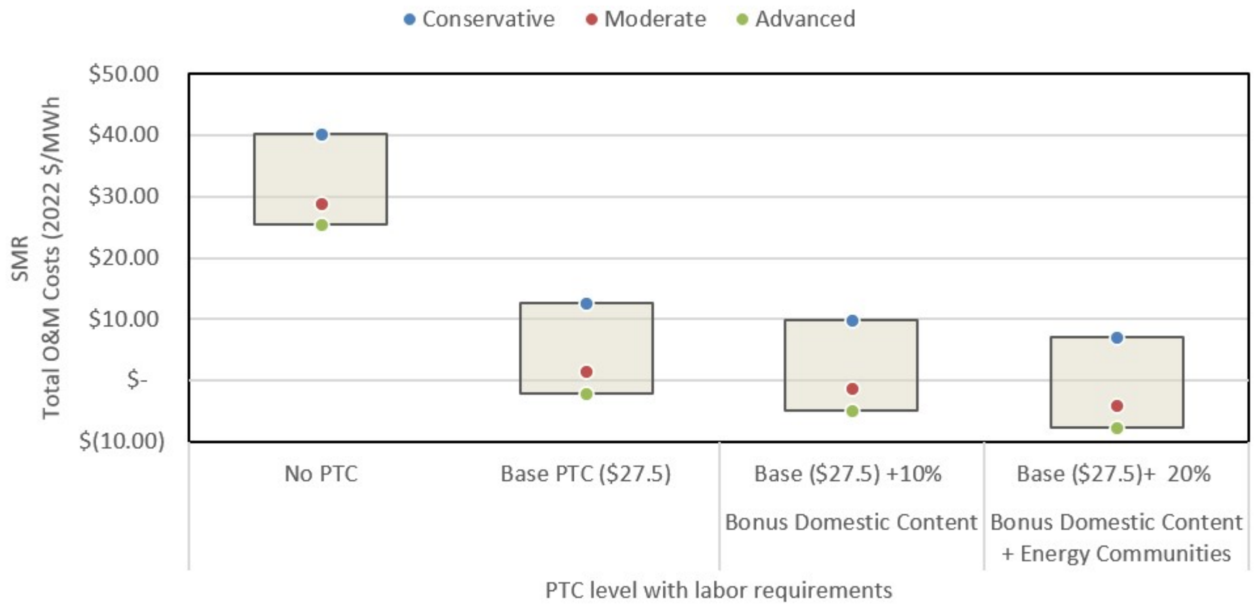

Figure 41. SMRs total O&M levels ($/MWh) on different levels of PTC with labor requirements.

A summary of the impact of PTCs is shown in Table 58. These values can be used to get a first-order estimate of the impact of PTCs on nuclear-power-plant economics. As shown, even for the base case, cost drops in the range of 75–133% can be expected for large reactors and on the order of 68–130% for SMRs.

Table 58. Impact of PTC with labor requirements on the total O&M costs of nuclear power plants.

	PTC	Conservative ($/MWh)	Moderate ($/MWh)	Advanced ($/MWh)
Large	0%	$40.18	$28.98	$25.39
	Base	$12.68	$1.48	($2.11)
	Base + 10%	$9.93	($1.27)	($4.86)
	Base + 20%	$7.18	($4.02)	($7.61)
SMR	0%	$37.69	$32.63	$24.61
	Base	$10.19	$5.13	($2.89)
	Base + 10%	$7.44	$2.38	($5.64)
	Base + 20%	$4.69	($0.37)	($8.39)

8.2 Coal-to-Nuclear Transition

Coal-to-nuclear (C2N) projects provide a potentially attractive path towards decarbonizing the power sector, with clear benefits to surrounding communities and utilities. A C2N project replaces a coal power plant (CPP) with a nuclear power plant that has comparable grid services without pollutant emissions and with a significant drop in CO_2 life-cycle emissions. These projects are likely to result in socioeconomic benefits to local energy communities with continued tax revenues and job creation and may result in specific federal incentives (as discussed in Section 8.1.4) (Hansen 2022, Hansen 2023). Previous work from DOE-NE (Hansen 2022) showed that 80% of recently retired or still-operating CPP sites can host SMRs, and 32% of these sites can host a GW-scale LWR (note that the large-reactor percentage is calculated from data in the report).

The cost estimates provided in this report will be impacted when considering C2N projects with potential re-use of CPP infrastructures. These include transportation infrastructure, transmission lines, switchyard equipment, office building, CPP site, electrical components and grid interconnections, cooling water supply and heat sink components, environmental permits (water and transmission rights), and potentially some balance of plant systems such as turbomachinery and steam generators. Compatibility of CPP site infrastructure for reuse in different NPP concepts was discussed in (Hansen, 2022) and (Hansen, 2023), and depends on CPP&NPP unit power sizes, associated technologies, and operating steam temperatures. Detailed infrastructure mapping and bottom-up cost savings estimates were included in (Hansen, 2022) and demonstrated the nuclear OCC could decrease by 15% to 35% when compared to a greenfield construction project, through the reuse of infrastructure from the coal facility. However, these savings may also be associated with increased operating costs from added maintenance associated with re-used components.

The costs provided in Table 59 show the OCC and operating costs for a C2N project on a large reactor and an SMR compared with reference (greenfield) ranges obtained in this study. The cost impact of C2N projects includes decommissioning and demolition requirements for CPP, the increase in O&M from added maintenance costs, and reduced OCC based on infrastructure reuse (and refurbished), as justified in Hansen (2022). These estimates use costs savings[d] obtained from Table 4–9 in Hansen (2022), with the following assumptions:

- The C2N scenarios referred to as "PWR/C2N#1" are assumed for a large reactor built on the CPP site where the nuclear power plant directly reuses the electrical and heat-sink CPP components, together with site and office buildings.
- The C2N scenarios referred to as "SFR/C2N#3" is assumed for an SMR built on the CPP site and connected to the retrofitted CPP balance of plant through thermal-energy storage. Direct connection (without energy storage) was proposed under "VHTR/C2N#2" scenario and provides a similar level of savings. This C2N scenario considers reuse of the CPP's steam generator and turbine plant equipment in addition to infrastructure reused under the C2N#1 scenario.
- For both types of reactors, the advanced of Table 59 includes the baseline savings assumptions with regards to corresponding greenfield scenario (C2N#0) from Table 4–9 in Hansen (2022). Similarly, conservative corresponds to conservative savings from Hansen (2022), and moderate corresponds to the average between baseline and conservative savings in Hansen (2022).
- For the conservative estimates, the 25% add-on to the fuels and O&M costs suggested in Hansen (2022) was not included in this analysis as more case-by-case assessment would be required to quantify the increased operating costs from C2N projects. Only the fixed O&M are varied, assuming that any decrease in nuclear OCC would be 1%-to-1% proportional to the increase in maintenance Fixed O&M. This accounts for increased maintenance costs associated with the re-use of older CPP components which were not designed for use in a nuclear plant, and which may be run at slightly off-optimal temperatures and pressures.

Future work should consider updating these numbers by applying the bottom-up cost impact assessment methodology developed in Hansen (2022) based on EEDB to the larger database gathered in this work to further refine these estimates. The most optimistic C2N cost savings reflected under the advanced scenario (up to 35% for SMR) assumes reuse of turbomachinery components, which may bring challenges to the project such as risks of extended timeline for refurbishment to meet licensing requirements, and associated costs. A more detailed case-by-case assessment is recommended to verify compatibility of these CPP components and cost savings associated with their reuse in the new NPP.

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[d] The term "savings" is used here as there are expected cost reductions on the OCC, which should be a dominating factor motivating a utility to undergo a C2N project. However, C2N projects may lead to increased O&M costs (resulting in negative savings).

Table 59. Cost ranges for C2N projects compared with reference costs.

		Ref			C2N		
		Advanced	Moderate	Conservative	Advanced	Moderate	Conservative
Large Reactor	OCC 2030 ($/kWe)	5,250	5,750	7,750	3,750	4,500	5,750
	OCC 2050 ($/kWe)	2,250	3,250	6,000	1,750	2,500	4,250
	Fuel Costs ($/MWh)	9.1	10.3	11.3	8.1	10.4	12.6
	Fixed O&M ($/kW-yr)	126.42	175.42	204.42	156	275	382
	Variable O&M ($MWh)	1.9	2.8	3.4	1.9	3.2	4.3
SMR	OCC 2030 ($/kWe)	5,500	8,000	10,000	3,250	4,750	7,250
	OCC 2050 ($/kWe)	1,750	3,750	6,250	1,250	2,000	4,000
	Fuel Costs ($/MWh)	10	11	12.1	10.0	12.4	15.1
	Fixed O&M ($/kW-yr)	126.42	175.42	204.42	114	146	268
	Variable O&M ($MWh)	1.9	2.8	3.4	2.2	2.9	3.5

8.3 Non-Electric Applications

While the report focused primarily on electric-grid applications, nuclear reactors primarily produce energy in the form of heat. This can be directly leveraged for a wide range of processes (e.g., chemical refining, hydrogen production, district heating, and desalination). Hence, there is a need to relate thermal-only costs for nuclear reactors for heat-based applications. This section discusses how to adjust costs (beyond simply multiplying by thermal efficiency) to account for these target markets. Note that for reactor concepts that are intended for both electric and heat application, the original BOAK estimates from Section 5.4 are still adequate.

8.3.1 Cost-Adjustment Methodology

Reactor costs were adjusted for thermal-only applications in a two-step process:

- Step 1: Account for reduction in capital and operating expenses from not using any power-conversion system.
- Step 2: Multiply the adjusted cost by thermal efficiency based on the specific type of reactor.

Step 1 consists of multiplying the reactor OCC and O&M costs by an adjustment factor. Note that simply removing the power-conversion cost (Account 23) is overly simplistic. This approach would not account for additional changes in direct costs (e.g., piping to turbine) or beyond (e.g., changes in indirect costs). Hence, a more-representative methodology was selected. Several of the data sets reviewed as part of this meta-analysis conducted comprehensive reactor-cost studies with and without associated turbomachinery. The estimates accounted for broader implications of heat-only systems to other direct costs, as well as indirect ones. The variation in total costs (including indirect) are summarized in Table 60. The average multiplier across the data set was found to be 0.795 for capital costs and 0.966 for O&M costs.

Table 60. Ratio of electric versus heat-only costs for advanced reactors.

		Capital Cost Ratio	Operating Cost Ratio
ORNL 1988	GE-LWR, Richland	0.931	0.974
	GE-LWR, Idaho	0.931	0.974
	GE-LWR, Savannah	0.930	0.974
	RI-LMR, Richland	0.915	0.973
	RI-LMR, Idaho	0.943	0.973
	RI-LMR, Savannah	0.916	0.973
	SWR, Richland	0.800	0.954
	SWR, Idaho	0.663	0.956
	SWR, Savanah	0.795	0.958
	WNP-1, Richland	0.894	0.953
INL 2010	VHTR, NOAK, 600 MWth, 1-unit, 750°C	0.805	
	VHTR, NOAK, 600 MWth, 1-unit, 800°C	0.796	
	VHTR, NOAK, 600 MWth, 1-unit, 850°C	0.786	
	VHTR, NOAK, 600 MWth, 1-unit, 900°C	0.794	
	VHTR, NOAK, 600 MWth, 1-unit, 950°C	0.789	
	VHTR, NOAK, 600 MWth, 4-unit, 750°C	0.755	
	VHTR, NOAK, 600 MWth, 4-unit, 800°C	0.743	
	VHTR, NOAK, 600 MWth, 4-unit, 850°C	0.732	
	VHTR, NOAK, 600 MWth, 4-unit, 900°C	0.741	
	VHTR, NOAK, 600 MWth, 4-unit, 950°C	0.734	
	VHTR, NOAK, 300 MWth, 1-unit, 750°C	0.797	
	VHTR, NOAK, 300 MWth, 1-unit, 800°C	0.787	
	VHTR, NOAK, 300 MWth, 1-unit, 850°C	0.777	

		Capital Cost Ratio	Operating Cost Ratio
	VHTR, NOAK, 300 MWth, 1-unit, 900°C	0.785	
	VHTR, NOAK, 300 MWth, 1-unit, 950°C	0.779	
	VHTR, NOAK, 300 MWth, 4-unit, 750°C	0.740	
	VHTR, NOAK, 300 MWth, 4-unit, 800°C	0.726	
	VHTR, NOAK, 300 MWth, 4-unit, 850°C	0.630	
	VHTR, NOAK, 300 MWth, 4-unit, 900°C	0.724	
	VHTR, NOAK, 300 MWth, 4-unit, 950°C	0.716	
	VHTR, NOAK, 600 MWth, 1-unit, 750°C	0.805	
	Average:	**0.795**	**0.966**

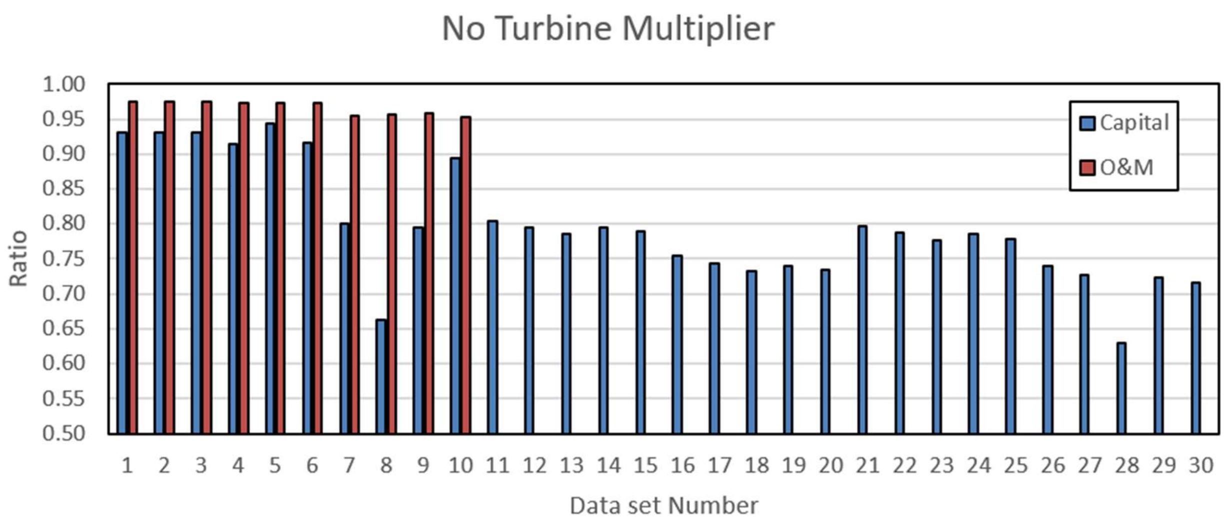

Figure 42. Visualization of the variations observed within the data set on ratio of reactor with versus without turbine.

The next step is to adjust cost values in previous sections from MWe to MWth. Thermal efficiency is very reactor and power-conversion dependent. Hence, care must be taken when attempting to infer thermal costs based on the system considered. Recommended efficiencies based on reactor types are provided in Table 61; the average efficiency in the data set is also shown. This can then be leveraged to adjust the large reactor and SMR cost ranges from previous sections. Additionally, the reactor-outlet temperature (ROT) is also listed to showcase the variations in the quality of heat from each reactor type.

Table 61. Thermal efficiencies based on reactor type.

Reactor Type	LWR	SFR	HTGR	All data
Thermal efficiency	33%	37%	40%	39%
ROT	325°C	550°C	750°C	727°C

8.3.2 Thermal-Only Cost Results

Adjusted thermal-only cost results are shown in Figure 43 and Table 62. The overall cost range is much lower than for electric applications, highlighting the inherent benefit of leveraging heat from nuclear directly and avoiding thermal-efficiency penalties. While LWR thermal energy costs may appear to be slightly lower than for the GenIV counterparts, it is important to note that the steam provided would be of much lower quality owing to the lower ROT.

Figure 43.Thermal-only OCC values based on reactor type.

Table 62. Summary of thermal-only OCC values based on reactor size and type.

Data Average ($/kWth)		LWR ($/kWth)		HTGR ($/kWth)		SFR ($/kWth)	
Large Reactors	SMR	Large Reactors	SMR	Large Reactors	SMR	Large Reactors	SMR
$1,500	$1,750	$1,500	$1,500	$1,750	$1,750	$1,500	$1,500
$1,750	$2,500	$1,500	$2,000	$1,750	$2,500	$1,750	$2,250
$2,500	$3,000	$2,000	$2,500	$2,500	$3,250	$2,250	$3,000

Similarly, the adjusted O&M costs are summarized in Figure 44 and Table 63. Similar trends to the OCC adjustment are observed.

Figure 44. Thermal-only O&M values based on reactor type.

Table 63. Summary of thermal-only O&M ($/MW$_{th}$h) values based on reactor size and type.

Data Average		LWR		HTGR		SFR	
Large Reactors	SMR	Large Reactors	SMR	Large Reactors	SMR	Large Reactors	SMR
$10	$10	$8	$8	$10	$10	$9	$10
$13	$11	$11	$10	$13	$12	$12	$11
$15	$15	$13	$13	$15	$16	$14	$15

8.4 Levelized Cost of Electricity

Estimating LCOE can be fraught with misrepresentation. This is especially the case when comparing variable energy sources with firm baseload capacity, such as nuclear, and because LCOE does not account for system-wide costs. For this reason, care must be taken when leveraging the metrics shown here and comparing them with other sources. Nevertheless, a discussion on LCOE can highlight some of the dynamics between OCCs of different nuclear systems and how they relate to overall costs.

8.4.1 Estimating Costs of Nuclear Reactors

The LCOE formula offers a high-level method for determining a metric that represents the expense of generating electricity for a specific renewable-energy technology that covers capital costs, O&M, performance, and fuel costs. In other words, it measures the lifetime costs of a technology, divided by its energy production. It is important to note that the simplest formulation excludes considerations such as financing, discounts rates, future replacements, or degradation costs.

Through a net present value calculation, the LCOE is determined in a manner that sets the project's net present value to zero for the chosen LCOE value (Short et al. 1995). Following Short et al. (1995), if the system output remains constant over time, the equation for LCOE can be reduced as follows:

$$LCOE = \frac{CRF*(1+FS\quad)*OCC+Fixed\ O\&M}{CF*8760\ hours/year} + Variable\ O\&M + Fuel \tag{15}$$

$$CRF = \frac{\{WACC*(1+WAC\quad)^{n}\}}{\{[(1+WACC)^{n}]-1\}} \tag{16}$$

$$FSIM = 0.5*\left(\frac{\left(1+e^{(LN(1+WACC)*CT))}\right)}{\left[\left(LN(1+WAC\quad)*\frac{CT}{PI}\right)^{2}+1\right]}\right)-1 \tag{17}$$

where

CRF = capital recovery factor, which represents the future uniform payments to repay the capital expenditure

Fixed O&M = fixed O&M costs

Variable O&M = variable O&M costs

Fuel = fuel cost

CF = capacity factor

WACC = weighted average cost of capital

n = number of years

FSIM = Financing Spend Impact Multiplier, which represents the interests paid during construction

e = exponential function

CT = construction time (years)

LN = natural logarithm

PI = pi

The LCOE formula should not be confused with an estimation of the cost of nuclear reactors. Note that the formula not only includes all the physical inputs used in a nuclear reactor (contained in the OCC), but also the O&M costs, fuel costs, and the interest rate, which is contained in the CRF. The CRF reduces to (1 + WACC) if n = 1. When n tends towards infinity, the CRF becomes equal to the WACC. This means that the formula expresses all costs incurred, not only for the construction, but also for the operation of the reactor, including what the owners expect to pay for interest. Furthermore, the LCOE expresses the price of electricity needed to cover all the cost incurred in nuclear-reactor construction, principal loan, and a normal interest rate. It means that using equation (15), if the energy units ($CF * 8760\mathrm{hours/year}$) are sold for said LCOE over the lifespan of the plant, the investor will be able to pay the loan and interests to recover the initial investment as well as annualized O&M costs.

8.4.2 LCOE Caveats

Sometimes the comparison of LCOE from different technologies could make one think that they are comparing full costs for different technologies. However, it is critical to note that the LCOE does not represent the cost of a nuclear reactor. LCOE represents at what price the electricity produced by a nuclear reactor should be sold to recover not only the capital expenditure, but also the cost of generating electricity during the life of the reactor and the interest rate (embedded in the CRF). In other words, the LCOE represents a theoretical sell price of electricity that is the product of the nuclear reactor.

The LCOE faces some limitations. First, it could underestimate costs by not including certain financial considerations crucial to actual decision making, such as interest-rate variations between and within the life period and construction period of the project. Additionally, it does not include risk premiums on interest rates; furthermore, it is consistent to use it for similar systems in similar contexts. Second, LCOE does not incorporate externalities such as regulatory changes affecting the cost structure of nuclear reactors. Finally, economic-factor dynamics or uncertain factors are not considered, providing a biased picture of investment-project competitiveness and profitability.

It is better to use the LCOE formula expressed in kWh for technical reasons. As it is possible to install a solar field that, in theory, produces a lot of power at the peak (measured in kWe), but the load factor might be low and, in kWh, the technology would not be profitable. Technologies are not compared by kWe because this would not consider the operability and load factors.

An additional consideration for LCOE evaluation is the implication of tax credits. Estimates have typically incorporated the ITC as a factor that affects the CRF, and the PTC as a factor that affects the O&M costs of electricity generation. This means that the numerator in the LCOE formula will be affected by the tax credits, decreasing its value and, furthermore, decreasing the LCOE. This procedure can lead one to think that the IRA affects nuclear-reactor costs. But the IRA does not affect the cost of physical inputs (labor, steel, cement, turbines, etc.) used to build nuclear reactors. The cost of the nuclear reactor is still the same as before and after the IRA. What would change, following the LCOE formula, is the theoretical sell price of electricity to recover a set of costs in a period of time. In financial terms, what is changing for the company is the income after tax it will receive.

8.4.3 WACC

The WACC can be understood as the weighted aggregation of each capital source (debt and equity). The WACC has different applications depending on what the company wants to do. For instance, the WACC could be used to represent the average after-tax cost of capital from all sources used by a company to finance its project. In this way, the WACC is used to determine the internal required rate of return, which expresses the return that other stakeholders demand to provide the company with financial capital. In this context, a lower WACC indicates a solid financial business understood as lower financial costs (Short et al. 1995). Additionally, WACC may also include a premium that accounts for project specific risk. In this report, the values shown are assumed to include this risk premium.

A single standard WACC cannot be used under any other contexts. The WACC is a function of many variables, such as equity and debt shares, federal warranty and loan programs, inflation, Federal Reserve interest rate, and economics. Given this, the WACC is super sensitive to the project, company, or any other assumptions made on economic parameters. For instance, companies use diverse different sources of debt funding with different interest rates for different periods, which makes it difficult to estimate the WACC for a given project. Also, these interest rates are affected by market and economic conditions. For example, between 2020 and 2023, the Federal Reserve interest rate went from +0.25 to +5.5%.

8.4.4 Discussion of SMRs vs Large Reactors

SMRs and large reactors exhibit distinct economic characteristics. SMRs generally entail lower initial capital costs owing to their modular design, facilitating cost savings through standardized components and factory fabrication. The construction time for SMRs is shorter thanks to concurrent manufacturing and onsite assembly. In terms of financing and investment, SMRs may attract more private funding due to their manageable scale and potentially quicker returns. Their operational flexibility allows for scalability and phases deployment, aligning with varying energy demands. Moreover, SMRs can benefit from potentially lower ongoing O&M costs, driven by their modular structure and simplified systems.

By contrast, large reactors involve higher upfront capital costs, longer construction times, and require substantial funding from government entities or major utility companies. While large reactors lack the flexibility of SMRs, they play a role in meeting specific capacity needs. The economic dynamics of SMRs and large reactors are influenced by factors such as reactor design, regulatory environments, and technological advancements, with each serving distinct niches in the energy landscape.

It is important to note that SMRs have a shorter construction time (measured as the time it takes from the first laying of concrete to the date that commercial operation starts), and for this reason, they incur less interest during construction. Modularization and standardization can reduce the time needed to build a new nuclear power plant. Given this, the financing needed would be less, which would decrease the interest burden.

8.4.5 Resulting LCOE Range

The Overnight Capital Cost (OCC), Total Capital Cost (TCC), and Levelized Cost of Electricity (LCOE) are crucial metrics in assessing the economic viability of a power plant. The OCC encompasses Direct (attributable to labor and materials) and Indirect costs (associated with manufacturing and construction activities) and does not include financing costs. Given this, OCC serves as a direct indicator of manufacturing and construction cost efficiencies. TCC adds financial costs, which includes the cost of equity, debt, and construction duration, reflecting the benefits of schedule reduction and risk perception.

Finally, LCOE extends beyond capital expenses, also including operation, maintenance, and decommissioning costs. Furthermore, LCOE represents the price of electricity needed to recover lifetime expenses, which includes the previous OCC and TCC.

The dynamic discussed above can be clearly seen in Figure 45. Here, the WACC is parametrized to evaluate its impact on the overall LCOE under given OCC and O&M values assuming a construction time, reactor lifetime, and capacity factors. Even at low WACC values, while SMR OCC cost range used in this study are higher than those of large reactors, the corresponding LCOEs are much closer. The LCOE for SMRs for the advanced case becomes cheaper than that of a larger reactor when the WACC increases. This is primarily due to the shorter timeline for construction of these smaller systems. This chart is based on the 2030 OCC values, so no learning is attributed. Once learning is achieved, it’s expected that the SMR LCOE costs would fall significantly versus the large reactor costs. Overall, the plot highlights the substantial contribution of financing costs on nuclear energy. For instance, the LCOE almost doubles for an increase in the WACC from 4 to 10%. Higher interest rates significantly increase the LCOE.

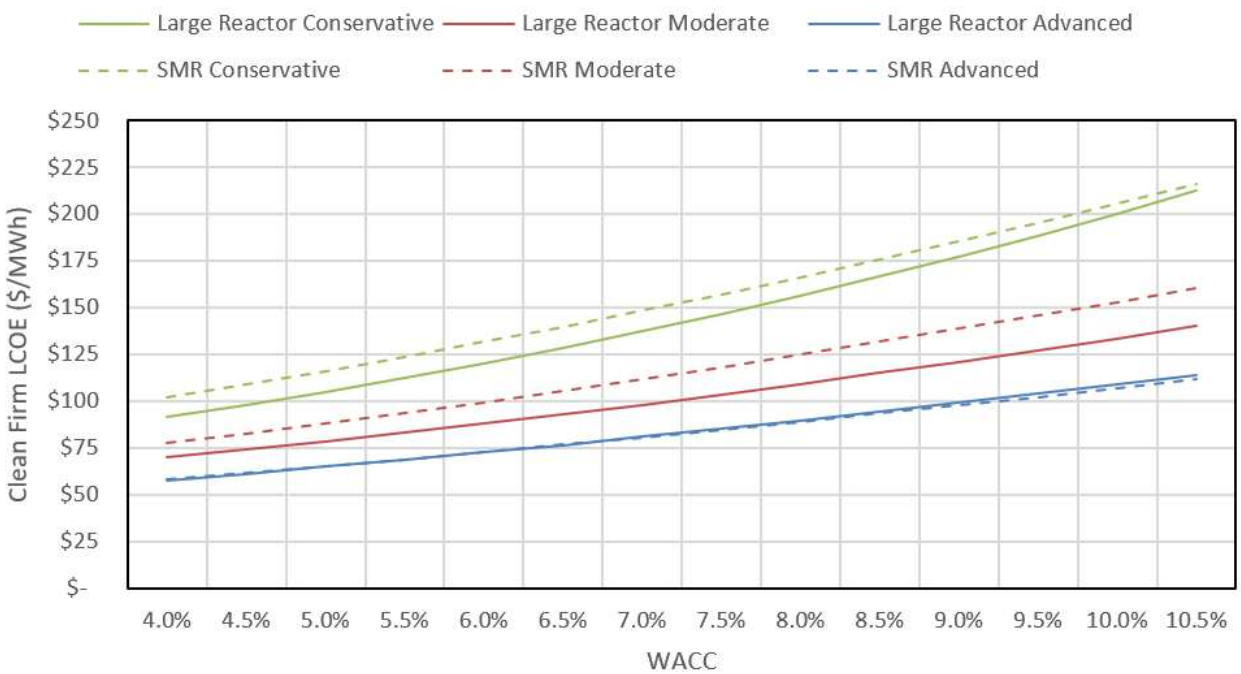

Figure 45. Impact of variations in WACC on overall LCOE for 2030 reactor OCC.

As an illustrative example, a WACC of 7.5% was selected based Lazard (2023). Table 64 summarizes the resulting LCOE values for 2030 and 2040, with and without investment credits. LCOE for 2040 were estimated assuming the same O&M costs as 2030. Note that O&M costs are assumed to be constant overtime, but the OCC values decrease over time due to deployment and learning.

A cost reduction of 37% for large reactors and small modular reactors could be possible if the ITC is claimed. For this example, it is assumed that the ITC goes beyond 2032 and remains valid till 2040.

Table 64. Estimated LCOE for large reactors and SMR under a given WACC value and with/without tax credits.

Year	WACC and ITC	Large Reactor ($/MWh)			SMR ($/MWh)		
		Conservative	Moderate	Advanced	Conservative	Moderate	Advanced
2030 OCC	7.5% WACC	$147	$104	$85	$157	$118	$85
	7.5% WACC + 40% ITC	$93	$66	$54	$100	$75	$54
2040 OCC	7.5% WACC	$143	$92	$60	$134	$88	$53
	7.5% WACC + 40% ITC	$91	$58	$38	$85	$56	$34

9. NEXT STEPS AND FURTHER IMPROVEMENTS

The work in this report is not without limitations and should be viewed as a first attempt at defining reference costs for nuclear power plants. A systematic methodology for aggregating a significant amount of cost estimate data was developed and can provide a foundation for additional refinements in the future. The analysis is highly dependent on the data itself; adding more data sets would help refine the cost ranges as the industry moves closer to nuclear deployment. Better granularity is particularly needed between reactor types. The current data set contains too few FOAK estimates, which are also below the observed costs of the Vogtle plant. It is likely that limitations in the current data are biasing the conservative costs for large reactors downwards slightly. In addition to seeking other large reactor FOAK bottom-up data sets, other options would include manipulating public Vogtle cost estimates to ensure financial costs are treated separately or incorporating more historical data from US reactors built in the past.

Further, including more data sets would be especially useful if cost trends within subgroupings (e.g., GenIV SMR or Large HTGR) are to be evaluated in a statistical fashion. Future work should consider the inclusion of additional data sets where gaps exist and as more data is made available in the literature. Additionally, data sets that are built on actual commercial nuclear-plant offerings should be prioritized. Adding different designs would also help better elucidate the differences between reactor types and sizes and their respective cost drivers. A more-thorough qualification of the estimate type (Class 1–5 in project management) would result in a better understanding of the robustness of estimates and could perhaps be leveraged to weigh estimates against one another in the future. Currently, this is not explicitly specified in the compiled data sets; hence, expert judgement will need to be needed to determine the quality of a given estimate.

Specifically, determining conclusively how costs change between reactor types would require substantially more data generation. Ideally, several cost estimators would conduct independent estimates across reactor types (and with similar design assumptions) in a round-robin fashion. Relying on the same contractor to evaluate multiple reactor types would control for biases while having several estimators repeating the same analysis would build confidence in the end results. These cost estimates would then be aggregated and compared to draw any conclusion on how costs compare across reactor types.

As reactor demonstration efforts pick up pace and cost estimates are refined, incorporating these estimates into this study would help significantly improve the confidence of the projected ranges. Similarly, there would be value in surveying reactor vendors on their cost projections, anonymizing them, and then processing their estimates to project an industry-average cost. On a similar note, the analyses could greatly benefit from evaluating nuclear-cost evolutions from defense applications. This is likely the only source of observed recent data on nuclear-grade construction; therefore, it would be invaluable for furthering this study.

As previously discussed, many reactors are considering pairing the plant with thermal-energy storage to support more-flexible operations and energy peaking. None of the data sets included looked at the cost of including thermal-energy storage at the reactor. Going forward, consideration of the added cost/benefit of thermal-energy storage should be evaluated more closely.

For many of the estimates included, data was needed to fill missing items within estimates. The synthesized data are only as good as the data that was used to support them, which were typically based on averages from other estimates. There is room to improve this data-synthetization approach by developing better estimates of the specific costs that must be synthesized.

The cost-projection analysis could be expanded further as well. Contingency costs could be accounted for on a percentage basis, and it could estimate for each level 2 account accordingly. More scenarios can be compiled and considered (beyond those evaluated here). An average of sorts could be conducted. Sensitivity analysis on the learning rate could be useful; similarly, a better methodology for matching different learning rates to different starting costs would strengthen the analysis as well. Last, the market-share assumption should be revisited and refined if possible as the market evolves.

Ultimately, the main goal of updating the work is to help refine the cost ranges further and update them as needed. While the spread in costs of nuclear reactors is relatively high at this stage, this is expected to decrease as commercial nuclear reactors near deployment. This will provide resource planners with higher confidence in estimates as they look to an ever-changing future energy landscape.

10. SUMMARY

This report set out to identify reference cost values and trends for nuclear reactors. Because most of the attention in the US has shifted towards advanced SMRs, the work attempted to develop a methodology that can encompass these costs. Hence, a broad set of detailed cost estimates from the literature was compiled, mapped, escalated, and processed. The intent was to detect ranges between estimators, rather than select single data points or estimates. Once all data were normalized to a given baseline, cost ranges were obtained by studying quartiles within groupings of the data. This option was favored because it provided a statistically neutral approach to determine cost ranges, one that would not be overly biased by outliers in the estimates. The large set of estimates used in the analysis provided greater confidence in the range obtained.

Because the data consisted of a mix of FOAK and NOAK, the resulting quartile values were termed BOAK. This term was intentionally defined loosely so that, in some sense, it can represent a next commercial offering (between the second and fourth unit deployed of a given kind). The analysis avoided estimating FOAK values because demonstrations are expected to occur by 2030 via the DOE ARDP or through other commercial companies. The study essentially focused on cost ranges for projections between 2030 and 2050. Hence the BOAK estimate was deemed adequate.

Once the BOAK ranges were identified. The evolution of these costs was projected in different scenarios with varying degrees of optimism and pessimism. The literature on LRs was reviewed, and average LRs for SMRs and large reactors were calculated among a curated list of data points. The BOAK OCC values and corresponding LRs were then matched to different deployment scenarios. This allowed the report to assess the overall evolution in costs by applying learning adjustment to the number of units deployed.

In addition to the OCC estimates, ranges were also provided for O&M values. Fuel costs were calculated using reference values and basic assumptions on the main reactor types under consideration. Other operational costs were either obtained from the existing US fleet (for large reactors) or from evaluating the data set compiled (for SMRs). Resulting cost ranges were also provided in the form of quartiles based on reactor types.

Last, additional considerations were included on a wide variety of topics in this report. This included an assessment of the impact of subsidies and C2N transitions. Parametric evaluations of LCOE calculations were also discussed. Workflows to produce heat-only conversion factors for the cost estimates were included as well. All this information can be used to help energy planners in their efforts to evaluate potential future energy-generation technologies.

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Appendix A

Original Reference Cost Data

The following tables provide the COA structures and total costs in which most of the input data were organized. Most sources followed the EEDB or GIF COA while some used a hybrid structure. One such hybrid was used for documenting cost estimates for ABR1000 in the source.

	Source	(Idaho National Laboratory 2010)	(Idaho National Laboratory 2010)	(Idaho National Laboratory 2010)
	Reactor Name	VHTGR	VHTGR	VHTGR
	Reactor Size Per Unit (MWe)	281	281	281
	Source Dollar Year	2009	2009	2009
All	**Account Title**	**Total Costs**	**Total Costs**	**Total Costs**
10	**Capitalized Pre-Construction Costs**	**$76,500,000**	**$91,000,000**	**$89,500,000**
11	Land and Land Rights	$5,000,000	$10,000,000	$5,000,000
13	Plant Licensing	$50,000,000	$55,000,000	$63,000,000
131	Preapplication	$15,000,000	$15,000,000	$15,000,000
132	Preparation	$23,000,000	$28,000,000	$23,000,000
133	Regulatory Review	$12,000,000	$12,000,000	$25,000,000
14	Plant Permits	$3,000,000	$3,000,000	$3,000,000
18	Other Pre-Construction Costs	$18,500,000	$23,000,000	$18,500,000
20	**Capitalized Direct Costs**	**$669,270,000**	**$2,138,423,569**	**$1,082,075,000**
21	Structures and Improvements	$116,460,000	$330,756,763	$185,670,000
22	Reactor System	$215,460,000	$633,928,981	$300,000,000
221	Reactor Components	$127,340,000	$366,981,975	$156,950,000
221.12	Outer vessel structure	$80,560,000	$232,090,065	$94,800,000
221.13	Inner vessel structure	$30,510,000	$88,689,054	$35,780,000
221.33	Moderator	$16,270,000	$46,202,855	$26,370,000
222	Main Heat Transport System	$18,840,000	$55,564,593	$21,980,000
222.13	Heat exchangers	$18,840,000	$55,564,593	$21,980,000
223	Safety Systems	$12,620,000	$50,461,591	$28,910,000
223.6	Reactor Cavity Cooling System (RCCS)	$12,620,000	$50,461,591	$28,910,000
225	Fuel Handling Systems	$56,660,000	$160,920,822	$92,160,000
225.6	Core Refueling Equipment	$56,660,000	$160,920,822	$92,160,000
23	Energy Conversion System	$203,490,000	$745,260,000	$379,990,000
232	Energy Applications	$103,180,000	$412,740,000	$266,900,000
233	Ultimate Heat Sink	$39,980,000	$159,130,000	$42,020,000
237	Miscellaneous Energy System Equipment	$60,330,000	$173,390,000	$71,070,000
29	Contingency on Direct Costs	$133,850,000	$427,680,000	$216,420,000

30	**Capitalized Indirect Services Cost**	**$327,860,000**	**$1,003,670,000**	**$517,750,000**
31	Factory & Field Indirect Costs	$307,860,000	$983,670,000	$497,750,000
35	Engineering Services Offsite	$20,000,000	$20,000,000	$20,000,000
353	Owner's Engineering Oversight	$20,000,000	$20,000,000	$20,000,000
40	**Capitalized Pre-COD Personnel Costs**	**$80,310,000**	**$256,610,000**	**$129,850,000**
50	**Capitalized Supplementary Costs**	**$195,610,000**	**$781,470,000**	**$236,130,000**
55	Initial Fuel Inventory	$72,410,000	$289,660,000	$112,920,000
58	Decommissioning	$123,200,000	$491,810,000	$123,210,000

	Source	(Idaho National Laboratory 2010)	(Idaho National Laboratory 2010)	(Idaho National Laboratory 2010)
	Reactor Name	VHTGR	VHTGR	VHTGR
	Reactor Size Per Unit (MWe)	281	164	164
	Source Dollar Year	2009	2009	2009
All	**Account Title**	**Total Costs**	**Total Costs**	**Total Costs**
10	**Capitalized Pre-Construction Costs**	**$104,000,000**	**$76,500,000**	**$91,000,000**
11	Land and Land Rights	$10,000,000	$5,000,000	$10,000,000
13	Plant Licensing	$68,000,000	$50,000,000	$55,000,000
131	Preapplication	$15,000,000	$15,000,000	$15,000,000
132	Preparation	$28,000,000	$23,000,000	$28,000,000
133	Regulatory Review	$25,000,000	$12,000,000	$12,000,000
14	Plant Permits	$3,000,000	$3,000,000	$3,000,000
18	Other Pre-Construction Costs	$23,000,000	$18,500,000	$23,000,000
20	**Capitalized Direct Costs**	**$3,576,750,000**	**$475,060,000**	**$1,513,310,000**
21	Structures and Improvements	$527,300,000	$88,950,000	$252,620,000
22	Reactor System	$894,190,000	$151,960,000	$447,960,000
221	Reactor Components	$452,030,000	$86,500,000	$249,450,000
221.11	Reactor support	$0	$0	$0
221.12	Outer vessel structure	$273,130,000	$55,650,000	$160,390,000
221.13	Inner vessel structure	$104,010,000	$21,550,000	$62,660,000
221.33	Moderator	$74,890,000	$9,300,000	$26,400,000
222	Main Heat Transport System	$64,800,000	$13,320,000	$39,280,000
222.13	Heat exchangers	$64,800,000	$13,320,000	$39,280,000
223	Safety Systems	$115,630,000	$9,640,000	$38,540,000
223.6	Reactor Cavity Cooling System (RCCS)	$115,630,000	$9,640,000	$38,540,000
225	Fuel Handling Systems	$261,730,000	$42,500,000	$120,690,000
225.6	Core Refueling Equipment	$261,730,000	$42,500,000	$120,690,000
23	Energy Conversion System	$1,439,910,000	$118,100,000	$425,850,000
232	Energy Applications	$1,067,600,000	$76,710,000	$306,850,000
233	Ultimate Heat Sink	$168,070,000	$0	$0

237	Miscellaneous Energy System Equipment	$204,240,000	$41,390,000	$119,000,000
29	Contingency on Direct Costs	$715,350,000	$95,010,000	$302,660,000
30	**Capitalized Indirect Services Cost**	**$1,665,310,000**	**$238,530,000**	**$716,120,000**
31	Factory & Field Indirect Costs	$1,645,310,000	$218,530,000	$696,120,000
35	Engineering Services Offsite	$20,000,000	$20,000,000	$20,000,000
353	Owner's Engineering Oversight	$20,000,000	$20,000,000	$20,000,000
40	**Capitalized Pre-COD Personnel Costs**	**$429,210,000**	**$57,010,000**	**$181,060,000**
50	**Capitalized Supplementary Costs**	**$943,500,000**	**$118,870,000**	**$474,460,000**
55	Initial Fuel Inventory	$451,690,000	$46,860,000	$187,430,000
58	Decommissioning	$491,810,000	$72,010,000	$287,030,000

	Source	(Idaho National Laboratory 2010)	(Idaho National Laboratory 2010)	(Stewart et al. 2020)
	Reactor Name	VHTGR	VHTGR	AP1000
	Reactor Size Per Unit (MWe)	164	164	1100
	Source Dollar Year	2009	2009	2017
All	**Account Title**	**Total Costs**	**Total Costs**	**Total Costs**
10	**Capitalized Pre-Construction Costs**	**$89,500,000**	**$104,000,000**	**$0**
11	Land and Land Rights	$5,000,000	$10,000,000	$0
13	Plant Licensing	$63,000,000	$68,000,000	$0
131	Preapplication	$15,000,000	$15,000,000	$0
132	Preparation	$23,000,000	$28,000,000	$0
133	Regulatory Review	$25,000,000	$25,000,000	$0
14	Plant Permits	$3,000,000	$3,000,000	$0
18	Other Pre-Construction Costs	$18,500,000	$23,000,000	$0
20	**Capitalized Direct Costs**	**$799,550,000**	**$2,646,860,000**	**$7,340,000,000**
21	Structures and Improvements	$141,810,000	$402,730,000	$2,580,000,000
22	Reactor System	$218,560,000	$652,530,000	$2,570,000,000
221	Reactor Components	$111,830,000	$322,110,000	$0
221.12	Outer vessel structure	$65,470,000	$188,720,000	$0
221.13	Inner vessel structure	$25,270,000	$73,480,000	$0
221.33	Moderator	$21,090,000	$59,910,000	$0
222	Main Heat Transport System	$15,530,000	$45,800,000	$0
222.13	Heat exchangers	$15,530,000	$45,800,000	$0
223	Safety Systems	$22,080,000	$88,320,000	$0
223.6	Reactor Cavity Cooling System (RCCS)	$22,080,000	$88,320,000	$0
225	Fuel Handling Systems	$69,120,000	$196,300,000	$0
225.6	Core Refueling Equipment	$69,120,000	$196,300,000	$0
23	Energy Conversion System	$279,270,000	$1,062,230,000	$1,450,000,000
232	Energy Applications	$198,430,000	$793,710,000	$0

233	Ultimate Heat Sink	$32,090,000	$128,370,000	$280,000,000
237	Miscellaneous Energy System Equipment	$48,750,000	$140,150,000	$0
24	Electrical Equipment	$0	$0	$540,000,000
26	Miscellaneous Equipment	$0	$0	$200,000,000
29	Contingency on Direct Costs	$159,910,000	$529,370,000	$0
30	**Capitalized Indirect Services Cost**	**$387,790,000**	**$1,237,560,000**	**$0**
31	Factory & Field Indirect Costs	$367,790,000	$1,217,560,000	$0
35	Engineering Services Offsite	$20,000,000	$20,000,000	$0
353	Owner's Engineering Oversight	$20,000,000	$20,000,000	$0
40	**Capitalized Pre-COD Personnel Costs**	**$95,950,000**	**$317,620,000**	**$0**
50	**Capitalized Supplementary Costs**	**$145,080,000**	**$579,300,000**	**$0**
55	Initial Fuel Inventory	$73,070,000	$292,270,000	$0
56	Spent Fuel Storage	$0	$0	$0
58	Decommissioning	$72,010,000	$287,030,000	$0
59	Contingency on Supplementary Costs	$0	$0	$0

	Source	(Stewart et al. 2020)	(Stewart et al. 2020)	(Stewart et al. 2020)
	Reactor Name	AP1000	Traditional HTGR	Traditional HTGR
	Reactor Size Per Unit (MWe)	1100	275	275
	Source Dollar Year	2017	2017	2017
All	**Account Title**	**Total Costs**	**Total Costs**	**Total Costs**
20	**Capitalized Direct Costs**	**$4,220,000,000**	**$2,610,000,000**	**$5,290,000,000**
21	Structures and Improvements	$1,490,000,000	$810,000,000	$1,870,000,000
22	Reactor System	$1,480,000,000	$830,000,000	$1,580,000,000
23	Energy Conversion System	$830,000,000	$430,000,000	$1,000,000,000
233	Ultimate Heat Sink	$160,000,000	$60,000,000	$110,000,000
24	Electrical Equipment	$310,000,000	$230,000,000	$310,000,000
26	Miscellaneous Equipment	$110,000,000	$310,000,000	$530,000,000

	Source	(Energy Economic Data Base Program 1987)	(Energy Economic Data Base Program 1987)	(Energy Economic Data Base Program 1987)
	Reactor Name	PWR12-BE	Improved PWR 06-BE	Improved PWR 12-BE
	Reactor Size Per Unit (MWe)	1144	587	1144
	Source Dollar Year	1987	1987	1987
All	**Account Title**	**Total Costs**	**Total Costs**	**Total Costs**
10	**Capitalized Pre-Construction Costs**	**$11,315,000**	**$6,764,000**	**$10,385,000**
11	Land and Land Rights	$0	$0	$0
12	Site Permits	$11,315,000	$6,764,000	$10,385,000
20	**Capitalized Direct Costs**	**$1,006,557,232**	**$607,704,875**	**$758,372,158**

21	Structures and Improvements	$298,128,527	$179,999,523	$273,167,950
211	Site Preparation/Yard Work	$24,992,519	$15,328,062	$25,641,072
212	Reactor Island Civil Structures	$65,817,870	$41,029,493	$63,287,700
213	Core Function Buildings	$49,592,346	$24,961,637	$49,542,988
213.1	Energy Conversion Building	$23,152,330	$14,537,640	$24,016,965
213.2	Control Building	$18,187,781	$86,093	$17,552,526
213.3	Pipe Tunnels	$8,184,465	$10,296,565	$7,908,317
213.4	Electrical Tunnels	$67,770	$41,339	$65,180
213.5	Emergency and Start-up Power Systems	$0	$0	$0
214	Buildings to Support Core Function	$32,579,727	$45,116,755	$32,806,652
214.1	Spent Fuel Management Building	$9,879,103	$0	$9,603,975
214.3	Wastewater Treatment Building	$767,292	$742,688	$742,688
214.5	Fire Protection Building	$426,826	$412,888	$412,880
214.6	Non-essential Switchgear Building	$535,897	$364,403	$520,479
215	Supply Chain Buildings	$14,367,318	$0	$13,883,581
215.4	Radwaste Building	$14,367,318	$0	$13,883,581
216	Human Resources Buildings	$8,797,747	$5,946,576	$8,509,957
216.1	Administration Building	$6,646,347	$3,872,369	$6,435,750
216.2	Security Building and Gatehouse	$1,361,955	$1,312,224	$1,312,224
216.4	Operation and Maintenance (O&M) Center	$789,445	$761,983	$761,983
218	Temporary Structures	$101,981,000	$47,617,000	$79,496,000
22	Reactor System	$303,048,181	$203,948,640	$116,453,881
221	Reactor Components	$189,856,879	$138,083,977	$10,304,492
222	Main Heat Transport System	$9,898,419	$5,752,906	$9,526,332
223	Safety Systems	$12,416,260	$6,613,860	$11,541,651
224	Radioactive Waste Processing Systems	$20,942,407	$12,486,384	$19,885,175
225	Fuel Handling Systems	$3,167,160	$1,950,571	$3,103,137
225.6	Core Refueling Equipment	$0	$0	$0
226	Other Reactor Plant Equipment	$37,759,511	$19,157,902	$33,544,955
227	Reactor Instrumentation and Control (I&C)	$21,555,270	$14,921,307	$21,329,518
228	Reactor Plant Miscellaneous Items	$7,452,275	$4,981,733	$7,218,621
23	Energy Conversion System	$277,355,902	$146,263,869	$261,890,265
232	Energy Applications	$156,307,467	$83,934,713	$150,048,591
232.1	Electricity Generation Systems	$22,323,194	$10,735,434	$18,690,726
233	Ultimate Heat Sink	$82,559,522	$41,358,879	$78,029,301
233.1	Water Condensing Systems	$48,980,965	$23,552,562	$47,841,279
234	Feed Heating Systems	$23,588,801	$11,575,348	$19,800,879
236	Common Instrumentation & Controls	$6,854,212	$4,140,594	$6,216,008
237	Miscellaneous Energy System Equipment	$8,045,900	$5,254,335	$7,795,486

24	Electrical Equipment	$81,322,724	$47,514,226	$62,241,755
241	Switchgear	$11,946,283	$9,091,207	$11,225,531
242	Station Service Equipment	$20,163,388	$16,662,791	$19,039,790
243	Switchboards	$2,048,898	$1,504,622	$1,858,721
244	Protective Systems Equipment	$4,261,386	$3,486,736	$4,308,153
245	Electrical Raceway Systems	$22,301,683	$8,729,658	$12,419,117
246	Power and Control Cables and Wiring	$20,601,086	$8,039,212	$13,390,443
25	(Not used)	$0	$0	$0
26	Miscellaneous Equipment	$46,701,898	$29,978,617	$44,618,307
261	Transportation and Lift Equipment	$5,993,830	$4,427,051	$6,607,780
262	Air, Water, Plant Fuel Oil, and Steam Systems	$31,557,038	$18,504,606	$29,234,187
263	Communications Equipment	$6,415,046	$4,973,234	$6,139,079
264	Furnishing and Fixtures	$2,735,984	$2,073,726	$2,637,261
30	**Capitalized Indirect Services Cost**	**$375,569,000**	**$141,193,000**	**$216,867,000**
31	Factory & Field Indirect Costs	$63,546,000	$35,410,000	$56,182,000
32	Factory & Construction Supervision	$79,703,000	$36,151,000	$56,321,000
33	Commissioning and Startup Costs	$11,267,000	$4,937,000	$7,714,000
35	Engineering Services Offsite	$208,083,000	$59,546,000	$88,729,000
351	Off-Site	$200,871,000	$57,482,000	$85,654,000
353	Owner's Engineering Oversight	$7,212,000	$2,064,000	$3,075,000
36	PM/CM Services	$12,970,000	$5,149,000	$7,921,000
362	On-Site	$4,659,000	$1,333,000	$1,987,000
50	**Capitalized Supplementary Costs**	**$62,192,000**	**$31,670,000**	**$49,589,000**
54	Insurance	$62,192,000	$31,670,000	$49,589,000

	Source	(Energy Economic Data Base Program 1987)	(Oak Ridge National Laboratory 1988)	(Oak Ridge National Laboratory 1988)
	Reactor Name	Advanced PWR 6-BE	GA/MHTGR - Commercial	SAFR
	Reactor Size Per Unit (MWe)	587	133	300
	Source Dollar Year	1987	1988	1988
All	**Account Title**	**Total Costs**	**Total Costs**	**Total Costs**
10	**Capitalized Pre-Construction Costs**	**$6,269,000**	**$0**	**$0**
12	Site Permits	$6,269,000	$0	$0
20	**Capitalized Direct Costs**	**$558,035,000**	**$1,275,921,000**	**$1,110,000,000**
21	Structures and Improvements	$173,317,000	$546,348,000	$160,000,000
211	Site Preparation/Yard Work	$10,577,000	$0	$0
212	Reactor Island Civil Structures	$85,753,000	$0	$0
213	Core Function Buildings	$24,831,000	$0	$0
213.1	Energy Conversion Building	$14,537,000	$0	$0

213.3	Pipe Tunnels	$10,294,000	$0	$0
214	Buildings to Support Core Function	$10,228,000	$0	$0
214.3	Wastewater Treatment Building	$743,000	$0	$0
214.5	Fire Protection Building	$412,000	$0	$0
216	Human Resources Buildings	$5,179,000	$0	$0
216.1	Administration Building	$3,868,000	$0	$0
216.2	Security Building and Gatehouse	$1,311,000	$0	$0
218	Temporary Structures	$36,749,000	$162,923,000	$40,000,000
22	Reactor System	$180,298,000	$577,247,000	$762,000,000
221	Reactor Components	$128,335,000	$0	$0
222	Main Heat Transport System	$6,323,000	$0	$0
223	Safety Systems	$4,928,000	$0	$0
224	Radioactive Waste Processing Systems	$10,211,000	$0	$0
225	Fuel Handling Systems	$1,004,000	$0	$0
226	Other Reactor Plant Equipment	$9,301,000	$0	$0
227	Reactor Instrumentation and Control (I&C)	$14,921,000	$0	$0
228	Reactor Plant Miscellaneous Items	$5,275,000	$0	$0
23	Energy Conversion System	$143,378,000	$55,481,000	$122,000,000
233	Ultimate Heat Sink	$38,474,000	$0	$30,000,000
233.1	Water Condensing Systems	$23,553,000	$0	$0
234	Feed Heating Systems	$11,575,000	$0	$0
236	Common Instrumentation & Controls	$4,140,000	$0	$0
237	Miscellaneous Energy System Equipment	$5,254,000	$0	$0
24	Electrical Equipment	$30,560,000	$72,675,000	$36,000,000
241	Switchgear	$5,306,000	$0	$0
242	Station Service Equipment	$4,734,000	$0	$0
243	Switchboards	$1,504,000	$0	$0
244	Protective Systems Equipment	$3,486,000	$0	$0
245	Electrical Raceway Systems	$8,293,000	$0	$0
246	Power and Control Cables and Wiring	$7,237,000	$0	$0
25	(Not used)	$0	$0	$0
26	Miscellaneous Equipment	$30,482,000	$24,170,000	$30,000,000
261	Transportation and Lift Equipment	$4,932,000	$0	$0
262	Air, Water, Plant Fuel Oil, and Steam Systems	$18,504,000	$0	$0
263	Communications Equipment	$4,972,000	$0	$0
264	Furnishing and Fixtures	$2,074,000	$0	$0
30	**Capitalized Indirect Services Cost**	**$157,106,000**	**$190,377,000**	**$385,000,000**
31	Factory & Field Indirect Costs	$30,870,000	$0	$0
32	Factory & Construction Supervision	$65,180,000	$56,179,000	$17,000,000

33	Commissioning and Startup Costs	$3,667,000	$0	$0
35	Engineering Services Offsite	$53,657,000	$134,198,000	$227,000,000
351	Off-Site	$51,797,000	$0	$118,000,000
353	Owner's Engineering Oversight	$1,860,000	$0	$0
36	PM/CM Services	$3,732,000	$0	$141,000,000
362	On-Site	$1,201,000	$0	$141,000,000
50	**Capitalized Supplementary Costs**	**$28,957,000**	**$0**	**$0**
54	Insurance	$28,957,000	$0	$0

	Source	(Oak Ridge National Laboratory 1988)	(Stewart W. R., J. Gregory, and K. Shirvan 2022)	(Stewart W. R., J. Gregory, and K. Shirvan 2022)
	Reactor Name	PRISM	SMBWR	MMNC
	Reactor Size Per Unit (MWe)	104	290	77
	Source Dollar Year	1988	2023	2022
All	**Account Title**	**Total Costs**	**Total Costs**	**Total Costs**
20	**Capitalized Direct Costs**	**$1,374,000,000**	**$658,573,056**	**$1,191,459,081**
21	Structures and Improvements	$205,000,000	$246,664,601	$504,996,019
211	Site Preparation/Yard Work	$0	$17,787,226	$32,669,418
212	Reactor Island Civil Structures	$0	$110,711,726	$335,287,820
213	Core Function Buildings	$0	$71,755,090	$78,247,399
213.1	Energy Conversion Building	$0	$27,766,424	$40,496,303
213.2	Control Building	$0	$37,550,206	$37,092,956
213.3	Pipe Tunnels	$0	$6,392,987	$524,573
213.4	Electrical Tunnels	$0	$45,472	$133,567
213.5	Emergency and Start-up Power Systems	$0	$0	$0
214	Buildings to Support Core Function	$0	$15,329,818	$25,055,014
214.1	Spent Fuel Management Building	$0	$9,137,485	$20,343,743
214.3	Wastewater Treatment Building	$0	$459,442	$0
214.5	Fire Protection Building	$0	$854,863	$854,863
214.6	Non-essential Switchgear Building	$0	$380,105	$0
215	Supply Chain Buildings	$0	$12,793,082	$19,513,657
215.4	Radwaste Building	$0	$12,793,082	$19,513,657
216	Human Resources Buildings	$0	$18,287,659	$14,222,711
216.1	Administration Building	$0	$13,627,491	$9,562,543
216.2	Security Building and Gatehouse	$0	$3,075,988	$3,075,988
216.4	Operation and Maintenance (O&M) Center	$0	$1,584,180	$1,584,180
218	Temporary Structures	$85,000,000	$0	$0
22	Reactor System	$944,000,000	$169,648,321	$289,662,627
221	Reactor Components	$0	$90,190,473	$145,491,170

222	Main Heat Transport System	$0	$0	$18,007,919
223	Safety Systems	$0	$1,046,570	$0
224	Radioactive Waste Processing Systems	$0	$8,525,582	$16,846,479
225	Fuel Handling Systems	$0	$5,739,716	$11,234,571
226	Other Reactor Plant Equipment	$0	$20,144,539	$30,538,377
227	Reactor Instrumentation and Control (I&C)	$0	$27,595,376	$60,688,183
228	Reactor Plant Miscellaneous Items	$0	$16,406,065	$6,855,928
23	Energy Conversion System	$133,000,000	$146,213,791	$222,594,041
232	Energy Applications	$0	$72,220,447	$100,578,447
232.1	Electricity Generation Systems	$0	$15,285,726	$23,202,711
233	Ultimate Heat Sink	$37,000,000	$54,474,665	$93,000,473
233.1	Water Condensing Systems	$0	$36,182,665	$71,290,082
234	Feed Heating Systems	$0	$13,043,555	$19,040,514
236	Common Instrumentation & Controls	$0	$2,933,774	$4,554,936
237	Miscellaneous Energy System Equipment	$0	$3,541,350	$5,419,671
24	Electrical Equipment	$57,000,000	$47,049,328	$62,215,674
241	Switchgear	$0	$6,071,974	$8,029,274
242	Station Service Equipment	$0	$4,978,375	$6,583,154
243	Switchboards	$0	$1,559,535	$2,062,251
244	Protective Systems Equipment	$0	$3,347,615	$4,426,718
245	Electrical Raceway Systems	$0	$17,194,721	$22,737,438
246	Power and Control Cables and Wiring	$0	$13,897,108	$18,376,840
26	Miscellaneous Equipment	$35,000,000	$48,997,015	$111,990,719
261	Transportation and Lift Equipment	$0	$12,676,936	$21,850,753
262	Air, Water, Plant Fuel Oil, and Steam Systems	$0	$30,724,661	$74,817,763
263	Communications Equipment	$0	$3,758,722	$10,292,690
264	Furnishing and Fixtures	$0	$1,836,696	$5,029,513
30	**Capitalized Indirect Services Cost**	**$478,000,000**	**$0**	**$0**
32	Factory & Construction Supervision	$33,000,000	$0	$0
35	Engineering Services Offsite	$280,000,000	$0	$0
351	Off-Site	$152,000,000	$0	$0
36	PM/CM Services	$165,000,000	$0	$0
362	On-Site	$165,000,000	$0	$0

	Source	Shirvan Private Communication (Tim Cat Data)	Prosser, J. H., et al. 2023	Prosser, J. H., et al. 2023
	Reactor Name	AP1000	SFR SAINC	SFR SAINC
	Reactor Size Per Unit (MWe)	0	165	311
	Source Dollar Year	0	2023	2023
All	**Account Title**	**Total Costs**	**Total Costs**	**Total Costs**
10	**Capitalized Pre-Construction Costs**	**$0**	**$78,492,125**	**$94,789,878**
11	Land and Land Rights	$0	$11,000,000	$11,000,000
12	Site Permits	$0	$1,332,867	$1,598,891
13	Plant Licensing	$0	$12,932,869	$24,382,988
14	Plant Permits	$0	$12,679,167	$12,679,167
15	Plant Studies	$0	$12,679,167	$12,679,167
16	Plant Reports	$0	$2,106,869	$3,972,186
18	Other Pre-Construction Costs	$0	$12,679,167	$12,679,167
19	Contingency on Pre-Construction Costs	$0	$13,082,021	$15,798,313
20	**Capitalized Direct Costs**	**$1,894,115,598**	**$522,517,443**	**$802,309,257**
21	Structures and Improvements	$476,998,990	$95,629,345	$116,911,260
211	Site Preparation/Yard Work	$40,670,128	$0	$0
212	Reactor Island Civil Structures	$319,285,818	$0	$0
213	Core Function Buildings	$56,643,683	$0	$0
213.1	Energy Conversion Building	$50,565,739	$0	$0
213.2	Control Building	$5,056,418	$0	$0
213.3	Pipe Tunnels	$1,021,526	$0	$0
214	Buildings to Support Core Function	$36,656,499	$0	$0
214.1	Spent Fuel Management Building	$14,173,479	$0	$0
214.5	Fire Protection Building	$854,863	$0	$0
215	Supply Chain Buildings	$14,793,465	$0	$0
215.4	Radwaste Building	$14,793,465	$0	$0
216	Human Resources Buildings	$8,949,398	$0	$0
216.1	Administration Building	$4,289,230	$0	$0
216.2	Security Building and Gatehouse	$3,075,988	$0	$0
216.4	Operation and Maintenance (O&M) Center	$1,584,180	$0	$0
22	Reactor System	$599,647,151	$103,339,440	$168,954,960
221	Reactor Components	$144,187,946	$0	$0
222	Main Heat Transport System	$248,993,597	$0	$0
223	Safety Systems	$41,553,629	$0	$0
224	Radioactive Waste Processing Systems	$39,479,223	$0	$0
225	Fuel Handling Systems	$4,481,758	$0	$0
226	Other Reactor Plant Equipment	$58,801,764	$0	$0

227	Reactor Instrumentation and Control (I&C)	$48,256,492	$0	$0
228	Reactor Plant Miscellaneous Items	$13,892,741	$0	$0
23	Energy Conversion System	$614,814,270	$132,152,226	$221,628,126
232	Energy Applications	$349,983,438	$0	$0
232.1	Electricity Generation Systems	$67,683,950	$0	$0
233	Ultimate Heat Sink	$177,529,180	$17,362,219	$28,452,265
233.1	Water Condensing Systems	$108,229,671	$0	$0
234	Feed Heating Systems	$60,323,015	$0	$0
236	Common Instrumentation & Controls	$12,685,348	$0	$0
237	Miscellaneous Energy System Equipment	$14,293,290	$0	$0
24	Electrical Equipment	$105,668,741	$56,420,704	$93,718,631
241	Switchgear	$13,637,131	$0	$0
242	Station Service Equipment	$11,181,002	$0	$0
243	Switchboards	$3,502,581	$0	$0
244	Protective Systems Equipment	$7,518,454	$0	$0
245	Electrical Raceway Systems	$38,617,864	$0	$0
246	Power and Control Cables and Wiring	$31,211,709	$0	$0
26	Miscellaneous Equipment	$96,986,446	$47,811,287	$67,299,871
261	Transportation and Lift Equipment	$12,615,175	$0	$0
262	Air, Water, Plant Fuel Oil, and Steam Systems	$70,091,635	$0	$0
263	Communications Equipment	$9,592,346	$0	$0
264	Furnishing and Fixtures	$4,687,291	$0	$0
28	Simulator	$0	$78,200	$78,200
29	Contingency on Direct Costs	$0	$87,086,240	$133,718,210
30	**Capitalized Indirect Services Cost**	**$0**	**$317,954,906**	**$474,353,968**
31	Factory & Field Indirect Costs	$0	$131,256,382	$201,540,085
33	Commissioning and Startup Costs	$0	$13,960,144	$19,168,403
35	Engineering Services Offsite	$0	$84,659,197	$123,100,443
36	PM/CM Services	$0	$35,086,698	$51,486,042
361	Off-Site	$0	$14,708,518	$20,195,981
362	On-Site	$0	$20,378,180	$31,290,061
39	Contingency on Indirect Services Cost	$0	$52,992,484	$79,058,995
40	**Capitalized Pre-COD Personnel Costs**	**$0**	**$156,098,569**	**$156,098,569**
41	Staff Recruitment and Training	$0	$81,563,820	$81,563,820
42	Staff Housing	$0	$5,900,000	$5,900,000
43	Staff Salary-Related Costs	$0	$42,618,321	$42,618,321
49	Contingency on Owner's Costs	$0	$26,016,428	$26,016,428
50	**Capitalized Supplementary Costs**	**$0**	**$218,717,196**	**$396,659,489**

51	Shipping and Transportation Costs	$0	$1,614,001	$1,614,001
52	Spare Parts	$0	$11,890,753	$19,218,004
53	Taxes	$0	$1,862,043	$3,510,602
54	Insurance	$0	$9,189,645	$13,714,531
55	Initial Fuel Inventory	$0	$144,233,628	$279,724,434
58	Decommissioning	$0	$14,606,673	$14,606,673
59	Contingency on Supplementary Costs	$0	$35,320,454	$64,271,243

	Source	Prosser, J. H., et al. 2023	Prosser, J. H., et al. 2023	Prosser, J. H., et al. 2023
	Reactor Name	SFR SAINC	SFR SAINC	SFR SAINC
	Reactor Size Per Unit (MWe)	311	311	311
	Source Dollar Year	2023	2023	2023
All	**Account Title**	**Total Costs**	**Total Costs**	**Total Costs**
10	**Capitalized Pre-Construction Costs**	**$129,550,576**	**$199,160,897**	**$338,332,534**
11	Land and Land Rights	$11,000,000	$11,000,000	$11,000,000
12	Site Permits	$2,210,965	$3,509,217	$6,064,884
13	Plant Licensing	$48,765,977	$97,531,954	$195,063,908
14	Plant Permits	$12,679,167	$12,679,167	$12,679,167
15	Plant Studies	$12,679,167	$12,679,167	$12,679,167
16	Plant Reports	$7,944,372	$15,888,743	$31,777,487
18	Other Pre-Construction Costs	$12,679,167	$12,679,167	$12,679,167
19	Contingency on Pre-Construction Costs	$21,591,763	$33,193,483	$56,388,756
20	**Capitalized Direct Costs**	**$1,374,312,697**	**$2,480,534,867**	**$4,554,682,834**
21	Structures and Improvements	$165,877,192	$269,737,393	$474,190,698
22	Reactor System	$301,181,474	$572,490,428	$1,095,689,053
23	Energy Conversion System	$412,776,490	$782,931,698	$1,485,240,090
233	Ultimate Heat Sink	$52,390,709	$98,187,960	$184,205,485
24	Electrical Equipment	$163,208,222	$284,231,234	$495,013,752
26	Miscellaneous Equipment	$102,139,004	$157,565,237	$245,279,035
28	Simulator	$78,200	$156,400	$156,400
29	Contingency on Direct Costs	$229,052,116	$413,422,478	$759,113,806
30	**Capitalized Indirect Services Cost**	**$790,078,201**	**$1,396,113,839**	**$2,526,179,555**
31	Factory & Field Indirect Costs	$345,227,350	$623,110,358	$1,144,136,328
33	Commissioning and Startup Costs	$27,108,216	$38,336,807	$54,216,432
35	Engineering Services Offsite	$203,903,310	$364,848,213	$672,041,379
36	PM/CM Services	$82,159,625	$137,132,821	$234,755,490
361	Off-Site	$28,561,430	$40,391,961	$57,122,860
362	On-Site	$53,598,195	$96,740,860	$177,632,631
39	Contingency on Indirect Services Cost	$131,679,700	$232,685,640	$421,029,926

40	**Capitalized Pre-COD Personnel Costs**	**$207,188,420**	**$325,194,471**	**$565,891,313**
41	Staff Recruitment and Training	$107,935,430	$169,343,035	$294,641,585
42	Staff Housing	$7,850,000	$12,325,000	$21,450,000
43	Staff Salary-Related Costs	$56,871,587	$89,327,358	$155,484,509
49	Contingency on Owner's Costs	$34,531,403	$54,199,079	$94,315,219
50	**Capitalized Supplementary Costs**	**$773,590,381**	**$1,541,650,585**	**$3,128,619,141**
51	Shipping and Transportation Costs	$8,968,615	$35,874,461	$143,497,845
52	Spare Parts	$34,084,069	$62,676,467	$116,161,713
53	Taxes	$7,021,205	$14,042,410	$28,084,820
54	Insurance	$22,939,415	$40,758,096	$74,191,949
55	Initial Fuel Inventory	$559,448,868	$1,118,897,736	$2,237,795,472
58	Decommissioning	$15,460,830	$18,450,379	$18,521,559
59	Contingency on Supplementary Costs	$125,667,380	$250,951,035	$510,365,784

	Source	Prosser, J. H., et al. 2023	INL Internal Numbers	(Black, G. A., F. Aydogan, and C. L. Koerner. 2019)
	Reactor Name	SFR SAINC	Versatile Test Reactor	NuScale SMR
	Reactor Size Per Unit (MWe)	311	VTR is not intended for electricity production	60
	Source Dollar Year	2023	2020	2015
All	**Account Title**	**Total Costs**	**Total Costs**	**Total Costs**
10	**Capitalized Pre-Construction Costs**	**$407,957,224**	**$25,812,500**	**$0**
11	Land and Land Rights	$11,000,000	$0	$0
12	Site Permits	$7,375,110	$700,000	$0
13	Plant Licensing	$243,829,884	$0	$0
14	Plant Permits	$12,679,167	$0	$0
15	Plant Studies	$12,679,167	$23,625,000	$0
16	Plant Reports	$39,721,859	$1,487,500	$0
18	Other Pre-Construction Costs	$12,679,167	$0	$0
19	Contingency on Pre-Construction Costs	$67,992,871	$0	$0
20	**Capitalized Direct Costs**	**$5,557,882,456**	**$1,819,576,266**	**$1,805,616,142**
21	Structures and Improvements	$579,008,809	$989,307,663	$612,136,797
211	Site Preparation/Yard Work	$0	$16,241,336	$0
212	Reactor Island Civil Structures	$0	$47,253,121	$0
213	Core Function Buildings	$0	$49,689,595	$0
213.1	Energy Conversion Building	$0	$47,253,121	$0
213.4	Electrical Tunnels	$0	$2,436,474	$0
214	Buildings to Support Core Function	$0	$153,122,842	$0
215	Supply Chain Buildings	$0	$201,764,455	$0

215.5	Fuel Service Building	$0	$201,764,455	$0
216	Human Resources Buildings	$0	$39,784,667	$0
216.2	Security Building and Gatehouse	$0	$5,892,123	$0
216.4	Operation and Maintenance (O&M) Center	$0	$33,892,544	$0
217	Miscellaneous Other Structures	$0	$10,424,376	$0
217.3	Roads and Paved Areas	$0	$10,424,376	$0
22	Reactor System	$1,351,816,912	$585,238,012	$869,360,876
221	Reactor Components	$0	$132,698,750	$0
222	Main Heat Transport System	$0	$83,049,256	$0
223	Safety Systems	$0	$8,600,000	$0
224	Radioactive Waste Processing Systems	$0	$16,755,000	$0
225	Fuel Handling Systems	$0	$28,000,000	$0
226	Other Reactor Plant Equipment	$0	$10,211,000	$0
228	Reactor Plant Miscellaneous Items	$0	$13,305,000	$0
23	Energy Conversion System	$1,825,277,326	$111,750,000	$226,202,162
232	Energy Applications	$0	$0	$196,121,808
233	Ultimate Heat Sink	$225,609,336	$111,750,000	$30,080,354
233.1	Water Condensing Systems	$0	$55,875,000	$0
24	Electrical Equipment	$591,817,894	$93,381,024	$34,982,052
241	Switchgear	$0	$6,664,781	$0
242	Station Service Equipment	$0	$29,260,917	$0
244	Protective Systems Equipment	$0	$1,640,141	$0
245	Electrical Raceway Systems	$0	$9,124,673	$0
26	Miscellaneous Equipment	$283,413,173	$15,700,000	$62,934,255
261	Transportation and Lift Equipment	$0	$5,000,000	$0
262	Air, Water, Plant Fuel Oil, and Steam Systems	$0	$1,500,000	$0
263	Communications Equipment	$0	$1,350,000	$0
27	Material Requiring Special Consideration	$0	$5,180,000	$0
28	Simulator	$234,600	$19,019,567	$0
29	Contingency on Direct Costs	$926,313,743	$0	$0
30	**Capitalized Indirect Services Cost**	**$3,070,984,429**	**$710,537,810**	**$663,710,610**
31	Factory & Field Indirect Costs	$1,396,140,073	$17,928,500	$224,894,794
32	Factory & Construction Supervision	$0	$132,532,500	$246,930,385
33	Commissioning and Startup Costs	$60,615,813	$5,787,500	$0
35	Engineering Services Offsite	$821,775,090	$472,311,310	$130,978,572
351	Off-Site	$0	$0	$130,978,572
352	On-Site	$0	$108,606,500	$0
36	PM/CM Services	$280,622,715	$81,978,000	$60,906,859
361	Off-Site	$63,865,299	$81,978,000	$0

362	On-Site	$216,757,416	$0	$60,906,859
39	Contingency on Indirect Services Cost	$511,830,738	$0	$0
40	**Capitalized Pre-COD Personnel Costs**	**$685,839,620**	**$226,865,600**	**$0**
41	Staff Recruitment and Training	$357,036,675	$219,865,600	$0
42	Staff Housing	$26,000,000	$0	$0
43	Staff Salary-Related Costs	$188,496,341	$0	$0
44	Other Owner's Costs	$0	$7,000,000	$0
49	Contingency on Owner's Costs	$114,306,603	$0	$0
50	**Capitalized Supplementary Costs**	**$3,952,609,521**	**$165,965,215**	**$0**
51	Shipping and Transportation Costs	$224,215,383	$0	$0
52	Spare Parts	$141,893,471	$0	$0
53	Taxes	$35,106,025	$21,558,273	$0
54	Insurance	$90,368,241	$15,210,337	$0
55	Initial Fuel Inventory	$2,797,244,340	$129,196,605	$0
58	Decommissioning	$18,521,559	$0	$0
59	Contingency on Supplementary Costs	$645,260,502	$0	$0

	Source	(Ganda, F., T. A. Taiwo, and T. K. Kim. 2018)	(Holcomb, D. E., F. J. Peretz, and A. L. Qualls. 2011)	(Holcomb, D. E., F. J. Peretz, and A. L. Qualls. 2011)
	Reactor Name	ABR1000	AHTR - 9% initial enrichment	AHTR - 19.7% initial enrichment
	Reactor Size Per Unit (MWe)	380	1500	1500
	Source Dollar Year	2017	2011	2011
All	**Account Title**	**Total Costs**	**Total Costs**	**Total Costs**
10	**Capitalized Pre-Construction Costs**	**$0**	**$6,000,000**	**$6,000,000**
11	Land and Land Rights	$0	$6,000,000	$6,000,000
20	**Capitalized Direct Costs**	**$1,256,970,000**	**$2,371,538,458**	**$2,371,538,458**
21	Structures and Improvements	$338,710,000	$450,257,750	$450,257,750
211	Site Preparation/Yard Work	$71,700,000	$61,982,046	$61,982,046
212	Reactor Island Civil Structures	$162,840,000	$132,962,887	$132,962,887
213	Core Function Buildings	$24,800,000	$121,521,630	$121,521,630
213.1	Energy Conversion Building	$24,800,000	$63,065,592	$63,065,592
213.2	Control Building	$0	$38,650,674	$38,650,674
213.3	Pipe Tunnels	$0	$19,642,716	$19,642,716
213.4	Electrical Tunnels	$0	$162,648	$162,648
214	Buildings to Support Core Function	$12,470,000	$48,485,184	$48,485,184
214.3	Wastewater Treatment Building	$0	$1,841,501	$1,841,501
214.5	Fire Protection Building	$0	$1,024,382	$1,024,382
214.6	Non-essential Switchgear Building	$0	$1,286,153	$1,286,153
215	Supply Chain Buildings	$66,900,000	$64,191,410	$64,191,410

215.4	Radwaste Building	$38,750,000	$34,481,563	$34,481,563
215.5	Fuel Service Building	$28,150,000	$29,709,847	$29,709,847
216	Human Resources Buildings	$0	$21,114,593	$21,114,593
216.1	Administration Building	$0	$15,951,233	$15,951,233
216.2	Security Building and Gatehouse	$0	$3,268,692	$3,268,692
216.4	Operation and Maintenance (O&M) Center	$0	$1,894,668	$1,894,668
22	Reactor System	$558,080,000	$818,006,909	$818,006,909
221	Reactor Components	$258,410,000	$197,406,910	$197,406,910
221.11	Reactor support	$16,250,000	$0	$0
221.13	Inner vessel structure	$227,420,000	$0	$0
221.21	Reactivity control system	$14,740,000	$0	$0
222	Main Heat Transport System	$139,110,000	$162,573,716	$162,573,716
222.12	Reactor coolant system	$15,500,000	$0	$0
222.14	Pressurizer system	$1,520,000	$0	$0
223	Safety Systems	$0	$61,456,240	$61,456,240
224	Radioactive Waste Processing Systems	$59,600,000	$73,511,203	$73,511,203
225	Fuel Handling Systems	$0	$51,361,584	$51,361,584
226	Other Reactor Plant Equipment	$39,100,000	$147,876,233	$147,876,233
227	Reactor Instrumentation and Control (I&C)	$61,860,000	$55,253,448	$55,253,448
228	Reactor Plant Miscellaneous Items	$0	$68,567,575	$68,567,575
23	Energy Conversion System	$140,810,000	$520,632,168	$520,632,168
232	Energy Applications	$66,960,000	$268,970,111	$268,970,111
233	Ultimate Heat Sink	$73,850,000	$178,598,826	$178,598,826
233.1	Water Condensing Systems	$44,780,000	$109,042,060	$109,042,060
234	Feed Heating Systems	$0	$56,613,122	$56,613,122
236	Common Instrumentation & Controls	$0	$16,450,109	$16,450,109
24	Electrical Equipment	$137,570,000	$171,974,536	$171,974,536
241	Switchgear	$21,910,000	$30,171,079	$30,171,079
242	Station Service Equipment	$36,980,000	$39,792,131	$39,792,131
243	Switchboards	$0	$4,817,355	$4,817,355
244	Protective Systems Equipment	$0	$10,227,326	$10,227,326
245	Electrical Raceway Systems	$40,900,000	$51,524,039	$51,524,039
246	Power and Control Cables and Wiring	$37,780,000	$35,442,606	$35,442,606
26	Miscellaneous Equipment	$81,800,000	$113,084,556	$113,084,556
261	Transportation and Lift Equipment	$0	$15,385,192	$15,385,192
262	Air, Water, Plant Fuel Oil, and Steam Systems	$81,800,000	$75,736,892	$75,736,892
263	Communications Equipment	$0	$15,396,110	$15,396,110
264	Furnishing and Fixtures	$0	$6,566,362	$6,566,362

27	Material Requiring Special Consideration	$0	$297,582,539	$297,582,539
30	**Capitalized Indirect Services Cost**	**$475,800,000**	**$1,322,536,800**	**$1,322,536,800**
31	Factory & Field Indirect Costs	$0	$573,681,600	$573,681,600
32	Factory & Construction Supervision	$0	$191,287,200	$191,287,200
33	Commissioning and Startup Costs	$0	$27,040,800	$27,040,800
35	Engineering Services Offsite	$0	$482,090,400	$482,090,400
351	Off-Site	$0	$482,090,400	$482,090,400
36	PM/CM Services	$0	$48,436,800	$48,436,800
361	Off-Site	$0	$28,490,400	$28,490,400
362	On-Site	$0	$19,946,400	$19,946,400
39	Contingency on Indirect Services Cost	$475,800,000	$0	$0
40	**Capitalized Pre-COD Personnel Costs**	**$0**	**$300,000,000**	**$300,000,000**

	Source	(Department of Energy 1987)	(Department of Energy 1987)	(Department of Energy 1987)
	Reactor Name	MHTGR LEAD NOAK PLANT	MHTGR REPLICA PLANT	MHTGR NOAK PLANT
	Reactor Size Per Unit (MWe)	540	540	540
	Source Dollar Year	1987	1987	1987
All	**Account Title**	**Total Costs**	**Total Costs**	**Total Costs**
10	**Capitalized Pre-Construction Costs**	**$12,567,000**	**$11,835,000**	**$11,250,000**
12	Site Permits	$12,567,000	$11,835,000	$11,250,000
20	**Capitalized Direct Costs**	**$678,513,000**	**$636,863,000**	**$601,726,000**
21	Structures and Improvements	$164,785,000	$158,315,000	$151,280,000
211	Site Preparation/Yard Work	$11,717,000	$11,457,000	$11,196,000
212	Reactor Island Civil Structures	$63,765,000	$62,265,000	$59,554,000
213	Core Function Buildings	$11,339,000	$10,697,000	$10,467,000
213.1	Energy Conversion Building	$10,903,000	$10,271,000	$10,051,000
213.5	Emergency and Start-up Power Systems	$436,000	$426,000	$416,000
214	Buildings to Support Core Function	$39,466,000	$37,678,000	$35,029,000
214.2	Balance of Plant Service Building	$24,243,000	$22,724,000	$20,432,000
214.4	Maintenance Shops	$962,000	$938,000	$916,000
214.5	Fire Protection Building	$113,000	$110,000	$107,000
215	Supply Chain Buildings	$3,806,000	$3,714,000	$3,621,000
215.1	Storage and Warehouse Buildings	$1,313,000	$1,297,000	$1,273,000
215.4	Radwaste Building	$2,493,000	$2,417,000	$2,348,000
216	Human Resources Buildings	$9,288,000	$9,088,000	$8,874,000
216.2	Security Building and Gatehouse	$55,000	$54,000	$53,000
216.4	Operation and Maintenance (O&M) Center	$7,266,000	$7,087,000	$6,925,000
218	Temporary Structures	$25,404,000	$23,416,000	$22,539,000

22	Reactor System	$296,918,000	$262,517,000	$236,944,000
221	Reactor Components	$156,600,000	$135,439,000	$121,921,000
221.11	Reactor support	$76,985,000	$68,356,000	$61,600,000
222	Main Heat Transport System	$49,404,000	$43,900,000	$37,893,000
223	Safety Systems	$17,526,000	$15,638,000	$13,903,000
223.4	Containment Spray System	$11,791,000	$10,213,000	$9,068,000
223.6	Reactor Cavity Cooling System (RCCS)	$5,735,000	$5,425,000	$4,835,000
225	Fuel Handling Systems	$36,501,000	$33,871,000	$30,350,000
227	Reactor Instrumentation and Control (I&C)	$22,903,000	$22,441,000	$22,000,000
228	Reactor Plant Miscellaneous Items	$13,984,000	$11,228,000	$10,877,000
23	Energy Conversion System	$150,597,000	$149,240,000	$148,007,000
232	Energy Applications	$84,135,000	$83,654,000	$83,217,000
232.1	Electricity Generation Systems	$17,348,000	$17,109,000	$16,893,000
232.3	Hydrogen Production Systems	$27,000	$27,000	$26,000
233	Ultimate Heat Sink	$37,130,000	$36,522,000	$35,967,000
233.1	Water Condensing Systems	$23,970,000	$23,550,000	$23,165,000
234	Feed Heating Systems	$13,672,000	$13,481,000	$13,308,000
236	Common Instrumentation & Controls	$15,660,000	$15,583,000	$15,515,000
24	Electrical Equipment	$53,080,000	$51,854,000	$50,757,000
241	Switchgear	$10,775,000	$10,731,000	$10,691,000
242	Station Service Equipment	$10,479,000	$10,427,000	$10,380,000
243	Switchboards	$1,270,000	$1,264,000	$1,258,000
244	Protective Systems Equipment	$1,659,000	$1,604,000	$1,556,000
245	Electrical Raceway Systems	$16,658,000	$15,920,000	$15,251,000
246	Power and Control Cables and Wiring	$12,239,000	$11,908,000	$11,621,000
26	Miscellaneous Equipment	$13,133,000	$12,937,000	$12,738,000
261	Transportation and Lift Equipment	$3,358,000	$3,344,000	$3,322,000
262	Air, Water, Plant Fuel Oil, and Steam Systems	$5,368,000	$5,262,000	$5,156,000
263	Communications Equipment	$2,645,000	$2,581,000	$2,522,000
264	Furnishing and Fixtures	$1,762,000	$1,750,000	$1,738,000
30	**Capitalized Indirect Services Cost**	**$178,699,000**	**$132,875,000**	**$117,178,000**
31	Factory & Field Indirect Costs	$24,090,000	$22,437,000	$21,465,000
33	Commissioning and Startup Costs	$3,932,000	$3,752,000	$3,613,000
35	Engineering Services Offsite	$99,873,000	$73,263,000	$59,367,000
351	Off-Site	$75,873,000	$50,522,000	$37,632,000
352	On-Site	$3,376,000	$3,206,000	$3,073,000
353	Owner's Engineering Oversight	$20,624,000	$19,535,000	$18,662,000
36	PM/CM Services	$50,804,000	$33,423,000	$32,733,000
361	Off-Site	$14,158,000	$10,780,000	$10,114,000

363	Owner's Engineering Oversight	$35,940,000	$21,970,000	$21,970,000
40	**Capitalized Pre-COD Personnel Costs**	**$79,810,000**	**$73,540,000**	**$68,760,000**
41	Staff Recruitment and Training	$22,000,000	$20,000,000	$18,000,000
43	Staff Salary-Related Costs	$57,810,000	$53,540,000	$50,760,000
50	**Capitalized Supplementary Costs**	**$32,761,247**	**$31,478,247**	**$30,773,247**
52	Spare Parts	$14,610,000	$14,610,000	$14,510,000
54	Insurance	$16,867,000	$15,584,000	$14,979,000
58	Decommissioning	$1,284,247	$1,284,247	$1,284,247

	Source	(Department of Energy 1987)	(Department of Energy. 1993)	(Department of Energy. 1993)
	Reactor Name	MHTGR LARGE NOAK PLANT	MHTGR - SC - Prototype	MHTGR - SC - Replica
	Reactor Size Per Unit (MWe)	540	173.25	173.25
	Source Dollar Year	1987	1992	1992
All	**Account Title**	**Total Costs**	**Total Costs**	**Total Costs**
10	**Capitalized Pre-Construction Costs**	**$22,162,000**	**$1,997,622**	**$1,769,796**
12	Site Permits	$22,162,000	$1,997,622	$1,769,796
20	**Capitalized Direct Costs**	**$1,158,996,000**	**$989,593,375**	**$903,164,218**
21	Structures and Improvements	$285,440,000	$271,765,620	$250,752,628
211	Site Preparation/Yard Work	$22,310,000	$7,293,886	$7,203,883
212	Reactor Island Civil Structures	$119,100,000	$117,606,194	$113,752,882
213	Core Function Buildings	$20,932,000	$24,440,533	$23,792,405
213.1	Energy Conversion Building	$20,100,000	$24,440,533	$23,792,405
214	Buildings to Support Core Function	$57,141,000	$58,397,343	$52,754,576
214.2	Balance of Plant Service Building	$28,970,000	$58,247,373	$52,606,391
215	Supply Chain Buildings	$6,640,000	$3,430,970	$3,397,036
215.4	Radwaste Building	$4,697,000	$3,430,970	$3,397,036
216	Human Resources Buildings	$14,909,000	$4,448,469	$4,411,344
216.4	Operation and Maintenance (O&M) Center	$11,012,000	$4,448,469	$4,411,344
218	Temporary Structures	$44,408,000	$56,148,225	$45,440,502
22	Reactor System	$447,889,000	$464,641,631	$410,567,509
221	Reactor Components	$243,842,000	$283,043,280	$252,326,434
221.11	Reactor support	$123,201,000	$137,003,284	$127,020,579
222	Main Heat Transport System	$75,786,000	$114,415,068	$99,718,145
223	Safety Systems	$27,808,000	$21,109,062	$18,191,996
223.4	Containment Spray System	$18,137,000	$4,306,570	$3,966,647
223.6	Reactor Cavity Cooling System (RCCS)	$9,671,000	$16,802,492	$14,225,349
225	Fuel Handling Systems	$39,400,000	$17,149,794	$15,515,701
227	Reactor Instrumentation and Control (I&C)	$44,000,000	$15,267,327	$13,883,237

228	Reactor Plant Miscellaneous Items	$17,053,000	$13,657,100	$10,931,996
23	Energy Conversion System	$295,678,000	$196,431,765	$187,032,978
232	Energy Applications	$166,435,000	$86,524,974	$79,175,902
232.1	Electricity Generation Systems	$33,786,000	$0	$0
232.3	Hydrogen Production Systems	$52,000	$0	$0
233	Ultimate Heat Sink	$71,934,000	$46,110,503	$45,066,146
233.1	Water Condensing Systems	$46,331,000	$31,243,027	$30,504,183
234	Feed Heating Systems	$26,280,000	$34,769,738	$34,048,750
236	Common Instrumentation & Controls	$31,029,000	$2,673,283	$2,637,768
237	Miscellaneous Energy System Equipment	$0	$26,353,267	$26,104,412
24	Electrical Equipment	$101,512,000	$54,754,359	$52,811,103
241	Switchgear	$21,383,000	$7,361,977	$7,287,866
242	Station Service Equipment	$20,761,000	$13,997,832	$13,888,619
243	Switchboards	$2,515,000	$4,106,724	$4,098,023
244	Protective Systems Equipment	$3,111,000	$490,835	$484,366
245	Electrical Raceway Systems	$30,501,000	$14,430,149	$13,429,632
246	Power and Control Cables and Wiring	$23,241,000	$14,366,842	$13,622,597
26	Miscellaneous Equipment	$25,477,000	$0	$0
261	Transportation and Lift Equipment	$6,644,000	$2,640,696	$2,624,005
262	Air, Water, Plant Fuel Oil, and Steam Systems	$10,312,000	$32,081,945	$31,649,226
263	Communications Equipment	$5,045,000	$4,661,137	$4,614,021
264	Furnishing and Fixtures	$3,476,000	$1,907,915	$1,905,161
30	**Capitalized Indirect Services Cost**	**$200,134,000**	**$297,034,075**	**$169,894,918**
31	Factory & Field Indirect Costs	$42,290,000	$34,602,923	$29,135,150
33	Commissioning and Startup Costs	$7,302,000	$11,514,277	$10,022,662
35	Engineering Services Offsite	$99,689,000	$203,799,676	$108,082,670
351	Off-Site	$56,400,000	$153,639,671	$61,881,183
352	On-Site	$6,149,000	$6,978,842	$6,175,664
353	Owner's Engineering Oversight	$37,140,000	$43,181,163	$40,025,823
36	PM/CM Services	$50,853,000	$47,117,199	$22,654,436
361	Off-Site	$17,900,000	$22,976,782	$11,097,620
363	Owner's Engineering Oversight	$31,640,000	$21,969,402	$9,672,650
40	**Capitalized Pre-COD Personnel Costs**	**$124,210,000**	**$109,298,514**	**$109,589,725**
41	Staff Recruitment and Training	$34,200,000	$57,148,514	$52,039,725
43	Staff Salary-Related Costs	$90,010,000	$52,150,000	$57,550,000
50	**Capitalized Supplementary Costs**	**$56,263,000**	**$80,759,021**	**$73,786,360**
52	Spare Parts	$26,750,000	$31,705,610	$31,112,018
54	Insurance	$29,513,000	$49,053,411	$42,674,342

	Source	(Department of Energy. 1993)	(Department of Energy. 1993)	(Department of Energy. 1993)
	Reactor Name	MHTGR - SC - Target	MHTGR - GT/IC - Prototype	MHTGR - GT/IC - Replica
	Reactor Size Per Unit (MWe)	173.25	201.5	201.5
	Source Dollar Year	1992	1992	1992
All	**Account Title**	**Total Costs**	**Total Costs**	**Total Costs**
10	**Capitalized Pre-Construction Costs**	**$1,746,101**	**$2,064,483**	**$1,835,885**
12	Site Permits	$1,746,101	$2,064,483	$1,835,885
20	**Capitalized Direct Costs**	**$857,367,653**	**$1,103,572,778**	**$1,136,815,118**
21	Structures and Improvements	$242,268,622	$291,647,801	$269,878,329
211	Site Preparation/Yard Work	$7,045,691	$6,921,326	$6,836,896
212	Reactor Island Civil Structures	$111,733,668	$130,146,453	$125,696,010
213	Core Function Buildings	$23,461,555	$22,748,203	$22,152,161
213.1	Energy Conversion Building	$23,461,555	$22,748,203	$22,152,161
214	Buildings to Support Core Function	$48,018,001	$64,665,007	$58,841,640
214.2	Balance of Plant Service Building	$47,872,968	$64,515,257	$58,693,675
215	Supply Chain Buildings	$3,336,927	$3,427,625	$3,393,691
215.4	Radwaste Building	$3,336,927	$3,427,625	$3,393,691
216	Human Resources Buildings	$4,346,034	$4,448,469	$4,411,344
216.4	Operation and Maintenance (O&M) Center	$4,346,034	$4,448,469	$4,411,344
218	Temporary Structures	$44,326,746	$59,290,718	$48,546,587
22	Reactor System	$375,353,849	$429,830,424	$508,135,120
221	Reactor Components	$231,447,653	$162,054,255	$274,624,595
221.11	Reactor support	$120,802,079	$16,014,257	$149,318,740
222	Main Heat Transport System	$90,213,463	$199,484,734	$173,967,685
223	Safety Systems	$16,570,614	$22,249,763	$19,304,092
223.4	Containment Spray System	$3,671,601	$5,027,187	$4,684,296
223.6	Reactor Cavity Cooling System (RCCS)	$12,899,013	$17,222,576	$14,619,796
225	Fuel Handling Systems	$14,330,012	$17,135,480	$15,500,944
227	Reactor Instrumentation and Control (I&C)	$12,760,834	$14,889,092	$13,445,806
228	Reactor Plant Miscellaneous Items	$10,031,273	$14,017,100	$11,291,998
23	Energy Conversion System	$185,816,216	$324,172,968	$302,909,448
232	Energy Applications	$78,902,241	$101,491,428	$94,822,464
233	Ultimate Heat Sink	$44,598,688	$33,392,021	$32,563,240
233.1	Water Condensing Systems	$30,172,968	$21,927,301	$21,305,307
234	Feed Heating Systems	$33,723,708	$162,936,252	$149,419,332
236	Common Instrumentation & Controls	$2,621,910	$0	$0
237	Miscellaneous Energy System Equipment	$25,969,669	$26,353,267	$26,104,412
24	Electrical Equipment	$51,928,966	$55,921,585	$53,892,221

241	Switchgear	$7,254,527	$7,356,697	$7,282,585
242	Station Service Equipment	$13,833,124	$13,984,422	$13,875,209
243	Switchboards	$4,094,085	$4,104,324	$4,096,623
244	Protective Systems Equipment	$473,829	$1,075,601	$1,028,815
245	Electrical Raceway Systems	$12,983,583	$14,938,534	$13,900,178
246	Power and Control Cables and Wiring	$13,289,818	$14,462,007	$13,708,811
261	Transportation and Lift Equipment	$2,610,992	$2,473,437	$2,458,217
262	Air, Water, Plant Fuel Oil, and Steam Systems	$31,093,933	$31,962,404	$31,926,336
263	Communications Equipment	$4,561,332	$4,634,999	$4,587,736
264	Furnishing and Fixtures	$1,900,251	$1,903,666	$1,900,911
30	**Capitalized Indirect Services Cost**	**$153,036,113**	**$304,464,830**	**$176,134,723**
31	Factory & Field Indirect Costs	$28,566,423	$36,207,600	$30,721,236
33	Commissioning and Startup Costs	$9,694,727	$12,343,389	$10,809,934
35	Engineering Services Offsite	$94,012,287	$207,968,901	$111,390,759
351	Off-Site	$48,681,108	$155,608,562	$63,099,972
352	On-Site	$5,999,064	$7,425,286	$6,599,580
353	Owner's Engineering Oversight	$39,332,115	$44,935,053	$41,691,207
36	PM/CM Services	$20,762,676	$47,944,940	$23,212,794
361	Off-Site	$11,024,407	$23,645,079	$11,504,540
362	On-Site	$0	$0	$0
363	Owner's Engineering Oversight	$7,917,168	$21,969,402	$9,672,690
40	**Capitalized Pre-COD Personnel Costs**	**$83,135,433**	**$117,433,363**	**$116,300,051**
41	Staff Recruitment and Training	$32,375,433	$57,283,363	$47,750,051
43	Staff Salary-Related Costs	$50,760,000	$60,150,000	$68,550,000
50	**Capitalized Supplementary Costs**	**$72,342,846**	**$91,002,884**	**$83,108,533**
52	Spare Parts	$30,332,019	$40,077,350	$38,583,758
54	Insurance	$42,010,827	$50,925,534	$44,524,775

	Source	(Department of Energy. 1993)	(Department of Energy. 1993)	(Department of Energy. 1993)
	Reactor Name	MHTGR - GT/IC - Target	MHTGR - -GT/DC - Prototype	MHTGR - -GT/DC - Replica
	Reactor Size Per Unit (MWe)	201.5	217.25	217.25
	Source Dollar Year	1992	1992	1992
All	**Account Title**	**Total Costs**	**Total Costs**	**Total Costs**
10	**Capitalized Pre-Construction Costs**	**$1,813,428**	**$1,230,707**	**$1,001,166**
12	Site Permits	$1,813,428	$1,230,707	$1,001,166
20	**Capitalized Direct Costs**	**$1,069,788,330**	**$989,809,280**	**$896,769,705**
21	Structures and Improvements	$261,879,432	$254,507,916	$233,598,850
211	Site Preparation/Yard Work	$6,706,490	$4,533,371	$4,473,276
212	Reactor Island Civil Structures	$123,687,647	$119,990,669	$116,017,308

213	Core Function Buildings	$21,883,339	$2,446,188	$2,421,083
213.1	Energy Conversion Building	$21,883,339	$2,446,188	$2,421,083
214	Buildings to Support Core Function	$54,416,129	$62,129,006	$56,132,391
214.2	Balance of Plant Service Building	$54,270,992	$61,979,256	$55,984,426
215	Supply Chain Buildings	$3,340,806	$3,129,700	$3,103,915
215.4	Radwaste Building	$3,340,806	$3,129,700	$3,103,915
216	Human Resources Buildings	$4,353,981	$4,435,757	$4,396,096
216.4	Operation and Maintenance (O&M) Center	$4,353,981	$4,435,757	$4,396,096
218	Temporary Structures	$47,491,040	$57,843,225	$47,054,781
22	Reactor System	$468,744,071	$498,740,633	$443,208,160
221	Reactor Components	$255,254,994	$309,244,373	$277,549,395
221.11	Reactor support	$143,002,059	$163,204,375	$152,243,540
222	Main Heat Transport System	$158,333,455	$119,964,582	$105,519,631
223	Safety Systems	$17,806,818	$21,526,266	$18,603,563
223.4	Containment Spray System	$4,394,893	$4,303,690	$3,983,767
223.6	Reactor Cavity Cooling System (RCCS)	$13,411,925	$17,222,576	$14,619,796
225	Fuel Handling Systems	$14,445,579	$17,135,490	$15,500,944
227	Reactor Instrumentation and Control (I&C)	$12,406,455	$16,852,822	$14,742,629
228	Reactor Plant Miscellaneous Items	$10,496,770	$14,017,100	$11,291,998
23	Energy Conversion System	$284,078,122	$178,927,002	$164,241,826
232	Energy Applications	$88,261,207	$145,790,716	$132,020,685
233	Ultimate Heat Sink	$32,236,342	$28,126,067	$27,482,276
233.1	Water Condensing Systems	$21,059,448	$27,865,273	$27,223,203
234	Feed Heating Systems	$137,576,988	$0	$0
237	Miscellaneous Energy System Equipment	$26,003,585	$5,010,219	$4,738,865
24	Electrical Equipment	$53,086,705	$55,633,729	$53,720,869
241	Switchgear	$7,253,289	$6,951,996	$6,876,454
242	Station Service Equipment	$13,826,526	$13,245,821	$13,138,713
243	Switchboards	$4,092,252	$3,706,710	$3,704,859
244	Protective Systems Equipment	$1,007,686	$672,655	$647,671
245	Electrical Raceway Systems	$13,493,289	$13,697,144	$12,728,212
246	Power and Control Cables and Wiring	$13,413,663	$17,359,403	$16,624,960
261	Transportation and Lift Equipment	$2,447,334	$2,156,748	$2,142,239
262	Air, Water, Plant Fuel Oil, and Steam Systems	$31,033,486	$23,316,883	$22,982,899
263	Communications Equipment	$4,541,260	$4,234,686	$4,210,155
264	Furnishing and Fixtures	$1,896,667	$1,904,175	$1,901,411
30	**Capitalized Indirect Services Cost**	**$160,528,248**	**$294,110,107**	**$155,739,505**
31	Factory & Field Indirect Costs	$30,182,233	$29,536,966	$24,027,973

33	Commissioning and Startup Costs	$10,489,139	$13,863,600	$12,317,098
35	Engineering Services Offsite	$98,528,559	$200,073,297	$95,950,521
351	Off-Site	$51,062,576	$163,281,436	$63,262,839
352	On-Site	$6,432,228	$7,465,015	$6,632,283
353	Owner's Engineering Oversight	$41,033,755	$29,326,846	$26,055,399
36	PM/CM Services	$21,328,317	$50,636,244	$23,443,913
361	Off-Site	$11,435,353	$25,687,371	$11,054,839
363	Owner's Engineering Oversight	$7,917,168	$22,282,796	$10,020,401
40	**Capitalized Pre-COD Personnel Costs**	**$90,524,824**	**$107,128,959**	**$100,881,940**
41	Staff Recruitment and Training	$30,764,824	$51,478,959	$43,081,940
43	Staff Salary-Related Costs	$59,760,000	$55,650,000	$57,800,000
50	**Capitalized Supplementary Costs**	**$81,199,698**	**$105,102,732**	**$93,778,319**
52	Spare Parts	$37,303,759	$70,642,938	$65,745,684
54	Insurance	$43,895,939	$34,459,794	$28,032,635

	Source	(Department of Energy. 1993)	Engel, J. R., W. R. Grimes, H. F. Bauman, H. E. McCoy, J. F. Dearing, and W. A. Rhoades. 1980
	Reactor Name	MHTGR - -GT/DC - Target	DSMR
	Reactor Size Per Unit (MWe)	217.25	0
	Source Dollar Year	1992	1978
All	**Account Title**	**Total Costs**	**Total Costs**
10	**Capitalized Pre-Construction Costs**	**$974,757**	**$0**
12	Site Permits	$974,757	$0
20	**Capitalized Direct Costs**	**$839,377,729**	**$566,000,000**
21	Structures and Improvements	$225,604,574	$199,000,000
211	Site Preparation/Yard Work	$4,380,413	$0
212	Reactor Island Civil Structures	$114,195,633	$0
213	Core Function Buildings	$2,382,111	$0
213.1	Energy Conversion Building	$2,382,111	$0
214	Buildings to Support Core Function	$51,429,115	$0
214.2	Balance of Plant Service Building	$51,283,978	$0
215	Supply Chain Buildings	$3,063,836	$0
215.4	Radwaste Building	$3,063,836	$0
216	Human Resources Buildings	$4,339,885	$0
216.4	Operation and Maintenance (O&M) Center	$4,339,885	$0
218	Temporary Structures	$45,813,581	$75,000,000
22	Reactor System	$409,113,420	$180,000,000
221	Reactor Components	$257,903,995	$0
221.11	Reactor support	$145,651,060	$0

222	Main Heat Transport System	$95,522,392	$0
223	Safety Systems	$17,115,322	$0
223.4	Containment Spray System	$3,703,397	$0
223.6	Reactor Cavity Cooling System (RCCS)	$13,411,925	$0
225	Fuel Handling Systems	$14,445,579	$0
227	Reactor Instrumentation and Control (I&C)	$13,629,362	$0
228	Reactor Plant Miscellaneous Items	$10,496,770	$0
23	Energy Conversion System	$149,701,136	$114,000,000
232	Energy Applications	$118,008,683	$0
233	Ultimate Heat Sink	$27,215,288	$14,000,000
233.1	Water Condensing Systems	$26,958,837	$0
237	Miscellaneous Energy System Equipment	$4,477,165	$0
24	Electrical Equipment	$52,958,599	$54,000,000
241	Switchgear	$6,846,243	$0
242	Station Service Equipment	$13,090,806	$0
243	Switchboards	$3,700,735	$0
244	Protective Systems Equipment	$635,085	$0
245	Electrical Raceway Systems	$12,348,514	$0
246	Power and Control Cables and Wiring	$16,337,216	$0
26	Miscellaneous Equipment	$0	$17,000,000
261	Transportation and Lift Equipment	$2,132,434	$0
262	Air, Water, Plant Fuel Oil, and Steam Systems	$22,605,319	$0
263	Communications Equipment	$4,172,168	$0
264	Furnishing and Fixtures	$1,897,151	$0
30	**Capitalized Indirect Services Cost**	**$139,765,581**	**$87,000,000**
31	Factory & Field Indirect Costs	$23,394,169	$0
32	Factory & Construction Supervision	$0	$34,000,000
33	Commissioning and Startup Costs	$11,961,638	$0
35	Engineering Services Offsite	$82,904,635	$53,000,000
351	Off-Site	$51,186,826	$0
352	On-Site	$6,435,497	$0
353	Owner's Engineering Oversight	$25,282,312	$0
36	PM/CM Services	$21,505,139	$0
361	Off-Site	$10,973,237	$0
363	Owner's Engineering Oversight	$8,233,510	$0
40	**Capitalized Pre-COD Personnel Costs**	**$28,302,615**	**$0**
41	Staff Recruitment and Training	$28,252,605	$0
43	Staff Salary-Related Costs	$50,010	$0
50	**Capitalized Supplementary Costs**	**$86,947,453**	**$224,300,000**

52	Spare Parts	$59,654,256	$0
54	Insurance	$27,293,197	$0
55	Initial Fuel Inventory	$0	$224,300,000