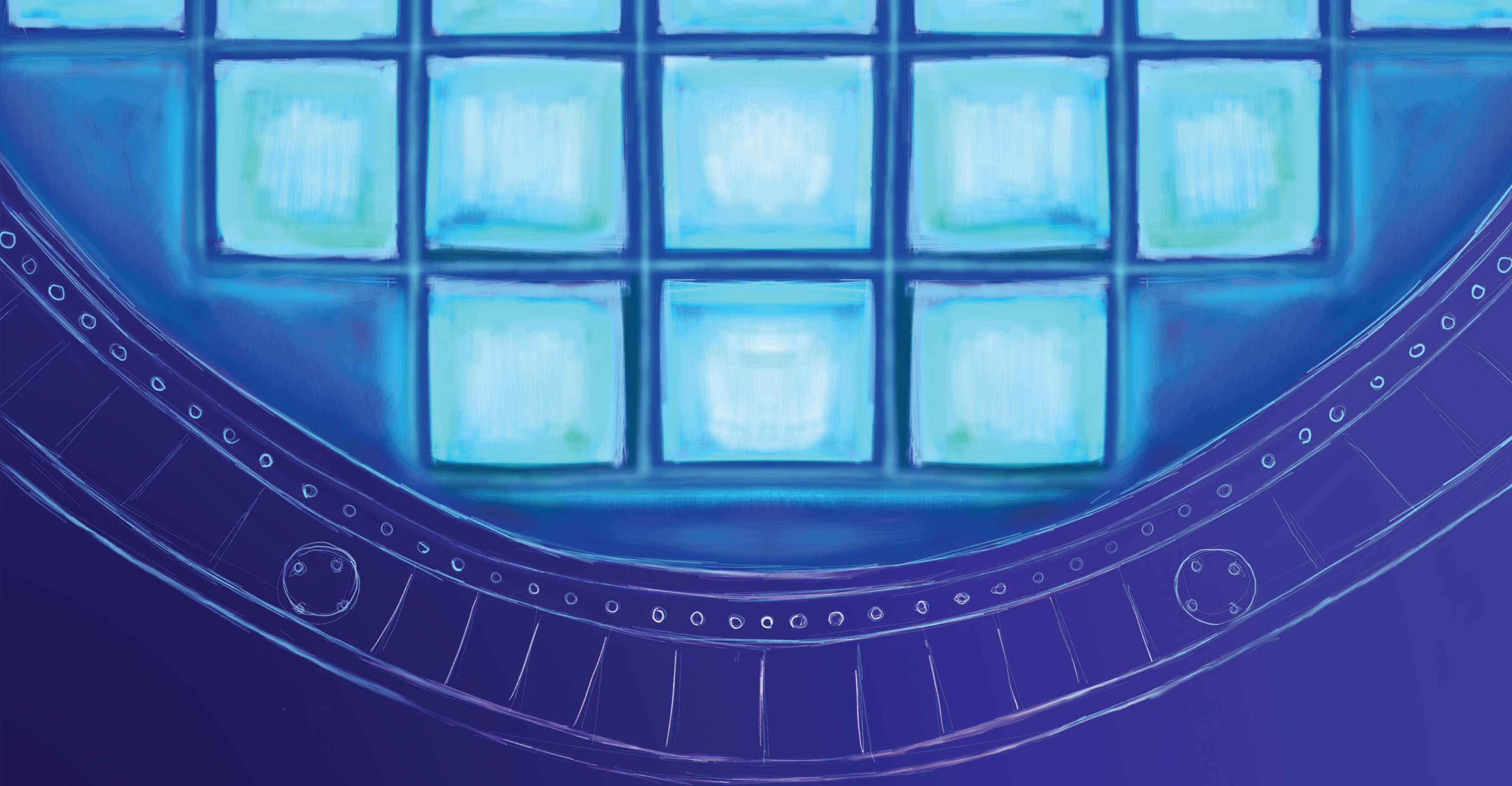

The Future of Nuclear Energy in a Carbon-Constrained World

AN INTERDISCIPLINARY MIT STUDY

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Foreword and Acknowledgments

The MIT *Future of Nuclear Energy in a Carbon-Constrained World* study is the eighth in the MIT Energy Initiative's "*Future of*" series, which aims to shed light on a range of complex and important issues involving energy and the environment. A central theme is understanding the role of technologies that might contribute at scale in meeting rapidly growing global energy demand in a carbon-constrained world. Nuclear power could certainly play an important role, and it was the subject of the first of these interdisciplinary studies at MIT—the 2003 *Future of Nuclear Power* report. More recent studies have looked at the roles of CO_2 sequestration, natural gas, the electric grid, and solar power. Following a 2009 update to the original nuclear study, now is an appropriate time to take a fresh look at nuclear, given advances in inherently safer technologies, a sharpened focus on the need to reduce CO_2 emissions in the energy sector, and challenges of cost and public perceptions of safety.

The study is designed to serve as a balanced, fact-based, and analysis-driven guide for stakeholders involved in nuclear energy. Policy makers, utilities, existing and startup energy companies, regulators, investors, and other power-sector stakeholders can use this study to better understand the challenges and opportunities currently facing nuclear energy in the U.S. and around the world. The report distills results and findings from more than two years of primary research, a review of the state of the art, and quantitative modeling and analysis.

The MIT *Future of Nuclear Energy in a Carbon-Constrained World* study was supported by a number of sponsors and was complemented by a distinguished Advisory Committee and Review Team. We gratefully acknowledge the support of our major sponsor The Alfred P. Sloan Foundation and important contributions from Shell, Électricité de France (EDF), The David and Lucile Packard Foundation, General Atomics, the Anthropocene Institute, MIT's International Policy Laboratory, Mr. Zach Pate, Mr. Neil Rasmussen, and Dr. James Del Favero. We also thank the Idaho National Laboratory, Dominion Engineering Inc., Blumont Engineering Solutions (Paul Meier and his JuiceBox work for Chapter 1), Professor Giorgio Locatelli from the University of Leeds (for his work on Megaprojects in Chapter 2), the Breakthrough Institute, and Lucid Strategy for their generous in-kind contributions. We also wish to acknowledge Professor Jessika Trancik and Dr. James McNerny from the Institute for Data, Systems, and Society at MIT for their valuable input to the analysis of the cost breakdown of nuclear power plants.

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This report represents the opinions and views of the researchers, who are solely responsible for its content, including any errors. The Advisory Committee and the Reviewers are not responsible for the findings and recommendations it contains, and their individual opinions and views may differ from those expressed herein.

Dedicated to the memory of our friend and colleague Mujid Kazimi.

Executive Summary

Harnessing the power of the atomic nucleus for peaceful purposes was one of the most astonishing scientific and technological achievements of the 20th century. It has benefitted medicine, security, and energy. Yet, after a few decades of rapid growth, investment in nuclear energy has stalled in many developed countries and nuclear energy now constitutes a meager 5% of global primary energy production.

In the 21st century the world faces the new challenge of drastically reducing emissions of greenhouse gases while simultaneously expanding energy access and economic opportunity to billions of people. We examined this challenge in the electricity sector, which has been widely identified as an early candidate for deep decarbonization. In most regions, serving projected load in 2050 while simultaneously reducing emissions will require a mix of electrical generation assets that is different from the current system. While a variety of low- or zero-carbon technologies can be employed in various combinations, our analysis shows the potential contribution nuclear can make as a dispatchable low-carbon technology. Without that contribution, the cost of achieving deep decarbonization targets increases significantly (see Figure E.1, left column). The least-cost portfolios include an important share for nuclear, the magnitude of which significantly grows as the cost of nuclear drops (Figure E.1, right column).

Despite this promise, the prospects for the expansion of nuclear energy remain decidedly dim in many parts of the world. The fundamental problem is cost. Other generation technologies have become cheaper in recent decades, while new nuclear plants have only become costlier. This disturbing trend undermines nuclear energy's potential contribution and increases the cost of achieving deep decarbonization. In this study, we examine what is needed to arrest and reverse that trend.

We have surveyed recent light water reactor (LWR) construction projects around the world and examined recent advances in cross-cutting technologies that can be applied to nuclear plant construction for a wide range of advanced nuclear plant concepts and designs under development. To address cost concerns, we recommend:

(1) *An increased focus on using proven project/construction management practices to increase the probability of success in the execution and delivery of new nuclear power plants.*

The recent experience of nuclear construction projects in the United States and Europe has demonstrated repeated failures of construction management practices in terms of their ability to deliver products on time and within budget. Several corrective actions are urgently needed: (a) completing greater portions of the detailed design prior to construction; (b) using a proven supply chain and skilled workforce; (c) incorporating manufacturers and builders into design teams in the early stages of the design process to assure that plant systems, structures, and components are designed for efficient construction and manufacturing to relevant standards; (d) appointing a single primary contract manager with proven expertise in managing multiple independent subcontractors; (e) establishing a contracting structure that ensures all contractors have a vested interest in the success of the project; and (f) enabling a flexible regulatory environment that can accommodate small, unanticipated changes in design and construction in a timely fashion.

(2) *A shift away from primarily field construction of cumbersome, highly site-dependent plants to more serial manufacturing of standardized plants.*

Opportunities exist to significantly reduce the capital cost and shorten the construction schedule for new nuclear power plants. First, the deployment of multiple, standardized units, especially at a single site, affords considerable learning from the construction of each unit. In the United States and Europe, where productivity at construction sites has been low, we also recommend expanded use of factory production to take advantage of the manufacturing sector's higher productivity when it comes to turning out complex systems, structures, and components. The use of an array of cross-cutting technologies, including modular construction in factories and shipyards, advanced concrete solutions (e.g., steel-plate composites, high-strength reinforcement steel, ultra-high performance concrete), seismic isolation technology, and advanced plant layouts (e.g., embedment, offshore siting), could have positive impacts on the cost and schedule of new nuclear power plant construction. For less complex systems, structures, and components, or at sites where construction productivity is high (as in Asia), conventional approaches may be the lowest-cost option.

It is important to emphasize the broad applicability of these recommendations across all reactor concepts and designs. Cost-cutting opportunities are pertinent to evolutionary Generation-III LWRs, small modular reactors (SMRs), and Generation-IV reactors.[1] Without design standardization and innovations in construction approaches, we do not believe the inherent technological features of any of the advanced reactors will produce the level of cost reductions needed to make nuclear electricity competitive with other generation options.

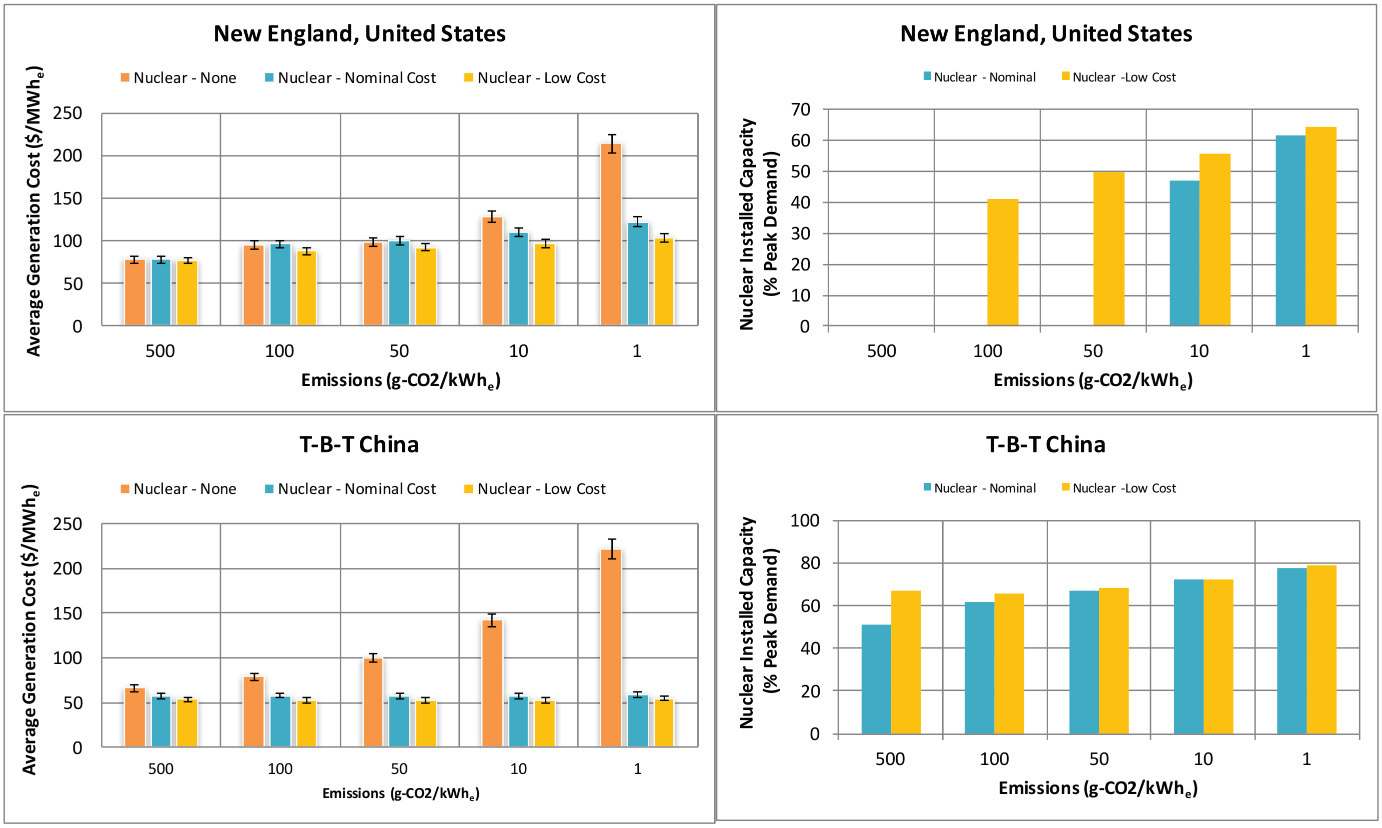
In addition to its high cost, the growth of nuclear energy has been hindered by public concerns about the consequences of severe accidents (such as occurred at Fukushima, Japan in 2011) in traditional Generation-II nuclear power plant designs. These concerns have led some countries to renounce nuclear power entirely. To address safety concerns, we recommend:

(3) *A shift toward reactor designs that incorporate inherent and passive safety features.*

Core materials that have high chemical and physical stability, high heat capacity, negative reactivity feedbacks, and high retention of fission products, together with engineered safety systems that require limited or no emergency AC power and minimal external intervention, will likely make operations simpler and more tolerable to human errors. Such design evolution has already occurred in some Generation-III LWRs and is exhibited in new plants built in China, Russia, and the United States. Passive safety designs can reduce the probability that a severe accident occurs, while also mitigating the offsite consequences in the event an accident does occur. Such designs can also ease the licensing of new plants and accelerate their deployment in developed and developing countries. We judge that advanced reactors like LWR-based SMRs (e.g., NuScale) and mature Generation-IV reactor concepts (e.g., high-temperature gas reactors and sodium-cooled fast reactors) also possess such features and are now ready for commercial deployment. Further, our assessment of the U.S. and international regulatory environments suggests that the current regulatory system is flexible enough to accommodate licensing of these advanced reactor designs. Certain modifications to the current regulatory framework could improve the efficiency and efficacy of licensing reviews.

[1] Reactor designs are frequently classified into four generations. The first commercial nuclear reactors built in the late 1950s and 1960s are classified as Generation-I systems. Generation-II systems include commercial reactors that were built from 1970 to 1990. Generation-III reactors are commercial designs that incorporate evolutionary improvements over Generation-II systems. Generation-IV is the classification used to describe a set of advanced reactor designs that use non-water coolants and are under development today.

Figure E.1: (left) Average system cost of electricity (in $/MWh_e$) and (right) nuclear installed capacity (% of peak demand) in the New England region of the United States and the Tianjin-Beijing-Tangshan (T-B-T) region of China for different carbon constraints (gCO_2/kWh_e) and three scenarios of various available technologies in 2050: (a) no nuclear allowed, (b) nuclear is allowed at nominal overnight capital cost ($5,500 per kW_e for New England and $2,800 per kW_e for T-B-T), and (c) nuclear is allowed with improved overnight capital cost ($4,100 per kW_e for New England and $2,100 per kW_e for T-B-T)



Simulations were performed with an MIT system optimization tool called GenX. For a given power market the required inputs include hourly electricity demand, hourly weather patterns, economic costs (capital, operations, and fuel) for all power plants (nuclear, wind and solar with battery storage, fossil with and without carbon capture and storage), and their ramp-up rates. The GenX simulations were used to identify the electrical system generation mix that minimizes average system electricity costs in each of these markets. The cost escalation seen in the no-nuclear scenarios with aggressive carbon constraints is mostly due to the additional build-out and cost of energy storage, which becomes necessary in scenarios that rely exclusively on variable renewable energy technologies. The current world-average carbon intensity of the power sector is about 500 grams of CO_2 equivalent per kilowatt hour (g/kWh_e); according to climate change stabilization scenarios developed by the International Energy Agency in 2017, the power-sector carbon intensity targets to limit global average warming to 2°C range from 10 to 25 g/kWh_e by 2050 and less than 2 g/kWh_e by 2060.

Lastly, key actions by policy makers are also needed to capture the benefits of nuclear energy:

(4) *Decarbonization policies should create a level playing field that allows all low-carbon generation technologies to compete on their merits.*

Investors in nuclear innovation must see the possibility of earning a profit based on selling their products at full value, which should include factors such as the value of reducing CO_2 emissions that are external to the market. Policies that foreclose a role for nuclear energy discourage investment in nuclear technology. This may raise the cost of decarbonization and slow progress toward climate change mitigation goals. Incorporating CO_2 emissions costs into the price of electricity can more equitably recognize the value to all climate-friendly energy technologies. Nuclear generators, both existing plants and the new builds, would be among the beneficiaries of a level, competitive playing field.

(5) *Governments should establish reactor sites where companies can deploy prototype reactors for testing and operation oriented to regulatory licensing*.

Such sites should be open to diverse reactor concepts chosen by the companies that are interested in testing prototypes. The government should provide appropriate supervision and support—including safety protocols, infrastructure, environmental approvals, and fuel-cycle services—and should also be directly involved with all testing.

(6) *Governments should establish funding programs around prototype testing and commercial deployment of advanced reactor designs using four levers: (a) funding to share regulatory licensing costs, (b) funding to share research and development costs, (c) funding for the achievement of specific technical milestones, and (d) funding for production credits to reward successful demonstration of new designs.*

Many more findings emerged in the course of the research undertaken for this study. A detailed discussion of these findings is contained in the overview and main body of the study report, which is organized into five major topic areas (with corresponding chapter titles): Opportunities for Nuclear Energy, Nuclear Power Plant Costs, Advanced Reactor Technology Evaluation, Nuclear Industry Business Models and Policies, and Nuclear Reactor Safety Regulation and Licensing.

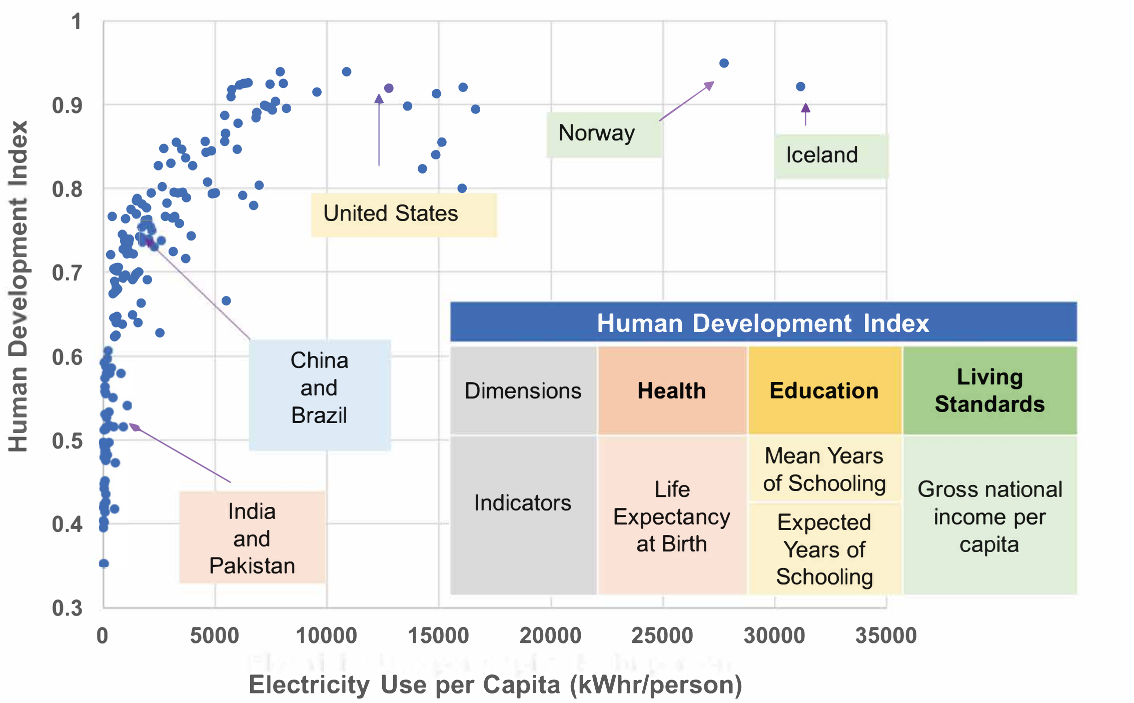
Background and Overview

THE BIG PICTURE

Access to electricity plays a vital role in improving standards of living, education, and health. This relationship is illustrated by Figure 1, which locates various countries according to their score on the Human Development Index, a well-known metric of economic and social development, and per capita electricity use. As countries develop, electricity use tends to rise; according to current forecasts, electricity consumption in developing non-OECD (Organisation for Economic Co-operation and Development) countries is expected to grow 60% by 2040, whereas worldwide use is expected to grow 45% in the same timeframe (U.S. Energy Information Administration 2017).

Expanding access to energy while at the same time drastically reducing the emissions of greenhouse gases that cause global warming and climate change is among the central challenges confronting humankind in the 21st century. This study focuses on the electric power sector, which has been identified as an early target for deep decarbonization. In the foreseeable future, electricity will continue to come primarily from a mix of fossil fuels, hydropower, variable renewables such as solar and wind, and nuclear energy (U.S. Energy Information Administration 2017). At present nuclear energy supplies about 11% of the world's electricity and constitutes a major fraction of all low-carbon electricity generation in the United States, Europe, and globally (Figure 2). Nuclear energy's future role, however, is highly uncertain for several reasons: chiefly, escalating costs and, to a lesser extent, the persistence of historical challenges such as spent fuel disposal and concerns about nuclear plant safety and nuclear weapons proliferation.

Figure 1: Human Development Index versus per capita electricity consumption for different countries



(United Nations Development Programme 2017)

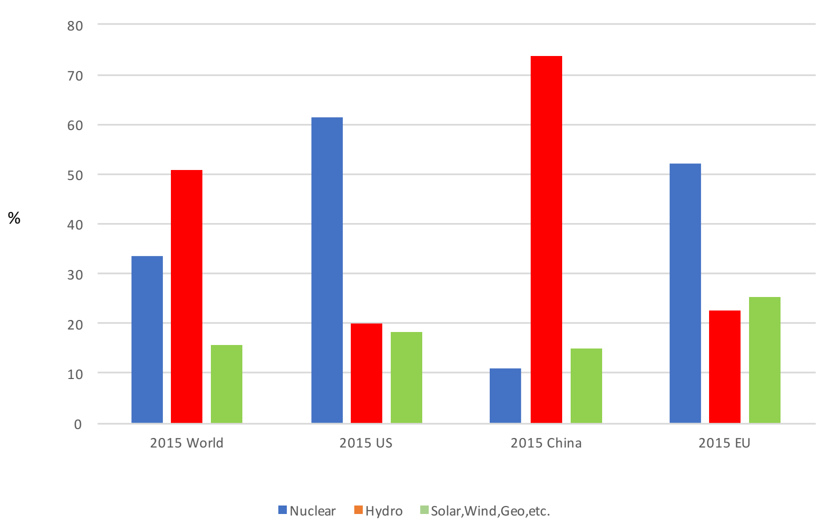
THE NUCLEAR ENERGY LANDSCAPE

Since MIT published its first *Future of Nuclear Power* study (Deutch, et al. 2003), the context for nuclear energy in the United States and globally has changed dramatically for the worse. Throughout most of the 2000s, the U.S. fleet of nuclear power plants was highly profitable: their capital costs had been largely amortized over previous decades and their production costs were low compared to the relatively high cost of fossil and renewable alternatives. As utilities sought to maximize the value of their nuclear assets, they embarked on a flurry of market-driven nuclear power plant purchases, power uprates, and license extensions. The situation changed quickly after 2007, as large quantities of inexpensive shale natural gas became available in the United States and the Great Recession depressed electricity demand and prices. Since then, nuclear power plants in the United States have become steadily less profitable and the industry has witnessed a wave of plant closures. Two recent examples include the Kewaunee plant in Wisconsin, which shut down in 2013 (Dotson 2014), and the Fort Calhoun plant in Nebraska, which shut down in 2016 (Larson 2016). Both plants shut down because they could not compete with cheaper generation options. Falling natural gas prices in Europe and Asia have put more economic pressure on nuclear power in those regions also.

While the U.S. nuclear industry remains exceptionally proficient at operating the existing fleet of power plants, its handling of complex nuclear construction projects has been abysmal, as exemplified by the mismanagement of component-replacement projects at the San Onofre (Mufson 2013) and Crystal River (Penn 2013) plants, which led to the premature closure of both plants in 2013. Other projects, including the troubled Vogtle (Proctor 2017) and V. C. Summer (Downey 2017) expansion projects, have experienced soaring costs and lengthy schedule delays. In the case of Vogtle and V.C. Summer, costs doubled and construction time increased by more than three years, causing the reactor supplier Westinghouse (Cardwell and Soble 2017) to declare bankruptcy (Westinghouse only began emerging from Chapter 11 protection in 2018) (Hals and DiNapoli 2018). The V. C. Summer project was ultimately abandoned in 2017 (Plumer 2017).

New nuclear plant construction projects by French reactor suppliers Areva and EDF at Olkiluoto (Finland) (Rosendahl and Forsell 2017), Flamanville (France) (Reuters 2018), and Hinkley Point C (United Kingdom) (BBC News 2017), have suffered similarly severe cost escalation and delays. Clearly, the goal of deploying new nuclear power plants at an overnight capital cost of less than $2,000 per electric kilowatt, as claimed

Figure 2: Share of carbon-free electricity sources in several major economies and worldwide



(International Energy Agency 2017)

by the North American and European nuclear industries in the 2000s (Winters, Corletti, and Thompson 2001) (World Nuclear Association 2008), turned out to be completely unrealistic. New nuclear plant construction (International Atomic Energy Agency 2017) has continued at a steady rate in countries like South Korea, China, and Russia; construction has also recently started in the Middle East. Many of these projects have been completed more or less on time, and likely at significantly lower cost than comparable projects in the West, although it is often challenging to independently validate the cost figures published in these countries.

In 2011, the combined effects of a massive earthquake and tsunami triggered an accident at the Fukushima Daiichi nuclear power plant in Japan and led to an unfortunate decision by Japanese authorities to force the evacuation of nearly 200,000 people from the region surrounding the site. This event renewed public concerns about the safety of nuclear installations. Although the radiological consequences of the accident have been minimal (United Nations Scientific Committee on the Effects of Atomic Radiation 2017), by 2012 the entire nuclear fleet in Japan was temporarily shut down, and only a handful of nuclear plants are currently back online in that country. In the wake of Fukushima, five countries (Germany, Switzerland, Belgium, Taiwan, and South Korea) announced their intention to ultimately phase out nuclear energy (World Nuclear Association 2017), though to date only Germany has taken immediate action toward actually implementing this policy.

Against this bleak backdrop, some opportunities have nonetheless emerged for the nuclear energy industry. Heightened awareness of the social, economic, and environmental risks of climate change and air pollution has provided a powerful argument for maintaining and potentially increasing nuclear energy's share of the global energy mix (Hansen, et al. 2015). Private investors appear interested in developing and deploying advanced reactor technologies (Brinton 2015), even as the readiness of these technologies has significantly increased in the past 15 years (ANL-INL-ORNL 2016) (Generation-IV International Forum 2014). Finally, there seems to be bipartisan support in the U.S. Congress for renewed American leadership in commercializing new nuclear technology (115th U.S. Congress 2017–2018).

THIS STUDY

In light of the important changes that have occurred since MIT's 2003 *Future of Nuclear Power* report and the 2009 update to the study, coupled with the existential challenges that now confront the nuclear industry, we concluded that it was time to conduct a new interdisciplinary study analyzing the future prospects of nuclear energy in the United States and internationally.

Based on the findings that emerged from this study, we contend that, as of today and for decades to come, the main value of nuclear energy lies in its potential contribution to decarbonizing the power sector. Further, we conclude that cost is the main barrier to realizing this value. Without cost reductions, nuclear energy will not play a significant role.

Nuclear energy does provide other benefits: it reduces other types of air pollution associated with electricity production; in addition, it contributes to fuel diversification and grid stability, has low land requirements, and creates well-paid jobs. These benefits are important in certain contexts; for example, nuclear energy may be attractive in countries that do not have enough land or suitable weather patterns for large-scale deployment of renewables, or in countries that are seeking to reduce coal use to improve air quality, or in countries that are concerned about the security and reliability of their energy supply. However, we believe that the primary, generally applicable attribute of nuclear energy that may justify its *future growth on a global scale* is its low-carbon nature. As such, we posit that special consideration should be given to preserving the existing nuclear power plant fleet as a bridge to a carbon-constrained future (as recognized in recent legislation adopted by the U.S. states of New York (Larson 2016), Illinois (Anderson 2016), and

New Jersey (Sethuraman 2018)), and to retaining essential expertise for operating the nuclear systems of the future.

We draw important lessons from a representative set of recent and ongoing nuclear construction projects worldwide and identify best practices that must be applied to any future projects. Further, we analyze the cost drivers for new nuclear builds—in particular, the relative importance of site preparation, civil works, equipment, equipment installation, engineering, and financing costs. We examine a broad range of technology innovations, from new construction techniques to advanced concrete solutions and from robotics to advanced manufacturing, in the quest to identify cost reduction opportunities for new nuclear.

We evaluate the benefits and challenges of advanced reactor technologies, defined here as light-water-cooled small modular reactors (SMRs) and non-water-cooled reactors (Generation-IV systems). These systems incorporate inherent safety features and passive safety systems that may simplify operations, reduce the probability of severe accidents, and limit the offsite consequences of such accidents, thus potentially broadening the number of suitable sites for nuclear power plants. We note that some Generation-III light water reactor (LWR) designs, such as the AP1000 and economic simplified boiling water reactor (ESBWR), have already adopted this approach. With the increasing role of variable renewables on the grid, a certain flexibility in operations is expected from all dispatchable power generators. Nuclear plants were traditionally designed for baseload operation, but, as has been recently demonstrated in Europe and the United States (Jenkins, et al. 2018), nuclear plants can adapt to provide load-following generation and many advanced reactor concepts are being designed for that capability as well. Advanced reactors are also expected to utilize simpler and more compact designs to reduce cost and capture new markets such as process heat for industry. This study critically assesses such claims and expectations.

Historically, time-to-market and development costs for new nuclear reactors have been too high, making them fundamentally unattractive to private investors, and leading some to advocate for direct government involvement in the development of these technologies (Secretary of Energy Advisory Board 2016). Prototype Generation-IV systems are currently being explored by the governments of several countries, including China, which has deployed high-temperature gas-cooled reactors (HTGRs) (Zhang, et al. 2016), Russia (Digges 2016), and India (Patel 2017), both of which have deployed sodium-cooled fast reactors (SFRs). We examine the regulatory framework for these advanced reactor designs to determine if there are any impediments to licensing them in the United States and to identify opportunities for making the regulatory framework for these designs more efficient. We also assess options for shortening the time to commercialization for certain less mature Generation-IV reactors (e.g. molten salt, gas-cooled fast, and lead-cooled fast reactors), and discuss what role the U.S. government and its national laboratories are likely to play in that process. Finally, we review and recommend specific government policies that would put all low-carbon energy technologies on an equal footing, which we deem essential to incentivizing private investment in new nuclear capacity.

This study does not address the disposal of radioactive waste (or, more properly, spent nuclear fuel) or proliferation risks. While these issues are universally considered barriers to the expansion of nuclear energy use, the political dimensions of finding solutions to waste disposal and managing proliferation risks far outweigh the technical challenges. We have reviewed recent studies of the nuclear fuel cycle that focused on the management and disposal of spent fuel (Blue Ribbon Commission on America's Nuclear Future 2011) (Kazimi, et al. 2011) (Wigeland, et al. 2014) and have found their recommendations to be valid. Briefly, there exist robust technical solutions for spent fuel management, such as interim storage in dry casks and permanent disposal in geological repositories with excavated tunnels or deep boreholes—the greater difficulty, historically, has been siting such facilities. But the evidence suggests that these solutions can be implemented through a well-managed, consensus-based decision-making process, as has been demonstrated in Finland (Fountain 2017) and Sweden (Plumer 2012). Domestically, the U.S. government should follow these examples and swiftly move on the recommendations for spent fuel management that have been put before it.

The question of nuclear materials proliferation is more complex. Adopting certain fuel cycle facilities such as international fuel banks and centralized spent fuel repositories can make the civilian nuclear fuel cycle unattractive as a path to gaining nuclear weapons materials or capability. At the same time, there is a desire on the part of established nuclear countries to supply nuclear technologies to newcomer countries, both because it constitutes a business opportunity and as a means to gain considerable, decades-long geopolitical influence in key regions of the world. Currently Russia and, to a lesser extent, China are aggressively pursuing opportunities to supply nuclear energy technology to other countries. Some have argued that if the United States wishes to pursue such opportunities and advance other geo-political objectives while simultaneously sustaining the non-proliferation and safety norms it has advocated around the world, it has a compelling interest in maintaining a robust domestic nuclear industry (Moniz 2017) (Center for Strategic and International Studies 2018) (Aumeier and Allen 2008).

This study is organized into five chapters that focus on several key issues:

1. Opportunities for Nuclear Energy
2. Nuclear Power Plant Costs
3. Advanced Reactor Technology Evaluation
4. Nuclear Industry Business Models and Policies
5. Nuclear Reactor Safety Regulation and Licensing

The remainder of this overview briefly describes each chapter and summarizes findings and recommendations. A full discussion of the analyses and considerations that led to these findings and recommendations can be found in the chapters that comprise the main body of the report.

SUMMARY OF FINDINGS AND RECOMMENDATIONS

Chapter 1: Opportunities for Nuclear Energy

We evaluate market opportunities for nuclear energy in electricity generation and other energy products in the United States and other countries. We also explore in detail how imposing a carbon constraint affects the optimal electricity generation mix in different regions of the world.

Finding: The cost of new nuclear plants is high, and this significantly constrains the growth of nuclear power under scenarios that assume 'business as usual' and modest carbon emission constraints. In those parts of the world where a carbon constraint is not a primary factor, fossil fuels, whether coal or natural gas, are generally a lower cost alternative for electricity generation. Under a modest carbon emission constraint, renewable generation usually offers a lower cost alternative.

As the world seeks deeper reductions in electricity sector carbon emissions, the cost of incremental power from renewables increases dramatically. At the levels of 'deep decarbonization' that have been widely discussed in international policy deliberations—for example, a 2050 emissions target for the electric sector that is well below 50 grams carbon dioxide per kilowatt hour of electricity generation (gCO_2/kWh)—including nuclear in the mix of capacity options helps to minimize or constrain rising system costs, which makes attaining stringent emissions goals more realistic (worldwide, electricity sector emissions currently average approximately 500 gCO_2/kWh).

Lowering the cost of nuclear technology can help reduce the cost of meeting even more modest decarbonization goals (such as a 100 gCO_2/kWh emissions target).

Chapter 2: Nuclear Power Plant Costs

We analyze attributes for successful nuclear build projects and cost drivers for those projects. Then we review a range of enabling technologies (such as innovations in construction approaches) and examine their ability to substantially reduce the cost of new nuclear power plants.

Finding: New nuclear plants are not a profitable investment in the United States and Western Europe today. The capital cost of building these plants is too high.

Finding: Successful nuclear builds tend to have the following attributes:

a) Completion of needed portions of the design prior to start of construction,[1]

b) Development of a proven supply chain for nuclear steam supply system (NSSS) components and access to a skilled labor workforce,[1]

c) Inclusion of fabricators and constructors in the design team to ensure that components can be manufactured and structures can be built to relevant standards,

d) Appointment of a single primary contract manager with proven expertise in managing multiple independent subcontractors,

e) Establishment of a contracting structure in which all contractors (and subcontractors) have a vested interest in the success of the project,

f) Adoption of contract administrative processes that allow for rapid and non-litigious adjustments to unanticipated changes in requirements or subcontractor performance, and

g) Operation in a flexible regulatory environment that can accommodate small, unanticipated changes in design and construction in a timely fashion.

Recommendation: Focus on using proven project and construction management practices to increase the probability of success in the execution and delivery of new nuclear power plants.

Finding: Cost reduction efforts need to be focused not on the NSSS design or the specific reactor technology but on (a) improvements in how the overall plant is constructed (or delivered to the site), and (b) ways to accelerate the construction process to reduce interest costs during this period.

Finding: Modularization, when used judiciously in nuclear plant construction and component fabrication, could be a viable cost-reduction strategy in advanced reactor designs. In addition, our examination suggests that (a) countries with high labor rates and low productivity have stronger incentives to use modular construction in factories and shipyards to reduce labor requirements (especially for very expensive labor at the plant site), and (b) if the factories and shipyards used to produce components are located in countries with low labor rates and high productivity, overall savings could be substantial. However, for structures, systems, and components that are less complex, onsite assembly may still be the less expensive option.

Finding: New reactor buildings and structures need to be optimized, taking into account both the amount of material and the amount of labor necessary for fabrication and installation in an effort to minimize the overall cost of commodities used in plant construction as much as possible.

Finding: Civil engineering activities in support of new reactor construction can be performed in a modular fashion by employing structures that are designed to be manufactured and assembled using advanced concrete techniques when such an approach is less expensive than conventional 'stick building.'

Finding: Standardization (especially at multi-unit sites), embedment below grade or underground (or, alternatively, offshore siting), and seismic isolation can reduce construction costs and improve safety and security.

[1] Note that attributes (a) and (b) are typical issues for first-of-a-kind projects.

Chapter 3: Advanced Reactor Technology Evaluation

We review the technical characteristics of advanced reactor technologies that may be considered in the future. Our evaluation focuses on important attributes including safety, operability and maintainability, and potential range of applications as enabled by specific features of the different reactor technologies. We also assess technical readiness and discuss the costs, lead-times, technical challenges, and financial requirements for developing and commercializing different advanced reactor systems.

Finding: In advanced reactors, the combination of fuel, coolant, and moderator results in a set of core materials that has high chemical and physical stability, high heat capacity, negative reactivity feedbacks, and high retention of fission products. In addition, these systems include engineered safety systems that require no emergency AC power and minimal external interventions. This type of design evolution has already occurred in advanced LWRs and is exhibited in new plants built in China, Europe, and the United States. These design attributes will make plant operations much simpler and more tolerable to human errors, thereby reducing the probability that severe accidents occur and drastically reducing offsite consequences in the event that they do. Their improved safety characteristics can also make licensing of new nuclear plants easier and accelerate their deployment in developed and developing countries.

Finding: Technology advances in plant design, not in the reactor, hold the greatest promise for reducing capital cost. All the broadly discussed reactor concepts, including incumbent LWR technology and several of the Generation-IV designs, can potentially exploit many of these advances. The challenge for any proposed plant design is to achieve the radical cost reductions needed to make a new nuclear plant competitive in the on-grid electricity market.

Finding: Traditionally, early-stage cost estimates have been significantly biased toward *underestimating* costs and hence have been unreliable predictors of the eventual cost of a given nuclear technology once its technical readiness increases and the reactor design matures. Nevertheless, our assessment of advanced reactor systems suggests that these systems have the potential to exploit inherent and passive safety features to improve overall safety and operation. These systems have promise, but their economic potential is not yet proven. A commitment to explore and test advanced reactor technologies may provide significant economic benefit for future electricity systems.

Recommendation: Future research, development, and demonstration (RD&D) funding should prioritize reactor designs that are optimized to substantially lower capital costs, including construction costs. Innovations in fast reactors that are advertised on the basis of fuel cycle metrics are unlikely to advance commercial deployment.

Finding: Each advanced reactor system is at a different level of technical maturity and as such requires a number of key technology development activities to be completed before it can be commercialized. The overall time needed to reach commercialization depends on the technical maturity of the concept and prior experience with the specific reactor technology involved. More mature concepts, such as the advanced small modular reactor (SMR) design being marketed by NuScale, a sodium fast reactor, and a modular high temperature gas-cooled reactor, are technically ready for commercialization by 2030. Less mature reactor concepts, including lead fast reactors, gas-cooled fast reactors, and molten salt systems, however, would not be expected to reach commercialization before 2050 if the traditional approach to nuclear development is followed.

Recommendation: A more innovative approach to deployment is needed to advance less mature advanced reactor designs. Under this new paradigm, proof of concept and proof of performance would be demonstrated using a single reactor that would be: (a) designed at full scale to reduce scale-up risks, (b) designed with conservative thermo-mechanical margins, (c) licensed under the prototype rule developed by the U.S. Nuclear Regulatory Commission (NRC) to provide flexibility and reduce the burden of proof typically expected in licensing, and (d) sited on a remote U.S. Department of Energy (DOE) site as an extra precaution to remove some safety constraints on the design and allow for integral testing. Using this new paradigm, development of the least mature systems could be accelerated and the expected timeframe for commercial deployment could be moved up to the mid- to late-2030s.

Chapter 4: Nuclear Industry Business Models and Policies

We examine the current market for nuclear energy in the United States and worldwide and explore the market challenges that currently confront the existing nuclear fleet. We then discuss the policy changes and possible business models that are needed to accelerate the deployment of advanced reactor systems.

Finding: In most cases, existing nuclear is a cost-efficient provider of low-carbon electricity. Premature closures of existing plants undermine efforts to reduce carbon dioxide and other power sector emissions and increase the cost of achieving emission reduction targets.

Finding: A major source of revenue deficiency for nuclear generators today is the fact that they are not fully compensated for their low-carbon attributes. Ameliorating this deficiency would change nuclear energy's market position and conserve much existing nuclear capacity.

Recommendation: Public policies to advance low-carbon generation should treat all technologies comparably. There should be no discrimination against nuclear energy.

Finding: There is little evidence that revenue deficiencies for existing nuclear power plants in the United States are due to 'attributes' that are being systematically mispriced by wholesale electricity market rules, aside from the failure to properly price nuclear energy's climate benefits.

Finding: Discrimination against nuclear as a low-carbon energy source is not rooted in technical issues of electricity market design. Rather, it is primarily rooted in public attitudes towards nuclear. These public attitudes translate into discriminatory public policies outside of wholesale market rules, which in turn shape profitability.

Recommendation: Achieving deep reductions in global carbon emissions will require a dramatic restructuring of the technologies deployed in the electricity industry. Constant adjustments will be needed to align market rules to the new technologies being deployed. The nuclear energy industry has a stake in ongoing research to assure that changes in market design are consistent with the deployment of advanced nuclear systems.

Recommendation: The implementation of a politically durable solution for the management of spent nuclear fuel would greatly facilitate significant investment in new nuclear technologies.

Finding: Private business is well suited to driving innovations that would lead to new reactor designs with radically lower capital costs. To harness this capability, the private sector must make the technology choices and supply the major capital investments. Private companies must enjoy the potential for profit and also bear the risk of loss.

Recommendation: Governments should establish reactor parks where companies can site prototype reactors to conduct testing and operations oriented to licensing. These parks should be open to diverse reactor concepts chosen by the companies. Governments should provide appropriate supervision and support–including safety protocols, infrastructure, environmental approvals, and fuel cycle services–and should be directly involved with all testing.

Recommendation: Governments should establish programs to fund prototype testing and commercial deployment of new, advanced reactor designs. These programs should focus on four levers for advancing progress toward commercialization:

1. Funding to share R&D costs related to moving new reactor designs toward the construction of a demonstration reactor,
2. Funding to share licensing costs for new demonstration reactors and commercial designs,

3. Funding for milestone payments for construction and operation of a demonstration reactor, and
4. Funding for production credits to reward successful demonstration of new designs.

Chapter 5: Nuclear Reactor Safety Regulation and Licensing

We review the regulatory structure for nuclear energy in the United States and around the world and assess the ability of current regulatory structures and approaches to accommodate the licensing of advanced nuclear reactor systems.

Finding: Regulatory agencies around the world have adopted basic principles similar to those described in the policies of the International Atomic Energy Agency (IAEA) and in U.S. NRC regulations, though they vary in their detailed application of these policies and principles—for example, with respect to required burden of proof. While significant cultural, social, and political differences may exist between countries, the fundamental basis for assessing the safety of nuclear reactors is fairly uniform among countries with established nuclear power programs.

Recommendation: Regulatory requirements for advanced reactors should be coordinated and aligned internationally to enable international deployment of commercial reactor designs, and to standardize and ensure a high level of safety worldwide. National differences in safety regulations due to accepted cultural practices make it difficult to develop a universally accepted regulatory licensing regime. But certain basic standards for nuclear safety should be maintained internationally due to the far-reaching environmental and social/political effects of nuclear plant operation. Initial international agreement on specific topics (e.g., station blackout resiliency) and joint licensing evaluations could advance discussions about undertaking reciprocal reactor design evaluations between nations or standardizing international safety requirements.

Finding: A wide variety of pathways and strategies are available for licensing new reactors (including advanced reactors) in the United States. These include using existing regulatory processes such as topical reports, standard design approvals, standard design certification, and either Part 50 or Part 52 licensing.

Recommendation: While current regulatory structures have sufficient flexibility to allow for technology- or reactor-specific licensing pathways, the U.S. NRC should continue to move toward the use of performance-based and risk-informed design criteria for new reactors.

Recommendation: In the United States, the NRC should test its advanced reactor licensing process in the next few years to identify unanticipated licensing hurdles and to train NRC staff.

Finding: In the United States, the NRC currently has the regulatory processes available to implement a phased licensing approach for advanced reactors—thus no new formal regulatory processes are needed. Use of phased licensing processes, however, may increase the total cost, time, and uncertainty related to advanced reactor licensing. Applicants must determine on a case-by-case basis which licensing approaches best suit their project and should work with the NRC to create design-specific licensing plans that use the most appropriate set of regulatory tools to achieve desired outcomes from the licensing process.

Finding: The U.S. NRC's prototype rule can provide an alternative pathway for licensing advanced nuclear reactor designs.

Recommendation: The U.S. NRC should clarify its prototype rule and licensing pathway to allow for more rapid licensing of prototype reactors without excessive regulatory burden. While additional safety features may be required to license a prototype reactor, regulators and license applicants should agree to conditions (experimental tests and data) that would allow for these features to be removed in future plants. The prototype licensing pathway should be available to all reactor technologies.

Finding: Inconsistency in the design margins required by different codes and standards can result in relative underdesign or overdesign of structures, systems, and components.

Recommendation: Consensus codes used in the design and construction of nuclear power plants should be re-evaluated in terms of their efficacy in ensuring safety. The nature of system interactions in advanced reactor designs may fundamentally differ from previously operated reactor designs. Existing consensus codes should be reviewed so that overlapping standards are properly harmonized. This harmonization will both reduce the regulatory burden and help to ensure safe operation for advanced reactor designs.

Finding: Adequate funding for advanced reactor licensing efforts is necessary to ensure timely licensing actions. In the United States, funding for such licensing development efforts is currently limited and comes from operating nuclear facilities.

Recommendation: The U.S. government should provide funding for advanced reactor regulation outside the NRC's 90% fee recovery model to ensure that sufficient resources are available when needed. At the same time, the nuclear energy industry must communicate regulatory function and research needs with key U.S. entities, including the NRC, DOE, and Congress, to ensure that adequate funding is appropriated.

CONCLUSION

In summary, this study delivers four key messages:

- The central opportunity for nuclear energy over the next several decades is tied to its potential contribution to decarbonizing the power sector;
- The central challenge to realizing this contribution is the high cost of new nuclear capacity;
- There are ways to reduce nuclear energy's cost, which the industry must pursue aggressively and expeditiously;
- Government help, in the form of well-designed energy and environmental policies and appropriate assistance in the early stages of new nuclear system deployment, is needed to realize the full potential of nuclear.

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Chapter 1

Opportunities for Nuclear Energy

Internationally, concern over climate change continues to grow. With rising population and economic output, only a concerted global effort to decarbonize current energy production systems will have any meaningful impact on climate change. In this context, we examine opportunities for nuclear energy technologies to play a larger and more consequential role in meeting U.S. and global energy needs in a carbon-constrained world. First, we review the status of nuclear energy today and the outlook for the industry over the next couple of decades. We then develop projections to 2050 for optimal electrical generation system capacities in the United States and internationally under a variety of low-carbon scenarios. We consider whether equipment supply chain barriers could impede the industry's growth opportunities over this timeframe and assess nuclear energy's potential to play an expanded role in industrial applications beyond electricity supply.

1.1 CURRENT STATUS AND OUTLOOK FOR NUCLEAR ENERGY

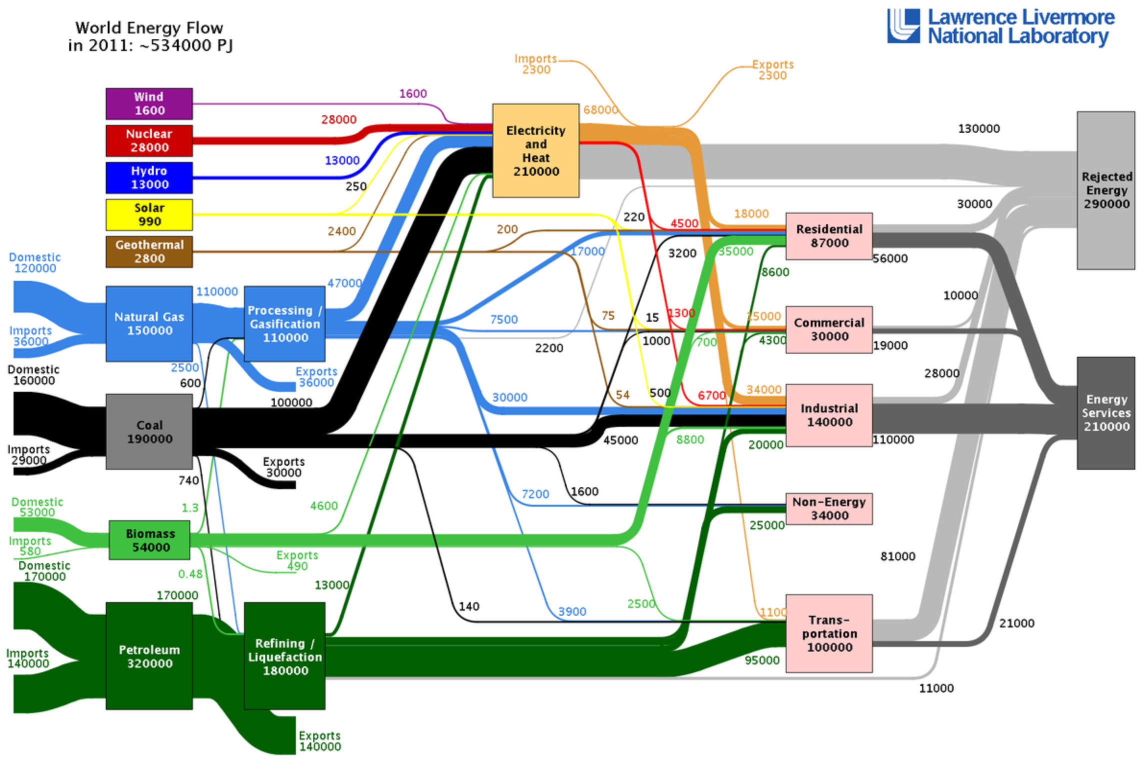
Electrical energy production is a major component of the energy industry in the United States: about 40% of primary energy consumption goes to producing electricity and the fraction is similar worldwide (Figures 1.1a and 1.1b) (Lawrence Livermore National Laboratory 2014). Electricity is a versatile form of energy and useful in all aspects of daily life, including for residential, commercial, industrial, and transportation applications. The electrical energy sector is also projected to grow (U.S. Energy Information Administration 2017a) given electricity's flexibility as an intermediate form of useful energy (an example would be the electrification of the transportation sector for mass transit and for individual transportation).

International Outlook for Electricity Production

The electrical energy sector is one of the more dynamic growth areas among all energy markets internationally and electricity is the world's fastest-growing form of energy, as it has been for many decades. The U.S. Energy Information Administration's International Energy Outlook (IEO) estimates that net electricity generation worldwide will grow almost 45% by mid-century, from 23.4 trillion kilowatt hours (kWh) in 2015 to 25.3 trillion kWh in 2020 and 34.0 trillion kWh in 2040 (U.S. Energy Information Administration 2017b). The strongest growth is projected to occur among developing, non-OECD[1] nations: led by China and India, the growth rate for electrical energy generation in non-OECD countries is projected to average 1.9% per year from 2015 to 2040. In the OECD nations, where infrastructures are mature and population growth is relatively slow or declining, electric power generation is projected to increase by an average of 1% per year from 2015 to 2040 (according to the IEO Reference case). In the United States, electricity demand is projected to grow between 0.5% and 1% per year over the same time period—less than the OECD average.

[1] The Organisation for Economic Co-operation and Development is an intergovernmental economic organization with 35 member countries. It was founded in 1960 to stimulate economic progress and world trade (OECD 2017).

Figure 1.1a: 2011 world energy flow



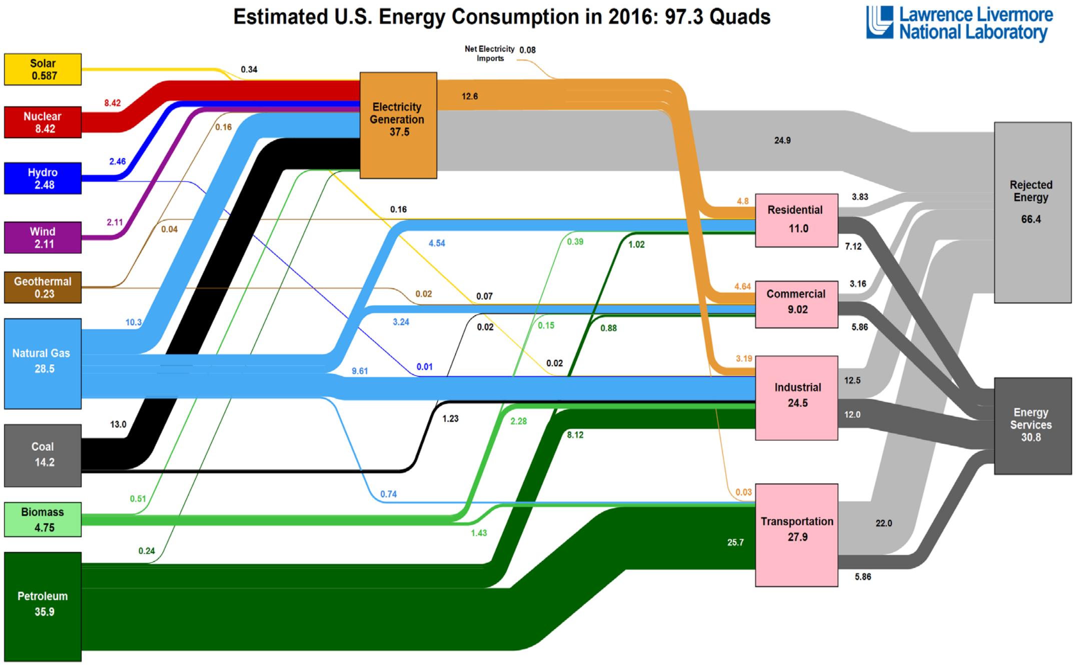
(Lawrence Livermore National Laboratory 2014) (1 Petajoule = 1×10^{15} Joules ≈ 0.001 Quadrillion BTU)

Source: LLNL 2014. Data is based on IEA's *Extended World Energy Balances* (2013 Edition). All quantities are rounded to 2 significant digits and annual flows of less than 0.05 PJ are not included. Totals may not equal sum of flows due to statistical differences. Imports and Exports represent gross global trade. Further detail on how all flows are calculated can be found at flowcharts.llnl.gov. LLNL-MI-410527.

Long-term global prospects continue to improve for electricity generation from renewable energy sources (including hydropower) and natural gas (Figure 1.2). Worldwide, renewable generation is projected to increase at a rate of 2.8% per year from 2015 to 2040. Natural gas is the next fastest-growing source of electricity generation with a projected average annual growth rate of 2.1% worldwide. Nuclear energy, by contrast, is projected to grow more slowly, at a rate of 1.5% per year worldwide. In China alone, electricity demand is projected to increase at a rate of 1.7% per year over the same 2015–2040 period, while generation from renewables is projected to grow by 3.5% per year and generation from natural gas and nuclear (together) by more than 6.5% per year.

Many countries have enacted environmental policies and regulations that are intended to curtail greenhouse gas emissions from the power sector by reducing the use of fossil fuels. These efforts have continued to reduce the relative importance of coal as a dominant fuel source for electricity generation. By 2040, electricity generation from natural gas and renewable energy sources is estimated to surpass electricity generation from coal on a worldwide basis. These projections do not include the implications of actions that could be taken to reduce carbon dioxide (CO_2) emissions under the Paris Agreement, nor do they include the effects of the Clean Power Plan in the United States since that policy has been targeted for repeal and is subject to legal challenges.

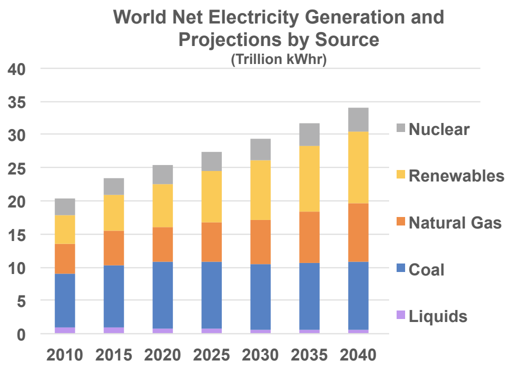
Figure 1.1b: 2016 U.S. energy flow



(Lawrence Livermore National Laboratory 2017) (Quad = Quadrillion BTU = 1×10^{15} BTU ≈ 1,000 Petajoules)

Source: LLNL March, 2017. Data is based on DOE/EIA MER (2016). This chart was revised in 2017 to reflect changes made in mid-2016 to the Energy Information Administration's analysis methodology and reporting. The efficiency of electricity production is calculated as the total retail electricity delivered divided by the primary energy input into electricity generation. End U.S. efficiency is estimated as 65% for the residential sector, 65% for the commercial sector, 21% for the transportation sector, and 49% for the industrial sector, which was updated in 2017 to reflect DOE's analysis of manufacturing. Totals may not equal sum of components due to independent rounding. LLNL-MI-410527.

Figure 1.2: Current and projected world net electricity generation by energy source, 2010–2040 (trillion kilowatt hours)



(U.S. Energy Information Administration 2017b)

Note: Renewables include hydroelectric power

International Status and Outlook for Nuclear Energy

Today, the world produces as much electricity from nuclear energy as it did from all sources combined in the early 1960s. Civilian nuclear power plants supply 11% of global electricity needs, with reactors in 32 countries. The installed electrical generating capacity of commercial nuclear power reactors worldwide totals more than 392 gigawatts (GW_e). At present, 55 nuclear power reactors are under construction, equivalent to 16% of existing nuclear capacity (International Atomic Energy Agency 2018). However, in a few countries (e.g., Slovakia, Ukraine) plant construction has been delayed for many years, while in the United States, plans to build two new reactor units at the V.C. Summer Nuclear Generating Station in South Carolina were canceled in 2017.

Electricity generation from nuclear energy worldwide is projected to increase from 2.3 trillion kWh in 2012 to 2.7 trillion kWh in 2020 and 3.7 trillion kWh in 2040 based on estimates in the IEO Reference case. Concerns about energy security and CO_2 emissions are influencing the development of new nuclear generating capacity. Virtually all the projected net expansion in worldwide installed nuclear capacity occurs in non-OECD countries, led by planned additions of nuclear capacity in China and India specifically over the 2012–2040 timeframe. Other non-OECD countries that are interested in nuclear energy have smaller but still noteworthy plans to develop new nuclear capacity. For example, the United Arab Emirates has embarked on a nuclear power program in close consultation with the International Atomic Energy Agency (IAEA). Led by a Korean electric power consortium, four Korean-designed nuclear power reactors (with combined capacity of 5.6 GW_e) are under construction at the United Arab Emirates' Barakah site for 2020. The first unit is complete and expected to go online in 2018.

In the OECD portion of Europe, overall nuclear capacity is expected to decline by more than 30%. In Japan, nuclear generation is likewise expected to fall (in the IEO Reference case, Japan's nuclear capacity in 2040 remains far below the level it was prior to the Fukushima accident). As a result, the combined capacity of all nuclear power plants in OECD countries is projected to decrease by 6 GW_e from 2012 to 2040 (World Nuclear Association 2017). This estimate does not include recently announced plant closures in the United States (as noted previously, these closures are being caused by the inability of plant owners to recover production costs in a deregulated market and make the additional capital investments needed to extend plant operating life).

Decarbonizing the Electrical Energy Sector

Deep decarbonization of the electrical energy sector globally, where "deep decarbonization" means a substantial reduction (one order of magnitude or more) in greenhouse gas emissions, is needed to mitigate the effects of climate change in this century. Achieving deep decarbonization requires a technical pathway to reduce CO_2 emissions. A number of studies have noted that different mitigation pathways are possible with different likelihoods of achieving an emissions reduction goal that meets or exceeds the widely accepted 2050 target of limiting global average warming to 2°C (International Energy Agency 2017) (Chen, et al. 2016). Political and cultural factors will influence the choice of any particular decarbonization pathway in individual countries. Currently, energy efficiency and energy conservation measures are being employed as a cost-effective way of reducing energy demand and thereby reducing carbon emissions. However, these measures will not be adequate to markedly reduce global emissions. Studies that have explored options for achieving deep decarbonization by 2050 have primarily focused on the potential to transform the electricity sector because the costs of carbon reductions in this sector are initially lower than for other major energy sectors. By contrast, significantly changing and decarbonizing the transportation and industrial sectors by mid-century is expected to be more difficult and costly.

In this analysis, we considered a broad range of decarbonization targets for the electricity generation system. For example, in 2010, CO_2 emissions from U.S. electricity generation averaged about 500 grams per kilowatt hour (gCO_2/kWh). To do its part to reach the 2050 climate stabilization goal set by the Paris Agreement, the United States would need to reduce CO_2 emissions from electricity generation by more than 97%—in other words, reduce the carbon intensity of its electricity mix from 500 gCO_2/kWh to less than 15 gCO_2/kWh. This target is based on analyses that have estimated the scale of emissions reductions needed in the electric and non-electric sectors to limit greenhouse gas concentrations in the atmosphere to 450 parts per million (ppm) CO_2 equivalent (Sachs, et al. 2014).

To provide context for these emissions targets, Table 1.1 presents information about CO_2 emissions rates for electricity generation in selected countries in 2017 (the same countries

Table 1.1: Current electricity sector CO_2 emission rates[a] compared to 2050 emissions goals

Country	2017 CO_2 Emissions from Electricity	2050 IEA Energy Technology Perspectives 2°C Scenario	MIT Joint Program Outlook[f]
United States	≈470 gCO_2/kWh[b]	11 gCO_2/kWh[e]	≈1 gCO_2eq/kWh
China	≈680 gCO_2/kWh[c]	24 gCO_2/kWh[e]	≈1 gCO_2eq/kWh
United Kingdom	≈350 gCO_2/kWh[d]	11 gCO_2/kWh (for EU)[e]	≈1 gCO_2eq/kWh
France	≈90 gCO_2/kWh[d]	11 gCO_2/kWh (for EU)[e]	≈1 gCO_2eq/kWh

[a] Note that these emission rates are technically given in CO_2-equivalent terms—that is, they include emissions of non-CO_2 greenhouse gases, such as methane, converted to a CO_2-equivalent mass based on their relative warming effects in the atmosphere. [b] (U.S. Energy Information Administration 2017a); [c] (Liu, Ma, and Kang 2017); [d] (Gogan, Partanen, and Denk 2017); [e] (International Energy Agency 2017); [f] (Chen, et al. 2016)

are included in the modeling analysis discussed in Section 1.2). For comparison, we reference two analyses that estimate the CO_2 reductions needed to achieve the 2°C climate stabilization goal by 2050 (in other words, deep decarbonization). One analysis, by the International Energy Agency (IEA) estimates that emissions for the electricity generation sector must be below 11–24 gCO_2/kWh. In a separate study, researchers at MIT estimate that emissions need to be reduced to levels approaching 1 gCO_2/kWh. Another study finds that to mitigate financial risk given uncertainty about future climate policy, the best strategy for the energy industry is to invest in a range of electricity generation sources, including a significant fraction of non-carbon technologies (Morris, et al. 2018). Thus, our analysis considers a range of emission constraints from modest carbon reductions to deep decarbonization. This approach is consistent with past work (Sepulveda 2016), which has examined emission targets for the year 2050 that range from 400 gCO_2/kWh to 1 gCO_2/kWh.

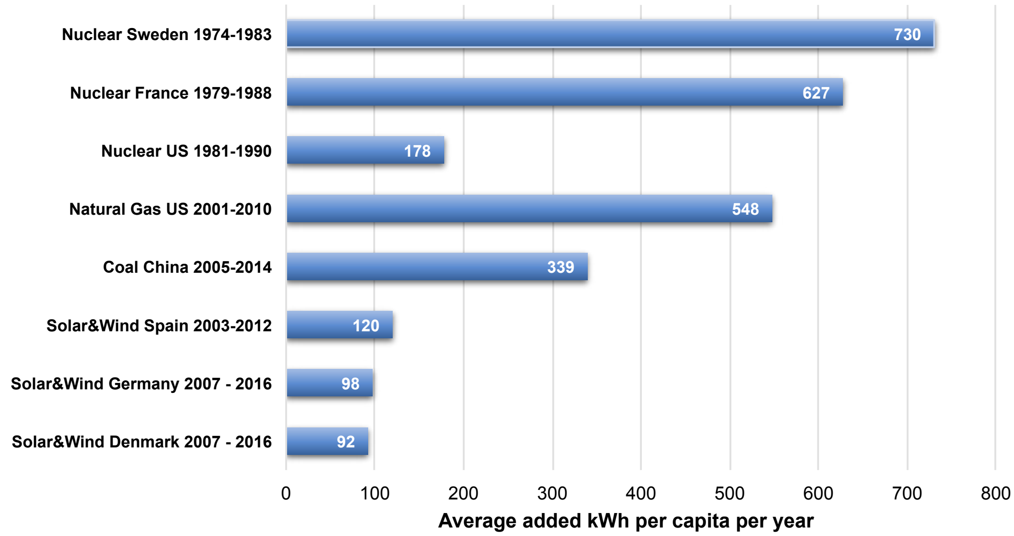
Another consideration is whether the deployment of low-carbon energy technologies like renewables or nuclear can be accomplished in the timeframe needed to substantially displace fossil fuels by 2050. Rapid deployment is critical to achieve current international climate mitigation goals. In many countries, solar and wind have achieved notable levels of penetration in electricity generation markets over the last decade, and this trend is expected to continue based on current IEO estimates. Our analysis indicates that, historically, large-scale increases in low-carbon generation have occurred most rapidly in connection with additions of nuclear power (Figure 1.3).

Recent work by Qvist and Brook (2015) examines the potential for a large-scale expansion of nuclear energy globally to replace fossil fuel electricity production. Their analysis uses empirical data from the French and Swedish light water reactor programs, when those countries aggressively pursued nuclear power expansion as part of their national energy policies. The results indicate that if many nations added nuclear capacity at the same rate per capita that France and Sweden achieved during their national expansion, coal- and gas-fired generation could be replaced worldwide. In their projections, Qvist and Brook consider potential constraints and uncertainties that could affect future nuclear expansion, such as differing relative economic output across regions, current and past unit construction time and costs, electricity demand growth forecasts, and the retirement of existing nuclear plants. Their analysis concludes that the global share of fossil fuel electricity could be replaced in 25–35 years.

1.2 THE ROLE OF NUCLEAR ENERGY IN THE OPTIMAL ELECTRICITY GENERATION SYSTEM IN 2050

The challenge for future electricity generation systems worldwide is to avoid harming the environment while delivering high levels of electricity security, reliability, and affordability. Carbon reduction objectives will be a key factor,

Figure 1.3: Electricity growth (kWh per year per capita) based on actual data for added power capacity in various countries



Assumes 90% capacity factor for dispatchable energy sources (nuclear, natural gas, coal) and the following capacity factors for wind/solar: Germany 19%/9%; Spain 25%/33%; Denmark 26%/7% (based on historical record for best 10-year period).

with national and international energy and climate policies providing guidance for future investment decisions. While there is agreement about the need to decarbonize the electric power sector to mitigate climate change, considerable uncertainty and debate remains about the relative contribution of various low-carbon technologies in future power systems. The optimal technology mix in a carbon-constrained environment will depend on the characteristics of the individual energy technologies employed.

While government policies and business models will continue to evolve, our goal here is to examine the role nuclear energy can play in a decarbonized electricity market in the 2050 timeframe. We address two questions:

1. What are the long-term prospects for nuclear energy in a decarbonized electricity market under different technological scenarios?

2. What would the cost of nuclear technology need to be for nuclear energy to have a role?

Using only energy technology costs or levelized cost of electricity (LCOE), a widely-used metric for comparing electricity generation costs, fails to adequately value the production of dispatchable, low-carbon power at the system level; furthermore, these metrics have shortcomings when it comes to evaluating system integration costs. The overall value of a given technology to the electricity system can only be understood when technologies are assessed together, not in isolation. Decision support tools, including power system optimization models, can help explore these synergies; illuminate key mechanisms, uncertainties, and risks; and guide power system planners, policy makers, and businesses. In particular, capacity expansion (or capacity planning) modeling tools have historically been used to explore what mix of available electricity generation resources would produce least-cost outcomes for the system as a whole under different scenarios.

GenX Simulation Approach

To quantify the role of nuclear power, we use GenX, a power system decision support tool (Jenkins and Sepulveda 2017), to explore the optimal electricity generation mix for minimizing total system generation costs subject to a set of pre-specified scenarios. Each scenario is characterized by a CO_2 emissions limit; a year-long hourly demand profile; region-specific, year-long hourly availability profiles for solar and wind resources; and a set of investment and operational costs for different systems under different carbon constraints. We consider two alternative pathways for each scenario. In the first one, nuclear power technology is allowed as an investment option in the least-cost system portfolio; in other words, nuclear is deployed only if it is economically efficient for the electricity generation system. In the second pathway, nuclear power technology is excluded as an investment option and cannot be deployed. The difference in total system generation costs between these two pathways represents the value of nuclear power and is termed the 'opportunity cost' of nuclear energy. We consider carbon emission targets of 100, 50, 10, and 1 gCO_2/kWh in our system analysis, as well as a 'business-as-usual' target of 500 gCO_2/kWh.

Our analysis includes a wide range of assumptions about cost and technology to investigate the breadth of conditions under which nuclear energy can play a significant role. The different technology scenarios, wherein input parameters for individual technologies vary from an assumed 'nominal case' scenario, can be used to assess the sensitivity of our results to changes in these assumptions.

GenX optimizes the electricity generation capacity mix by minimizing the objective function of total annualized system generation cost for a given scenario. Its results account for capital cost and financing charges, fixed operating costs, and variable operating costs, including fuel charges. The optimization for each scenario is subject to several constraints: (a) the need to match hourly electricity dispatch to electricity demand; (b) technology-specific operating constraints, such as allowable ramp rates and unit commitments for dispatchable generators; and (c) CO_2 emission limits (expressed in gCO_2/kWh).

GenX is configured to consider a full year of operating decisions, in hourly intervals, to represent a future planning year. In this sense, the model is static because its objective is not to determine when investments should take place over time to reach a given end state, but rather to produce a snapshot of the minimum-cost technology mix for the electricity system under a set of pre-specified conditions for some year in the future (in this case, 2050).

We express our results in terms of (a) the average cost of generation in dollars per megawatt hour ($/MWh), where this cost figure represents total system cost over total demand served by the system throughout the year; and (b) electricity generation capacity required to meet the load. For our analysis, we characterized different systems in the United States, Europe, and China using region-specific data on chronological hourly demand and hourly capacity factors for renewable generators.

To make the simulation computationally tractable in all our scenarios, transmission networks were simplified to a single node representation (i.e., there are no transmission bottlenecks or losses; this is sometimes referred to as the 'copper plate assumption'), assuming no transmission constraints exist given future network reinforcements. We further assume that electricity flows are unimpeded within regions and electricity generated in a region serves only electricity demand in that same region. In other words, our scenarios do not allow for out-of-region imports or exports of electricity. Table 1.2 summarizes required inputs and simulation outputs using the GenX modeling tool. Electricity transmission costs are also not considered. Details are provided in Appendix A.

Due to computational time constraints, we limited the number of technology options for each optimization scenario. A large light water reactor (1,000 MW_e) is used as the surrogate for advanced nuclear technologies since the estimated capital, fuel and operating costs of these technologies are considered to be

Table 1.2: Inputs and outputs of the GenX model

Inputs	Outputs
• Solar PV hourly capacity factor • Wind hourly capacity factor • Hourly historical demand and demand growth • Fixed (capital and O&M) and variable (O&M, cycling, etc.) costs for each resource technology • Operational parameters for each technology • Fuel parameters such as emissions rate and cost	• Optimal installed electricity generation capacity mix • Total system cost • Hourly operation of each resource technology • System carbon emissions • Energy contribution and capacity factor for each technology

comparable to current light water reactor systems, as will be discussed in Chapter 3. Table 1.3 shows technology options for both pathways (with and without nuclear energy as an option in the capacity mix).

We used GenX to model the optimal electricity system mix in selected regions of the world in 2050. This global perspective is important since the cost of different electricity generation technologies varies regionally as do the availability of renewable resources and expected electricity demand patterns. All of these elements shape the least-cost electricity generation mix. We modeled electricity systems for a total of six regions in China, Europe, and the United States:

- Tianjin, Beijing, and Tangshan (T-B-T), China
- Zhejiang, China
- France, Europe
- United Kingdom, Europe
- Texas, United States
- New England, United States

The data sources used as inputs for each electricity system are summarized in Table 1.4.

Operating parameters (e.g., efficiencies) for each technology option were assumed to be constant across all the electricity systems modeled and are given in Appendix A. Estimated technology costs for the United States in 2050 were taken from National Renewable Energy Laboratory (2016); battery storage costs were taken from Lazard (2015). For all other regions (i.e., China, France, and the United Kingdom), technology costs—except costs for storage—were scaled from U.S. costs based on scaling factors calculated by comparing U.S. data to costs reported by the International Energy Agency (2015). Overnight costs are shown in Table 1.5. Cost assumptions are discussed in detail in Appendix A.

GenX Simulation Results

Figure 1.4a presents the results of our analysis for Texas, showing the total system cost of electricity generation for five technology scenarios:

1. A ***No Nuclear*** case where nuclear is not an allowed option.

2. A ***Nuclear—Nominal Cost*** case in which nuclear technology can be selected at the currently projected 'nth-of-a-kind' (NOAK) overnight cost of $5,500/kW$_e$ in 2050 (National Renewable Energy Laboratory, 2016).

3. A ***Nuclear—Low Cost*** case in which nuclear technology can be selected at a cost that is 25% lower than currently projected for 2050. This estimate is based on our analysis of opportunities to reduce the overnight cost of nuclear by employing innovations in enabling technologies (see Chapter 2).

4. A ***Nuclear—Extremely Low Cost*** case in which nuclear technology can be selected at a cost that is 50% that of the currently projected cost for 2050. This is a long-term cost goal for many advanced reactor technologies (U.S. Department of Energy 2016).

Table 1.3: Technology options for each pathway

Nuclear Energy IS An Allowed Option	Nuclear Energy Is NOT An Allowed Option
Carbon-Free Options • Photovoltaic (PV) Solar • On-shore Wind • Light-water Reactor (LWR) Nuclear • Coal with Carbon Capture and Storage (CCS) • Natural Gas with CCS **Carbon Options** • Open Cycle Gas Turbine (OCGT) • Combined Cycle Gas Turbine (CCGT) • Coal (IGCC) **Storage Options** • Battery Storage • Hydro-electric Storage (Fixed)	**Carbon-Free Options** • PV Solar • On-shore Wind • Coal with CCS (IGCC-CCS) • Natural Gas with CCS **Carbon Options** • OCGT • CCGT • Coal (IGCC) **Storage Options** • Battery Storage • Hydro-electric Storage (Fixed)

Table 1.4: Data sources for GenX scenarios

	Tianjin, China	Zhejiang, China	France	United Kingdom	Texas, United States	New England, United States
Solar Hourly Capacity Factor (2016)	Renewables Ninja[a]	Renewables Ninja[a]	Sepulveda 2016	Sheffield Solar[d]	Sepulveda 2016	Sepulveda 2016
Wind Hourly Capacity Factor (2016)	Renewables Ninja[a]	Renewables Ninja[a]	Sepulveda 2016	EnAppSys[e]	Sepulveda 2016	Sepulveda 2016
Historical Hourly Elec. Demand	CEIC[b] and SWITCH[c]	CEIC[b] and He et al.[c]	Sepulveda 2016	Gridwatch[f]	Sepulveda 2016	Sepulveda 2016

[a] (Pfenninger and Staffell 2016) (Staffell and Pfenninger 2016) (Pfenninger and Staffell, Renewables.ninja)
[b] (CEIC 2017); [c] (He, et al. 2016); [d] (The University of Sheffield 2017); [e] (EnAppSys 2017); [f] (Gridwatch 2017)

Table 1.5: Overnight cost inputs

	Cost ($/kW)	OCGT	CCGT	Coal IGCC	Nuclear	Wind	Solar	Battery Storage	Coal IGCC+CCS	Gas CCGT+CCS
United States	Low				4,100	1,369	551	429		
	Nominal	805	948	3,515	5,500	1,553	917	715	5,876	1,720
	High				6,900	1,714	1,898	1,430		2,215
China	Low				2,094	1,117	404	429		
	Nominal	421	496	1,160	2,796	1,267	671	715	1,940	900
	High					1,398	1,389	1,430		1,159
United Kingdom	Low Cost				6,070	1,887	484	429		
	Nominal	865	953	3,515	8,142	2,142	804	715	5,875	1,434
	High					2,363	1,665	1,430		1,847
France	Low				5,067	1,511	481	429		
	Nominal	890	980	3,515	6,797	1,715	801	715	5,876	1,475
	High				8,496	1,892	1,657	1,430		1,899

Assumed LCOEs for different technologies, based on nominal U.S. costs, were as follows: wind – $72/MWh; solar – $99/MWh; nuclear – $97/MWh; CCGT-CCS – $90/MWh; OCGT – $87/MWh; CCGT – $64/MWh; IGCC – $77/MWh; IGCC-CCS – $125/MWh. Note that these LCOEs assume U.S. Energy Information Administration capacity factors of 34% for wind and 25% for solar.

5. ***Nuclear—High Cost*** case where the nuclear cost is 25% higher than the currently projected cost for 2050 based on current first-of-a-kind (FOAK) costs.

Texas has high renewable potential (windy and sunny climate) and low natural gas costs. This suggests a region where nuclear may not be competitive or play a large role. Consistent with this prediction, nuclear is not part of the least-cost generation mix for Texas in 2050 in the 'business as usual' case where carbon emissions are unconstrained and the average emissions rate remains at the 500 gCO_2/kWh current world average. Even in Texas, however, nuclear capacity (at a nominal overnight cost of $5,500/$kW_e$) is part of the least-cost generation mix in cases where CO_2 emissions are limited to less than 50 gCO_2/kWh. This is due to the value that nuclear energy offers to the system as a low-carbon generation option. If the capital costs of nuclear generation are reduced to the extent discussed in Chapter 2, nuclear energy becomes more competitive and begins to contribute to the system mix at a less stringent emissions limit of 100 gCO_2/kWh. This result shows that capital cost has a major influence on nuclear energy's ability to be part of the least-cost electrical system generation mix.

Figure 1.4b shows installed capacity by generation technology for the optimal (least-cost) generation mix under different nuclear cost scenarios and a discrete set of emission constraints between 100 and 1 gCO_2/kWh. We also include a 'business as usual' case (at 500 gCO_2/kWh) to show the calculated optimal electrical system mix in 2050 with current CO_2 emissions.

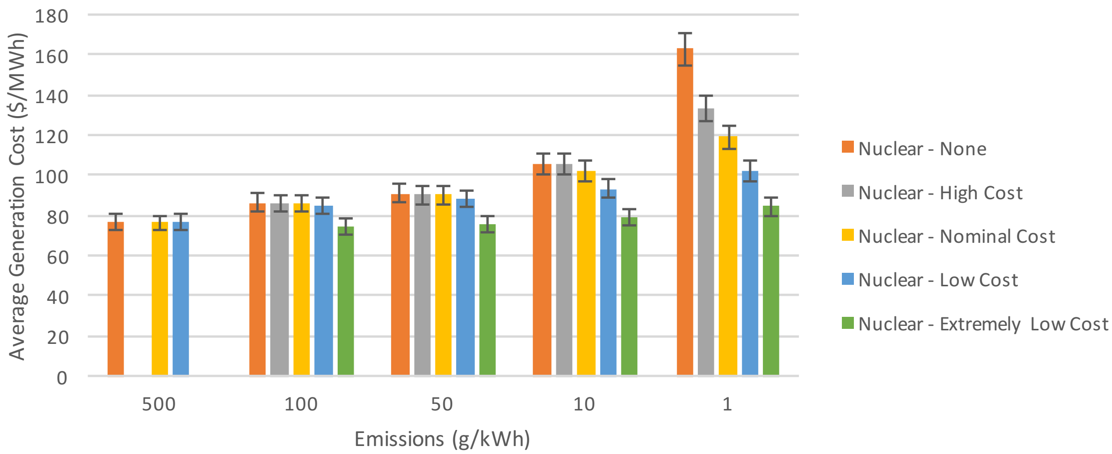
As can be seen in Figures 1.4a and 1.4b, which show system cost and system capacities, respectively, imposing a carbon limit reduces the deployment and use of fossil fueled generation. The figure shows this impact for Texas, but the result is generalizable to any power system. The effect of a carbon constraint on fossil fuel generation, at the specific level of that constraint, depends on the availability and cost of renewable resources. Reductions in fossil fuel capacity have a direct impact on the value of renewables, even when renewables are paired with energy storage, due to the lack of backup capacity during periods of rapid change in renewable output and the need to move greater amounts of energy from hours with higher renewable output to hours with lower renewable output. This increases system requirements for battery storage and for added renewable generation to act as backup capacity—and results in higher system costs.

Figure 1.4a shows that excluding the deployment of a firm low-carbon generation resource, like nuclear, noticeably increases system costs because it necessitates the deployment of less efficient forms of generation and energy storage to back up intermittent renewables. This effect is most pronounced at carbon emission targets below 50 gCO_2/kWh (i.e., at 10 gCO_2/kWh and 1 gCO_2/kWh). Figure 1.4b also shows that reductions in nuclear capital cost lead to nuclear deployment not only in scenarios that feature near-zero emissions limits but also in scenarios with more modest emissions targets (100 gCO_2/kWh and 50 gCO_2/kWh).

The modeling results for installed capacity (Figure 1.4b) point to a further explanation for the higher system costs that result when nuclear is excluded as an option in scenarios with carbon constraints. With no nuclear contribution, large build-outs of wind, solar, and battery storage are required to meet a stringent CO_2 constraint. This is evident in the 10 gCO_2/kWh scenario and even more so in the 1 gCO_2/kWh scenario, where total installed capacity in the no-nuclear case is two to three times total installed capacity in the nuclear-nominal case. This significant increase in installed capacity comes at a large investment cost, which increases total system cost.

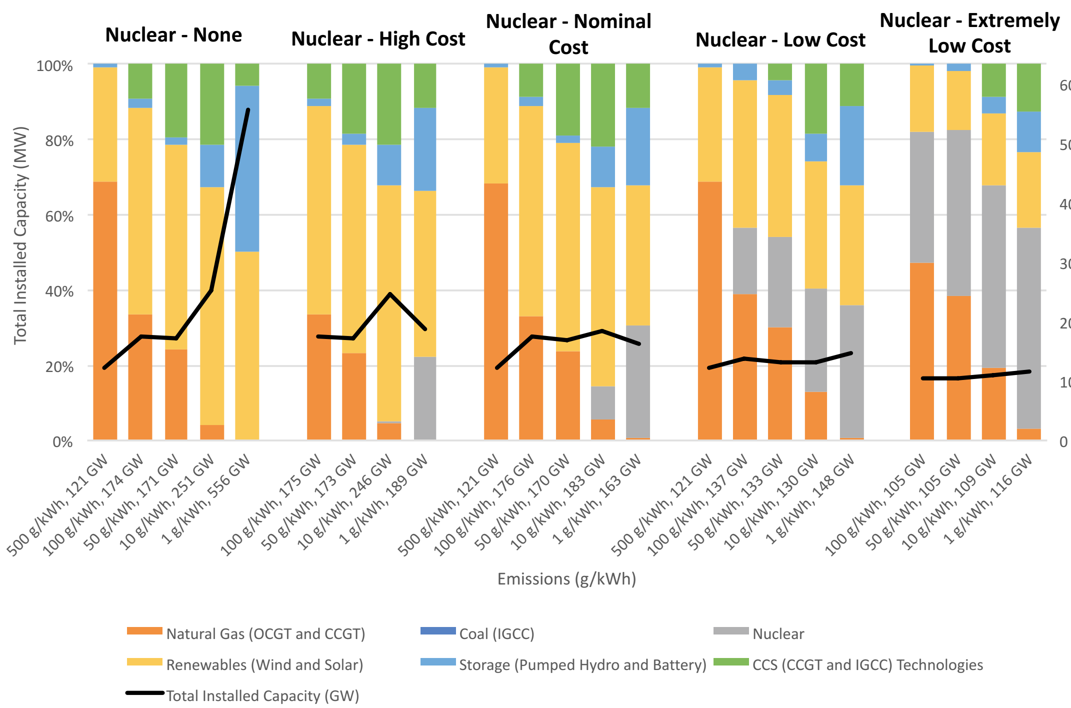
Another way to understand these results is to infer the 'marginal cost of carbon' by looking at changes in system cost in relation to changes in the CO_2 target. At progressively lower levels of allowable CO_2 emissions, one could expect average electric system costs to increase, since lower cost, fossil fuel generation technologies (coal or natural gas) are being replaced by higher-cost, low-carbon

Figure 1.4a: Texas cost of electricity generation



The error bars in the figure represent numerical uncertainty in the calculations.

Figure 1.4b: Optimal capacity mixes for Texas



(The left axis shows % of aggregate installed capacity; the right axis shows total installed capacity.)

technologies (renewables, nuclear, or natural gas with carbon capture and storage). The marginal cost of carbon is an equivalent way to characterize the effect of performance-based carbon emissions targets. Table 1.6 shows the estimated marginal cost of carbon based on the ratio of difference in electric system costs to difference in CO_2 targets. As one would suspect, the marginal cost of carbon increases as the emissions target becomes more restrictive. The relationship is non-linear at less stringent emissions targets (i.e., 100–500 gCO_2/kWh) so these values are lower bounds.

In addition to the large investments required to build out renewables, low-carbon scenarios that exclude the use of nuclear energy come at the cost of sizable land usage. As an illustration, for the 1 gCO_2/kWh target in the Nuclear—None case, the land requirements for solar and wind generation total just under 4 million hectares (about 5.5% of the land area of Texas). This represents the largest build-out of renewable energy in any of the Texas scenarios. Land usage would be proportionately larger for a no-nuclear, deep-decarbonization scenario in any of the other regions we analyzed, since none of them are as favorable for renewable generation and hence have lower renewable capacity factors.

We did not consider land requirements for CO_2 disposal as a constraint in our analysis. However, we did model a limited set of scenarios for the Texas region in which natural gas (combined cycle gas turbine) generation with carbon capture and storage (CCS) is not available. Results for these scenarios indicate that the relative nuclear share increases for all the deep decarbonization emission targets. This is not unexpected as a proportionate increase in nuclear capacity and renewables with battery storage would be needed to meet load if natural gas with CCS were not available.

In regions that have more modest renewable resource availability (in the United States and internationally) and face different costs for renewable generation, we limited our nuclear technology cases to Nuclear—Nominal Cost and Nuclear—Low Cost based on estimates from the U.S. National Renewable Energy Laboratory for the nominal case and our own estimates of the potential for cost improvement in the low-cost case. Figures 1.5a through 1.5e show how including nuclear as an option affects optimal system generation costs under different carbon constraints for the regions included in our analysis.

Results for New England (Figure 1.5a) are similar to those for Texas in terms of the cost impacts of including nominal cost nuclear technology in scenarios that feature a carbon constraint. As in the Texas case, nominal cost nuclear is deployed only at emission targets of 10 and 1 gCO_2/kWh. With reduced nuclear costs (as in the Nuclear—Low Cost scenario), nuclear generation plays a role at even the less stringent targets of 50 and 100 gCO_2/kWh.

Compared to Texas, the cost-reduction benefits of nuclear are higher in New England because this region is less favorable for renewable resources. As a result, there is less renewable generating capacity available in New England when demand is high than there is in Texas when that state's demand is high. To generate enough electricity in periods of higher demand, New England requires a larger amount of installed renewable capacity and storage. This build-out of installed capacity requires large capital expenditures, which translate to higher system costs. Given less favorable renewable conditions, imposing a more stringent CO_2 constraint causes a steep increase in the cost of generation. As the emissions constraint tightens to require increasing reductions below the 'business as usual' rate of 500 gCO_2/kWh, the cost of substituting the next kWh of carbon-emitting electricity with low-carbon electricity increases. At less stringent emissions targets, carbon-emitting generation is displaced by renewables during periods of high renewable potential (i.e., sunny and windy days). As the carbon constraint tightens further, electricity generation during high renewable potential times is already low-carbon and the challenge becomes displacing carbon-emitting generation during periods of lower renewable potential. This requires either a large build-out of renewable capacity

Table 1.6: Marginal cost of carbon ($/ton-$CO_2$) in Texas for a range of CO_2 emission targets

CO_2 Emission Target (gCO_2/kWh)	No Nuclear	Nuclear High Cost	Nuclear Nominal Cost	Nuclear Low Cost	Nuclear Very Low Cost
500 to 100	25	25	25	20	20
100 to 50	92	84	81	76	28
50 to 10	363	374	292	128	88
10 to 1	6,390	3,087	1,907	1,000	557

Figure 1.5a: New England cost of electricity generation

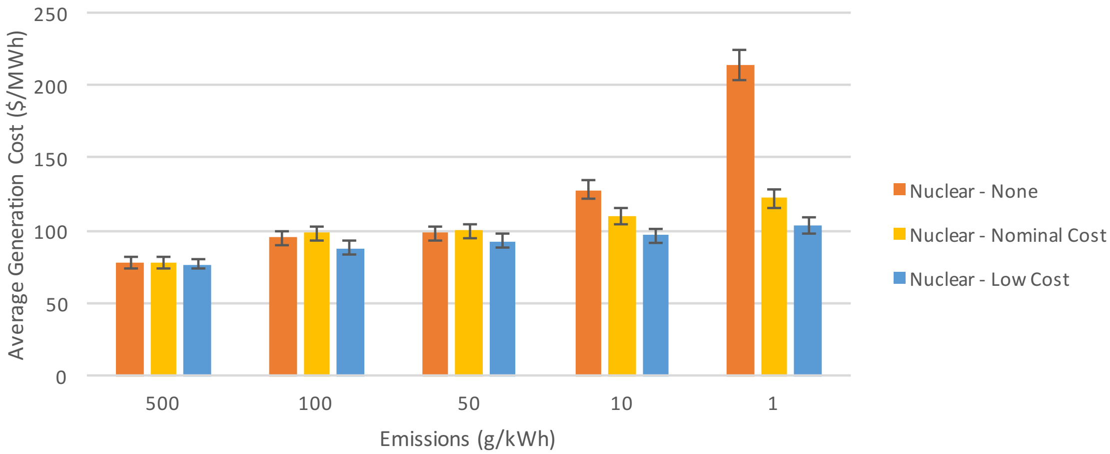
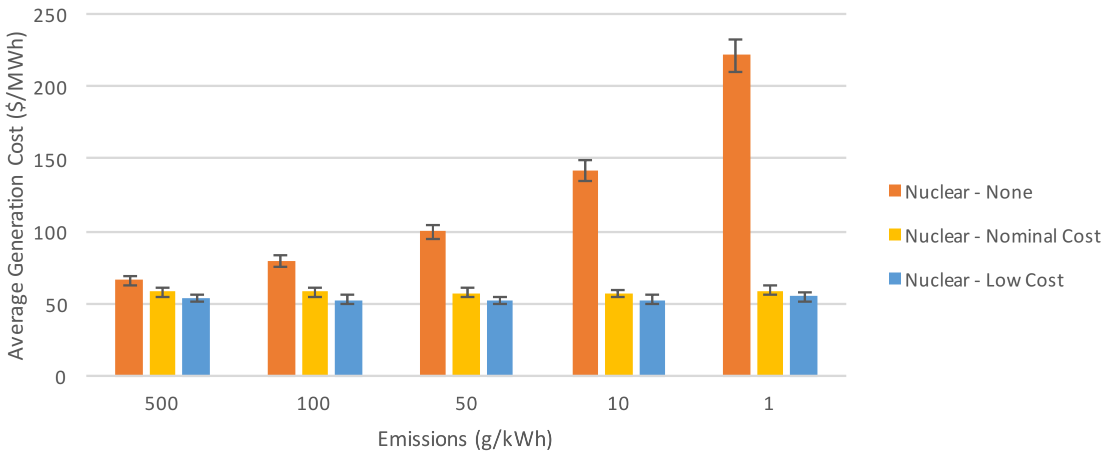


Figure 1.5b: T-B-T cost of electricity generation



with storage to compensate for periods of lower renewable generation potential or a low-carbon generation technology that is also dispatchable (i.e., available on demand), such as nuclear. As a result, displacing a unit of carbon-emitting energy generation at stricter carbon constraints becomes much more expensive when nuclear is not an option. Figures 1.6–1.10 show how excluding nuclear affects renewables build-out.

In the two Chinese provinces considered, T-B-T and Zhejiang (Figures 1.5b and c), the system cost benefits of including nuclear technology as an option under nominal conditions are seen over the full range of emission targets modeled (that is, from 100 gCO_2/kWh to 1 gCO_2/kWh). For example, in the Nuclear—Nominal Cost case, the average system cost of generation without nuclear as an option at a 10 gCO_2/kWh emission target is more than three times the cost when nuclear is included. This is because nuclear technology is comparatively less expensive in China. Thus, it is selected to be part of the generation mix even at the least restrictive CO_2 constraint. Notably, nuclear technology is selected even in periods of high renewable potential because it is the less costly option. However, it should also be noted that this result is highly dependent on the low cost of nuclear in the China scenarios. The values used to scale nuclear costs for China are taken from available public information that is used in OECD estimates (as noted in Chapter 2). If the actual cost of nuclear technology in China is higher, the opportunity cost of excluding nuclear will be lower than our modeling results indicate.

In the United Kingdom (Figure 1.5d), the cost implications of including nuclear as an option are similar to those calculated for the United States, with the same steep increase in average generation costs with increasing strictness of carbon emission constraints. Nuclear provides notable cost benefits at emission targets of 10 and 1 gCO_2/kWh. An emissions target of 10 gCO_2/kWh is consistent with the level of CO_2 reduction estimated to be needed by 2050 for the U.S. and U.K. electricity sectors to achieve international climate stabilization goals, according to the IEA analysis discussed previously (Table 1.1).

In France (Figure 1.5e), low-cost nuclear is part of the optimal system generation mix at a carbon emissions target of 100 gCO_2/kWh. At nominal cost, nuclear is part of the optimal mix at an emissions target of 10 gCO_2/kWh. Also, as in the other regions modeled for this analysis, system costs rise sharply as the carbon target becomes more stringent in scenarios that exclude nuclear technology.

Figure 1.6 shows the optimal capacity mix for New England for each of the cases: Nuclear—None, Nuclear—Nominal Cost, and Nuclear—Low Cost. As noted previously, this region's more limited wind and solar resource potential means that large amounts of installed renewable capacity and battery storage are needed to meet system generation needs during periods of high demand. In addition, substantial battery storage capacity must be supplied to compensate for weather variability.

Figures 1.7 and 1.8 show the optimal capacity mix for China's T-B-T and Zhejiang regions, respectively, for each of the cases: Nuclear—None, Nuclear—Nominal Cost, and Nuclear—Low Cost. The capacity trends shown in these figures for renewables and battery storage are qualitatively similar to those of the Texas and New England regions of the United States but are even more pronounced.

Similarly, Figures 1.9 and 1.10 show the optimal capacity mix for the United Kingdom and France for each of the cases: Nuclear—None, Nuclear—Nominal Cost, and Nuclear—Low Cost.

Comparing optimal capacity mixes (Figures 1.6–1.10) with system electricity costs (Figures 1.5a–e), we find that higher system costs are always associated with greater amounts of installed renewable capacity (both wind and solar) combined with battery storage. At lower carbon targets when nuclear technology is not allowed as an option, electricity generation must come from renewables as the only other completely low-carbon option. Due to the intermittent nature of wind and solar generation, large amounts of installed renewable and battery storage capacity

Figure 1.5c: Zhejiang cost of electricity generation

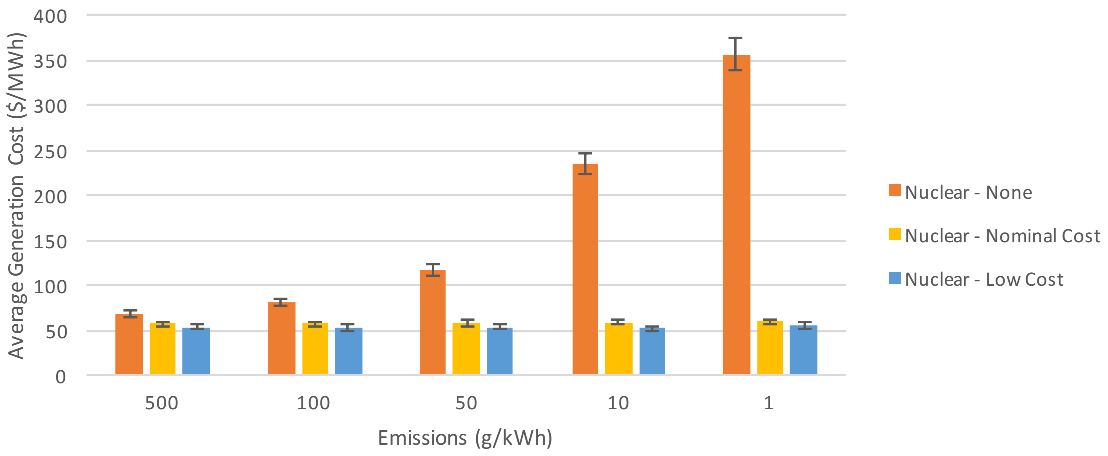


Figure 1.5d: United Kingdom cost of electricity generation

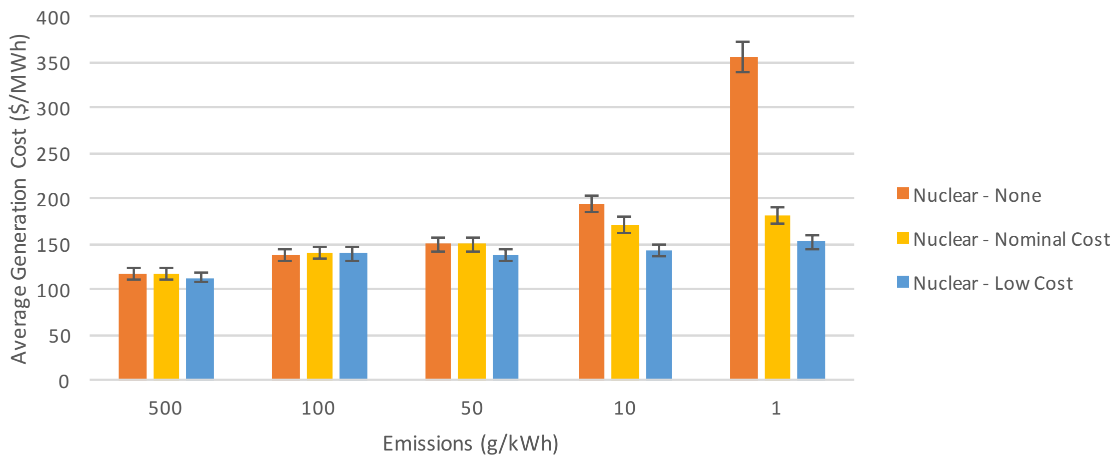
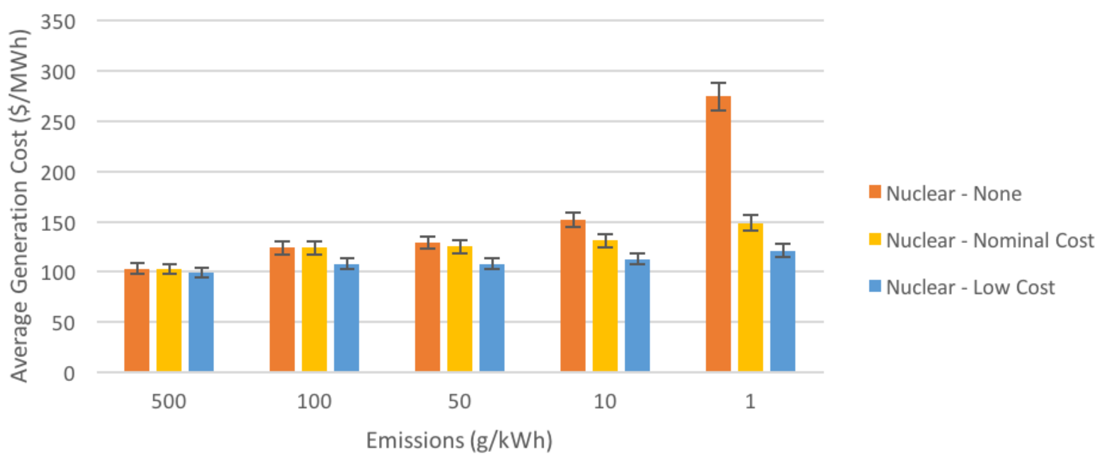


Figure 1.5e: France cost of electricity generation



Figures 1.5a-1.5e: The error bars in the figure represent numerical uncertainty in the calculations.

Figure 1.6: Optimal capacity mixes for New England

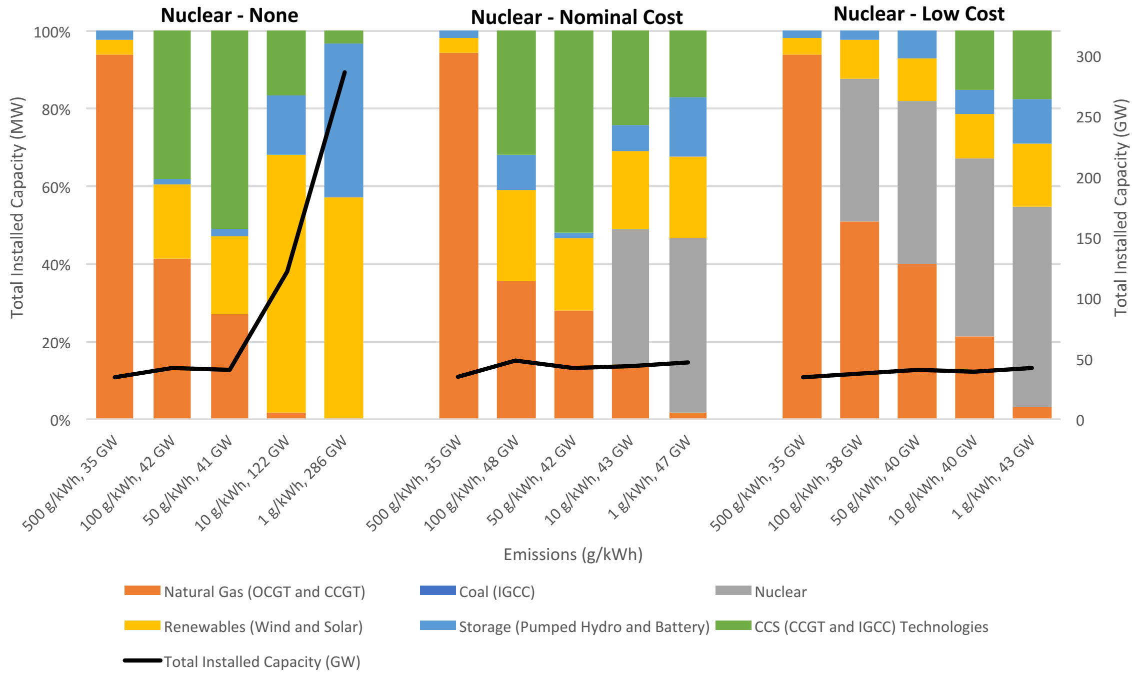


Figure 1.7: Optimal capacity mixes for T-B-T

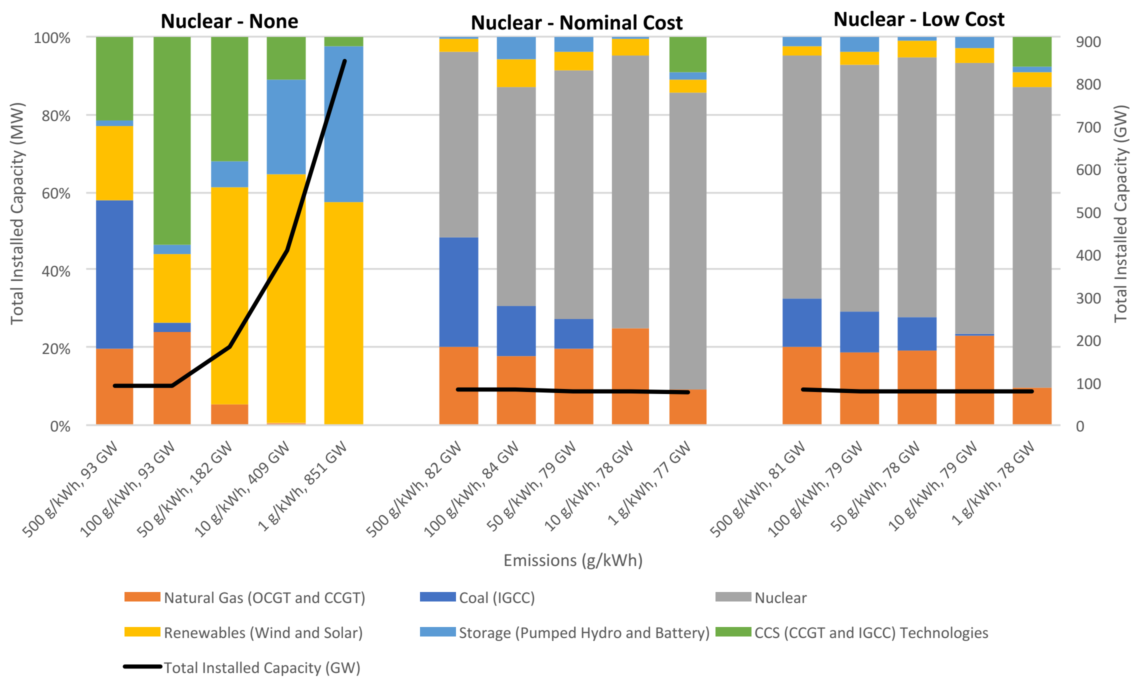


Figure 1.8: Optimal capacity mixes for Zhejiang

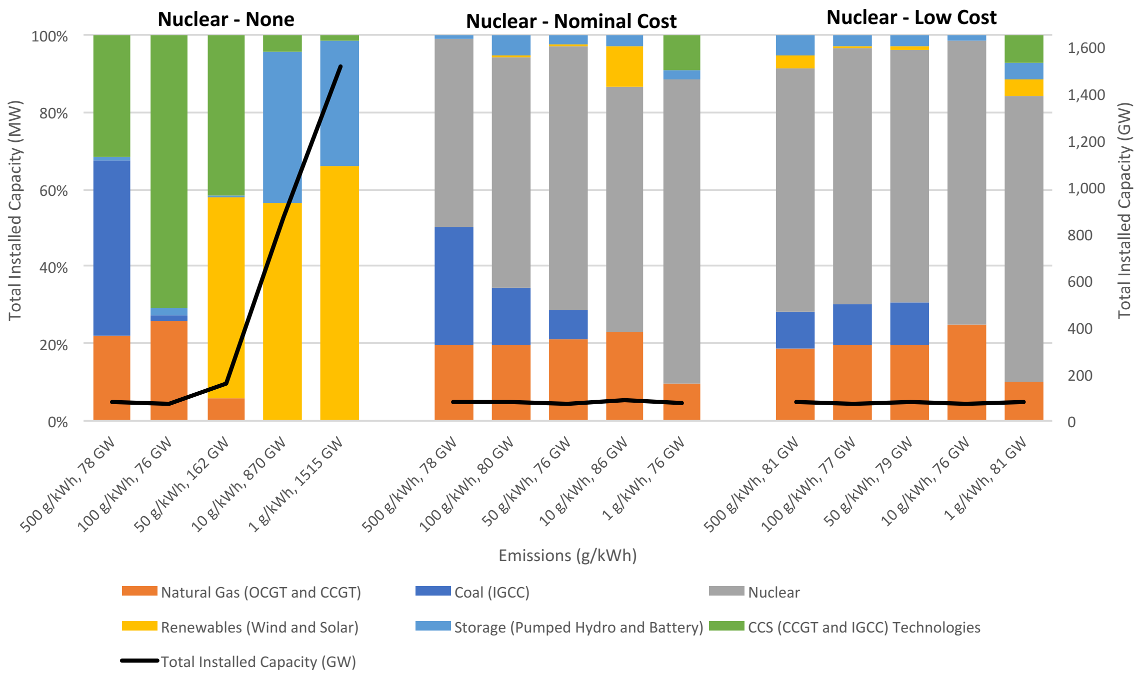


Figure 1.9: Optimal capacity mixes for the United Kingdom

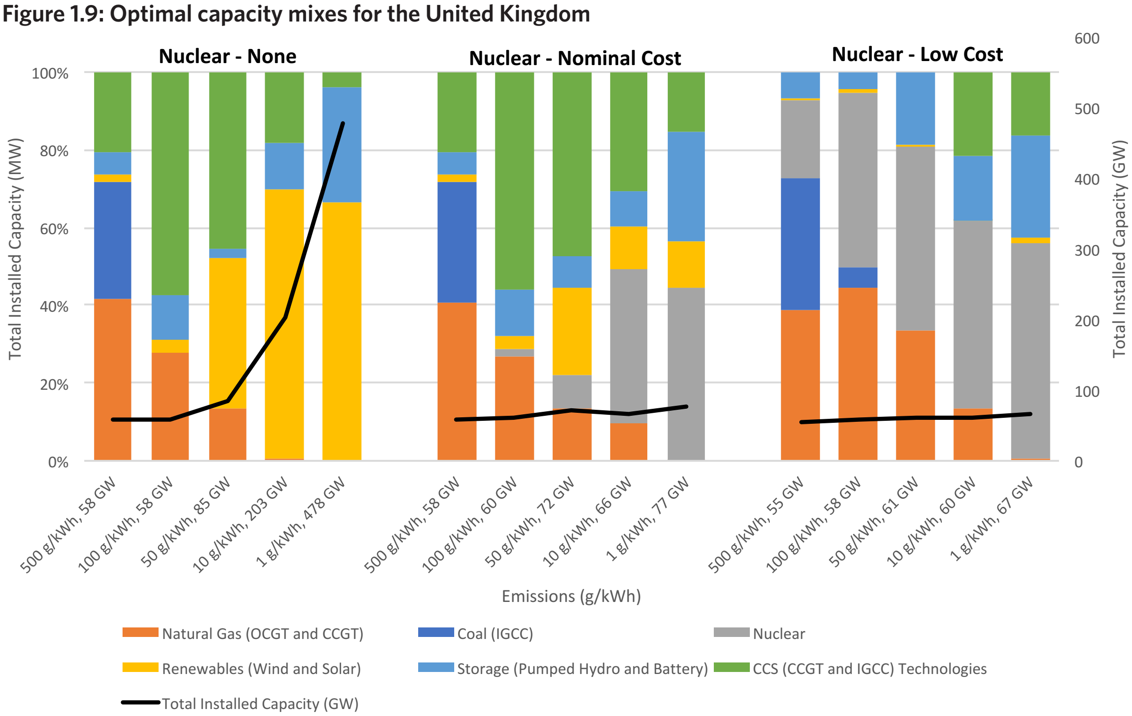
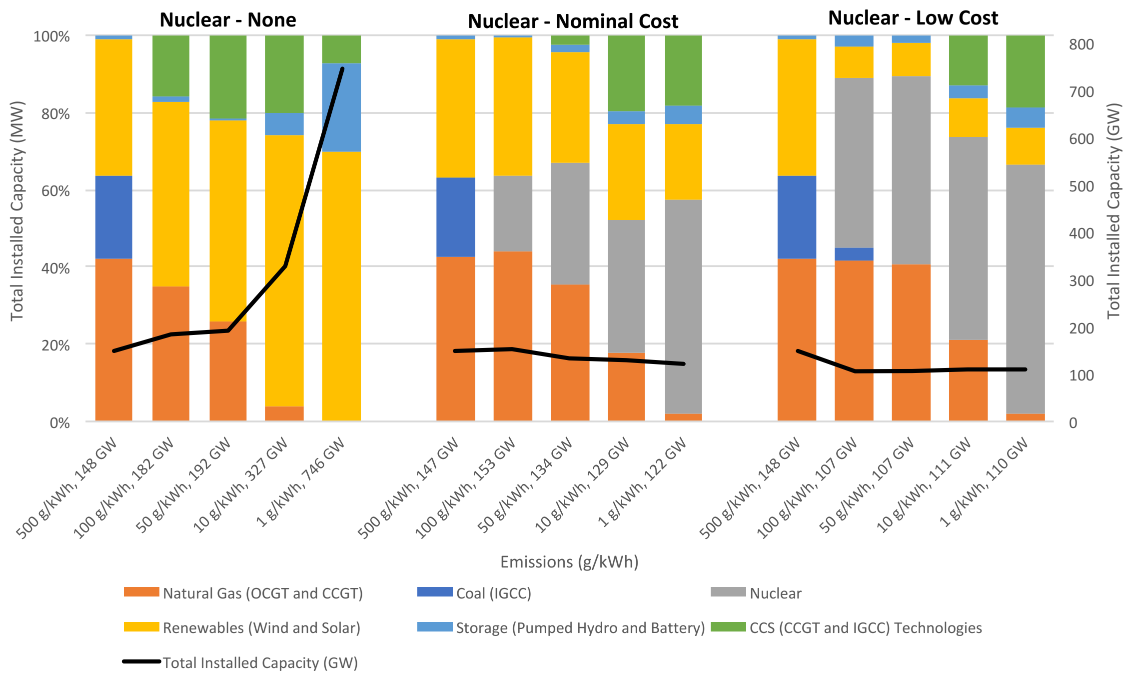


Figure 1.10: Optimal capacity mixes for France



are needed to ensure that the system is always able to meet demand. The large investments needed to install this additional capacity increase total system cost. This represents an opportunity for nuclear technology, as the installed capacity needed to meet demand using nuclear generation is much less than the build-out required for renewables. Because nuclear plants are dispatchable (they can operate when needed and are not dependent on an intermittent fuel source), their average operating capacity factors are substantially higher than the operating capacity factors for solar and wind generators without battery storage capacity.

Table 1.7 shows the cost of excluding nuclear technology as an option in the optimal capacity portfolio mix for each of the six regions. This cost is termed the 'opportunity cost' of foregoing nuclear energy as a low-carbon option.[2]

We measure opportunity cost in two ways: as an absolute increase in generation cost and as a percentage increase in generation cost. Both approaches are defined below.

Absolute Opportunity Cost

$$\textit{Opportunity Cost} = \left(\begin{array}{c}\textit{Average cost of electricity}\\ \textit{generation without nuclear}\\ \textit{technologies available}\end{array}\right) - \left(\begin{array}{c}\textit{Average cost of electricity}\\ \textit{generation with nuclear}\\ \textit{technologies available}\end{array}\right)$$

Percentage Opportunity Cost

$$\textit{\% Opportunity Cost} = \frac{\left(\begin{array}{c}\textit{Average cost of electricity}\\ \textit{generation without nuclear}\\ \textit{technologies available}\end{array}\right) - \left(\begin{array}{c}\textit{Average cost of electricity}\\ \textit{generation with nuclear}\\ \textit{technologies available}\end{array}\right)}{\left(\begin{array}{c}\textit{Average cost of electricity}\\ \textit{generation with nuclear}\\ \textit{technologies available}\end{array}\right)}$$

Table 1.7: Opportunity cost of excluding nuclear in the optimal installed capacity mix[a]

Region	Nuclear Costs	Carbon Emissions				
		500 gCO_2/kWh	100 gCO_2/kWh	50 gCO_2/kWh	10 gCO_2/kWh	1 gCO_2/kWh
Texas	Nominal	~0% [b]	~0% [b]	~0% [b]	~0% [b]	$43.89/MWh (36.9%)
	Low	~0% [b]	~0% [b]	~0% [b]	$12.02/MWh (12.9%)	$60.53/MWh (59.1%)
New England	Nominal	~0% [b]	~0% [b]	~0% [b]	$17.93/MWh (16.3%)	$91.73/MWh (75%)
	Low	~0% [b]	$6.89/MWh (7.8%)	$5.67/MWh (6.1%)	$31.64/MWh (32.8%)	$110.37/MWh (106.4%)
T-B-T	Nominal	$8.38/MWh (14.5%)	$21.46/MWh (37%)	$42.48/MWh (73.9%)	$84.87/MWh (148.7%)	$162.41/MWh (273.9%)
	Low	$12.73/MWh (23.8%)	$26.55/MWh (50.2%)	$47.19/MWh (89.4%)	$89.03/MWh (168.3%)	$166.97/MWh (305%)
Zhejiang	Nominal	$10.91/MWh (19.2%)	$22.91/MWh (40%)	$59.51/MWh (103.3%)	$176.58/MWh (299.2%)	$296.46/MWh (497.2%)
	Low	$14.39/MWh (26.9%)	$27.49/MWh (52.1%)	$64.15/MWh (121.1%)	$182.97/MWh (347.6%)	$300.66/MWh (542.5%)
United Kingdom	Nominal	~0% [b]	~0% [b]	~0% [b]	$23.79/MWh (14%)	$175.34/MWh (97.6%)
	Low	~0% [b]	~0% [b]	$11.53/MWh (8.4%)	$51.83/MWh (36.5%)	$202.79/MWh (133.2%)
France	Nominal	~0% [b]	~0% [b]	~0% [b]	$20.35/MWh (15.5%)	$125.91/MWh (84.7%)
	Low	~0% [b]	$15.97/MWh (14.8%)	$21.13/MWh (19.6%)	$38.69/MWh (34.2%)	$153.27/MWh (126.4%)

[a] The absolute opportunity cost is shown in $/MWh and the percentage opportunity cost is shown in % in the parentheses.
[b] These results are within the error band, and so are insignificant.

[2] The opportunity cost of nuclear is defined as the difference in price between a scenario that excludes nuclear technology and a scenario that includes nuclear technology, with all other variables held constant.

As part of this analysis, we also examined the sensitivity of the GenX results to changes in the cost and technology parameters that were used for each region. The sensitivity study was performed using costs from the National Renewable Energy Laboratory (2016) and included the following cases:

- Low Renewables/Storage Cost (60% of nominal costs)
- High Renewables/Storage Cost (200% of nominal costs)[3]
- High CCS Cost (130% of nominal cost)
- Low Natural Gas Cost (75% of nominal cost)
- High Natural Gas Cost (125% of nominal cost)
- 99% Efficient CCS Systems (nominal efficiency used was 90%)
- Demand Side Resources Considered[4]
- Extreme Weather Year for Renewable Potential[5]

The results of the sensitivity study for Texas and T-B-T are shown in Figures 1.11a and 1.11b. We use the definition of opportunity cost discussed previously and shown in Table 1.7.

Only three sensitivity cases produce results that deviate significantly from the base case (with nominal assumed costs and performance for nuclear technology). In both the 'High Renewable/Storage Costs' and the 'Extreme Weather' sensitivity cases, the opportunity cost of excluding nuclear technology is higher. In fact, higher renewable/storage costs more than double the opportunity cost of nuclear. Conversely, low renewable/storage costs significantly decrease the opportunity cost of excluding nuclear. This is because with low renewable/storage costs, the build-out of installed renewable capacity and associated battery storage, though still significant in magnitude, is less costly and is chosen over building nuclear (at nominal cost) in the cost optimization. This result again underlines the influence of energy technology capital costs in determining what is the least-cost electrical system generation mix.

Very similar patterns are seen in the sensitivity results for all the other regions, which are presented in Appendix B. To illustrate this point, consider the sensitivity results for the T-B-T region in China (Figure 1.11b). The opportunity cost of excluding nuclear is notable even at 100 gCO_2/kWh and increases at lower CO_2 emissions targets. In both the 'High Renewable/Storage Costs' and 'Extreme Weather' sensitivity cases, the opportunity cost of excluding nuclear technology is higher, while in the 'Low Renewable/Storage Costs' case the opportunity cost is lower.

Appendix C presents two supporting analyses to help validate our GenX results. First, we developed a GenX optimization for a simplified electrical generation system and compared it to an analytic solution. In addition, we performed a benchmarking exercise that compared cost and emissions results from GenX to results obtained using another electrical system capacity expansion model, JuiceBox. This benchmarking exercise was performed for two regions: Texas and T-B-T.

Yet another way to compare the different modeling scenarios is to examine the quantity of electricity supplied by different generation options under different cost, technology, and emissions

[3] This case assumes that the current cost of renewables and storage, as reported in the National Renewable Energy Laboratory's *Annual Technology Baseline* report (2016), remains unchanged in 2050—in other words, costs for these technologies do not fall over the next 30 years.

[4] The term 'demand side resources' refers to the grid operator's ability to shift demand when generation is low and to the ability of electricity consumers to curb demand when prices are high. In this case we assume that the grid operator can shift up to 5% of demand each hour, with a maximum shift of six hours without additional cost. The amount that consumers will curb demand depends on how much they value the electricity. Further detail concerning assumed inputs for the value of electricity can be found in Appendix A.

[5] To model an extreme weather year we arbitrarily lowered the generation potential for both wind and solar to 10% of its original value for the entire first week of July. This time of year was chosen to illustrate the effect of prolonged cloudy and windless days.

Figure 1.11a: Texas sensitivity study results

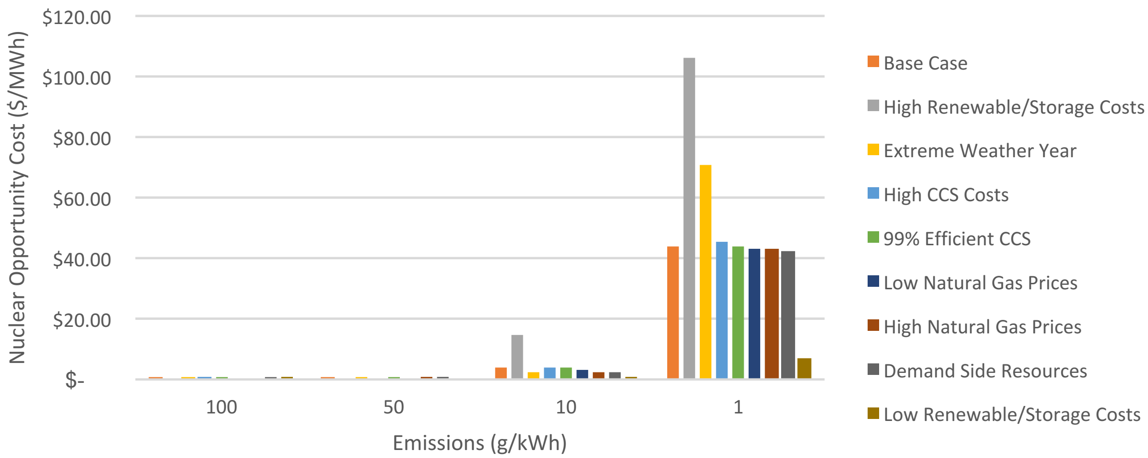
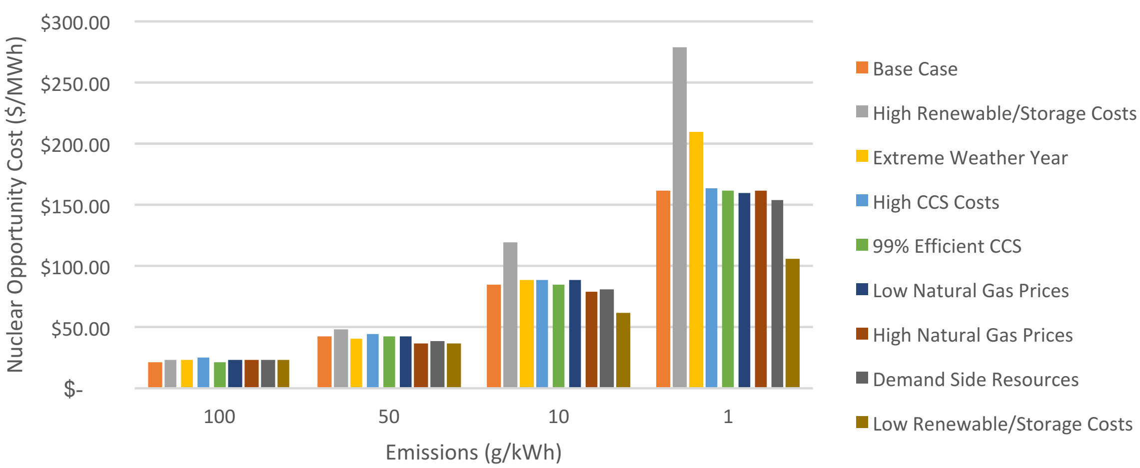


Figure 1.11b: T-B-T sensitivity study results



constraints. Figures 1.12a and 1.12b show total electricity generation (TWh) for each technology for Texas and T-B-T, respectively, over the time span of one year.[6]

In Texas, for the cases with either no nuclear or high-cost nuclear, natural gas with CCS and renewables are used to satisfy demand at moderate CO_2 emission targets. However, with a deep decarbonization constraint, more than 80% of demand is met with renewables if nuclear is excluded. Due to the intermittent characteristics of wind and solar generation, this requires a large expansion of renewable and energy storage capacity—in fact, the capacity additions required substantially exceed expected load. For the cases with nominal or low-cost nuclear, nuclear generation is selected to meet demand, even at moderate emission targets in the low-cost nuclear cases. This result can be visualized by examining the dynamics of load and generation over the course of a week. Appendix D shows the electrical load curve in Texas that must be met hour-by-hour over the course of a summer week.

[6] In Figure 1.12, the total electricity generation reported is essentially 'double counted' when an oversupply of renewable electricity goes into battery storage and then is fed back to the grid at a later time. This explains the increase in generation noted for scenarios with no nuclear at low carbon targets.

Figure 1.12a: Texas dispatchable electricity generation technologies

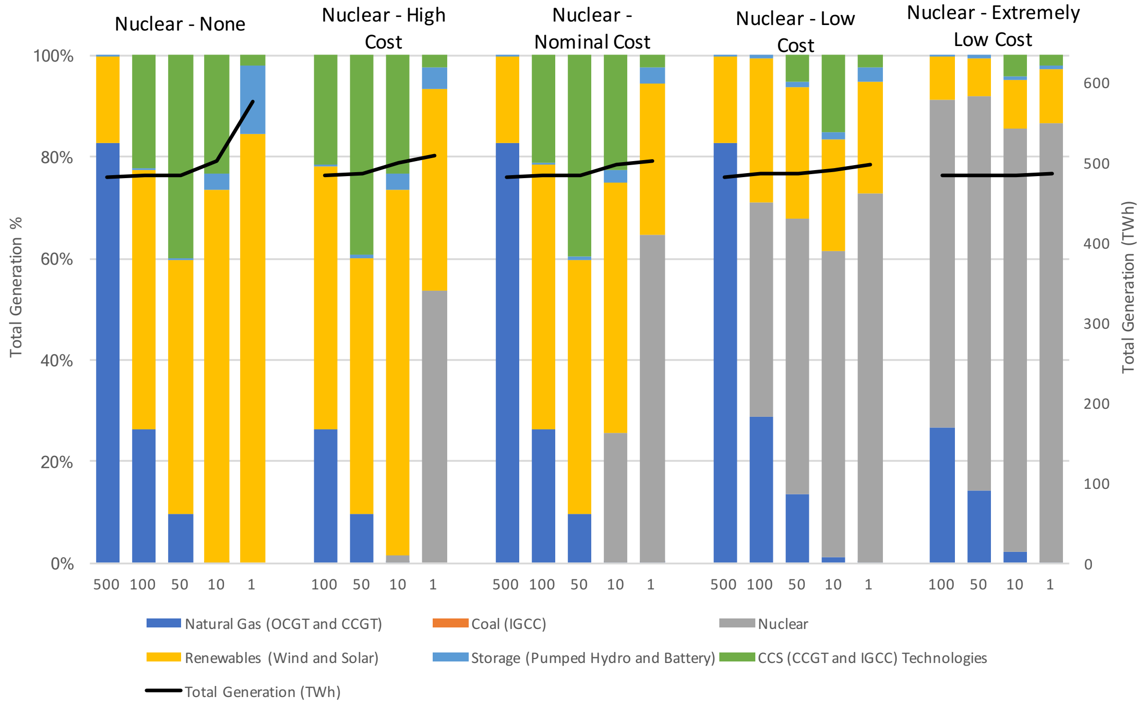
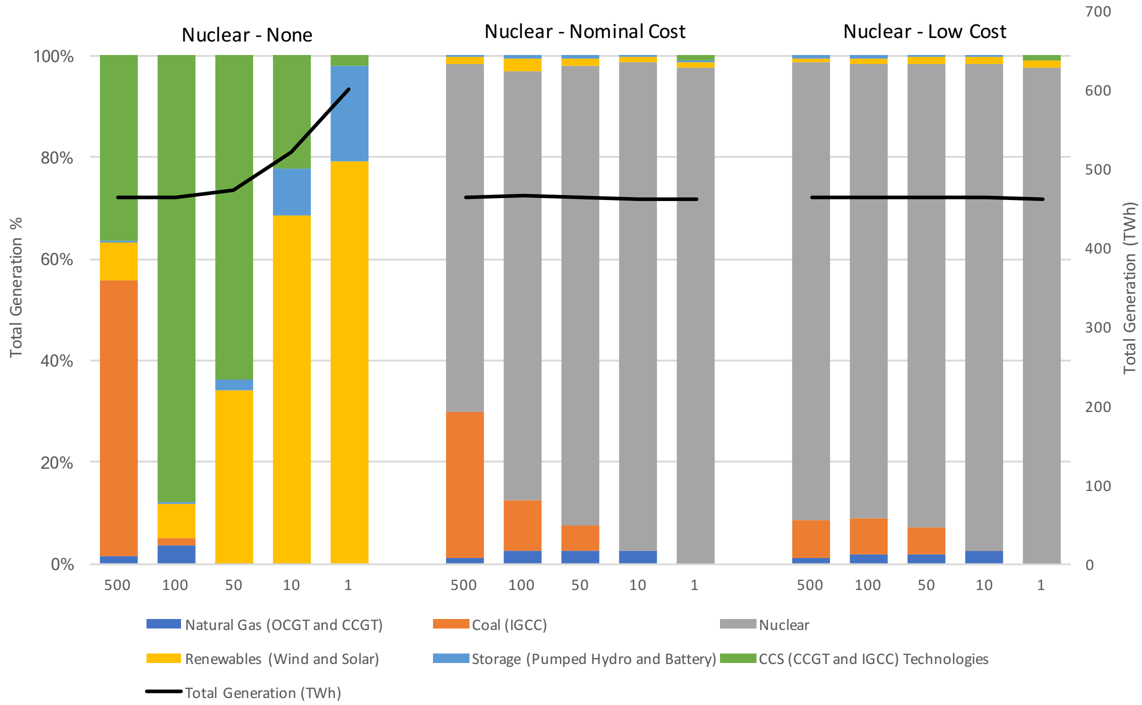


Figure 1.12b: T-B-T dispatchable electricity generation technologies



When nuclear generation is an option, it supplies increasingly larger fractions of demand. Figure 1.12 and Appendix D show that generation from CCS technology declines as the stringency of the carbon limit increases. This is because CCS is not 100% efficient—as a result, it still emits some CO_2 and cannot satisfy all of the demand without exceeding the carbon emission limit. Only nuclear and renewables with storage have the ability to supply zero-carbon generation while minimizing capacity expansion needs and thereby cost.

In the T-B-T cases, if nuclear power generation is not an allowed option, the optimal system mix under a modest carbon constraint uses either fossil fuel generation or renewables to satisfy periods with high demand, even with low renewable generation potential. The cases that require a large expansion of renewable capacity are evident from the installed capacity results shown in Figure 1.7. If nuclear is an option, then it will be chosen during high demand periods since this minimizes system costs over the range of emission targets.

Summary

Achieving the widely accepted international goal of stabilizing global average warming at 2°C by 2050 requires 'deep decarbonization' of the electricity generation mix. Specifically, expert analyses have concluded that average CO_2 emissions rates for electricity generation worldwide must decline to a range of 10–25 gCO_2/kWh (compared to the current world average of approximately 500 gCO_2/kWh). For the United States, we focused on two regions, Texas and New England, that represent a range of weather conditions. In both these regions, nuclear technology provides notable system advantages in terms of the average cost of electricity and the optimal generation mix when the allowable carbon emissions rate is reduced to less than 50 gCO_2/kWh. These advantages become particularly pronounced in cases where the target emissions rate is at and below 10 gCO_2/kWh. These advantages grow in cases where we considered enabling technologies that could lower the capital cost of nuclear technology from the nominal values discussed in Chapter 2. Conversely, nuclear energy's advantages decreased notably in cases that assumed cost improvements for renewables and battery storage far beyond those already projected for 2050. All other sensitivity cases we considered had a small effect on the optimal generation mix and cost advantages of nuclear technology. These results also indicate that meeting deep decarbonization goals without nuclear as an option will require a very substantial expansion of renewable and battery storage capacities, leading to significant cost increases. These results are quite consistent with those found in a recent study by the Electric Power Research Institute (Bistline and James 2018) that considers the role of advanced nuclear technologies in future U.S. energy markets. Similar outcomes for cost and nuclear penetration are also observed for the United Kingdom and France.

In contrast to our modeling results for the United States and Europe, the inclusion of nuclear as a generating option for the eastern provinces of China (T-B-T and Zhejiang) produces substantial cost advantages even at less restrictive emission targets, such as 100 gCO_2/kWh—well above the 25 gCO_2/kWh emission rate needed for China to meet its 2050 climate change mitigation goals. This result is largely driven by the relative capital costs of available energy technologies. As with the U.S. and European cases, the results for China are sensitive to assumptions about renewable energy and storage costs compared to nuclear technology costs but are not substantially affected by any of the other sensitivity cases considered.

Our analysis provides a comprehensive picture of the opportunities for nuclear energy. Its results point to several policy-relevant findings.

Findings:

The cost of new nuclear plants is high, and this significantly constrains the growth of nuclear power under scenarios that assume 'business as usual' and modest carbon emission constraints. In those parts of the world where a carbon constraint is not a primary factor, fossil fuels, whether coal or natural gas, are generally a lower cost alternative for electricity generation. Under a modest carbon emission constraint, renewable generation usually offers a lower cost alternative.

As the world seeks deeper reductions in electricity sector carbon emissions, the cost of incremental power from renewables increases dramatically. At the levels of 'deep decarbonization' that have been widely discussed in international policy deliberations—for example, a 2050 emissions target for the electric sector that is well below 50 grams carbon dioxide per kilowatt hour of electricity generation (gCO_2/kWh)—including nuclear in the mix of capacity options helps to minimize or constrain rising system costs, which makes attaining stringent emissions goals more realistic (worldwide, electricity sector emissions currently average approximately 500 gCO_2/kWh).

Lowering the cost of nuclear technology can help reduce the cost of meeting even more modest decarbonization targets (such as a 100 gCO_2/kWh emissions target).

1.3 THE NUCLEAR EQUIPMENT SUPPLY CHAIN

A robust nuclear supply chain is critical to the success of the nuclear industry. As can be seen in recent nuclear plant construction projects in the southeastern United States, when key construction and construction management capabilities atrophy, they can cause delays. Such delays in turn lead to cost overruns and threaten the project's viability. These challenges are discussed in additional detail in Chapter 2. The nuclear supply chain has become increasingly consolidated and globalized (World Nuclear Association 2014). It must be able to support current projections of growth in the nuclear industry, as well as the further expansions potentially needed to achieve deep decarbonization scenarios. We therefore investigated capacity challenges along the nuclear supply chain to identify any potential bottlenecks.

For this portion of the analysis we simplified the nuclear supply chain into three components (Figure 1.13): manufacturing, construction, and operation. Manufacturing includes the manufacture of all necessary equipment for the reactor (for example, pressure vessel, steam generators, etc.) as well as the transportation of manufactured equipment to the reactor site. Construction includes the labor necessary to construct the reactor (for example, welders, electricians, etc.). It also includes the construction management needed to complete projects in a timely manner and on budget. Since this component of the supply chain can affect the final cost of the plant via labor costs and productivity, construction management experience, and interaction between various construction trades, it is important to consider supply chain challenges related to plant construction. There

Figure 1.13: Nuclear supply chain components

is potential to address some construction supply chain challenges with increased use of factory manufacturing. Finally, the operation component includes the labor and equipment needed on an ongoing basis to operate the reactor (for example, certified operators, fuel enrichment, etc.).

Our analysis of the nuclear supply chain is described in Appendix E; we highlight only a few key conclusions here. A 2014 survey of existing nuclear component suppliers (including consolidations) by the World Nuclear Association found no capacity constraints in the nuclear equipment supply chain that would be expected to hinder the industry's current growth projections. Similarly, considering the typical duration of the training cycle for construction labor and power plant operators, we anticipate that nuclear capacity growth would not be limited by that part of the supply chain. Somewhat more challenging is the development of an experienced cadre of construction managers. This is an issue in all major construction projects. With over 55 new nuclear reactors under construction at 32 sites worldwide, junior construction managers could be embedded at many of these sites as a way to provide on-the-job training. Having managers with real nuclear construction experience lead this effort could be an effective way to supply the next wave of nuclear construction, which is expected to start in the late 2020s and last until the late 2030s. Nevertheless, human resource development requires a deliberate and concerted effort by the nuclear industry. An international collaborative effort in support of such development could start now.

1.4 NUCLEAR ENERGY OPPORTUNITIES BEYOND ELECTRICITY

Current nuclear power reactors produce usable energy in the form of heat at modest temperatures (approximately 300°C); this heat is then converted to electricity by the use of a steam turbine power cycle. In advanced nuclear reactors (so-called Generation-IV designs), the primary energy product is again heat but the heat is delivered at potentially much higher temperatures (500°C–800°C). These higher operating temperatures offer a potential opportunity for nuclear high temperature reactor (HTR) technology to provide useful process heat in industrial applications (Figure 1.14).

The industrial sector is an important energy user in the U.S. economy and elsewhere: in the United States, 25% of all useful energy produced is used for industrial processes and 80% of that energy is in the form of process heat. However, industrial applications are diverse in terms of the forms of energy used (from petroleum to specialty products), the size of their energy demands (from 1 MW to hundreds of MW of thermal energy), and the temperatures required (which can range from 200°C to 1,500°C). To determine the potential applicability of nuclear-based process heat in the current U.S. industrial sector, we considered two major attributes: the size of the industrial site, where size is measured in terms of thermal output (denoted by the subscript 'th'), and the required process temperature. Each year the U.S. Environmental Protection Agency (EPA) publishes emissions information from every industrial site in the United States that produces more than 25,000 metric tons of CO_2-equivalent emissions per year (equivalent to a 0.2 MW_{th} natural gas facility) (U.S. EPA 2017). This database was used to identify sites that would be large enough to support nuclear process heat and would have temperature requirements that are compatible with advanced reactors. The site analysis assumed a standard nuclear reactor size of 300 MW_{th}. We also considered a smaller reactor size of 150 MW_{th} as part of a sensitivity study. A detailed list of assumptions and a complete description of the analysis are provided in Appendix F.

Using these data and information about the U.S. market, we then used scaling factors to estimate the number of reactors that could potentially be used in industrial applications worldwide. (The scaling factors were calculated by comparing the size of the relevant U.S. market to the world market. Alternatively, if a market comparison was unavailable, we used a GDP comparison to calculate the scaling factor.) The results of this analysis are presented in Table 1.7 and Figure 1.15.

Figure 1.14: Potential industrial process heat applications for advanced high-temperature nuclear reactors

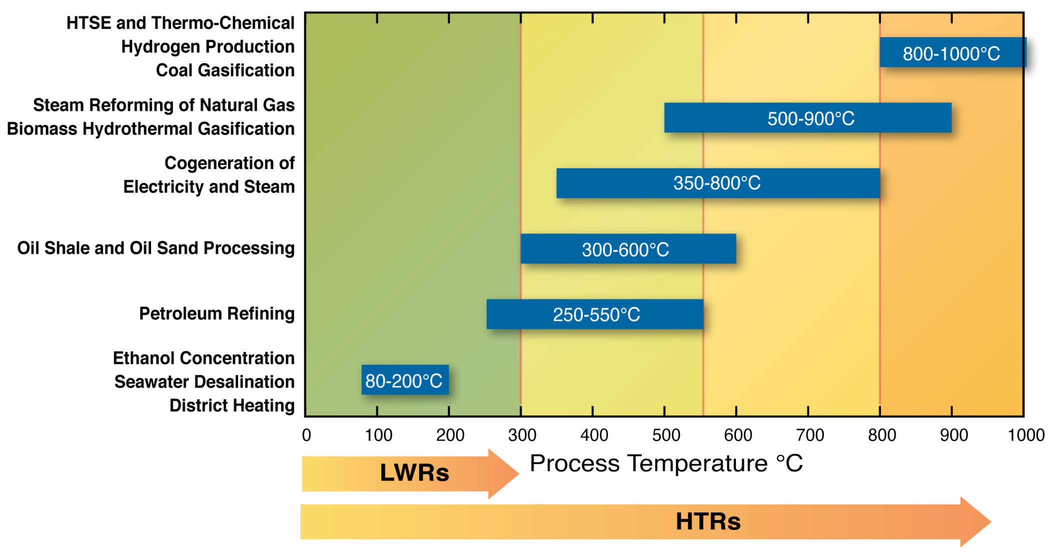
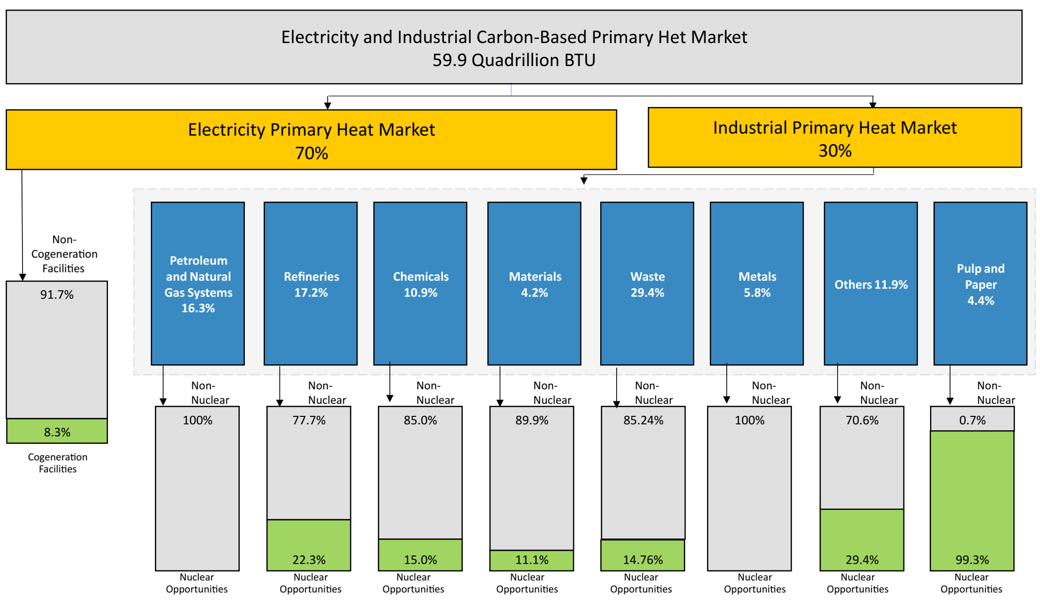


Figure 1.15: Nuclear process heat potential



They indicate that nuclear process heat could capture about 17% (134 GW_{th}) of the 795 GW_{th} industrial heat market in the United States. For a smaller nominal reactor size of 150 MW_{th}, nuclear's potential share of the industrial process heat market increases to 19%. By comparison, current installed nuclear capacity in the U.S. power sector is about 300 GW_{th}.

The main reason for nuclear technology's relatively low potential to be used in industrial process heat applications is industry's current practice of integrating heat from fossil fuels into processes that use the same fossil fuels as feedstocks. A further issue is the low technical readiness of alternative processes that do not require fossil fuels as feedstock. In particular, refineries are very large energy consumers, but they supplement their external energy sources by using internally produced fuel gas from their own refining processes—the fuel gas is otherwise a waste product of refining crude oil. Hydrogen is also needed in the refinement of petroleum products. But there is currently no economically competitive industrial method that would be suitable for nuclear process heat integration in refineries, though major research campaigns are underway.

If a carbon constraint were to be imposed on industrial sector emissions, the use of internally produced fuel gas from refinery processes would be highly discouraged. A carbon constraint would also require the process heat industry to re-engineer many existing processes to enable greater integration of low-carbon energy sources. The net effect would be a larger market for nuclear energy than is shown in Table 1.8.

The results shown in Table 1.8 are from an analysis of current and near-term industrial heat markets. In the future, however, there could be new energy markets to satisfy—potentially with nuclear energy. The most obvious market that could see major changes is energy for transportation, which could take the form of additional grid-supplied electricity for electric cars, electricity and/or process heat to produce hydrogen for fuel cells, or process heat to produce biomass-based synthetic fuels. We assessed the magnitude of these three potential opportunities using information about current U.S. transportation fuel use.

The results of this assessment are shown in Table 1.9. They indicate that for all three transportation-energy market opportunities we considered, the potential heat load could be quite substantial, particularly relative to the current installed nuclear capacity base in the United States (at 300 GW_{th}). Thus, if nuclear energy were able to capture a major portion of new transportation energy markets, this would expand its role very significantly.

Table 1.8: Nuclear process heat potential

	300 MW_{th} Reactor		150 MW_{th} Reactor	
Industry	**U.S. Capacity (MW_{th} Installed) (%)**	**Global Capacity (MW_{th} Installed) (%)**	**U.S. Capacity (MW_{th} Installed) (%)**	**Worldwide Capacity (MW_{th} Installed) (%)**
Co-Generation Facilities	82,800 (61.7%)	340,800 (59.8%)	86,250 (57.5%)	355,050 (55.7%)
Refineries	15,600 (10.4%)	76,800 (12.1%)	17,250 (11.5%)	84,750 (13.3%)
Chemicals	7,800 (5.2%)	36,600 (5.7%)	7,050 (4.7%)	34,200 (5.4%)
Minerals	2,100 (1.4%)	8,700 (1.4%)	2,100 (1.4%)	8,700 (1.4%)
Pulp and Paper	12,600 (8.4%)	51,900 (8.1%)	21,300 (14.2%)	87,750 (13.8%)
Other	13,200 (8.8%)	55,200 (8.7%)	16,050 (10.7%)	66,450 (10.4%)
Total	**134,100 (100%)**	**570,000 (100%)**	**150,000 (100%)**	**636,900 (100%)**

Table 1.9: Comparison of transportation energy and reactor requirements for the United States

Category		Required Electricity Load	Required Heat Load (corresponding # of 300 MWth reactors)
Transport Electrification		335 GW_e	956 GW_{th}[a] (3,186)
Hydrogen	Electrolysis[b]	574 GW_e	1,630 GW_{th}[a] (5,461)
	Thermochemical[b]	—	803 GW_{th} (2,676)
Bio-based Synfuel Production		—	1,305 GW_{th} (4,348)

[a] At 35% thermal efficiency.
[b] These two options are not cumulative.

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Chapter 2

Nuclear Power Plant Costs

Nuclear energy would seem to be ideally placed to meet the challenge of dramatically reducing emissions of greenhouse gases while at the same time expanding access to energy and opportunity for billions of people around the world. Already, nuclear technology provides the largest share of the world's carbon-free energy, and the nuclear industry's early history demonstrated the feasibility of quickly scaling up production. However, prospects for the continued expansion of nuclear energy are decidedly dim in many parts of the world. Why would a technology that holds such promise for abundant, clean, and reliable energy not be thriving? The problem is cost.

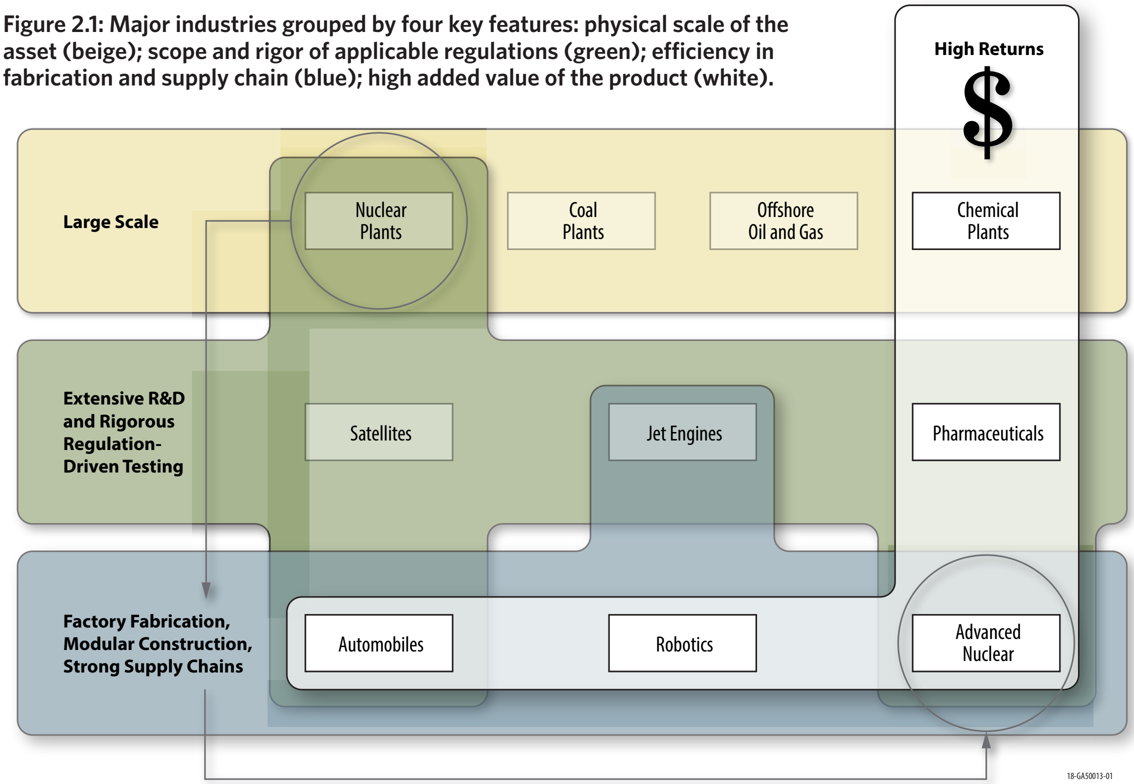
Our findings in Chapter 1 suggest that the imposition of carbon constraints creates opportunities for nuclear. The magnitude of those opportunities increases as the cost of nuclear decreases. This chapter focuses on better understanding the costs of nuclear power systems because these costs impact the overall opportunities for nuclear energy. As a starting point, we survey the innovation cycle of a set of important industries, old and new. Understanding deployment and commercialization paradigms in other industries can help crystallize similarities and differences with nuclear energy as a first step toward identifying the important inherent characteristics that create challenges for nuclear technology from a cost and development perspective. We then examine the high cost of recent nuclear plant construction projects, the root causes of these high costs, and the new technologies that hold potential for reducing the cost of all nuclear energy systems.

2.1 DEVELOPMENT, DEMONSTRATION, AND DEPLOYMENT PARADIGMS IN OTHER INDUSTRIES

To better inform our understanding of cost-reduction opportunities in the nuclear energy industry, we began by surveying development and deployment paradigms for new products across a diverse set of technologies and industries, including chemical plants, coal plants, offshore oil and gas production, jet engines, pharmaceuticals, automobiles, satellites, and robotics. Through a series of interviews, summarized in Appendix G, we sought to assess whether features of these industries, or of the product development strategies they have used, could be adopted by the nuclear industry to reduce the high cost and long time to deployment associated with new nuclear technologies. Although most of the survey subjects represented multibillion-dollar industries, their business models varied substantially and included some aspects that were relevant for the nuclear energy industry. The industries we surveyed are pictured in Figure 2.1 and grouped in terms of common features.

A comparison of these features and of estimated deployment timeframes and costs (discussed in Appendix G) indicates that nuclear energy compares poorly to most other technology-intensive industries. This is likely due to a combination of factors, including the large scale of nuclear projects, high levels of regulation-driven research and development (R&D) and extensive

Figure 2.1: Major industries grouped by four key features: physical scale of the asset (beige); scope and rigor of applicable regulations (green); efficiency in fabrication and supply chain (blue); high added value of the product (white).



Nuclear power currently has a unique combination of features that adversely affect its cost and time to commercial deployment. The challenge for new nuclear systems is to move from the top left corner of this chart to the bottom right corner. Taking advantage of factory fabrication, modular construction, and a strong supply chain could help shorten the innovation cycle for nuclear technology and improve the industry's economic returns. The introduction of a price on carbon emissions would make all non-carbon energy sources more competitive and create added value for nuclear power plants.

testing requirements to license new facilities, inefficient construction practices, and the low-value-added nature of the product nuclear energy supplies (i.e., electricity). The role of these cost drivers for nuclear energy in comparison to other industries is summarized below.

Large Scale

Several industries build facilities (such as chemical plants, oil refineries, coal plants, and off shore oil platforms) that are similar in scale to nuclear power plants, are likewise highly engineered, and thus require significant planning and project management during the construction phase. The development cycle for these large, construction-based industries (chemical, offshore oil and gas) is similar to that for nuclear power in that it involves a progression from R&D to small-scale prototype to large-scale pilot plant and eventual commercial offering. Nonetheless, typical timeframes for this development cycle are somewhat shorter in these industries than they are for nuclear power. Other industries (e.g., robotics, automotive, and coal) have much shorter product development timelines and operate in very competitive markets. They integrate all key functions at the start of a project to design a product (and associated systems and subsystem parts) to meet a stringent cost target, with a total project schedule from conception to product of 18 to 36 months.

Many of the industries we surveyed are capital intensive. Jet engine development, for example, is very expensive. The cost of a jet engine is not recovered on the sale of the engine but rather on servicing it once it is in use on an airplane. This is similar to nuclear power. Reactor sales are rarely profitable but fuel and services are.

Extensive Regulation-Driven R&D and Rigorous Testing

Like the nuclear energy industry, the jet engine and pharmaceuticals industries face extensive R&D and rigorous testing requirements to license their products because of the potential consequences associated with the use of these products. In the United States, the drug trial program for new pharmaceuticals is intensive and expensive; to be approved, new products must be tested according to detailed protocols defined by the U.S. Food and Drug Administration. In the case of jet engines, detailed regulations guide the types of testing that must be performed, including testing prototype engines under extreme conditions. Licensing a nuclear reactor likewise requires a very complete understanding of the reactor—the difference is that it is often difficult to test nuclear systems except at scale, which makes product development more expensive for the nuclear industry. In both the jet engine and automobile manufacturing industries, computation models have evolved enough to give companies the engineering confidence to enable performance testing at full scale. Some of the other industries are self-regulated and some only require testing to demonstrate regulatory compliance for particular attributes of the final product (e.g., compliance with emissions limits). Nuclear energy, by contrast, is subject to regulation during all phases of product development and deployment: during design, during construction, and during operation. Regulatory oversight includes reviewing the fabrication of key components and testing key systems on site, as well as monitoring during operation, all of which add to cost.

Inefficient Construction

Some of the industries we surveyed use factory fabrication and modularity in construction/assembly to reduce both cost and deployment time. The nuclear industry, however, typically does not. Manufacturers of jet engines and airplanes, for example, leverage the economies of serial production in the assembly of aircraft. Barriers to entry in that industry are high, so only a few producers are in the market. In other industries, such as automobile manufacturing, parts standardization is critical and factory fabrication is highly optimized to enable mass production at many facilities around the world. To be profitable and to recover the $3–$5 billion investment associated with developing and producing a new model vehicle, a car company has to have product sales in the tens of millions. The auto industry relies on strong supply chains for parts, electronics, and other components to make standardized mass production in factories viable.

Insufficient Value Added

Many industries we surveyed produce high-value-added products. For example, with a new drug, the pharmaceutical industry garners significant value in each step of the development and deployment trajectory. The process is lucrative in part because new drugs often enjoy a natural monopoly: there is no substitute or alternative source for the same product. By contrast, nuclear energy producers are in a competitive market for a commodity (electricity) where it is difficult to receive full value for the attributes of their product. The industry's ability to change its development and deployment trajectory in ways that enhance value creation is constrained by the current electricity market.

For all of these reasons, the ability of the nuclear energy industry, as presently configured, to innovate over its product development cycle is limited compared to other technology-intensive industries. Several features of the industry are worth underscoring in this regard: (a) current nuclear power plants are very large facilities that require a massive investment to deploy; (b) these plants, rather than being manufactured in factories, are constructed and assembled in the field, making it difficult for the industry to invest in delivery models that could benefit from substantial advances in productivity and thus reduce costs; (c) licensing a new nuclear facility requires lengthy R&D and rigorous testing; (d) nuclear energy's unique quality, safety, and security requirements relative to other energy technologies necessitate costly systems, structures, and components that must be designed to survive extreme external events and natural phenomena (e.g. earthquakes, airplane crashes, floods, hurricanes) and mean that the industry's operations are highly regulated; and (e) the industry's product (electricity) is a commodity with many alternative suppliers and low added value. This combination of characteristics has resulted in long lead times (20–30 years) and high cost ($10–$15 billion) to bring new reactor technologies to market. These characteristics also make the nuclear energy industry very risk averse, which can stifle innovation and slow the potential to learn from other sectors. Later sections of this chapter, and later chapters in this report, discuss the changes required to remove current roadblocks to innovation and growth in the nuclear energy industry.

2.2 REACTOR TECHNOLOGY COSTS

This section discusses the critical cost challenges that confront nuclear power. We begin by examining light water reactor (LWR) costs around the world since these provide a true baseline for the construction and operating costs of a nuclear system. We then take a close look at the major contributors to this baseline cost.

Basics of Power Plant Cost

There are three basic components to the cost of a new power plant that produces electricity (or any other energy product), whether the plant uses nuclear technology or any other technology: capital cost, operating cost, and fuel. Capital cost is composed of two parts: (a) the 'overnight cost,' which refers to the cost of building the plant, including equipment, construction materials, and labor, independent of how long it takes to actually build the plant (hence the term 'overnight') and (b) the cost of interest on funds raised to build the plant (either as loans-debt or stock-equity). Interest cost is affected by the time required to construct the plant and the composite interest rate of the funds used. This financing cost is termed either 'interest during construction' (IDC) or 'accumulated funds during construction' (AFDC). Once a plant is built, operation and maintenance (O&M) costs depend on the personnel needed and the consumables used to run the facility. The final major cost component is the cost of the fuel used to produce the electricity. Capital and operating costs can be considered fixed costs that are incurred whether the plant produces electricity or not, although operating costs do have a variable component that is affected by workforce changes, training needs, and materials used. Fuel costs, by contrast, are wholly variable since they are incurred only when the plant is operating.

Nuclear energy technology is capital-intensive. Depending on the plant, capital cost can account for more than 80% of the cost of energy from a new nuclear plant, with the remainder of the cost typically divided between O&M costs (15%) and fuel costs (5%). These percentages can vary somewhat for different plants depending on interest rate, actual construction time (which affects the amount of interest paid), and the nature of contracted engineering services. Note that this cost structure for nuclear plants is quite different from that for a natural gas plant, where 80% of the cost is the fuel cost. Appendix K provides more explanation of these costs with some simple examples.

Historic Experience with LWR Construction

Figure 2.2 displays overnight construction costs in 2017 dollars per kilowatt of electrical generating capacity (kW_e) installed for LWR plants around the world. The figure includes older plants and plants that have been recently completed or proposed, or are under construction (Lovering, Yip, and Nordhaus 2016). Costs for nuclear builds in China are estimates from Ganda (2015) and the World Nuclear Association (2018). South Korean costs are from Chung (2018). Cost data for EPR and AP1000 reactors and for the U.A.E. project are from press reports, as discussed in Appendix H.

The basis for these costs may not be the same in different countries. For example, the price negotiated for a given plant may not represent the actual cost because of direct or indirect government subsidies. Some of the cost data are for FOAK units, while others are clearly for more standardized, 'nth-of-a-kind' (NOAK) offerings. Some are for single-unit plants and some are for multi-unit plants. Some are only estimates for plants that are yet to be built. Financial markets are also different in different countries. Of greatest concern are data from the Chinese and South

Korean builds, where a lack of transparency and detail makes it difficult to scrutinize and validate available cost estimates. For example, there is some uncertainty in the cost of the South Korean build in the United Arab Emirates because it may not include all of the owner's cost (see Appendix H). Nevertheless, we include the U.A.E. estimate because of the construction discipline that South Korea has shown in its reactor builds, both domestically and now in the Emirates.

The range displayed in Figure 2.2 is quite large and extremely variable. The lowest costs being reported today are in South Korea and China, and for the U.A.E plant that is being built by South Korean engineering companies. Costs for current Western plant designs (i.e., the EPR and AP1000) are significantly higher than for other types of reactors, in part because of many FOAK issues associated with the hiatus in nuclear construction in Europe and the United States over the last three decades. For existing plants, the lowest costs are in South Korea, India, and France, followed by Japan and the United States. The older U.S. LWR fleet shows a large range in cost, in part because of the significant turbulence in electricity demand, construction delays, and regulation (following the Three Mile Island accident) that characterized the late 1970s and 1980s.

The stubbornly high capital cost of new nuclear plants, along with lengthy construction delays, is a major factor in the dim outlook for new nuclear power plant construction in the United States and Western Europe. Both the original 2003 MIT *Future of Nuclear Power* study and a 2009 update stressed the impact of these factors, and the situation is only worse today. The early history of plant construction in the United States was plagued by significant construction delays and cost overruns. New Generation-III+ (Gen-III+) reactor designs were intended to reduce construction costs, and improve other aspects of economic and safety performance. In assessing these new designs, the authors of the 2003 MIT study wrote "...plausible reductions by industry in capital cost, operation and maintenance costs, and construction time could reduce the [competitive] gap. We judge the indicated cost improvements for nuclear power to be plausible, but not proven" (Deutch, Moniz 2003). The 2009 update asked, "Will construction proceed on schedule and without large cost overruns? The first few U.S. plants will be a critical test for all parties involved" (Deutch, Forsberg, et al. 2009).

Actual experience with the first few new builds of Gen-III+ designs in the United States and Western Europe failed that test spectacularly. All of the projects have experienced long delays and large cost overruns. Figure 2.3 shows the latest estimated overnight costs for the first five builds in the United States and Western Europe against the target benchmark proposed in the MIT 2009 update report. The left three bars on the figure show the cost for the first three European builds of the EPR, a pressurized water design that was created by a joint venture of Framatome (then a subsidiary of Areva), Siemens, and Électricité de France (Framatome has since been sold to

Figure 2.2: LWR construction costs around the world

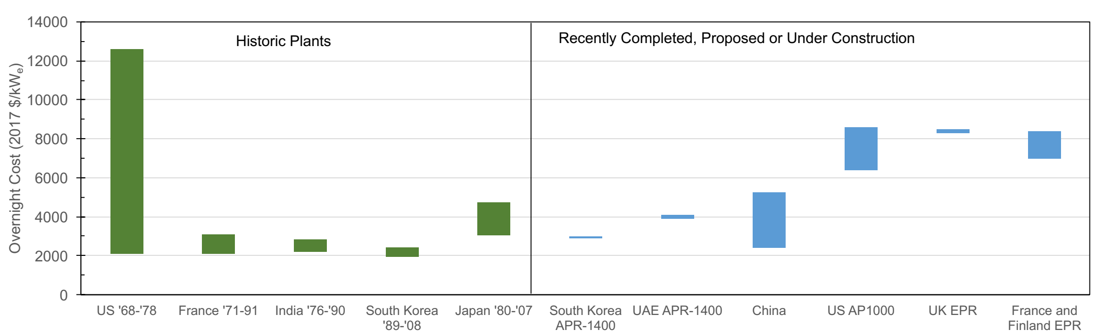
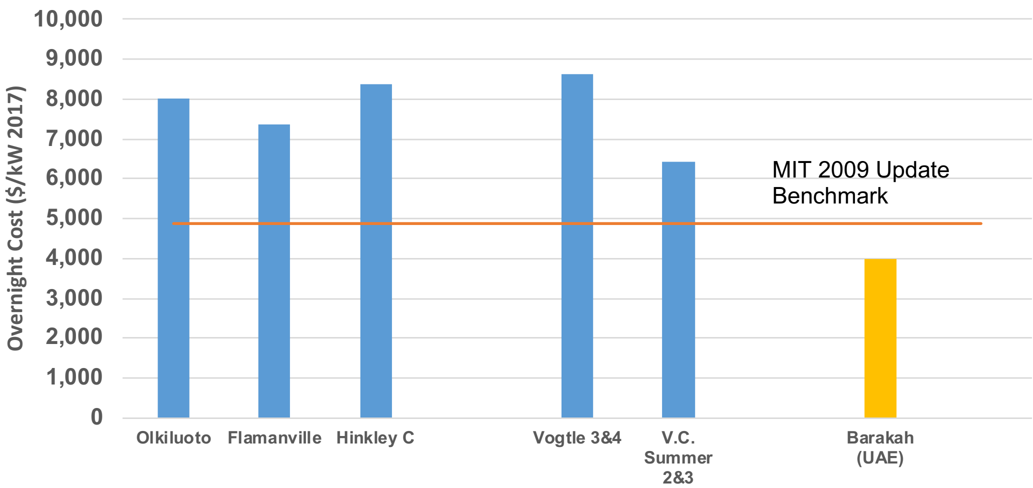


Figure 2.3: Overnight cost of recent Gen-III+ builds versus benchmark



Électricité de France and Areva has been renamed Orano). The next two bars show the cost for the two U.S. builds of the AP1000 design, created by Westinghouse (Westinghouse was once owned by Toshiba, recently went through bankruptcy, and has since been purchased by Brookfield Asset Management). Of these two, the V.C. Summer project was recently canceled due to cost overruns. The final bar is for the South Korean build currently underway at the Barakah site in the United Arab Emirates; as of this writing, the first reactor unit at that site is nearing completion, but has recently announced a delay of one year for operational readiness reasons. As noted earlier, there is uncertainty about the U.A.E. cost figures, thus the bar is colored differently in the figure.

Comparisons to Other Energy Sources

For this part of the analysis we compared levelized costs of electricity (LCOEs) for natural gas, coal, and advanced LWRs in OECD countries, China, and South Africa using information from the Nuclear Energy Agency (2015). Consistent assumptions were used to calculate these LCOEs: specifically, a discount rate of 7%, a capacity factor of 85%, and a carbon price of $30 per metric ton of carbon dioxide (CO_2) for all three energy systems. Assumed natural gas costs were $5.50 per million British thermal units (MMBtu) in the United States, $11.10/MMBtu in Europe, and $14.40/MMBtu in Asia for liquefied natural gas (LNG). However, significant reductions in the price of natural gas have occurred since the Nuclear Energy Agency report was published. As of this writing, the cost of natural gas in Europe is at $5/MMBtu; in Asia it is $7/MMBtu. Table 2.1 compares *normalized* levelized costs in the United States, South Korea, China, Japan, and France. For each country, absolute cost values were normalized to a value of 1.0 for LWRs. Thus, if the normalized value is less than 1.0 that energy option is more competitive than nuclear and if it is greater than 1.0, nuclear is more competitive. Normalized values cannot be compared across countries. For natural gas a range of LCOEs is shown based on today's actual, lower natural gas costs and the higher values used in the original analysis.

As discussed in Chapter 1 and shown in the table, without a carbon constraint, nuclear does not appear economic compared to other energy sources and cannot supplant cheap natural gas in the U.S. context. A recent study found that nuclear overnight costs would have to be between $2,000 and $4,000 per kW_e to be competitive with natural gas when natural gas prices are between approximately $3.50 and $4.75 per MMBtu (U.S. Department of Energy 2016).

In Asia, LWRs are generally competitive with coal and natural gas when a carbon constraint is imposed, but at lower natural gas costs

Table 2.1: Normalized LCOEs for natural gas, coal, and nuclear in different countries with different costs of natural gas

	Natural Gas		Coal		Nuclear
	LCOE	LCOE with Carbon Cost[a]	LCOE	LCOE with Carbon Cost	LWR
US	0.67	0.85	0.88	1.21	1.0
South Korea	1.54–2.69	1.78–2.93	1.40	1.99	1.0
Japan	0.92–1.46	1.05–1.58	0.94	1.23	1.0
China	0.74–1.72	0.97–1.95	1.03	1.63	1.0
France	0.58–1.05	0.71–1.18	–	–	1.0

[a] Assumed carbon cost is \$30/tonne of CO_2

the competitiveness decreases substantially, especially in China and Japan. In Europe, without a carbon constraint, natural gas is less expensive than nuclear. With a carbon constraint, LCOEs for nuclear and natural gas are similar.

Finding:

New nuclear plants are not a profitable investment in the United States and Western Europe today. The capital cost of building these plants is too high.

2.3 ROOT CAUSES OF NUCLEAR PROJECTS' HIGH COSTS

A number of well-known factors explain most of the wide range of costs in Figures 2.2 and 2.3, none of which are inherent to nuclear technology. FOAK plants in any country are typically 30% more expensive than subsequent plants of the same design. This 'cost of learning' is likely to be even higher if the firm/industry responsible for construction has not built any new plants in a generation and so must rebuild or relearn all of the expertise and how-to knowledge that is required. In addition, delays, rework, supply chain issues, and other factors that extend the construction schedule can further increase the cost, even before considering interest costs. FOAK, single units, or projects with a smaller number of units per site, also have to carry the full costs of licensing a new reactor as well as any site development and infrastructure/mobilization costs. The AP1000 in the United States and the EPRs in Finland, France, and the United Kingdom all fit this pattern. By comparison, the most cost-effective plants have been built with multiple (up to six) units per site using a standardized design (Lovering, Yip, and Nordhaus 2016), with the same vendors and workers working on each unit, and with a continuous build. This avoids additional costs for mobilization or to restart component production and maximizes learning for process improvement. This has been the approach in South Korea and, earlier, in France. A recent example of this approach is the Barakah project in the United Arab Emirates, which experienced a 40% reduction in labor costs between the construction of Units 1 and 4. Nuclear plants started off in China, Korea, and Japan being fairly expensive, but with very concerted efforts at cost reduction and schedule improvement, learning over time has reduced their costs relative to those of earlier plants. Figures 2.2 and 2.3 tell the story of two sets of projects: one in which all the factors that can significantly drive up costs were active, while almost none of the drivers of cost reductions were present; and a second set in which the reverse was true: cost-increasing factors were absent, while cost-reducing factors were in force.

Other features related to the execution of large complex construction projects also help to explain the cost differences seen in Figures 2.2 and 2.3. First, lower labor rates in China and South Korea make it cost effective to maintain large construction staffs on site, which allows junior workers to shadow senior workers in the manner of an apprenticeship and gain relevant training for future projects. (Differences in labor wage rates among various countries are discussed in the next section.) Second and perhaps more important, recent project experience in the United States and Europe has demonstrated repeated failures of construction management practices compared to projects in China, South Korea, and the United Arab Emirates. Finally, strong government support in the latter countries was critical to the success of their nascent nuclear power industries.

Interviews with managers of construction projects in the United States (i.e., Vogtle) and overseas (i.e., in Europe and at the U.A.E. Barakah site) point to several project attributes that seem to correlate with success or failure.

Finding:

Successful nuclear builds tend to have the following attributes:

a) Completion of needed portions of the design prior to start of construction,*

b) Development of a proven supply chain for nuclear steam supply system (NSSS) components and a skilled labor workforce,*

c) Inclusion of fabricators and constructors in the design team to ensure that components can be manufactured and structures can be built to relevant standards,

d) Appointment of a single primary contract manager with proven expertise in managing multiple independent subcontractors,

e) Establishment of a contracting structure in which all contractors (and subcontractors) have a vested interest in the success of the project,

f) Adoption of contract administrative processes that allow for rapid and non-litigious adjustments to unanticipated changes in requirements or subcontractor performance, and

g) Operation in a flexible regulatory environment that can accommodate small, unanticipated changes in design and construction in a timely fashion.

* Note that attributes (a) and (b) are typical issues for FOAK projects.

This finding echoes recommendations made by the Institute of Nuclear Power Operations (2009) when that organization, anticipating a renaissance of investment in nuclear energy, sought to identify the characteristics of successful new builds. Notably, many of these attributes were also *absent* in the effort to build a new AP1000 reactor at the V.C. Summer site, as Bechtel (2016) noted in an independent assessment of that project (the Bechtel assessment was conducted 18 months prior to the project's cancellation, but its findings only became public in late 2017).

When these attributes are missing in a new build, the result is a loss in productivity on the site and the need to rework and/or redesign aspects of the project, all of which are likely to cause delays and interfere with efficient project execution. These delays and changes in turn ripple through the entire project, often causing significant cost increases because of the additional accrual of interest on what are typically very large construction loans while any issue is resolved.

Recommendation:

Focus on using proven project and construction management practices to increase the probability of success in the execution and delivery of new nuclear power plants.

2.4 A BREAKDOWN OF NUCLEAR ENERGY CAPITAL COSTS

Setting aside project execution issues, it is important to understand determinants of the overnight capital cost of a new nuclear power plant. Table 2.2 breaks down this cost by major component for a generic AP1000 (Black & Veatch 2012), for historic U.S. LWRs, and for the South Korean APR1400 (Kim 2016) and the French EPR (de Toni 2017). For historic U.S. LWRs, the table shows two figures: the best plant (Ganda, Hansen, et al. 2016) and a median plant (Lucid Strategies 2018) based on detailed historic costs

Table 2.2: Cost breakdown for various LWRs

	Cost Breakdown (% of total cost)				
	Generic AP1000	Historic U.S. LWR Median Case	Historic U.S. LWR Best Case	South Korean APR1400	EPR
Nuclear Island Equipment	12.6	9.9	16.5	21.9	18.0
Turbine – Gen. Equipment	4.9	7.0	11.9	5.6	6.3
Yard, Cooling, and Installation	47.5	46.3	49.3	45.5	49.7
Engineering, Procurement, and Construction Cost	15.9	17.6	7.7	20.0	15.3
Owner's Cost	19.1	19.2	14.6	7.0	10.7

from the U.S. Energy Economic Data Base (1986), with costs for individual labor components and materials escalated to current dollars.

The costs in Table 2.2 are disaggregated into five major categories following the accounting breakdown used by Black & Veatch (2012):

- Nuclear island equipment includes physical equipment for the nuclear island (e.g., reactor vessel, piping, steam generator).
- The turbine generator equipment is the secondary side of the plant.
- The category termed 'yard, cooling, and installation' includes costs for civil works to prepare the site, including excavations and foundations, the ultimate heat sink (cooling towers or river cooling), other equipment, and the installation of plant components.
- Engineering procurement and construction costs are related to indirect engineering, quality assurance (QA), and supervisory costs for engineering, procurement, and construction (EPC).
- Owner's cost includes fees and permits, taxes, owner's engineering costs, and costs for spare parts and commissioning.

Interest during construction, which is the cost for carrying the loan prior to plant operation, is *not* included for two reasons: (a) it is not part of the overnight cost and (b) large differences in construction times and associated financing costs in the United States and South Korea would skew the comparison.

Several points emerge from an examination of the cost components shown in Table 2.2: First, the reactor and power conversion system equipment represent only 17%–28% of total cost. The remainder of the cost comes from site preparation, installation of components and associated field and home engineering, and owner's costs. Based on a more detailed breakdown of historic data on median LWR costs, direct site labor and field and home engineering are about 60% of the total cost (or about 75% of non-equipment costs). If interest costs during construction are included, the fraction of total cost associated with the nuclear reactor and turbine islands is even smaller because the long construction times in the United States result in significant interest payments.

Finding:

Cost reduction efforts need to be focused not on the NSSS design or the specific reactor technology but on (a) improvements in how the overall plant is constructed (or delivered to the site), and (b) ways to accelerate the construction process to reduce interest costs during this period.

Labor Rates and Labor Productivity

Labor costs account for a large part of the capital cost of building a nuclear power plant. Overnight costs differ by country or across different regions of the world in part because of large differences in the wages paid to construction workers (Bureau of Labor Standards 2012) (Richardson 2016) (World Salaries 2008) (The Conference Board 2016), as indicated in Figure 2.4. Although different sources report different absolute hourly wage rates, in part because they use different methodologies to calculate average wages, the data show that labor costs in Europe range from about 50% to 160% of U.S. costs, with most sources citing costs within 50% to 80% of the U.S. average. In South Korea, by contrast, labor costs are about 55% of the U.S. average and in China they are even lower, just 5% to 18% of the U.S. figures.

We performed our own assessment of labor rates at nuclear construction sites around the world for professionals (Appendix I provides details on the methodology), including field supervisors, engineers and technicians with different levels of experience and skill, and administrators. Their hourly rates are shown in Figures 2.5a and b.

Average hourly rates from the different countries with appropriate overheads were then used to estimate the cost of building the best and median U.S. LWRs based on the U.S. Department of Energy (DOE) code of accounts and the number of hours associated with each plant component, as given in the U.S. Energy Economic Data Base (1986). Overall construction labor costs are shown in Figure 2.6. The cost of South Korean and Chinese labor is respectively about \$400/kW$_e$ and about \$900/kW$_e$ less than the U.S. labor cost, which is generally consistent with the construction database estimates from Figure 2.4. South Korean labor cost is about 50%–60% that of the U.S. figure, while French construction labor rates are approximately 60%–80% of those in the United States and Chinese labor rates are less than 20% of the U.S. rate. These analyses suggest that while differences in labor rates play an important role, they do not account for all the variation in overnight construction costs observed in nuclear plant projects around the world.

Beyond wage differences, the actual labor productivity of construction workers in different countries is important. Figure 2.7 plots changes in U.S. labor productivity for a number of industries over time from a study by McKinsey Global Institute (2017). It shows that labor productivity in the U.S. construction industry has declined relative to other industries, including manufacturing, which saw an eight-fold improvement in labor productivity over the same period due in large part to automation. This lack of productivity growth

Figure 2.4: Construction labor costs in different regions of the world

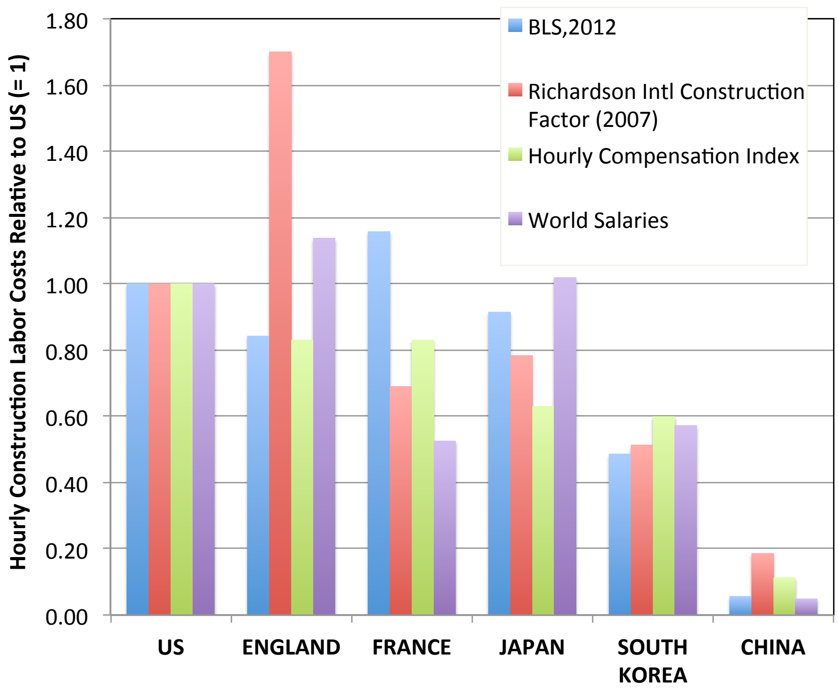
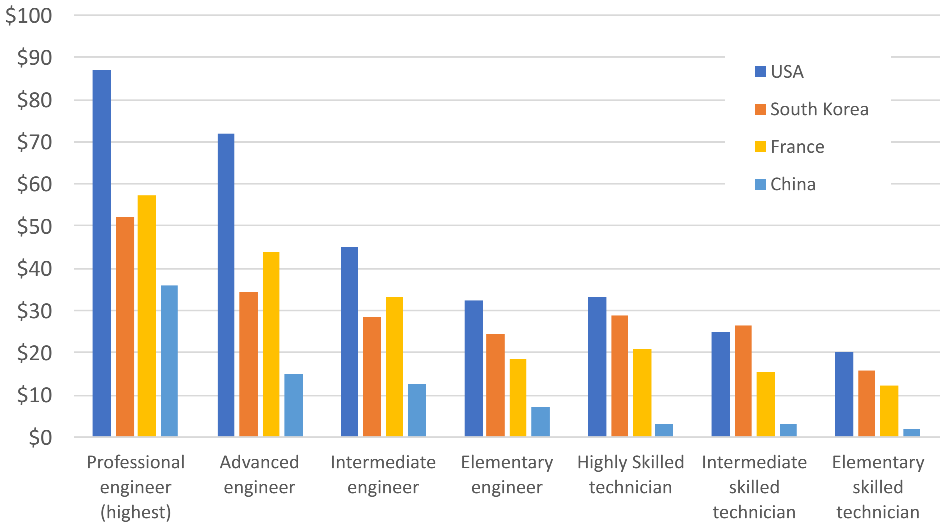


Figure 2.5a and b: Hourly wages for a variety of professionals involved in nuclear plant construction



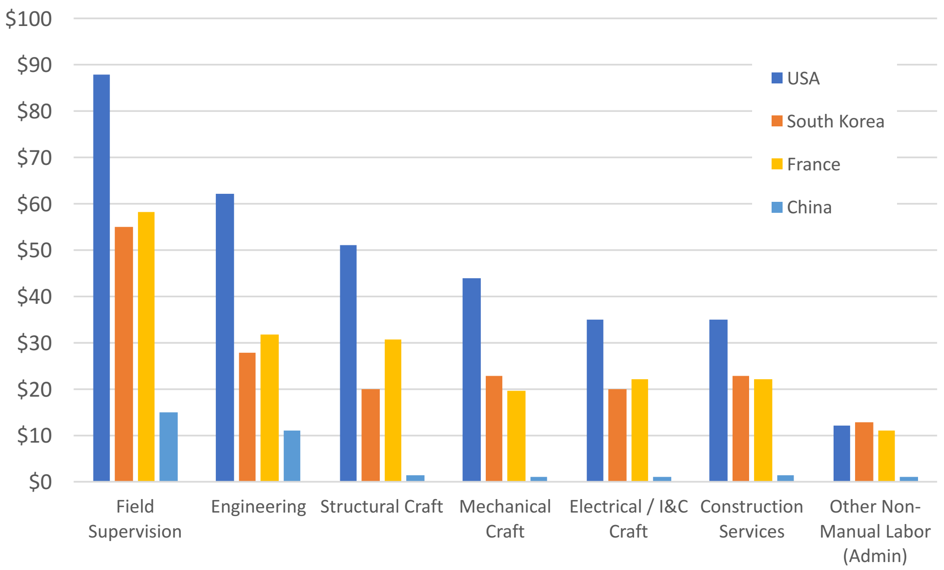


Figure 2.6: Estimated labor cost for building the best and median U.S. LWR in different countries

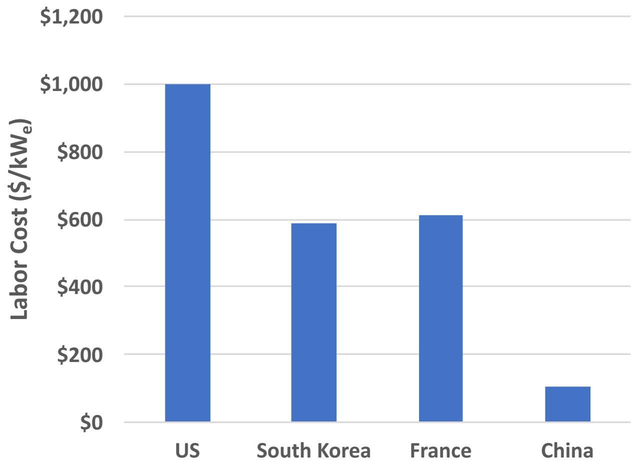
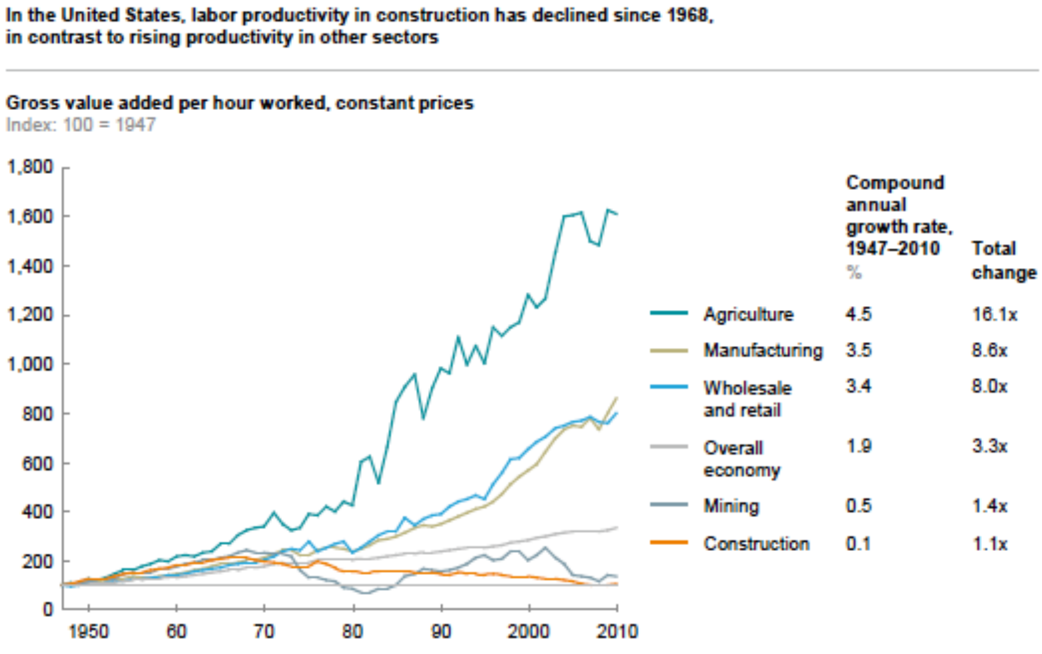


Figure 2.7: Labor productivity in the U.S. for a number of industries in the past half-century



(McKinsey Global Institute 2017)

in the construction industry is also observed globally, especially in wealthier countries like Japan, Germany, France, and Italy (The Economist 2017a). By comparison, labor productivity has been growing in South Korea and China compared to the United States and most of Europe (McKinsey Global Institute 2017).

Changes in plant design during construction, whether for regulatory, quality, or owner-induced reasons, as noted earlier, compound the impact of these differences. Thus, we conclude that in countries or regions where construction labor rates are high and productivity is low, new construction techniques (for example, greater modularity, which we discuss in the next section) will be necessary to reduce overall labor requirements and reduce construction time and cost. Further improvements in construction productivity should be pursued through automation, data collection, and analysis—potentially useful tools are available to assist in all these areas (Rhumbix 2017).

2.5 STRATEGIES FOR COST REDUCTION AND REVENUE ENHANCEMENT

Detailed cost breakdowns for LWRs, as well as for the high-temperature gas reactor (HTGR), a low power density, high-pressure design, and sodium-cooled fast reactor (SFR), a high-power density, low-pressure design (Appendix K), show that the nuclear reactor and turbine islands do not dominate the costs of these advanced systems. Costs are dominated by civil works, structures, and buildings; electrical equipment installation; and associated indirect costs for this work on site. Cost reduction strategies focusing on these items *should* be most fruitful. We examine the potential to achieve cost reductions and/or revenue enhancement by changing how the reactor is built, standardizing reactor design, reducing commodity use, and incorporating technology advances from other fields that are applicable to nuclear power. Our goal in examining those crosscutting technologies is to determine if they have significant capability to reduce the capital, fuel, and/or operating costs associated with nuclear power, or to increase the revenue nuclear plants produce. We also attempt to quantify these benefits to the degree possible. Table 2.3 summarizes the technologies considered and their economic benefit. Further detail can be found in Champlin (2018). Although the table lists all the technologies we considered, only those identified to have the highest impact are included in the discussion that follows.

Advanced Construction Techniques: Modularization and Factory or Shipyard Fabrication

Historically, cost overruns in nuclear power plant projects were associated with changes in plant design during construction. Whether these changes were prompted by regulatory, quality, or owner-induced considerations, they increased direct and indirect labor requirements and delayed the overall construction schedule (Ganda 2016). In many cases, construction productivity was impaired because the large on-site work force would be left idle while changes rippled through the re-engineering process, licensing review, and construction. Comparing best and median LWR experiences suggests that the range of indirect costs from project to project can be quite large. The historic database does not provide any data on the linkage between direct and indirect costs but begs a key question:

> Are there ways to reduce both direct and indirect costs by changing the way systems are delivered to the site?

The answer to this question may lie in the extent to which nuclear plant construction can be modularized. Modular fabrication and/or construction techniques can be employed on

Table 2.3 Summary of Major Crosscutting Technologies and their Benefits

Technology	Benefit
Accident Tolerant Fuels	Depending on reactor design, these fuels can mitigate the consequences of severe accidents and can enable downgrading of safety-relevant equipment and reduction of associated O&M costs.
Additive Manufacturing	Useful for difficult-to-make parts. Allows for faster/cheaper prototyping. Reduces waste in fabrication.
Advanced Concrete	Automated/Prefab Functionalized **Steel Plate Composite:** Eliminates formwork and reduces rebar; 50% less installation time; 25% less concrete and steel **Ultra-High-Performance Concrete:** Similar impact as steel plate composite **High-strength Reinforcement Steel:** Reduces rebar amount by as much as 40%
Advanced Construction Techniques	**Modular Construction in Factories and Shipyards:** 10–20% less capital and shorter construction time Optimized Power Conversion System Layout
Advanced Siting Options	**Standardization and Multi-unit Sites:** Key role in reducing cost because it enables faster learning by construction crews, thereby enabling economy of replication. **Seismic Isolation:** Enhances plant standardization; ≈5% less capital **Embedment:** Protects against design basis threats. Reduces size and cost of shield building, reduces seismic load. **Offshore siting:** Enables shipyard construction and efficient delivery of an entire nuclear plant.
Advanced Power Conversion	Air or Helium Brayton: higher efficiency to reduce overnight cost SCO2 Brayton: higher efficiency to reduce overnight cost
Coatings and Nano-textured Surfaces	**Hydrophobic in condensers:** +1–2% efficiency Hydrophilic in steam generator: +0–1% efficiency CRUD repellent: Saves ≈ \$1–\$3 million/reactor-year
Instrumentation and Control Technologies	Improved operational efficiency and reduced uncertainties in key plant parameters (core power, thermal margin, fuel burnup and radiation damage).
Robotics	Replace humans with robots in difficult environments (radiation, confined space, temperature, high humidity) in operations, maintenance, and emergency response.
Energy Storage	Enables modulation of electric output to the grid without affecting power of the reactor.

(bold font designates those technologies with the highest cost-reduction potential) engineering systems of all sizes and scales. For example, both automobiles and jet engines are built in a modular fashion in factories but their sizes are quite different. Thus, nuclear reactors of all sizes can employ modular fabrication/construction techniques to varying degrees, depending on the design of their specific systems or subsystems.

In recent years, other large industries and parts of the nuclear industry have used modularity and factory or shipyard fabrication (also termed advanced manufacturing or advanced construction techniques) to reduce on-site labor. Components are assembled into larger modules at existing factories or shipyards and are shipped to the building site with reduced installation time. The number of modules and the size of each module are dictated by the transportation alternatives (barge, truck, train, airship) available for delivering them to the site. Based on experience in the chemical industry, a range of options is available and in use today. Thus, modular factory/shipyard assembly offers a different approach to construction, essentially turning nuclear components into a product suitable for mass production and delivery versus a customized process that builds on site. The objective of this new delivery paradigm is a net reduction in on-site labor requirements, in associated home and field engineering costs, and in the time required to complete construction.

Modularity is already being used effectively by other heavy industries including for the construction of chemical plants, offshore oil and gas platforms, and LNG plants (Fluor 2017), (Epic Process Systems 2017), (Brookfield and Cooke 2011). Module sizes can vary from barge/ship-mounted modules, skid-mounted modules for equipment, modules that fit on trucks, and intermediate (100-ton modules) to very large modules (600 tons). Modular building, on land and at sea (in the marine industry (The Economist 2017 b)) has been found to accelerate construction and enhance overall construction productivity. Large gains in productivity have been attributed to investment in machines rather than labor as projects have become larger and more complex. Results have included dramatic cost reductions for dredging and constructing offshore oil platforms as the speed and quality of work has increased. Modularity is also occurring in the electrical cable industry (Eby 2010), which is using prefabricated and pre-tested electrical components and modular wiring systems. Finally, the chemical manufacturing industry is increasingly adopting modular fabrication techniques (European Commission 2014). Studies suggest that these techniques can enable significant reductions in capital cost (20%), time (40%), and labor (25%–50%) (De La Torre 1994).

Some researchers have examined the effect of modularization on the economics of small nuclear reactors (Locatelli, et al. 2016) (Boarin, et al. 2014) (Maronati, et al. 2018). Small reactors suffer from a lack of economies of scale (relative to large LWRs) but the research suggests that this disadvantage could be balanced by the economies of multiples. Modularizing small reactors would enable shop, factory, or shipyard fabrication; standardization; and accelerated learning as components are repeatedly factory manufactured for multiple reactor orders. In addition, modularization would divide the total capital investment (and associated risk) of a project into smaller pieces, thereby reducing construction time and interest costs during construction. The hope would be that all these factors, taken together, would offset the penalty associated with a lack of economies of scale. A compelling case can be made for this approach, but it has yet to be proved in practice by the nuclear industry.

Some of the earliest ideas on modular construction for the nuclear industry were reviewed in 2004 (Schlaseman 2004). A number of then novel construction techniques were evaluated and used by reactor vendors on large LWRs. For example, modularization was used successfully in the construction of numerous subsystems and large parts of LWRs in Japan—extensively in that country's fleet of advanced boiling water reactors (ABWRs)—and to a lesser extent in China, India, and South Korea (Presley and Weber 2009) (Nuclear Energy Agency 2015) to reduce construction time. In Japan, ABWR construction schedules were reduced by nearly 20% and non-civil construction person-hours were reduced by nearly 40% relative to experience with new reactor construction prior to the ABWR buildout (Tuohy and Yonemura 2008). As a result, these plants had some of the shortest construction times for LWRs around the world. In the new pressurized heavy water reactor design being deployed in India, preassembling the entire calandria/core package is believed to save 10–12 months in the overall construction schedule (Vhora 2018).

More current experience in the United States suggests that the cost savings being achieved through modularization are only about 10%–15% compared to the larger values seen in other industries and in nuclear projects in other countries. For example, modularization techniques were applied to some subsystems and structures of the AP1000 (Deng 2011). Components and supports were delivered to the construction site, assembled into larger modules in a dedicated on-site building, and finally lifted into their final location. Self-consolidating concrete was also employed in many places. The expectation was that this approach would do more to reduce construction time (and associated cost) than it would do to reduce actual labor requirements (O'Connell 2017). However, Westinghouse has had both positive and negative experiences with modularization in the AP1000 reactor. Much of the company's negative experience has been related to FOAK issues. Westinghouse believed that the construction schedule for the AP1000 could be reduced to 30% that of the Vogtle unit based on prior learning. Furthermore, the company has stressed the importance of a judicious approach to modularization. In some cases, traditional stick-built structures are less expensive, especially if they are not very complex and can be efficiently fabricated and installed on site.

NuScale, a U.S.-based vendor of SMRs, is also employing modularity for their reactor system, rooms containing ancillary equipment, and other non-nuclear systems. Using chemical experience in modularity from Fluor, NuScale expects overnight cost savings of about 10% but more significant reductions in construction time (and associated financing costs) as well as increased confidence and certainty about the schedule for project delivery since higher-risk components will be assembled in the factory (Perez 2017).

By contrast, the experience of Newport News Shipbuilding and Electric Boat in building nuclear submarines (Mills 2017) has provided a more striking demonstration of the potential for improvements in construction efficiency, showing that a task, such as performing a weldment, that requires one person-hour to complete in a modular fabrication shop will require three person-hours at an open site in the field (such as an assembly platen) and eight person-hours at the final location (in this case, a dry dock). This is widely known at Newport News Shipbuilding and Electric Boat as the '1-3-8 rule.' The reason for this dramatic difference in labor and cost for tasks performed in the shop compared to the field is that the processes, procedures, access, tooling, workforce proficiency, and environmental controls in place in a shop setting provide the most efficient environment for completing the work. Modular design and construction save time and money by moving portions of the work to centers of skilled labor, instead of requiring skilled workers to perform under more difficult conditions on site. This also improves product quality and worker safety and reduces the number of tradesmen as well as the average skill levels required on site, with corresponding reductions in on-site labor costs. Like automobile assembly plants, factories used to produce nuclear system components should also be designed for maximum automation to reduce labor costs as much as possible.

To make the most of its advantages, modularization must be considered at the conceptual design stage, especially for the more mundane parts of plant design that involve buildings, rooms, structural concrete, electrical conduit/cable trays, and piping runs. However, there are drawbacks to modularity. Engineering limitations of this approach include tolerance stack-up effects, increased work to connect modules, and the need to assure structural integrity of the module during transportation to the site. In fact, the g-forces associated with transport are larger than traditional seismic loads. Modular construction will also shift some costs, transferring some of the site labor costs for stick building to the factory. Financing and building the factory itself, if an existing facility is not available, presents new supply chain risks—in fact, industry investors may need to have multiple orders in hand before they are willing to step forward and take the risk of developing a factory to capture the economic benefits of modularity. In many cases, a modular approach requires sizable up-front investments in design, procurement, and fabrication—not only several years prior to commissioning but also prior to start of plant construction, which can increase financial risks and overall financing costs. In addition, new costs will be incurred to transport large modules to the site. Site considerations can limit the size of modules that can be transported, depending on the physical location of the site and the capacity of local roads and bridges. For these reasons, Framatome (formerly Areva) is said to be cautious about modularization and prefers to stay with a stick-built approach at this time (International Atomic Energy Agency 2009). This decision, however, may be influenced by the company's EPR design, which is large and complex and may be less compatible with modularization than other reactor systems.

Another early study, done in 2003, looked at the potential modularization of a number of Gen-IV systems (Mynatt 2003) and concluded that all of them could be modularized. It examined the MIT pebble bed design in more detail and found that modularization could potentially reduce construction costs for this design between 20% and 50%. The 2003 study concluded that the cost savings realizable from modular construction were greatly influenced by how well the modules fit together during final assembly, an engineering challenge noted earlier. Companies exploring other advanced reactor concepts e.g. high-temperature gas reactors (General Atomics 2011), fluoride-salt-cooled high-temperature reactors (Hong, et al. 2017), sodium-cooled fast reactors (Kwant and Boardman 1992), and molten salt reactors (Thorcon Team 2017) have begun to consider modularization techniques in parts of their designs. (Chapter 3 discusses advanced reactor technologies in more detail.)

As an example of the potential for advanced manufacturing/modular assembly and construction to reduce advanced reactor costs, we estimate that reducing the cost and construction time for a notional advanced reactor by 20% would reduce the overnight cost by about \$1,000/kW$_e$. It would also reduce interest costs during construction by one-third or approximately \$600/kW$_e$ for a combined savings of \$1,600/kW$_e$, or roughly 30% of estimated overall capital cost, and a corresponding reduction of approximately \$30/MWh in the LCOE.

Beyond modularization, optimized layouts for the power conversion system, such as in the Advanced Modern 600 MW$_e$ LWR (AM600) design described by (Field 2017), could reduce costs by reducing the number of components and using more modern upgrades and planning.

Finding:

Modularization, when used judiciously in nuclear plant construction and component fabrication, could be a viable cost-reduction strategy in advanced reactor designs. In addition, our examination suggests that: (a) countries with high labor rates and low productivity have stronger incentives to use modular construction in factories and shipyards to reduce labor requirements (especially for very expensive labor at the plant site), and (b) if the factories and shipyards used to produce components are located in countries with low labor rates and high productivity, overall savings could be substantial. However, for structures, systems, and components that are less complex, onsite assembly may still be the less expensive option.

Commodity Usage

Data from the best and median LWR builds from the 1970s (Figure 2.8) indicate that commodities (concrete, steel, piping, and electrical cables) drive installation costs in nuclear reactors because they are so labor intensive. This was re-affirmed by discussions with Westinghouse regarding the AP1000. For example, a detailed examination reveals that the fabrication of concrete forms dominates the cost of concrete, reinforcing steel dominates the overall cost of steel, and non-nuclear-grade carbon steel piping dominates the cost of piping. Concrete accounts for 25% of the total cost of 1970s-era pressurized water reactors (PWRs), while rebar accounts for 35% of total steel input for these plants. Nuclear concrete comprises about half the total concrete used at a nuclear power plant but it costs at least twice as much as non-nuclear-grade concrete (Peterson, Zhao, and Petroski 2005) so minimizing the use of this material will reduce costs. Nuclear-quality structures also take approximately 30% longer to build and use approximately three times more steel than conventional structures (Champlin 2018).

Figure 2.9 plots the amounts of concrete and steel used in the construction of a variety of LWR plants, advanced reactor designs, and coal plants on a per-MW_e basis. The data exhibit a wide range of scatter and come from a variety of sources (Peterson, Zhao, and Petroski 2005) (Roulstone 2017) (Thorcon Team 2017).

More importantly, our discussions with Westinghouse indicate that these commodity metrics can be misleading. Careful engineering is required on a structure-by-structure basis to determine the optimal approach to fabrication and installation. While some structures may use less concrete, they can be more expensive overall because of their overall complexity, which may create other challenges in fabrication and installation depending on the nature of the concrete and on the amount of rebar and shear ties in the structure. For example, there is significantly more concrete in the ABWR than in the AP1000, but according to Westinghouse, the ABWR was easier to construct.

Finding:

New reactor buildings and structures need to be optimized, taking into account both the amount of material and the amount of labor necessary for fabrication and installation in an effort to minimize the overall cost of commodities used in plant construction as much as possible.

Figure 2.8: Breakdown of commodity use in LWRs

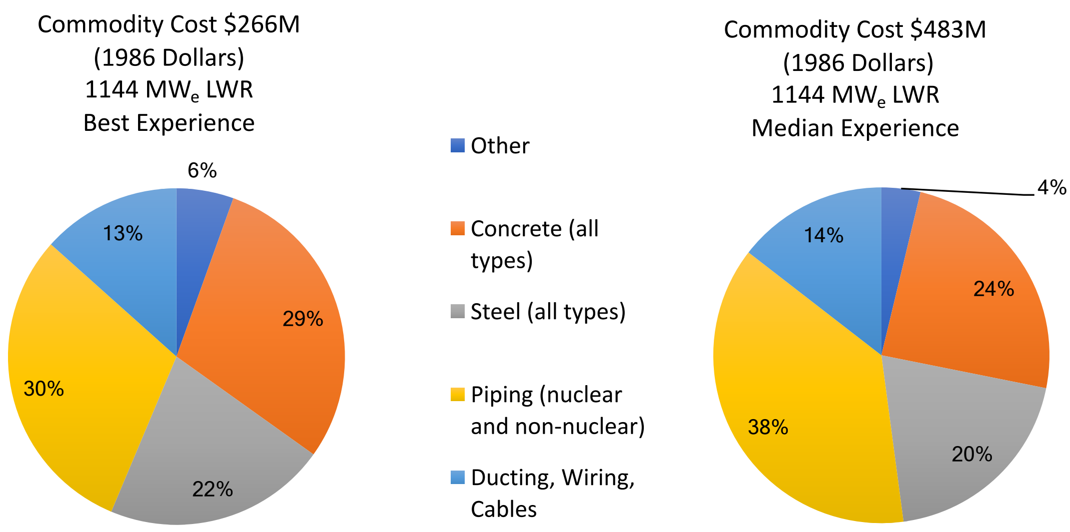
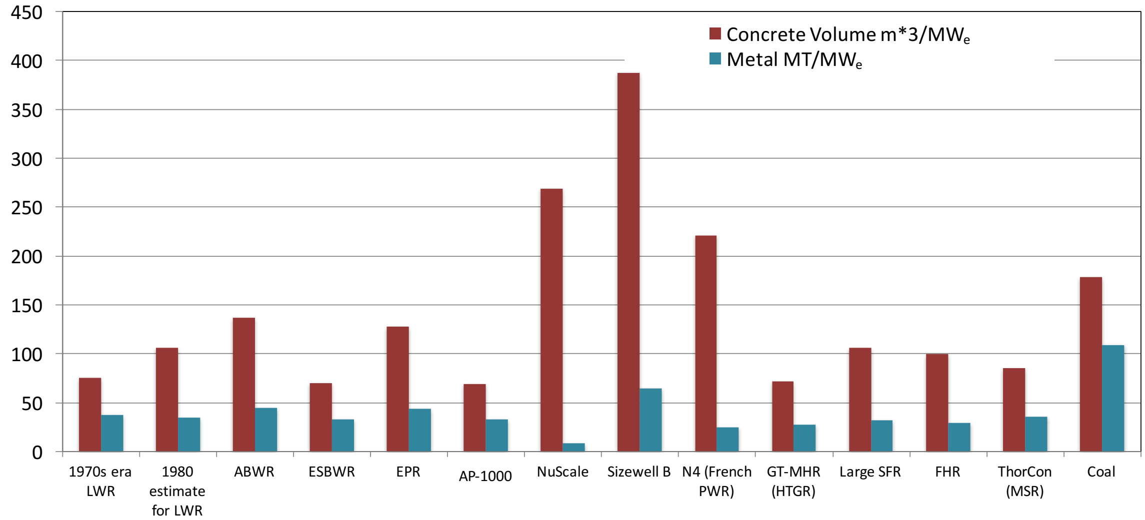


Figure 2.9: Comparison of commodity use in a variety of nuclear reactors and coal plants



Advanced Concrete

A variety of advanced concrete products and related construction techniques, including automated pouring, functionalized concrete, prefabricated concrete, steel plate composites, ultra-high performance concrete, high-strength reinforcing steel, and geopolymer concrete have been introduced that have the potential to reduce capital costs for new nuclear plants:

- Automated pouring, in which the concrete is poured by a machine rather than by hand, can reduce formwork and labor (which drives costs in LWRs today), and improve standardization.
- Functionalized concrete uses cheap additives such as fly ash to improve specific properties of the concrete. This could, for example, reduce the thickness of the concrete walls needed in an aggressive environment such as a nuclear plant.
- Prefabricated concrete is pre-poured at an offsite facility and then delivered to the site. This offers several benefits, including mass production, much faster installation, and the ability to check the quality of pieces before installation. Prefabricated concrete does, however, involve higher transportation costs.
- Steel plate composites (SPCs) consist of concrete sandwiched between two steel plates connected by tie bars. SPC forms can include any necessary penetrations and piping runs. Structural credit for the steel–concrete combination can reduce the amount of rebar required, and because the steel plate structure can be self-supporting, reinforced concrete sections can be modularized and prefabricated off-site and subsequently placed and welded on site—potentially cutting the installation time in half (Omoto 2002). This technology achieved nuclear certification in the United States in 2015 (Varma 2017).
- Ultra-high performance concrete (UHPC) is a concrete that achieves very high strength with dispersed steel fibers or admixtures of silica fume and fly ash (Li, et al. 2017). It is designed to replace reinforced concrete. The largest source of commercially available UHPC is Ductal®; similar products include Cor-Tuf (Williams 2009) and CEMTEC (Rossi 2005). Because it costs more than regular concrete, UHPC would only be used in rebar-dense areas or as a liner.
- High-strength steel in reinforced concrete is used to reduce the amount of rebar needed and thus reduce the time and cost associated with rebar placement. It also reduces problems associated with the concrete voiding that is typical in high-density rebar cages (this was experienced, for example, in the EPR design) (National Earthquake Hazards Reduction Program Consultants Joint Venture 2014).

- Geopolymer concrete is similar to UHPC in that it incorporates dispersed fibers, but it is not expected to be much more expensive than regular reinforced concrete.

Ideally these advanced concrete technologies would not be independent. An example of a streamlined process might involve pre-fabricating a UHPC or SPC shell in a factory, and then shipping the shell to the site. On arrival, these shells are pre-stressed and joined together (in the case of UHPC) and filled with functionalized concrete by an automated pourer. Similarly, modular floor design and installation can be used in conjunction with slip forming for the walls. After the outer vertical walls of a building are installed by slip forming, the modular floors can be installed through the open top of the building by means of a heavy lift crane. Modular floors consist of steel modules that include rebar but no concrete; the modules are placed on supports embedded in the concrete walls during the slip-forming process. Modular floors are designed to be transported from the assembly shop, installed by cranes, welded to supports embedded in the walls, and then filled with concrete.

A project in the United Kingdom (Locke 2016) has shown that 70% of the civil engineering activities in a nuclear reactor new build can be re-engineered to take place in a modular fashion in a factory. Furthermore, using concrete structures that are designed for manufacturability and assembly and employing advanced concrete manufacturing techniques can reduce the construction time for these components by 80%. Most of these options are or will soon be commercially available. Some will require approval by the nuclear regulatory authority. A key step toward such approval is incorporating innovative concrete solutions into relevant codes and standards for use in nuclear systems (e.g. American Concrete Institute).

Finding:

Civil engineering activities in support of new reactor construction can be performed in a modular fashion by employing structures that are designed to be manufactured and assembled using advanced concrete techniques when such an approach is less expensive than conventional 'stick building.'

Advanced Siting Options: Standardization and Multi-Unit Sites

As demonstrated by the KEPCO Engineering and Construction Company (both in South Korea and the United Arab Emirates), having a complete standardized design that is built repeatedly, at many different sites, is key to successful nuclear builds because it allows a construction team to learn with each subsequent unit. Even better is building multiple units at the same site. This approach was also demonstrated in the construction of Japan's boiling water reactors (BWRs). Standardization results in an economy of replication, which should reduce costs.

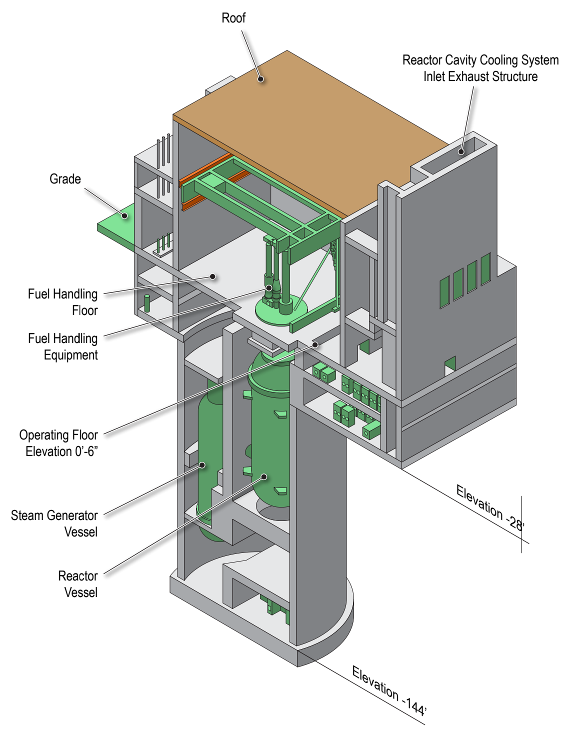
Similar results have also been confirmed by Berthélemy and Escobar-Rangel (2013). They found that standardization in the French fleet played an important role in cost reduction because it enabled learning by doing. Conversely, these researchers concluded that a diversity of nuclear reactor models can lead to delays because of supply chain constraints or increased workload for regulators. Vertical integration of the architect engineering firm and the utility can also reduce cost. More interestingly, Berthélemy and Escobar-Rangel also found that incremental innovation, as has occurred with LWRs, increases the complexity of nuclear reactors. This result is in direct contrast to the pattern in other energy industries where technical progress has typically contributed to cost reductions. Berthélemy and Escobar-Rangel explain this trend by noting the importance of safety regulation in the nuclear power sector, which improves safety performance but at the expense of increased construction costs. In particular, they note that the U.S. nuclear industry was hampered in efforts to standardize plant designs by the myriad new safety regulations that were introduced following the accident at Three Mile Island Unit 2. Nonetheless, these authors posit that radical technology changes—like those incorporated in Generation-IV technologies (see Chapter 3)—might reduce cost.

Advanced Siting Options: Embedment and Seismic Isolation

Nuclear power plants, unlike natural gas, coal, and chemical plants, are required by regulators to address a set of natural and man-made external events (e.g., earthquake, tornado, flood, airplane crash, fire) and malicious acts as part of the design basis. Thus, plant buildings and structures, and plant safety systems are hardened to withstand these events and maintain their safety function. (This hardening imparts a high degree of resilience to nuclear systems.) Because safety requirements can be major cost drivers, new technology options for meeting these requirements can help reduce plant costs.

Most of the advanced reactor designs being proposed today would be located in a below-grade embedment, both because they are smaller than conventional LWRs and because embedment may be a more economical way to address certain natural phenomena and design basis threats (Figure 2.10). A recent HTGR embedment study (General Atomics 2008) discusses the tradeoffs of embedment and concludes that feasibility and economic potential are dependent on the plant site and water table. The depth of the embedment is determined by the size of plant components (vessel and steam generator) and in some cases by the need for natural circulation—that is, some concepts may require a minimum gravity head. The technology to efficiently excavate a large, deep hole exists for a variety of soil types. The mining industry uses vertical shaft machines to create ventilation shafts. Two companies currently offer this technology: Herrenknecht can produce holes with depths of up to 5 meters per working shift to a maximum diameter of approximately 16 meters and a maximum depth of about 80 meters (Kiewit 2018) (Herrenknect AG 2018).

Figure 2.10: Cutaway schematic of reactor embedment



For modular HTGRs that use TRISO-coated particle fuel, a functional containment approach has been adopted whereby the fuel is the major radionuclide retention barrier, not traditional containment structures. (More detail on TRISO-coated fuel as used in HTGRs is provided in Chapter 3.) In such reactors, locating the plant below grade could obviate the need for a strong above-ground containment structure. In the 1990s, a team estimated cost savings for a conventional confinement building compared to a traditional high-pressure containment building as part of a broad cost-reduction strategy for HTGR technology (Gas Cooled Reactor Associates 1990). The team found savings of up to \$93 million (in 1990 dollars) for a plant containing four 450 MW_{th} reactors; these savings corresponded to an overnight cost savings of \$134/kW_e (again, in 1990 dollars) or \$250/kW_e today. This cost savings does not consider any additional hardening required to meet design basis threats such as large airplane crashes (airplane crashes were not considered in 1990) nor does it include the cost of seismic isolation (discussed next).

Adaptations to accommodate seismic hazards are a large fraction of the site-specific cost of a nuclear plant. In fact, costs related to this type of hazard have increased in the United States by a factor of two since the Three Mile Island accident (Champlin 2018). Seismic isolation offers a means to minimize the impact of site-specific features on the design. By digging out a second basemat beneath the main plant, isolators can be installed below the traditional basemat to act as shock absorbers for plant buildings. Horizontal acceleration from an earthquake is effectively dampened by the isolation system, although vertical displacements must still be considered. Seismic isolation will reduce the need for extensive plant modifications in locations that are highly seismically active, including reducing the need for hardening measures (e.g., snubbers, thickness of concrete structures). A schematic is shown in Figure 2.11. Seismic isolation technology increases the number of potential sites for a nuclear power plant and, more importantly, allows for much greater standardization and less site-dependent designs. This could play a large part in reducing site-adaptation design costs. The technology is technically ready and has already been implemented by other industries and in nuclear facilities overseas. Three major nuclear systems that use (or will use) seismic isolation include the Koberg PWR in South Africa, the ITER facility in southern France, and the new Jules Horowitz irradiation test reactor in southern France. U.S. regulators have recently drafted guidance on seismic isolation (Kammerer, Whittaker, and Constantinou 2013) but have not yet approved the use of this technology in nuclear power plants as a way to improve seismic safety. According to a recent study by (Bolisetti, et al. 2016), the isolators provide an overall net cost reduction when the peak ground acceleration exceeds 0.2 g—which notably includes every nuclear plant site in the United States ('g' is a unit of measure for acceleration due to gravity). Based on other non-reactor nuclear facilities, overall seismic isolation could reduce overnight costs by approximately 5%, not including the benefits from standardization. More recent work has focused on developing solutions to reduce both horizontal and vertical displacements during a seismic event using phononic crystals to dampen acoustic waves. Recent work (Yan, Cheng, et al. 2015) (Xiang, et al. 2012) (Yan, Laskar, et al. 2016) is extremely promising but has not yet been incorporated into relevant regulatory standards.

Advanced Siting Options: Offshore Platforms

Offshore platform designs, in which the reactor is integrated in an offshore rig, offer an alternative to embedment for coastal sites since site preparation is reduced to installing attachment and/or mooring systems (Figure 2.12). Also, a concrete shield may not be necessary in these designs, since the NSSS can be situated below the water line and behind multiple thick steel hulls. Two general designs have been proposed: floating platforms (Buongiorno, et al. 2016) (Ford, Abdulla, and Granger Morgan 2017) (D.W. Richardson 2014) (Ganesan 2016)

Figure 2.11: Examples of seismic isolation

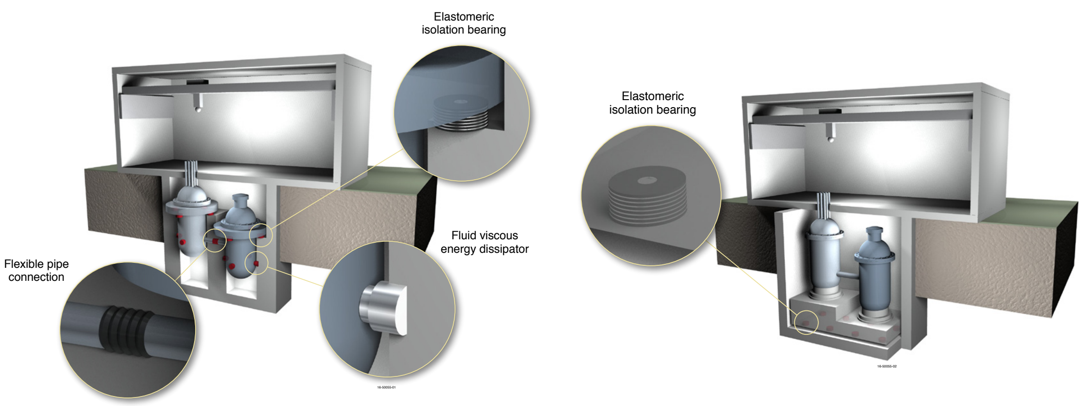
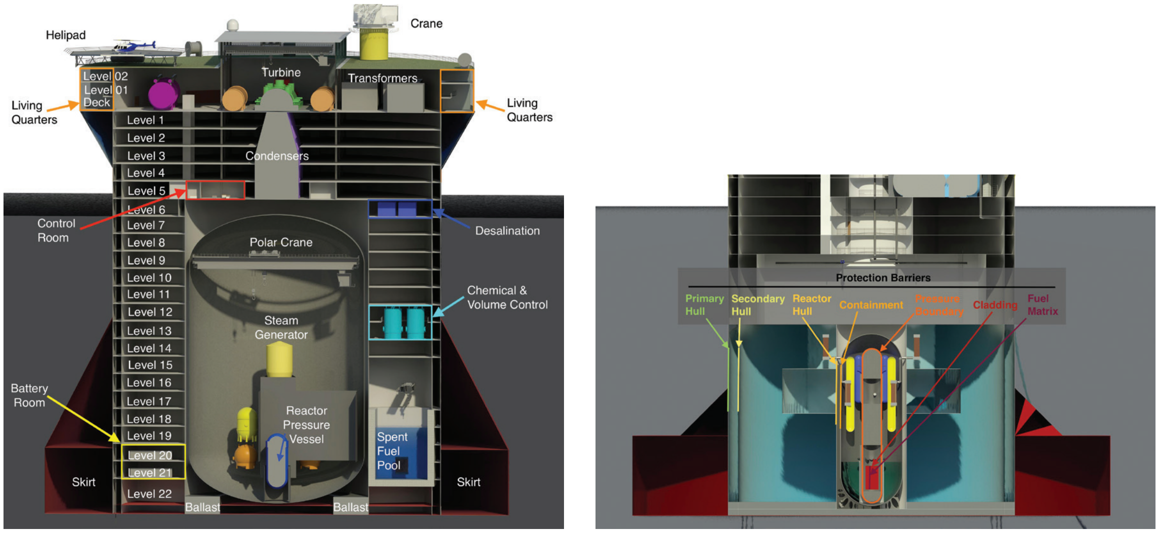


Figure 2.12: Example of offshore floating power plant



and standing platforms (Ashworth 1974) (Lee, et al. 2013). Floating platforms eliminate seismic concerns, but introduce other considerations associated with the potential for platform sinking and the effects of platform motion on reactor behavior, especially with respect to safety systems that rely on natural circulation. Standing platforms eliminate such issues but are limited to relatively shallow water sites. In either case, other external hazards (storms, tornadoes, marine collisions) as well as the in-leakage of water need to be considered. Offshore designs can reduce siting difficulties by making it possible to use sites that are uninhabited and do not compete with other land uses. They would also allow for rapid decommissioning via removal of the platform at the end of plant life. Ocean delivery, in which the entire plant is constructed in a shipyard and delivered in one piece to the site, would mean moving from a sequential, low-productivity construction process to a parallel, high-productivity manufacturing process—with potentially large impacts on the cost and schedule for plant delivery. Substantial cost reductions versus an nth-of-a-kind land-based PWR could be realized in the following categories: elimination of site preparation costs (approximately 10% of plant cost), direct labor (20% reduction in expected cost on first plant compared to a conventionally built plant, and greater reductions on subsequent plants), materials (concrete eliminated along with formwork, rebar, inspection, etc.), construction supervision (approximately 50% reduction due to work practices in the shipyard), and field engineering (near complete elimination due to completed engineering prior to fabrication). However, operating costs are expected to be higher for offshore plants because of higher labor rates for offshore personnel and somewhat higher electricity transmission costs with underwater cables. Lastly, we note that the idea of a 'shipyard made' plant can also be applied to a coastal site that is not offshore—in that case, the plant is built in a shipyard, is then towed to an artificial wet dock at the site, the dock is drained, the plant operates for its lifetime, and at the end of its lifetime the dock is flooded and the plant is towed away for decommissioning.

Finding:

Standardization (especially at multi-unit sites), embedment below grade or underground (or, alternatively, offshore siting), and seismic isolation can reduce construction costs and improve safety and security.

Coatings and Nano-Textured Surfaces

Hydrophilic or hydrophobic coatings are a surface treatment that can be applied to various power cycle components to affect how the coolant interacts with them. The result is improved heat transfer on hydrophobic condenser tubes due to the elimination of the condensation-inhibiting liquid films that typically form, or enhanced boiling in hydrophilic steam generators and BWR cores due to a reduction of insulating steam (or Leidenfrost) layers. Both of these effects improve the thermodynamic efficiency of the cycle by allowing the affected heat exchanger to operate at lower temperature differences for the same performance, which in turn translates to higher pressure drops across (and thus more work out of) the turbine. Additionally, these coatings can reduce the buildup of harmful deposits, such as Chalk River Unidentified Deposits (CRUD), and prevent corrosion in reactor cores; thus, the coatings are also characterized as 'CRUD-phobic.'

Heat transfer coatings can improve efficiency for little additional cost. For example, hydrophobic coatings are expected to cost less than $1 per square meter to implement, can be retrofitted on old condensers, and are technically ready now (Varanasi 2017). Our analysis (Champlin 2018) of the effects of introducing hydrophobicity to a PWR condenser shows a 1.3% (additive) increase in plant efficiency, for a reduction of approximately 1% in outlet steam quality and a negligible increase in air in-leakage. The durability of these coatings, however, has yet to be proven. For example, debris problems could arise if the coating is susceptible to flaking after extended use. A coating should not need to be replaced more often than the component it is applied to would otherwise need maintenance. Achieving this level of durability has been an issue in the past, but companies such as DropWise and NEI Corp's Nanomyte (NEI Corporation 2016) claim to offer hydrophobic coatings that are technically ready now.

The cost impact is similar for hydrophilic and CRUD-phobic coatings, which offer a 0.6% increase in efficiency and savings of approximately $1–$3 million per year in fuel costs (Karoutas 2017). However, durability remains a key issue because these coatings have not yet been found to be capable of performing under industrial conditions for extended periods of time. It is hoped that these types of coatings will be ready for use in nuclear power plants by 2030.

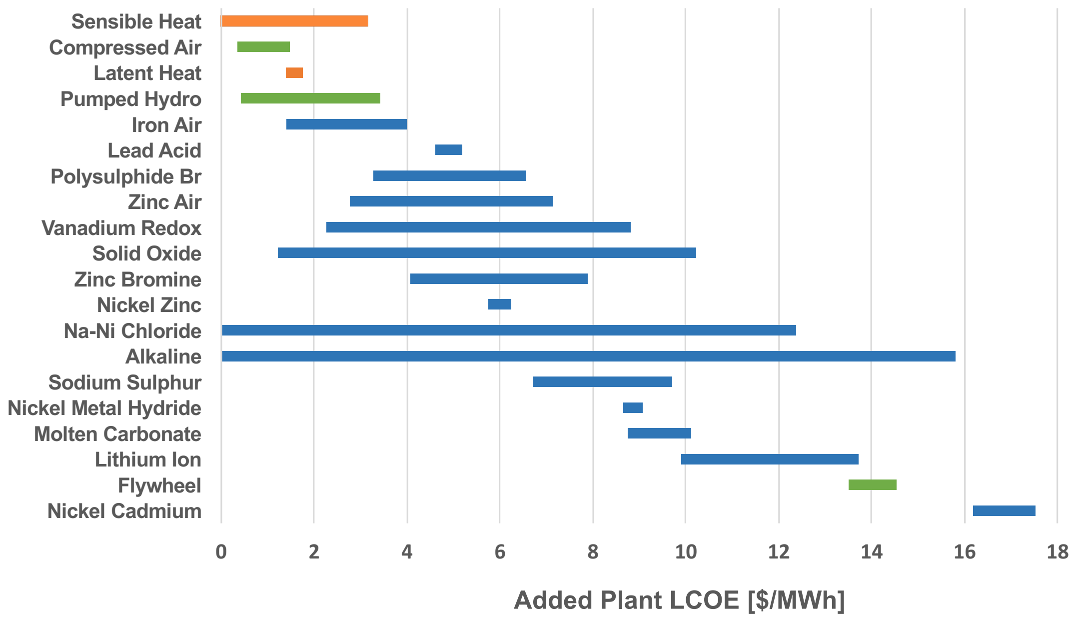
Energy Storage

The use of energy storage technologies is a potential mechanism for enhancing revenues from baseload nuclear power plants because it would allow plant operators to store energy when the price of electricity is low, and then sell that energy when demand is high. (Energy storage may also be useful for other types of generation technologies, notably intermittent renewables, but perhaps at a different scale.) In essence this would open up new peaking markets for nuclear beyond traditional baseload operation. We examined a broad range of energy storage technologies (Champlin 2018) including electrical storage (capacitors and electromagnetic devices), mechanical storage (pumped hydro, compressed air, and flywheels), batteries (including a range of static and flow types), and thermal storage (of both sensible heat and latent heat). A plot of projected storage costs at the scale necessary for integration with a nuclear reactor is shown in Figure 2.13. These results show that, in general, thermal and some mechanical storage is cheaper than electrical storage (Forsberg, C. 2017). Additional details are provided in Appendix J.

Because storing heat from a nuclear reactor is inherently lower cost and has a higher overall round-trip efficiency than storing electricity, we examined several thermal or heat storage technologies in more detail, including steam accumulators, sensible heat fluid systems, cryogenic air systems, packed bed thermal energy storage, hot rock storage, and geologic storage systems.

With these options, the reactor operates at full power and a large fraction of the power conversion fluid is diverted from the turbine to the heat storage system at times when electricity prices are low. The remainder of the steam goes to the turbine to produce a minimum level of electricity.

Figure 2.13: Added cost ($/MWh$_e$) of different energy storage options in nuclear power plant applications



The color of the bars signifies the type of storage: green is mechanical, orange is thermal, and blue is electrical.

In this case, because the turbine always remains in operation, it can be rapidly returned to 100% power output as necessary. Integration options vary for these technologies. In some cases, the energy is converted directly from the heat storage system into electricity using power conversion equipment similar to that used by a nuclear reactor. In nuclear systems that have an oversized turbine (a new build or modification of an existing reactor), the energy can be returned to the turbine inlet to make electricity. To ensure that generation is available to meet peak demand in situations where the stored heat might be depleted, boilers fueled by natural gas, oil, biofuels, or ultimately hydrogen can be added as a backup to provide steam that would otherwise come from storage. This may be an economic option for providing extra capacity to meet demand for assured electricity production and for generating additional revenue in the form of capacity payments (Forsberg and Varrin 2018). As with any hybrid energy system, an economic tradeoff exists between investing in storage technology versus the revenue that can be generated.

The first three technologies we considered (steam accumulators, sensible heat fluid systems, and cryogenic air systems) have been demonstrated at the 1–100 MWh scale. Steam accumulators were used as early as the 1920s for variable electricity production and are available today. Sensible heat fluid systems have been used with solar thermal power systems using oil as the heat transfer fluid. Cryogenic air systems can be coupled to any heat source and a pilot plant is currently in operation in the United Kingdom. The other technologies are longer-term options. Most of them can provide for daily up to weekly variations in electricity demand. Geologic storage systems, which are the least mature technology, could provide for seasonal storage and could be used to provide a strategic heat reserve though such systems could be deployed only in specific local geologies.

The overall economics of many potential energy storage systems have not been extensively studied yet. Furthermore, each storage technology has different characteristics such as rate of charging, round-trip efficiency, rate of discharge, cost of storage ($/MWh) and cost of associated energy conversion ($/MW$_e$). As a consequence, the preferred option will depend on the electricity market. In a grid with large concentrated solar power capacity and the need for daily energy storage, the preferred heat storage system will likely be different than in a system with excess wind capacity and multi-day cycles of low- and high-priced electricity. Several of the technologies (e.g., hot rock and geological) may be able to participate in capacity markets since they can produce electricity when needed. The ability of the other technologies to participate in capacity markets will depend on how these markets are defined. This is in contrast to many other storage technologies where incremental storage costs are too large for participation in capacity markets to be viable. Today, natural gas generation is the preferred option for dealing with temporal changes in electric load—largely because of the low cost of natural gas. However, with a carbon constraint, thermal energy storage systems could offer a cost-effective, carbon-free alternative.

Our assessment of cost-reduction opportunities and technologies suggests that the overnight cost of nuclear reactors in the United States could be reduced by 25% to 30% (modular construction: 15%–20%; embedment: 5%; seismic isolation: 5%) from the nominal benchmark value of approximately \$5,000/kW$_e$ (in the 2009 update to MIT's original *Future of Nuclear* study) to \$3,500–\$3,750/kW$_e$. A 25% reduction from a nominal overnight cost of \$5,500/kW$_e$ provided the basis for the 'Low Cost Nuclear' modeling scenarios discussed in Chapter 1. As noted previously, overnight costs for advanced nuclear systems built in China or South Korea, where labor rates are lower than in the United States and construction productivity is higher, could be significantly lower. The crosscutting technological innovations discussed in this chapter are applicable to all nuclear reactor concepts, including evolutionary LWRs, small modular reactors, and Generation-IV reactors.

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Chapter 3

Advanced Reactor Technology Evaluation

This chapter reviews the range of advanced reactor technologies, currently proposed or under development, that could be deployed as part of a new wave of nuclear energy investments this century. These systems include small modular light water reactors and Generation-IV reactors that use non-water coolants. These advanced systems have attributes that allow for missions beyond electricity generation and many have desirable safety characteristics. We also estimate costs for these technologies. Each is at a different level of technical maturity and as such has a number of key technology development challenges to overcome prior to being ready for commercial deployment. We discuss the overall timeframe needed to reach commercialization for different reactor concepts based on their current technical maturity, prior experience with the specific technology involved, and historical experience related to the commercialization of nuclear systems more broadly. Finally, we draw on our findings to propose a new deployment strategy for the least mature of the advanced nuclear energy systems.

3.1 REACTOR TECHNOLOGIES

Advanced reactor technologies can be characterized by the coolant they use and by their neutron spectrum as shown in Table 3.1. The coolant transfers heat produced in the reactor to the electrical generator or other systems that utilize the heat. Many key reactor features (e.g., operating temperature, pressure, materials) are designed to assure compatibility with the coolant. The neutron spectrum refers to the kinetic energy of the neutrons in the reactor. Fission neutrons are born fast and can be slowed down by collisions with a moderator. Fast reactors do not have a moderator to slow down the energy of the neutrons; thus, fission reactions occur only at high neutron energies. Thermal reactors use a moderator to slow down the neutrons and most of the fission reactions occur at low energy. Most existing reactors used to generate electricity are light water reactors (LWRs), which are cooled with water and operate with a thermal neutron spectrum. Fusion technology is summarized in a Sidebar 3.1, but we do not cover this technology in detail.

This chapter begins by providing a brief description of different types of advanced reactors, which can range in power output from micro-size (less than 10 megawatts of electrical generating capacity or MW_e), to small modular designs (up to 300 MW_e per reactor module depending on the

Table 3.1: Characterization of advanced nuclear reactor systems by coolant and neutron spectrum

Coolant	Thermal Neutron Spectrum	Fast Neutron Spectrum
Water	Small Modular Reactor (SMR)	
Helium	High Temperature Gas-Cooled Reactor (HTGR) and Very High Temperature Reactor (VHTR)	Gas-Cooled Fast Reactor (GFR)
Liquid Metal	—	Sodium Fast Reactor (SFR), Lead-Cooled Fast Reactor (LFR)
Molten Salt	Fluoride-Cooled High Temperature Reactor (FHR), Molten Salt Reactor–Fluoride (MSR–fluoride)	Molten Salt Reactor–Chloride (MSR–chloride)

design), all the way up to larger units (as much as 1,200 MW_e). Information about each technology can be found in the literature (Generation IV International Forum 2002) (Pioro 2016), (International Atomic Energy Agency 2013), including details about its scientific status (Abram and Ion 2008) (Locatelli, Mancini, and Todeschini 2013) (Futterer, et al. 2014) and engineering challenges (Allen, Sridharan, et al. 2008) (Allen, Busby, et al. 2010). (Note that for purposes of this chapter, references to 'modular' designs indicate that multiple reactor modules can be put on the same site to obtain the overall generating capacity desired by the customer. In Chapter 2, which focuses on cost, the concept of modularization is discussed in relation to the opportunity to fabricate nuclear power plant components in a factory as a way to reduce costs and simplify construction. This type of modularization should be applicable to nuclear power systems of all sizes.)

Small Modular Light Water Reactor (SMR)

'Small modular light water reactor' is a term that has been coined for small LWRs with a high degree of passive safety. As noted earlier, SMR designs encompass plants with an electrical generating capacity of less than 300 MW_e for an individual module. The SMR design being offered by NuScale Power (2018) is the most mature concept in this technology space. It consists of multiple (up to a dozen) 50-MW_e reactors that use a common water pool as their ultimate heat sink. The NuScale design and similar concepts leverage the large operating experience of the current LWR fleet with smaller and simpler configurations. This allows designers to eliminate active safety systems and rely on passive safety features. In these types of designs, minimal-to-no electrical power is required to actuate safety systems and provide long-term core cooling in the case of an accident.

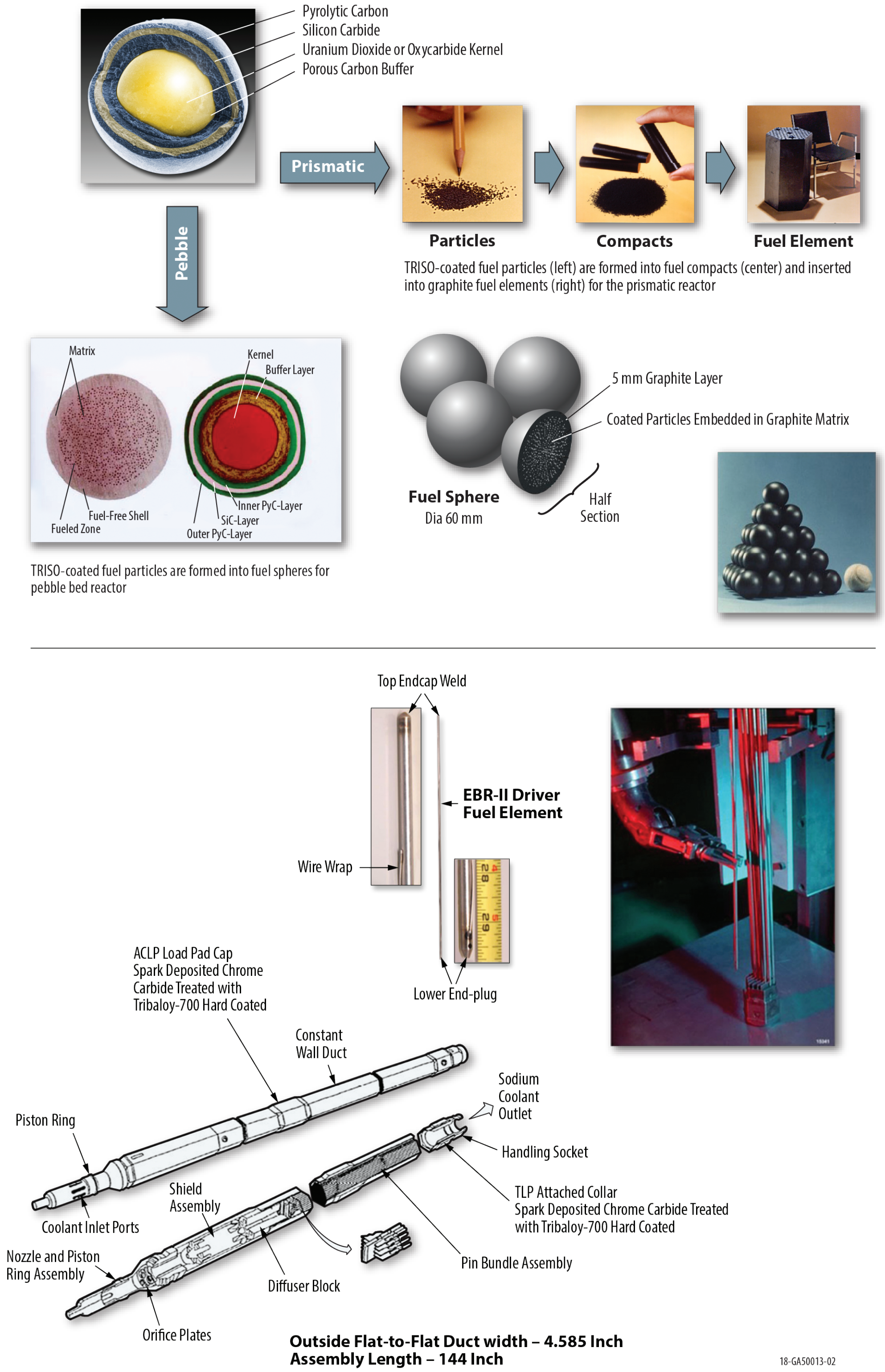
Modular High Temperature Gas-Cooled Reactor (modular HTGR)

This term describes a graphite-moderated helium-cooled thermal reactor (Kadak 2016). The reactor's low power density (i.e., power per unit volume of the reactor core), coupled with a high heat capacity graphite moderator and robust TRISO-coated particle fuel (Figure 3.1a) provides a high degree of inherent safety. TRISO-coated particles are small poppy-seed-sized particles containing a core of ceramic uranium (oxide, carbide, or a mixture) encapsulated in layers of dense carbon and silicon carbide. These particles provide containment of the radioactive byproducts of fission and their robustness minimizes radioactive releases to the environment. Two design variants exist: (a) a prismatic graphite moderator block that contains graphite cylinders laden with the TRISO particles and (b) a pebble bed made of cue-ball-sized graphite pebbles, also containing TRISO fuel particles. The pebbles slowly circulate through the core allowing for on-line refueling. The reactor coolant outlet temperature is generally between 700°C and 850°C for most of these designs. A variant of this design features higher outlet temperatures (900°C–950°C) and is called the 'very high temperature reactor' (VHTR). The VHTR concept requires additional technology development; there is interest in this design because the higher outlet temperature may be important for the process heat applications that are discussed later in this chapter. Companies that are currently working on HTGR technology include Framatome, X-energy, U-Battery, and STARCORE.

Gas-Cooled Fast Reactor (GFR)

The GFR is a high-power-density fast reactor cooled by high-pressure helium. Conceptual designs envision a core that contains ceramic (as opposed to metallic) fuel and structures to accommodate the high temperatures. Uranium mono-carbide fuels are usually considered for use in this design because they meet the high fissile density requirements for a fast reactor (fissile density refers to the concentration of uranium atoms per unit volume of fuel). Outlet temperatures for most proposed designs of this type would be approximately 850°C. The GFR concept has been considered in the past by France (Dumaz, et al. 2007) and more recently by General Atomics (Choi and Schleicher 2017) but has never been built.

Figure 3.1: Fuels for advanced reactors



(a) TRISO-coated particle fuel is used in high temperature gas-cooled reactors (upper panel); (b) metallic fuel is used in many sodium fast reactor designs (lower panel). Both of these fuel systems have higher burnups than LWR fuel rods. They also offer greater compatibility between fuel, cladding, and coolant, which results in superior accident tolerance. (Burnup—also known as fuel utilization—is a measure of how much energy is extracted from the primary nuclear fuel source.)

Sodium Fast Reactor (SFR)

As its name suggests, this type of fast reactor is cooled by liquid sodium. It operates at very high power density given the absence of a moderator and the excellent heat removal capability of the sodium coolant. Most of the designs under consideration today are small SFRs that have inherent and passive safety features that may not be viable in larger sodium systems. The fuel of choice in the United States is a metallic alloy of uranium and zirconium clad in steel, while international programs (Russia, France, Japan) utilize oxide fuels. Metal alloy fuel, shown in Figure 3.1b, has low stored thermal energy and the core expands under off-normal high-temperature conditions, providing a negative nuclear reactivity feedback to limit any power increase. Many SFR concepts, like GE's PRISM design (Triplett and Loewen 2012), recycle their fuel and thus operate on a fuel cycle in which the fuel contains both uranium and plutonium to keep the core very compact. Larger cores that do not contain recycled plutonium and achieve very long-lived fuel cycles (that is, the fuel can be used for decades before it needs to be changed) are under development (for example, by Terrapower (Ahlfeld 2011)); these designs, however, require advances in fuel and materials technology to meet performance objectives. Outlet temperatures for SFRs are generally between 500°C and 600°C due to structural material limitations. Advanced SFRs are under consideration that use different structural materials or different power conversion technologies to further improve overall performance. These concepts have the potential to reduce cost but require additional technology development.

Lead-Cooled Fast Reactor (LFR)

The LFR is an alternative fast reactor concept that uses liquid lead for cooling instead of sodium. It derives from Russian submarine technology and experience. Two different fuel forms are usually considered with this system. Some proposed designs utilize uranium dioxide (UO_2) fuel, which has been used in older sodium fast reactors. Other designs propose to use uranium nitride (UN) fuel because it offers high fissile density compared to oxide but this fuel technology is not yet mature and thus would require significant development. Some concepts, leveraging Russian submarine experience, involve low outlet temperatures between 300°C and 500°C, while others propose to operate at higher temperatures of 500°C–600°C like sodium systems. Even higher temperatures are a goal for some designs but before operation at outlet temperatures of 700°C–750°C is possible, further technology development is needed to address issues related to the corrosion and erosion of metallic structures in the core by the lead coolant. In the United States, Westinghouse has been exploring this advanced reactor concept (Ferroni 2017).

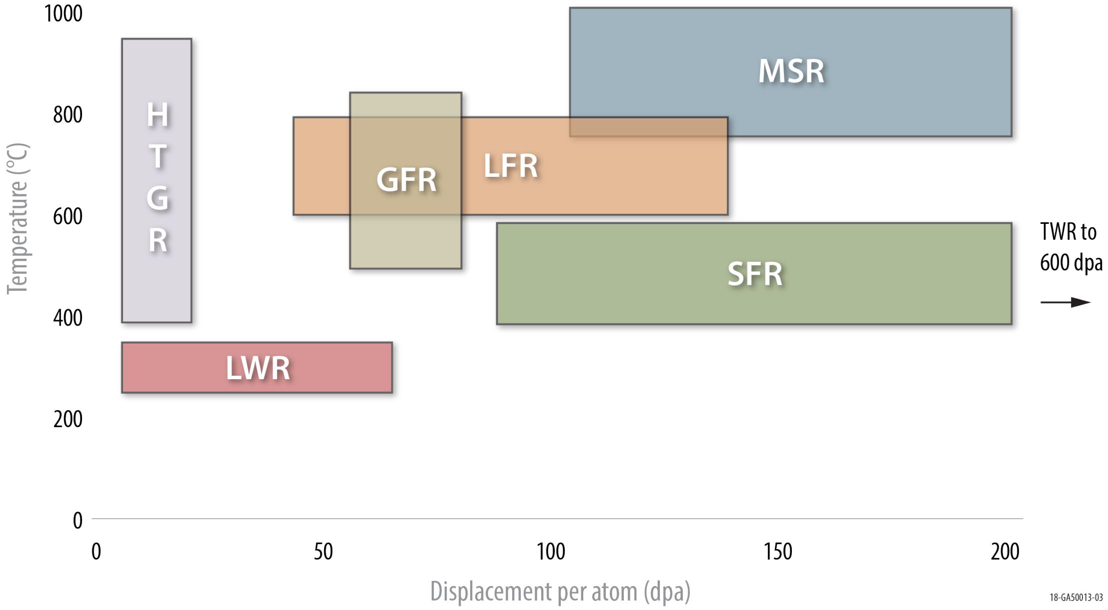
Fluoride-Cooled High Temperature Reactor (FHR)

The FHR is a high temperature reactor that uses a fluoride-based salt (such as FLiBe, a mixture of lithium fluoride and beryllium fluoride) as the coolant instead of helium (Forsberg 2014). The reactor is designed to operate at four to ten times the power density of an HTGR, with TRISO-particle fuel technology. The use of a fluoride-based molten salt, with its superior heat transfer characteristics compared to helium, results in lower fuel temperatures. Both prismatic and pebble designs have been considered; the pebble design is currently more advanced. The outlet temperature of the molten salt coolant in proposed designs of this type is approximately 700°C, however, as discussed later, there are significant material challenges associated with long-term operation above 650°C. Kairos, a recent startup, is developing the pebble bed version of the FHR.

Molten Salt-Fueled Reactor (MSR)

The MSR class of reactors uses a molten salt as both coolant and fuel because the fuel is dissolved in the salt. There are both thermal and fast variants of this design. The thermal systems use a fluoride salt (i.e., salt that contains the element fluorine) with graphite or another material as a moderator to slow the fission neutrons down to thermal energies. The fast reactor variant uses chloride salts (i.e., salt that contains the element chlorine). Power densities are generally as high as

Figure 3.2: Temperature and displacement damage windows for advanced reactor concepts



Adapted from Zinkle and Was (2013).

those of LWRs for thermal systems and as high as sodium fast reactors for fast systems. Proposed outlet temperatures from the reactor core are in the range of 700°C–850°C, however as discussed later there are significant material challenges associated with long-term operation above 650°C. Higher temperatures up to 1,000°C are proposed but would only be achievable if concerns about material corrosion by the salt coolant, along with concerns about radiation damage and material strength are resolved. Fluoride and chloride salts have high melting points and thus the reactor inlet coolant temperature for these systems must be above 500°C to prevent freezing during normal operation. A variety of conceptual designs have been proposed (World Nuclear Association 2017), all of which require significant technology development. Companies that are currently pursuing this technology include Southern Company/Terrapower in the United States, Terrestrial Energy in Canada, Moltex in the United Kingdom, and ThorCon, a U.S.-based company that is planning to deploy in Indonesia.

Nuclear reactor systems can be compared using key parameters—such as operating temperature and neutron damage to important core structures, such as the fuel cladding—that limit operational conditions. A key metric for the level of neutron damage is the neutron-induced displacement of atoms from their original positions in the material lattice, which is measured in terms of displacements per atom (dpa). The level of damage is a function of the material being tested, the damage probability, the neutron spectrum, the neutron flux, and the irradiation time. High levels of displacement damage (high dpa) challenge a material's ability to perform its function in the neutron environment. The level of displacement damage can determine the lifetime of the component, which may have to be replaced once that level of damage is exceeded. New radiation-resistant materials may be required to accommodate damage levels in excess of 200 dpa.

Figure 3.2 shows neutron damage/temperature operating windows for LWRs (Generations II–III and SMRs) and for different Generation-IV concepts. The damage levels shown in Figure 3.2 span the values expected for both fuel cladding and structural materials in the reactor core; for shielded load-bearing components, the damage levels will be much lower. LWRs (including SMRs) operate at low outlet temperatures (approximately 300°C) and low damage levels (i.e., less than 5–60 dpa). (Note that, with life extension, 80 dpa

Sidebar 3.1: What About Fusion?

Fusion is a nuclear technology that harnesses fusion reactions between atoms, instead of fission reactions—as in conventional nuclear power reactors—wherein atoms are split apart, to generate useful energy. If fusion could be practically implemented, it would offer a low-carbon energy source with many positive safety and environmental attributes. However, uncertainty in the science of net-energy-producing fusion plasmas, and the massive size and complexity of the devices required to produce them, continue to make fusion the energy source that is perpetually many decades into the future. This situation is perhaps best exemplified by ITER (for 'International Thermonuclear Experimental Reactor'), an ambitious international fusion research and engineering demonstration project in which some 35 nations are involved. ITER is now constructing a large tokamak reactor in southern France with the aim of demonstrating a net-positive fusion energy process by 2035. The reactor is expected to take 20 years and cost approximately $20 billion to construct. This development pathway, while scientifically sound and justified, is taking much longer and proving much more expensive than originally anticipated, pushing hopes for commercializing fusion power to beyond 2050. Clearly, fusion energy is a technology in need of innovation, especially in the engineering required to deliver it as a practical energy source.

Recent advances in materials enable an alternative development path for fusion energy. For example, the availability of high-temperature superconductors (HTS) could change the design of a tokamak in key ways. Electromagnets using HTS can produce magnetic fields with double the field strength of previous superconductor technology, resulting in an order-of-magnitude increase in the fusion power density and a correspondingly large volume reduction of the fusion device. In addition, HTS magnets have a much wider operating space, allowing for design features that can increase the modularity of the fusion device and achieve more effective heat removal, thereby overcoming limitations in the traditional configuration.

These advances open a potential pathway to improving the cost-competitiveness of fusion energy systems. However, significant technology development is still required in several areas to make fusion a reality (e.g., tritium processing and breeding, blanket and divertor technology). While it is too early at this juncture to evaluate precisely how future technology innovation will affect the overall trajectory for developing, demonstrating, and eventually commercializing fusion energy, the development of large-bore HTS magnets will clearly play a large role. This development is now underway.

is being reached in some existing LWRs.) VHTR/HTGRs and FHRs also operate at low damage levels (i.e., less than 5–30 dpa) but high temperatures (600°C–950°C). Components in fast neutron systems (such as the SFR, LFR, GFR, and fast-spectrum MSR) are subjected to much higher damage levels (50–200 dpa) and operate over a range of temperatures (400°C–1,000°C) depending on the design concept. The figure includes the Terrapower Traveling Wave Reactor (TWR), an SFR concept that proposes to reach damage levels up to 600 dpa because of its long-lived core.

Technical Characteristics

The different technical characteristics of advanced reactor systems shown in Table 3.2 (e.g., higher outlet temperature, different neutron spectra, different safety characteristics) have some potentially positive impacts on operation and economics. They also influence potential applications for the reactor as discussed later.

Except LWR-based SMRs, all of these systems have outlet temperatures higher than conventional LWRs. As a result, the overall thermal efficiency is higher (generally between 40% and 50%). This would tend to reduce the cost of electricity relative to the traditional 33%–35% efficiency of LWRs, assuming comparable capacity factors. This also reduces associated water use for waste heat rejection by up to 50% on a per-unit-electricity-generated basis, which can be even more important in more arid locales. Water use could be eliminated altogether if dry cooling were adopted (at the cost of a reduction in overall thermal efficiency).

Except for SMRs, most fuels proposed for advanced reactor concepts require uranium enrichments above 5%, usually between 10% and 20%. The added cost of this enrichment must be weighed against the significantly higher fuel burnups attained in these systems: typical burnups are two-to-three times higher than conventional LWR fuels. New fuel forms will also entail higher fuel fabrication costs in the early stages of deployment.

Table 3.2: Select technical characteristics of advanced reactors

Technology	Core Outlet Temperature	Efficiency	Fuel Burnup[a]	Water Use[b]
NuScale SMR	310°C	32%	5-6 atom% using shorter length LWR fuel rods	Similar to LWRs
Rolls Royce SMR	327°C	≈35%	5.5-6 atom% using shorter length LWR fuel rods	Similar to LWRs
Modular HTGR	750°C–950°C depending on design and mission	43.5%–50% depending on outlet temperature	10%–20 atom% using TRISO fuel corresponding to enrichments of 10 to 20%	≈36%–50% less than LWR because of higher thermal efficiency
GFR (EM2 concept)	850°C	43%–50% depending on design of power conversion system	8%–14% using uranium carbide fuel in SiC cladding	≈35%–50% less than LWR because of higher thermal efficiency
SFR like PRISM or Terrapower	500°C–600°C	≈35%–40% (the use of an intermediate loop reduces the overall efficiency)	7%–10% using metallic fuel with recycle; >40% once-through	≈8% less than an LWR given slightly greater thermal efficiency
LFR	300°C–750°C depending on design and mission	≈34%–45% depending on the design	7%–10% for oxide fuel (much higher proposed for long-lived cores)	Up to 40% less than LWR because of higher thermal efficiency
FHR	700°C	≈42%	Similar to HTGR. Uses TRISO fuel.	≈32% less than LWR because of higher thermal efficiency
MSR	700°C–750°C	≈40%–42%	High fissile burnup is proposed because fuel is dissolved in coolant. Burnup is limited by reactivity considerations and the efficacy of on-line fission product removal, if required.	≈32% less than LWR because of higher thermal efficiency

[a] Atom% designates the percentage of fissile and fertile atoms that underwent fission in the fuel.

[b] Defined as water use per unit electricity generated with respect to a LWR with 33% efficiency using the formula $(1-\eta)/\eta$, where η is the thermal efficiency of the plant.

Safety Characteristics

The safety of a nuclear system can be thought of as a series of safety functions that must be satisfactorily accomplished to control the reactor when it is operating normally and to remove decay heat when the reactor is shut down, thereby preventing the release of radioactive material to the environment in the event of an accident. Controlling the inadvertent release of radioactive material to the environment requires that the energy sources that can mobilize the material be minimized or controlled. This leads to the following key safety functions:

- Control of nuclear reactivity (reactor startup, operation, and shutdown),
- Assurance of heat removal to an ultimate heat sink,
- Control of coolant inventory (to prevent loss of coolant),
- Minimization of chemical energy release (e.g., from ingress of air and/or steam, or other chemically reactive fluids), and
- Reliability of mechanisms for actuating and operating the engineered safety systems.

To achieve a low level of risk from accidents, advanced reactor designs must have safety features and systems that show physical separation, independence, diversity, and redundancy with defense-in-depth to cover the potentially unanticipated risks that can arise from an incomplete understanding of reactor system behavior.

Historically in LWRs, safety functions were accomplished with a diverse and redundant combination of backup safety systems and alternative sources of water to reduce the likelihood and mitigate the consequences of a challenge to any of these functions. Regulators have developed specific reactor design criteria to assure that the energy sources that drive the possible release of radioactive material are controlled for a range of postulated design basis accidents. This design approach has worked in the sense that current LWRs operate with a high degree of reliability and safety. Additional safety features were also installed at nuclear plants worldwide following the accidents at Three Mile Island and Fukushima to protect against accidents beyond the design basis, to further reduce the likelihood of such accidents and to mitigate any releases of radiological materials.

Some current LWRs accomplish key safety functions using engineered safety systems that require electrical power (so-called active systems[1]) to actuate valves, water pumps, and spray systems and to achieve containment isolation. This approach has been followed in some advanced LWR designs, including the European EPR design and the Korean APR1400 design. At the same time, other advanced LWR designs have evolved to reduce reliance on active systems and accomplish some needed safety functions by using natural forces of gravity or gas pressure (so-called passive systems). Examples of this approach include the Westinghouse AP1000, the economic simplified boiling-water reactor (ESBWR), and advanced Chinese and Russian designs. Finally, the NuScale SMR is a prime example of an LWR system that is quite innovative in its design. It has virtually eliminated the need for active systems to accomplish safety functions, relying instead on a combination of passive systems and the inherent features of its geometry and materials.

Designs for non-LWR advanced reactor systems have taken an approach similar to that of the LWR small modular designs (like NuScale), implementing and integrating safety functions in the system design with a decisively greater emphasis on inherent and passive features than in current LWRs, as noted in Table 3.3.

These advanced reactor designs employ different fuels and different coolants than LWRs. The selection of fuel, coolant, and moderator (for thermal systems only) affects the inherent safety of the system through the basic material properties and chemical characteristics of system components. Advanced reactor systems have several inherent safety attributes:

- Large margin from operating temperature to boiling point for sodium, lead, and molten salt cooled systems, combined with coolants that have high thermal conductivity (in the case of sodium and lead) and high heat capacity.
- Strong negative Doppler coefficient for HTGR system designs.
- Negative power reactivity coefficient for SFR and LFR systems (with proper design).
- Robust fuel (TRISO) and high heat capacity graphite in HTGRs and FHRs.
- Strong fission product retention in sodium, salts, graphite, and, to a lesser extent, lead.
- Low chemical reactivity of coolants such as helium, lead, and salts.

The inherent safety characteristics of SFRs and HTGRs have been confirmed through actual testing in demonstration plants. Designs for these advanced plants also propose passive systems for heat removal and reactor shutdown. These inherent and passive safety characteristics accomplish three things, the importance of which cannot be overstated in a post-Fukushima world:

- Obviate the need for AC power in off-normal events, and enable long coping times during a postulated station blackout;
- Simplify overall plant design to allow for fewer auxiliary components or systems and enable a more automated, streamlined, and potentially more effective response to accidents; and

[1] Active, passive, and inherent safety features are defined here as follows:
Active safety features require electrical or mechanical power to actuate the safety function.
Passive safety features require only natural forces (gravity or gas pressure) to actuate the safety function.
Inherent safety features derive from basic properties of the material that function as a safety feature.

Table 3.3: Passive safety characteristics of non-LWR advanced reactors

Coolant	Passive Safety Characteristics
Helium	**Modular HTGR:** Inherent and passive safety because of lower power density coupled with high heat capacity of graphite and passive heat removal from core and reactor vessel. Passive shutdown from negative reactivity feedback in anticipated transients without scram and other transients has been demonstrated on existing smaller versions of HTGRs.
	GFR: Claims to be passively safe but demonstration will be required. Historically GFRs have had difficulty attaining high degrees of passive decay heat removal given high power density, low thermal capacity in the core, and poor conductivity of the helium coolant.
Liquid Metals	**Small SFRs:** Low pressure pool design to eliminate loss of coolant. Through a combination of reactivity feedbacks[a] from enhanced neutron leakage, this design achieves a negative power reactivity feedback, which helps to control the system under all postulated unprotected (no scram) transients without operator intervention. Passive safety of these concepts has been demonstrated in tests done at EBR-II. A variety of passive decay heat removal systems exist that can provide a connection to an ultimate heat sink for the long term.
	Large SFRs: Designing for overall negative reactivity feedback is more challenging for larger systems given the lower neutron leakage and positive reactivity void coefficient of these types of reactors. Passive heat removal is also more difficult given the decay heat load and lower surface-to-volume ratio of the reactor vessel compared to small SFRs.
	LFR: Lead provides a large heat sink, especially in unprotected events. Reactivity feedbacks prevent severe accidents, similar to SFR approach. However, because the Russian LFR was built for submarine service, testing of passive safety systems that is representative of commercial designs would be required.
Molten Salt	**FHR:** Combines passive safety features of HTGR with the large heat capacity and natural circulation capabilities of molten salt to obtain excellent safety profile. No integral testing of passive safety has been conducted but will be required.
	MSR: To provide passive safety, drain tanks with a passive fuel plug that will melt if high temperatures occur under off-normal conditions are incorporated into the design. Drain tanks will have to be designed to avoid criticality events and to remove decay heat. Integral testing has never been performed to confirm the safety benefits. Heat content of the off-gas system containing noble gases and volatile fission products needs to be considered in design. Holdup of highly radioactive molten salt in reactor piping might severely limit operator access even after molten salt draining. Fast-spectrum MSRs have large negative temperature and void coefficients because liquid fuel is expelled from the core if voids are formed or if the temperature increases. Criticality might occur under accident conditions if the fissile materials were to leak from the primary system and come near neutron moderators, such as concrete.

[a] Thermal fission reactors use a neutron moderator to slow down ('thermalize') the neutrons produced by nuclear fission. The probability of fission for fissile nuclei such as uranium-235 or plutonium-239 is much greater at thermal neutron energies. In addition, uranium-238 has a much lower probability of capture than uranium-235 and plutonium-239 for thermal neutrons, allowing more neutrons to cause fission of fissile nuclei and propagate the chain reaction, rather than being captured by uranium-238. An increase in fuel temperature also raises uranium-238's neutron absorption by a phenomenon termed Doppler broadening, thereby providing a rapid negative feedback to help control the reactor. Also, if water is used as a moderator and a circulating coolant, boiling of the coolant will reduce the moderator density and provide negative feedback (termed a negative void coefficient). Fast reactors use un-moderated fast neutrons to sustain the reaction and therefore require fuel that contains a higher concentration of fissile material relative to fertile uranium-238. However, fast neutrons have a better fission/capture ratio for many nuclides, and each fast fission releases a larger number of neutrons, which can be used to convert uranium-238 into plutonium-239, thus potentially 'breeding' more fissile fuel than the reactor consumes. Fast reactor control cannot depend solely on Doppler broadening and the reactor does not have a negative void coefficient from a moderator. Instead, thermal expansion of the fuel itself can provide quick negative feedback.

- Have the potential, because of their lower reactor source terms,[2] to reduce the size of emergency planning zones to the site boundary.

It is important to note that the safety goals and inherent behavior are similar for the less mature advanced reactor concepts (LFR, GFR, MSR, FHR), but these safety attributes still need to be validated with relevant experimental data at appropriate scales to support associated licensing activities.

[2] Source term is the release of radiological material (e.g., fission products) from the reactor.

Despite these positive safety characteristics, some safety concerns about advanced reactors remain and will need to be mitigated by design:

- Chemical reactivity of sodium with water, air, and concrete (in SFRs).
- Oxidation of graphite by air and/or water ingress following helium leakage (in HTGRs).
- Reaction of molten salts with moist air to produce corrosive acids (in MSRs and FHRs).
- Positive void coefficients with some coolants (depends on system design and coolant) (in SFRs and LFRs).
- High heat content of the off-gas systems that contain noble gases and other volatile fission products (in MSRs).

As discussed in Chapter 5, the U.S. Nuclear Regulatory Commission (NRC) is developing safety design criteria for some advanced systems. As of this writing, the focus has been on the three most mature technologies: LWR-based SMRs, HTGRs, and SFRs. In this regard, it is very important to note that there is no defined safety basis for licensing a dissolved fuel MSR currently. This gap presents a unique challenge for the general MSR concept. In the historical regulatory paradigm, the behavior of the fuel and associated fission products (quantities, physical and chemical forms, location in space and time, and integrity during operations and postulated accidents) needs to be known with high certainty because it:

- Affects operational (operating and design limits) and off-normal safety aspects of the reactor system (e.g., reactivity control),
- Represents an important part of defense-in-depth, and
- Impacts worker radiation protection.

Thus, developing such a basis would help many of the MSR concepts and is recommended as a high-priority technology need going forward.

Beyond these reactor safety characteristics, it is important to note that the operational safety of many advanced reactor systems cannot be firmly established today. Developing a cadre of proficient operators for these new technologies will require a significant effort because of new man–machine interfaces, new training requirements, and the lack of operating experience for these systems.

Table 3.4: Operability and maintainability for advanced reactor systems

Coolant	Operations, Maintenance, and Worker Safety
Helium	**Modular HTGR:** Prior HTGRs have been shown to be operable, and some have had low capacity factors due to maintenance issues. Radiation dose to workers is very low because the helium coolant is not activated and corrosion products are minimal.
	GFR: Unknown given low technical readiness of concept but use of helium as a coolant and demonstrated reliable fuel should enable clean operation as a power plant.
Liquid Metals	**SFRs:** Prior SFRs have been shown to be operable, but with low capacity factors in many cases. Fuel shuffling and other maintenance activities are more difficult because the coolant is not transparent. In addition, designs must accommodate the potential for fires when small sodium leaks occur. Engineering solutions have adequately addressed both of these concerns at SFRs around the world.
	LFR: Lead is a toxic coolant so protections are needed for workers when dealing with spills. Lead also has a high melting point (330°C) so freeze prevention will be a necessary part of the design. Maintenance strategies will have to be developed to accommodate the high melting point. Coolant activation (producing radio-toxic polonium-210) is also an issue that must be accommodated in maintenance activities.
Molten Salt	**Fluoride salts:** FLiBe as a coolant has three challenging operational issues: (1) high melting temperature (>460°C), (2) the beryllium (Be) component is carcinogenic, and (3) the lithium (Li) in the salt produces tritium. Freeze protection will be required in these designs. Strategies to protect workers during maintenance and operation of the system will also be required. Beryllium in the salt will condense dendritically (BeF2) on cold spots in the system (valve stems, pump bowl). These dendritic growths break off easily and can be transported in the air. Because it is a high temperature system, in lithium-containing salts, tritium will permeate through hot structures, making tritium control important. Workers may need respirators and/or tritium bubble suits to perform maintenance and operations depending on details of the design and its use of tritium control technologies. (Other salts such as sodium-zirconium fluoride have been used and do not have these problems.)
	MSR: In addition to worker safety issues for FHRs, the circulation of dissolved fuel gives rise to serious radiological concerns for workers. Dose rates near the flowing salt are lethal and must be heavily shielded. The circulation of fuel transports delayed neutrons to the intermediate heat exchanger (IHX), resulting in significant activation. It is unclear how maintenance and inspection activities will be performed in this environment. Robot electronics may not survive.

Complexity of Operations and Maintenance

The nature of the coolant and its level of radioactivity and chemical toxicity are important when considering the operations and maintenance (O&M) needs of the integrated system. Examples of O&M activities include: (a) refueling operations; (b) preventative and corrective maintenance of mechanical and electrical equipment, instrumentation and control (I&C), and chemical systems; (c) cleanup/recovery from minor spills and leaks; (d) inspection of key components/systems as required to meet regulatory requirements and standards; and (e) coolant sampling and routine radiological surveys around plant equipment. The ease (or, conversely, the complexity) of maintenance, inspection, and decontamination of plant components impacts worker safety. The physical layout and size (or compactness) of the overall system design also affects ease of access for maintenance. In addition, all of these factors affect the overall reliability of plant systems and the availability of the reactor. Table 3.4 summarizes operability and maintainability aspects of these systems.

Several key observations concerning the O&M requirements of advanced reactors emerge from this brief technology review:

- Operational exposure to radiation for systems will be reduced (relative to LWRs) for systems that use very high-quality fuel and graphite (e.g., TRISO fuel in HTGRs).
- Some coolants (sodium, salt, lead) produce activation products that must be addressed during maintenance operations:
  - Sodium-24 for sodium coolant and sodium-bearing salts,
  - Tritium for lithium-containing salts, and
  - Polonium-210 for lead (even more so if bismuth is used to reduce the melting point of the lead coolant).
- Some coolants (e.g., lead, beryllium-containing salts) are chemically toxic and require special attention to worker protection during commissioning and O&M activities.
- Because MSRs contain dissolved fissile material and fission products in the salt coolant, radiation levels for MSRs are significantly higher than in other advanced reactor concepts (in some cases they are lethal). This will lead to serious challenges for in-service or out-of-service inspection and maintenance of components (heat exchangers, pumps, reactor vessel).
- Coolants that can freeze at high temperatures (e.g., salts, lead) will require refueling at elevated temperatures and will rely on highly reliable engineered systems to prevent freezing in order to ensure coolant flow as well as to protect the vessel and other components in the system that may not be able to accommodate freeze-thaw cycles.
- High temperature coolants (salt) and non-transparent coolants (sodium and lead) can make refueling (if required) and in-service inspection difficult; however, engineering solutions are available.
- Leak protection/minimization for all of these systems (e.g., sodium) must be provided.

Finding:

In advanced reactors, the combination of fuel, coolant, and moderator results in a set of core materials that has high chemical and physical stability, high heat capacity, negative reactivity feedbacks, and high retention of fission products. In addition, these systems include engineered safety systems that require no emergency AC power and minimal external interventions. This type of design evolution has already occurred in advanced LWRs and is exhibited in new plants built in China, Europe, and the United States. These design attributes will make plant operations much simpler and more tolerable to human errors, thereby reducing the probability that severe accidents occur and drastically reducing offsite consequences in the event that they do. Their improved safety characteristics can also make licensing of new nuclear plants easier and accelerate their deployment in developed and developing countries.

3.2 ASSESSMENT OF COST ESTIMATES FOR ADVANCED REACTORS

Advanced reactor costs are much more difficult to establish because of a lack of design detail, different historical bases for the construction of these systems, and variations in the assumptions used to estimate costs. We relied solely on open sources for estimates of overnight capital costs and not on industry sources so that we could compare cost projections for different advanced reactors in an internally consistent manner. The results of our analysis are presented in Table 3.5; more detail is provided in Appendix K.

Estimates of projected cost are based on traditional stick-built construction in the United States for a NOAK plant. The NOAK plant is assumed to be identical to the FOAK plant supplied and built by the same vendors and contractors with only the site-specific scope altered to meet the needs of the NOAK plant site. Costs for NOAK plants are achieved only after many such reactors (approximately eight in the case of large reactor plants and many more in the case of smaller plants) have been constructed for a particular nuclear energy system (Economic Modeling Working Group 2007). For comparison, the current FOAK overnight cost for NuScale, a small LWR, is projected to be approximately $5,100 per kilowatt of electrical generating capacity (kW_e). Projected costs for HTGR (Gandrik 2012) and SFR (Ganda 2015) systems are based on the most current estimates available from open sources. These estimates are considered more reliable because such systems have been built in the past and are based on conceptual designs that have evolved over the past 25 to 30 years. Cost estimates for FHR (small (Andreades 2015) and large (Holcomb 2011)) and MSR (Engle 1980) systems are highly uncertain because they are based on early pre-conceptual designs.

Direct costs in Table 3.5 include costs for reactor and turbine plant equipment and labor costs for installation, the cost of civil works to prepare the site and its buildings and structures, and the cost of electrical and miscellaneous equipment and associated labor costs for installation.

Indirect costs include several sub-categories of cost:

- Construction services—including but not limited to costs for construction management, procurement, scheduling, cost control, site safety, and quality inspections.
- Home office and engineering services—including but not limited to costs for estimating, scheduling, project expediting, project general management, design allowance, and project fees.
- Field office and engineering services—including but not limited to costs for the field office, field engineering, field drafting, field procurement, and field administrative and general expenses.

Table 3.5: Comparison of projected NOAK advanced reactor capital costs, including contingency to account for level of design maturity and uncertainty (to two significant figures)

Cost ($/$kW_e$)	HTGR	SFR	FHR (Large)	FHR (Small)	MSR
Machine Size[a]	4 × 600 MW_{th}	4 × 840 MW_{th}	3,400 MW_{th}	12 × 242 MW_{th}	2275 MW_{th}
Design Stage	Conceptual approaching preliminary	Conceptual approaching preliminary	Early pre-conceptual	Early pre-conceptual	Early pre-conceptual
Direct Cost	2,400	2,500	2,100	2,300	2,500
Indirect Cost	1,400	1,600	1,400	1,300	1,700
Contingency	800	800	1,100	1,100	1,200
Total Overnight Cost	4,600	4,900	4,600	4,700	5,400
Interest During Construction	600	700	600	700	700
Total Capital Invested	5,200	5,600	5,200	5,400	6,100

[a] Reactor size is given in megawatts of thermal output (MW_{th})

- Owner's costs—including but not limited to project fees, taxes, and insurance; spare parts and other capital expenses; staff training and startup costs; and administrative and general expenses but not interest during construction.
- Design costs—including preconstruction engineering, design, and layout work associated with the site.

Given limited experience in the construction of advanced reactor systems, indirect costs (oversight on installation, home and field engineering, and construction services) are expressed as a percentage of direct costs. Slightly different values were used for the indirect cost multipliers in the cost assessments for different reactors: 57% was used for the HTGR and 64% for the SFR. Indirect costs for the small FHR are based on those for the HTGR. Large FHR costs were escalated to current costs based on the work of Ganda, Hansen, et al. (2016). MSR direct costs were based on an early-1980s vintage pre-conceptual design escalated to current costs using estimates for LWR direct costs from the same time period. To make a fair comparison we used the indirect cost percentage of the large FHR for consistency. As noted earlier, indirect costs taken together are a large part of the overall cost. Estimates of actual indirect costs as a percentage of direct costs from the historical LWR fleet span a large range. In some cases, the ratio has been as low as 20%, but a best-practices value from the LWR fleet is about 40% whereas the fleet average is 50%. Cost estimates developed by the U.S. Department of Energy (DOE) (1980) (1988) suggest an indirect-to-direct cost ratio of 51% for reactors built prior to the Three Mile Island accident and 77% for reactors built after Three Mile Island. The International Atomic Energy Agency (1978) recommends a value of 52%. Thus, the values used here are considered reasonable based on the open literature on this topic.

A variable contingency is provided for these estimates based on the maturity of the designs, associated technology development, and supply chain considerations. Mature concepts that are approaching the level of preliminary design (HTGR and SFR) were thus assigned a contingency of 20% while early, pre-conceptual designs were assigned a contingency of 30% to reflect the lower level of technical detail in these designs. As discussed later, these percentages may be considered low, especially for the lower maturity concepts where some significant design detail is absent. Nevertheless, these contingency values are used here primarily for comparison purposes. Finally, all systems were assumed to have construction times of 60 months and be subject to an interest rate of 8% (based on 50% debt and 50% equity financing and 30-year economic life of the plant) for purposes of calculating financing costs during construction and the levelized cost of electricity (LCOE).

With these assumptions and the low level of design detail available for some concepts, projected overnight costs for all the advanced reactors we considered appear to be within a range between $4,600/kW$_e$ and $5,400/kW$_e$. Given the uncertainty in these values, slight differences in the approach used to project costs for different concepts, and the methodology used to normalize costs to the current decade, *differences between the cost estimates for different advanced reactor concepts are not considered substantial or meaningful*. These estimates are consistent with the cost expectations expressed by experts on Generation-IV systems (Anadón, et al. 2012) and are somewhat lower than costs estimated by the Generation-IV International Forum (van Heek, Roelofs, and Ehlert 2012). More importantly, the actual costs of these systems when built will depend on the construction management practices applied to new builds in the future: as discussed in Chapter 2, the reactor design is secondary. As with the LWR fleet, costs could be lower in international markets where lower rates for labor and different levels of labor productivity apply; costs could also be lower if the new construction approaches discussed in Chapter 2 are adopted and succeed in reducing installation costs and project timelines.

Figure 3.3 compares projected LCOEs for each advanced reactor concept and for advanced LWRs, assuming a uniform capacity factor of 90% for all concepts. Fuel costs for HTGRs (TRISO fuel) and SFRs (metallic fuel) are significantly higher than for current LWRs, in part because these fuels require higher enrichment but also because they involve different fabrication methods. Neither type of reactor has been deployed yet on large scale so fabrication cost reductions might be possible in the future. For FHR fuel costs, the costs originally projected for both small and large systems that use TRISO fuel were underestimated and were corrected based on the HTGR cost estimate, which comes from vendor quotations. Detailed cost estimates for MSR fuel were not available but a nominal value was used based on the level of uranium enrichment required for the system.

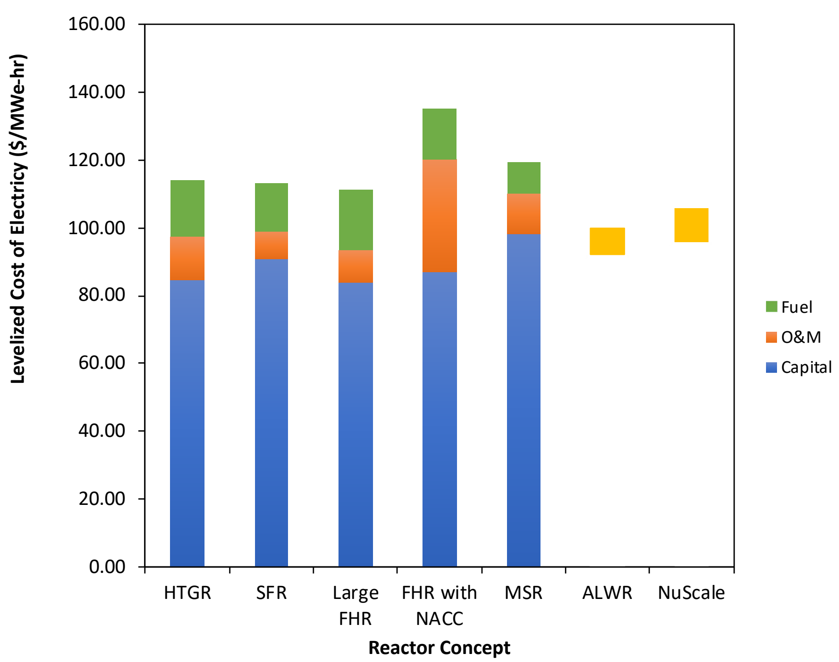
For a small FHR with the NACC, projected costs assume operation with natural gas 50% of the time. This mode of operation boosts the thermal power output for an individual unit operating at 100 megawatts of thermal output (MW_{th}) and 53% efficiency in reactor-only mode to 242 MW_{th} and 70% efficiency for the reactor and natural gas firing mode. The estimate also includes the cost of natural gas associated with the NACC, which is assumed to be \$3.40 per megawatt hour of electrical output (MWh_e)—only about 10% of the O&M costs. Higher O&M costs are associated with a large staff at each of the individual units.

Operational costs are generally similar except for the small FHR, a 12-module plant for which costs were estimated by scaling from the HTGR. Had a common cost for O&M been used, all of the systems would have an LCOE of approximately \$110/MWh_e–\$115/MWh_e. These values are slightly higher than the \$92/MWh_e–\$100/MWh_e cost estimate for advanced LWRs provided by the U.S. Energy Information Administration (2016); they are also higher than the NuScale estimate (Surina 2016) of \$96/MWh_e–\$106/MWh_e. Reduced interest rates and shorter construction times could reduce the LCOE values presented here.

These projected costs for advanced reactor systems are also very comparable to the cost levels required for nuclear energy to compete in U.S. electricity markets under a fairly aggressive carbon constraint, based on the analysis discussed in Chapter 1—specifically, under an emissions limit of 50 grams carbon dioxide per kilowatt hour of electricity generation (gCO_2/kWh_e) or lower.

While all the advanced reactor concepts currently being considered can produce electricity, the key question is which reactor concept is best suited to producing electricity cheaply. For the most part, the answer comes down to which reactor concept has

Figure 3.3: Projected LCOE for different advanced reactor concepts



the lowest capital cost. All nuclear systems face the same fundamental challenges with respect to cost. As discussed in Chapter 2 on the industry's cost-reduction opportunities, cost differences between any of the advanced reactor concepts and the expensive incumbent LWR designs may be small if reactors continue to be built on a large scale at construction sites in countries with low productivity and high wages in the construction sector. However, many of the new capital cost reduction opportunities reviewed in Chapter 2 are potentially applicable to all the different reactor concepts. All of these concepts can be realized in smaller reactors and by using reactor components that can be factory made, to reduce the portion of plant installation that has to be completed on site. All the designs can use seismic isolation. All have the potential to exploit passive safety principles and each reactor type can exploit the unique safety features that are inherent to its particular design. However, without these cost-cutting innovations, we do not see that any of the advanced reactor concepts offer inherent potential to significantly reduce the cost of nuclear electricity.

Finding:

Technology advances in plant design, not in the reactor, hold the greatest promise for reducing capital cost. All the broadly discussed reactor concepts, including incumbent LWR technology and several of the Generation-IV designs, can potentially exploit many of these advances. The challenge for any proposed plant design is to achieve the radical cost reductions needed to make a new nuclear plant competitive in the on-grid electricity market.

Uncertainties and Contingency

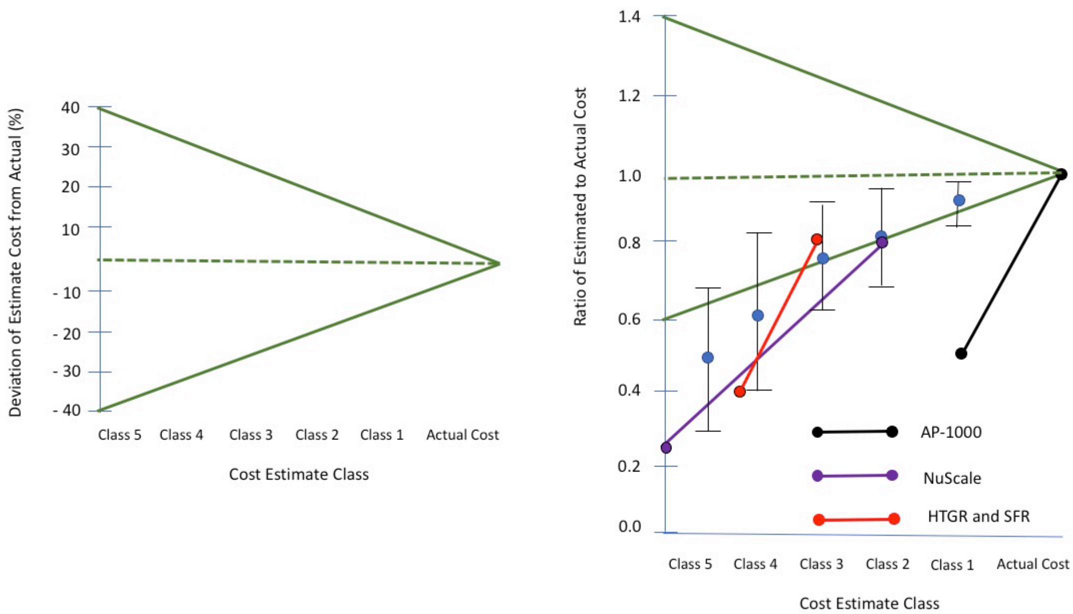
It is critical to stress that the uncertainty in current cost estimates is large, given the lack of design detail underpinning projections of overnight cost and LCOE, especially for some concepts that are at an early design stage. Uncertainty is accommodated by carrying contingency in costs estimates from the early stages of design. Table 3.6 presents recommended contingency ranges from the Association for the Advancement of Cost Engineering International (1997) and the Electric Power Research Institute (1993). Carrying contingencies of 20% to 30% at the early design stage is within the ranges recommended for Class 3 and Class 4 cost estimates but values approaching 50% to 100% are recommended for cost estimates conducted for low-maturity designs (Class 5).

Critical reviews by the RAND Corporation (Merrow, Chapel, and Worthing 1979) (Merrow, Phillips, and Myers 1981) examined the cost growth in large engineering megaprojects (chemical, public works, and nuclear weapons) over 35 years ago. The results are relevant and offer a cautionary reminder about the uncertainty of estimating costs over the course of a large complex project. Figure 3.4 (left panel) provides a conceptual illustration of traditional cost estimates and associated uncertainty as technologies progress. As greater design detail and additional R&D results are obtained, the magnitude of the uncertainty should decline. The right panel shows the actual experience of large projects superimposed on the conventional model shown in the left plot. The data are plotted as a fraction of final total project cost. The data points represent the mean and the uncertainty bars represent the standard deviation of projects

Table 3.6: Recommended contingency ranges based on level of design maturity

Estimate Class	Maturity Level of Project Definition Deliverables	End Usage	Methodology	Expected Accuracy Range
Class 5	0% to 2%	Concept screening	Capacity factored, parametric models, judgement, or analogy	Low: -20% to -50% High: +30% to +100%
Class 4	1% to 15%	Study or feasibility	Equipment factors or parametric models	Low: -15% to -30% High: +20% to +50%
Class 3	10% to 40%	Budget authorization or control	Semi-detailed unit costs with assembly level line items	Low: -10% to -20% High: +10% to +30%
Class 2	30% to 75%	Control or bid/tender	Detailed unit cost with forced detailed take-off	Low: -5% to -15% High: +5% to +20%
Class 1	65% to 100%	Check estimate or bid/tender	Detailed unit cost with detailed take-off	Low: -3% to -10% High: +3% to +15%

Figure 3.4: Cost estimation in large complex projects showing that as designs mature and incorporate more detail, cost uncertainty decreases but (more importantly) actual cost increases significantly



examined in the study. As uncertainties decline, overall cost grows significantly, suggesting an implicit low bias in early cost estimates for large megaprojects. The tendency of early estimates to understate costs can be attributed to several factors: (a) how different (and unproven at scale) the new technology is compared to past plants, (b) insufficient project definition—in terms of detail and comprehensiveness—to perform a sound cost estimate, and (c) project complexity. Other experts who study megaprojects claim that beyond these technical reasons, optimism bias (a cognitive predisposition to judge future events in a more positive light than is warranted by actual experience) and strategic misrepresentation (deliberately and strategically overestimating benefits and underestimating costs to increase the likelihood that a given project, and not the competition's, gains approval and funding) are additional reasons why early cost estimates are not good predictors of the ultimate cost of large projects. Appendix L provides more detail about the characteristics of megaprojects in general and nuclear power plants as a prime example of such projects.

The cost patterns seen in other technologies are also relevant to advanced reactor systems, as evidenced by large increases in projected costs for a number of reactors and shown in the right panel of Figure 3.4. Advertised overnight costs for the AP1000 have increased from a "certified" public utility commission value of approximately $\$4,500/kW_e$ to $\$8,600/kW_e$. Early pre-conceptual cost estimates for NuScale were $\$1,200/kW_e$ (Modro, et al. 2003) but are now projected to be approximately $\$5,000/kW_e$ (Perez 2017). Projected costs for more mature advanced reactor technologies (sodium or gas cooled reactors) have increased similarly. A cost of $\$1,365/kW_e$ was reported for modular HGTR systems (University of Chicago 2004) more than a decade ago but the projected cost estimates shown in Table 3.5 are about three times this value. Early estimates of overnight cost (Shropshire 2009) for a PRISM type SFR reactor were approximately $\$1,300/kW_e$ but are projected to be closer to $\$5,000/kW_e$ in Table 3.5. These increases are too large to be attributed solely to cost escalation for labor and commodity inputs. Instead, they highlight the enormous difficulty of accurately predicting the actual cost of new technologies at early stages of design conception.

Finding:

Traditionally, early-stage cost estimates have been significantly biased toward underestimating costs and hence have been unreliable predictors of the eventual cost of a given nuclear technology once its technical readiness increases and the reactor design matures. Nevertheless, our assessment of advanced reactor systems suggests that these systems have the potential to exploit inherent and passive safety features to improve overall safety and operation. These systems have promise, but their economic potential is not yet proven. A commitment to explore and test advance reactor technologies may provide significant economic benefit for future electricity systems.

3.3 POTENTIAL APPLICATIONS FOR ADVANCED NUCLEAR ENERGY SYSTEMS

Because of their technical characteristics, advanced nuclear technologies are being explored not only as potential generators of cheap electricity, but also for their potential to serve other product missions including supplying process heat for the production of chemicals, synthetic fuels, and hydrogen or for water desalination. In addition, some advanced nuclear technologies have the potential to be used in microgrid applications and actinide transmutation, as shown in Table 3.7. Of the diverse applications shown in Table 3.7, the generation of cheap, grid-connected baseload electricity is potentially the most consequential and is therefore generally assumed to be the primary mission for most advanced nuclear energy systems. The combination of inherent and passive safety characteristics and higher thermal efficiency may

Table 3.7: Recommended contingency ranges based on level of design maturity

Application	Technical Aspects of the Reactor that Enable Application	Potentially Suitable Reactor Concepts
Generation of Electricity for Delivery to the Grid	The combination of inherent and passive safety characteristics and higher thermal efficiency may enable simpler designs that can exploit modularity and factory production to reduce cost (as discussed in Chapter 2).	All systems considered here.
Process Heat for Producing Hydrogen, Synfuels, and Other Chemicals	Requires temperatures greater than 600°C for most applications. Reactivity feedback from chemical plant to nuclear plant needs to be examined for salt and lead coolants (not an issue for helium coolant). Developing a heat exchanger at high temperature to meet process heat needs is key technology challenge.	Modular HTGR. In principle, LFR, FHR, MSR, and GFR because of their high proposed outlet temperature, but with much less certainty because of the magnitude of the materials challenges that must be overcome.
Variable Power Instead of Baseload with a Topping Cycle	High temperature is needed for this cycle to be economically attractive. Integrating the cycle with the reactor is a key technology development item.	FHR, LFR (high outlet temperature version), MSR, modular HTGR, and GFR.
Water Desalination	Works with waste heat and/or electricity from the reactor.	All systems producing electricity or with an appropriate, low-temperature heat extraction loop.
Power and Heat to Microgrids	Very small reactors (<10 MW_e) of rugged design, coupled to ultra-compact power conversion systems such as Stirling engines, supercritical CO_2 cycles or direct conversion devices. Must be capable of semi-autonomous operations and easy to transport. Could serve mining sites, remote communities, offshore platforms, industrial complexes, military bases, or expeditionary forces.	Microreactors of various designs (typically not LWR based).
Actinide Transmutation (fuel cycle mission)	Fast spectrum is favored over thermal spectrum systems. Small probabilities of neutron interaction in fast systems imply large inventories and multiple recycling passes in fixed fuel systems to meet transmutation goals. In thermal systems, destruction of uranium and plutonium is possible but higher order actinides produced via capture reactions (e.g., americium, curium) are very difficult to manage. Long-lived cores and fuel qualification remain technology development issues.	SFR, MSR (fast), LFR.

enable simpler and cheaper advanced reactor designs that can exploit modularity and factory production. Reducing the capital cost of advanced designs is very challenging but necessary.

Cheap, Grid-Connected Electricity

The growth projections discussed in Chapter 1 suggest that electricity demand will increase more rapidly over the next several decades in Asia than in the West. In areas of faster demand growth, large LWRs, which are being built efficiently in Asia, will probably continue to dominate because of their ability to quickly add large increments of generating capacity. By contrast, many of the advanced reactor systems are smaller and could be deployed in regions where electricity demand growth is more modest or to replace retiring fossil-fired generation.

The incumbent nuclear reactor concept—using light water coolant and a thermal neutron spectrum—is already being redesigned by a number of companies that are building SMRs. A notable example is the design that has been developed by NuScale Power, which is relatively well advanced along a path to potential deployment. In place of one large reactor system driving the power plant, the NuScale design substitutes a set of 6–12 smaller, self-contained reactor modules, which are then aggregated inside a single reactor building and share a single water coolant pool. While each of the individual modules is small (50 MW_e), assembling 12 modules in one plant yields a large, 600-MW_e power plant that can compete head-to-head against incumbent, large-scale LWRs and other generation technologies to supply on-grid electricity. The use of smaller reactor modules enables increased reliance on factory production, which is key to the hoped-for drop in construction cost. NuScale's design exploits passive safety features to eliminate or simplify many systems. According to the company's plans, on-site construction of the reactor building and assembly of the modules should be much less demanding than building larger LWRs, allowing the on-site construction schedule to be reduced to three years. Proponents of this design argue that the long history of experience with light water technology justifies projections that envision a relatively short path to deployment and scale.

The main economic question is whether an SMR can be built at a substantially lower unit capital cost (i.e., per kW of capacity) and therefore generate baseload electricity at lower total unit cost (i.e., per MWh). NuScale advertises a capital cost of less than \$5,100/kW_e, which is only a modest improvement over the advertised cost of certain Gen-III+ systems and still not competitive against natural gas-fired generation under current circumstances. A 2016 study performed by Atkins for the U.K. government estimates the FOAK cost of power from integral PWR SMR designs to be about 30% above the NOAK cost of a traditional, large LWR. The Atkins study (2016) scales up companies' own capital cost estimates to correct for the 'optimism bias' discussed earlier, while also noting both the potential for sharp cost declines with volume production of factory builds *and* the enormous uncertainties involved in attempting to estimate this decline.

Proponents of many small reactor designs also advertise other advantages besides lower capital costs. Some focus on the advantages of smaller total plant size. They point out that this opens up sections of the market that are unsuited to large LWRs of 1 gigawatt (GW) capacity or more. They also point out that buyers will be better able to finance capacity purchases in smaller bites.

A note of caution is in order when evaluating claims concerning the ancillary advantages of small size. The challenge facing the nuclear industry is to reduce unit capital cost (i.e., cost per kW_e) to be more competitive in generating the lowest unit cost electricity. If the size of a small plant also happens to be the size that offers the lowest unit capital cost, then the ancillary benefits of a smaller plant are an extra bonus. However, the extra advantages of small plant size are unlikely to make up for a failure to radically reduce unit capital cost.

The problem is that, with respect to size, there is often a tradeoff between the technically optimal design and the needs of some customers. This is an age-old issue for the nuclear industry, as it is in many other industries. The optimally-sized reactor suits some segments of the market, but not all. Therefore, many reactor vendors size their technically optimal reactor first, and later produce smaller versions to serve segments of the market to which the most efficient design is not suited. Among LWR designs, examples of this approach include the Russian VBER-300, Holtec's SMR-160, and China's ACP1000. The industry's problem is not that it has overlooked valuable market segments that need smaller reactors. The problem is that even its optimally scaled reactors are too expensive on a per-unit-power basis. A focus on serving the market segments that need smaller reactor sizes will be of no use unless the smaller design first accomplishes the task of radically reducing per-unit capital cost. If nuclear technology cannot be competitive at its optimal scale of generation, whether large or small, it is difficult to see how it will succeed by scaling plants below the optimal size.[3] If, on the other hand, smaller designs are optimal and can radically reduce unit capital costs, then the ancillary advantages of accessing a larger market will be a nice bonus.

Process Heat and High Temperature Applications

While traditional LWRs operate at relatively low outlet temperatures, many of the various advanced reactor designs operate at an array of higher outlet temperatures. A higher outlet temperature can improve the thermal efficiency of electricity generation, which is a valuable feature. As noted earlier, it also increases electricity output, reduces fuel consumption, and reduces water usage per unit of energy produced.

Besides their benefits for generating electricity, high outlet temperatures open up the possibility of selling the heat itself, which is valuable for other purposes. In general, process heat missions favor reactor systems with higher outlet temperatures, a high degree of safety, low reactor source terms, and minimum coolant reactivity feedbacks between the reactor and the process heat application—all of which are necessary attributes for siting a nuclear plant in close proximity to an industrial facility.

Many nonelectrical uses exist even for the heat produced by relatively lower temperature LWRs. For example, a number of existing nuclear power plants supply district heating systems, and some provide process heat to industry (International Atomic Energy Agency 2002). Some of the heat from the Soviet Union's BN-350 fast reactor was used for desalination. However, many industrial processes require higher-temperature heat, so advanced reactors with higher outlet temperature can expand the potential customer base. Chapter 2 and Appendix F discuss the current size of this potential market. While not as large as the electricity market, the heat market could potentially support hundreds of small- to medium-sized reactors. In this way, nuclear energy systems could reduce the large carbon footprint of the industrial sector in the United States and around the world. The market for process heat could be larger if society becomes more serious about shifting to hydrogen or synthetic fuels.

Notable experiments with truly high temperature gas-cooled reactors (HTGRs) began in the 1960s.[4] The United Kingdom's Dragon facility, built in 1964, was used to test fuel and materials and not to generate electricity. In the United States, the Peach Bottom 1 reactor, in Pennsylvania, was an experimental HTGR. It was connected

[3] The U.K. National Nuclear Laboratory-led Small Modular Reactor (SMR) Feasibility Study of December 2014 analyzed two scenarios. In scenario A, SMRs were more costly on a per-unit basis, but they could serve pockets of the market that were too small for large LWRs. In scenario B, SMRs were assumed to reach cost parity with large LWRs and compete head-to-head for the whole market. Interestingly, the U.K. study did not explore the possibility that SMRs would be cheaper than large LWRs.

[4] A large number of operating nuclear power stations have been gas-cooled. Some of the earliest were built in the U.K. and France starting in the 1950s when the design also produced needed weapons material. A later, advanced gas-cooled design using carbon dioxide as the coolant became the workhorse for the U.K. nuclear power fleet, many of which remain operational today.

to the grid in 1967 and operated until 1974. Germany's AVR was another experimental HTGR; it was connected to the grid in 1967 and operated until 1988. A commercial-scale HTGR was built at Fort St. Vrain in the U.S. state of Colorado and operated commercially from 1979 to 1989. It demonstrated the very high thermal efficiency achievable in these designs, but also had operational problems related to the helium circulator. Germany's THTR (where 'TH' stood for the thorium fuel) was another commercial-scale HTGR that began commercial operation in 1987, but it was permanently shut down the next year. In 1999, Japan's experimental high-temperature test reactor began operation. More recently, China has been operating a test HTGR known as the HTR-10. Current plans envision a full commercial-scale, six-module version known as the HTR-PM 600. A two-module version is currently under construction as Unit 1 of the Shidao Bay Nuclear Power Plant. It is being built by the Chinese State Nuclear Power Technology Corporation (SNPTC). The first of the two Shidao modules is expected to come online in 2018.

Over the years, the product focus for HTGRs has varied between electricity generation and industrial process heat. Early experimental HTGRs produced electricity, although if the concept proved viable, it was understood that the process heat market was a candidate use. More recently, as the problem of climate change has grown increasingly salient, the focus has shifted to industrial process heat. HTGRs were seen as offering one of few low-carbon options for supplying industrial process heat. In the United States, the Energy Policy Act of 2005 established the Next Generation Nuclear Plant (NGNP) program to develop a very-high-temperature reactor (VHTR) for industrial purposes. The mission of the associated NGNP Industry Alliance is to seek out and promote industrial uses for HTGR technologies, which provide high temperature process heat for industrial applications and which promise to provide new sources of hydrogen and ways to shift chemical and fuels production to new feedstocks with reduced greenhouse gas emissions (NGNP Alliance 2018). However, in light of cheap natural gas, the NGNP program is on hold in the United States. Most recently, there is renewed interest in using HTGRs primarily as a source of electricity. The German design adopted for the Chinese HTR-PM is an example, as is X-Energy's pebble bed design. The Chinese project is intended to pave the way eventually for a larger-scale plant with 600 MW_e capacity using six reactor units. China National Nuclear Corporation (CNNC) is looking to export the new design to Saudi Arabia, Dubai, and South Africa, among other countries. Of course, design variants can be optimized for the electricity market, for the heat market, or for co-generation.

Flexible Operation

The high penetration of renewables in some markets, coupled with natural gas power plants to provide flexible backup capacity, has replaced traditional baseload power plants. In such markets, LWRs may be forced into load-following mode (as is now the case in France and in certain regions of the United States), and will incur the associated economic penalty for not operating at full capacity all of the time. To minimize or obviate this economic penalty, any of the advanced nuclear systems that operate at high temperature could provide a variable mix of power and heat (or other energy products), both to accommodate the intermittency of renewables and to provide power when renewables are not available (e.g., on cloudy or windless days), while the reactor would operate at steady 100% thermal output. It is important to note that a reactor that produces multiple energy products at variable levels will, by definition, be more expensive to build than a reactor that produces a single product, because the two product lines must be included in the design. However, if the second product has more value than electricity, which is a low-value commodity, it may be possible to offset the extra investment cost. Detailed economic analysis would be required to assess these tradeoffs.

Alternatively, a topping cycle fired by natural gas has been proposed to provide variable power, again with the reactor operating at steady 100% thermal output. As noted earlier, an example would be an FHR that uses a Nuclear Air-Brayton

Combined Cycle as a topping cycle (Forsberg 2014). This type of system offers a potential new mission/market for advanced reactors in addition to traditional baseload electricity generation. While greater revenue could be expected from such a system because of its higher overall thermal efficiency compared to a combined cycle natural gas plant, the cost implications have not yet been evaluated in detail. Furthermore, under a stringent carbon constraint, designs that use natural gas would not be viable.

A third approach is to use heat storage and then modulate the reactor's electrical output and heat storage reservoir based on the need (e.g., with a salt loop) (Sullivan 2017). Another innovative idea for HTGR applications is to operate the plant such that the high-heat-capacity graphite in the core is used to absorb load fluctuations and electrical output is allowed to vary depending on the helium inventory control (Yan 2017). Other examples of thermal heat storage that can be used with any reactor system are discussed in Chapter 2. Many of these ideas are still at a conceptual stage and further economic analysis is warranted to determine their potential market viability.

Microreactors for Off-Grid Electricity and Heat

Very small reactors (i.e., less than 10 MW_e), also known as microreactors, could provide power and/or heat for a range of microgrid applications, including to serve mining sites, remote communities, offshore platforms, industrial complexes, military bases, or expeditionary forces that need a secure energy supply (Ontario Ministry of Energy 2016). To maximize their utility and minimize their cost, microreactors would have to be designed for several key features including easy transportation to the site where they will be used, autonomous operation, and ability to be coupled to ultra-compact power conversion systems such as Stirling engines, supercritical CO_2 cycles, or direct conversion devices. Examples of microreactors include Kilopower, eVinci, OKLO, and Holos Gen.

Scaling reactors down to very small sizes has certain technological disadvantages. For example, simply because the ratio of surface area to volume increases as the reactor becomes smaller, a higher fraction of the neutrons born in fission leak out before contributing to the chain reaction. Additional equipment can be included to reflect the neutrons back to the core, but this makes the reactor larger and adds to expense and materials. At the same time, small size also offers potential advantages. For example, the increased ratio of surface area to volume makes it easier to remove heat without recourse to active safety systems. It may also be much easier to embed microreactors and to provide seismic isolation.

Potentially compensating for any net diseconomies of scale is the fact that products for off-grid markets can be sold at a much higher price point than products for on-grid systems. For example, the main competing technology for off-grid power is a diesel generator, which has a high unit cost of power. Therefore, a new microreactor design could be profitable even where its unit electricity cost cannot be brought down low enough to be competitive against other on-grid generation technologies.

A number of entrepreneurs and investors are exploring microreactors as a first step on a more viable path to commercializing new reactor technologies. The idea is that off-grid uses are an early, more promising market for the first incarnations of such technologies. The small size of the reactor not only reduces the initial investment required,[5] it also enables the use of factory production techniques that can be gradually improved as production scales. If success can be achieved initially in off-grid markets, then the process of iterative innovation could open portions of the grid-connected electricity market to microreactor technology over time. Such iteration could take two very different pathways. Along one, microreactors are scaled up to larger reactor sizes so as to benefit from economies of scale. Along another, the

[5] However, the very large up-front investment in design, engineering and licensing required for any new reactor technology—on the order of roughly $1 billion—is largely independent of the size of the reactor to be built from the new technology. The investment can be lower if the design is leveraging an existing technology.

reactor size remains small and suitable for factory production, and as unit production costs decline with cumulative experience, it becomes economic to assemble many reactors in one plant location and compete for the on-grid market that way.

Both avenues offer a realistic answer to the important question of how a new technology can overcome financing challenges. They rely on a gradual investment process that is iteratively driven by commercial considerations and repetitive adaptation to information garnered along the way. Many developers find this approach more plausible and more attractive than a large-scale program designed to leap quickly from research to the construction of a multi-billion-dollar piece of infrastructure.

A prime example of another technology that has been successfully commercialized this way is the solar photovoltaic (PV) module. In this case, too, initial commercial applications centered on off-grid uses. As production expanded, PV manufacturers made gradual improvements in their production methods. They repeatedly transitioned from one production method to a new, lower cost method, which was itself then gradually improved before being abandoned for another. Costs for PV modules have continuously declined with cumulative production (Harmon 2000).

Optimism that microreactors can follow the deployment example set by solar PV modules must, however, be tempered by the recognition that there are important differences between the two technologies. A solar module converts one form of energy into another, and it generates little in the way of by-products. A nuclear power plant produces energy from mass and generates a number of by-products that must be managed, including heat, fission products, and other components of spent fuel. Many nuclear power plant systems are built for the purpose of managing these by-products, and for doing so under a range of postulated accident scenarios. Furthermore, maintenance activities in a radioactive environment are more complex than in other types of energy facilities.

As we highlighted in our discussion of costs in Chapter 2, nuclear island and turbine generator equipment are not the primary contributors to the capital cost of a nuclear plant. Rather, it is the on-site construction of the larger plant, including the installation of the many plant components, that is the main cost driver. Therefore, gaining efficiencies through the repetitive manufacture of the reactor itself does not solve the cost problem for a nuclear plant as a whole. The problem lies in the larger facility. Where we have emphasized the promise of factory production and modularization for reducing nuclear costs, it has been where they facilitate improved economics for the plant as a whole, not just the reactor. Applying this insight will be a challenge for companies interested in scaling microreactor technology. This is an important area for research and for innovation in both design and execution.

From a public policy perspective, it is important to consider how microreactors serve the objective of reducing carbon emissions. The off-grid electricity market is extremely small and makes a tiny contribution to global emissions, so developing microreactors to serve this market can only make a small contribution to reducing global greenhouse gas emissions. Deploying the technology in off-grid applications may eventually lead to options for addressing the on-grid market, but at a much later date.

In summary, microreactors designed for high-value, off-grid uses offer an innovation path that minimizes the scale of investment needed for early deployment. Initially targeting a small, but high-value market reduces the early pressure to achieve immediate success in lowering unit costs. Rather, it may provide a pathway to realizing cost reductions over time through experience and iterative re-design. However, there remain sizeable initial up-front design and testing costs, which do not scale down linearly with the size of the reactor design and which must be amortized over a smaller, but higher value market.

Desalination

Desalinated water is an increasingly important commodity in arid regions of the world that have limited access to freshwater resources, such as the Middle East (Lienhard, et al. 2016). Desalination can be achieved through reverse osmosis, which requires only electricity or a variety of low-temperature, heat-based processes. However, the size of the market is quite small: Meeting current global energy demand for desalinated water would require approximately 16 GW of electric generating capacity, assuming production of 100 million cubic meters of desalinated water per day using reverse osmosis with an energy requirement of 3.5 kWh per cubic meter and a 90% capacity factor for the power plant. This demand can be easily satisfied by nuclear reactors that are generating electricity and/or are equipped with an appropriate low-temperature heat extraction loop.

Generation-IV Reactors Targeted to an Improved Fuel Cycle

A variety of Generation-IV designs advertise fuel cycle benefits, but prime among them are fast reactor designs. Fast reactor systems are better suited for actinide transmutation/destruction than a thermal reactor system because of better fission-to-capture ratio in a fast spectrum than in a thermal spectrum. Although fissile isotopes can undergo fission in a thermal reactor, the probability of capture for fertile isotopes in a thermal spectrum are large enough to cause transmutation to higher order actinides (i.e., isotopes of americium and curium) that are even more difficult to manage than uranium and plutonium in terms of decay heat production and radiotoxicity for reprocessing and disposal.

A number of test or experimental or prototype fast reactors have been built in a number of countries, and some builds have included the provision of grid-connected electricity. These include the Dounreay dual fluid reactor (DFR) and prototype fast reactor (PFR) in the United Kingdom, connected in 1962 and 1975, respectively; Fermi 1 in the United States, connected in 1966; the Phenix in France, connected in 1973; the BN-350 in the former Soviet Union, connected in 1973; the KNK II in Germany, connected in 1978; Monju in Japan, connected in 1995; and the CEFR in China, connected in 2011. The U.S. Experimental Breeder Reactor II (EBR-II) supplied electricity from 1964 to its closing in 1994. The Prototype Fast Breeder Reactor (PFBR) is now under construction in India. Commercial-scale fast reactor builds include France's Superphenix, which was connected to the grid in 1986 and permanently shut down in 1998, and the BN-600 and BN-800 in Russia, which were connected to the grid in 1980 and 2015, respectively (both are still in operation).[6]

Performance experience at these reactors has been varied, which is not surprising given the prototype nature of the plants and the diversity of designs and missions they represent. Many of the reactors experienced operating difficulties, including a few more troublesome accidents that required long shutdowns, which drove capacity factors to remarkably low levels.[7] For example, the lifetime capacity factor of Britain's PFR is 27%. In the United States, Fermi 1 supplied electricity in only one of the seven short years of its operating life, whereas EBR-II is said to have operated smoothly throughout its three decades of experimentation and utilization and to have achieved a capacity factor of 80% during the last decade of its life.[8] France's Phenix plant is considered a success, albeit with a capacity factor of only 41% over 35 years of production. By contrast, the Superphenix was a commercial failure. It produced power in only six years of its

[6] With the exception of the EBR-II, the reactors mentioned here are those included in the IAEA PRIS database.

[7] Except as otherwise noted, all capacity factor data are from the IAEA PRIS database (The Database on Nuclear Power Reactors 2017).

[8] The EBR-II is not included in the IAEA's database. The 80% figure is taken from Till and Chang (2011). See also Koch (2008).

13-year life, with a cumulative capacity factor of 8% before it was permanently shut down.[9] Japan's Monju fast reactor was another commercial failure. Shortly after it was started, a sodium leak and fire forced a shutdown for repairs. A series of problems kept Monju offline for almost all of the years it was commissioned before the Japanese government finally made the decision to permanently shut it down. The best performance for fast reactors has been achieved in Russia. The BN-350 operated for 25 years, but the IAEA only has data for the last seven years when the capacity factor fluctuated between 19% and 72%, averaging 45%. Russia's subsequent prototype fast reactor, the BN-600, has a much better track record over its 35 years of operation to date, with a lifetime capacity factor of 75%. Russia's new BN-800 achieved a capacity factor of 85% in the first few months of operation.

In the early days of the nuclear power industry, many analysts predicted that a vibrant market for electricity generated exclusively by thermal reactors would quickly exhaust the stocks of uranium that were thought to be available worldwide, based on the estimates of that time. Thus, a chief motivation for pursuing fast reactors historically was to develop breeder reactors that could produce additional fissile material to stretch limited natural uranium resources. In many countries, this was viewed as a matter of assuring energy security and sustainability. However, the original logic for fast breeder reactors dissolved long ago. The uranium resource has proved much more abundant than had been imagined in the mid- to late-20th century, and forecasted industry growth rates never materialized. Consequently, the cost of raw uranium never escalated as feared, so that the extra capital cost of fast breeder reactors has continued to far outweigh any potential savings on fuel costs (Bunn, et al. 2003) (De Roo and Parsons 2011) (Kazimi, et al. 2011) (Cochrane 2010). For this and other reasons, state funding for the deployment of new fast breeder reactors disappeared in many countries.[10]

More recently the focus of research on fast reactors has shifted from so-called breeders, which maximize the useful recycled fuel produced, to so-called burners, which minimize the most harmful waste elements from stockpiles of spent nuclear fuel—a mission known as actinide management. Using fast reactors to recycle spent fuel does reduce the volume and heat load of spent fuel ultimately destined for final disposal. So, in light of the widely held belief that this would be the dominant practice in the future, many nations institutionalized a commitment to recycling in their national waste management plans. In pursuit of its long-held waste management strategy, France is tentatively planning to build a new prototype fast reactor, ASTRID, with the support of the European Union and perhaps Japan. In the United States, there was interest in making a future shift to recycling[11] but that objective has waned in recent years, although research in the area continues. Russia, which has had the most success in operating fast reactors, plans to build the commercial scale BN-1200. Russia intends to be able to offer complete fuel-cycle services, including waste management, as a critical element of its commercial export portfolio. Several of the companies pursuing Generation-IV fast reactor designs also advertise reduced waste volumes

[9] Much of the time that the Superphenix was shut down was because of regulatory reviews and public policy debates, so the cumulative capacity factor is perhaps not representative of the reactor's performance given the narrowly defined engineering problems it experienced. However, even after eliminating these periods from the calculation, Superphenix was available for power generation in only 34 months out of 70, and during those months it was available in only 41.5% of the hours, which yields a total availability of 20%. One analysis points to the final 16-month operating period and, adjusting certain elements of the usual calculation, reports an availability factor for this period of 51.3%, "which is an honourable result for a prototype with less than a year equivalent full power, and which had not time yet to achieve all the necessary 'debuggings'" (Guidez and Prêle 2017).

[10] While funding for the actual deployment of fast reactors has dried up, several countries have maintained active research programs targeted to issues such as new fuel designs, new materials, etc., that would be relevant to some future deployment of reactors of this type.

[11] For example, see U.S. Department of Energy (2003).

as one of this technology's advantages, a point that has also been made by the U.S. DOE and the Generation IV International Forum.

It is difficult to make a case for directing research dollars to innovative designs that focus solely on breeding to conserve fuel resources or on burning actinides when the real target should be designs that reduce the capital cost of nuclear energy. Fuel cost is typically only 5% of the total LCOE for different reactor technologies. Similarly, the realized or projected dollar cost of waste management is a small fraction of the LCOE from nuclear, so reducing the volume of waste has a very limited potential to reduce the LCOE of nuclear energy. In fact, an all-in analysis shows that the extra capital cost of fast breeder or burner reactors far outweighs any cost benefits from reducing the volume of waste ultimately sent for disposal (Bunn, et al. 2003).[12, 13] The issue of fuel economy or fuel recycling distracts from the essential focus on reducing reactor capital costs, which account for more than 70% of the total LCOE for nuclear generation.

Although reduced waste streams cannot materially reduce the LCOE of nuclear power, this feature of fast reactor designs may have an important role to play in public acceptance of nuclear energy in some countries. Public concern about radioactive waste is a critical issue for nuclear energy, so a case could be made in favor of a system with a different waste stream. However, it must be admitted that the problem of public acceptance of nuclear energy goes well beyond the technical character of the waste issue (including the volume of waste that needs to be disposed of and the level of hazard it presents). So, while there might be some modest benefit in engaging public opinion, the problem of public acceptance remains.

Some research into fast reactor designs is focusing on improvements to reduce capital costs while other research is looking at long-lived all-uranium cores to avoid recycling to obtain fissile material. Some new fast reactor designs emphasize smaller size and modularity, which may serve to lower unit capital cost. Whether cost reductions can actually be realized has yet to be proven out in practice. Of course, if a new design could dramatically reduce the capital cost of fast reactors, that would directly lower the LCOE. Any reduction in waste management costs would be an ancillary benefit.

Recommendation:

Future research, development, and demonstration (RD&D) funding should prioritize reactor designs that are optimized to substantially lower capital costs, including construction costs. Innovations in fast reactors that are advertised on the basis of fuel cycle metrics are unlikely to advance commercial deployment.

Proliferation

In the context of fuel cycles and efforts to limit the proliferation of nuclear materials or expertise that could be used for nuclear weapons, the reactor is not the principle concern. Rather, the primary concerns are associated with uranium enrichment and/or reprocessing facilities; in other words, the front-end and back-end fuel cycle facilities that could be a source of weapons-useable materials. Establishing enrichment and/or reprocessing capability is not an economic choice for small reactor programs. Current IAEA material control verification activities would have to be followed for new entrant countries if they were to employ enrichment facilities for low-enriched uranium or if they were to undertake reprocessing. Nevertheless, proliferation will remain an issue of concern for many advanced

[12] Relatedly, proponents have argued for fast reactors as a way to manage legacy stockpiles of nuclear waste—i.e., as an incinerator that produces electricity as a by-product. This argument may have some merit, but it implicitly concedes that a fast reactor is not cost competitive for producing electricity under other circumstances.

[13] Moreover, most advertisements of the waste reduction benefits credited to fast reactors naively imply a proportional relationship between volume and cost.

reactor concepts. Many of them can operate on or have demonstrated the use of alternative fuel cycles using thorium or plutonium. Proliferation concerns need to be addressed for concepts that propose to use fuel recycle, for pebble bed systems, and for thorium-based MSRs that employ a delay tank to allow protactinium decay to the fissile nuclide uranium-233. In all of these cases, the concern is the separation of fissile material in a non-safeguarded form that could be diverted for nefarious purposes. In particular, on-line refueling (in the case of pebble bed systems) and liquid-based fuel systems (in the case of MSRs) need to be considered. These processes result in new physical reactor configurations that will need to directly address the intrinsic (physical and technical design characteristics) and extrinsic (institutional arrangements) measures that are in place to prevent the theft, diversion, or misuse of fissile material. Moreover, additional attention will be needed at the design stage to develop material accounting approaches for dissolved fuel systems given their differences from conventional solid fuel reactor systems. Regardless of the commercial entity involved and the reactor technology being considered, safeguards and security measures will have to be developed to meet IAEA standards as the design of these systems evolve. This has been the case for the Westinghouse AP1000, the European EPR, and, more recently, the Korean APR1400, and it will certainly be necessary if advanced reactor systems are deployed in the future on a scale commensurate with deep decarbonization of energy systems worldwide. An international methodology to systematically address these issues is found in Bari (2015).

3.5 TECHNICAL READINESS, DEPLOYMENT, DEMONSTRATION, AND COMMERCIALIZATION

Several interrelated factors affect the ability to commercialize an advanced reactor system, including (a) the readiness of the technologies and sub-systems used; (b) the need for development activities to mature the technology to the point that an engineering demonstration system can be designed, operated, and licensed; and (c) the feasibility of reaching commercial scale to confirm that performance, safety, reliability, and operability meet requirements. This section reviews the maturity of different advanced reactor systems, assessing their technical readiness and likely timelines to commercialization. Table 3.8 summarizes the key technical issues for each concept with respect to deployment, demonstration, and commercialization.

A number of organizations around the world have studied the readiness of advanced reactor technologies. Although each applies its own specific scales for the evaluation (Generation IV International Forum 2014) (Gougar, et al. 2015) (Sowder 2015), broadly the technologies can be grouped according to readiness as follows:

- **Lowest maturity**
  LFRs (nitride fuel), GFRs, MSR (fast) and MSR (thermal using salt other than FLiBe)
- **Low to moderate maturity**
  Advanced SFRs, FHRs, MSRs (thermal using FLiBe), LFRs (oxide fuel), VHTRs (900°C outlet)
- **Moderate to high maturity**
  Small conventional SFRs and modular HTGRs (750°C outlet)

These ratings are based on three primary criteria: (a) the extent of further technology development needed to resolve technical, design, and/or licensing issues, especially for fuels, cladding, coolants and/or moderators, and combinations thereof for which little to no data exist on their behavior in a neutron flux and/or at prototypical temperatures and mechanical stresses; (b) prior successful operating experience with the integrated system (or one similar to it); and (c) the level of existing safety demonstration of the system or its key components/subsystems. In general, the technology development issues identified in Table 3.8 for lower maturity options are related to the viability and performance confirmation of key reactor features (fuel, coolant, structures), whereas the technology development issues for higher maturity options are related to licensing qualification and extension to new performance regimes.

Table 3.8: Advanced reactor operating experience, technology development issues, and technical readiness

Coolant	Technology and Prior Operating Experience	Technology Readiness Level	Outstanding Technology Development Issues
Helium	Small HTGR; half dozen around the world	Moderate to high for 750°C outlet design; Low to moderate for 900°C outlet temperature design	For designs with 750°C outlet temperature, complete fuel and graphite qualification by 2022. For 900°C outlet temperature, additional work is required for intermediate heat exchanger and other system components that can operate at that high temperature.
	GFR; none	Lowest. A gas-cooled fast reactor has never been built anywhere in the world	Fuel requires qualification. Internal structures must be able to sustain high levels of radiation damage for the long-lived cores being proposed. Safety systems require demonstration.
Liquid Metal	Small SFR like PRISM or ARC; several dozens around the world	High for traditional small SFR. Medium for longer lived, higher burnup breed-and-burn cores or for SFRs using advanced steel alloys that have yet to be qualified	Source term experiments for metallic fuel to reduce conservatism in safety analysis. Major fuel qualification effort if reactor is to be used with transmutation fuel. Development of a fuel vendor for commercialization. For more advanced SFRs, longer lived, higher burnup breed-and-burn cores need to be demonstrated and concepts using advanced structural alloys need to be qualified
	LFR; Russian subs (none elsewhere)	Lowest	Corrosion and erosion of coated cladding by lead at higher temperatures (≈700°C–750°C outlet) and higher flow velocities. Testing of passive safety behavior of the plant/key systems. Major qualification effort is needed for transmutation fuel (if reactor is used in that manner). Some concepts favor the use of nitride fuel—qualifying this fuel system in an LFR would require a significant effort and increase time to reach commercial readiness.
Molten Salt	FHR; none	Low to moderate	Prove REDOX corrosion/control in non-uranium-based salt in the presence of a neutron field. Need a demonstrated material solution (strength, corrosion resistance, irradiation stability) for long-term operation. Demonstrate tritium mitigation solution. Test passive safety aspects of the plant/design.
	MSR thermal; two thermal experiment systems (MSRE and ARE). No power conversion in these experiments	Low to moderate for FLiBe-based thermal reactor systems. Low for other salts in both thermal and fast spectrums. Most systems outside the reactor dealing with removal of fission products, actinides and fissile/fertile material are low maturity. Such systems are needed to maintain reactivity at high burnup. Many of these proposed reactor systems have not yet been built anywhere in the world.	Depending on the design, long-term corrosion is an issue unless major components are replaced frequently as is proposed in some designs. Demonstration of REDOX control in a neutron field in the salt will be required if the salt is not FLiBe. For lithium-containing salts, tritium mitigation solution must be demonstrated. Behavior of noble fission products plating out in IHX and corrosion and embrittlement by fission product tellurium (leading to cracking) over longer operation are also uncertain. High nickel alloy (Hastelloy X) developed at Oak Ridge National Laboratory in the United States is not code qualified for use by the American Society of Mechanical Engineers (ASME). This alloy also has poor irradiation stability and insufficient strength above 700°C. A demonstrated material solution is needed for long-term operation. (Some designers propose replacing structural materials every 4 to 6 years for this reason with an associated increase in cost and reduction in availability.) Unclear how inspection requirements per ASME Section XI will be implemented. Instrumentation in this system will require some development. Proliferation and materials accounting issues remain in this system since fission products and actinides are removed from the system and fissile material can in principle be diverted.
	MSR fast; no fast systems have ever been built	Lowest. Similar concerns as thermal MSRs	Chloride salts, strategies for corrosion control must be demonstrated. A materials solution must be demonstrated. Similar issues on inspection as MSR thermal systems. High power densities in some systems require high flow rates that can lead to erosion/corrosion concerns. Also, high flow rates can lead to very low delayed neutron fraction in the core, which makes reactivity control problematic.

Historical Experience

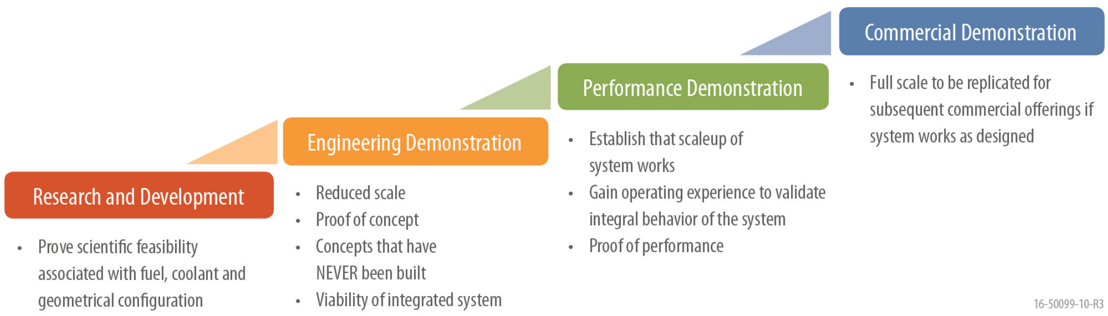
Historically, nuclear energy systems (LWRs, SFRs, and HTGRs) have passed through a number of developmental steps prior to commercialization, as shown in Figure 3.5 (Petti, et al. 2017):

- Research and development to prove the *scientific feasibility* of key features associated with fuel, coolant, and geometrical reactor system components and configurations.
- Engineering demonstration at reduced scale for *proof of concept* for designs that have never been built. The goal at this stage is to demonstrate the viability of the integrated system. Historically, these engineering demonstrations have involved very small reactors (less than 50 MW_e).
- Performance demonstration(s) to confirm effective scale-up of the system and to gain operating experience to validate the integral behavior of the system (including the fuel cycle in some cases) resulting in *proof of performance*.
- Commercial demonstrations that will be replicated for subsequent commercial offerings if the system works as designed.

We have deliberately avoided the terms 'demonstration,' 'prototype,' or 'first-of-a-kind,' in describing these steps, since these terms can be somewhat ambiguous depending on the context in which they are used. In almost all cases, new reactor systems historically were connected to the grid to enable electricity production during this development process. Similar development steps apply in the chemical and offshore oil industries.

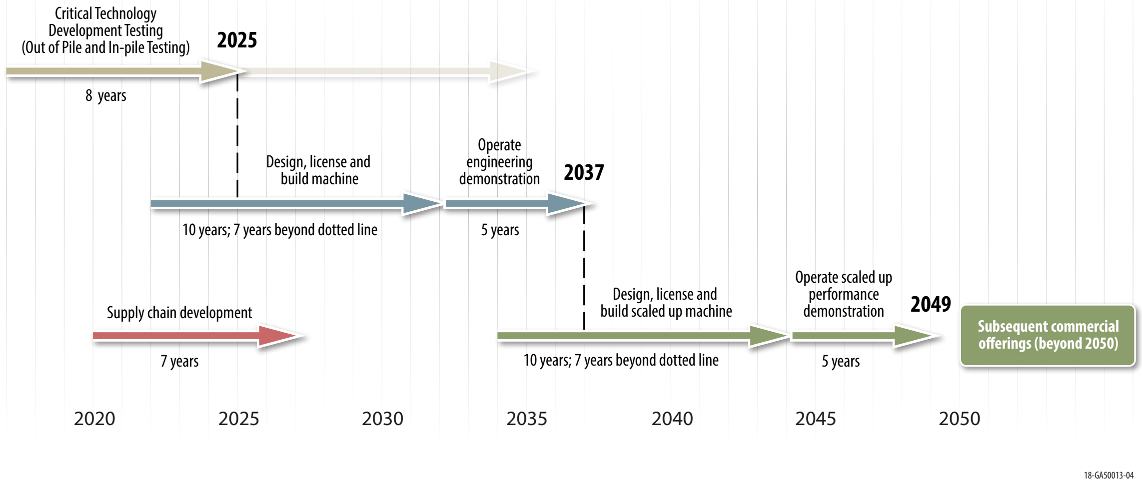
Similar steps are needed, particularly for the less mature technologies (i.e., LFR, FHR, MSR, and GFR), to complete required technology demonstration activities, gain operating experience, demonstrate effective system scale-up, reduce commercialization risk, and establish mature supply chains. These items are all important prerequisites for establishing viable commercial offerings for these technologies. Based on the maturation trajectories of the Integral Fast Reactor project (Till and Chang 2011), which led to GE's PRISM design; the NGNP project (and earlier U.S. DOE funding of HTGR programs), which led to a mature HTGR (Idaho National Laboratory 2011); the NuScale small modular LWR (McGough 2017); and estimates of the R&D necessary to advance MSR technology (Engle 1980) in the United States in the late 1970s, the cost and time required to mature a nuclear technology is significant: in the range of $1–$2 billion per concept, corresponding to several million person-hours of design/engineering work and 15–20 years to get to the point where a coherent validated demonstration system can be designed with the level of technical confidence demanded by regulatory authorities. In our assessment, an initial commercial offering could occur in 2030 for SFRs and HTGRs, with follow-on commercial units between 2030 and 2050. Early-phase developmental machines could be anticipated in the 2030–2040 timeframe for the less mature technologies.

Figure 3.5: Historical paradigm for commercializing new nuclear power technologies



(Petti, et al. 2017)

Figure 3.6: Notional advanced reactor development schedule for less mature technologies based on historical practice



Test beds also need to be established for these less mature technologies. In particular, sufficient single-effects feasibility R&D to resolve some of the issues in Table 3.8 is a critical bottleneck that must be overcome early in the development process to enable the low-maturity technologies to progress to the next step of technology readiness. Properly scaled out-of-pile loops can help qualify the components outside the reactor itself (e.g., steam generator, intermediate heat exchangers, pumps, valves).

In-pile experiments and test loops can be used to qualify components (e.g., structural materials, fuel, control rod sleeves, moderator rods) that must be exposed to the actual environment in the reactor core to assess issues related to material swelling, component performance (e.g., degradation, corrosion, stability), and lifetime. Development and qualification of fuels and materials for fast reactors such as the lead-cooled fast reactor and chloride-salt fast reactor concepts will require irradiations in test reactors with significant fast neutron fluxes—i.e., on the order of 10^{15} neutrons per centimeter squared per second ($n/(cm^2\text{-sec})$) and higher. Such capability currently does not exist in the United States. However, fast-neutron test reactors are available in Russia and will soon be available in China, India, and possibly France. If agreements can be reached to collaborate with any of those countries, there may not be a compelling reason for the United States to develop a domestic duplicate. Furthermore, it is worth noting that development and commercialization of most of the Generation-IV systems does not require a fast-neutron test reactor because their fuels and materials are either already qualified (for example, in the case of traditional sodium-cooled reactor designs) or the expected fast neutron fluxes are low (in the case of all thermal-neutron reactor designs).

Reduced-scale engineering demonstrations may be necessary for systems that have never been built before to understand the integrated behavior of the system prior to scale-up to a performance demonstration of commercial size. In the United States, DOE's national laboratories are the logical location for developing these capabilities in collaboration with private industry. Similar research laboratories exist in other countries that have established nuclear energy programs.

While this traditional process for nuclear reactor development has been used in the United States and around the world for LWRs, sodium-cooled, and gas-cooled reactors, it is very lengthy. Figure 3.6 illustrates a typical development timeline based on historic experience. While some of the original LWRs back in the 1960s were able to complete this approach in 13 to 15 years, today the process can be expected to take much longer because of the increased level of knowledge needed to comply with regulations, the introduction of codes and standards (e.g., Institute of Electrical and Electronics Engineers (IEEE) Class 1E, ASME Section 3) that did not exist when nuclear power was first developed, and the greater assurance of performance demanded by investors given the magnitude of the financial resources required at each step.

Of particular importance is the need to mature the supply chains for advanced reactor systems. These reactors use different fuels, coolants, and moderators and thus only some of the existing LWR supply chain is relevant. For example, fuels used in almost all of the advanced systems require uranium enrichments greater than the current licensed limit of 5% in the United States. Currently, down blending of highly enriched uranium (HEU) is used for current research needs in the United States (BWXT and Y-12 provide these services for various DOE fuel programs.) There are no large commercial-scale fuel cycle facilities anywhere in the world that can deliver such feedstocks, termed 'high assay low enriched uranium' (HALEU) (Schnoebelen and Kick 2017). While the centrifuge technology used to enrich uranium is certainly capable of producing 20% uranium-235, there are two very long lead-time aspects to actually delivering HALEU: the process of licensing such facilities (due to issues related to criticality and materials safeguarding) and second, commercial-scale transport packages for most chemical forms of HALEU must also be designed and licensed. This second aspect could require a decade-long project. It might be avoided or minimized by co-locating enrichment, chemical conversion, and fabrication facilities at a single site to avoid the need to transport intermediate uranium products on public highways. Another example of a supply chain challenge involves pumps for sodium, lead, and salt systems and circulators for gas-cooled reactors. These are unique components that will require industrial capability to be developed and demonstrated.

Based on numerous studies of the technology readiness of different advanced reactor options, the maturity of the underlying technologies, and the amount of information (a mixture of operating experience, testing, data, and analysis) necessary to complete a validated design under existing licensing rules, *commercial* deployments (the initial commercial deployment and subsequent commercial units shown in the blue box in Figure 3.5) can be expected in the following timeframes:

Reactor Technology	Initial Commercial Deployment	Subsequent Commercial Units
NuScale and other LWR SMRs	Between now and 2030	Between 2030 and 2050
SFRs and HTGRs	2030	Between 2030 and 2050
FHRs, MSRs, LFRs, VHTRs, and advanced SFRs	Beyond 2050	Beyond 2050

Recognizing that these are very long timelines that effectively require governments to invest in advanced nuclear technologies (given the risks and timelines involved, no other entity is likely to be interested), we next examined opportunities to reduce the overall development and deployment schedule.

An Accelerated Deployment Paradigm for Nuclear Energy Innovations

The traditional development and deployment paradigm for commercializing nuclear energy technologies is long and quite costly. Today, both HTGRs and SFRs can proceed directly to a commercial offering based on the experience base that already exists worldwide. (Plants involving both technologies are already under construction or operating in China and Russia.) However, for *the less mature technologies* (e.g., FHR, MSR, LFR, GFR), we have outlined a different approach or strategy that, by combining proof of concept and proof of performance in a single full-scale machine, could substantially accelerate the overall deployment paradigm. This new approach comprises three elements:

- Develop a robust design for the reactor, with extra margins in thermo-mechanical terms so that ASME stress allowables are not challenged, to bound uncertainties in operation and safety, as was done in the early days of LWRs.

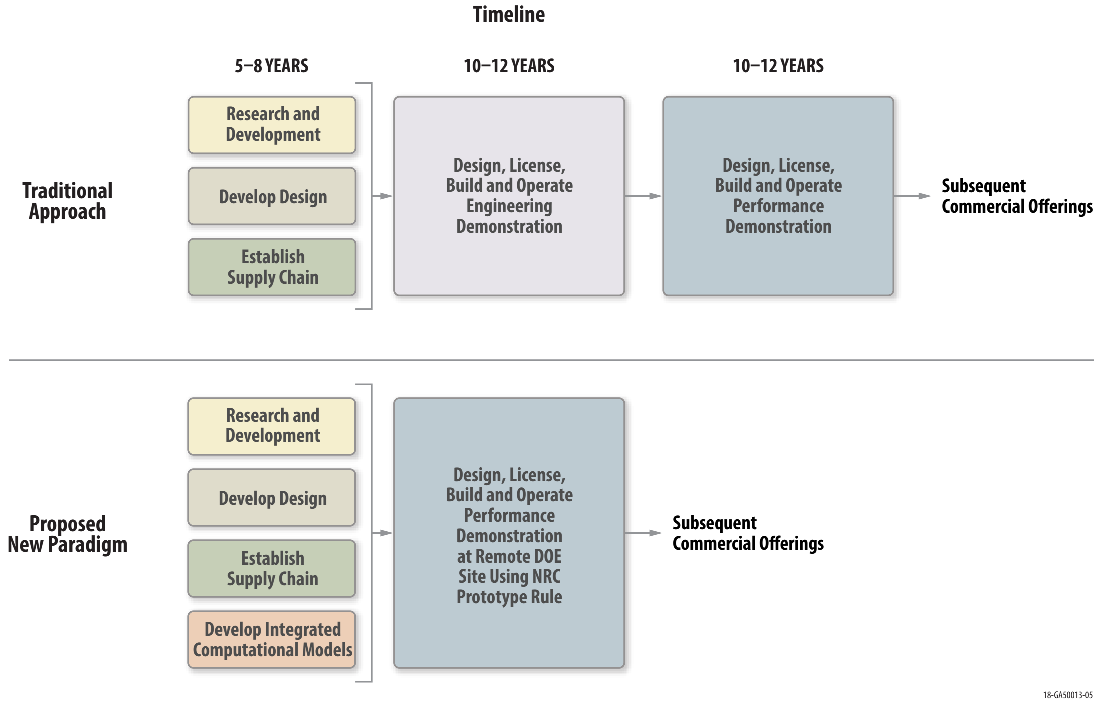
- License the reactor using the NRC 'prototype rule.' Prototype reactors have particular significance in NRC regulation. If a nuclear reactor is constructed using designs that "differ significantly from light-water reactor designs that were licensed before 1997, or use simplified, inherent, passive, or other innovative means to accomplish their safety functions," (U.S. Nuclear Regulatory Commission 2018a) the applicant must demonstrate the safety of the plant using additional testing. NRC regulations provide two avenues for demonstrating safety:
  - Combination of analysis, appropriate test programs, and operating experience; or
  - Operation of a prototype reactor under normal and off-normal conditions.

  If a prototype reactor is used to demonstrate safety "...the NRC may impose additional requirements on siting, safety features, or operational conditions for the prototype plant to protect the public and the plant staff from the possible consequences of accidents during the testing period" (NRC 2018b). The prototype class of reactors (in its current form) was not added to NRC regulation until 2007 (NRC 2007). No applicant has pursued licensing of a prototype reactor under this new rule and little NRC guidance exists on the process for prototype reactor licensing. Based on feedback from stakeholders on the topic of advanced reactor licensing, NRC staff is currently drafting white papers and more detailed guidance on prototype reactors (NRC 2017).
- Locate the reactor at a site that features low population density and a large site boundary as an extra layer of safety and as a way to effectively remove many safety constraints on the design. This also allows the facility to undergo a range of integral tests to demonstrate safety performance without the need for additional safety systems. Significantly reducing public safety concerns in this manner allows for a less stringent burden of proof and/or exemptions from some safety regulations. For example, the computer codes used to design the plant do not have to be completely validated, demonstrations of passive safety features are not required before the plant is built, inherent safety demonstrations are conducted during the operation of demonstration plants as has been done with both HTGR and SFR technologies. Examples of favorable sites include the Idaho National Laboratory, Savannah River National Laboratory, and Pacific Northwest National Laboratory in the United States; the Cadarache site in France; and the Canadian National Laboratory in Canada. These locations have the added benefit of having relevant power and nuclear infrastructure.

This strategy alters the traditional project risk profile that has been associated with nuclear technology development and deployment in the past. Historically, overall project risk was reduced in the most cost-effective manner, which usually meant building the smallest possible machine to retire early technical risk (associated with engineering demonstration for proof of concept). That machine was then scaled up in size (and in financial commitment) to address technical risks associated with proof of performance. Altering this overall project risk profile by combining the proof-of-concept and proof-of-performance demonstration steps may enable acceleration of the development and deployment timeline even if it involves greater financial risk earlier in the process. Westinghouse has in fact proposed this as a strategy for their lead-cooled fast reactor.

Historically, engineering demonstrations of early reactor concepts were performed to demonstrate proof of concept because there were so many uncertainties associated with a new nuclear concept involving new combinations of fuel, coolant, and moderator. Integrated system testing was a necessary part of the process to prove both the neutronic and thermal hydraulics aspects of the system and to provide valuable information to reduce the technical risk associated with system integration at this early stage. However, given the simplicity of most new reactor designs and today's computational capabilities (Gaston, et al. 2015), proof of concept could be established (and much of the technical risk could be removed)

Figure 3.7: Comparison of timelines under the traditional and proposed new development and deployment paradigms for nuclear reactors



by using computation as a direct tool to shorten the development cycle. Developing a computer system to simulate the coupled response of the reactor (fuel, coolant, structure, balance of plant, safety response) will be a significant challenge but is clearly less costly than constructing an extra demonstration facility. This approach is used today in both jet engine design and automobile development—for example, computational fluid dynamics are used in lieu of conducting wind tunnel tests on scale models and performance is tested at full scale.

Finally, designing a performance demonstration machine at full scale minimizes scale-up risk to validate/confirm computation simulations related to proof of concept, and allows work toward the performance demonstration objective to proceed in a deliberate manner (including prudent power ascension, tests of off-normal situations, and longer-term operation to establish the reliability of the integrated system).

In principle, this strategy could apply to a reactor of any size. However, it would not be attractive for very large reactors (on the order of 1 GW_e) because of the enormous upfront cost of the demonstration machine. At the other extreme, microreactors (smaller than 10–25 MW_e) inherently combine these two steps because the final reactor design is small enough to preclude the need for an explicit scale-up step, which is a major objective of the performance demonstration. For reactors between these two extremes, which is the size range of many of the low-maturity small modular advanced reactors, this strategy appears attractive.

This overall strategy does affect risks related to supply chain development and component integration. More work will have to occur in non-nuclear test stands to qualify components that are at or near full scale (either at vendor facilities or in dedicated test loops) and component integration risk will have to be deferred until the full-scale performance demonstration can be built and operated.

Figure 3.7 compares the traditional paradigm and our proposed new paradigm for new reactor technology development and deployment. The new paradigm is more aggressive and entails greater financial risk than the traditional approach. However, if successful it could accelerate the overall development and deployment schedule by more than a decade, approximately, such that commercial offerings could be possible in the mid- to late-2030s. If the new paradigm is not successful, significant capital investment losses could occur. Obviously even with an accelerated strategy, detailed engineering and design work (on the order of millions of person-hours) would need to be performed before construction of an engineering/performance demonstration machine could proceed. Financial aspects of commercialization are discussed in Chapter 4, which focuses on business models and policy context.

Finding:

Each advanced reactor system is at a different level of technical maturity and as such requires a number of key technology development activities to be completed before it can be commercialized. The overall time needed to reach commercialization depends on the technical maturity of the concept and prior experience with the specific reactor technology involved. More mature concepts, such as the advanced small modular reactor (SMR) design being marketed by NuScale, a sodium fast reactor, and a modular high temperature gas-cooled reactor, are technically ready for commercialization by 2030. Less mature reactor concepts, including lead fast reactors, gas-cooled fast reactors, and molten salt systems, would not be expected to reach commercialization before 2050, however, if the traditional approach to nuclear development is followed.

Recommendation:

A more innovative approach to deployment is needed to advance less mature advanced reactor designs. Under this new paradigm, proof of concept and proof of performance would be demonstrated using a single reactor that would be: (a) designed at full scale to reduce scale-up risks, (b) designed with conservative thermo-mechanical margins, (c) licensed under the prototype rule developed by the U.S. Nuclear Regulatory Commission (NRC) to provide flexibility and reduce the burden of proof typically expected in licensing, and (d) sited on a remote U.S. DOE site as an extra precaution to remove some safety constraints on the design and allow for integral testing. Using this new paradigm, development of the least mature systems could be accelerated and the expected timeframe for commercial deployment could be moved up to the mid- to late-2030s.

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Chapter 4

Nuclear Industry Business Models and Policies

This chapter discusses the actions that must be taken, by industry and government, in order for nuclear technology to continue making an important contribution to the global supply of low-carbon electricity. Decarbonization is necessary to mitigate the risks posed by climate change but it will be difficult to achieve given the magnitude of global energy demand and the scale of the infrastructure investments needed to transform existing energy systems. Developing a wide array of low-carbon technology options, nuclear among them, is vital to meeting this enormous challenge.

4.1 INTRODUCTION

As outlined in the earlier chapters, the major obstacle for nuclear energy is cost. This holds equally for the light water reactor (LWR) technology used in most existing commercial nuclear power plants, as well as for the various advanced reactor technologies discussed in Chapter 3. Government-supported R&D has already helped advance some of the crosscutting technology options discussed in Chapter 2. Integrating these options into product design and production processes to drive down costs is primarily industry's responsibility. Government policies can assist industry by establishing better frameworks within which companies can compete. Both the rules that govern power markets and the regulatory framework in which reactors are licensed, sold, and operated have an important influence on the economics of nuclear energy.

We outline three major areas for action. The first is electricity market reform so that investors can expect that competitive, cost-efficient nuclear plants will be remunerated for the full value of delivering low-carbon electricity. The second action area focuses on identifying sites and developing accompanying services to enable the accelerated deployment of certain advanced reactors. The third action area involves support for research, development, and demonstration of advanced reactors.

4.2 ELECTRICITY MARKET REFORM AND REMUNERATION OF LOW-CARBON ELECTRICITY

Chapters 1 and 2 showed that investments in new nuclear power plants are uneconomical in most circumstances under currently weak or non-existent carbon constraints. Reducing the capital cost of new plants is essential if nuclear energy is to remain a significant part of the overall electricity generation mix in the future. While plant cost is the primary issue, it is only one part of the equation. The profitability of nuclear investments also depends on how much revenue they generate. Are investments in nuclear power plants fully remunerated for the value of the electricity they supply to the grid? At present, the answer is clearly 'no.'

Nuclear Power Plants in Crisis

A dramatic result of markets' current under-remuneration of nuclear-generated electricity has been the recent closure, or announced closure, of several operating nuclear plants in the United

States before these plants reach the end of their current licenses. These early retirements are noteworthy, since the cost to construct the reactors is sunk. Even in a market where building a new plant would be unprofitable, the continued operation of a well-maintained and operated plant might be expected to be profitable. A decision to close means the wholesale price of electricity does not even cover a plant's ongoing operating and maintenance costs, including any capital investments needed to keep the facility in safe working order. While the exact circumstances for these decisions differ from plant to plant, a key issue for many closed or endangered plants is low profitability due to a very low wholesale price of power. Low wholesale prices, in turn, are driven by the record low price of natural gas, among other factors.[1]

For consumers and the broader economy, low-cost natural gas has been a welcome development because it means lower prices for electricity. Cheap natural gas has also facilitated a solid first increment of reduction in U.S. electric sector carbon emissions as natural gas-fired generation has increasingly replaced coal-fired generation. However, the simultaneous closure of existing nuclear plants undercuts that success. Because natural gas use still produces carbon emissions (albeit less than coal), nuclear plant closures always mean that carbon reductions are smaller than they could have been–indeed, in some cases these plant closures have led to a measurable increase in emissions.[2] Also, nuclear plant closures, by removing a non-carbon source from the resource mix, threaten the ability to achieve future, deeper decarbonization targets, in the United States and elsewhere.

Analyses of the cheapest ways to achieve decarbonization point to the value of keeping most of the existing nuclear reactor fleet operating. For example, a study by Haratyk estimates that in the United States, nuclear plants with a combined capacity of 20 gigawatts (GW) have operating deficits of less than $12 per megawatt hour (MWh), which suggests that a credit of this amount should be enough to keep these plants open (Haratyk 2017). Twelve dollars per MWh is a low premium to pay for low-carbon electricity. For example, it is much less than the cost of current subsidies used to incentivize additional wind generation.

Finding:

In most cases, existing nuclear is a cost-efficient provider of low-carbon electricity. Premature closures of existing plants undermine efforts to reduce carbon dioxide and other power sector emissions and increase the cost of achieving emission reduction targets.

The fact that existing nuclear plants are a cost-efficient source of low-carbon electricity has recently become salient to authorities in certain U.S. states that are wrestling with exactly how to achieve their increasingly ambitious decarbonization targets. A few states, beginning with New York, Illinois, and New Jersey, have moved to provide some of the nuclear plants in their states with supplemental credits in order to keep the plants operating.

[1] (Haratyk 2017) (Jenkins 2018) (U.S. Department of Energy 2017) However, a few closures were dictated by factors other than simply low profitability. For example, public opposition is central to Entergy's agreement to close its Indian Point units which are located north of New York City. Also, in certain cases, although the power plant was already built and long operating, it needed new capital investments in order to continue operating even to the end of the license. For example, Exelon's Oyster Creek would have needed to make investments in new cooling equipment.

[2] In New England, carbon emissions had been gradually falling prior to the closure of the Vermont Yankee nuclear plant and rose for the first time in the year after the closure. Similarly, when California closed the San Onofre nuclear plant, a portion of the power was replaced with natural gas-fired generation, which increased emissions (Davis 2016). The agreement to close the Diablo Canyon nuclear recognizes that some of its power generation will be replaced with natural gas-fired plants, again resulting in an increase in emissions.

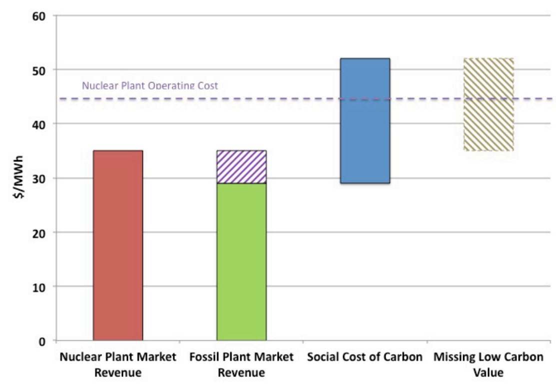
Policy makers in other countries have also revisited the value of existing plants. In 2009, the Swedish government reversed course and chose to retain nuclear power in its generation mix in light of the importance of taking action on climate change (Regeringskansliet 2009). Similarly, the French government recently postponed previous commitments to reduce the share of nuclear power in its generation mix. In contrast, Germany's decision to prioritize closing all of its nuclear plants has made it difficult for the country to achieve its 2020 greenhouse gas reduction targets.

Although many existing nuclear plants are a cost-efficient option for low-carbon generation, they are sometimes the least profitable option for prospective investors because of the way that policies for low-carbon generation are structured. Instead of applying a uniform penalty for carbon emissions, many countries have adopted an amalgam of push and pull policies that are designed to promote certain technologies and discourage others. For example, several U.S. states have introduced disincentives to coal-fired generation on the basis of its carbon emissions, but levy no comparable penalties on natural gas-fired generation for its carbon emissions. Similarly, policies such as feed-in tariffs or renewable portfolio standards have been established to reward wind and solar generation, but these policies exclude nuclear, an equally climate-friendly technology.

Figure 4.1 illustrates the situation for many nuclear plants. The values in the figure are hypothetical, though they are based on public reports for the U.S. state of New York.

The bar on the left shows the $35/MWh total market revenue earned by the nuclear plant. This is less than the plant's hypothetical operating cost of $43/MWh, so the plant is unprofitable. The second bar shows the market revenue for a comparable fossil fuel-fired plant, which, by definition, is also $35/MWh. However, in this example, the fossil plant must pay a carbon

Figure 4.1: An illustrative example of how the missing payment for nuclear energy's low-carbon attribute affects nuclear plant economics



charge of $6/MWh, so that the fossil plant's net revenue is $29/MWh. The full social cost of carbon, translated into emissions is $23/MWh, which is the third bar. The difference between the full social cost of carbon and the carbon charge levied is $17/MWh, which is shown in the fourth bar. If the nuclear plant were compensated for this difference, it would earn a total of $52/MWh and be profitable.[3]

The shortfall illustrated here using numbers scaled for the state of New York can be replicated in many other contexts. The European Union's Emission Trading System (ETS) price for carbon emissions is suppressed below what it would otherwise be due to EU policies targeting only renewables as a desirable low-carbon resource. This produces a similar situation with respect to the competitiveness of nuclear generation.

Finding:

A major source of revenue deficiency for nuclear generators today is the fact that they are not fully compensated for their low-carbon attributes. Ameliorating this deficiency would change nuclear energy's market position and conserve much existing nuclear capacity.

[3] Numbers for the existing carbon charge levied on the comparable fossil fuel-fired plant, for the social cost of carbon, and the missing carbon value are based on material from the State of New York Public Service Commission (2016).

The majority of existing nuclear plants provide a vital social benefit by delivering low-carbon electricity in a reasonably cost-efficient way. To avoid premature shutdowns and to incentivize rational investments in extending the operating life of these plants, they should be fully remunerated by electricity markets for the value of their generation, including the social value of avoiding carbon emissions.

Recommendation:

Public policies to advance low-carbon generation should treat all technologies comparably. There should be no discrimination against nuclear energy.

In principle, equal treatment of diverse technologies could be implemented through a uniform carbon tax or through a universal cap-and-trade system. Next best options include broadening renewable portfolio standards or auctions for the procurement of low-carbon electricity to incorporate all low-carbon technologies, including nuclear. Policy makers should push in this direction. In practice, energy and climate policies are an accumulation of overlapping mandates, regulations, and taxes. In this context, implementing the principle of uniformity requires a broad appreciation of all the different objectives that have shaped past policy decisions, together with the exercise of reasonable judgment. It is clear, however, that the current system in many countries is far from the ideal of uniformity and discourages cost-efficient nuclear investments.

Competitive Electricity Markets

Some owners of nuclear power plants and other industry advocates complain that other attributes of nuclear power are also inadequately compensated, such as its contribution to grid stability, its ability to produce baseload power, and its reliability and resiliency (Nuclear Energy Institute 2015). They advocate changes to market rules aimed at properly valuing these attributes.

Some critics expand this critique to a broader indictment of competitive wholesale markets generally. In 2017, the U.S. Department of Energy (DOE) proposed a radical change to the way many nuclear and coal plants are remunerated: Under the proposal, revenues for these plants would not be determined in a competitive market but on a cost-of-service regulated basis.[4]

While the details of electricity market design need scrutiny and improvement, market design failures have not been a primary factor in the recent closure of existing U.S. nuclear plants. Indeed, the critique of wholesale markets implicit in the recent U.S. DOE proposal seems designed to elude the simple fact that nuclear power faces strong new competition as a provider of baseload power. In the United States, most of the system benefits advertised as unique to nuclear power can now be provided by competing technologies at lower cost. The decline in natural gas prices has made natural gas combined cycle (NGCC) plants a lower-cost alternative for providing baseload power in the United States and around the globe. NGCC plants provide most if not all of the additional attributes that nuclear plants do, including grid stability. It is true that NGCC plants depend on the reliable delivery of natural gas, and that fuel availability varies by region and country. Consequently, there can be specific locations where an NGCC plant cannot provide the same reliable capacity or the same resiliency. But in many U.S. regions, natural gas supplies are readily available, so that NGCC plants are able to provide the same services and at a lower cost. Reliability also depends on market structure and on the contract terms that govern natural gas supplies to a given NGCC plant. Thus, there may be specific NGCC plants with gas supply contract terms that do not provide the same reliable capacity. However, these market structures and contracting terms can be modified and in key U.S. markets where reliability of fuel supply was a concern, adaptations have been made. The bottom line is that falling natural gas prices have driven down the value of all generation attributes provided by nuclear power plants except one: avoided carbon emissions.

[4] The proposal was ultimately rejected by the Federal Energy Regulatory Commission, which decided instead to further investigate the issue of resilience as experienced in different electricity markets (U.S. DOE 2017a).

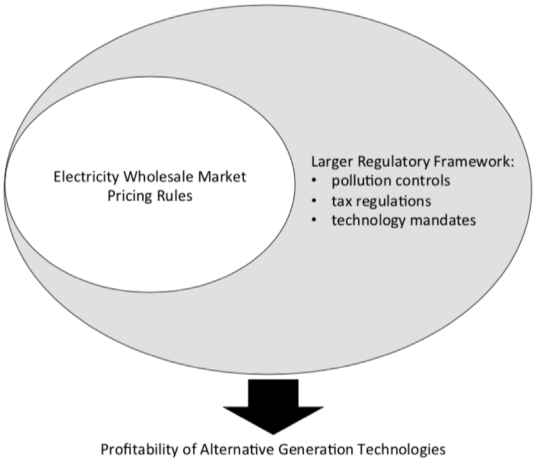
In addition, certain attributes highlighted by nuclear energy advocates, such as grid stability, do not currently have high value because low-cost sources of these services are plentiful relative to the need. Contributions to grid stability, for example, come in many forms. Most thermal generators that drive steam turbines provide valuable inertia to the system and thereby automatically contribute to frequency stabilization. Some generators allocate a portion of their capacity to provide regulation services. The current market value of inertia is effectively zero on most systems since the number of turbines is so large relative to the need for inertia. The market price of regulation service is more than zero, but trivial in the overall scheme of the wholesale market. In 2016, in the market served by PJM, a large grid operator in the northeastern and mid-Atlantic region of the United States, total charges for many different ancillary services provided to the grid amounted to less than 2% of the average hourly wholesale price (Monitoring Analytics 2016). This could change and ancillary services could become more valuable if markets are eventually dominated by renewable generators that provide no inertia and frequency regulation at all, but a conjectured future has little to do with the nuclear industry's revenue problems today. Indeed, renewable energy technologies have been evolving, and system codes are being adapted so that new wind and solar installations are increasingly able to provide some fast-acting reserves that contribute to grid stability.

Finding:

There is little evidence that revenue deficiencies for existing nuclear power plants in the United States are due to 'attributes' that are being systematically mispriced by wholesale electricity market rules, aside from the failure to properly price nuclear energy's climate benefits.

Where nuclear is significantly undervalued, the source of the problem is not the rules of the market per se, but rather broader public policies regarding renewables and nuclear. These policies shape market outcomes, but it is incorrect to blame the market. The schematic in Figure 4.2 helps make the point that the revenue earned by a nuclear power plant—or by any power plant—is determined by wholesale market pricing rules, and also by a variety of other policies outside the wholesale market.

Figure 4.2: Electricity wholesale market pricing rules combine with the larger regulatory framework to determine the profitability of different generation technologies



A concrete example is the federal production tax credit paid to wind generators in the United States. This is an out-of-market payment that supplements what the wind generator receives from the competitive electricity market. The fact that the wind generator receives an out-of-market payment influences the generator's operating decisions and thereby affects the market price. This is most transparently seen on the occasions when the market price becomes negative, which can occur when the wind resource is plentiful at times of low load. The wind generator is willing to continue operating at a negative price because it can capture the federal tax credit only by putting power onto the grid (U.S. DOE 2017b). While the rare occasions when wind generators operate at a negative price represent an extreme case, it is more generally true that the out-of-market payment lowers the average competitive wholesale price of electricity. It creates a differential between the per-unit revenue earned by a nuclear generator and a wind generator operating in the same location and delivering the same power. Where the nuclear generator earns only the market price, the wind generator earns the market price plus the out-of-market payment, potentially leading to investments in new renewable generation and simultaneous retirements of existing nuclear capacity.

In the United States and elsewhere, public policies operating outside the narrow rules of the wholesale market are creating incentives for low-carbon generation in a discriminatory fashion that is designed to benefit some low-carbon technologies but not others. These policies operate in conjunction with market rules, but the market rules themselves are not discriminatory. (FERC 2017) On the contrary, public policies are often designed to achieve a particular outcome that the market alone, operating in a non-discriminatory fashion, would not deliver.

No amount of tinkering with market rules will make nuclear energy more competitive so long as public policies prefer one low-carbon technology over another. In Germany, where the government has adopted a plain mandate to force the closure of nuclear plants, market rules are irrelevant. In other countries, like the United States, public attitudes and policies toward nuclear energy are less unambiguously negative, but policies that favor renewables over nuclear remain a root cause of the industry's revenue problems. The U.S. state of New York provides another example of how public views and political considerations can shape policies and override markets. In an effort to preserve a pair of existing nuclear plants, New York proposed to extend to these plants the same low-carbon incentives that it provides to renewables. However, the Indian Point nuclear plant was specifically excluded from this policy because powerful political interests oppose the continued operation of a plant so close to New York City. This differential treatment of the upstate plant relative to downstate plants had nothing to do with how the competitive wholesale electricity market functions and everything to do with the inescapable fact that public attitudes, as expressed through political decisions, drive ultimate outcomes.

Finding:

Discrimination against nuclear as a low-carbon energy source is not rooted in technical issues of electricity market design. Rather, it is primarily rooted in public attitudes towards nuclear. These public attitudes translate into discriminatory public policies outside of wholesale market rules, which in turn shape profitability.

Nonetheless, it remains important to regularly revisit the issue of electricity market design as public authorities have done for the past few decades. A well-designed market is shaped by the profile of the technologies that are in the market. As more renewables have moved onto the system in recent decades, market rules and practices have gradually adapted to incorporate and shape these new technologies, too. Progress toward the deep decarbonization of the electric power sector worldwide will bring an even more significant shift in the profile of technologies on the grid, including an expanded role for renewables and greater reliance on energy storage and demand response, among other changes. Further modifications to market design may be needed to respond to these changes.

In particular, a shift away from fossil fuel-fired generation, which has significant variable operating costs, toward low-carbon technologies like renewables and nuclear, which have low or zero variable operating costs, could further reduce the share of revenues earned in the energy market and increase the importance of the capacity market. In that case, continuing improvements in the design and operation of capacity markets will be important (Seel 2018).

Recommendation:

Achieving deep reductions in global carbon emissions will require a dramatic restructuring of the technologies deployed in the electricity industry. Constant adjustments will be needed to align market rules to the new technologies being deployed. The nuclear energy industry has a stake in ongoing research to assure that changes in market design are consistent with the deployment of advanced nuclear systems.

Policy Support for Cost-Efficient Nuclear Energy Technology

Changing the revenue side of the equation for nuclear generators through uniform carbon policies is not just relevant for existing plants. It is also necessary to properly incentivize innovations in nuclear energy technology and investments in future new builds of nuclear plants where appropriate. Investors pursuing new, truly low-cost nuclear designs must see the possibility of earning a fair profit based on selling their products for their full value, including the social value of providing low-carbon generation. Current policies that disregard the social value of nuclear energy's contribution to climate change mitigation reduce the prospect for profit and discourage investments in nuclear innovation.

Alongside uniform carbon policies, following through on a number of other enabling actions is important to demonstrate to potential private investors that nuclear energy has a future. For example, in the United States, the federal government's decades-long failure to implement a coherent nuclear waste policy has created a cloud hanging over investments in new advanced reactors. Although the U.S. Congress ostensibly settled on a waste management policy by passing the Nuclear Waste Policy Act Amendments in 1987, from a practical perspective U.S. policy is in disarray. The process to license a deep geological repository for the permanent disposal of spent nuclear fuel at Yucca Mountain in Nevada has been started and then stopped. The current Trump administration has stated its intention to get on with licensing efforts again, but it is sure to face opposition and its intention has not been accompanied by any political plan for winning over opponents of a repository at Yucca Mountain. Establishing a politically durable waste policy—by which we mean a policy that has the broad political support to continue through changes of administration and Congress—would be helpful to encourage investment in new reactor designs. Garnering the buy-in needed to construct such a durable policy is extremely difficult in the current era, but it is nevertheless critical for future investment flows. One option that has some support (Kazimi, et al. 2011) (Blue Ribbon Commission on America's Nuclear Future 2011) would be to pursue a consent-based approach to siting, perhaps starting with local communities in places such as New Mexico and Texas that have expressed interest in potentially hosting a repository (Bryant 2017).

Some other countries have made notable progress on the waste management issue. In particular, Finland has successfully sited its Onkalo spent nuclear fuel repository and has begun construction (Fountain 2017). Sweden's process for developing a repository is also moving forward (Plumer 2012).

Recommendation:

The implementation of a politically durable solution for the management of spent nuclear fuel would greatly facilitate significant investment in new nuclear technologies.

4.3 ENABLING NUCLEAR INNOVATION

The current moment brings significant opportunity for the nuclear energy industry. The need for low-carbon electricity is enormous and likely to grow in the near future. As detailed in Chapter 3, the industry is developing a wide range of advanced reactor concepts, in addition to the familiar light water reactor. While many of these concepts have been around since the dawn of the nuclear age—indeed, several were tested and demonstrated long ago—improvements in associated technologies, such as the development of new materials and analytic tools, make practical today what was impractical yesterday. The challenge is to translate these concepts into plant designs that can produce cheap, grid-connected, low-carbon electricity.

The Changing Global Market

The global marketplace for nuclear power plants is changing rapidly, on both the demand and the supply sides. Economic development in non-OECD countries is rapidly shifting the center of gravity for global electricity demand, and interest in new nuclear plant investments, too. The largest numbers of new reactors under construction are in China, India, Russia, Korea, and the United Arab Emirates. The United States and France still have the largest and second-largest fleets of operating reactors, respectively, but China will soon overtake France. In the U.S. Energy Information Administration's International Energy Outlook 2017 'Reference Scenario,' net nuclear generation in the OECD countries is projected to be flat or slightly declining through 2050. By contrast, net nuclear generation in the non-OECD countries is projected to increase nearly four–fold over the same timeframe. As a result, nuclear generation in non-OECD countries equals generation in the OECD by 2038 and then grows beyond it, according to the U.S. Energy Information Administration (EIA) projections. For companies that are developing energy technologies and products for export, it is important to have in mind the increasing diversity of the international marketplace. In particular, while some countries will make decarbonizing the electricity sector a top priority, others will prioritize expanding access to energy. This means that nuclear generation options will be compared against other low-carbon technologies in some countries, and against fossil fuel technologies in others. To capture a larger market worldwide, it will be even more imperative for the nuclear energy industry to radically reduce costs.

The home base for reactor vendors is shifting also. Until recently, the United States, Western Europe, and Japan had been the major global exporters of civilian nuclear energy technology and expertise. Now there are additional players. Russia, building on the legacy Soviet industry, is advancing nuclear energy as a major export industry. Korea has become a competitive exporter, and China is preparing to become one. The global export market for nuclear technology is therefore much more competitive.

For example, the state-owned Korea Electric Power Company (KEPCO) developed the Generation-III+ Advanced Power Reactor 1400 (APR1400) by building on the success of its construction program for the Generation-II Optimum Power Reactor (OPR). The first build of an APR1400 was completed in 2016 at the domestic Shin-Kori 3 unit. In 2009, KEPCO won a competitive bidding process to provide four reactors of this design to the United Arab Emirates at that county's Barakah site, with Hyundai as the engineering, procurement, and construction (EPC) contractor. The first unit will soon be operational. The reported price for the reactors is $3,457 per kilowatt of electrical generating capacity (kW_e). It is difficult to be sure what is included in this number,[5] but the figure represents an important data point given KEPCO's design success and Hyundai's construction experience in the Emirates, and their ability to win the Barakah tender.

The Russian state-owned company Rosatom has continued its line of Vodo-Vodyanoi Energetichesky Reactors (VVER) with the Gen III+ VVER-1200, also known as the AES-2006 (Goldberg and Rosner 2011). The first reactor of this design went into commercial operation in 2017 as Unit 1 at the

[5] KEPCO, December 2016, Investor Presentation, reports a total cost of $18.6 billion. Dividing this by the total 5,380 GW capacity of the 4 units yields the $3,457/kW figure. The presentation provides no detail about what is included in this figure or the quotation convention. For example, it probably excludes owners' costs which could add another 20% in order to be comparable to other figures. Press reports variously report the deal to be worth $20 billion, $25 billion, $30 billion, or even $40 billion. This latter figure is from the *Korea Herald*, June 20, 2015. For a detailed analysis of KEPCO's bid, see Berthélemy (2011).

Novovoronezh II plant, and a second is currently under construction at the same site. Two units are also under construction at the Leningrad II plant. In addition, construction has begun on the first unit at the Kaliningrad or Baltic plant. Russia considers its AES-2006 design to be a valuable export product. Construction on the first two units to be built outside Russia began in 2013 and 2014 at the Ostrovets site in Belarus; construction on another unit began in 2017 at the Rooppur site in Bangladesh. Russia also has an agreement with Turkey to build four units at the Akkuyu site, although the ownership structure for this project is unsettled at the moment. Rosatom has an agreement with Hungary for two units at the Paks site, an agreement with Finland for one unit at the Hanhikivi site, and an agreement with Egypt for four units at El Dabaa. Which of these projects will be realized, and how quickly, is unclear.

The Akkuyu agreement is notable for Russia's use of a build–own–operate model to advance its exports. In this model, the buyer is relieved of a significant amount of risk. But Russia is taking this approach a step further: in addition to supplying the fuel for Akkuyu, Rosatom is said to be taking back the spent fuel for reprocessing. The final disposition of waste destined for a repository is unclear.

Of all countries currently investing in nuclear energy, China has the largest number of new reactors under construction. Many of these are designs exported to China from a diverse set of companies and countries. The Chinese have also been developing their own designs. Of particular note for the global marketplace is a joint venture of the China General Nuclear Power Group (CGN) and the China National Nuclear Corporation (CNNC) to develop the Generation-III Hualong One (HPR1000) reactor. The first domestic units using this design are under construction at Fuqing 5 and 6 and Fangchenggang 3 and 4, and more are planned. Two HPR1000 reactors are under construction at Karachi Nuclear Power Plant (Kanupp) in Pakistan. CGN–CNNC has an agreement for a build in Argentina and is exploring a build in the United Kingdom at the Bradwell site.

Development of advanced reactor concepts is proceeding globally, too. The United States has a rich legacy of experimentation and demonstration in this domain. Several U.S. companies have designs built on that experience, and the U.S. government continues a small R&D program in support of continued reactor development. Many countries have experience operating fast reactors, led today by Russia and including France and the United States. China is currently building a demonstration high temperature gas-cooled reactor (HTGR) and is experimenting with other concepts. Companies exploring new designs are based in various countries.

Dramatic shifts in who is buying and who is offering commercial nuclear reactor technology will undoubtedly reshape the structure of the global marketplace for this energy source. In an earlier era, the United States played an important leadership role for the global nuclear energy industry, both in its role as a supplier of technology and because of its outsized share of operating nuclear power plants. As a result, U.S. influence shaped licensing and safety standards as well as anti-proliferation protocols worldwide. In the current era, global practice will evolve in response to multiple players. Domestic policies to enable nuclear innovation sit inside this larger global context.

Commercially Driven Innovation

In the past, governments often directed the development of new reactor designs. This included the early development of the pressurized water reactor for naval propulsion, which was leveraged into commercialized LWR designs for power generation. In pursuit of fuel security, governments have also pushed forward breeder reactor designs and, more recently, high temperature reactors. Individual nations may still see a valuable role for specific government-directed programs. However, we believe that the specific challenge of developing and deploying a new generation of nuclear technologies as part of a global effort to achieve deep carbon reductions can be best met with a shift away from government-directed programs towards commercially driven innovation.

The public interest in affordable low-carbon electricity can potentially be fulfilled by a variety of reactor designs, and, except in special cases, there is little public interest in favoring one design or another at the outset. The public interest is in enabling competition among designs. Exactly which concept is most suited to exploiting cost-saving technologies, such as those discussed in Chapter 2 or others, is something that can only be determined through continued R&D, by actually building demonstration reactors, and by producing plants. The task is to select from an array of possible designs those technology choices that are most likely to lead to a low-cost power plant, and then to carefully manage and 'ride herd on' the testing and development process as it moves toward deployment. This is exactly the type of innovation process that private industry manages well, that competition promotes, and that governments should enable. Great value can be gained from harnessing commercial interests to select among technology options and drive key technology choices through development and deployment.

As discussed in Chapter 3 as well as in the next section, the resources required to bring new designs to market are very large and the time horizons are long. There will be a need for government support, and with government support must come public accountability. Nevertheless, accountability to overall project goals can be built in without the government directing specific technology choices. Governments around the world have been and should continue to be important funders of basic research. Indeed, most of the advanced reactor concepts being considered today were developed in various government-funded programs, as were many of the crosscutting technology options we have identified as holding promise for reducing costs. The next section returns to the role of public funding in advancing basic science. However, the further development of different reactor concepts and the integration of various related technology options is a different enterprise. Therefore, we also outline specific actions to enable innovation driven by industry.

Finding:

Private business is well suited to driving innovations that would lead to new reactor designs with radically lower capital costs. To harness this capability, the private sector must make the technology choices and supply the major capital investments. Private companies must enjoy the potential for profit and also bear the risk of loss.

The type of shift we are proposing here, from government-directed to commercially-directed technology development, has occurred in other fields. A recent notable example is the Commercial Orbital Transportation Services (COTS) program in the United States, which was established by the National Aeronautics and Space Administration (NASA) in 2005 (Lovering, King, and Nordhaus 2017). COTS was designed to encourage the emergence of a U.S.-based spaceflight industry managed by the private sector. The idea was that NASA, instead of purchasing space vehicles through cost-plus contracts, would incentivize companies to develop and own their own equipment. NASA would then purchase these companies' products and services as needed (National Aeronautics and Space Administration 2014). NASA defined a set of mission capabilities but left it to private companies to decide how best to design and build equipment to provide these capabilities. To help companies get started and begin developing capacity, NASA would make an early financial commitment, but companies would also have to prove their commercial viability by raising their own capital as well.

NASA solicited proposals and by August 2006, it had signed agreements with two companies: SpaceX and Rocketplane-Kistler (RpK). The agreements defined a sequence of intermediate milestones towards the final mission capability; under the agreements, the companies would get a fixed payment from NASA for reaching each of the milestones. Eventually, the agreement with RpK was abandoned when the company failed to raise the promised outside financial investments needed to continue; NASA then put out a second-round solicitation and awarded an agreement to Orbital Sciences Corp. Although responsibility for execution remained with the companies, the relationship was a cooperative one. For example, the companies occasionally took advantage of NASA subject matter experts to help tackle difficult technical problems, and NASA provided the sites from which the commercial vehicles were launched. By 2012 and 2013, both SpaceX and Orbital had completed demonstrations of their mission capability as defined under their agreements with NASA. Both companies are now vendors to NASA, providing resupply services to the International Space Station under contracts that are awarded through a competitive process.

The U.S. DOE also has experience with this type of public-private cooperation. Most recently, DOE established its Gateway for Accelerated Innovation in Nuclear (GAIN) program. Through this program, commercial nuclear companies can be awarded vouchers that enable them to make use of federal laboratory facilities and staff as they pursue technical research on fuels, materials, and other issues that will help advance reactor designs.

The urgency of the climate problem and the need for dramatic progress toward decarbonization argue for government efforts to enable the accelerated technology development pathway discussed in Chapter 3. That pathway shortens the time for demonstration by identifying a site where a prototype reactor can be built and tested under appropriate safety regulations. Government owned, operated, and supervised sites still offer the best settings to assure public safety and continue government engagement with testing. Such sites should be made available to demonstrate properly vetted commercial reactor prototypes. In addition to its interest in safe testing, the government's vital interest in the fuel cycle necessitates its involvement in the production of new fuels and in the safe management and disposal of wastes.

The Canadian Nuclear Laboratories (CNL) recently proposed an initiative that would allow its facilities to be utilized in cooperation with private companies to "demonstrate the commercial viability of the small modular reactor by 2026" (Canadian Nuclear Laboratories 2017a) . CNL intends to host a demonstration or prototype reactor and recently published a 'Request for Expressions of Interest' to seek feedback from industry and stakeholders on how to structure a successful program. It has received 80 submissions and 19 expressions of interest from technology developers (Canadian Nuclear Laboratories 2017b). CNL has stated that it is open to hosting multiple prototype reactors and reactor types, subject to its own support capabilities (Nuclear Energy Insider 2017). CNL is already in the midst of a major capital investment program at its Chalk River site; initial actions undertaken as part of its small modular reactor (SMR) initiative should help CNL identify what new facilities are most needed for this mission (Atomic Energy of Canada Limited and Canadian Nuclear Laboratories 2017).

Recommendation:

Governments should establish reactor parks where companies can site prototype reactors to conduct testing and operations oriented to licensing. These parks should be open to diverse reactor concepts chosen by the companies. Governments should provide appropriate supervision and support—including safety protocols, infrastructure, environmental approvals, and fuel cycle services—and should be directly involved with all testing.

Participation in this type of initiative should be determined via an open solicitation that allows for a wide variety of reactor types and designs. Choice of the reactor design would be up to the sponsoring company, subject to established safety protocols and to the government's ability to provide needed support obligations. The company would be responsible for constructing the reactor and would have to demonstrate the appropriate financial capability. The government would work with the company to procure the fuel feedstock needed to test and operate the reactor and would act as the agent for handling spent fuel and other hazardous materials. The agreement would enable sale of the power onto the grid through normal commercial channels, consistent with grid protocols. It would also make provisions for the disposition of the prototype reactor, including eventual dismantling at company expense once testing and operation for reactor licensing have concluded and, in some cases, after further operation on a commercial basis consistent with the site's safety requirements.

Establishing reactor parks with the necessary infrastructure will require direct funding to handle expenses incurred by the government outside the construction and operation of prototype reactors. Mechanisms for charging fees to reactor park users can be established, but some direct, additional funding would have to be provided. This is appropriate in light of the government's interest in various aspects of the innovation process and in developing and maintaining its own capabilities by means of its participation.

4.4 PUBLIC SUPPORT FOR RD&D ON ADVANCED NUCLEAR TECHNOLOGIES

This section discusses how governments can support research, development, and demonstration (RD&D) on advanced nuclear technologies. The focus here is on advanced reactor concepts that have not yet been demonstrated. We do not discuss RD&D on established LWR technology.

Cost and Time for a Technology Development Project

The complete process of bringing a reactor concept to commercial deployment involves many expensive steps, including further R&D, full detailed engineering design work, development of fuel and provisions for spent fuel disposition, construction and testing of a prototype, and licensing. The cost of completing this process will vary based on the reactor design. A number of studies in recent years have estimated these costs for particular designs. Several of these studies were produced in connection with the U.S. government's interest in developing HTGR technology, which culminated in the Next Generation Nuclear Plant (NGNP) program (Idaho National Laboratory 2007) (U.S. Government Accountability Office 2014) (U.S. Department of Energy 2010) (NGNP Industry Alliance 2015). All of them projected cumulative costs in the neighborhood of $4 billion to construct the first full-scale plant. This figure does not include up-front R&D and design costs, which could run up to $1 billion. Commercialization would also incur additional costs for post-design licensing related to developing a supply chain for fuel and other equipment, as well as extra shakeout costs on the first new builds. These could also easily run in the neighborhood of $1 billion, bringing the total cost of the development program to more than $6 billion. A later study by several DOE national laboratories detailed additional costs for less mature designs (Argonne National Laboratory, Idaho National Laboratory, Oak Ridge National Laboratory 2017) (Petti, et al. 2017). A recent DOE Task Force Report included a mid-range estimate of $11.5 billion for the total cost of implementing a generic program that would take two reactor designs through the demonstration phase and bring one design to construction of a first-of-a-kind commercial reactor. This estimate included pre-demonstration costs, the cost of two demonstration reactors, and the cost to build a first-of-a-kind commercial reactor (U.S. DOE 2016). The time horizon between the up-front investment and the date when the first commercial returns begin to arrive is quite long.

To illustrate the potential time and cost involved in a major technology development project, we constructed a pair of hypothetical examples based on the sources mentioned above. One is a technology with high maturity, so, in accordance with the discussion in Chapter 3, after some additional work on design and licensing, and investments in supply chains, it can go directly to a commercial demonstration. The second is a technology with lower maturity. In accordance with the accelerated development paradigm proposed in Chapter 3, it requires additional preliminary R&D and design work, and a performance demonstration reactor before going to commercial demonstration.

Table 4.1: Input values for illustrative examples of required costs for two alternative advanced reactor development projects

			Higher Maturity Technology	Lower Maturity Technology
Early Development	Years		3	8
	Expenses, $ million	R&D	50	300
		Design Development	100	200
		Supply Chain	100	200
Performance Demonstration	Years	Pre-build		2
		Build		7
		Operational Testing		5
	Plant	Capacity, MW_e		250
		Unit cost, $/kW		9,200
	Expenses, $ million	Design Completion		300
		Licensing		200
		Construction		2,300
		Operational Testing		400
Commercial Demonstration	Years	Pre-build	2	2
		Build	5	5
		Operational Testing	2	2
	Plant	Capacity, MW_e	250	250
		Unit cost, $/kW	6,900	7,100
	Expenses, $ million	Design Completion	100	100
		Licensing	200	100
		Construction	1,725	1,775
		Operational Testing	200	200
Total Expense of Development			**2,475**	**6,075**

The values in Table 4.1 are all real or constant dollars. In Figure 4.3 the values are nominal and so reflect a 2% inflation rate.

Our assumptions with respect to timing and cost for both development projects are detailed in Table 4.1. The cumulative cost for each project through completion of the first demonstration reactor and its initial operation and testing are shown as the orange lines in Figures 4.3 and 4.4. The x-axis of each figure shows the stages of the development process. Figure 4.3 shows that the high maturity technology requires three years of early development. It also requires final design work and licensing, which happen at the same time in years two and three. Then the commercial demonstration reactor is constructed over a period of seven years. Finally, the commercial demonstration reactor requires two years of operational testing before the development project is complete at the end of twelve years. Figure 4.4 shows that the low maturity technology requires eight years of early development. It also requires final design work and licensing, which happen contemporaneously in years seven and eight. Then the performance demonstration reactor is constructed over a period of seven years. Five years of operational testing are then required before the performance demonstration stage of the development project is complete at the end of twenty years. At that point, the low maturity technology is ready to progress to commercial demonstration.

The two figures make a powerful point about the size of the investment and the length of time required before a new technology can begin earning revenue. The two figures also show the impact of government funding, as discussed in more detail later in this section.

Figure 4.3: Illustrative example of cumulative total cost and net investor cost for a high maturity technology

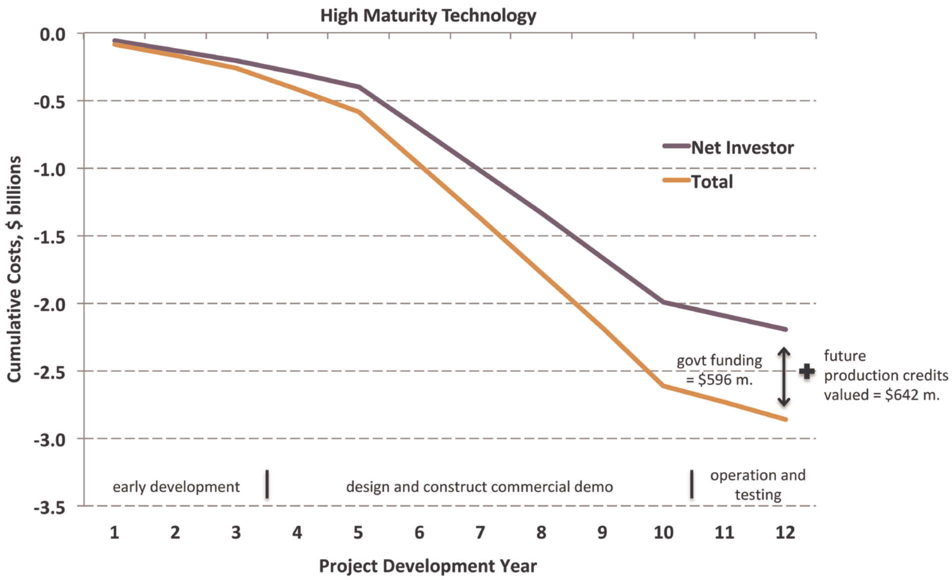


Figure 4.4: Illustrative example of cumulative total cost and net investor cost for a low maturity technology

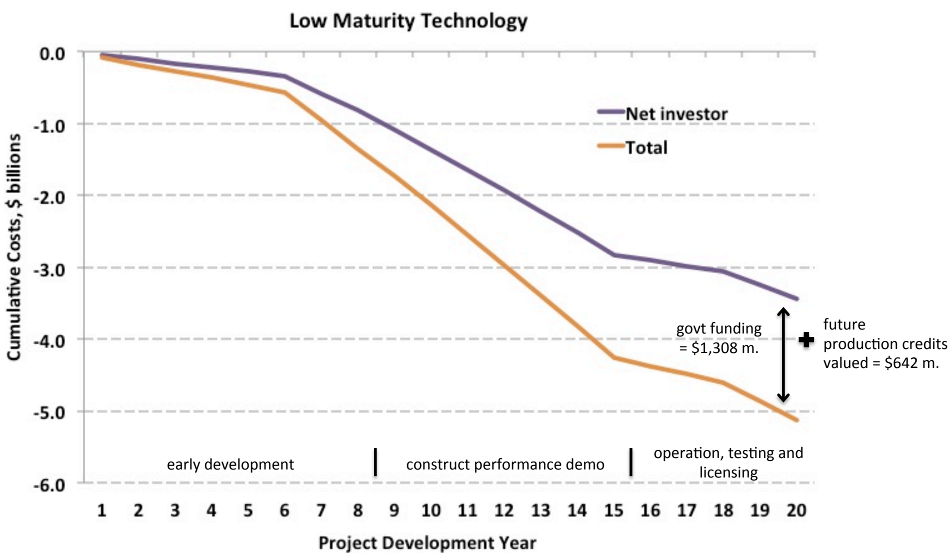


Table 4.2: Input values for illustrative examples of sources of earnings for two advanced reactor development projects

			Higher Maturity Technology	Lower Maturity Technology
NOAK Deployment (2nd comm. +)	Plant	Capacity, MW_e	250	250
		Unit cost, $/kW	4,600	4,600
		Expense, real $ million	1,150	1,150
	Build rate	Years @ 4/yr, thereafter @ 8/yr	4	4
	Design fee	$/kW	920	920
		% overnight cost	20%	20%

Table 4.2 summarizes our assumptions about how each development project will earn a return. It details the projected cost of a NOAK plant and a build rate. The development project earns a return during the build-out phase through profits earned on selling its plants and providing various associated technical services. We represent these earnings as a design fee paid for each plant built.

Figures 4.5 and 4.6 show the time scale required for each development project to recoup its investment—i.e., the payback period. How quickly this happens will depend on the demand for each design, and on how quickly it can scale up production. The orange line shows the total value of cash invested, net of receipts, through any given date. Note that the total goes to nearly -$5 billion, which is far below the $2.5 billion sum that was invested at the conclusion of the development project. That is because this figure also includes the return required on invested capital. (The uptick in the curves around years 12 to 13 is due to the production credits paid to the demonstration plant. The curve then decreases as the subsequent plants are built.)

At the conclusion of the development project, the investment can begin to earn a return from the deployment of subsequent plants. The gross investments needed to build subsequent plants and the payments received for those plants are not shown here. Instead, to focus on the return to the development project, the calculation shows the developer receiving a royalty on the plant design for each subsequent plant built. Construction of the next four plants is assumed to begin immediately at the conclusion of the development project and to take five years. Once the first four commercial-scale reactors come on line in year 18, another four come on line in each successive year until year 22 when the rate doubles to eight plants each year. In the figure, the orange line becomes positive in year 21—when the investment in the development project has been recouped.

The low maturity technology requires a much deeper investment. At the conclusion of the performance demonstration in year 20, the first commercial demonstration reactor remains to be built. Only once that is complete can a full-scale build out

Figure 4.5: Time to recoup investment in development project for high maturity technology

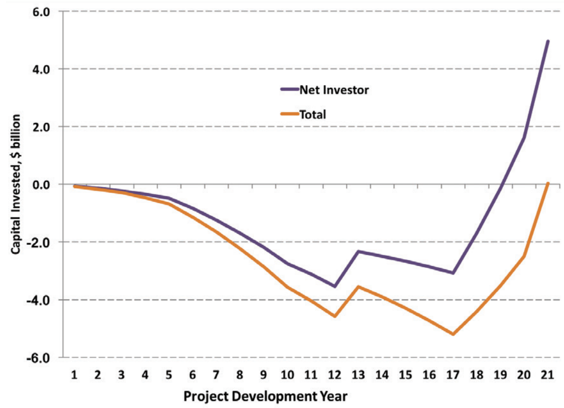
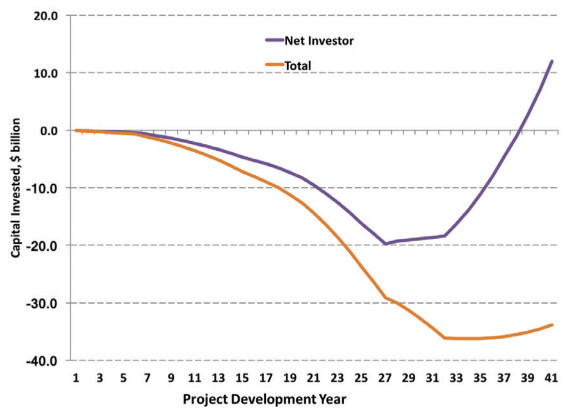


Figure 4.6: Time to recoup investment in development project for low maturity technology



begin. The orange line shows the total value of cash invested net of receipts through any given date. Note that the total goes to nearly -$40 billion, which is far below the $6 billion sum that was invested at the conclusion of the development project. As the figure shows, the total investment cost is not recouped until sometime after year 41.

The two figures also show how government support affects investor returns for the two hypothetical technologies.

Government Support for Technology Development

Governments are a valuable and often essential partner in funding RD&D for new technologies. This is true for nuclear as well as for other energy technology options, such as photovoltaics, batteries, and so on. Historically, government support has made it possible to ready numerous important technologies for commercial deployment. The urgent public need for a suite of low-carbon generation options warrants a sizable investment. It is impossible today to say with any confidence exactly how or when the goal of decarbonizing the electricity sector might be achieved. In fact, the uncertainties and contingencies are so great that it would be imprudent to count on any single technology or technology path. In the face of great uncertainty, the option value of having multiple low-carbon energy alternatives is enormous. To develop those options requires funding many possible technologies. In sum, we need more shots on goal.

Government support for the demonstration of new, advanced reactor concepts is also essential for attracting and making feasible the scale of private investment shown in our examples. Reactor developers and governments are inescapable partners to some degree. No matter how promising or potentially cost-effective it is, a new reactor design can only go to market with the benefit of government cooperation on a range of issues. Given the size of the upfront investment required and the long time horizon before investors can expect to see any returns, government buy-in to the development process will be extremely important to private investors. We do not advocate government funding for the ongoing commercial deployment of any specific low-carbon generation technology, whether nuclear or any other, beyond its initial launch.

The structure through which government support is channeled is important to maximize the likely success and impact of public funding. As we have already emphasized, we believe commercial interests should make key choices among competing reactor concepts and should guide the detailed implementation of any design. That will require that companies put their own capital at risk and enjoy both the prospect of profit and possibility of loss. The public's interest is in the development of any options that will successfully deliver a product. The funding program we are proposing for U.S. government support of advanced nuclear technologies is structured accordingly; it also draws on several existing U.S. funding channels and program experiences. This framework can be applied by any government that seeks to implement advanced nuclear technology.

First, there is a need for specific R&D funding to bring some advanced reactor designs to the point of readiness for demonstration. The U.S. DOE already plays a vital role in funding R&D, at its own labs, at universities, and in collaboration with businesses. Expanded funding targeted to advanced reactor designs is appropriate, and appropriate avenues for delivering this funding can be created using models such as the GAIN program.

Second, funding is needed to facilitate the licensing of new reactor designs. The next chapter discusses funds that the U.S. Nuclear Regulatory Commission (NRC) has dedicated to develop its capability to license advanced reactors. Here we highlight the need for funding to help share the licensing costs incurred by reactor developers for the first advanced reactor designs. DOE employed this sort of cooperative arrangement in its NP2010 program, which was established to support the licensing process for new reactors under the Energy Policy Act of 2002 (U.S. DOE 2012).

In addition to funding for R&D and licensing, we advocate a third and fourth lever for supporting the large capital investments that will have to be made up-front by private investors. These are milestone payments for prototype reactors and production credits for energy delivered from the first reactors.

Milestone payments were a feature of NASA's COTS program. Under that program, the agreements NASA negotiated with individual companies included a suite of intermediate milestones towards the final demonstration of mission capability. Accomplishing each milestone triggered pre-specified payments from NASA to the companies. Individual milestone payments ranged in size from $4 million to $31 million, with the program paying out about $780 million in total. For the two companies that successfully participated in COTS, these payments recouped slightly less than half the total development costs they incurred to demonstrate mission capability (NASA 2014). The other half of the costs represents the net investment by the companies looking towards the future value of selling their newly won capability.

Milestone payments must remain focused, however, on rewarding performance. They should not be transformed into a type of up-front cost sharing. Companies must make the up-front investments, and upon reaching a milestone and validating that achievement with a commitment to move on to the next stage, they should receive a pre-specified payment from the government for their performance. The amount of the milestone payment should be determined in advance and should not be adjusted to cover cost overruns.

Breaking the development process into milestones also creates options for responding to interim results and modifying or adapting the process if necessary. It allows companies to obtain cycles of funding based on interim demonstrations of success, including payouts received midway. And, it makes it possible to stop a failing project before further expenses are incurred. Negotiating interim milestones up front also helps define all parties' mutual responsibilities, including the government's necessary role regarding fuel and waste. Under NASA's COTS program, one of the first two recipients of a completed agreement was scheduled to receive a total of $207 million for completing all milestones. Early on, however, the company failed to demonstrate that it had obtained the next round of financial backing needed to proceed. As a result, the agreement was terminated after only $32 million in NASA funding had been paid out. NASA put out a new solicitation and the new company that came in ultimately completed all the milestones (National Aeronautics and Space Administration 2014).

Production credits work like production tax credits. They are set at a pre-specified unit amount ($/MWh) and awarded for the quantity of electricity generated over a window of time. Typically, an upper limit is set on the quantity of production that can receive the credit. Payment is made when production occurs—for example, as electricity is sold onto the grid. The reactor owner receives both the market price for the electricity and the supplementary production credit.

Production credits have important advantages as a lever for providing support. First, because they reward performance, they leave private business bearing the important technology and construction risk. If a reactor is never completed, then the supplementary production credit is never paid. If a reactor is completed with delays or at greater cost than originally estimated, the size of the supplementary production credit is not adjusted and the reactor builder earns a smaller profit or suffers a loss. This creates a strong incentive for private investors to guide the innovation process in the most cost-efficient direction.

Second, production credits are readily grafted onto a larger system without coming into conflict with important rules and principles of that system. In particular, they are preferable to mandating special purpose power purchase agreements (PPAs) in which government agencies or departments commit to purchase power from particular reactors. Normal PPAs are negotiated with the objective of providing the government with a commodity service at commercial prices. There are rules and principles that govern how normal PPAs are negotiated and how their terms are evaluated. Special PPAs intermingle a subsidy with a commercial transaction and make it difficult to enforce the normal rules and principles associated with procuring power. Instead of resorting to a special PPA, production credits separate the problem of providing a subsidy from the commercial transaction. Contracting for a PPA proceeds as always, without interference and subject to all the rules and principles that normally govern the procurement process. The production credits are then a simple add-on to whatever normal commercial arrangements are made for the sale of power. In other words, the credits are completely separable. Whatever amount of financial support could have been provided through a special PPA can also be provided by adding a supplemental production payment on to a normal PPA.

The size of the supplementary production credit is flexible. To be efficient, it should reflect the social value of accelerating innovation in advanced nuclear energy technologies.

Recommendation:

Governments should establish programs to fund prototype testing and commercial deployment of new, advanced reactor designs. These programs should focus on four levers for advancing progress toward commercialization:

1. Funding to share R&D costs related to moving new reactor designs toward the construction of a demonstration reactor,
2. Funding to share licensing costs for new demonstration reactors and commercial designs,
3. Funding for milestone payments for construction and operation of a demonstration reactor, and
4. Funding for production credits to reward successful demonstration of new designs.

We use the two hypothetical examples constructed earlier to show how a proposed government funding program would align with the investments needed to demonstrate a new reactor and how this support would affect the time horizon for earning a return on investment.

Table 4.3: Input values for illustrative examples of sources of government support for two alternative advanced reactor development projects

		Higher Maturity Technology	Lower Maturity Technology
Government Funding Program	Rate for R&D cost sharing	50%	50%
	Rate for licensing cost sharing	50%	50%
	Rate for milestones	21%	31%
	Production credit, $/MWh	27	27

Table 4.3 shows specific assumptions for the four funding levers discussed previously. Using these input values, Table 4.4 itemizes costs, government funding, and net investor cost for the high maturity technology. Column A shows specific phases of the technology development process. The different levers of government funding appear in columns C through F, while column G shows the total amount of government funding.[6] Disbursements under the R&D cost sharing and licensing columns occur simultaneously as costs are incurred. Disbursements for milestone payments occur with a lag: the company first spends money to accomplish the milestone and then receives payment. An actual agreement would contain many intermediate milestones, so the payments shown here reflect an aggregate. A subtotal is shown for expenditures and payments through completion of the development phase and before production credits are earned on generation.

At the end of the development phase, government funding has covered 23% of expenses, and the investors' net cost is 77%. The amounts shown under column F represent the present value of production credit payments to be made over time for generation produced. The column shows production credits for output from the commercial demonstration reactor on the assumption that the reactor continues operating after testing is completed and a design license has been approved. The column also shows payments earned on future builds. The amounts shown correspond to a $27/MWh payment earned on a total capacity of 1.25 GW operating at a 90% capacity factor for 10 years using a 10% discount rate. These production credits are equal in value to 26% of the development cost. Therefore, in this illustrative example, government funding in aggregate covers 50% of the total development cost, with 23% coming from the combination

[6] Not explicitly shown in the table is the government expense to establish the reactor park and provide fuel and spent fuel management services. The government will incur up-front costs to establish a reactor park and outfit it with infrastructure and to establish generic fuel and spent fuel capabilities. Companies can be charged for certain services, which will defray some of the government's costs. Companies will contract for some specific fuel and spent fuel handling services. Both of these type of costs are contained in the table.

Table 4.4: Illustrative example of government funding levers for the high maturity technology example

			Government Funding					
	Item [A]	Cost [B]	R&D [C]	Licensing [D]	Milestone Payments [E]	Production Credits [F]	Total Federal [G]	Net Investor Cost [H]
Early Development	R&D	50	25				25	25
	Design & Engineering	100			21		21	79
	Supply Chain	100			21		21	79
Commercial Demonstration	Design & Engineering	100			21		21	79
	Licensing	200		100			100	100
	Construction	1,725			365		365	1,360
	Operation & Testing	200			42		42	158
Subtotal at end development		2,475	25	100	471		596	1,879
			1%	4%	19%		24%	76%
Commercial Operation	Demonstration plant					456	456	-456
	Next 4 modules					186	186	-186
Total		2,475	25	100	471	642	1,238	1,238
			1%	4%	19%	26%	50%	50%

(all figures in $ millions)

Table 4.5: Illustrative example of government funding levers for the low maturity technology example

			Government Funding					
	Item [A]	Cost [B]	R&D [C]	Licensing [D]	Milestone Payments [E]	Production Credits [F]	Total Federal [G]	Net Investor Cost [H]
Early Development	R&D	300	150				150	150
	Design & Engineering	200			62		62	138
	Supply Chain	200			62		62	138
Performance Demonstration	Design & Engineering	300			93		93	207
	Licensing	200		100			100	100
	Construction	2,300			716		716	1,584
	Operation & Testing	400			125		125	275
Subtotal at end development		3,900	150	100	1,058		1,308	2,592
			4%	3%	27%		34%	66%
Commercial Operation	Demonstration plant					456	456	-456
	Next 4 modules					186	186	-186
Total		3,900	150	100	1,058	642	1,950	1,950
			4%	3%	27%	16%	50%	50%

(all figures in $ millions)

of government funding for R&D, licensing, and milestone payments, and another 26% coming from production credits earned on generation.

The role of government funding is shown in Figure 4.3 where the second, purple line represents the total present value of investors' net cost. Because of government payments, the investors recoup their investment in year 19. The figure also illustrates the way that production credits are paid out later, as production occurs.

Table 4.5 shows comparable results for the low maturity technology. The impact of government funding appears in Figure 4.4 in the smaller total for cumulative net investor cost. As in Figure 4.3, the second, purple line shows the total present value of investors' net cost. Because of the government payments, the investors' recoup their investment in year 39. As with the high maturity technology, production credits are paid out later, as production occurs.

The estimates shown here and in various government reports all assume that the technology development program proceeds through this sequence of steps to a final, successful conclusion. Provisions are made early on for a review of multiple options, but these examples assume a down selection to the winning option, which is the one option for which a prototype is constructed. Success is presumed through every milestone. Under the program we have detailed, the same steps and costs would be incurred to arrive at the endpoint of one or more new reactors that have been prototyped and licensed, and are ready for deployment.

A key feature of our proposed program, however, is that by leaving the choice of which technology to pursue to private investors, we also ask these investors—rather than the government—to assume associated risks, meaning that they bear both the potential for profit and the risk of loss. The government does not, in the first instance, assume direct responsibility for all costs. Companies are expected to cover the costs of engineering design work and, most importantly, of reactor construction. This funding program allows the government to provide milestone payments as a prototype reactor is successfully constructed, tested, and operated to provide data in support of licensing. These payments can be viewed as a kind of reward intended to reimburse companies for the cost of design and construction. However, these payments are not guaranteed. They are contingent on the achievement of defined milestones.[7] Moreover, the size of the milestone payments is fixed up front, and the company bears the full risk of achieving each milestone in a cost-efficient way.

A second key feature of this proposed approach is that it recognizes the contingency inherent in any effort to support innovation. There is no single direct, unbroken path through R&D, onward through design, and through prototype to deployment. A venture cannot simply barrel forward down a path that has been laid out from start to finish. The process begins with uncertainty and must incorporate new information along the way. One of the striking features of the current moment of innovation in Gen-IV reactor designs is the array of different startup companies that have been founded to produce different designs and that have received early-stage funding. These startups exist alongside several major companies that have long been part of the industry and that are advocating different Gen-IV designs of their own. There is no reason to ask the government to pick one winner. Instead, the government should enable a healthy competition. If multiple designs can succeed in finding investors willing to provide the capital required to finance their up-front engineering costs, then multiple designs should be tried. Along the way, each design will encounter successes and setbacks. Some designs may need to be abandoned. Others may need to be reworked, in which case the realized up-front costs will be higher than had been hoped. And some designs may proceed forward as planned. The final amount that is spent on any particular design will be highly contingent on the number of companies that make the assessment that it is worthwhile to initiate a project. It will also be highly contingent on what those companies learn along the way and how many decide to continue.

The government's role, however, should be more stable. One role is to provide an enabling platform where prototyping can be done. The government's up-front investment to provide this platform will be relatively fixed, insofar as the cost of building needed infrastructure and support facilities is relatively fixed. The government's facilities for testing and prototyping new reactors should be open to a wide variety of designs, but an optimist might expect perhaps two or three

[7] Recall that in the first round of NASA's COTS program, two agreements were made with SpaceX and Rocketplane Kistler. However, Rocketplane Kistler failed to raise the necessary private capital and NASA terminated their agreement. This freed up $175 million to go to other companies.

to become operative in the short-term—thus, it is unlikely that capacity constraints will need to be adapted very quickly. If one of the first designs proves a success, that may open up capacity for new designs to use the prototyping facility. Another role for government is to provide funding to support and encourage prototypes. This support should be relatively fixed and limited. And if success is achieved in shepherding one or two projects to licensing, subsequent projects should need less support.

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Chapter 5

Nuclear Reactor Safety Regulation and Licensing

This chapter begins with a discussion of the regulatory framework used to license nuclear reactors. We then provide a brief history of nuclear regulation in the United States to demonstrate the evolution of nuclear safety regulation and licensing principles. Next, we characterize regulatory and licensing frameworks in other countries. Finally, we focus on the U.S. regulatory system and review best practices and areas of improvement for licensing and regulating advanced reactors.

5.1 NUCLEAR REACTOR SAFETY

The safety of a nuclear reactor system depends on a set of safety functions that must be satisfactorily accomplished to control the reactor under normal operation and to assure its safety if an off-normal event, either internal to the plant or due to an external hazard, were to occur. Such safety functions would remove residual heat from the reactor core to assure long-term cooling of the core when the reactor is shut down. Successful completion of these safety functions prevents or limits to acceptable levels the release of radioactive materials into the environment. The safety functions that must be maintained for all reactor systems include:

- Control of reactor reactivity during startup, operation, and shutdown;
- Control of heat removal to an ultimate heat sink;
- Control of coolant inventory (volume, temperature, flow rate); and
- Control of any chemically reactive or radiological materials.

Nuclear reactors must be designed with safety features and systems that can successfully complete these safety functions. This includes design, operation and maintenance of supporting systems (electric power, cooling, pressurized air, etc.) that are required to accomplish the safety functions. Reactor designs must also provide, where appropriate, physical separation, independence, diversity, and redundancy in safety systems to reduce the likelihood of common-cause or single-point failures that could lead to failure in executing a safety function. Finally, designs must utilize defense-in-depth and engineering margins to cover the possibility that challenges to safety functions could arise from an incomplete understanding of reactor system behavior. These design principles are intended to ensure all safety functions are successfully completed and that the overall reactor system is safe.

The role of nuclear reactor safety regulation and licensing is for the government to review and independently verify that a given nuclear reactor system design can perform needed safety functions with reasonable assurance to protect public health and safety, and the environment.

Worldwide, 85% of all currently operating commercial nuclear reactors are light water reactors (LWRs) that use slightly enriched uranium fuel and are cooled by water (International Atomic Energy Agency 2017). In current LWRs, critical safety functions are accomplished through a combination of active and passive backup systems (e.g., reactor shutdown, cooling, and electrical systems) and operator actions. These systems reduce the likelihood of safety function failure and mitigate the consequences should a failure occur. Specific design criteria assure that system conditions that could drive possible radiological releases are controlled for a range of postulated design basis accidents (U.S. Nuclear Regulatory Commission (NRC) 2007c). For advanced reactor systems, these safety functions are integrated in the system design with a greater emphasis on inherent and passive design features[1] than in current LWRs (NRC 2008). Chapter 3 reviews technical information and safety characteristics for specific advanced reactor designs.

The current safety regulation and licensing framework for commercial nuclear power plants is the product of policy evolution that has been driven by social and political forces, increasing knowledge of nuclear power design and operation, and major industry events with associated lessons learned. While different countries have different regulatory processes based on their historical experiences and economic and political systems, the basic principles of nuclear regulation are quite similar around the world.

5.2 CHARACTERIZING REGULATORY FRAMEWORKS

The regulatory frameworks used to review the safety of nuclear power plants and license new plants can generally be described in terms of three characteristics:

- *Technology*—Can the framework be used to regulate any generic nuclear reactor technology or are its requirements technology-specific?
- *Risk*—How does the framework consider licensing event risks (probability and consequence) in determining requirements?
- *Prescriptive or Performance-Based Requirements*—Is plant safety determined by implementing prescribed design and operational features or by evaluating overall plant performance?

Though different regulatory frameworks may have the same end goal—i.e., adequate protection of public health and safety—the choice of a particular framework will have an impact on how technologies are regulated and how the industry thinks about and addresses safety.

Technology

A regulatory framework can be written to work with specific reactor technologies (technology-specific) or to allow more broadly for regulation of any reactor technology (technology-neutral).

Technology-specific regulatory requirements have been refined for a particular reactor technology. This reduces uncertainty for applicants because it provides specific performance requirements that applications will be evaluated against and helps ensure consistent application of regulation (Walker and Mazuzan 1992). Additionally, technology-specific requirements can reduce repeated licensing efforts and help ensure consistent implementation and enforcement of regulations.

One significant drawback of technology-specific requirements is that they may discourage innovation and delay the review of novel reactor concepts, such as the high temperature gas-cooled reactor (HTGR), or concepts that are a significant variation on existing technologies, such as the integral pressurized water reactor (iPWR) (Petti, et al. 2017). New technologies that do not have a regulatory precedent can encounter significant licensing challenges in a technology-specific regulatory framework. Conversely, the primary advantage of a technology-neutral regulatory framework is that novel reactor concepts may be more easily accommodated (Finan 2016).

[1] The International Energy Agency (IAEA) defines active, passive, and inherent safety features as follows (IAEA 1991): Active safety features "rely on external electrical or mechanical power, signals, or forces to complete a safety function." Passive safety features "only require natural forces (gravity or gas pressure), properties of materials, or internally stored energy to complete a safety function." Inherent safety features "rely on fundamental properties (materials or design choices that cannot be changed by internal or external conditions) to complete a safety function. An inherent safety feature has no failure mechanism."

In a technology-neutral framework, requirements are written in a manner that allows for application to any reactor technology. However, these requirements often lack the specificity necessary to ensure consistent and uniform interpretations by regulatory staff and applicants (NRC 2007b). While this adaptability can be valuable for new technologies, it may slow the licensing process. A technology-neutral licensing framework can provide guidance for developing and applying needed technology-specific criteria (NRC 2007d). A mixed framework could support licensing of any reactor technology but also capture lessons learned and allow expedited licensing for applicants that reference and incorporate established regulatory precedents (NRC 2007b).

Risk

A regulatory framework can also be characterized based on how it considers the risk of specific possible accident sequences. Overall risk is defined, for purposes of this discussion, by the 'risk triplet': (1) what can go wrong (definition of the event sequence), (2) how likely is it to go wrong (the sequence probability), and (3) what are the consequences of the sequence. Three approaches have commonly been used to evaluate safety risks for nuclear power plants as characterized by the 'risk triplet' (Vietti-Cook 1999):

- Deterministic—Regulatory requirements are based on event sequence definition and event sequence consequences. Event sequence probability is not explicitly considered when setting deterministic requirements.
- Risk-Based—Regulatory requirements are based on the event sequence probability and consequences using best estimate values. Conservative assumptions of failures or conditions are not considered, but uncertainties are considered.
- Risk-Informed—Regulatory requirements are based on deterministic requirements derived from dominant event sequence probabilities. Event sequences chosen for safety analyses are based on risk but limiting safety analyses that include uncertainty analyses or conservative event sequence definitions can be performed.

These different approaches to risk assessment have varying benefits and drawbacks and are closely linked to the historical development of nuclear regulation in the United States. While a deterministic regulatory approach may focus on extremely high consequence events with near-zero probability, a risk-informed or risk-based regulatory approach may instead focus on an initiating event with lower consequence but higher probability because the total risk from such events is higher (Vietti-Cook 1999) (see Sidebar 5.1).

A risk-informed framework is useful because the insights gained from probabilistic risk assessment (PRA) can guide design decisions, safety analyses, and help develop specific safety criteria. This type of framework acknowledges the potential safety and design benefits from incorporating risk information while also accounting for the uncertainties inherent in current 'state of the art' PRA and the use of deterministic principles such as defense-in-depth where required by social safety goals (NRC 2007b). For advanced reactor designs with limited operating experience, the use of PRA allows for a greater understanding of the relative risk of different event sequences and the design features of critical safety functions. PRA was used extensively and successfully in regulatory reviews of conceptual designs for the proposed modular HTGR as part of a draft preliminary safety evaluation (Williams, King, and Wilson 1989).

Prescriptive or Performance-Based Requirements

Technical requirements can be either prescriptive or performance-based. Prescriptive requirements specify the design features, analysis techniques, or operational practices that an applicant must use to satisfy a safety objective. An example would be requiring specific maintenance, testing, and inspection of emergency diesel generators at specified time intervals to ensure reliability (Kadamabi 2002). By contrast, performance-based requirements present an overall safety objective or metric that must be met by the design but allow the applicant to select the specific design features, analysis techniques, or operational practices that can satisfy the objective.

Sidebar 5.1: Consequences, Probability, and Risk in Historic Approaches to Nuclear Safety Regulation

A major feature of deterministic regulatory approaches is the use of bounding analyses that consider system performance against a single limiting or worst-case event. For example, to develop deterministic safety requirements to address the risk of coolant loss—also known as 'loss of coolant accidents' (LOCA)—U.S. regulators have defined the bounding or worst-case event as "a break equivalent in size to the double-ended rupture of the largest pipe of the reactor coolant system" (NRC 2007c). The rationale is that a system designed to survive the most severe accident of this type, in other words, a 'large-break LOCA,' would also be able to survive all smaller break events (small-break LOCAs).

This deterministic approach has two problems: The first is the low probability that the bounding event will actually occur. The second arises from a conflation of consequence and risk in terms of decision-making. Engineering analyses of pipe systems suggest that the likelihood of a pipe failing in a double-ended rupture is extremely small given the ductility of the pipe (which makes it far more likely that a pipe would leak before it breaks) and the extremely high loads required to generate stresses sufficient for a double-ended rupture (Holman 1984). While the consequence of a large-break LOCA could be exceedingly high, the likelihood of this event is also exceedingly low.

Use of large-break LOCA as a bounding event in regulatory determinations for nuclear power plants has resulted in safety features and systems that are specifically designed for that event. One weakness of this approach is that smaller consequence events may not always be completely bounded. For example, the Three Mile Island (TMI) accident demonstrated that the safety features used to mitigate a large-break LOCA could not mitigate a small-break LOCA under all plant conditions. This resulted in a series of system failures at TMI and an inadvertent release of radiological materials. While the consequences of an unmitigated small-break LOCA might be less severe in some scenarios than those of an unmitigated large-break LOCA, the higher probability of occurrence for a small-break LOCA can mean that this type of event creates a higher total risk. Sole reliance on deterministic analyses that design for the consequences of a single bounding event without considering the probability (and, by extension, the risk) associated with that event may cause designers to miss or underestimate the impacts of lower-consequence, higher-probability events.

For new reactor designs with limited or no operating experience, a combination of deterministic methods and risk analysis methods would provide a risk-informed approach to safety regulation that balances consequences, probability, risk, and uncertainty to deliver better public health and safety protection.

Requiring diesel generators or other backup power sources to show 95% reliability of operation for design basis accidents would be a performance-based requirement (Kadamabi 2002).

In sum, prescriptive requirements specify how safety objectives must be accomplished while performance-based requirements specify which safety objectives must be accomplished. The major advantage of prescriptive requirements is that they reduce regulatory uncertainty and provide applicants with clear criteria for licensing; much less engineering judgment is required during evaluations by regulatory staff. The major disadvantage of prescriptive requirements is that they focus on the method used to achieve the safety objective and not on the final objective itself. This disadvantage has two implications. First, it discourages innovative safety solutions because the need to seek exemptions creates a barrier to implementation (Finan 2016). Second, focusing on the method and not the outcome can result in less emphasis on ensuring that the ultimate safety objective is fulfilled by prescribed methods.

Performance-based requirements specify which safety objectives must be met and emphasize that applicants must demonstrate how their design fulfills safety objectives. The major advantage of this approach is that it can allow for design and operational flexibility and can be adapted to any reactor technology if the safety objectives specified are sufficiently broad (e.g., off-site dose limits for accident conditions). The major disadvantage of performance-based requirements is that engineering judgment has to be used to evaluate uncertainties and assess whether the requirements have been met—and such judgments are open to interpretation by applicants, staff, and other reviewing bodies, such as the U.S. Nuclear Regulatory Commission's Advisory Committee on Reactor Safeguards (ACRS) and Atomic Safety Licensing Board (ASLB), as well as interveners and courts (Coglianese, Nash, and Olmstead 2003). Flexibility can result in regulatory uncertainty and may delay projects if significant analysis, experiments, or redesign are required for an applicant to demonstrate that the reactor design satisfactorily fulfills the safety objectives.

A performance-based framework that introduces technology-specific requirements only where such requirements are actually needed gives applicants maximum flexibility to innovate on reactor designs and features while ensuring adequate protection of public health and safety. Limited use of technology-specific requirements helps improve regulatory transparency and increases public assurance that lessons learned from the operation of existing plants will be captured and included in future designs to increase overall plant safety.

5.3 DEVELOPMENT OF NUCLEAR REGULATION IN THE UNITED STATES

Nuclear regulation in the United States has evolved since the creation of the Atomic Energy Commission (AEC) in 1946 and the passage of the Atomic Energy Act of 1954 that launched the development of the commercial nuclear power industry. This evolution has been shaped by the changing state of knowledge regarding nuclear power plant design and operation, as well as by changing public opinions about nuclear power.

The regulatory authority for the first commercial nuclear power reactors and prototypes in the United States was the AEC, which was tasked with developing, promoting, and regulating the fledgling nuclear power industry (Hogerton 1963) (Mazuzan and Walker 1985). In the 1950s and early 1960s, the federal government's support of nuclear energy led to the design and construction of a wide range of different reactor technologies, both as demonstration systems and for commercial use (Hogerton 1963). These public/private commercial reactors included (International Atomic Energy Agency 2017):

- Light water reactors (Shippingport Reactor 1957),
- Sodium-cooled fast breeder reactors (Enrico Fermi Reactor Unit 1 1963),
- Sodium-cooled and graphite moderated reactors (Hallam Nuclear Facility 1963),
- Organic-cooled and moderated reactors (Piqua Nuclear Reactor 1963),
- Heavy water reactors (Carolina Virginia Tube Reactor 1963), and
- High-temperature gas reactors (Peach Bottom Reactor Unit 1 1966).

Given that reactor technologies were still developing, the AEC had to regulate individual reactors on a case-by-case basis, relying on limited experimental data, engineering judgment, and expert advice from the ACRS to establish the technical basis for licensing and operation (Mazuzan and Walker 1985).

Reactor safety was satisfied largely through four strategies (Mazuzan and Walker 1985):

- Remote Siting—putting reactors in sparsely populated areas to limit public exposure in case of accidental release.
- Containment—including structures and systems to limit accidental radiological releases.
- Low Reactor Power—using designs that resulted in a smaller source term of radionuclides from accidents.
- Engineering Margin—adding engineering design margins to account for uncertainties.

While case-by-case evaluations enabled the construction and licensing of novel reactor designs, the AEC's congressional oversight committee, the Joint Committee on Atomic Energy, and the industry sought formalized design criteria for nuclear power plants. Development of these criteria was intended to reduce regulatory uncertainty and shorten licensing review periods by aligning the applicant's prepared safety analysis with AEC staff expectations (Walker and Mazuzan 1992).

AEC technical staff first developed general design criteria in 1971. These criteria outlined the general design characteristics required for commercial plants and the types of technical information that applicants were expected to include in a nuclear power plant license application. As AEC staff revised draft design criteria based on industry groups and the public feedback, the criteria shifted from general, technology-neutral criteria to specific requirements for LWR technology, which industry had selected for first commercialization. The formalization of technology-specific reactor requirements was designed to optimize plant designs and introduce more regulatory certainty for LWR technology. In 1974, the Energy Reorganization Act separated the AEC's nuclear development and regulatory functions. The nuclear development function was assigned to the new Energy Research and Development Administration (later merged with the Federal Energy Administration to form the Department of Energy), and the nuclear regulatory function was assigned to the new U.S. NRC.

Current principles of nuclear regulation and safety have evolved based on increased technical understanding and lessons learned from major industry events (which illustrated strengths and weaknesses of existing plant designs) and public concerns related to the safety of nuclear power plants. While reactors of varying 'advanced' designs were safely constructed and operated in the early 1960s, regulatory optimization to increase regulatory certainty led to LWR-focused licensing guidelines and processes. Changes in the basic safety philosophy applied to nuclear reactors, increasing reactor sizes, and siting policies changed the number, type, and stringency of regulatory requirements for nuclear power plants. Table 5.1 summarizes current principles of nuclear safety along with an industry event that demonstrated the importance of these principles.

While this discussion has focused on U.S. regulatory history, the evolution of safety regulations and the lessons learned that have

Table 5.1 Regulatory Safety Principles

Safety Principle	Definition	Case Example[a]
Reactor Siting	The location of a nuclear power plant can significantly impact the risks posed by that plant. Siting reactors away from population or agricultural centers can help minimize public exposure and consequences in the event of an accident.	1961 SL-1 Nuclear Reactor Accident
Defense in Depth	Use of multiple independent and redundant barriers to prevent and mitigate accidents so that no single layer, no matter how robust, is exclusively relied upon to prevent the release of radiological materials.	1966 Fermi Unit 1 Fuel Melt Incident
Redundant and Independent Safety	Use of multiple, physically separated, independent, and fully redundant components or systems when the performance of the safety function is necessary to prevent and mitigate accidents.	1975 Brown Ferry Unit 1 Cable Fire
Human Factors	The probability of success or failure of operator actions must be considered when designing safety systems. Operators will not always make timely or correct decisions when called upon and the potential for these errors must be accounted for in the design of systems and components.	1979 Three Mile Island Unit 1 Accident
Inherent Reactor Safety	Control and operation of nuclear power plants should be inherently stable based on the physics of reactor design. This inherent stability can be defined by the feedback mechanisms or long-term behavior of different reactor characteristics such as thermo hydraulic or neutronic performance.	1986 Chernobyl Nuclear Accident
Active vs. Passive Safety	Active safety systems require external action (e.g., operator action, electric motors and valves) to fulfill their safety function. Passive safety systems fulfill their safety functions without external action and only rely on natural forces (e.g., gravity, pressure differential). The safety implications of passive and active systems differ based on application and design.	2011 Fukushima Nuclear Accident
Conservative Calculations to Account for Uncertainties	The design of nuclear systems requires the use of parameters and values that are subject to high amounts of uncertainty. Calculations related to the safety of nuclear facilities must appropriately consider these uncertainties or use bounding 'worst case' values to create a safe operating envelope for the plant.	2011 North Anna Power Station Seismic Event Exceeds Plant Design Basis

[a] Each case example results from a confluence of multiple safety principles but is provided to illustrate the impact of a particular failure or an individual safety principle.

influenced this evolution are similar in most countries. Thus, although other countries have developed slightly different approaches to assuring plant safety, the fundamental principles remain the same (International Nuclear Safety Advisory Group 1999). Differences in regulatory frameworks are largely attributable to differences in cultural expectations of safety, political systems, and economic systems.

5.4 NUCLEAR REGULATION AROUND THE WORLD

Nuclear regulation in most countries has evolved over a period of decades to support the most efficient licensing of a single reactor technology. In most cases, this has resulted in regulatory systems optimized for the regulation of large, light-water-cooled nuclear reactors. In Canada and the United Kingdom, the major indigenous reactor technologies are not light-water-based, but rather heavy-water-cooled and carbon-dioxide-cooled, respectively, and each country's regulations were optimized for the design and operation of their single dominant reactor technology. Different regulatory agencies have also evolved as the priorities of the national government and public/legislative discussion have shifted over time. The impact of the major nuclear accidents (Three Mile Island, Chernobyl, and Fukushima) on regulations worldwide was significant.

These international incidents highlight the point that nuclear safety is not solely a national issue: the consequences of a nuclear accident, both physically and psychologically, are experienced worldwide. The 1994 Convention on Nuclear Safety (CNS), organized by the International Atomic Energy Agency (IAEA), worked to address these issues by establishing a common international basis for nuclear safety (IAEA 1994). The Convention had several objectives:

1. To achieve and maintain a high level of nuclear safety worldwide through the enhancement of national measures and international cooperation including, where appropriate, safety-related technical cooperation.

2. To establish and maintain effective defenses in nuclear installations against potential radiological hazards to protect individuals, society, and the environment from harmful effects of ionizing radiation from such installations.

3. To prevent accidents with radiological consequences and to mitigate such consequences should an accident occur.

These high-level objectives, together with efforts to implement the IAEA's basic safety principles for nuclear power plants (International Nuclear Safety Advisory Group 1999), allowed development of different national regulatory structures while still promoting international accountability for nuclear regulation and safety.

Though their ultimate safety objectives are the same, cultural and political differences have led to variations in how countries implement nuclear regulation. These variations include both philosophical and practical differences. Philosophical differences with respect to technology-specific vs. technology-neutral requirements, deterministic vs. risk-based evaluations, and prescriptive vs. performance-based requirements result largely from differing cultural approaches to nuclear safety. Practical differences on issues such as the renewal frequency for reactor licenses—for example, 5 years in Canada, 10 years in France, 20 years in the United States—result from differing political environments. These philosophical and practical differences will have a notable impact on the licensing of new reactors in the next several decades and may enable new nuclear technologies in some countries while precluding them in others.

While national autonomy has been a cornerstone of nuclear reactor licensing, acceptance of international best principles and better alignment and cooperation between national regulators could remove unnecessary hurdles to enabling the worldwide deployment of new nuclear power plants. The design, construction, and deployment of nuclear reactors has always been an activity that occurred in many different countries. It is a global enterprise, but one that has been characterized by different design concepts. Enabling vendors to sell a single standardized design worldwide would reduce costs, shorten development schedules, and lessen licensing burdens. A standardized international deployment paradigm, however, requires alignment and agreement between different nuclear regulators to reduce or eliminate duplicative review efforts and allow for a uniform set of safety standards that are more specific than those currently agreed to in the CNS.

Nuclear Regulation in the United Kingdom

In the United Kingdom, commercial nuclear power plants are licensed and regulated by the Office of Nuclear Regulation (ONR). The ONR is a fully independent governmental agency that oversees nuclear safety as well as the use and transport of civilian nuclear materials (U.K. Department of Business, Energy, and Industrial Strategy 2017). The ONR was created in 2014 and integrates separate government offices that had previously overseen nuclear installations, nuclear security, and nuclear safeguards. It was created to enable the effective licensing of new nuclear power plants and oversee an expanding nuclear industry.

Regulation of nuclear facilities in the United Kingdom is almost entirely performance-based; the ONR sets high-level regulatory expectations and allows applicants wide flexibility in determining how to meet and demonstrate compliance with these standards. The ONR believes that a performance-based regulatory paradigm allows for innovation in safety, enables novel technologies, and "strengthens accountability and encourages the adoption of relevant good practice and continuous improvement" by nuclear facility licensees.

U.K. nuclear facility regulation is site-based. The ONR first approves a specific site for the applicant's proposed activities and then grants the applicant specific permissions (license instruments) to proceed through different stages of facility construction, commissioning, and operation. The initial site review process determines whether the applicant's safety case for the overall facility and site would protect public safety; its purpose is not to review a particular reactor design.

Regulatory documentation of a specific reactor design and safety analysis is submitted on an agreed-upon schedule throughout facility construction and commissioning. A generic design assessment (GDA) process was created to help expedite reviews of standardized reactor designs and allow for earlier regulatory intervention and feedback in the design and licensing process. The GDA is non-binding but "will make a significant contribution to ONR's assessment of the license applicant's safety case."

Nuclear Regulation in Canada

In Canada, commercial nuclear power plants are licensed and regulated by the Canadian Nuclear Safety Commission (CNSC). The CNSC is a fully independent governmental agency that oversees nuclear safety as well as the use and transport of civilian nuclear materials (Canadian Nuclear Safety Commission 2016). It was created in 2000, replacing the Atomic Energy Control Board that had acted as Canada's regulator for all nuclear energy activities since 1946. This change was intended to ensure independence of the nuclear safety regulator from development activities, and to allow the CNSC greater legal power in the review, approval, and enforcement of licenses.

Regulation of nuclear facilities in Canada is typically non-prescriptive; current regulatory guidance is largely technology-neutral and the CNSC is working towards making regulations performance-based and risk-informed where appropriate. The CNSC aims to set "general, objective, performance-based regulatory requirements" and allow applicants to develop their own methods for meeting the requirements. However, more specific requirements may be established where necessary. The CNSC has also put greater emphasis on risk-informed regulations; risk-graded approaches to safety analysis can be used both by applicants when preparing facility designs and by CNSC staff when determining focus areas and scope of assessment for regulatory review.

In Canada, nuclear power plant regulation is phase-based. The life cycle of a nuclear facility is divided into five distinct phases: site preparation, construction, operation, decommission, and abandonment. Each phase requires a separate regulatory review and approval. While each of these reviews is separate and distinct, applications for the first three phases (site preparation, construction, and operation) can be assessed by the CNSC in parallel provided that sufficient information is submitted by the applicant.

Regulatory review and safety analyses for a specific reactor design (the safety case) are conducted throughout the first three phases of the regulatory process, with increasing levels of design detail and technical review. The pre-licensing vendor design review (VDR) was created to "verify, at a high level, the acceptability of a nuclear power plant design with respect to Canadian nuclear regulatory requirements and expectations, as well as Canadian codes and standards" (Canadian Nuclear Safety Commission 2012). The VDR is intended to help vendors identify fundamental barriers to licensing and paths to resolve any serious design issues identified by the CNSC. The process is fully optional for applicants and VDR conclusions are non-binding and non-influencing for the CNSC in subsequent licensing reviews for plant designs.

Nuclear Regulation in China

In China, commercial nuclear power plants are licensed and regulated by the National Nuclear Safety Administration (NNSA) within the Ministry of Environment Protection. The NNSA is an independent governmental body that oversees nuclear safety as well as the use of all civilian nuclear materials and activities (The People's Republic of China 2016). It is complemented by the China Atomic Energy Authority, which promotes and implements the peaceful use of atomic energy in China, and by the National Energy Administration which provides technical standards and advice on nuclear power plant projects.

Regulation of nuclear facilities in China is based primarily on deterministic methods, although probabilistic and risk-informed methods have been required to support and validate the conclusions of deterministic safety analyses since 2009. Probabilistic methods are also being implemented for operational considerations such as risk-informed maintenance activities. Despite requirements that appear to be largely prescriptive (e.g., specific acceptance criteria, conservative assumptions), the NNSA has successfully licensed a wide range of different reactor designs (LWR, HTGR, heavy water reactor). This suggests that the NNSA has effective internal processes for licensing facilities using technology-neutral requirements or on a case-by-case basis.

In China, regulatory approvals are granted to a nuclear power plant for different phases or major milestones in plant construction and operation. Phases or milestones that require regulatory review include initial siting, construction, initial fuel loading, initial criticality, operator training, and start of decommissioning.

At each stage of the regulatory process, the applicant completes different safety assessment and verification activities, which are then reviewed by the regulator to determine whether the specific activity can be completed safely. The review determination is based on a number of factors including compliance with existing regulations and adequacy of nuclear quality assurance programs.

The NNSA was formed in 1984 and was largely modeled on the laws and regulations present in other countries with established nuclear power sectors. As a result, the regulatory system in China in some ways closely resembles the system in the United States with its emphasis on defense in depth, deterministic analyses, and conservative assumptions. Despite these similarities, however, the presence of state-owned energy companies and the absence of significant public and court challenges to licensing and deploying nuclear technology significantly change how the NNSA can review and regulate plants.

Finding:

Regulatory agencies around the world have adopted basic principles similar to those described in the policies of the IAEA and in U.S. NRC regulations, though they vary in their detailed application of these policies and principles—for example, with respect to required burden of proof. While significant cultural, social, and political differences may exist between countries, the fundamental basis for assessing the safety of nuclear reactors is fairly uniform among countries with established nuclear power programs.

Recommendation:

Regulatory requirements for advanced reactors should be coordinated and aligned internationally to enable international deployment of commercial reactor designs, and to standardize and ensure a high level of safety worldwide. National differences in safety regulations due to accepted cultural practices make it difficult to develop a universally accepted regulatory licensing regime. But certain basic standards for nuclear safety should be maintained internationally due to the far-reaching environmental and social/political effects of nuclear plant operation. Initial international agreement on specific topics (e.g., station blackout resiliency) and joint licensing evaluations could advance discussions about undertaking reciprocal reactor design evaluations between nations or standardizing international safety requirements.

5.5 AN ASSESSMENT OF LICENSING PATHWAYS IN THE UNITED STATES

The licensing of a nuclear reactor requires analysis and approval of all features that could affect safety. These include the facility site, the reactor design, and support facility designs. The licensing process also requires verification and approval of the facility's construction and operational procedures. Additional reviews and approvals may be needed to verify the safety of continued operation after initial startup, as well as safe shutdown and facility decommissioning. In every country with a commercial nuclear power program, regulators review all aspects of nuclear facilities. However, countries differ in how they conduct licensing reviews and in the degree of public participation and input they seek during these reviews.

Licensing pathways can be divided into two general classes: (a) staged processes that require approval at each phase of facility design, construction, and operation and (b) one-step processes that provide a single regulatory approval for all stages of reactor construction and operation (Figure 5.1). We consider the advantages and disadvantages of these two approaches to licensing new commercial power plants in the United States.

Two-Step Licensing Approach

In the United States, Part 50 of Title 10 of the Code of Federal Regulation (10 CFR 50) provides the regulatory basis for licensing and regulating nuclear power plants. It requires that plants obtain a "construction permit/operating license" (CP/OL) (NRC 2007a) through a two-step process (historically, this process was based on the process for licensing radio stations under the 1934 Federal Communications Act) (Mazuzan and Walker 1985).

First, applicants submit a preliminary safety analysis report that provides initial details on the siting, design, and operation of the proposed reactor. The construction permit application does not need to have complete information on the reactor design and site but must provide "reasonable assurance" that, by the end of construction, the reactor can be operated safely.

The construction permit allows the applicant to begin work but does not provide guarantees that the reactor will be licensed to operate.

The application for an operating license is submitted when the reactor and plant are nearing completion. This application includes the final safety analysis report on the site, design, and operation of the reactor, a physical security plan for the facility, details on safeguards for nuclear materials, and additional technical details on plant safety features. Staff of both the NRC and the Advisory Committee on Reactor Safeguards (ACRS), a statutory body of experts that provides independent technical assessments for the NRC, review CP/OL applications under the Part 50 licensing process. Public hearings are also conducted before issuing the CP/OL to allow the public to provide input or voice objections to the proposed applications.

The CP/OL model has been used to license all commercial nuclear reactors constructed and operated in the United States prior to 2012.

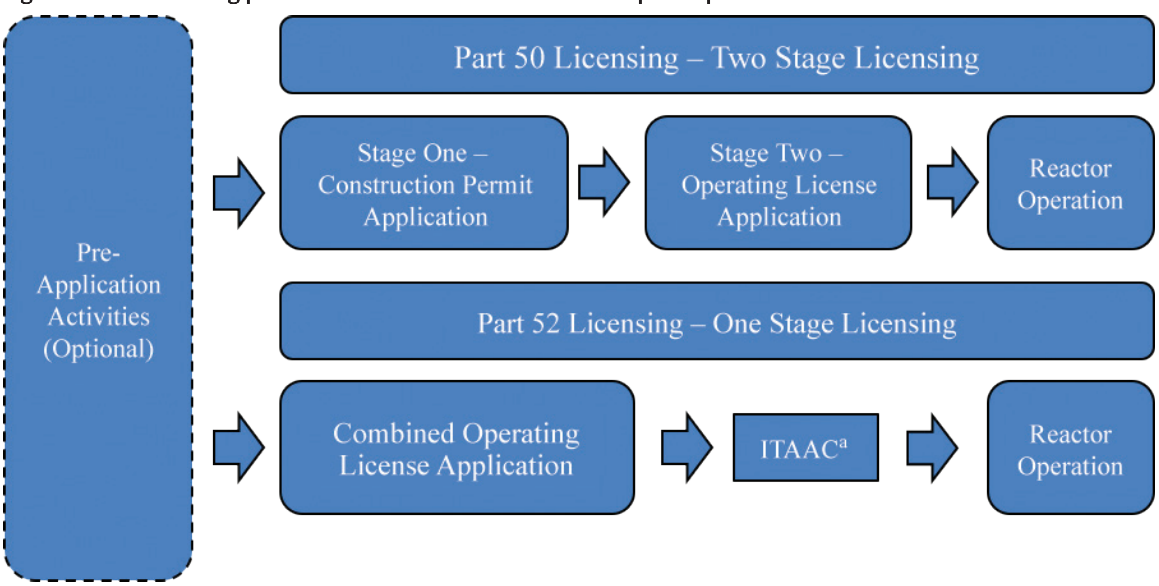
One-Step Licensing Approach

In the United States, Part 52 of Title 10 of the Code of Federal Regulation (10 CFR 52) provides the regulatory basis for licensing nuclear power plants using a 'combined operating license' (COL) model (NRC 2007e). Under 10 CFR 52, reactors can be licensed for construction and operation in a single step with optional separate approvals for the reactor design.

Applicants for a COL submit a single license application (COLA) that contains the same complete site, design, and operation information required for an operating license granted under 10 CFR 50. The application also includes 'Inspections, Tests, Analyses, and Acceptance Criteria' (ITAAC) for the specific facility and site (NRC 2007e). ITAAC are designed to give "reasonable assurance" that the reactor design approved in the COL application will be constructed correctly. Instead of having two sets of reviews and public hearings as required under 10 CFR 50, a single set of hearings occurs before plant construction begins. If a plant receives a COL and successfully completes all required ITAAC, its operation is guaranteed and is not subject to additional hearings. The complete COLA is still reviewed to assure technical accuracy and completeness.

Applicants will often seek a COL after obtaining a design certification (DC) or standard design approval (SDA) for a reactor facility or major portion thereof. In a DC or SDA, applicants seek approval for the generic design of a reactor facility or major portion thereof, independent of the site

Figure 5.1 Two licensing processes for new commercial nuclear power plants in the United States



[a] Inspections, Tests, Analyses, and Acceptance Criteria

where it will be constructed. The application for a DC or SDA will contain, depending on the scope of approval, the same level of technical design information that is present in an OL or COL application, but it will consider facility operation for a generic site operational envelope instead of a specific site. NRC staff reviews the DC or SDA application and works with the applicant to resolve technical issues before issuing the safety certification.

Applicants have also sought COLs after obtaining an early site permit (ESP) for a specific plant site. In an ESP, applicants seek approval for a reactor site, independent of the reactor design. General reactor design parameters, including reactor size, number of reactors, typical cooling configuration, and bounding radiological releases, are considered and evaluated for the geological and hydrological features of the specific site. The ESP application contains the same site-specific information that is present in a CP or COL application, but it considers site suitability for a generic reactor design envelope instead of a plant configuration. NRC staff reviews the application and works with the applicant to resolve technical issues before issuing the ESP.

The advantage of a DC, SDA, or ESP is that they provide a designer or applicant with different levels of regulatory assurance that their design is acceptable to the regulator and could be approved for construction and operation. A DC is considered a final regulatory decision and is not subject to additional review unless substantial new evidence is discovered. An SDA is a quasi-final regulatory decision and regulatory staff is instructed to avoid additional reviews absent new evidence (NRC 2007e). The DC and SDA are also useful from the standpoint of standardizing reactor designs: a DC or SDA may be cited by subsequent site-specific licenses, thereby avoiding the need for redundant reviews and reducing regulatory risk and uncertainty. The Part 52 process has been used to license eleven nuclear reactors in the United States, two of which (the Westinghouse AP1000 reactors at the Vogtle site in Georgia) are currently under construction.

Licensing and Regulatory Support Processes

The COL approach was created in 1989 in the United States and was intended to improve the licensing process for new reactors by reducing the number of hearings and approvals required and by guaranteeing that a reactor that receives a COL can operate (assuming all ITAAC are satisfied) (NRC 1989). Prior to 1989, reactors could be granted a construction permit, complete construction, but have facility operation delayed by several years due to regulatory and public legal challenges related to the issuance of the operating license (Walker and Wellock 2010). While the COL process requires applicants to have complete design and site information years before construction begins (increasing the time and investment required before construction can begin), it increases the likelihood that a plant will operate after significant capital investments are made. The COL approach is optimal for reactor designs that have high design maturity (due to the technical information required as part of the DC or SDA approval process) and high operational maturity (standardization limits a designer's ability to make changes on subsequent reactors based on lessons learned from experience with operating a first reactor), or in cases where designers or owners intend to build in multiple locations (due to the regulatory costs borne by the applicant for completing the DC or SDA approval process).

Licensing activities for new reactors are not limited to formal reviews of license applications for specific reactor facilities or reactor designs. Applicants can receive regulatory feedback on a variety of subjects based on their specific licensing strategy and project needs. Common regulatory feedback processes include:

- Pre-application meetings and discussions to familiarize staff with the applicant's licensing strategy and design.
- Informal regulatory review and feedback on general reactor design features or formal review and approval of specific design and analysis methodologies.
- Formal review and approval of a proposed reactor site before the submission of a CP or COL application.

Table 5.2 summarizes the wide range of regulatory support processes that is applicable to new reactor licensing. These additional feedback processes are valuable because they allow applicants to resolve technical issues before submitting formal applications, avoiding a lengthy formal application amendment process. Pre-application meetings and informal review of a prospective design help ensure the regulatory staff has sufficient familiarity with the proposed design to perform an efficient licensing review. The NRC's staffing costs to support these regulatory feedback processes are paid by applicants on an hourly basis (NRC 2017a). Nevertheless, the interactions are generally recommended to facilitate a more efficient review and are now being used more extensively.

Proposed Licensing Strategies for New Reactors

Interest in advanced nuclear reactors has led different industry and government groups to study and propose new strategies for reactor licensing. These strategies address the applicability of current licensing processes to advanced reactors (including both LWR and non-LWR designs) and the need for processes that better align with timelines for advanced reactor deployment.

The strategies proposed by industry organizations vary from modified applications of existing regulations to the creation of entirely new licensing frameworks for advanced reactors. Use of a staged licensing approach with smaller, more frequent regulatory approvals using existing regulation has been proposed by the Nuclear Innovation Alliance (Finan 2016). This approach is designed to provide greater transparency in the licensing process for companies and investors while allowing for more direct feedback between regulators and applicants. A Nuclear Infrastructure Council white paper also emphasized the need for a staged licensing process together with the implementation of non-LWR-specific design criteria (Merrifield 2016). Such an approach is discussed in the next section.

Led by Southern Company, an industry group has proposed new regulatory frameworks. The Licensing Modernization Project has sought to identify regulatory gaps that must be resolved to support the licensing of non-LWR designs under current regulations. This effort seeks to enable regulatory frameworks that are risk-informed, performance-based, and technology-inclusive. The Licensing Modernization Project intends to submit white papers for NRC approval on three different topics: risk-informed licensing basis event selection, PRA technical adequacy evaluation processes for licensing basis event selections, and PRA technical adequacy evaluation processes for risk-informed, performance-based regulation (Nuclear Energy Institute 2017).

Recognizing public and industry interest in advanced reactor licensing, the NRC has proactively developed policy positions and early guidance on this topic (NRC 2012) (NRC 2017b, c, d). The NRC guidance is largely focused on generic design criteria for advanced reactors and requirements, and not on overall licensing strategy.

As part of the Next Generation Nuclear Plant (NGNP) program, the U.S. Department of Energy (DOE) and the NRC jointly published a licensing strategy document in 2008. The strategy document identified potential licensing strategies for an advanced reactor design and outlined potential changes to NRC licensing frameworks that could be used to accelerate licensing (U.S. Department of Energy and U.S. Nuclear Regulatory Commission 2008). Though the NGNP program did not move forward with efforts in this area, DOE continued work on advanced reactor licensing. The 2016 DOE Advanced Reactor Option Study (Petti, et al. 2017) described licensing pathways for different advanced reactors based on level of technological maturity and reactor license type (i.e., commercial power reactor, commercial prototype reactor, test reactor, research reactor). All pathways relied on existing, available regulatory tools and minimized new NRC decisions.

Table 5.2 Supplementary NRC Licensing Processes

Process		Objectives	Examples
Early Site Permits (ESP) (a,b)		Formal NRC review and certification of the acceptability of a specific site for the construction and operation of a nuclear power plant. The ESP focuses on the overall site characteristics (seismic, meteorological, hydrological, and geologic), surrounding populations and areas, and evaluates whether the site would be acceptable for a reactor of a generic specified design.	ESPs have been issued for Clinton, Grand Gulf, North Anna, Vogtle, and the PSEG site near Salem and Hope Creek Plants.
Manufacturing Licenses (ML) (a,b)		Formal NRC review and certification of the safety and acceptability of a reactor design for a generic site as well as the ability of an applicant to manufacture, transport, and install the reactor. The ML includes full approval of the reactor design and thus requires all of the same technical information required in an OL or COL final safety analysis report related to the design of the reactor. The ML approves the applicant's ability to manufacture and transport the proposed reactor with sufficient quality assurance, the site parameters required for installation of a reactor, and the required interface conditions between the manufactured reactor and the remainder of the plant.	In 1982, a ML was issued to Offshore Power Systems, a reactor designer that intended to construct offshore floating nuclear power plant.
Standard Design Approvals (SDA)		Formal NRC review of the safety and acceptability of a reactor or major portion thereof. Major portion is historically defined in terms of complete system sets (e.g., nuclear island, nuclear steam supply system, turbine island, balance of plant system). The SDA approves the design and operation of a portion of a reactor design and thus requires all of the same technical information required in an OL or COL final safety analysis report for the specific portions covered in the SDA.	SDAs have been issued for entire reactor systems including ESBWR, ABWR, AP600, AP1000, and CE System 80+.
Standard Design Certifications (SDC)		Formal NRC review and certification of the safety and acceptability of a complete reactor system. The SDC approves the design and operation of a portion of a reactor design and thus requires all of the same technical information required in an OL or COL final safety analysis report.	SDCs have been issued for the ESBWR, ABWR, AP600, AP1000, and CE System 80+.
Limited Work Authorizations		Formal NRC review and approval to begin limited site preparation and construction of portions of safety related building prior to receiving a CP or COL. The authorization requires description of all tasks to be completed as well as safety and environmental evaluations of those tasks. The applicant performs the work at risk because the work is completed while the application is still under review and technical details of the project may be subject change.	Limited work authorizations have been issued for a number of projects for site characterization and site preparation.
Pre-Application Meetings		Informal NRC communications, correspondence meetings, document submittals/reviews, and other interactions that occur before formal submittal of licensing applications. Pre-application meetings can provide early identification of regulatory requirements, development of resolution paths for open policy, technical and licensing issues, and increased staff familiarity with design-specific issues to help increase the stability and predictability of the licensing process and reduce time required for review of the formal license application. Pre-application meetings can begin at any point and meeting content will vary significantly on an applicant-by-applicant basis.	These meetings have been used by all reactor design applicants to help explain the system to regulators and get initial and informal regulator feedback on submission materials.
Additional Document Reviews	**White Papers**	Informal NRC review of reports that address and document an applicant's position on specific technical or regulatory issues facing the project. White papers are intended to increase NRC staff understanding of technical or regulatory issues; no formal staff review of the paper is published.	White papers were used to clarify the safety approach in the NGNP gas-cooled reactor system concept.
	Technical Reports	Informal NRC review of reports that provide supporting or supplemental information on technical safety topics in license applications. The technical reports may contain detailed technical information or testing data that support statements or conclusions made in the license application or they may provide more detailed discussion of application-specific methodologies. NRC staff may issue formal questions but will not publish a safety evaluation on the content of the technical report; instead, NRC staff evaluation of the report will be included with the evaluation of the license application.	This is a common approach used by many reactor design applicants to explain details of their safety analyses; e.g., LOCA safety analyses.
	Topical Reports	Formal NRC review and approval of technical topics related to nuclear safety that will apply to multiple applications or licensees. Topical reports allow for a single review of a broader technical issue separate from a specific application review; this is intended to increase regulatory efficiency and consistency. NRC staff may issue formal questions and will publish a final safety evaluation on the contents of the topical report that can be referenced in subsequent applications as precedent.	Topical reports have been issued as part of the design certification for novel reactor protection systems and electrical system designs.

[a] Applicants for supplementary processes can be submitted independent of a CP/OL or COL application and can be submitted before other applications.

[b] Approval of information is considered final and is not subject to re-review if the valid application is referenced and substantial changes or new information has been discovered that could invalidate the original findings.

Creating new regulatory tools—such as a new 'Part 53' licensing process for advanced reactors—through formal rulemaking would take several years and probably would not result in a process that actually expedites licensing (see Sidebar 5.2). The NRC should instead continue to work with applicants to prepare project-specific licensing plans that describe the specific licensing processes and timelines that an applicant can expect to use to license a new reactor. Early discussion and consensus on a licensing plan would be the most effective way to utilize NRC staff and applicant resources to complete licensing using existing regulatory processes. Creating a new regulatory agency specifically for the purpose of licensing advanced reactors would require substantial efforts by Congress and the executive branch, such as amending the Atomic Energy Act or passing new legislation and rulemaking. The political capital and focus necessary for these actions seems unlikely to materialize given current political priorities.

The optimal licensing strategy for new reactor designs, especially advanced reactor designs, will vary significantly based on the reactor technology, its design maturity, and the business model being used. Various proposals by regulatory agencies, industry groups, and non-governmental organizations have suggested different pathways that could be used to license new designs and facilities. These pathways and strategies demonstrate that licensing can be accomplished using existing regulatory processes such as topical reports, standard design approvals, standard design certification, and either Part 50 or Part 52 licensing (see Figure 5.1).

Finding:

A wide variety of pathways and strategies are available for licensing new reactors (including advanced reactors) in the United States. These include using existing regulatory processes such as topical reports, standard design approvals, standard design certification, and either Part 50 or Part 52 licensing.

Recommendation:

While current regulatory structures have sufficient flexibility to allow for technology- or reactor-specific licensing pathways, the U.S. NRC should continue to move toward the use of performance-based and risk-informed design criteria for new reactors.

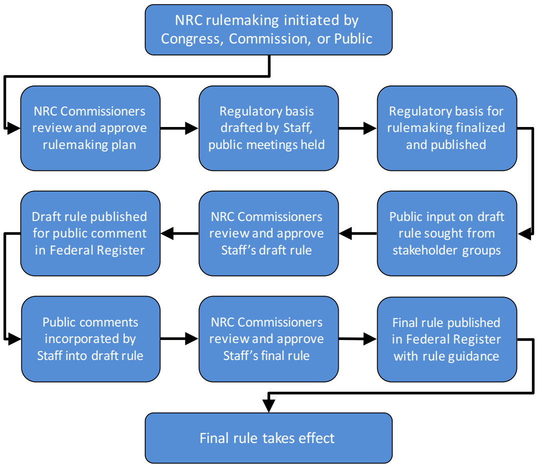
The NRC should work to endorse and implement the use of risk-informed and performance-based design criteria to license new reactors within the current regulatory framework. Use of modern risk assessment techniques can expedite regulatory reviews and focus the allocation of staff and applicant resources. Use of performance-based criteria will be valuable when reviewing new reactor designs that employ innovative approaches to safety that are not well described by current regulation. The combination of risk-informed and performance-based design criteria will provide the greatest flexibility for both designers and regulators in the licensing of new nuclear power plants. Additionally, future design criteria should be written in a technology-neutral matter to ensure their applicability to all advanced reactor types. Use of technology-specific requirements will likely be appropriate in specific instances to reduce regulatory uncertainty. An individual applicant or groups of applicants (utilizing similar reactor technology) could then develop technology-specific requirements in coordination with the NRC as a part of pre-licensing interactions.

Although NRC staff has developed both policy positions and early guidance on portions of the advanced reactor technology licensing process, uncertainty remains with respect to licensing and commissioning an actual advanced reactor facility. The process difficulties encountered by applicants and NRC staff during the licensing of evolutionary LWR designs in the early 2000s led to further concerns about the ability to expeditiously and efficiently license an advanced reactor design. License applications that were missing critical technical details and frequent design changes by applicants reflected the industry's lack of

Sidebar 5.2: Creating New Regulatory Tools

Creating new regulatory tools in the United States can take significant time due to the need for legislative authority, U.S. Nuclear Regulatory Commission (NRC) direction, NRC staff action, and public involvement. The figure below outlines the typical steps required for major NRC rulemakings absent legal challenges or advance notices of proposed rulemaking. The rulemaking process for Part 52 of Title 10 of the Code of Federal Regulation (10 CFR Part 52) provides insights into the steps and time that would be required to develop new regulations for licensing advanced reactors.

Figure 5.3 Typical NRC rulemaking process



(U.S. Nuclear Regulatory Commission 2017f)

The creation of 10 CFR Part 52 was preceded by more than a decade of NRC efforts to develop rules for plant standardization based on existing regulations and on several unsuccessful proposals to Congress for authorization to modify the licensing process (NRC 1987) (NRC 1988) (NRC 1989) (United States Court of Appeals 1992). The formal rulemaking process—including announcement of intent to issue rules, issuance of proposed rules, and issuance of final rules—took approximately 18 months (from September 1987 to April 1989) (NRC 1989).

Legal challenges continued for several years after as the courts decided whether the NRC had the statutory authority to promulgate the new rules (United States Court of Appeals 1992). Passage of the Energy Policy Act of 1992 amended sections of the Atomic Energy Act and provided explicit statutory authority for the Part 52 licensing process (Energy Policy Act 1992).

In December 1998, the Commission agreed to an NRC staff proposal to fully revise and clarify Part 52 through additional rulemaking (NRC 2003). Over the next four and a half years, NRC staff discussed and revised draft rules with public and industry stakeholders. The NRC issued the updated 10 CFR Part 52 as a proposed rule in July 2003 for public comments but halted rulemaking when public comments led NRC staff to decide that further revisions were required. NRC staff made substantial revisions and issued a new proposed rule for public comment in March 2006. After incorporation of final comments, the rewritten 10 CFR Part 52 was issued as final rule in August 2007 (NRC 2007g). The first combined operating license granted under Part 52 was not issued until February 2012.

While the time required to complete the formal rulemaking for 10 CFR Part 52 was limited to between 12 and 18 months for each major revision, the Commission and NRC staff required substantial lead time to prepare for rulemaking and include public comment. The provisions of 10 CFR Part 52 represented a significant paradigm shift in U.S. reactor licensing and substantial time for rule revisions was needed to produce a functional rule even after the final rule was initially promulgated. More generally, new regulations very typically require additional time for the passage of authorizing legislative amendments and to resolve legal challenges, as applicable.

An effort to create new regulatory tools for the licensing of advanced reactors could take more than a decade, especially if the tools significantly depart from regulatory precedent. Smaller changes, such as clarifying existing NRC rules for advanced reactors, could likely be accomplished much more rapidly. Finally, internal policy changes from the Commission or revisions to NRC staff guidance on licensing issues can clarify advanced reactor licensing options without resorting to formal rulemaking. While formal new rules for non-LWR designs could reduce licensing times in the future, it is not clear that substantial schedule benefits could be gained from starting the rulemaking process before there is more of an experience base with commercial advanced reactors in the United States.

experience with the Part 52 licensing process and its difficulty understanding NRC staff expectations. The limitations of initial regulatory guidance on issues such as license application technical content or resolution processes for complex technical issues only became clear once the Part 52 licensing process was used to license evolutionary LWR designs (NRC 2013).

Recommendation:

In the United States, the NRC should test its advanced reactor licensing process in the next few years to identify unanticipated licensing hurdles and to train NRC staff.

While internal readiness reviews and other pre-application activities can help prepare applicants and NRC staff to license advanced reactor designs, actual experience with an advanced reactor design is necessary. Lessons learned from licensing the first non-LWR advanced reactor design will likely be pertinent to all later applicants and will be invaluable in optimizing regulatory procedures to ensure an efficient and effective licensing process. Partial government funding of a lead advanced reactor licensing effort (similar to the abandoned NGNP licensing effort) (U.S. Department of Energy and U.S. Nuclear Regulatory Commission 2008) could be used to improve the regulatory process in preparation for licensing privately funded advanced reactor designs. This policy issue is discussed in Chapter 4.

Phased Licensing Approaches

The concept of fixed licensing periods and costs closely relates to existing proposals for a phased licensing approach that breaks the process of regulatory decision making into several smaller, discrete steps (Finan 2016). When going through the Part 50 or Part 52 licensing process, applicants receive two or one formal regulatory decisions, respectively (CP/OL or COL). The rationale for a phased approach is to provide more frequent, limited milestones related to the licensing process, each of which provides incremental approvals of the design. Instead of spending several years in the licensing process for a construction permit or design certification, applicants could get preliminary approval on smaller portions of the design (e.g., the emergency core cooling system) more quickly and at lower cost.

Phased licensing approaches for advanced reactors have several distinct advantages, especially for companies pursuing highly innovative designs or business models such as staged venture capital funding. Formal regulatory evaluation of small portions of a design allows applicants to prioritize the review of critical systems or systems with high regulatory risk. Early regulatory feedback on these systems can help applicants assess the commercial viability of a design more accurately and inform their decision about whether to proceed with reactor licensing, potentially saving millions of dollars and years of effort if they were considering an infeasible or difficult-to-license design. A phased licensing review also provides greater transparency as applicants move through the licensing process. Formal approvals on portions of a design give applicants tangible insights about their progress through the regulatory process and a ‘citable’ metric that could be used to strengthen their business case when they solicit additional funding from investors to complete the licensing process.

While a phased approach provides flexibility, extensive use of a phased approach could introduce additional time and cost in the process of advanced reactor licensing. A significant challenge is the finality of regulatory decisions in a phased review. Nuclear power plant systems are highly interconnected: the design adequacy of one system depends heavily on boundary conditions or inputs from many other systems. The safety evaluation for a smaller portion of a plant may depend heavily on the design and performance of related systems. In that case, it may not be possible to reach a final regulatory decision until all related systems are evaluated together. A phased approach may provide formal feedback along the way, but the system being reviewed cannot be considered ‘approved’ until all related systems have been reviewed and potentially integral effects have been evaluated. This additional uncertainty about final approval can introduce schedule and cost risk into the licensing process. Additionally, the use of a phased approach could slow the process because the phases of the review would proceed in series, rather than in a parallel fashion. In sum, phased licensing may increase process flexibility, but it would likely also increase the cost, time, and uncertainty involved in licensing an advanced reactor.

Because the NRC already has the regulatory tools in place to implement a phased licensing approach, no new formal regulatory processes are needed. Different regulatory processes can be used depending on methodology, design feature, or system under consideration and the level of finality desired in the regulatory evaluation.

Staff evaluation of applicant reports (such as the topical reports noted in Table 5.2) can provide applicants with feedback regarding design methodology and features, but such evaluations would not be considered formal licensing documents. SDAs can be used to obtain formal licensing approval of major portions of the reactor plant without submitting a full plant design for approval.

Finding:

In the United States, the NRC currently has the regulatory processes available to implement a phased licensing approach for advanced reactors—thus no new formal regulatory processes are needed. Use of phased licensing processes, however, may increase the total cost, time, and uncertainty related to advanced reactor licensing. Applicants must determine on a case-by-case basis which licensing approaches best suit their project and should work with the NRC to create design-specific licensing plans that use the most appropriate set of regulatory tools to achieve desired outcomes from the licensing process.

Licensing Processes for Prototype, Test, and Research Reactors

Licensing new reactor designs can be challenging if there is insufficient commercial operating experience to validate the design or performance of safety systems. Where operating experience is lacking, safety systems can be validated via separate and integral effects testing or via demonstration using a prototype reactor. While some tests can be performed in laboratories without nuclear fuel (such as verification of flow or heat transfer conditions), other tests (such as test validation of fuel feedback effects) will require the use of a full-size or reduced-scale nuclear reactor (NRC 2017e). The validation of critical safety features for innovative designs that have not amassed significant operating experience will thus likely need to be accomplished through the use of prototype, test, or research reactors. In this section we discuss licensing definitions, requirements, and pathways for prototype reactors. Prior sections have detailed the impact of reactor prototypes on technology development (Chapter 3) and business considerations (Chapter 4).

The terms ‘prototype,’ ‘test,’ and ‘research’ have at times been used interchangeably to describe the first reactors constructed using a new design. The terms ‘first-of-a-kind’ (FOAK) and ‘demonstration’ have also been used to describe such reactors. Each of these terms, however, defines a specific type of reactor or reactor license. Their formal definitions from a regulatory perspective are as follows:

- *Prototype reactors* are non-commercial or commercial reactors that use novel design features and have additional safety features to account for uncertainty related to their design.
- *Test reactors* are larger non-commercial reactors (in the sense that less than 50% of their operating costs are recovered by commercial activities). Any non-commercial reactor with power levels above 10 megawatts of thermal output (MW_{th}) or with power levels above 1 MW_{th} that uses novel design features is classified as a test reactor.

- *Research reactors* are small non-commercial reactors (less than 50% of operating costs recovered by commercial activities). They must have power levels below 10 MW_{th} to be classified as a research reactor or below 1 MW_{th} if they have novel design features.

- *FOAK reactor* has no formal regulatory definition, but the term 'FOAK' generally refers to any reactor that is the first commercial unit of that design to be constructed.

- *Demonstration reactors* have no formal or official regulatory definition.

Previous non-LWR designs have been categorized into these reactor types depending on reactor size, whether they were operated as commercial or non-commercial facilities, and the novelty of their design.

Research and test reactors can be licensed under either 10 CFR Part 50 or 10 CFR Part 52. The process is the same as that for commercial reactors, but Section 104(c) of the Atomic Energy Act directs the NRC to "impose only such minimum amount of regulation" to protect the public and to "permit the conduct of widespread and diverse research and development" (Atomic Energy Act of 1954). The NRC has published guidance on license applications for research and test reactors in NUREG-1537 and many of the best practices from commercial licensing (pre-application interactions, licensing plans, etc.) are also applicable to the efficient licensing of research and test reactors (U.S. Nuclear Regulatory Commission 1996). The novel design features that can distinguish such reactors include circulating loops for fuel testing or in-core experimental facilities over a certain size (NRC 2007a).

Limited regulatory guidance and no historical precedent exist for the modern licensing of prototype reactors. The addition of 10 CFR 50.43(e) to NRC regulations in 2007 was intended to open the door to prototype reactor testing as an acceptable method for demonstrating the safety of novel design features (NRC 2007f). A prototype reactor can be licensed under either 10 CFR Part 50 or 10 CFR Part 52 but due to engineering uncertainties in the design and operation of a reactor with novel design features, the NRC "may impose additional requirements on siting, safety features, or operational conditions" in the case of a prototype reactor (NRC 2007a). Since provisions for a prototype reactor were added to NRC regulations in 2007, no applicant has attempted to license such a reactor but there has been renewed interest in using the prototype reactor licensing process to license advanced reactors, and in fact this is the approach we recommended in Chapter 3 for the less mature Generation-IV reactors. In 2017, the NRC published the first in a series of staff white papers providing preliminary staff positions and guidance on the licensing of prototype reactors (NRC 2017e).

Prototype Licensing

The NRC should begin developing licensing strategies for prototypes of advanced reactor designs. U.S. nuclear regulations in the 1950s and 1960s permitted the design, construction, and operation of a wide range of nuclear technologies. As noted earlier, four main safety principles—engineering margin, lower reactor power, containment, and remote siting—characterized these early regulations (Walker and Mazuzan 1992).

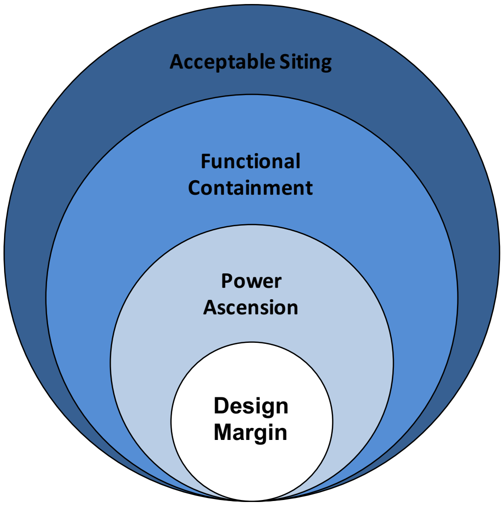
Application of these four safety principles can protect public health and safety independent of the specific reactor technology being considered (LWR or non-LWR) and can reduce accident-related risks by limiting the radiological source term and the consequences of an accident if one were to occur. These safeguards may also reduce the burden of proof required in license applications and expedite prototype license reviews.

Applicants with innovative reactor designs would not need to make a full, *a priori* demonstration of reactor safety. Rather, they could use the prototype reactor to generate needed engineering data and operating experience, and to conduct the integral testing required to license the next reactor based on the prototype design. This change could significantly reduce the time required to license a prototype reactor.

A licensing strategy for prototype reactors can have the following attributes (Figure 5.2):

- Conservative design margin – Design components and systems with additional engineering margin (beyond that required by consensus codes and standards) to help compensate for uncertainties related to operation or other physical phenomena.
- Power ascension – Limitation on the initial reactor power and/or radionuclide inventory to limit radiological release source term during testing. Power ascension programs could be used to reach final rated power given successful testing.
- Functional containment – Use of structures, systems, and components that can limit radiological releases, mitigate off-site consequences, and satisfy defense-in-depth principles.
- Acceptable siting – Sufficiently large site boundaries and/or siting away from population centers to minimize the potential for public exposure during operation and testing.

Figure 5.2 Conceptual Picture of Prototype Safety Attributes



Under this process, applicants could design and construct prototype reactors using a reactor technology with innovative features. With the attributes described above, the new process could accelerate early-stage research and development in new nuclear technologies. The regulator would need to agree on the conditions or analyses required to be completed before additional prototype reactor safety features could be removed. This would help ensure that safety features added to account for uncertainty in the prototype are not required on subsequent similar plant designs.

Another consideration is that a company may choose to build and test prototype reactors outside of its market territory for strategic or economic reasons—for example, testing reactors in Canada for sale in the United States (see Chapter 4). If a regulatory authority other than the NRC oversees prototype testing and licensing for a reactor design that will be sold in the United States, the results of the prototype testing must still meet NRC requirements. In that case, applicants must work with the NRC before prototype construction to ensure that the prototype test program will satisfy all applicable regulatory requirements. Specifically, data from the test program must meet NRC requirements for nuclear quality assurance (NRC 2017e).

Finding:

The U.S. NRC's prototype rule can provide an alternative pathway for licensing advanced nuclear reactor designs.

Recommendation:

The U.S. NRC should clarify its prototype rule and licensing pathway to allow for more rapid licensing of prototype reactors without excessive regulatory burden. While additional safety features may be required to license a prototype reactor, regulators and license applicants should agree to conditions (experimental tests and data) that would allow for these features to be removed in future plants. The prototype licensing pathway should be available to all reactor technologies.

Codes and Standards

The NRC relies in part on consensus codes and standards for the licensing and regulation of commercial nuclear activities. It incorporates such codes and standards into regulation by endorsing or approving the use of designs, codes, and standards created by industry groups, such as the Electric Power Research Institute (EPRI), or standards and professional organizations, such as the American Society of Mechanical Engineers (ASME), the American Concrete Institute (ACI), and the American Nuclear Society (ANS). These individual groups and organizations control the drafting, updating, and revision of all consensus codes and standards. In the United States, the federal government is required by law to use consensus codes and standards where appropriate to reduce duplicative work by taxpayer-funded agencies and to promote uniform adoption of standards (National Technology Transfer and Advancement Act of 1995 (1996)). Reliance on consensus codes and standards also allows the NRC to collaborate closely with groups of independent subject matter experts to determine appropriate design requirements and methods for commercial nuclear activities.

While the NRC's use of consensus codes and standards has resulted in the safe design and operation of nuclear power plants to date, there is a need to re-examine the cumulative impact of these codes and standards. In the past, consensus codes for specific types or classes of structures, systems, and components (SSCs) were developed independently by different organizations: for example, Section III of the ASME code for boilers and pressure vessels provides rules for the design and construction of pressure-retaining components and supports. As a result, the interactions between different codes (e.g., ACI's civil design codes for a building and ASME's mechanical design codes for a building component) within possible event sequences have typically not been explicitly examined. Conservative interface conditions are normally assumed but these assumptions are made at the discretion of the code committee. The overall system effects or event sequence consequences of these code interactions should be reviewed, since event sequences rarely involve a single type or class of SSC. For example, a component with a high design margin cannot perform its safety-related function if the low margin structure it is located in has collapsed.

Inconsistent requirements with respect to design margin under different codes and standards can result in the relative under-design or over-design of components. Individual consensus committees determine acceptable levels of safety based on the design philosophy particular to their practice. While the process results in codes that reflect an individual profession's definition of safety, the overall safety of the plant depends on interactions between these codes. Reviewing and aligning definitions of safety and design margin between different consensus codes and standards would have several important benefits:

- Harmonizing design margins could allow for reductions of excess margin in some types of SSCs where the safety benefits of the extra margin are never realized because other components would fail first in the event sequences of concern. Lower design margins could produce cost savings in the manufacture of some components or provide greater flexibility during operation. Harmonization could also result in increased design margins for some components, to ensure they do not disproportionately contribute to the risks or consequences associated with a given event sequence.
- Reviewing design margins in consensus codes could help address the phenomenon of gradual but continuous increases in safety requirements, commonly described as a 'ratcheting' of safety requirements. Explicitly quantifying the sources and rationale for design margin in codes and standards can be used to quantify the current safety of components and identify gaps or overlaps in design codes that could be resolved. Elimination of unneeded design requirements or margin could have significant impacts on cost and operations.

- Aligning the design margins contained in independent consensus codes and standards and in NRC rules could prompt larger discussions about assuring system safety and understanding system behavior during event sequences. Because nuclear power plants are not composed of isolated systems, system interactions are critical. For this reason, explicitly discussing the impacts of design margin on system performance is important to ensure the overall safety of plant operation, especially in off-normal or emergency conditions.

For example, studies of seismic codes have demonstrated that significant excess margin could be identified in existing codes. Thus, it is possible that consensus codes could be updated to remove or clarify required design margins (Budnitz and Mieler 2016). Such a review process could be extended to the major consensus codes and standards used in designing and constructing nuclear power plants. Larger discussions about the interactions between different consensus codes and about opportunities to standardize design margins across codes would likely need to be initiated by both industry groups and the NRC.

Finding:

Inconsistency in the design margins required by different codes and standards can result in relative under-design or over-design of structures, systems, and components.

Recommendation:

Consensus codes used in the design and construction of nuclear power plants should be re-evaluated in terms of their efficacy in ensuring safety. The nature of system interactions in advanced reactor designs may fundamentally differ from previously operated reactor designs. Existing consensus codes should be reviewed so that overlapping standards are properly harmonized. This harmonization will both reduce the regulatory burden and help ensure safe operation for advanced reactor designs.

5.6 CHALLENGES TO ADVANCED REACTOR LICENSING COST AND SCHEDULE

One of the most often cited barriers to licensing advanced reactor technologies is the cost and time associated with the licensing process (Finan 2016) (Merrifield 2016). Previous efforts to license reactors in the United States, whether under 10 CFR Part 50 or under 10 CFR Part 52, took longer than initially anticipated and incurred higher-than-expected regulatory costs (NRC 2015). Historically, licensing costs (i.e., fees billed by the NRC to the license applicant) have been on the order of $100 million for a complete design certification review and $25–$50 million for a site-specific combined operating license (NRC 2015). Typically, applicants have also incurred additional costs to complete the design work required for a license application and to respond to NRC staff questions on the application. Chapter 4 discusses the business implications of advanced reactor licensing costs.

The NRC has recently planned for a 42-month process to review two specific reactor designs: the Korean APR1400, a large Generation-III+ PWR, and the NuScale small modular reactor (SMR), an integral PWR with several novel features that pose policy issues for LWRs (Akstulewicz 2017). Based on previous experiences (see Sidebar 5.3), there is some uncertainty as to whether the planned 42-month review timeline can be met.

Several topics will need to be considered with respect to the licensing process for advanced reactors in the United States:

- License application quality, completeness of design, applicant design validation by test or analysis, and applicant–regulator interactions.
- Duration, cost, and uncertainties of the licensing process.
- Guidance for regulatory staff on efficient processes for resolving technical questions raised during license application reviews.
- Final resolution of policy issues before submissions of license applications.
- Appropriate NRC and senior management oversight of regulatory staff performing licensing reviews.
- Implementation of nuclear quality assurance programs and requirements
- Potential design and operational impacts of revisions to radiation health effects models.

If issues arise in connection with any of the above topics, they will likely result in schedule delays and increased costs associated with the licensing process. Additionally, detailed clarification of licensing rules related to prototype reactor designs will be critical if applicants decide to license their first commercial reactors as prototypes.

Regulatory Preparedness for Advanced Reactor Reviews

Regulatory staff must be available and trained to ensure that applications can be appropriately reviewed. In the United States, the NRC has stressed the importance of "the right number of people with the right skills at the right time" (Fitch and Weber 2015) as it seeks to refocus its resources on advanced reactor licensing through Project Aim. This effort is challenging given the fast-moving nature of startups and newly formed reactor design companies, the technological diversity of reactor designs currently being pursued (e.g., high temperature gas, molten-salt, sodium, lead and gas fast reactors), and the NRC's

Sidebar 5.3: Cost Increases and Schedule Delays for Advanced Reactors

In the United States, the design certification review process laid out in Part 52 of Title 10 of the Code of Federal Regulation (10 CFR Part 52) has resulted in significant delays for reactor designs that have already been licensed, and, in some cases, constructed, in other countries. Such delays (which have been caused, in part, by both applicants and regulators) may cause companies to choose not to complete the licensing process in the United States.

For example, the EPR was docketed for design certification in 2007 after nearly three years of pre-application interactions. At the time the license application was submitted to the U.S. Nuclear Regulatory Commission (NRC), the EPR was already approved and under construction at the Olkiluoto site in Finland and the Flamanville site in France. The project initially had a 38 month review timeline with the Final Safety Evaluation Report scheduled for release in 2011. By 2013, the timeline had extended to 80 months with the Final Safety Evaluation Report scheduled for release in 2015 due to challenges (technical and regulatory) encountered during the review. NRC reviews continued (without a public updated schedule) until February 25, 2015 when Areva formally requested that the EPR review be stopped without receiving design certification. In total, Areva paid over $82 million for the incomplete review and never completed the licensing process for the EPR in the United States.

The Mitsubishi APWR was docketed for design certification in December 2007 after nearly two years of pre-application interactions. At the time of application submittal, the APWR was already undergoing a licensing safety evaluation for two units at the Tsuruga site in Japan. The project initially had a 45 month review timeline with the Final Safety Evaluation Report scheduled for release in 2011. By February 2013, the timeline had doubled to 93 months with the Final Safety Evaluation Report scheduled for release in 2015 due to challenges (technical and regulatory) encountered during the review. On November 5, 2013, Mitsubishi formally requested that the APWR review be stopped without receiving design certification. In total, Mitsubishi paid over $86 million for the incomplete review and never completed the licensing process for the APWR in the United States.

Advanced reactor designs could also be delayed by uncertainties related to design and technology. Recognizing this concern, applicants and regulators have begun taking preemptive action to mitigate the risk of such delays. These actions include initiating early interactions between applicants and regulatory staff, ensuring that adequate design and technical resources are made available, and communicating more clearly about schedule, questions, and technical expectations. In a notable demonstration of the success that can be achieved with these approaches, the Korean APR1400 was reviewed and is expected to receive its design certification with no delays from the original certification schedule.

funding limitations. While the first two challenges could be overcome given sufficiently large regulatory staffs, the cost and inefficiency of hiring staff to prepare for every potential application would be impractical (see Sidebar 5.4).

New business models for reactor development (e.g., venture capital funded startups) often have short timelines (one to five years) that require more rapid regulatory decision-making to be commercially viable. Regulatory agencies may be unable to accommodate sudden requests for extensive regulatory review so early communication about expected review scope and schedule is critical for their workload planning. It is also important to note that this communication is only valuable if it is accurate. Applicants' estimates of scope and schedule must be realistic and applicants' interactions with regulatory staff must not be used as a marketing tool with the aim, for example, of signaling commercial viability using idealized and unrealistic schedules.

As noted previously, the wide range of reactor technologies currently under development by different companies presents a challenge in terms of regulatory readiness. The cost of developing and maintaining a full regulatory staff to review reactor technologies that may never be built is not currently justifiable, so regulatory agencies must selectively hire, train, and maintain staffing based on credible information from industry about potential license applications. Early, frequent, and accurate communication (several years in advance) from companies regarding their plans to apply for licenses is extremely valuable. This allows regulators to appropriately train staff to review advanced reactor license applications. Accurate representations of technical readiness are also important so that regulators can perform the research needed to support a robust review of the actual license application.

Adequate Regulatory Funding and Staff for Advanced Reactor Licensing

Adequate funding is critical to having the right people with the right skills at the right time to ensure timely licensing of advanced reactors. In the United States, the NRC, unlike most other federal agencies, is required to recover 90% of its total budget through annual fees on current licensees. These fees are variable and are in addition to the fees the NRC directly charges for its services (42 U.S.C. § 2214 (2005)), making it difficult for the NRC to hire and train staff in anticipation of advanced reactor license applications (even based on credible pre-application interactions). Furthermore, the operators of the current reactor fleet would have to pay for these preparatory activities, which do not benefit them and may not ultimately be needed if the license applications never actually materialize. Removing advanced reactor licensing infrastructure (staff training, procedure development, etc.) from the fee base and allowing for direct federal funding of these activities would give the NRC the flexibility to prepare, as the agency deems appropriate, for advanced reactor license applications. This approach is in line with the direct support and public funding provided to other federal agencies that work with rapidly developing technologies such as pharmaceuticals (in the case of the U.S. Food and Drug Administration) and aviation (in the case of the Federal Aviation Authority) (Finan 2016).

Finding:

Adequate funding for advanced reactor licensing efforts is necessary to ensure timely licensing actions. In the United States, funding for such licensing development efforts is currently limited and comes from operating nuclear facilities.

Recommendation:

The U.S. government should provide funding for advanced reactor regulation outside the NRC's 90% fee recovery model to ensure that sufficient resources are available when needed. At the same time, the nuclear energy industry must communicate regulatory function and research needs with key U.S. entities, including the NRC, DOE, and Congress, to ensure that adequate funding is appropriated.

Sidebar 5.4: Does the NRC Need to Be Reorganized to Effectively Regulate Advanced Reactors?

A number of proposals have been put forward for reorganizing the U.S. Nuclear Regulatory Commission (NRC) so as to improve its efficiency and effectiveness. One suggestion involves eliminating the NRC structure of appointed commissioners and moving to a single administrator, similar to the structure of other regulatory agencies, such as the U.S. Environmental Protection Agency (EPA). This is not a new recommendation, it was suggested as early as 1979 by the Kemeny Commission in the aftermath of the Three Mile Island accident (United States President's Commission 1979). The idea was raised again in discussions with multiple experts as part of the research for this study, the argument being that the current collegial five-member commission involves prolonged deliberations that may not be effective at responding to the regulatory and technical demands of assuring safety in advanced nuclear reactor designs. In our view, however, changing from the current commission structure to a single administrator would not be beneficial and while it might appear to improve regulatory efficiency in the short term, it could actually be counterproductive from an efficiency standpoint over the longer term. Reorganizing the NRC under a single administrator appointed by the president could subject the NRC to greater political pressure and distract its focus away from the core mission of protecting public health and safety. The current five commissioners are presidential appointees, but the organization is arranged to minimize political influence through the use of fixed five-year terms during which commissioners cannot be removed by presidential order. This structure has proved workable since it was introduced under the original Atomic Energy Act and as it was amended over the decades since, and it has served to de-politicize both the selection of commissioners and the decisions they make.

Another suggestion has been to reorganize the NRC staff to provide a more efficient and effective organizational structure for reviewing advanced reactor designs and for developing the needed technical basis to conduct license reviews. The NRC currently has three statutory offices: Nuclear Materials Safety and Safeguards (NMSS), which is responsible for radiological materials; Nuclear Reactor Regulation (NRR), which is responsible for licensing and regulating commercial and non-commercial reactors; and Nuclear Regulatory Research (RES), which is responsible for performing new research to support regulatory activities. The New Reactor Office (NRO) was established after 2000 in anticipation of advanced light water reactor (LWR) designs, but it is to be merged with NRR. NRR and RES collaborate to develop the appropriate technical bases and regulations for the current generation of LWRs. This collaborative approach has been quite successful as evidenced by the development of general design criteria (NRC 2007c), risk-informed regulatory advances, and all the supporting longer-range research that RES conducts by way of providing technical assistance to NRR.

A similar organizational arrangement could be developed for future regulatory initiatives related to advanced nuclear reactors. For example, a new division of NRR could be established to support advanced reactor concepts while a parallel division could be established in RES to support long-term research aimed at developing the needed technical bases for safety criteria and guidance. Since NRO is now being reintegrated into NRR, this division's mission could be specifically focused on regulating advanced reactor designs. A corresponding group within RES would also be needed to support longer-term research related to advanced reactors. Finally, the NRC would need to organize experienced senior managers and staff as well as new hires in NRR and RES to focus on advanced reactor designs over the next decade and to develop appropriate regulatory guidance for these designs.

Effective Reviews and Efficient Resolution of Staff Technical Questions

Reviewing license applications is a formal and iterative process. First, members of the regulatory staff review applications and submit clarifying questions or concerns as 'Requests for Additional Information' (RAI). Applicants then prepare responses or submit revisions to the license application based on the RAIs. Regulatory staff reviews the responses or updated application and repeats this review cycle until staff believes the applicable regulatory requirements have been satisfied. While the formal nature of the process guarantees public transparency, the process itself may require several iterations if RAIs or applicant responses are unclear or incomplete. These iterations can significantly extend the cost and time associated with license review. Both the regulator and the applicant need to address the question of how to minimize the number of review cycles and total time required to resolve technical questions related to the license application.

While a questioning attitude among regulatory staff is essential to protect public health and safety, staff and management need to clearly and directly communicate technical concerns and questions to allow for more rapid resolution of regulatory issues. Anecdotal evidence suggests that NRC staff can sometimes become focused on the precise resolution of technical questions without considering the larger safety significance of these questions. In other cases, staff may be unwilling to make a formal decision on a regulatory issue and may resort instead to additional RAIs to gain further information. NRC management may be hesitant to influence the staff to make expeditious decisions for fear that this will be misconstrued as direction to stop pursuing a safety concern. This concern can be exacerbated if NRC staff is using engineering judgment rather than historical precedent or external codes and standards to reach a decision on a regulatory issue.

Effective resolution of technical questions from regulatory staff is critical to control the duration and cost of license reviews. The licensing processes for the Areva[2] EPR and the Mitsubishi advanced pressurized water reactor (APWR) were substantially delayed by Areva's and Mitsubishi's slow resolution of technical questions raised by NRC staff. NRC staff filed 629 formal RAIs during the licensing process for the EPR and 1,111 RAIs during the licensing process for the APWR (NRC 2015). These cases illustrate how delays and cost overruns can arise as applicants attempt to fully answer staff requests and follow up on questions that may or may not actually impact public health and safety.

While resolving technical questions is critical to ensure the safe design and operation of advanced reactors, it could be accomplished more rapidly. NRC staff and management have recognized the need to keep the RAI mechanism focused on key safety issues and have begun scheduling more frequent face-to-face meetings with applicants in recent design certifications (e.g., for the APR1400 and NuScale licensing reviews). Such applicant–staff meetings have become a key way to clarify design details and minimize needless RAIs (NRC 2013). Both NRC staff and applicants have acknowledged that that this approach improves review effectiveness.

Nuclear Quality Assurance in the United States

Nuclear quality assurance (NQA) is a cornerstone of nuclear safety but the current implementation of NQA programs and requirements should be reviewed to ensure that the additional time and costs are justified and necessary to adequately protect public health and safety.

Nuclear quality assurance aims to ensure that the structures, systems, and components (SSCs) required for safe operation of a nuclear power plant will "perform satisfactorily in service." NRC requirements in 10 CFR Part 50, Appendix B, and consensus implementation guidance in the American Society of Mechanical

[2] As noted in previous chapters, Areva's reactor business was renamed Framatome and sold in 2018.

Engineers' (ASME's) Nuclear Quality Assurance Requirements for Nuclear Facility Applications (NQA-1) provide the basis for company-specific quality assurance programs for "designing, purchasing, fabricating, handling, shipping, storing, cleaning, erecting, installing, inspecting, testing, operating, maintaining, repairing, refueling, and modifying" nuclear safety-related SSCs (NRC 2007h). NQA requirements and procedures are intended to provide "reasonable assurance" that components can meet the performance criteria assumed in plant safety analyses. These requirements and procedures can include additional documentation related to procurement, additional physical inspections or testing, or additional verification of design or manufacturing activities.

The increased engineering and administrative overhead associated with greater quality oversight, coupled with additional manufacturing costs for higher-quality operations, are largely responsible for the increased costs associated with 'nuclear-grade' over 'commercial-grade' SSCs. For certain components, the costs of a nuclear-grade component may be substantially higher than a similar commercial-grade component due to additional environmental specifications and qualifications (e.g., operation in high temperature or high radiation environments). These additional specifications may accordingly result in substantial modifications to the design or manufacturing of the standard commercial-grade component.

The requirements and guidance in 10 CFR Part 50 Appendix B and NQA-1 for quality assurance, as written, allow for the implementation of flexible and user-defined requirements to create a systematic process for ensuring quality, accountability, and traceability of safety-related components. These written requirements do not appear to present an undue burden, rather anecdotal evidence suggests that deeper cultural issues may be responsible for many of the challenges and costs associated with NQA.

Inconsistent, overly conservative, or verbatim enforcement of subjective written quality requirements can result in significantly higher costs and longer production times for SSCs without a commensurate increase in reliability or quality. There are no published data comparing the quality or reliability of SSCs designed or produced under a nuclear quality assurance program to those designed or produced under a standard or commercial quality assurance program. It is currently unclear if NQA programs have a quantifiable effect on SSC quality and there was disagreement among interviewed quality assurance engineers as to the effect of NQA components on plant safety when compared with nominally identical, high-grade commercial components (specific environmental qualifications not withstanding).

The nuclear industry, consensus standards committees, and regulators need to ensure that the implementation of NQA programs actually increases plant safety and does not simply satisfy procedural quality requirements for their own sake. A better understanding is needed of the differences in terms of reliability, failure rates, and quality of SSCs produced under NQA programs and standard quality assurance programs. This is critical in making more informed decisions about the appropriate classification of SSCs and implementation of NQA programs for safety-related applications.

NQA-related costs could be mitigated by reducing the number of safety-related SSCs subject to NQA programs. Inherent reactor safety design features and other design choices can be used to reduce the number of components that must be categorized as safety related. Use of probabilistic risk assessment to assess the safety and risk significance of SSCs (e.g., risk-informed categorization of SSCs as discussed in 10 CFR 50.69) can also be used to properly categorize the quality requirements for low-risk SSCs. Qualification of commercial-grade SSCs as nuclear-grade SSCs through a commercial grade dedication process may reduce NQA-related costs for certain types of SSCs (e.g., pipes, conduit), but is unlikely to reduce overall costs related to NQA. High-quality verification standards required by commercial grade dedication processes still have the same cost challenges as NQA design and manufacturing processes.

Industry Licensing Challenges

The success of advanced reactor licensing depends on both regulator and applicant. As the designers of such reactors continue to engage in pre-application interactions with regulators, they must ensure that they provide adequate information and personnel support to enable effective and efficient licensing.

Companies interested in designing and licensing advanced reactor technologies must improve on historic industry performance in four key areas: regulator interactions, application quality, use of appropriate testing and analysis, and timely resolution of regulatory questions. First, applicants must provide realistic responses to NRC queries concerning expected licensing activities. This will help the NRC hire and train the right staff in the right timeframe. Using license applications as a marketing activity to demonstrate commercial viability limits the NRC's ability to appropriately prepare for advanced reactor reviews. Second, applicants must submit complete, high-quality license applications, not partially complete applications, to meet timetables. High-quality applications are critical to efficient review and approval. Third, in cases where there is limited operating experience with an advanced reactor design, the applicant must perform adequate experimental testing and associated validation of analysis methods to assure regulators of the safety of the design. Finally, applicants must allocate sufficient technical resources to respond to NRC RAIs in a timely manner. Failure to meet agreed-upon schedules for submitting RAI responses can challenge the scheduled availability of NRC staff resources and significantly impact the overall review timetable. Without performance improvements in these four areas, licensing processes for advanced reactors may be significantly more costly and take significantly longer.

Pre-application Resolution of Policy Issues

Final resolution of policy issues before a license application is submitted reduces the potential for extended discussions and delays as decisions are made on policy issues that could impact reactor design. An example would be the issue of digital protection systems in the Areva EPR design (Matthews 2013), which serves to highlight the importance of early interactions between applicants and regulatory staff and the need for timely decisions on policy questions that are critical to advanced reactor design. Some of the policy issues currently being considered by the NRC are emergency planning, physical security requirements, and allowable staffing of SMRs.

Safety and Operational Impacts of Revisions to Models of Radiation Health Effects

Current operational limits on worker exposure to radiation and emergency planning zone requirements are based on the assumption that exposure to any level of ionizing radiation constitutes a health hazard to humans with an incurred risk that is proportional to the dose received—this assumption is also known as the 'linear no-threshold' (LNT) hypothesis. As reflected in regulatory standards, the LNT hypothesis has significant implications for all aspects of nuclear reactor design, operation, maintenance, and emergency planning. Various professional societies have addressed the need for additional targeted research on the human health effects of low-dose ionizing radiation in light of advances in cellular biology (see Sidebar 5.5).

Sidebar 5.5: Rethinking the discussion on low-dose ionizing radiation

Current safety regulations for nuclear facilities are based on a model of health effects from exposure to ionizing radiation that assumes a linear relationship between health effect and radiation dose. The model also assumes that there is no 'safe' threshold for radiation exposure—that is, a level of exposure below which there are no health effects. Thus, the model is known as the linear, no-threshold (LNT) model. That a linear relationship exists between radiation exposure and health effects at high radiation doses is well established, largely based on the Life Span Study of survivors of the atomic bombings at Hiroshima and Nagasaki, Japan in 1945. The extrapolation of the LNT relationship to low radiation doses—that is doses below 100 millisievert (mSv) or 10 roentgen-equivalent-man (rem)—is, however, highly debated (100 mSv is approximately 20% of the average lifetime dose of radiation exposure in the United States, including all natural and man-made sources).

At low doses below 100 mSv, correlating radiation exposure with health effects is challenging due to the presence the other factors (e.g., environmental, genetic, etc.) that present known health risks of a similar magnitude and that are not easily separable from epidemiological data. Demonstrating a radiation-dose/health-effect relationship with statistical certainty from previous epidemiological data has thus proven impossible. Studies of human cells have provided insights to specific radiation damage and repair mechanisms. A number of these studies have suggested that a non-linear relationship exists between DNA damage due to radiation exposure and cellular DNA repair mechanisms, but this effect appears to be highly dose rate dependent. Applying these results to overall health effects is difficult, moreover, due to the complexity of interactions between human cells.

The LNT model is easy to understand, simple to use for radiation protection in practice, and may be considered a bounding hypothesis for radiation health effects. For these reasons, it continues to be the radiation protection model recommended by nearly all regulatory and advisory organizations, including the International Atomic Energy Agency (IAEA), the International Commission on Radiological Protection (ICRP), and the National Council on Radiation Protection and Measurements (NCRP). It is unclear, however, how accurate the LNT model may be at the annual doses (approximately 1–10 mSv/year) normally associated with background radiation and commercial applications of radiation protection. Use of the LNT model for health effects at low doses has had two major impacts on the licensing and operation of commercial nuclear power plants: it has led to the application of the ALARA ('as low as reasonably achievable') principle to worker radiation protection, and it has affected offsite emergency planning requirements for nuclear reactor plant sites.

In practice the ALARA principle means continuous efforts to keep radiation exposures as low as achievable, often far below the legally required radiation dose limits for nuclear workers. It follows from the LNT model assumption that an incremental increase in radiation dose has an incremental adverse health effect. ALARA is implemented as an iterative optimization process that seeks to balance radiation dose risks and the costs of further reducing radiation dose exposure. The result has been to impose significant constraints on the scope and duration of routine operation and maintenance activities at nuclear power plants. Utilities constantly strive to minimize worker exposure to radiation in order to keep average and total worker doses as low as reasonably achievable. While the use of ALARA has resulted in gradual but substantial reductions in average worker doses at light water nuclear power plants since the 1970s (from 9.7 mSv/year in 1973 to less than 1 mSv/year in 2015), the cumulative costs associated with this approach have grown substantially. The question is whether the costs associated with current levels of radiation protection have been justified compared with other risks and whether the resulting reductions in worker doses have had any measurable health benefits.

Offsite emergency planning requirements for nuclear power plants are based on the principle of minimizing public harm following an accident or radiological release at a nuclear facility. The current response to such an event is evacuation of the public away from areas around the plant that have been contaminated or from areas that plant and governmental officials believe may become contaminated. While evacuation is an effective strategy for reducing public dose, it carries significant risk of public harm. Emergency evacuations have resulted in significant numbers of injuries and premature deaths because they involve rapidly transporting large numbers of people, including moving and rehousing many sick and elderly individuals, and force residents to re-locate for long periods of times. The evacuation experiences following the Fukushima nuclear accident have shown that current emergency planning and evacuation requirements in all likelihood do not correctly balance the risks of large-scale evacuations with the health risks of low-dose radiation exposure. An improved scientific understanding of low-dose radiation health effects could inform better policy decisions with respect to emergency planning requirements for nuclear power plants.

The high financial and social costs associated with current radiation protection standards and practices can discourage the use of nuclear technology as an energy resource, which itself carries tangible social costs in terms of foregone opportunities to provide cleaner air, lower carbon emissions, and greater access to energy for economic development.

Several ideas are worthy of urgent examination and further research in the pursuit of a more effective and scientifically robust radiation protection standard. Specifically, we recommend efforts to study the feasibility of:

- Establishing an annual dose below which radiation exposure is not regulated. This dose, likely on the order of the background radiation, is not necessarily a threshold below which no health effects occur; rather it is a dose below which health effects simply cannot be identified in the presence of other health risks. This concept is consistent with the policy statements of the Health Physics Society and other international groups. (Health Physics Society 2016) (Pradhan 2013)
- Expressing regulatory limits to radiation exposure for workers and population groups in terms of 'added measurable radiological risk' (i.e., the health risk increment from radiation exposure), rather than in terms of effective dose. This change would enable a more transparent comparison of radiological risks to risks incurred in everyday life and other industrial activities. These limits would allow for a uniform evaluation of both worker protection and emergency planning requirements.
- Introducing individual dose limits by making use of advanced genomics techniques and assessing individual parameters that influence the likeliness of radiation-induced damage to an individual (e.g., genetics, individual sensitivity, organ size, metabolism, biokinetics, etc.). Advances in modeling and simulation, and in genomics and medical science may, in the long term, make it possible to individualize radiation protection requirements at the level of a specific worker. This would allow for the determination of individually-tailored dose and dose rate constraints that correspond to a regulatory limit.

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Appendix A

GenX Input Values

This appendix provides all GenX input values used in Chapter 1.

Table A.1: United States investment costs

Technology	Overnight Cost [$/MW]	Construction Period [years]	Life Time [yr]	Interest Rate	Future Cost [$/MW]	Investment Cost [$/MW-yr]
OCGT	$1,040,000	2	20	8%	$1,122,192	$114,334
CCGT	$1,140,000	2	20	8%	$1,235,708	$125,899
Coal	$3,510,000	4	40	8%	$4,116,254	$345,345
Nuclear (High)	$6,880,000	7	40	8%	$9,110,864	$764,383
Nuclear (Nominal)	$5,500,000	7	40	8%	$7,288,691	$611,506
Nuclear (Low)	$4,100,000	7	40	8%	$5,433,388	$455,850
Nuclear (Very Low)	$2,750,000	7	40	8%	$3,644,345	$305,753
Solar (High)	$1,900,000	1	20	8%	$1,972,723	$200,989
Solar (Nominal)	$917,000	1	20	8%	$952,782	$97,073
Solar (Low)	$551,000	1	20	8%	$573,062	$58,386
Wind (High)	$1,710,000	1	20	8%	$1,781,823	$181,539
Wind (Nominal)	$1,550,000	1	20	8%	$1,614,758	$164,518
Wind (Low)	$1,370,000	1	20	8%	$1,422,690	$144,950
Battery (Nominal)	$1,430,000	1	10	8%	$1,486,496	$221,574
Battery (Low)	$715,000	1	10	8%	$743,248	$110,787
Battery (Very Low)	$429,000	1	10	8%	$445,949	$66,472
Coal IGCC+CCS	$5,880,000	6	30	8%	$7,468,797	$663,698
Gas CCGT+CCS (High)	$2,215,000	3	25	8%	$2,491,724	$233,506
Gas CCGT+CCS (Low)	$1,720,000	3	25	8%	$1,934,883	$181,323
Hydro-Electric Storage	n/a[1]	n/a[1]	n/a[1]	n/a[1]	n/a[1]	n/a[1]

[1] Hydro-electric storage was considered to already be built, and so the investment cost is not considered.

Table A.2: China investment costs

Technology	Overnight Cost [$/MW]	Construction Period [years]	Life Time [yr]	Interest Rate	Future Cost [$/MW]	Investment Cost [$/MW-yr]
OCGT	$543,000	2	20	8%	$587,012	$59,807
CCGT	$598,000	2	20	8%	$646,392	$65,857
Coal	$1,160,000	4	40	8%	$1,358,804	$114,000
Nuclear (Nominal)	$2,800,000	7	40	8%	$3,705,368	$310,873
Nuclear (Low)	$2,080,000	7	40	8%	$2,762,183	$231,742
Solar (High)	$1,400,000	1	20	8%	$1,444,300	$147,151
Solar (Nominal)	$671,000	1	20	8%	$697,565	$71,071
Solar (Low)	$404,000	1	20	8%	$419,559	$42,746
Wind (High)	$1,400,000	1	20	8%	$1,453,702	$148,109
Wind (Nominal)	$1,270,000	1	20	8%	$1,317,401	$134,222
Wind (Low)	$1,120,000	1	20	8%	$1,160,703	$118,257
Battery (Nominal)	$1,430,000	1	10	8%	$1,486,496	$221,574
Battery (Low)	$715,000	1	10	8%	$743,248	$110,787
Battery (Very Low)	$429,000	1	10	8%	$445,949	$66,472
Coal IGCC+CCS	$1,940,000	6	30	8%	$2,465,502	$219,091
Gas CCGT+CCS (High)	$1,160,000	3	25	8%	$1,303,406	$122,145
Gas CCGT+CCS (Low)	$900,000	3	25	8%	$1,012,126	$94,849
Hydro-Electric Storage	n/a [1]	n/a [1]	n/a [1]	n/a [1]	n/a [1]	n/a [1]

[1] Hydro-electric storage was considered to already be built, and so the investment cost is not considered.

Table A.3: United Kingdom investment costs

Technology	Overnight Cost [$/MW]	Construction Period [years]	Life Time [yr]	Interest Rate	Future Cost [$/MW]	Investment Cost [$/MW-yr]
OCGT	$865,000	2	20	8%	$935,651	$95,328
CCGT	$953,000	2	20	8%	$1,030,298	$104,971
Coal	$3,510,000	4	40	8%	$4,116,254	$345,345
Nuclear (Nominal)	$8,140,000	7	40	8%	$10,790,818	$905,328
Nuclear (Low)	$6,070,000	7	40	8%	$8,044,064	$674,881
Solar (High)	$1,660,000	1	20	8%	$1,730,286	$176,289
Solar (Nominal)	$804,000	1	20	8%	$835,690	$85,144
Solar (Low)	$483,000	1	20	8%	$502,636	$51,211
Wind (High)	$2,360,000	1	20	8%	$2,456,820	$250,311
Wind (Nominal)	$2,140,000	1	20	8%	$2,226,466	$226,842
Wind (Low)	$1,890,000	1	20	8%	$1,961,639	$199,860
Battery (Nominal)	$1,430,000	1	10	8%	$1,486,496	$221,574
Battery (Low)	$715,000	1	10	8%	$743,248	$110,787
Battery (Very Low)	$429,000	1	10	8%	$445,949	$66,472
Coal IGCC+CCS	$5,875,883	6	30	8%	$7,468,797	$663,698
Gas CCGT+CCS (High)	$1,846,802	3	25	8%	$2,077,527	$194,690
Gas CCGT+CCS (Low)	$1,434,086	3	25	8%	$1,613,249	$151,181
Hydro-Electric Storage	n/a [1]	n/a [1]	n/a [1]	n/a [1]	n/a [1]	n/a [1]

[1] Hydro-electric storage was considered to already be built, and so the investment cost is not considered.

Table A.4: France investment costs

Technology	Overnight Cost [$/MW]	Construction Period [years]	Life Time [yr]	Interest Rate	Future Cost [$/MW]	Investment Cost [$/MW-yr]
OCGT	$890,000	2	20	8%	$962,159	$98,029
CCGT	$980,000	2	20	8%	$1,059,487	$107,945
Coal	$3,510,000	4	40	8%	$4,116,254	$345,345
Nuclear (Nominal)	$6,800,000	7	40	8%	$9,007,755	$755,732
Nuclear (Low)	$5,070,000	7	40	8%	$6,714,872	$563,364
Solar (High)	$1,660,000	1	20	8%	$1,722,902	$175,536
Solar (Nominal)	$800,000	1	20	8%	$832,124	$84,780
Solar (Low)	$481,000	1	20	8%	$500,491	$50,992
Wind (High)	$1,890,000	1	20	8%	$1,966,651	$200,370
Wind (Nominal)	$1,710,000	1	20	8%	$1,782,256	$181,584
Wind (Low)	$1,510,000	1	20	8%	$1,570,266	$159,985
Battery (Nominal)	$1,430,000	1	10	8%	$1,486,496	$221,574
Battery (Low)	$715,000	1	10	8%	$743,248	$110,787
Battery (Very Low)	$429,000	1	10	8%	$445,949	$66,472
Coal IGCC+CCS	$5,880,000	6	30	8%	$7,468,797	$663,698
Gas CCGT+CCS (High)	$1,900,000	3	25	8%	$2,136,386	$200,206
Gas CCGT+CCS (Low)	$1,470,000	3	25	8%	$1,658,955	$155,465
Hydro-Electric Storage	n/a [1]	n/a [1]	n/a [1]	n/a [1]	n/a [1]	n/a [1]

[1] Hydro-electric storage was considered to already be built, and so the investment cost is not considered.

Table A.5: United States operation cost

Resource	Unit Size (MW_e)	Fixed O&M Cost ($\$/MW_e$-yr)	Variable O&M Cost ($\$/MWh_e$)	Heat Rate (MMBtu/ MWh_e)	Fuel	Minimum Power (%)	Ramping Capability (%)	Fuel Cost ($/MMBtu)	CO_2 Emissions (tons/MMBtu)
OCGT	200	$7,300	$10.69	9.75	Natural Gas	24%	100%	$7.52	0.053
CCGT	500	$15,800	$3.37	6.43	Natural Gas	38%	70%	$7.52	0.053
IGCC	600	$52,000	$7.34	8.80	Coal	70%	30%	$3.14	0.097
Nuclear	1000	$95,000	$6.89	10.49	Uranium	50%	25%	$1.02	0.000
Wind	1	$51,000	$0.00	n/a	n/a	0%	100%	n/a	n/a
Solar	1	$17,000	$0.00	n/a	n/a	0%	100%	n/a	n/a
Battery	1	$5,000	$0.00	n/a	n/a	0%	100%	n/a	n/a
IGCC (CCS)	600	$74,000	$8.58	8.31	Coal (CCS)	70%	10%	$3.14	0.010
CCGT (CCS)	500	$32,300	$6.89	7.49	Natural Gas (CCS)	30%	70%	$7.52	0.005
Hydro-Electric Storage	(max total = 500)	$4,600	$4.00	n/a	n/a	0%	100%	n/a	n/a

Table A.6: China operation cost

Resource	Unit Size (MW_e)	Fixed O&M Cost ($/$MW_e$-yr)	Variable O&M Cost ($/$MWh_e$)	Heat Rate (MMBtu/ MWh_e)	Fuel	Minimum Power (%)	Ramping Capability (%)	Fuel Cost ($/MMBtu)	CO_2 Emissions (tons/MMBtu)
OCGT	200	$5,102	$7.47	9.75	Natural Gas	24%	100%	$12.92	0.053
CCGT	500	$11,043	$2.36	6.43	Natural Gas	38%	70%	$12.92	0.053
IGCC	600	$19,032	$2.69	8.80	Coal	70%	30%	$3.78	0.097
Nuclear	1000	$59,677	$4.33	10.49	Uranium	50%	25%	$0.84	0.000
Wind	1	$40,884	$-	n/a	n/a	0%	100%	n/a	n/a
Solar	1	$60,091	$-	n/a	n/a	0%	100%	n/a	n/a
Battery	1	$5,000	$-	n/a	n/a	0%	100%	n/a	n/a
IGCC (CCS)	600	$73,965	$8.58	8.31	Coal (CCS)	70%	10%	$3.78	0.010
CCGT (CCS)	500	$32,278	$6.89	7.49	Natural Gas (CCS)	30%	70%	$12.92	0.006
Hydro-Electric Storage	(max total = 500)	$4,600	$4.00	n/a	n/a	0%	100%	n/a	n/a

Table A.7: United Kingdom operation cost

Resource	Unit Size (MW_e)	Fixed O&M Cost ($/$MW_e$-yr)	Variable O&M Cost ($/$MWh_e$)	Heat Rate (MMBtu/ MWh_e)	Fuel	Minimum Power (%)	Ramping Capability (%)	Fuel Cost ($/MMBtu)	CO_2 Emissions (tons/MMBtu)
OCGT	200	$10,408	$15.24	9.75	Natural Gas	24%	100%	$15.39	0.053
CCGT	500	$22,528	$4.80	6.43	Natural Gas	38%	70%	$15.39	0.053
IGCC	600	$52,000	$7.34	8.80	Coal	70%	30%	$3.14	0.097
Nuclear	1000	$180,759	$13.11	10.49	Uranium	50%	25%	$1.02	0.000
Wind	1	$54,194	$-	n/a	n/a	0%	100%	n/a	n/a
Solar	1	$91,952	$-	n/a	n/a	0%	100%	n/a	n/a
Battery	1	$5,000	$-	n/a	n/a	0%	100%	n/a	n/a
IGCC (CCS)	600	$73,965	$8.58	8.31	Coal (CCS)	70%	10%	$3.14	0.010
CCGT (CCS)	500	$32,278	$6.89	7.49	Natural Gas (CCS)	30%	70%	$70.41	0.040
Hydro-Electric Storage	(max total = 500)	$4,600	$4.00	n/a	n/a	0%	100%	n/a	n/a

Table A.8: France operation cost

Resource	Unit Size (MW_e)	Fixed O&M Cost ($/$MW_e$-yr)	Variable O&M Cost ($/$MWh_e$)	Heat Rate (MMBtu/ MWh_e)	Fuel	Minimum Power (%)	Ramping Capability (%)	Fuel Cost ($/MMBtu)	CO_2 Emissions (tons/MMBtu)
OCGT	200	$9,812	$14.37	9.75	Natural Gas	24%	100%	$15.39	0.053
CCGT	500	$21,237	$4.53	6.43	Natural Gas	38%	70%	$15.39	0.053
IGCC	600	$52,000	$7.34	8.80	Coal	70%	30%	$3.14	0.097
Nuclear	1000	$115,123	$8.35	10.49	Uranium	50%	25%	$1.02	0.000
Wind	1	$93,177	$-	n/a	n/a	0%	100%	n/a	n/a
Solar	1	$54,194	$-	n/a	n/a	0%	100%	n/a	n/a
Battery	1	$5,000	$-	n/a	n/a	0%	100%	n/a	n/a
IGCC (CCS)	600	$73,965	$8.58	8.31	Coal (CCS)	70%	10%	$3.14	0.010
CCGT (CCS)	500	$43,385	$9.26	7.49	Natural Gas (CCS)	30%	70%	$70.41	0.040
Hydro-Electric Storage	(max total = 500)	$43,385	$4.00	n/a	n/a	0%	100%	n/a	n/a

Appendix B

GenX Sensitivity Studies

To explore the sensitivity of our GenX modeling results (discussed in Chapter 1) to different cost and technology assumptions, we performed a sensitivity study using alternative parameters.

Cost assumptions for these sensitivity cases were taken from a 2016 analysis by the U.S. National Renewable Energy Laboratory (NREL) and included the following:

- Low Renewables/Storage Cost (60% of nominal NREL cost estimates)
- High Renewables/Storage Cost (200% of nominal NREL cost estimates)
- High CCS Cost (130% of nominal cost)
- Low Natural Gas Cost (75% of nominal cost)
- High Natural Gas Cost (125% of nominal cost)
- 99% Efficient CCS Systems (nominal efficiency is 90%)
- Demand Side Resources Considered [1]
- Extreme Weather Year (10% wind and solar capacity for first week in July)[2]

The results of each region's sensitivity study are shown in Figures B.1 to B.6. We use the same definition of opportunity cost as in Table 1.7.

$$\textit{Opportunity Cost} = \begin{pmatrix} \textit{Average cost of electricity} \\ \textit{generation without nuclear} \\ \textit{technologies available} \end{pmatrix} - \begin{pmatrix} \textit{Average cost of electricity} \\ \textit{generation with nuclear} \\ \textit{technologies available} \end{pmatrix}$$

[1] 'Demand side resources' refers to the grid operator's ability to shift demand when the system is in danger of falling short of generation capacity, and to electricity consumers' ability to curb demand when prices are too high. Our scenarios assume that the grid operator can shift up to 5% of demand each hour, for a maximum period of six hours. The amount that consumers will curb demand depends on how much they value electricity consumption, also known as the price elasticity of demand for electricity (Sepulveda 2016).

[2] We assume an extreme weather year to model the scenario for low renewable potential. Specifically, we reduce wind and solar generation during the entire first week of July to 10% of its original value. The timing of this reduction was chosen arbitrarily to illustrate the effect of prolonged cloudy and windless days.

Figure B.1: Texas sensitivity study

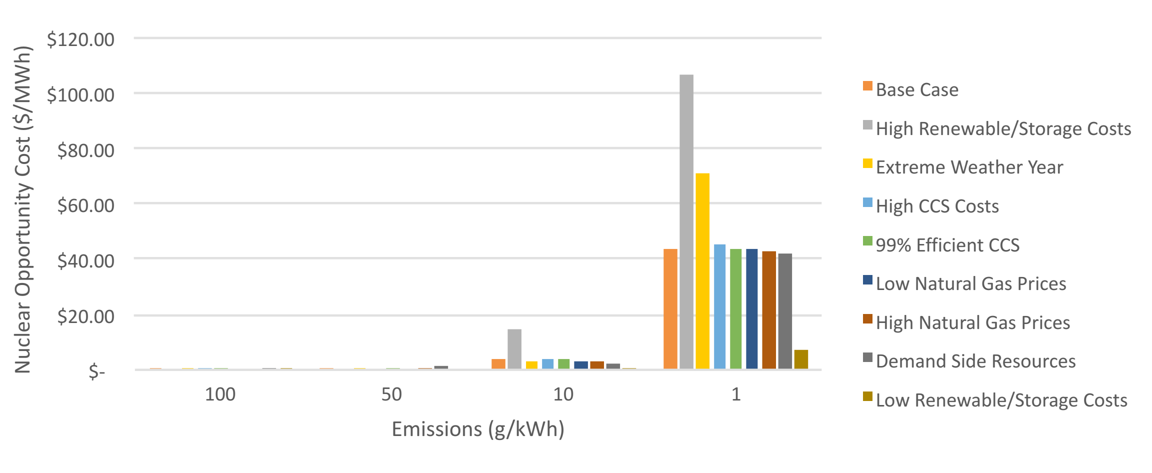


Figure B.2: New England sensitivity study

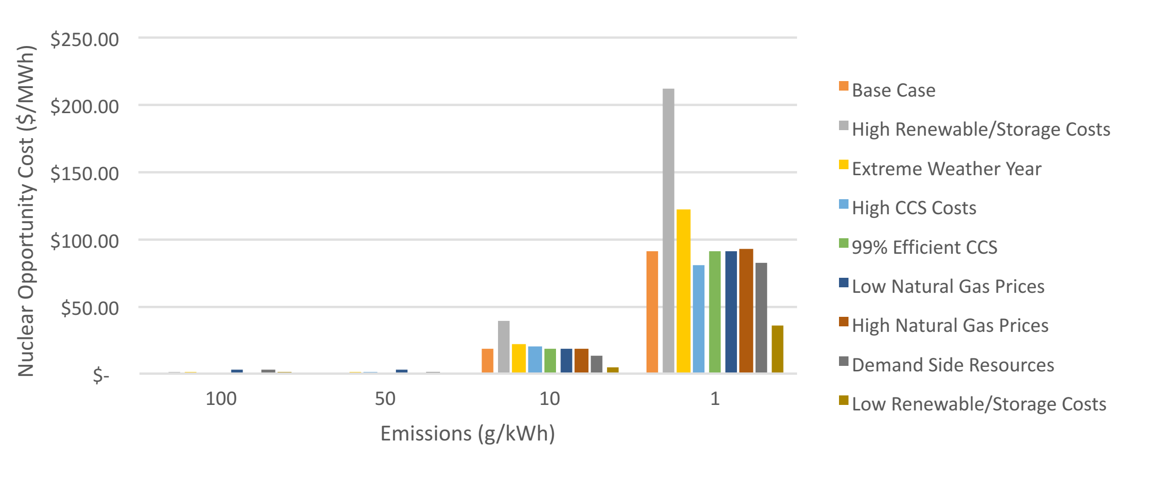


Figure B.3: T-B-T sensitivity study

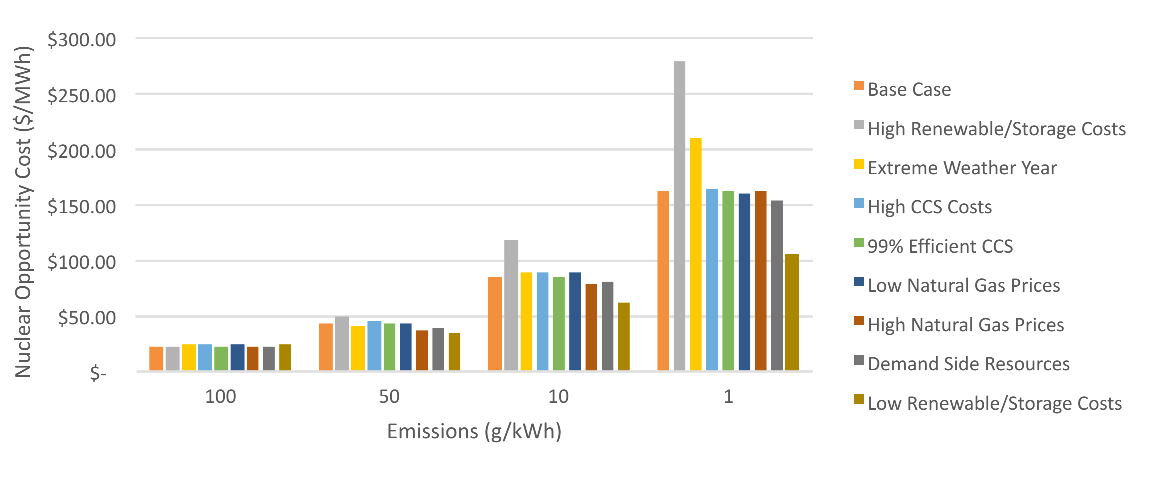


Figure B.4: Zhejiang sensitivity study

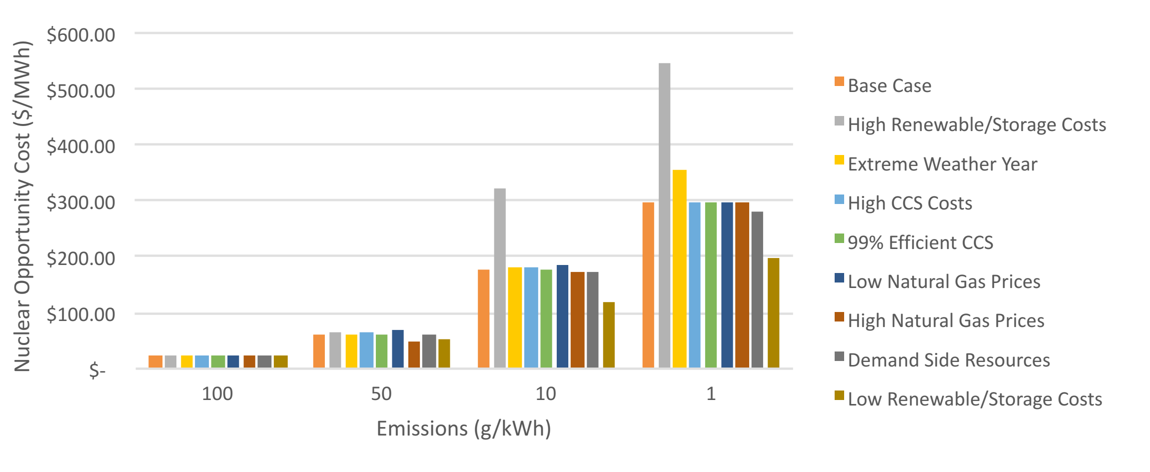


Figure B.5: United Kingdom sensitivity study

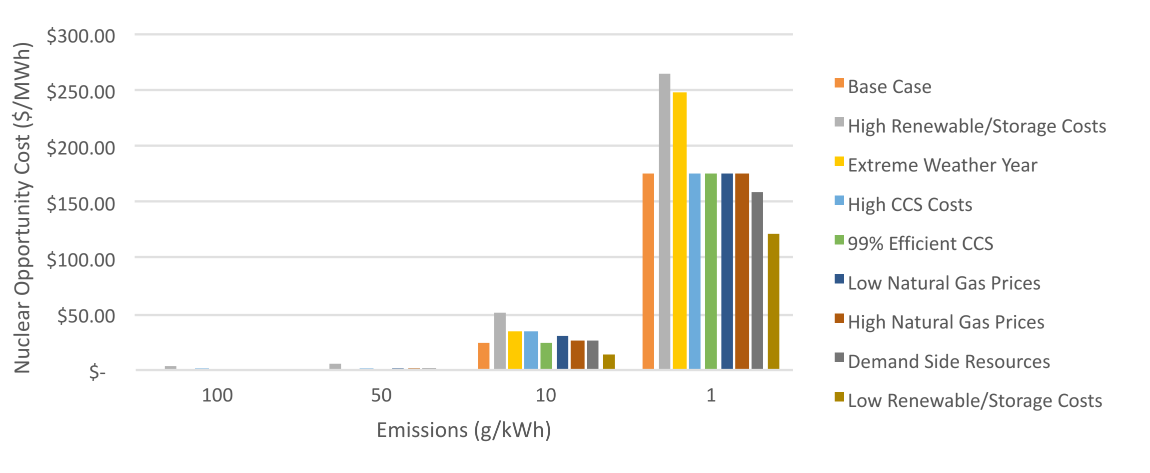
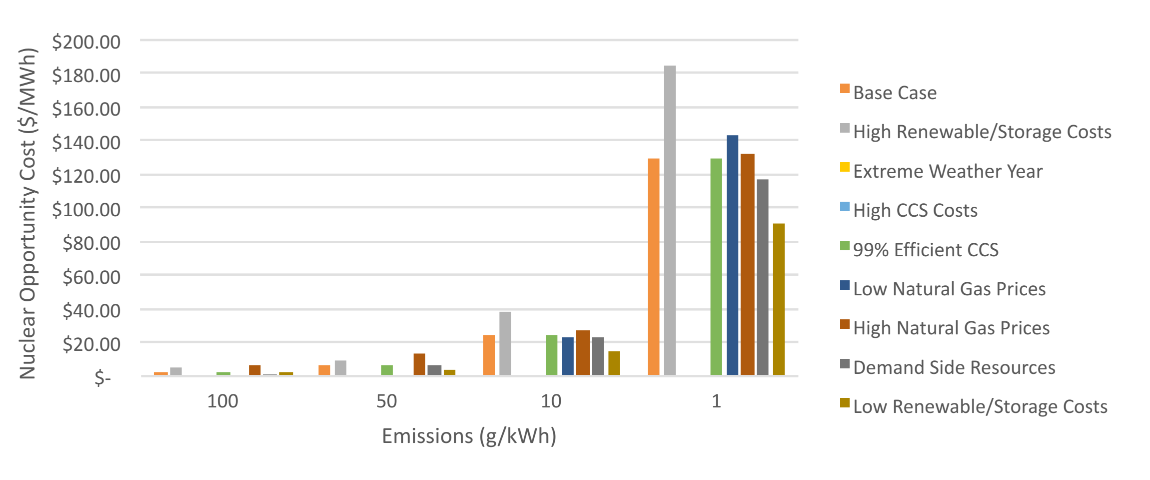


Figure B.6: France sensitivity study



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Appendix C

Verifying the GenX Results and Benchmarking GenX Results to JuiceBox Results

To verify the GenX model, we analyzed a simple test scenario with nuclear and natural gas generation. The GenX result for this simple scenario was compared to an analytical solution generated using a model that calculated every possible permutation and found the least-cost option. There is strong agreement between the analytical model results and the GenX results.

In our simple scenario, natural gas and nuclear are the only generation options available to satisfy electricity demand in the region served by ERCOT, the grid operator for the U.S. state of Texas (ERCOT stands for Electric Reliability Council of Texas). Our simple scenario further assumes that nuclear plants have to operate at 100% of capacity, whereas natural gas generators have unlimited ramping capabilities (that is, they can adjust quickly to any level of power output required by the system). The cost parameters assumed for each technology are shown in Table C.1.

To determine the lowest total system cost, the scenario was run for every permutation of natural gas installed capacity and nuclear installed capacity, from 0 gigawatts (GW) to 100 GW. It should be noted that peak demand on the ERCOT system is 94.2 GW. System outcomes were subject to two further criteria: (a) electricity demand had to be met in full at all times and (b) allowable carbon emissions were subject to a hard constraint (we tested for carbon limits of 1 gram carbon dioxide per kilowatt hour (gCO_2/kWh), 10 gCO_2/kWh, 50 gCO_2/kWh, 100 gCO_2/kWh, and 500 gCO_2/kWh). The results are shown in Figures C.1 to C.5.

Table C.1: Cost parameters for the simple benchmarking scenario

	Nuclear	Natural Gas
Investment Cost ($/MWh)	611,500	125,900
Fixed O&M Cost ($/MWh)	95,000	15,800
Variable O&M Cost ($/MWh)	6.89	3.37
Fuel Cost ($/MWh)	10.70	48.35

Figure C.1: Total cost array for carbon limit of 500g CO_2/kWh

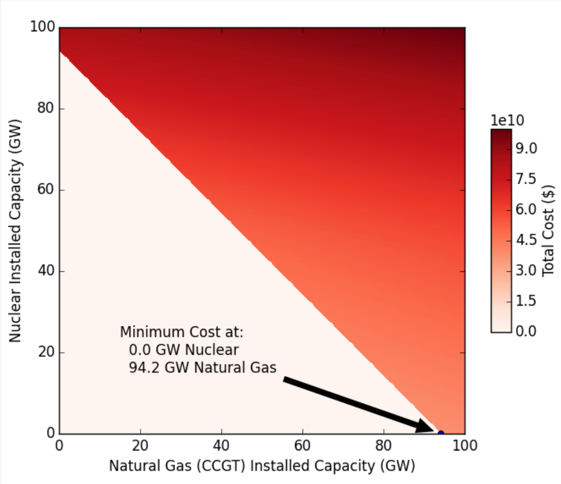


Figure C.2: Total cost array for carbon limit of 100g CO_2/kWh

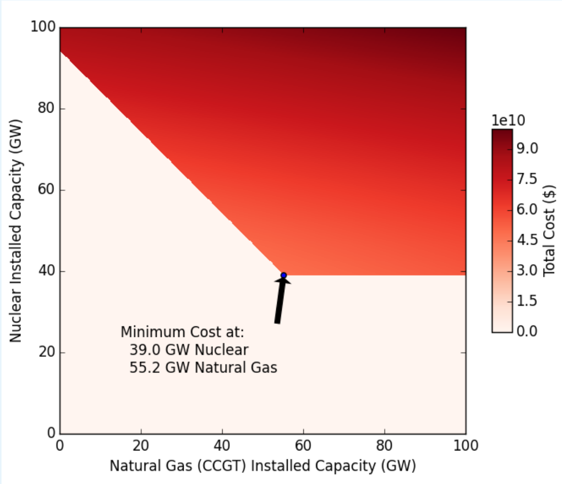


Figure C.3: Total cost array for carbon limit of 50g CO_2/kWh

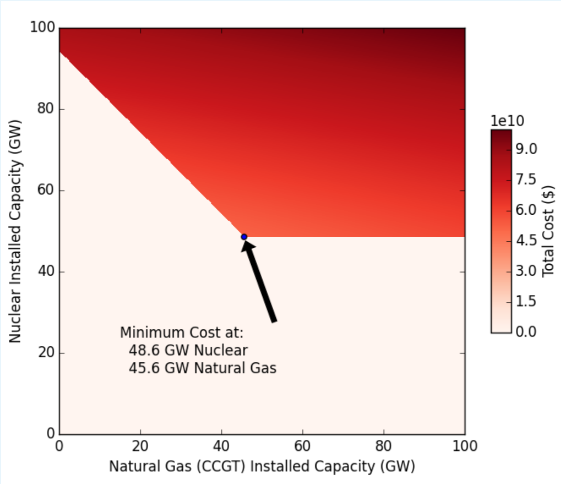


Figure C.4: Total cost array for carbon limit of 10g CO_2/kWh

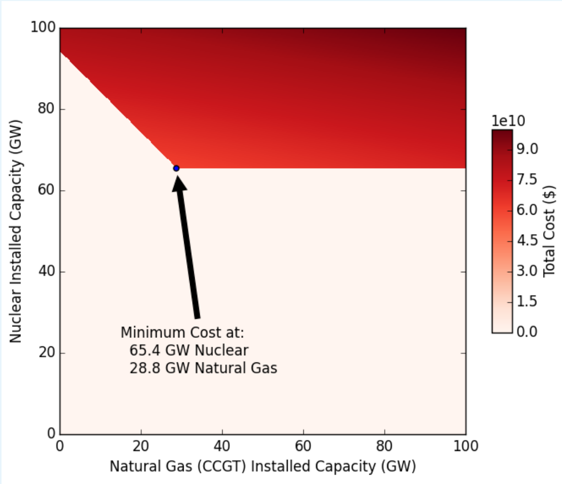
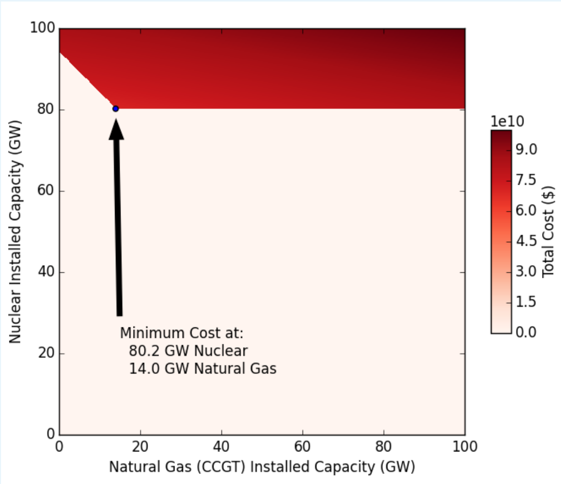


Figure C.5: Total cost array for carbon limit of 1g CO_2/kWh



Optimal installed capacities of nuclear and natural gas are shown in Figure C.6 for both the analytical model and GenX. The figure shows that there is very good agreement between the two calculation methods.

We also compared the average cost of electricity for each case (Figure C.7).

In Figure C.7, the average cost of electricity is higher at a carbon limit of 50 gCO_2/kWh than at the more stringent limit of 1 gCO_2/kWh.

This surprising result is an artifact of the input assumptions, which force nuclear generators to operate at 100% of capacity. As a result, the model calculates excess electricity generation during periods of low demand. This excess generation is included when calculating average electricity cost. In Figure C.8, which shows total system cost, the highest cost occurs at the 1 gCO_2/kWh emission limit, as one would expect.

Figure C.6: Optimal installed capacities from GenX and analytical model results

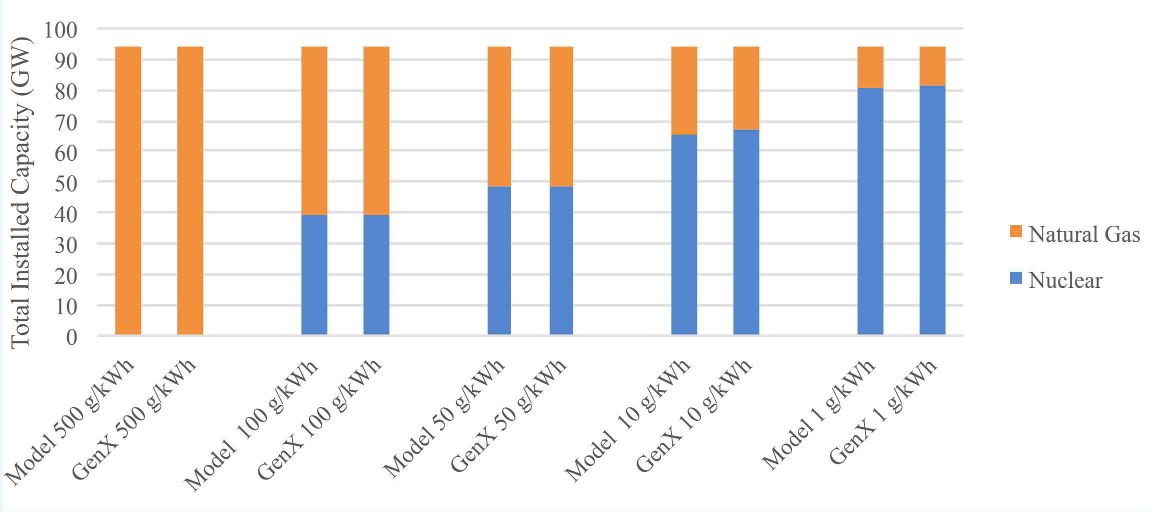


Figure C.7: Optimized average cost of electricity

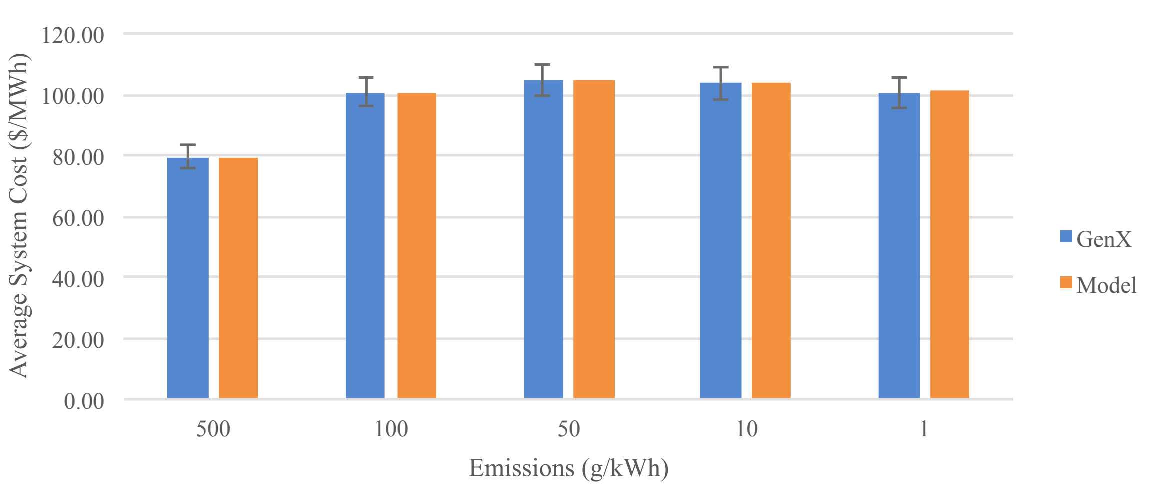


Figure C.8: Optimized total cost of electricity

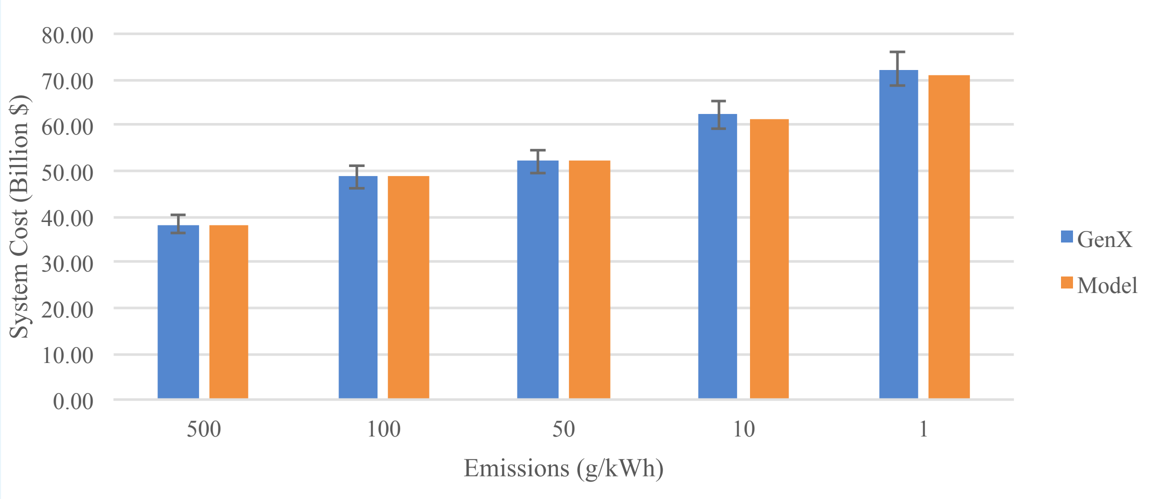
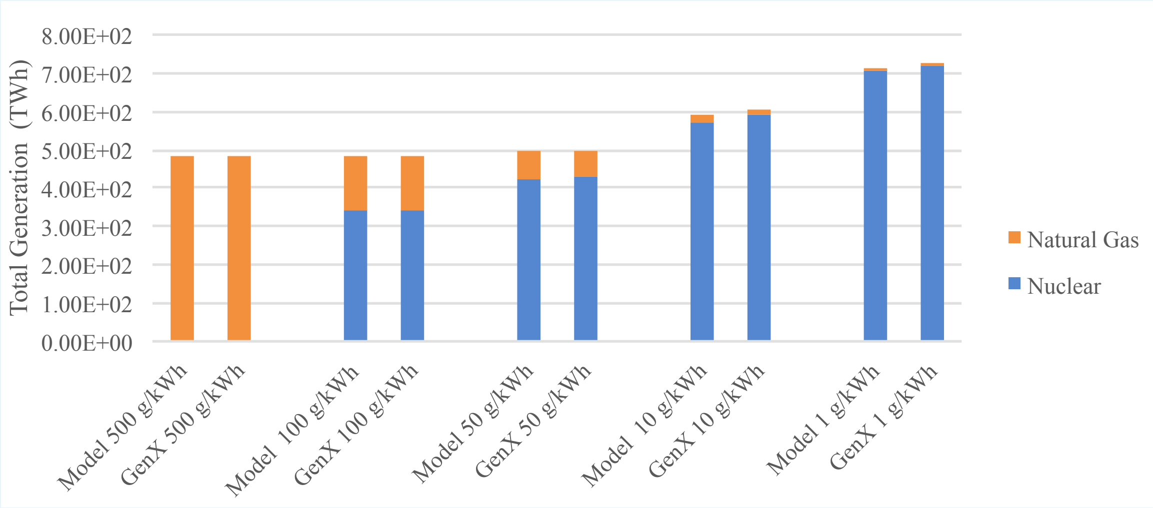


Figure C.9: Optimized total generation from nuclear and natural gas under different emissions constraints



Finally, Figure C.9 compares the amount of electricity generated from nuclear and natural gas under different carbon constraints. Here again, there is strong agreement between the results obtained using the analytical model and GenX.

GenX Benchmarking

To benchmark the GenX model, we recreated and simulated four of our GenX regional modeling cases using another electricity market decisionmaking model: JuiceBox (Meier 2017). The four scenarios are summarized in Table C.2.

Table C.2: Benchmarking cases modeled using JuiceBox

Case	Region	Nuclear Allowed?	GenX Emissions Target
T10Y	Tianjin, China	Yes	10 g/kWh
T50Y	Tianjin, China	Yes	50 g/kWh
E10Y	Texas, US	Yes	10 g/kWh
E50Y	Texas, US	Yes	50 g/kWh

Comparative Modeling Approaches

JuiceBox and GenX use different approaches to simulate power plant operation. As background for this benchmarking exercise, it is helpful to differentiate their underlying approaches. A recent federal summary of electricity supply forecasting models distinguishes between two approaches: electricity dispatch models and capacity expansion or planning models (EPA 2017a). Key features of each type of model are summarized below—based on these features, GenX can be considered an electricity dispatch model, while JuiceBox fits the description of a capacity expansion or planning model.

- Electricity dispatch models are regularly used by utilities and grid operators for short-term planning. These models are designed to estimate the operation of generating units in response to hourly, or sub-hourly, changes in load; thus they account for transient constraints on generator performance, such as start-up and ramping limitations.
- Capacity expansion or planning models simplify the treatment of short-term operational constraints, making them more convenient for long-term studies. Prominent examples of this type of model include the Electricity Market Module of the National Energy Modeling System (NEMS) (U.S. Department of Energy 2017) and the Integrated Planning Model (IPM), which has been used by the U.S. Environmental Protection Agency (EPA) to explore the impacts of environmental regulation on the U.S. power sector (EPA 2017b).

JuiceBox uses an industry-standard approach, termed load duration curve (LDC) modeling, to estimate the long-term performance of power plants. LDC modeling involves several discrete steps: (a) divide annual electricity demand into a discrete number of time periods, (b) establish a load duration curve by sorting demand from highest to lowest, (c) create loadshapes by mathematically characterizing the LDC (e.g., JuiceBox uses a polynomial spline to emulate the LDC), and (d) estimate each generating unit's contribution toward satisfying load based on least-cost dispatch—that is, by adding generating units to satisfy load in increasing order of marginal operating cost and fuel cost.

To benchmark the GenX simulations using JuiceBox, LDC loadshapes were created to emulate hourly electricity demand from GenX simulations for each of the four cases in Table C.1. A set of model generating units was constructed and characterized for each case to closely reflect the generation units simulated using GenX (in terms of technology and fuel type, heat rate, fixed and variable O&M costs, and capital cost). LDC dispatch modeling was used to estimate generating unit performance. Solar, wind, and energy storage units were constrained to provide the same annual output (in MWh) as estimated in the GenX cases. Least-cost dispatch was used to estimate the performance of the nuclear, coal, and natural gas units in satisfying residual load. In contrast to the GenX simulations, which were constrained by an emissions target, JuiceBox simulations included no emissions constraint. To mimic the effect of an emissions constraint, JuiceBox simulations applied a nominal carbon fee of $40 per ton of CO_2, so that power plants with carbon capture and storage (CCS) were preferentially dispatched ahead of non-CCS power plants.

JuiceBox versus GenX results for annual generation, CO_2 emissions, and system cost are discussed in the next section of this appendix. JuiceBox uses a cost-of-service approach to estimate system costs. Production costs for each power plant unit are estimated on the basis of capital cost, variable and fixed operating and maintenance (O&M) costs, and fuel cost. Fuel price assumptions are the same as those used in the GenX simulations. Cost of capital in the JuiceBox simulations was based on documentation for EPA's Integrated Planning Model (EPA 2013), which provides a technology-specific capital charge rate that takes into account discount rate, book and debt life, taxes and insurance costs, and depreciation schedule. The same U.S.-based capital charges were used for both the U.S. and China cases. JuiceBox emissions estimates are a function of fuel consumption and unit-specific emission factors per unit of fuel consumed, adjusted for the application of emissions controls. Fuel consumption is calculated based on the dispatch algorithm's estimate of generation- and unit-specific seasonal heat rate. A summary of JuiceBox input parameters is provided in Table C.3.

Table C.3: Power plant parameters used in JuiceBox simulations

Generating Unit Type	Available in Cases	Fuel ($/MMBtu)	Heat Rate (Btu/kWH)	FOM (S/kW-yr)	VOM (S/MWh)	Capital Cost ($/kW)	Capital Charge Rate	CO_2 (LB/MMBtu)	Capacity Factor Forcing
TX Gas Peaking	E10Y or E50Y	7.52	9,750	7.3	10.69	1,038	10.63%	117.0	—
TX Gas Combined Cycle	E10Y or E50Y	7.52	6,430	15.8	3.37	1,143	10.26%	117.0	—
TX Nuclear LWR	E10Y or E50Y	1.02	10,488	95.0	6.89	5,500	9.44%	0.0	—
TX Coal IGCC with CCS	E10Y or E50Y	3.14	8,307	74.0	8.58	5,876	9.68%	21.0	—
TX Gas CC with CCS	E10Y or E50Y	7.52	7,490	32.3	6.89	1,720	9.68%	10.6	—
CHN Gas Peaking	T10Y or T50Y	12.92	9,750	5.1	7.47	543	10.63%	117.0	—
CHN Gas Combined Cycle	T10Y or T50Y	12.92	6,430	11.0	2.36	598	10.26%	117.0	—
CHN Nuclear LWR	T10Y or T50Y	0.84	10,488	59.7	4.33	2,796	9.44%	0.0	—
CHN Coal IGCC with CCS	T10Y or T50Y	3.78	8,307	74.0	8.58	1,940	9.68%	21.0	—
CHN Gas CC with CCS	T10Y or T50Y	12.92	7,490	32.3	6.89	900	9.68%	10.6	—
T50Y – Solar PV	T50Y	—	—	60.1	0	671	10.85%	0	22.2%
T50Y – Wind	T50Y	—	—	40.9	0	1,267	10.85%	0	17.4%
T50Y – Battery Storage	T50Y	—	—	5.0	0	1,430	10.85%	0	5.3%
T10Y – Solar PV	T10Y	—	—	60.1	0	671	10.85%	0	18.2%
T10Y – Wind	T10Y	—	—	40.9	0	1,267	10.85%	0	17.4%
T10Y – Battery Storage	T10Y	—	—	5.0	0	671	10.85%	0	3.3%
E50Y – Solar PV	E50Y	—	—	17.0	0	917	10.85%	0	23.3%
E50Y – Wind	E50Y	—	—	51.0	0	1,553	10.85%	0	35.7%
E50Y – Battery Storage	E50Y	—	—	5.0	0	715	10.85%	0	7.1%
E50Y – Solar PV	E10Y	—	—	17.0	0	917	10.85%	0	22.9%
E50Y – Wind	E10Y	—	—	51.0	0	1,553	10.85%	0	35.6%
E50Y – Battery Storage	E10Y	—	—	5.0	0	715	10.85%	0	6.7%

Summary and Comparison of Model Results

Table C.4 and Figure C.10 summarize the GenX and JuiceBox results for each of the cases outlined in Table C.3.

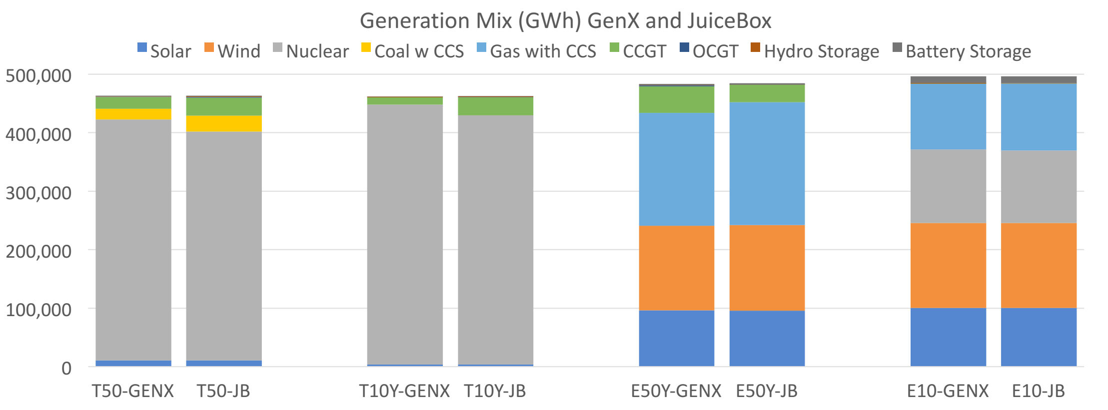
Figure C.10 compares GenX and JuiceBox results for electricity production by power plant fuel source (generation mix). For each case, total generation in the JuiceBox simulation is nearly identical to the GenX result. This is expected, given that JuiceBox loadshapes were derived from GenX hourly demand data. Contributions from solar and wind resources (green bars), and battery storage (yellow) were constrained in the JuiceBox simulations to provide nearly identical output. The remaining contributions from nuclear (purple), coal (black), and natural gas (blue) power plants provide a visual benchmark for comparing GenX and JuiceBox estimates of unit dispatch to satisfy residual demand. The figure shows that the two models' predictions for relative contribution by fuel source are quite similar overall for each of the cases analyzed.

Differences between the GenX and JuiceBox results reflect differences in their underlying modeling approaches. In the T50 cases, contributions from nuclear power are slightly lower in the JuiceBox simulation (T50-JB). This difference is attributable to power plant de-rating factors in the JuiceBox model. As is typical in long-term planning models, all generating units are de-rated to reflect the likelihood of planned and forced outages. In the T-50JB case, de-rating diminishes the maximum possible contribution from the nuclear units, thereby slightly increasing reliance on gas and coal units. The same effects of de-rating are visible when comparing results for the T10 cases. In the E50 cases, JuiceBox relies slightly more on natural gas units with CCS than on combined cycle gas units (CCGT). This result reflects slight differences between the JuiceBox load shapes and GenX's assumptions for hourly demand. It may also reflect operational constraints that are considered in the GenX model. Specifically, gas with CCS may operate slightly less in the E50Y GenX simulations due to ramping or start-up constraints.

Table C.4: Summary and comparison of modeling results

Case	T50Y		T10Y		E50Y		E10Y	
	GenX	JuiceBox	GenX	JuiceBox	GenX	JuiceBox	GenX	JuiceBox
Cost (¢/kWh)	5.84	6.24	6.23	6.12	9.19	8.75	10.26	10.43
Emissions (ton CO_2/GWh)	49.4	31.6	9.23	26.1	51.1	30.0	11.0	9.2
CO_2 Emission Reduction Relative to Gas CC[1] (%)	85.3	91.6	97.2	93.1	84.8	92.0	96.7	97.6

Figure C.10: Results for generation mix



[1] The CO_2 emission rate for combined cycle natural gas generation is 398 g/kWh in the GenX simulations and 342 g/kWh in the JuiceBox simulations.

Estimated emissions are a function of the generation mix, specifically expected reliance on coal units relative to natural gas units. Both models generate emissions estimates using generation requirements, fuel efficiency (i.e., heat rate), and fuel-specific emission rates. As already noted, both GenX and JuiceBox produce generally similar results for overall fuel mix in each of the cases analyzed. Differences between their results for emissions correspond to differences in predicted generation and, to a lesser extent, slight differences in the fuel-specific emission rates assumed by each model. As one would expect, both models show a reduction in average emissions from the 50 gCO_2/kWh scenario to the 10 gCO_2/kWh scenario. Though there are differences in the system-wide average emissions rate predicted by the two models (in part, because of differences in the emission rates each model assigns to different generation technologies, particularly natural gas), it is more informative to look at the level of overall system de-carbonization achieved under different scenarios. Thus, Table C.4 shows the average system emissions as a percent reduction from the emissions each model would estimate for combined cycle natural gas generation,[2] JuiceBox and GenX produce similar estimates of overall decarbonization, with results that differ by only 7% in the T50 case, 4% in the T10 case, 8% in the E50 case, and very little (0%) in the E10 case.

Cost results for different generation sources are also relatively similar across all the modeling cases, with discrepancies ranging from as little as 2% (in the T10 and E10 cases) to as much as 15% in the E50 case. Given that the JuiceBox model was populated with cost assumptions from GenX, these differences are a direct result of differences in the two models' predictions for fuel use (generation mix).

Figures C.11–C.14 show the estimated cost of electricity generation in the year 2050 by generation source for each of the cases in Table C.2. The figures show that GenX and Juicebox produce cost estimates of comparable magnitude for specific generation sources.

[2] The CO_2 emission rate for combined cycle natural gas generation is 398 g/kWh in the GenX simulations and 342g/kWh in the JuiceBox simulations.

Figure C.11: Cost by generation source for T10Y

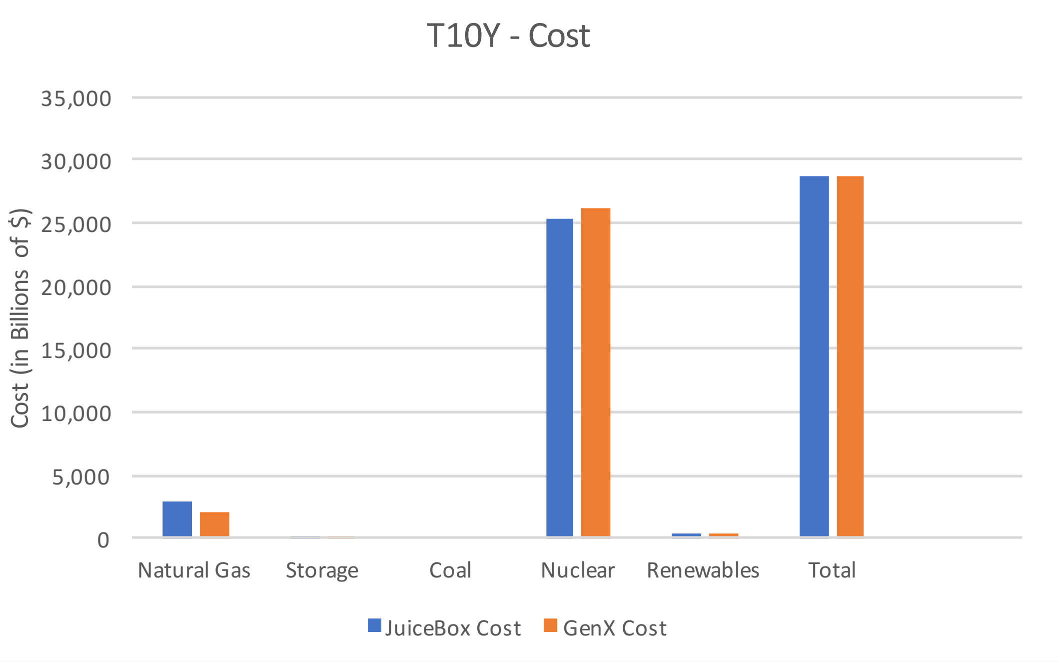


Figure C.12: Cost by generation source for T50Y

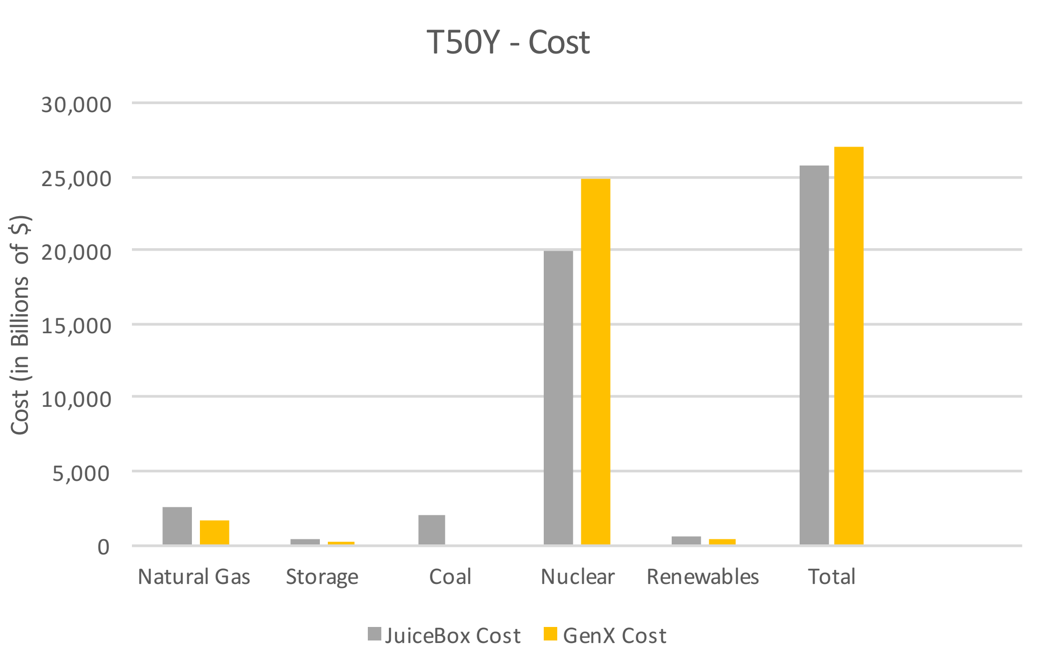


Figure C.13: Cost by generation source for E10Y

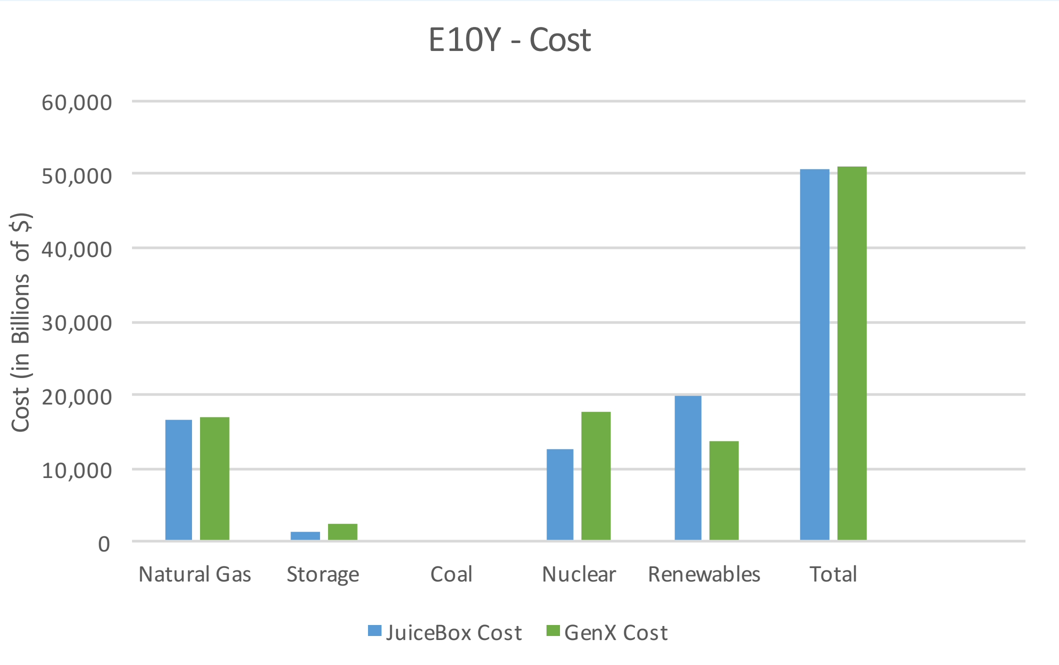
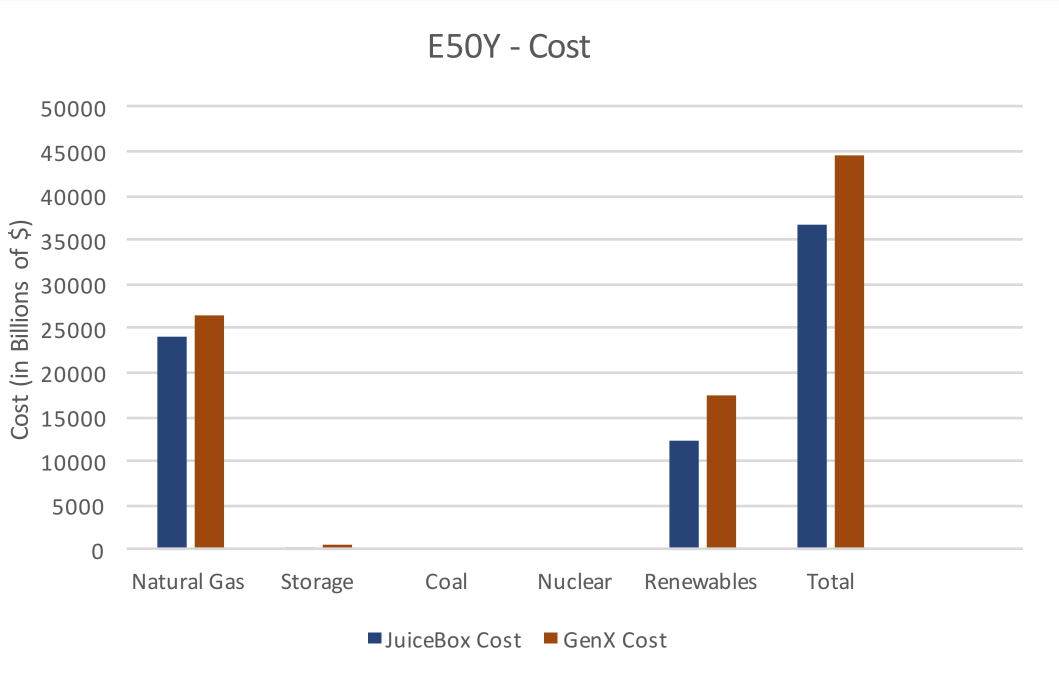


Figure C.14: Cost by generation source for E50Y



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Appendix D

One-Week Texas (ERCOT) GenX Analysis

This appendix provides a more detailed description of the GenX simulation results for a single summer week (June 1 – June 7) of electricity generation in the Texas ERCOT region for three technology scenarios ('no nuclear,' 'nominal cost nuclear,' and 'low cost nuclear') and four carbon dioxide (CO_2) emission limits (100, 50, 10, and 1 grams per kilowatt hour (gCO_2/kWh)). Each figure represents hourly electricity production by specific generation technologies. Note that negative generation values occur in periods when energy storage is being charged. Normally these periods are followed by periods when the energy storage system discharges power.

Figures D.1–D.4, show electrical power generation for June 1 – June 7 in ERCOT with no nuclear option at different CO_2 constraints.

Figure D.1: 'No nuclear' technology case with an emissions limit of 100 gCO_2/kWh in the ERCOT system: The results show strong reliance on renewable generation. Natural gas is used to generate electricity when renewable generation potential is low. Energy storage capacity is minimal.

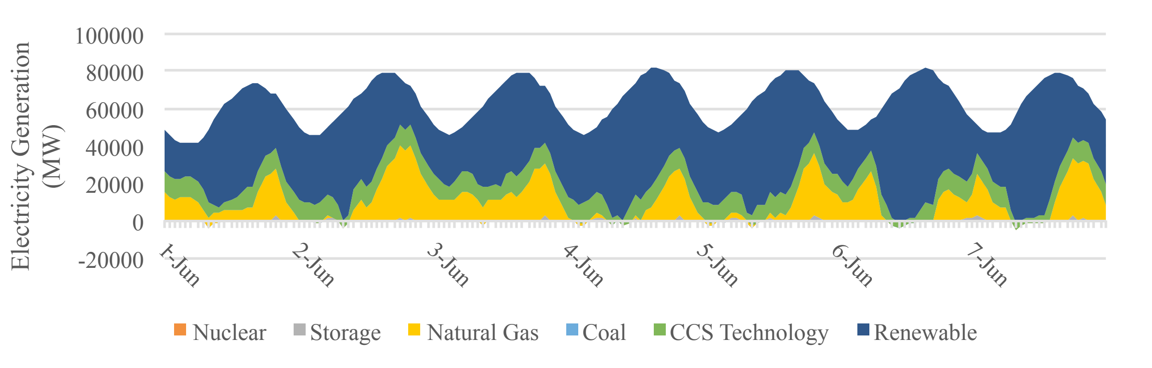


Figure D.2: 'No nuclear' technology case with an emissions limit of 50 gCO_2/kWh in the ERCOT system: The results show strong reliance on renewable generation. Natural gas powered combined cycle turbines (CCGT) technology with carbon capture and storage (CCS) replaces natural gas generation when renewable generation potential is low.

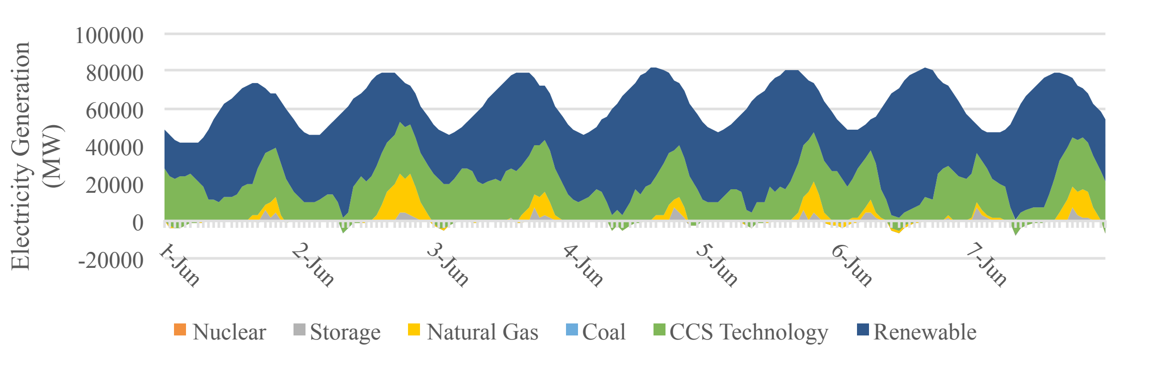


Figure D.3: 'No nuclear' technology case with an emissions limit of 10 gCO_2/kWh in the ERCOT system: The results show strong reliance on renewable generation. No natural gas CCGT is used. Natural gas fired generation with CCS and energy storage are used when renewable generation potential is low.

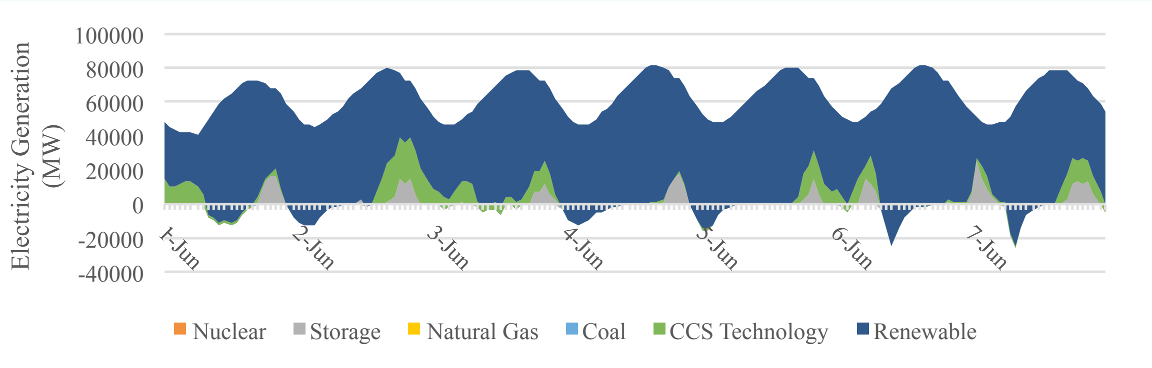
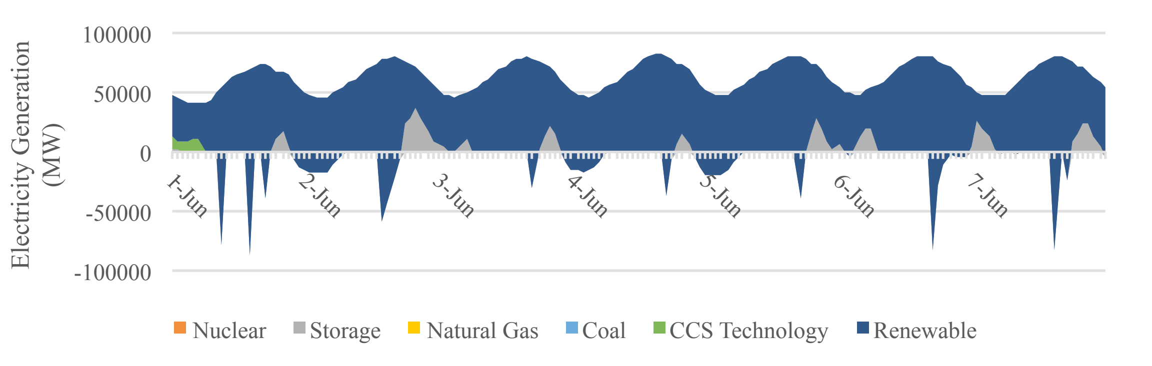


Figure D.4: 'No nuclear' technology case with an emissions limit of 1 gCO_2/kWh in the ERCOT system: The results show dominant reliance on renewable generation. Energy storage is heavily used (note the change in the y-axis scale) when renewable generation potential is low.



Figures D.5–D.8 show GenX results for the June 1 – June 7 period in ERCOT with nuclear available at nominal cost (i.e., $5,500/kWe overnight cost).

Figure D.5: 'Nominal cost nuclear' technology case with an emissions limit of 100 gCO_2/kWh in the ERCOT system: The results show strong reliance on renewable generation. Natural gas powered CCGT is used to generate electricity when renewable generation potential is low and there is minimal reliance on electricity storage.

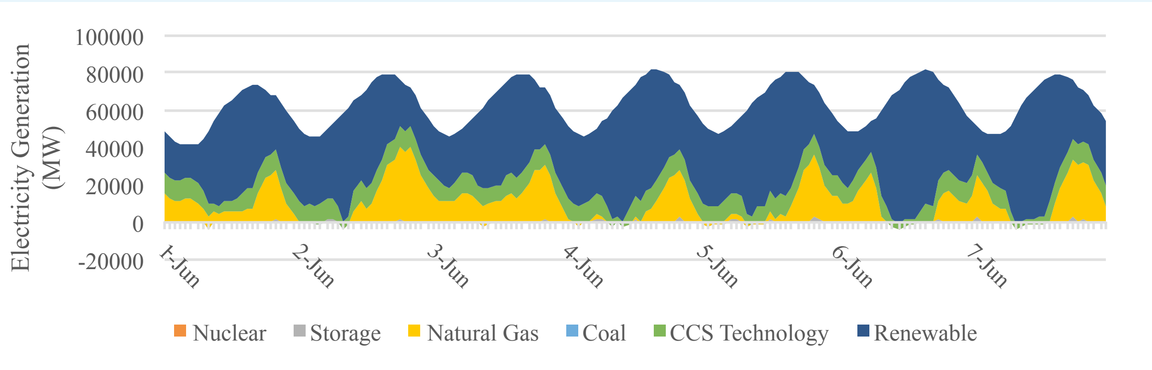


Figure D.6: 'Nominal cost nuclear' technology case with an emissions limit of 50 gCO_2/kWh in the ERCOT system: The results show strong reliance on renewable generation. Natural gas powered CCGT with CCS replaces natural gas generation when renewable potential is low.

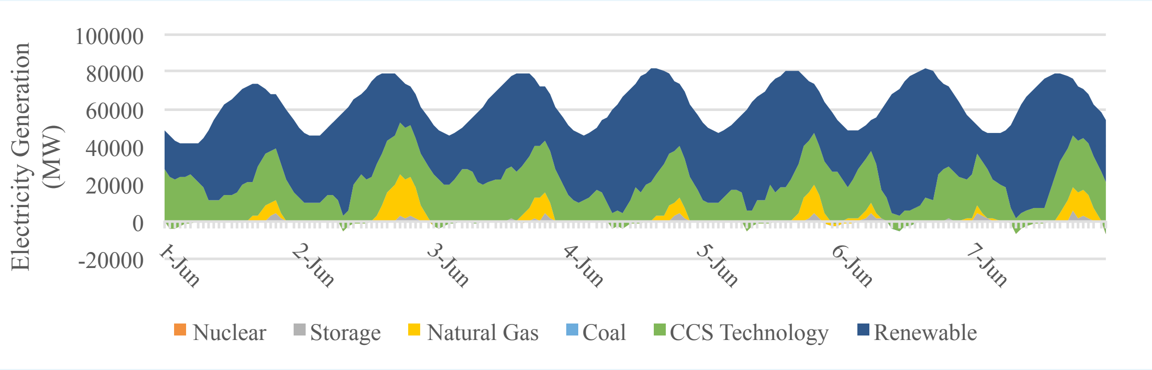


Figure D.7: 'Nominal cost nuclear' technology case with an emissions limit of 10 gCO_2/kWh in the ERCOT system: The results show strong reliance on renewable generation. Both CCS technology and nuclear are used to generate electricity when renewable potential is low, with some contribution from electricity storage.

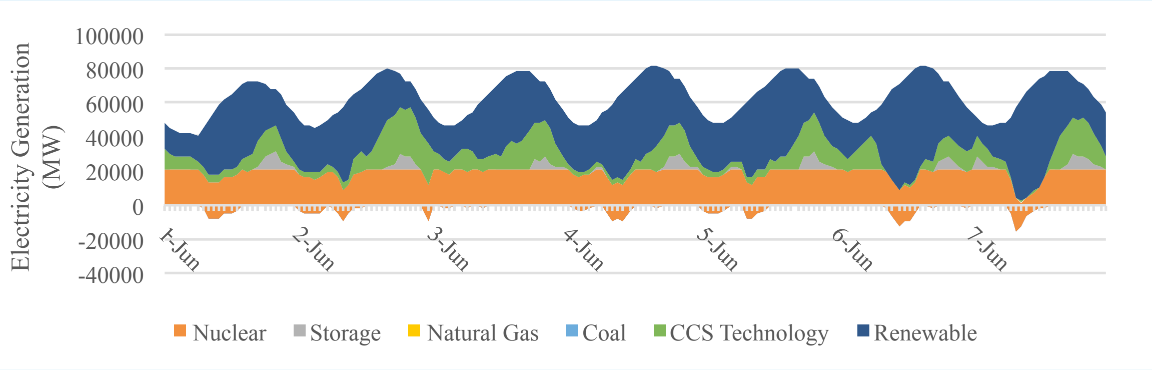
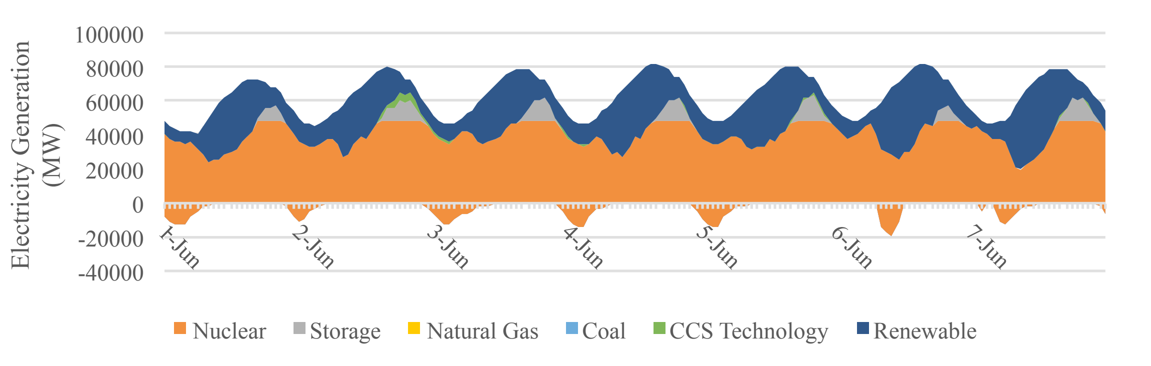


Figure D.8: 'Nominal cost nuclear' technology case with an emissions limit of 1 gCO_2/kWh in the ERCOT system: The results show strong reliance on nuclear and renewable generation.



Figures D.9–D.12 show GenX results for the June 1 – June 7 period in ERCOT with nuclear available at a low cost ($4,100/kWe overnight cost).

Figure D.9: 'Low cost nuclear' technology scenario with an emissions limit of 100 gCO_2/kWh in the ERCOT system: Nuclear provides reliable baseload generation, while natural gas and renewables provide peaking generation.

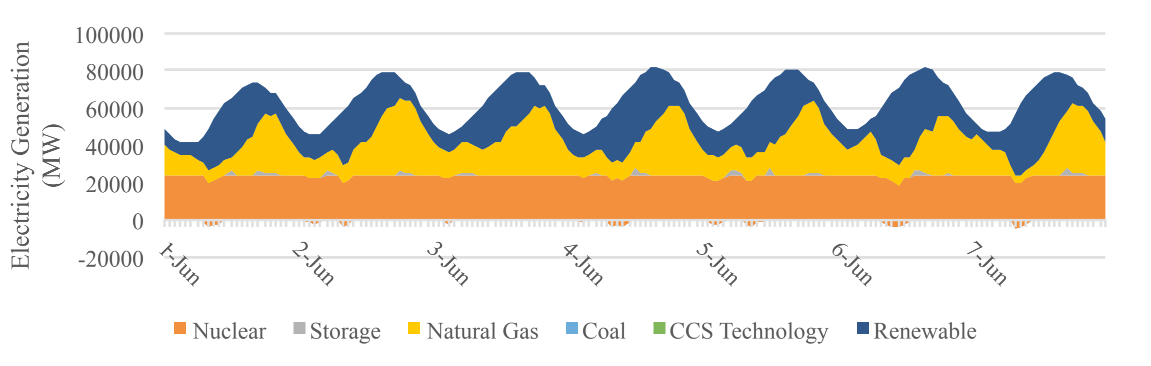


Figure D.10: 'Low cost nuclear' technology scenario with an emissions limit of 50 gCO_2/ kWh in the ERCOT system: Nuclear provides reliable baseload generation, while natural gas and renewables provide peaking generation.

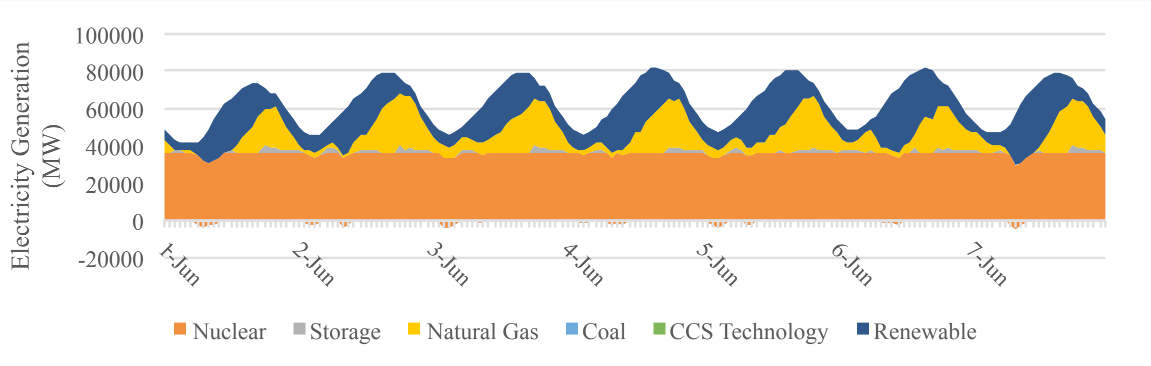


Figure D.11: 'Low cost nuclear', with an emissions limit of 10 gCO_2/ kWh in the ERCOT system: Nuclear provides reliable baseload generation, while renewables and natural gas CCGT with CCS provide peaking generation. Note that under this more stringent emissions limit, natural gas CCGT with CCS replaces conventional natural gas in providing peaking generation.

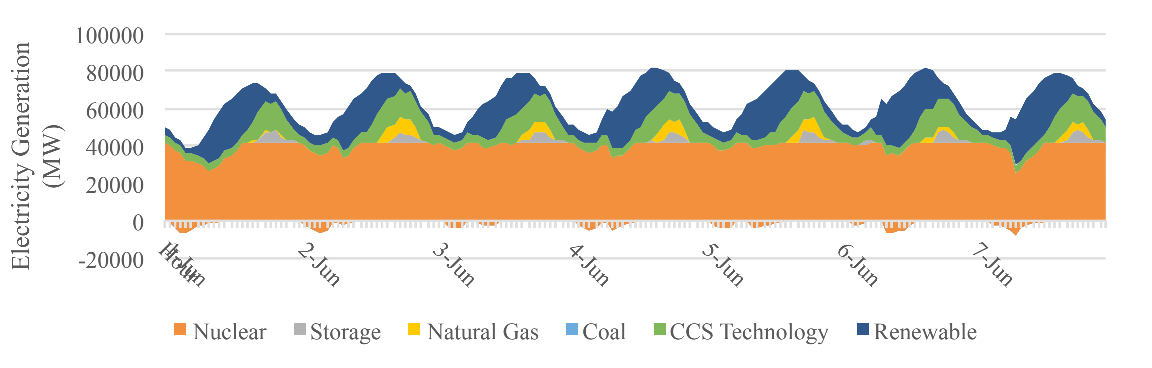
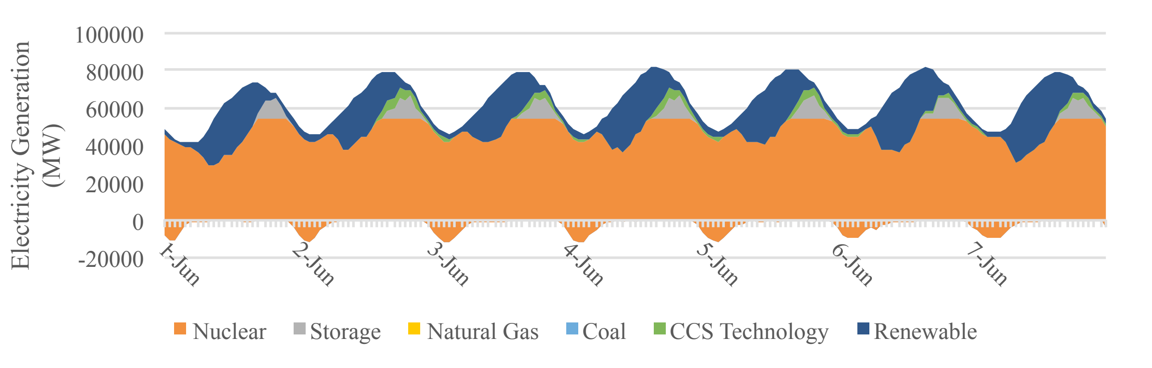


Figure D.12: 'Low cost nuclear' technology scenario with an emissions limit of 1 gCO_2/kWh in the ERCOT system: Nuclear provides reliable baseload generation, while energy storage and renewables provide peaking generation.



Appendix E

The Nuclear Supply Chain

The nuclear supply chain can be divided into three major components (Figure E.1): manufacturing, construction, and operation. Manufacturing includes the manufacturing of all necessary equipment for the reactor (e.g., reactor pressure vessel, steam generators, etc.) as well as the transport of manufactured equipment to the reactor site. Construction includes the labor necessary to construct the reactor (e.g., welders, electricians, etc.). It also includes the construction management needed to complete the project in a timely manner and on budget. Operation includes the necessary labor and components needed for continued operation of the reactor (e.g., certified operators, fuel enrichment, etc.).

Manufacturing Supply Chain

A modern light water reactor (LWR) has about 2,000 kilometers (km) of cabling, 210 km of piping, 5,000 valves, 200 pumps, and 4,000 metric tons of forgings (World Nuclear Association 2014). Major equipment includes the reactor pressure vessel, steam generators, pumps, turbine-generator, condensers, and more. There are 10 major consolidated nuclear reactor vendors: Framatome (formerly known as AREVA), Candu Energy, China National Nuclear Corporation, China's State Nuclear Power Technology Corporation, GE & Hitachi, Korea Electric Power Corporation, Mitsubishi Heavy Industries, Nuclear Power Corporation of India, RosAtom, and Toshiba/Westinghouse. Other significant nuclear technology vendors include Babcock and Wilcox, China General Nuclear Power Group, Doosan Corporation, OMZ/Skoda, and Larsen & Toubro.

In addition, there are about 240 other suppliers of nuclear-grade structures, systems, components, and services. In 2009, 147 companies were reported to hold an 'N-Stamp,' a nuclear component certification, from the American Society of Mechanical Engineers (ASME). More information on nuclear equipment suppliers can be found in the World Nuclear Association's Supply Chain Reports (World Nuclear Association 2014). Chapter 5 of this report delves deeper into the subject of nuclear-grade equipment versus commercial-grade equipment.

About a decade ago, there was concern about potential bottlenecks in the supply chain for large forging capabilities, specialized alloys, and rare earth materials. However, the cancellation of planned plants and new investments in the supply chain by existing suppliers have eased this concern. In addition, the transfer of manufacturing

Figure E.1: The nuclear supply chain

technology to China has resulted in an increase in overall global capacity for manufacturing nuclear equipment (especially forgings). In the event of a rapid build-out of the nuclear industry, supply bottlenecks should not be a concern as long as care is taken to invest in the supply chain for component and system manufacturing (World Nuclear Association 2014).

Construction Supply Chain

Nuclear power plant projects are usually managed by engineering, procurement, and construction (EPC) companies. The structure of these contracts varies from 'multi-package' contracts, where the plant owner has direct control over the construction of the plant and uses different contractors for each work scope, to 'single package' contracts where the EPC contractor is in charge of the entire construction project (World Nuclear Association 2014).

There are a number of EPC companies with experience in nuclear plant construction. Table E.1 lists the EPC companies for four major reactor designs (World Nuclear Association 2014).

While there are no logistical obstacles associated with the construction supply chain due to a shortage of EPC companies, the industry suffers from identified weaknesses in construction management. Developing an experienced cadre of construction managers is much more challenging. This is an issue in all major technology and infrastructure construction projects. With more than 55 new nuclear reactors under construction at 32 sites worldwide, efforts could focus on embedding junior construction managers at many of these sites, thereby providing on-the-job training. Having managers with real nuclear construction experience leading this effort could be an effective way to staff the next wave of nuclear construction, starting in the late 2020s and lasting until the late 2030s. Nevertheless, human resource development requires a deliberate and concerted effort by the nuclear industry. Such an international collaborative effort needs to start now. We would also note that increased use of factory manufacturing could help reduce construction supply chain challenges, in part by centralizing the needed expertise.

Operation Supply Chain

There are no identified supply chain obstacles in terms of current demand for personnel to operate nuclear power plants. Currently, about 600 employees are required to operate each reactor unit. At dual-unit sites, this number may be reduced because the same personnel can

Table E.1: EPC companies

Reactor Designer	EPC Companies
EPR (Framatome)	• Électricité de France • Bechtel Corporation • Jacobs Engineering Group • China Nuclear Power Engineering Corporation • Shanghai Electric Group Corporation Ltd. • Construtora Andrada Gutierrez SA • Construtora Quieroz Galvao
APR1400 (Korea Electric Power Corporation)	• Korea Hydro & Nuclear Power Corporation • Samsung C & T Corporation • Hyundai E & C • Daelim Industrial Corporation Ltd. • Daewoo E & C • Doosan Babcock Ltd. • SK E & C corporation Ltd. • GS E & C Corporation
AP1000 (Westinghouse)	• Chicago Bridge & Iron Corporation • Nuvia Ltd. • China Nuclear Power Engineering Corporation
ABWR1350 (Toshiba Corporation and Hitachi-GE)	• Shaw Power Group Inc. • Toshiba E & C Corporation Ltd. • Toshiba Plant Systems & Services Corporation

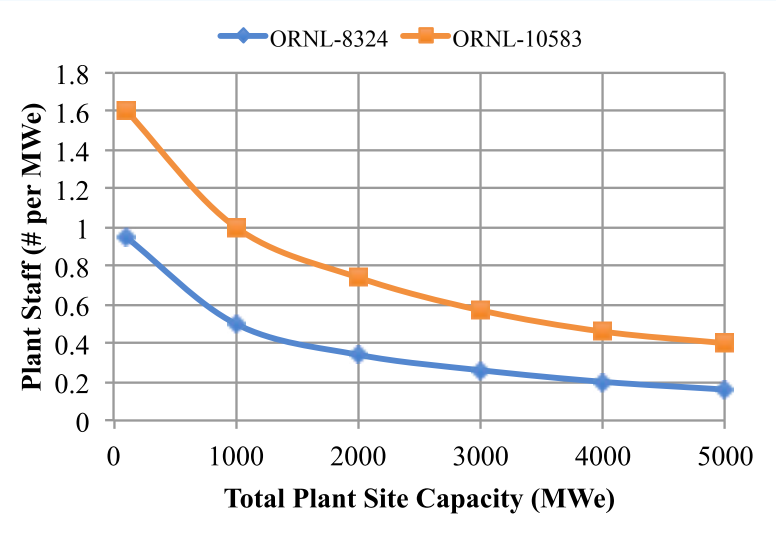
(World Nuclear Association 2014)

undertake common tasks. In addition, staffing needs can vary depending on the size of the reactor. Figure E.2 reports two estimates of the number of plant employees (not including security personnel) as a function of reactor size. In 2008, the average figure for the United States was 0.58 employees per megawatt of electrical generating capacity (MW_e), with a range of 0.45–0.74 employees/MW_e for single- to multiple-unit sites (Peltier 2010).

Figure E.3 shows the general break down of employees across five categories: operators, engineers, maintenance, security, and other (human resources, facilities, management, support, etc.).

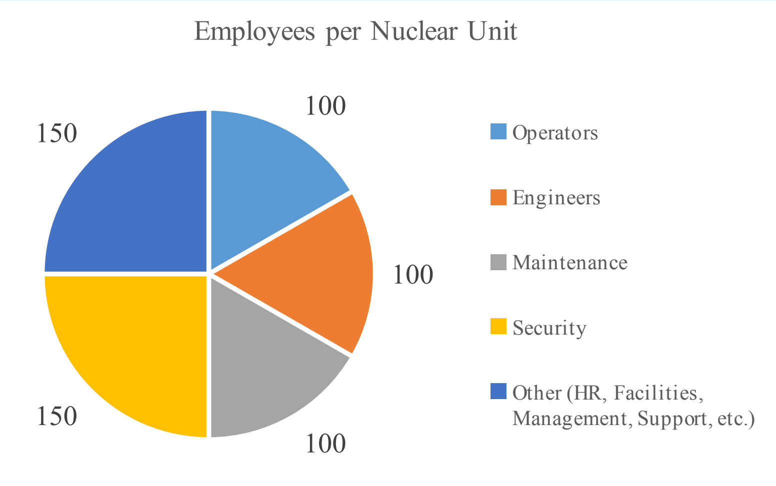
In the United States, it takes about two years to train a plant operator. From the position of reactor operator, it takes about one-to-five years to become a control room operator. From the position of control room operator, it takes about one-to-five

Figure E.2: Number of plant employees (not including security) as a function of reactor size



(ORNL/TM-8324 1982) (ORNL/TM-10583 1987)

Figure E.3: General breakdown of staffing needs for a nuclear power plant unit



(McAndrew-Benevides 2016)

years to become a reactor operator trainer (McAndrew-Benevides 2016). In total, it can take four-to-twelve years to become a senior reactor operator. These training times are outlined in Table E.2. The typical timeline indicates that there would be enough time from when a new plant construction project is announced to when the plant becomes operational to allow for the hiring and training of necessary operators at all levels. This conclusion is based on past U.S. experience as well as current international experience. In sum, there is no bottleneck in the operations supply chain.

Table E.2: Operator training times (United States)

Position	Years	Cumulative Years
Plant Operator	2	2
Control Room Operator	1–5	3–7
Senior Reactor Operator	1–5	4–12

(McAndrew-Benevides 2016)

The other employees at a nuclear reactor that require time to train are security personnel and engineers. The training schedule for security personnel is shorter than a year (McAndrew-Benevides 2016) and so there does not appear to be any supply chain issue for this aspect of plant operations.

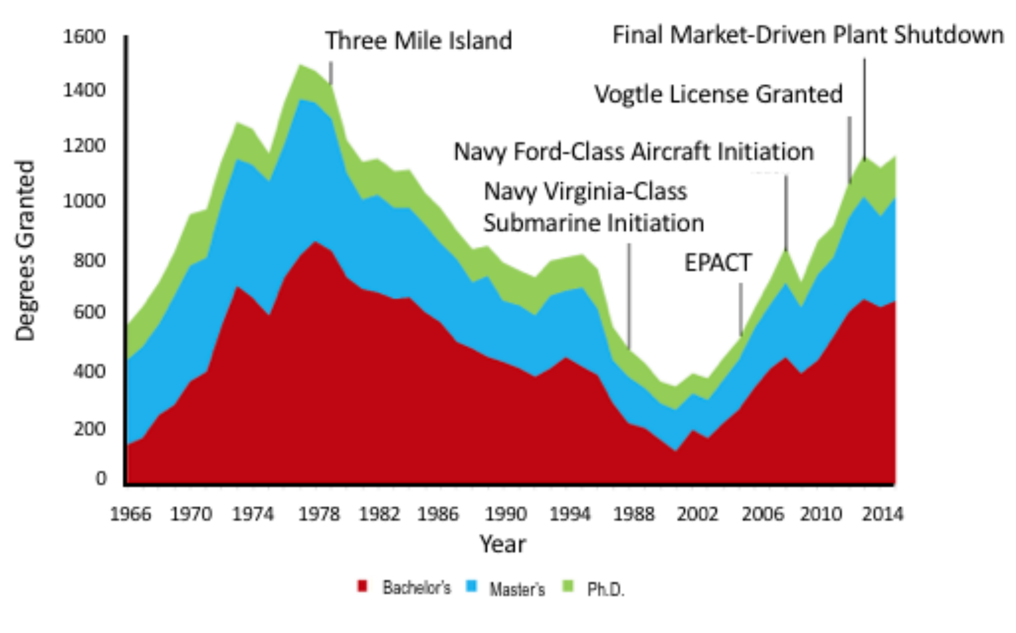
Engineers nominally require four years of education. However, there may be a deficit of engineers with the experience as well as the training for plant operations. Figure E.4 shows historical and current data on the number of nuclear engineering graduates at the bachelor's, master's, and Ph.D. level (Energy Futures Initiative, Inc. 2017). While graduation numbers have since risen, the low number of graduates in the later 1990s and early 2000s led to a deficit of nuclear engineers that would now be in their late 30s and early 40s with 15–20 years of experience in the industry. As a result, the workforce available to replace retiring senior engineers may be young and lacking in experience.

Figure E.5 shows the price of uranium over time. The figure shows that the price has declined since it peaked in 2007. Because of falling prices, investment in developing new uranium reserves has also declined. As a result, total identified uranium resources increased by only 0.1% between 2013 and 2015. During that time, world production of uranium also declined by 4.1% (from 58,411 tons in 2013 to 55,975 tons in 2015) (Nuclear Energy Agency 2016).

Though there has been little growth in identified uranium resources and uranium production over the last two decades, the uranium supply chain does not present an obstacle to the expansion of the nuclear energy industry going forward. This is because there are enough identified resources to handle an increase in demand. In 2011, MIT's *Future of the Nuclear Fuel Cycle* study (Kazimi, et al. 2011) found that currently existing as well as committed, planned, and prospective uranium production sites would be adequate to supply the International Atomic Energy Agency's (IAEA's) 'High Nuclear Growth' scenario in which nuclear generation grows from 377 gigawatts of electrical generating capacity (GWe), which requires 56,600 tons of uranium annually, to 683 GWe, which requires 104,740 tons of uranium annually. The concern is that current market conditions for nuclear fuel may discourage some planned and prospective investments in uranium production. However, if demand for uranium were to increase, this would re-incentivize investment in production facilities, averting supply shortages (Nuclear Energy Agency 2016).

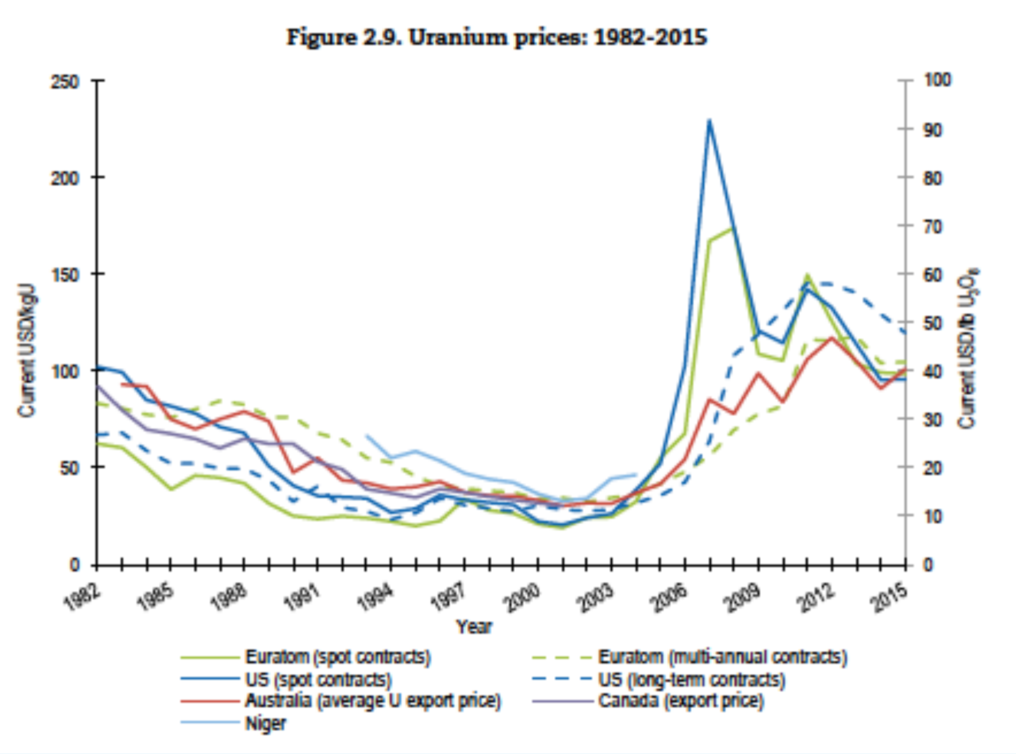
Current global uranium enrichment capacity is approximately 58.6 million separative work units (SWU), relative to current global demand of approximately 47.3 million SWU. Global enrichment capacity in the year 2020 is projected to be approximately 66.7 million SWU. Thus, there is no expectation that the nuclear industry will face near-term bottlenecks in the supply chain for enriched uranium (World Nuclear Association 2017).

Figure E.4: Numbers of nuclear engineering graduates in the United States



(Energy Futures Initiative, Inc. 2017)

Figure E.5: Historical and current prices of uranium



(Nuclear Energy Agency 2016)

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Appendix F

Process Heat Markets for Generation-IV Nuclear Reactors

Nuclear power plants have been producing commercial electricity in the United States for decades. In a traditional nuclear power plant, the reactor core produces heat, which is transferred to steam. The steam in turn generates electricity by a steam turbine. However, the original product from the reactor core is heat. When utilized effectively this heat may represent a product stream that has value independent of its potential for electricity production. Chapters 1 and 3 of this report discuss the potential market for process heat from various Generation-IV reactors in the United States and the rest of the world. This appendix presents a more detailed discussion of the realistic size of this potential market considering the fact that the major deployment hurdles for nuclear process heat at industrial locations are a function of the required process temperature and the size of the individual site.

PREVIOUS WORK

Previous efforts to analyze the potential use of Generation-IV reactors for process heat applications have been primarily focused around the U.S. Department of Energy's Next Generation Nuclear Plant (NGNP) project. Findings from three studies that have examined the use of nuclear process heat are detailed below.

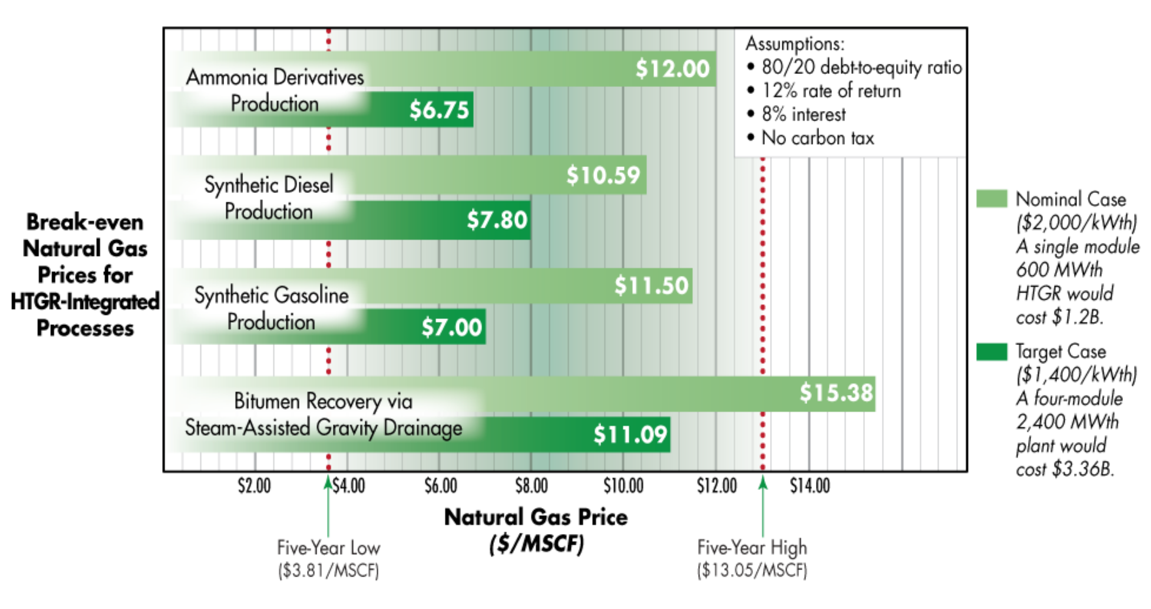
Report Summary: *Integration of High-Temperature Gas-Cooled Reactors into Industrial Process Applications*

A 2010 report by researchers at the Idaho National Laboratory, titled *The Integration of High-Temperature Gas-Cooled Reactors into Industrial Process Applications*, offers a technical and economic evaluation of the potential for utilizing high-temperature gas-cooled reactor (HTGR) technology for process heat applications (Nelson, et al. 2010). This report does not undertake a detailed market analysis, but rather assesses the potential use of HTGR technology in specific applications, including electricity generation, hydrogen production, methanol-to-synthetic gasoline production, synthetic diesel production, ammonia production, oil sands production, and natural gas production using coal as a feedstock. Results from this analysis, showing the natural gas price at which HTGR 'breaks even,' from a cost perspective, as an alternative source of process heat, are shown in Figure F.1.

Report Summary: *High Temperature Gas-Cooled Reactor Projected Markets and Preliminary Economics*

A report titled *High Temperature Gas-Cooled Reactor Projected Markets and Preliminary Economics* was completed in 2011 as part of the NGNP project (Idaho National Laboratory 2011). The authors assessed co-generation facilities in the United States and also examined the potential to use HTGR reactor technology for producing synthetic fuels. The findings of this report are summarized in Table F.1.

Figure F.1: Break-even natural gas prices calculated for four HTGR-integrated processes



(Nelson, et al. 2010)

Table F.1: Results from 2011 report "High Temperature Gas-Cooled Reactor Projected Markets and Preliminary Economics"

Item	Power Requirement (MWt)	Number of 600 MWt Modules	CO_2 Emissions Reductions (million metric tons)	Natural Gas Usage Reductions (trillion cubic feet)
Co-generation and Process Heat	75,000	125	110	2.2
Hydrogen Production	36,000	60	15	0.44
Oil Sands	18,000	30	23	0.41
Coal/Biomass to Fuel and Feedstock	249,000	415	80 to 410	N/A
Electricity Generation	110,400	184	~150 replacing CCGT* or ~300 replacing coal plant	3.4 (if replacing 150 CCGT units)
Total	488,400	814	378 to 858	6.45

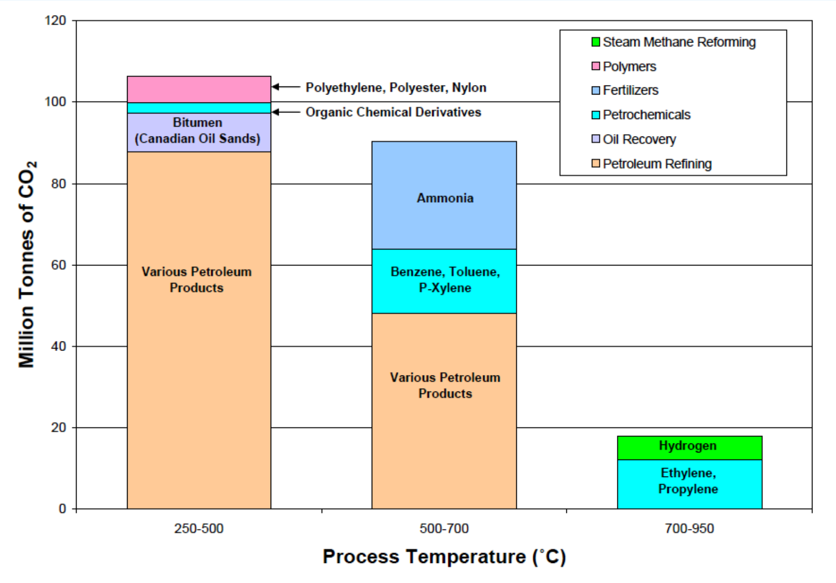
*Combined cycle gas turbine.

Report Summary: *Survey of HTGR Process Energy Applications*

This report, which surveyed potential process heat applications for HTGR technology, was produced by MPR Associates for the NGNP project (Konefal and Rackiewicz 2008). The authors analyzed 12 industries and assigned priorities to their availability for nuclear process heat, including petroleum refining, oil recovery, coal and natural gas derivatives, petrochemicals, industrial gases, fertilizers, metals, polymer products, cement, pharmaceuticals, and paper and glass. The number of reactors required to supply process heat for each of these industries in the United States is shown in Figure F.2.

There are limitations to the existing literature in this area. Previous reports did not assess the full market for process heat on a site-by-site basis, rather they undertook a market-wide analysis and focused on only a subset of all industrial sites in the United States. Our analysis, by

Figure F.2: Number of 500-MW_{th} HTGR modules at 85% capacity required to meet process heat demands for different industries



(Konefal and Rackiewicz 2008)

Table F.2: Overall assumptions for process heat market analysis

Assumption	Justification	Implication
Two reactor sizes are available for process heat applications: 150 MW_{th} or 300 MW_{th}.	Based on soliciting expert advice on optimal reactor sizes for industrial process heat applications.	Sites that are too small to accommodate either of these reactor sizes are excluded from the analysis. The flexibility of considering two potential reactor sizes, however, adds robustness to the calculation.
A minimum of two reactors are required at each site.	Based on discussions with industry concerning the high levels of reliability required for process heat supply. Natural gas has been proposed as an alternative back-up fuel, however the natural gas supply may not be guaranteed.	There will be excess capacity at each site.
Potential electricity generation capacity will be coupled to the thermal load to make use of excess heat capacity.	See section "Heat and Electricity Co-Generation" below.	—
At least a 50°C temperature differential is required for each potential application.	This level of differential is needed to give a high enough thermal driving force between the outlet heat and the process temperature.	High temperature applications are not considered in this analysis.

contrast, attempts to catalogue and analyze each individual industrial site in the United States to assess its potential suitability for nuclear process heat applications. This level of detail is important since an individual site may not be large enough to warrant a nuclear plant, even if the process heat the plant could provide would be of sufficient quality.

ASSUMPTIONS

Overarching assumptions for this analysis are summarized in Table F.2.

Each Generation-III+ and Generation-IV reactor concept has different available temperature limits, spanning a range from 60°C up to 900°C (with the very high temperature reactor). The section "Heat Availability" below outlines the heat quality available from each type of Generation-IV reactor.

Heat and Electricity Co-Generation

While the energy required at most industrial sites is in the form of process heat, these facilities also require electricity. As a result many industrial sites also co-generate electricity. Co-generation increases overall energy efficiency and reduces fuel consumption relative to producing the heat and electricity separately. The U.S. Energy Information Administration (EIA) collects and disseminates information on all electricity production facilities as part of its EIA-923 survey (U.S. Energy Information Administration 2017). For this analysis we extracted information on cogeneration facilities (Table F.3), including sites identified in the North American Industrial Classification System (NAICS) as 'industrial cogen,' 'NAICS-22 cogen,' and 'commercial cogen.'

Table F.3: Breakdown of U.S. fuel consumption for cogeneration in 2015

	Value	Percentage (%)
Total Fuel Consumed (TWh)	1,395	100.00
Electricity Fuel Consumed (MMBtu)	659	47.23
Heat Fuel Consumed (MMBtu)	736	52.77

(U.S. Energy Information Administration 2017)

The ability of cogeneration facilities to produce both electricity and heat provides an opportunity to use excess nuclear heat to serve electrical load on site. For example, if an industrial site requires 950 megawatts of thermal (heat) energy (MW_{th}), then installing four 300 MW_{th} reactors will mean that 250 MW_{th} is available for electricity co-generation.

Differential Temperature Requirement

Generally, there are two forms of heat exchangers: direct contact and indirect. Direct contact heat exchangers are systems where two streams are mixed to facilitate heat transfer. In indirect heat exchangers, by contrast, there is a barrier between the two process streams—for example, tubular heat exchangers. Indirect heat exchangers are governed by the following equation:

$$Q = UA\Delta T_{tm}$$

Where Q is the heat exchanger duty, U is the overall heat transfer coefficient, A is the surface area of the heat exchanger, and ΔT_{tm} is the log mean temperature difference in the heat exchanger. This governing equation shows that, holding duty and the overall heat transfer coefficient constant, a reduction in the log mean temperature difference means that the surface area of the heat exchanger must be increased. Therefore, to ensure that the driving force for the heat exchanger is adequate for the use of nuclear process heat without requiring significantly larger heat exchangers, we assume a minimum approach temperature of 50°C for the heat exchanger.

Technology Readiness

We examine the applicability of Generation-IV reactors to provide process heat for industrial processes that are already commercialized. Our broad analysis focuses on the utilization of nuclear process heat to produce synthetic fuels, a potentially enormous industry.

Synthetic gas or 'syngas' is a fuel gas mixture that can be used as a fuel and as a precursor to chemicals like methanol, di-methyl ether, and hydrogen. Syngas is comprised primarily of hydrogen, carbon monoxide, and limited amounts of carbon dioxide. Currently the major method used to produce syngas is steam reforming of natural gas. Water reacts with methane at high temperatures, normally 800°C–900°C, over a metal catalyst, typically nickel (Reimert, et al. 2011):

$$CH_4 + H_2O \leftrightarrow CO + 3H_2$$

The water–gas shift reaction can also be used to produce additional hydrogen by reacting carbon monoxide with excess water concurrently with the above reaction (Haussinger, Lohmuller, and Watson 2011):

$$CO + H_2O \leftrightarrow CO_2 + H_2$$

The potential to use nuclear-generated heat to produce syngas is very limited, as the process requires temperatures that are higher than the maximum temperature achieved by various

Generation-IV reactor designs. While the very high temperature reactor (VHTR) may produce process temperatures that are sufficiently high, the engineering feasibility of this production pathway is at low technical readiness. Currently, significant research efforts are underway to produce syngas at lower temperatures.

Heat Availability

Nuclear process heat is available at different temperatures depending on the reactor technology used. Table F.4 gives outlet temperature and assumed maximum process heat temperature available for different reactor designs. As an engineering limit, we assume a minimum difference of 50°C between the process heat temperature required and the reactor outlet temperature to provide a sufficiently large thermal driving force for heat transfer.

Table F.4: Breakdown of U.S. fuel consumption for cogeneration in 2015

Reactor Type	Reactor Outlet Temperature (°C)	Maximum Process Heat Temperature (°C)
Generation III+	300	250
Molten Salt Reactor	600	550
Very High Temperature Reactor	900	850
High Temperature Gas-cooled Reactor	700	650
Sodium Fast Reactor	500	450
Fluoride High Temperature Reactor	600	550

As shown in Table F.4, the maximum reactor outlet temperature is from the VHTR, which produces helium gas at 900°C. Accordingly, our analysis considers only those industrial processes that require heat at temperatures below 850°C.

THE POTENTIAL MARKET FOR NUCLEAR PROCESS HEAT IN THE UNITED STATES

This section examines the potential for nuclear process heat applications based on current process heat requirements in the United States.

Overall Energy Market in the United States

In 2014, the United States consumed 98.3 quadrillion British thermal units (Btu) of primary energy (Figure F.3 and Table F.5). If this total energy demand were to be met by a fleet of AP1000 reactors—at 1,117 MW_e/3,400 MW_{th} (Schulz 2006) —then this would require a fleet of approximately 1,040 reactors (Table F.5). At present, of course, not all primary energy demand could be met using nuclear reactors—particularly in the transportation system (barring the widespread deployment of electrified motor vehicles). We examine the ability of Generation-III+ and Generation-IV reactors to penetrate additional markets for process heat applications in the industrial sector.

Site-Specific Greenhouse Gas Emissions

The U.S. Environmental Protection Agency (EPA) collects greenhouse gas (GHG) emissions data from all industrial sites in the United States above a minimum carbon-dioxide-equivalent (CO_2-e) output of 25,000 metric tons (MT). The GHG emissions are broken down into tons of CO_2-equivalent emissions from various sources, including but not limited to direct CO_2 emissions, methane emissions, and chlorofluorocarbon (CFC) and hydrofluorocarbon (HFC and HCFC) emissions. The dataset is also broken down into 9 broad categories and 41 specific categories (Table F.6).

Figure F.3: 2014 primary U.S. energy consumption by source and sector

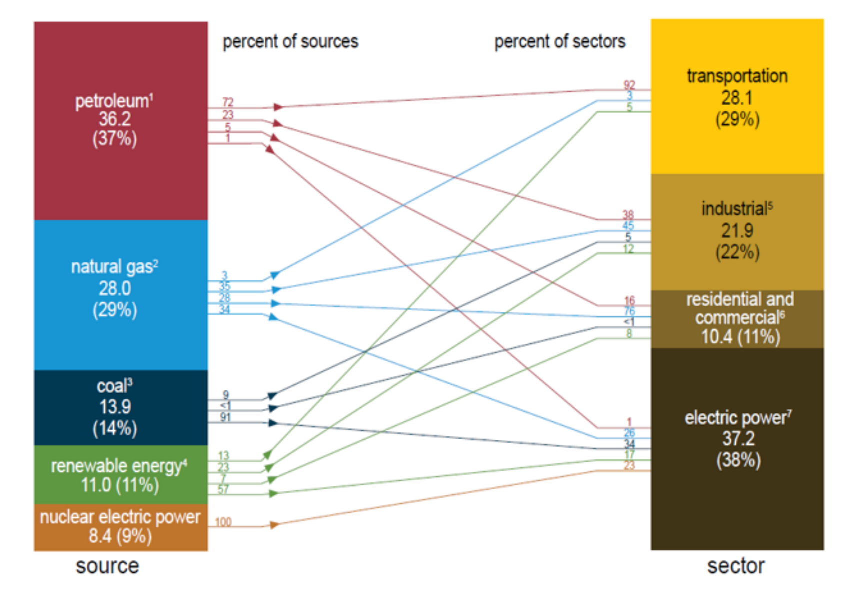


Table F.5: 2014 U.S. primary energy consumption and equivalent number of AP1000 nuclear reactors

Industry	Primary Energy Consumption (Quadrillion Btus)	Primary Energy Consumption (TWhr)	Equivalent Number of AP1000's for Thermal Load	Percentage (%)
Transportation	27.0	7910	286	27.5
Industrial	21.4	6270	227	21.8
Residential & Commercial	11.3	3310	120	11.5
Electric Power	38.5	11280	408	39.2
Total	98.3	28810	1040	100.0

Table F.6: Overview of sectors in EPA GHG dataset

Type of Site	Description	2015 GHG Emissions (Million MT CO_2-e)	Total Number of Reporting Facilities
Power Plant	Electricity-producing facilities that include coal-fired power stations and natural gas turbines.	1,696	1,480
Petroleum and Natural Gas Systems	Includes upstream oil and gas production facilities along with gas processing, compression, and pipeline facilities.	232	2,413
Refineries	Refineries for processing crude oil into gasoline, kerosene and other petroleum products.	176	144
Chemicals	Chemical facilities that include petrochemical and other commodity chemical products like ammonia and hydrogen.	174	462
Minerals	Includes cement, glass, lime, and soda ash production facilities.	115	379
Waste	Includes landfills, solid waste combustion, and wastewater treatment facilities.	112	1,540
Metals	Includes commodity metal production facilities such as steelworks and aluminum refineries.	90	297
Pulp and Paper	Facilities that produce wood pulp and paper.	38	232
Other	Includes a broad range of different facilities, e.g., food processing, ethanol production, and electronics production.	140	1,433
Total	Because multiple sites are included in multiple groups, the sum of the parts is greater than the actual total.	3,046	8,003

The EPA dataset was used to identify large industrial sites that could potentially use nuclear technology in process heat applications. Broad assumptions for this analysis are summarized in Table F.7. To calculate GHG reduction benefits, the analysis also accounts for the different carbon intensities of the fossil fuels being displaced (Table F.8).

Methodology

Direct interaction with the database was achieved with a web-based application programming interface (API) system, which was used to download relevant data for manipulation with Excel. Initially, the dataset was manipulated to compare direct CO_2 emissions from each site, curtailed to consider only those facilities with annual CO_2 emissions above 210,000 MT. The logic for this cut-off point was that that the cleanest natural-gas-burning facilities, operating at a 90% capacity factor, would produce approximately 147 MW, just below the minimum reactor size of 150 MW. This reduced the list of facilities to 1,398 individual sites. These 1,398 individual sites were then segregated into different sectors and industries based on their dominant purpose and analyzed individually to determine how much of their total fuel consumption could be replaced by nuclear process heat. Factors considered in the analysis included the required process temperatures and the size of the heat load that could be served by nuclear process heat.

Power Plants

Because the specific purpose of this analysis is to assess process heat applications for nuclear technology, we do not consider facilities whose primary business is to produce electricity (though obviously nuclear reactors can be used to generate electricity and can thus replace power plants that operate on other types of fuel).

Table F.7: Assumptions related to GHG emissions analysis

Assumption	Justification	Implication
The use of nuclear process heat affects only direct CO_2 emissions from heat production; it does not reduce process-related emissions.	If GHGs are produced by chemical reactions directly involved in the process, the use of nuclear technology to supply process heat would not affect these emissions.	None for results of this analysis.
The processing facility has a capacity factor of 90% (Sinnott, Richardson, and Coulson 2013).	No site runs consistently all year since time is required for maintenance and unplanned stoppages.	The equivalent power rating for each site will be higher than if averaged over the entire year.
Only non-biogenic emissions are considered.	Biofuels are considered to have no net CO_2 emissions on a full fuel-cycle basis because these emissions are captured in the regrowth of fuel feedstocks.	Sites that have high carbon emissions, but the emissions come from biofuels, e.g., sugar mills, are not considered.
If the process produces a waste stream that is used as a fuel then nuclear heat will not replace this fuel source.	If a waste product can be used as a fuel source then this is the most efficient use of the waste product.	Sites that have large waste product streams will not require as much additional heat.

Table F.8: CO_2 content by fuel source

Fuel	CO_2 Content (MT/GW_{th})
Coal (anthracite)	353.9
Coal (bituminous)	318.4
Coal (lignite)	333.4
Coal (sub-bituminous)	331.7
Diesel fuel and heating oil	249.7
Gasoline	243.3
Propane	215.2
Natural Gas	181.1

(U.S. Energy Information Administration 2016)

We do, however, consider co-generation facilities, which produce both heat (usually in the form of steam) and electricity. Out of the 776 power plants in EPA's database that produce CO_2 emissions above the 210,000 MT limit, 115 are cogeneration sites. These sites were analyzed to determine how many of them could be replaced with nuclear facilities. The results are shown in Table F.9. One of the largest steam production facilities in the United States is the Midland Cogeneration Venture (MCV), which supplies steam to Dow and Dow Corning. MCV can produce steam up to 580°C so we use this temperature as the required temperature limit for this analysis (Midland Cogeneration Venture 2017).

Petroleum and Natural Gas Systems

The EPA database includes 131 sites that are classified under petroleum and natural gas systems. These sites are all involved in the production or processing of oil and natural gas, e.g. onshore production facilities and natural gas processing facilities. Due to the nature of these sites, we determined that none of them are suitable for nuclear process heat applications.

Refinery

This section addresses nuclear process heat applications in standalone refineries and refineries coupled to petrochemical plants (chemical plants that are unrelated to refinery operations are covered in a later section). The EPA database lists 108 refinery facilities that meet our emissions threshold, of which 5 also have petrochemical plants associated with the site.

Table F.10 describes the typical major units in an oil refinery and their respective heat requirements. All of these units, except for the alkylation unit, operate at elevated temperatures—that is, above 350°C—with the fluidized catalytic converter operating at temperatures up to 700°C. All are therefore potentially suited to using process heat from a Generation-IV nuclear reactor.

Hydrogen is also commonly produced on site at refineries using steam methane reforming. As noted previously, hydrogen production by this method is not included in this analysis due to its heat requirements. The highest potential process temperature at a refinery is 700°C for the fluid catalytic cracker, so we assume that nuclear process heat must reach at least 750°C for use at this type of facility.

Standalone Refineries

Out of the 108 sufficiently large refinery sites in the EPA database, 103 of them do not have petrochemical plants associated with them. The purpose of these facilities is to process crude oil into gasoline, kerosene, and other hydrocarbon-based products. Petroleum refining is a highly complex and integrated process and each refinery is unique due to differences in desired output (e.g., aviation fuel versus diesel) and the crude feed supply (e.g., light versus heavy crude). It should be noted, however, that 47 of the refineries we analyzed also produce hydrogen on site; emissions from hydrogen production were not included in this analysis. As each refinery has different heat requirements, we examined each of the 103 sites to determine how much nuclear process heat they could utilize to replace fossil fuel consumption (Table F.11). Our results indicate a relatively small potential for the uptake of nuclear process heat in refineries, largely because of refineries' internal consumption of their own waste streams, primarily fuel gas. Fuel gas is a waste product from the refining of crude oil and is burned on site to provide process heat. For example, the CITGO Lemont Refinery in Illinois, with a refining capacity of 167,000 barrels of oil a day, produces only 5.36% of its emissions from fuel sources that could be replaced by nuclear process heat.

Refineries with Petrochemical Plants

Five refineries in the United States are co-located with petrochemical plants. These five facilities are ExxonMobil Baytown, ExxonMobil Baton Rouge, ExxonMobil Beaumont, Shell Deer Park, and Norco Manufacturing. All five facilities produce olefin on site, using a process that requires large amounts of heat to break down the alkane chains. The two major olefins produced are ethylene and propylene, which are primarily used in the production of polyethylene and polypropylene,

Table F.9: Co-generation nuclear process heat potential

Category	Reactor Size	Required Temperature	Number of Sites	Number of Reactors	Required Heat Load	Supplied Heat Load
Power Plants Cogeneration	150 MW	580°C	100	575	77,655 MW	86,250 MW
Power Plants Cogeneration	300 MW	580°C	70	276	70,983 MW	82,800 MW

Table F.10: Petroleum refinery major units with heat requirements

Processing Unit	Description	Heat Requirements	Energy Usage (in 1,000 Btus per barrel)
Atmospheric Distillation Unit	The atmospheric distillation unit is the major unit that performs the distillation of the crude oil. It separates naphtha, kerosene, diesel, and oil residue.	Before entering the column, the crude oil is heated to approximately 350°C. The temperature at the bottom of the column is also approximately 350°C.	109.1
Vacuum Distillation Unit	The vacuum distillation unit is used to separate out the components of the oil residue without thermally cracking them.	Requires a reboiler temperature of approximately 350°C.	89.1
Delayed Coker	The delayed coker is where the heaviest hydrocarbons are raised above their thermal cracking point so that shorter hydrocarbons and petroleum coke are formed.	The feed to the delayed coker has to be heated to approximately 480°C.	140.5
Visbreaker	The visbreaker is a unit that also thermally cracks heavy hydrocarbons into lighter hydrocarbons.	Feeds have to be heated to approximately 450°C.	88.5
Hydrotreater	The hydrotreater is used to remove sulfur from the refined petroleum products.	The reactions that occur in the hydrotreater occur between 300°C and 400°C (these are exothermic reactions and thus not necessarily capture-able).	80.8
Hydrocracker	Cracks heavier hydrocarbons in the presence of hydrogen to produce saturated hydrocarbons.	Temperature can be up to 425°C (these are exothermic reactions and thus not necessarily captureable).	158.9
Fluid Catalytic Cracker	Cracks heavier hydrocarbons to produce shorter chained hydrocarbons.	Operates at very high temperatures, approximately 700°C (needs to burn the coke and thus is not recoverable).	182.8
Catalytic Reformer	A process for converting low octane fuels into higher octane fuels by using a fixed bed catalytic reactor.	Requires heating up to approximately 550°C.	263.9
Alkylation	Converts low-value light hydrocarbons into higher-value high-octane hydrocarbons.	Operates at approximately 30°C.	244.6

(U.S. Energy Information Administration 2016b) (Hydrocarbon Publishing Company 2012)

Table F.11: Nuclear process heat potential for standalone refineries

Category	Reactor Size	Required Temperature	Number of Sites	Number of Reactors	Required Heat Load	Supplied Heat Load
Refineries – Stand Alone	150 MW	750°C	20	80	9,972 MW	12,000 MW
Refineries – Stand Alone	300 MW	750°C	10	33	7,920 MW	9,900 MW

respectively. Olefins are produced by steam cracking: decomposing ethane and propane in steam at high temperatures. The overall process is difficult due to the kinetics of the reaction, as coke can easily form in the reactor.

Steam cracking requires very high processing temperatures (Figure F.4): both the ethane and propane must be in the range of 880°C (Zimmermann and Walzl 2012). Due to the heat transfer constraints we applied in our analysis, we determined that nuclear technology does not produce process heat at sufficiently high temperatures to support olefin production. Thus, nuclear can supply process heat only for the refining process itself (Table F.12).

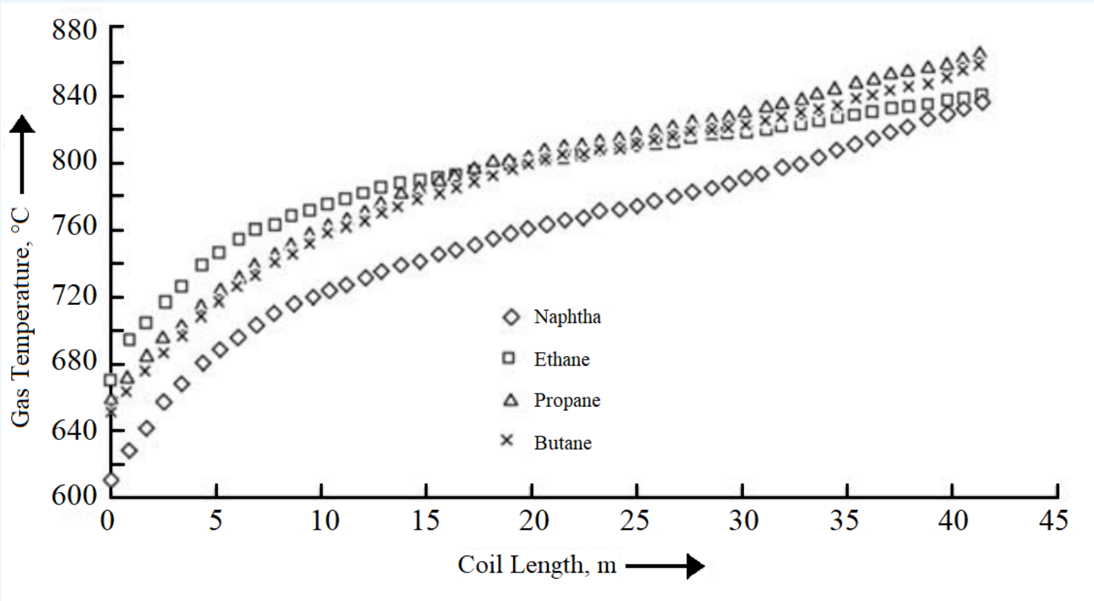
Chemicals

The EPA database includes a total of 124 chemical facilities of sufficient size (based on their CO_2 emissions) to justify examination for potential nuclear process heat applications. These facilities were divided into six subclasses for purposes of this analysis: fertilizers, hydrogen, petrochemicals, nylon 66, phosphoric acid, and air separation.

Fertilizers

Twenty-one fertilizer production facilities in the United States were considered in our analysis. The most widely used fertilizers in the world are ammonia-based compounds, which are used to enrich soil by adding nitrogen. Ammonia is also a vital commodity because it is widely used as a

Figure F.4: Process gas temperatures along radiant coils



(Zimmermann and Walzl 2012)

Table F.12: Nuclear process heat potential for refineries with petrochemical plants

Category	Reactor Size	Required Temperature	Number of Sites	Number of Reactors	Required Heat Load	Supplied Heat Load
Refineries – Petrochemical	150 MW	750°C	5	35	4,962 MW	5,250 MW
Refineries – SPetrochemical	300 MW	750°C	5	19	4,962 MW	5,700 MW

feedstock chemical. Ammonia is produced by the Haber-Bosch process, which involves reacting elemental hydrogen and nitrogen over an iron catalyst at approximately 550°C:

$$N_2 + 3H_2 \longrightarrow 2NH_3$$

Overall energy requirements for this process are intense due to the high pressure and chemical potential required, coupled with hydrogen production and nitrogen separation. Ammonia production facilities are usually co-located with urea and nitric acid production facilities, because ammonia is a precursor for both products. Urea is produced using the Bosch-Meiser process and nitric acid is produced using the Ostwald process; both processes are exothermic and do not occur at temperatures above 250°C.

Ammonia production involves two major reactions: the production of hydrogen by steam methane reforming and the synthesis of ammonia from nitrogen and hydrogen (Table F.13). Table F.13 shows that the first reaction, the production of hydrogen, is energy intensive and endothermic, while the second reaction is exothermic. As already noted, our analysis concludes that based on technical readiness today, hydrogen cannot be produced using nuclear process heat. Since the major heat requirements of ammonia production are associated with hydrogen production, nuclear process heat is also not suited for ammonia production.

Table F.13: Ammonia production reactions

Reaction	Enthalpy of Reaction
$CH_4 + 2H_2O \longrightarrow CO_2 + 4H_2$	ΔH = 252.8 kJ/mol
$N_2 + 3H_2 \longrightarrow 2NH_3$	ΔH = -91.8 kJ/mol

Hydrogen

Thirty-four hydrogen production facilities in the United States are sufficiently large to be considered for nuclear process heat applications. However, as already noted, current methods for hydrogen production require process temperatures higher than nuclear systems can provide. Thus, nuclear process heat would not be useable at these facilities with current technology.

Petrochemicals

Petrochemicals are the building blocks for modern products like plastics and lubricants. We identified 48 different petrochemical facilities of sufficient size to be considered in this analysis. These 48 plants were divided into seven sub-classes: olefins, carbon black, methanol, acrylonitrile, styrene, glycol, and vinyl. Some facilities produce multiple outputs: for example, some integrated chemical plants make more than 50 products; in those cases, the industrial facility was assigned to the sub-class that best fit its primary product.

Olefins

Olefins are a form of chained hydrocarbon that contains at least one carbon double bond; common examples include ethylene, propylene, and butadiene. Olefins are commonly used to produce long-chain polymer products like polyethylene and propylene. Our analysis includes 24 facilities in the United States that are primarily used to produce olefins. As already noted, however, the high temperatures required for the 'cracking' process mean that nuclear process heat is generally not applicable to olefin production (though cracking could potentially be done at 900°C with either a VHTR or Joule heating).

Carbon Black

Carbon black is a sooty material comprised of carbon; it is commonly used as a filler in rubber products, such as tires, and as a black pigment in plastics and paints. There are nine sites in the United States that primarily produce carbon black. Production temperatures range from 1,200°C to 1,900°C and are therefore unsuitable for nuclear process heat.

Methanol

Our analysis includes four facilities that have methanol as their major product. Methanol is primarily produced by passing syngas over a copper/zinc oxide (Cu-ZnO) catalyst at between 200°C and 300°C. Therefore, the limiting heat requirement is the production of syngas, which was shown in a previous section to be incompatible with nuclear process heat. As such nuclear process heat is not applicable to methanol production facilities.

Acrylonitrile

Our analysis includes three chemical plants in the United States that primarily produce acrylonitrile (C_3H_3N). The main use of acrylonitrile is as a building block in the production of polyacrylonitrile, a common plastic. The main reaction for producing acrylonitrile involves ammoxidation of propylene in the presence of a catalyst, typically a molybdate-based catalyst. This reaction takes place at 400°C–510°C and may produce CO_2 as a waste product.

$$2C_3H_6 + 2NH_3 + 3O_2 \longrightarrow 2C_3H_3N + 6H_2O$$

The required process temperature is suitable for the use of nuclear process heat; hence we analyzed the three U.S. acrylonitrile plants to determine their nuclear heat requirements. We did not include CO_2 produced in the reaction in our analysis. Only one of the sites had the potential to use nuclear process heat and only with a 150 MW reactor (Table F.14).

Styrene

Styrene (C_8H_8) is an important commodity chemical that is used in the production of polystyrene. Our analysis includes three industrial facilities in the United States that primarily produce styrene. The process involves the dehydrogenation of ethylbenzene, similar to the process used to make chained olefins, however at lower temperatures. The process reaction takes place around 620°C over an iron oxide catalyst with excess steam.

$$C_8H_{10} \longrightarrow C_8H_8 + H_2$$

The process temperature for styrene production is potentially suitable for nuclear process heat applications (Table F.15). None of the facilities was large enough to accommodate a 300 MW reactor.

Ethylene Glycol

Ethylene glycol ($C_2H_6O_2$) is a useful chemical that is used in anti-freeze and as a building block for polyester fibers. Our analysis includes five industrial facilities that primarily produce glycol. Ethylene glycol production involves reacting ethylene oxide with water at 200°C using sulfuric acid as a catalyst.

$$C_2H_4O + H_2O \longrightarrow C_2H_6O_2$$

The precursor ethylene oxide (C_2H_4H) is also produced on site for immediate use. Ethylene oxide is produced by the oxidation of ethylene between 220°C and 275°C with a silver catalyst.

$$C_2H_4 + \tfrac{1}{2}O_2 \longrightarrow C_2H_4O$$

Nuclear process heat could be used for ethylene glycol production (Table F.16). It should be noted that ethylene glycol is produced in large petrochemical plants that consume large quantities of fuel gas.

Vinyl Chloride

Our analysis includes four vinyl chloride production facilities. Vinyl chloride is most commonly used as a chemical building block in the production of polyvinyl chloride (PVC). The most common production pathway for vinyl chloride consists of three steps: direct ethylene

Table F.14: Acrylonitrile nuclear process heat potential

Category	Reactor Size	Required Temperature	Number of Sites	Number of Reactors	Required Heat Load	Supplied Heat Load
Chemicals – Acrylonitrile	150 MW	510°C	1	2	184 MW	300 MW

Table F.15: Styrene nuclear process heat potential

Category	Reactor Size	Required Temperature	Number of Sites	Number of Reactors	Required Heat Load	Supplied Heat Load
Chemicals – Styrene	150 MW	620°C	3	6	696 MW	900 MW

chlorination, ethylene oxychlorination and finally 1,2-dichloroethane cracking to produce the vinyl chloride.

The highest temperatures—between 500°C and 550°C—are required during the final cracking stage. This temperature range is compatible with potential nuclear process heat applications (Table F.17).

Nylon 66

Our analysis includes two facilities that produce nylon 66 and its precursors. Other than the hydrogen reformers at both sites, nuclear process heat could be used to replace all other fuel consumption at these facilities since the maximum process temperature for nylon 66 is approximately 300°C. The potential CO_2 reductions that could be achieved using nuclear process heat at these facilities (i.e., not including emissions from the hydrogen reformer) are summarized in Table F.18.

Both facilities are large enough under specified conditions to be potential candidates for nuclear process heat applications (Table F.19).

Phosphoric Acid

Our analysis includes two phosphoric acid production facilities in the United States. However, most GHG emissions from these facilities are process related and do not come from fossil fuel use to supply process heat. When only emissions

Table F.16: Ethylene glycol nuclear process heat potential

Category	Reactor Size	Required Temperature	Number of Sites	Number of Reactors	Required Heat Load	Supplied Heat Load
Chemicals - Ethylene Glycol	150 MW	275°C	5	17	2,090 MW	2,550 MW
Chemicals - Ethylene Glycol	300 MW	275°C	5	10	2,090 MW	3,000 MW

Table F.17: Vinyl chloride nuclear process heat potential

Category	Reactor Size	Required Temperature	Number of Sites	Number of Reactors	Required Heat Load	Supplied Heat Load
Chemicals - Vinyl Chloride	150 MW	550°C	4	16	2,119 MW	2,400 MW
Chemicals - Vinyl Chloride	300 MW	550°C	2	6	1,725 MW	1,800 MW

Table F.18: Annual CO_2 reduction potential using nuclear process heat applications at Nylon 66 production facilities

Site	Total CO_2 Emissions (tons)	Hydrogen Reformer Emissions (tons)	Nuclear-Displaceable Process Heat Emissions (tons)	MW equivalent
Ascend Performance Materials	1,061,220	186,991	874,229	613
Invista S.a.r.l.	907,103	70	907,033	635

Table F.19: Nylon nuclear process heat potential

Category	Reactor Size	Required Temperature	Number of Sites	Number of Reactors	Required Heat Load	Supplied Heat Load
Chemicals - Nylon	150 MW	300°C	2	6	1,248 MW	1,800 MW
Chemicals - Nylon	300 MW	300°C	2	10	1,248 MW	1,500 MW

related to process heat are considered, neither of the two facilities is large enough for a 150 MW_{th} nuclear reactor.

Air Separation

Our analysis includes two facilities in the United States that separate air. These facilities produce oxygen and nitrogen by cooling air to cryogenic levels and then distilling its two major components. The bulk of the associated CO_2 emissions come from combined cycle natural gas plants, which supply electricity—the major form of energy required at both sites. As a result, these facilities are not suitable for nuclear process heat applications.

Minerals

Our analysis includes 149 facilities in the United States that are involved in minerals-based production and are of sufficient size, based on their CO_2 emissions, to be potentially suitable for nuclear process heat applications. These facilities can be further divided into five product categories: cement production, lime production, glass production, soda ash production, and titanium dioxide production.

Cement Production

Cement is a key material in construction and building that has been used for thousands of years. The most common modern version of cement is known as Portland cement. Portland Cement is produced by milling and combining various materials and then heating them in a cement kiln. The kiln rotates while heating the materials up to 1,500°C and producing clinker. After the clinker is cooled, it is milled and then mixed with limestone and gypsum to produce the final cement product. The mix of materials used may include limestone, shells, chalk, marl, shale, clay, slate, blast furnace slag, silica sand, and iron ore. Due to the high temperatures required to operate the kiln, nuclear process heat is not applicable to cement production.

Lime Production

Lime, or calcium oxide, is a material used extensively in construction; it can also be used as a chemical feedstock. Lime is typically produced by the decomposition of calcium carbonate (i.e., limestone) into calcium oxide and carbon dioxide:

$$CaCO_3 \longrightarrow CaO + CO_2$$

This calcining process requires temperatures above 1,000°C; thus, nuclear process heat cannot be used in lime production facilities.

Glass Production

Glass is produced by mixing and then melting and annealing various oxides to form an amorphous state. Common oxides used in glass production include silicon dioxide, sodium oxide, calcium oxide, magnesium oxide, and aluminum dioxide. The required processing temperatures are high: upwards of 1,500°C. For this reason, nuclear process heat cannot be utilized for glass production.

Soda Ash Production

Soda ash, also known as sodium carbonate, is commonly used in glass production (hence the term 'soda glass') and other industrial processes. While there are numerous ways to produce soda ash, the United States has large deposits of trona, a double salt of sodium bicarbonate and sodium carbonate, which can be processed into soda ash. Trona is calcined at approximately 300°C to decompose the sodium bicarbonate into sodium carbonate and drive off any excess water:

$$2Na_3H(CO_3)_2 \bullet 2H_2O \longrightarrow 3Na_2CO_3 + 3H_2O + CO_2$$

Our analysis includes four facilities in the United States that produce soda ash (Table F.20).

All four of the facilities considered have sufficient heat requirements to be potentially suitable for nuclear process heat applications (note that this would displace only the CO_2 emissions attributable to existing combustion sources, not process emissions) (Table F.21).

Titanium Dioxide Production

Our analysis includes five titanium dioxide production facilities in the United States. Titanium dioxide, also known as Titania, has a range of uses from titanium metal production to use as a white pigment. Existing U.S. production facilities use a chloride process to produce a high-purity Titania product. The governing reactions are as follows:

$$TiO_2 + 2Cl_2 + C \longrightarrow TiCl_4 + CO_2$$

$$TiCl_4 + O_2 \longrightarrow 2Cl_2 + TiO_2$$

The first reaction takes place between 800°C and 1,200°C and the second reaction takes place between 900°C and 1,400°C. Due to large process-related CO_2 emissions and very high process temperatures, these facilities are not suitable for nuclear process heat applications.

Waste

There are 24 waste processing facilities in the United States that are large enough, based on their GHG emissions, to be considered in this analysis. These facilities include landfills and solid waste combustion plants. Because emissions from these sources come from unavoidable waste streams, nuclear process heat is not applicable to this category of facilities.

Metals

There are 64 individual facilities in the United States that are involved in metal production and that are large enough, based on their CO_2 emissions, to be considered for nuclear process heat applications. These metal production facilities can be broken down into six distinct categories: iron and steel production, aluminum production, ferroalloy production, magnesium production, alumina production, and manufacturing.

Iron and Steel Production

Iron and steel are produced from iron ore, typically hematite (Fe_2O_3) and magnetite (Fe_3O_4). The blast furnace is the primary technology for producing pig iron. Coke, flux, and sintered iron ore are charged into the top of the blast furnace while hot blast is injected through a tuyere at the bottom. The hot blast reacts with the coke and other injected fuels to produce carbon monoxide, which reduces the iron ore to pig iron. The escaping gases however are not fully oxidized and can be used as a further fuel, known as blast furnace gas.

Before the iron-making process, the coking coal must be transformed into coke. This is done by heating the coking coal in a coke oven in the absence of oxygen. The coking process drives off volatile gases from the coal and increases the carbon concentration in the coke. These volatile

Table F.20: U.S. Soda ash production facilities

Facility	Annual CO_2 Emissions from Combustion Source (tons)	Annual CO_2 Emissions from Soda Ash Process (tons)	Power Equivalent for CO_2 Combustion Source (MW)
Tronox Westvaco	1,590,456.72	306,023.10	697
Tata Chemicals Partners	1,130,499.91	279,818.40	531
Solvay Chemicals	829,434.56	319,673.00	352
Ciner Wyoming	317,395.76	423,996.78	222

Table F.21: Soda ash nuclear process heat potential

Category	Reactor Size	Required Temperature	Number of Sites	Number of Reactors	Required Heat Load	Supplied Heat Load
Minerals – Soda Ash	150 MW	300°C	4	14	1,802 MW	2,100 MW
Minerals – Soda Ash	300 MW	300°C	3	7	1,580 MW	2,100 MW

gases, known as coke oven gases, are combusted to provide heat for both the coke ovens and the rest of the steelworks.

Steel production presents opportunities to recover heat and fuel from the process itself, in the form of blast furnace gas and coke oven gas. The process requires minimal amounts of fuel in addition to the fuel that is directly produced from the process. We focused on ArcelorMittal Steelworks at Burns Harbor as a case study, since this facility produced the highest CO_2 emissions for a U.S. steelworks plant in 2015.

In 2015, the ArcelorMittal steelworks at Burns Harbor produced 9,460,478 MT of CO_2. Of this total, 6,290,873.9 MT came from stationary combustion sources and 3,169,604.1 MT came from the production process itself—that is, from the flares, coke pushing operations, and basic oxygen process furnaces. The breakdown of CO_2 emissions from stationary combustion sources at the ArcelorMittal facility in 2015 is shown in Table F.22.

Table F.22: Breakdown of fuel types used and CO_2 emissions at ArcelorMittal Steelworks at Burns Harbor in 2015

Fuel Type	MT of CO_2	Percentage (%)
Blast Furnace Gas	4,692,206	74.6
Coke Oven Gas	704,416	11.2
Natural Gas	894,252	14.2
Total	6,290,874	100.00

Table F.22 shows that 14% of CO_2 emissions from the Burns Harbor facility come from a non-process related fuel source, i.e., natural gas. However, the facility requires higher process temperatures than can be provided by nuclear process heat. For example, the sintering plant is a critical step to agglomerate iron ore fines into larger material. This process requires temperatures upwards of 1,200°C. Thus, nuclear process heat cannot replace the process heat generated by natural gas in current steel and iron making facilities.

Direct Reduced Iron (DRI)

An emerging technology uses syngas to directly reduce iron ore. However, this method currently accounts for only 6% (approximately) of global iron production. Since nuclear process heat is not suited for commercial syngas production at present, this type of facility was not considered for further analysis.

Aluminum Smelting

Aluminum smelting is used to reduce alumina into aluminum metal. This process is accomplished by using an electrochemical cell in what is known as the 'Hall-Heroult process.' The alumina is combined with molten cryolite (Na_3AlF_6) at 1,000°C, an electrical current is then run through this mixture, and the aluminum is reduced to metal while the oxygen reacts with the carbon anode.

$$Al_2O_3 + \tfrac{3}{2}C \longrightarrow 2Al + \tfrac{3}{2}CO_2$$

Because this process uses an electrochemical cell, it requires vast amounts of electricity. The two major sources of emissions from aluminum facilities are the production of electricity and the consumption of carbon anodes. Therefore, aluminum smelting is not a candidate for nuclear process heat applications.

Ferroalloy Production

We considered four facilities in the United States that produce ferroalloy, including silicon metal production facilities and iron-silicon alloy production facilities. All four facilities require temperatures much higher than can be provided using nuclear process heat.

Magnesium Production

There is only one magnesium production facility in the United States large enough to be considered in this analysis: U.S. Magnesium. The production process involves reducing magnesium chloride in an electrolytic cell. Because it relies on electrochemistry—in other words, electricity is used to produce the magnesium—this process is not suitable for nuclear process heat.

$$MgCl_2 \longrightarrow Mg + Cl_2$$

Alumina Production

Alumina is an oxide of aluminum that may be used as a refractory, as an abrasive, and in the production of aluminum metal. Alumina is produced primarily from bauxite, an aluminum-based ore, using the so-called Bayer process. In this process, the aluminum component of bauxite is dissolved in sodium hydroxide, at approximately 180°C, and then cooled and recrystallized to produce aluminum hydroxide:

$$Al_2O_3 + 2NaOH \longrightarrow 2NaAlO_2 + H_2O$$

$$2H_2O + NaAlO_2 \longrightarrow Al(OH)_3 + NaOH$$

This aluminum hydroxide is then calcined at high temperatures, approximately 1,100°C, to produce a purified alumina product:

$$2Al(OH)_3 \longrightarrow Al_2O_3 + 3H_2O$$

Due to the high temperatures required in the calcining process, nuclear process heat is not applicable to alumina production.

Manufacturing

There are three manufacturing facilities in the United States that are large enough, based on their GHG emissions, to be considered in this analysis. These are foundries; facilities that melt steel and then cast products. Due to the high temperatures required to melt steel, nuclear process heat is not suitable for these facilities.

Pulp and Paper

There are 59 pulp and paper production facilities in the United States that are sufficiently large, based on their CO_2 emissions, to be considered in this analysis. It should be noted that we consider emissions only from fossil-based sources and not from the combustion of residual biomass (biogenic sources). For example, in 2015, the general stationary fuel combustion units at the Westrock Virginia, Covington facility produced 1,036,795 MT of CO_2, primarily from natural gas, along with 604,235.5 MT of biogenic CO_2 from the combustion of wood and wood residues. Our analysis considers only non-biogenic heat sources as potential candidates for nuclear process heat applications.

Many different processes are involved in producing pulp, from mechanical separation to chemical processes. Once the pulp has been produced it is compressed in a paper making machine where the excess water is removed by compression and heating. What all these processes have in common, however, is that they require low process temperatures, with a maximum temperature of 300°C required for the steam used to dry the paper. Of the 59 sites we considered, 51 are large enough to warrant the use of process heat from a 150-MW nuclear reactor (see Table F.23).

Other

An additional 38 facilities in the EPA dataset fall in the category of 'other.' Of these, we analyzed 28 facilities, divided into six categories: food processing, cellulose acetate, specialty plastics and chemicals, universities, brine, and gold mining.

Table F.23: Pulp and paper nuclear process heat potential

Category	Reactor Size	Required Temperature	Number of Sites	Number of Reactors	Required Heat Load	Supplied Heat Load
Pulp and Paper	150 MW	300°C	51	142	16,890 MW	21,300 MW
Pulp and Paper	300 MW	300°C	22	42	10,742 MW	14,700 MW

Food Processing

Our analysis includes 18 food processing facilities across the United States, producing a range of products from vitamin E to bioethanol and sugar, to corn starch and fructose syrup. Given this broad variety of products, we make assumptions about maximum operating temperatures at these facilities. Specifically, we assume that the maximum operating temperature for processes that use complex organics and food-based materials is approximately 300°C (for example, given that sucrose decomposes at 186°C, higher temperatures can be assumed to cause the organic compounds in these products to begin decomposing). This assumption leads to the results summarized in Table F.24.

Cellulose Acetate

The cellulose acetate production plant in Narrows, Virginia, is the only U.S. facility of this type large enough to warrant consideration for nuclear process heat applications. Cellulose acetate is the acetate ester of cellulose; it has a wide range of uses, from film base to synthetic fiber. Cellulose acetate is produced by the reaction of acetic acid and acetic anhydride with cellulose material in the presence of a catalyst, typically sulfuric acid. The reaction has a long residence time during which the cellulose acetate precipitates out of solution and afterwards is filtered out and spun. The process temperatures involved are not excessively high, approximately 200°C. As such, nuclear process heat could be used at this facility (Table F.25).

Specialty Plastics and Chemicals

Our analysis includes five facilities that produce specialty chemicals and plastics (Table F.26). The maximum process heat requirement for these facilities is 550°C, for the production of catalysts. Results for these five facilities, including required heat loads, are summarized in Table F.27.

Table F.24: Food processing nuclear process heat potential

Category	Reactor Size	Required Temperature	Number of Sites	Number of Reactors	Required Heat Load	Supplied Heat Load
Other – Food	150 MW	300°C	14	78	10,345 MW	11,700 MW
Other – Food	300 MW	300°C	10	38	9,549 MW	11,400 MW

Table F.25: Other – Cellulose acetate nuclear process heat potential

Category	Reactor Size	Required Temperature	Number of Sites	Number of Reactors	Required Heat Load	Supplied Heat Load
Other – Cellulose Acetate	150 MW	200°C	1	3	350 MW	450 MW
Other – Cellulose Acetate	300 MW	200°C	1	2	350 MW	600 MW

Table F.26: Required temperatures at specialty plastics and chemicals production facilities

Site	Product	Required Temperature	Justification
SABIC Innovative Plastics, Mt. Vernon	Thermoplastics	300°C	Above this temperature thermoplastics start to degrade
Ticona Polymers Incorporated	Acetyl and liquid crystal polymers and thermoplastics	300°C	Above this temperature polymers and plastics start to degrade
Oxea Corp Bay City Plant	Intermediate alcohols, aldehydes and esters	250°C	Process temperature for the hydroformylation of olefins to produce aldehydes
Kraton Polymers US	Synthetic polymers and rubbers	300°C	Above this temperature polymers start to degrade
BASF Corporation	Catalysts	550°C	Production of zeolite catalysts require the conversion of kaolin to metakaolin at this temperature

Universities

Seven universities are included in this analysis in the 'other' category. These are all large facilities that produce their own heat and cooling water on site with no industrial purpose for their heat generation. We assume that the required temperature for internal heat loads at these universities is 200°C. Due to their smaller size, none of these facilities is large enough for a 300 MW_{th} reactor. The total potential for nuclear heat is shown in Table F.28.

Brine

Searles Valley Minerals is an industrial facility located in California that produces borax, boric acid, sodium carbonate, and other products using the brine from Searles Lake. Ninety-five percent of the facility's direct CO_2 emissions are from two pulverized coal boilers; the remaining 5% is attributed to natural gas consumption. These three energy sources produced approximately 4853.91 gigawatt hours (GWh) of heat in 2015, representing an effective heat load of 616 MW. Most of this thermal energy was used to evaporate water from the brine solution in order to produce anhydrous products; given the low process temperature required, nuclear process heat is potentially applicable. Subject to our assumptions, Searles Valley Minerals would have the potential to operate three 300-MW reactors (Table F.29).

Gold Mining

One gold mine is included in the 'other' category. This facility is vertically integrated in that it both mines and processes gold. Due to the high temperatures required to smelt gold, which has a melting point of 1,064°C, nuclear process heat is not applicable to this facility.

THE OVERALL MARKET FOR INDUSTRIAL PROCESS HEAT IN THE UNITED STATES

Our estimate of the overall potential for nuclear process heat applications in the United States is summarized in Tables F.30 and F.31, which assume reactor sizes of 150 MW_{th} and 300 MW_{th}, respectively. The total heat load in our analysis is 131,231 MW, or 1,035 terawatt hours (TWh) per year. This represents only 16.5% of the total primary heat used in the U.S. industrial sector. There are two major reasons for this relatively small market potential. The first is that some major industrial consumers of heat energy, primarily refineries, use fuel gas produced during

Table F.27: Specialty thermoplastics nuclear process heat potential

Category	Reactor Size	Required Temperature	Number of Sites	Number of Reactors	Required Heat Load	Supplied Heat Load
Other – Specialty Chemicals	150 MW	550°C	4	9	994 MW	1,350 MW
Other – Specialty Chemicals	300 MW	550°C	1	2	349 MW	600 MW

Table F.28: Universities nuclear process heat potential

Category	Reactor Size	Required Temperature	Number of Sites	Number of Reactors	Required Heat Load	Supplied Heat Load
Other – Universities	150 MW	200°C	6	12	1,308 MW	1,800 MW

Table F.29: Brine nuclear process heat potential

Category	Reactor Size	Required Temperature	Number of Sites	Number of Reactors	Required Heat Load	Supplied Heat Load
Other – Brine	150 MW	300°C	1	5	616 MW	750 MW
Other – Brine	300 MW	300°C	1	2	616 MW	900 MW

the refining process to meet a large share of their own energy needs. A second reason is the inability to commercially produce hydrogen under current constraints. If hydrogen could be produced on a commercial scale at nuclear process heat temperatures, the potential size of the market would expand rapidly. The current installed capacity of Generation-II reactors in the United

Table F.30: Nuclear process heat potential – 150-MW_{th} reactor size

Category	Required Temperature	Number of Sites	Number of Reactors	Required Heat Load	Supplied Heat Load
Power Plants – Cogeneration	580°C	100	575	77,655 MW	86,250 MW
Refineries – Stand Alone	750°C	20	80	9,972 MW	12,000 MW
Refineries – Petrochemical	750°C	4	35	4,962 MW	5,250 MW
Chemicals – Acrylonitrile	510°C	1	2	184 MW	300 MW
Chemicals – Styrene	620°C	3	6	696 MW	900 MW
Chemicals – Ethylene Glycol	275°C	5	17	2,090 MW	2,550 MW
Chemicals – Vinyl Chloride	550°C	4	16	2,119 MW	2,400 MW
Chemicals – Nylon	300°C	2	6	1,248 MW	1,800 MW
Minerals – Soda Ash	300°C	4	14	1,802 MW	2,100 MW
Pulp and Paper	300°C	51	142	16,890 MW	21,300 MW
Other – Food	300°C	14	78	10,345 MW	11,700 MW
Other -Cellulose Acetate	200°C	1	3	350 MW	450 MW
Other – Specialty Chemicals	550°C	4	9	994 MW	1,350 MW
Other – Universities	200°C	6	12	1,308 MW	1,800 MW
Other – Brine	300°C	1	5	616 MW	750 MW

Table F.31: Nuclear process heat potential – 300-MWt_h reactor size

Category	Required Temperature	Number of Sites	Number of Reactors	Required Heat Load	Supplied Heat Load
Power Plants – Cogeneration	580°C	70	276	70,983 MW	82,800 MW
Refineries – Stand Alone	750°C	10	33	7,920 MW	9,900 MW
Refineries – Petrochemical	750°C	4	19	4,962 MW	5,700 MW
Chemicals – Ethylene Glycol	275°C	5	10	2,090 MW	3,000 MW
Chemicals – Vinyl Chloride	550°C	2	6	1,725 MW	1,800 MW
Chemicals – Nylon	300°C	2	10	1,248 MW	1,500 MW
Minerals – Soda Ash	300°C	3	7	1,580 MW	2,100 MW
Pulp and Paper	300°C	22	42	10,742 MW	14,700 MW
Other – Food	300°C	10	38	9,549 MW	11,400 MW
Other – Cellulose Acetate	200°C	1	2	350 MW	600 MW
Other – Specialty Chemicals	550°C	1	2	349 MW	600 MW
Other – Brine	300°C	1	2	616 MW	900 MW

States is approximately 300 GW_{th}, meaning that our estimate of overall potential for heat load applications comes to approximately two-fifths the capacity of the existing fleet.

MARKETS FOR NUCLEAR PROCESS HEAT OUTSIDE THE UNITED STATES

The detailed information used to generate the results shown in Tables F.30 and F.31 is not available for industrial facilities in the rest of the world. To produce a rough estimate of the size of the global market for industrial process heat, we scaled the U.S. data using two factors: U.S. refining capacity relative to worldwide refining capacity and U.S. gross domestic product (GDP)—a measure of overall economic output—relative to world GDP. Our major assumption in applying these scaling factors is that the global distribution of plant capacities is the same as in the United States. In general, however, the United States has a higher proportion of large-capacity plants. This means that our estimate likely over-predicts the potential for nuclear process heat applications at industrial facilities worldwide.

SCALING FACTORS

This section describes the methodology used to generate factors for scaling U.S. results to the rest of the world, based on refinery capacity and GDP.

Refinery Capacity

In 2015, average U.S. daily refinery throughput was 6,207,000 barrels, which represented 20.4% of the global total that year (BP 2016). This value, 20.4%, was used to scale the data on U.S. refineries and petrochemical plants to estimate the size of the global process heat market for these types of facilities.

GDP Comparison

While petroleum and fertilizer production facilities had clearly defined production rates and capacities, this information is not available for other types of industrial facilities that could potentially use nuclear energy for process heat applications. For these industries, we assume the ratio of potential process heat applications relative to the U.S. potential mirrors the ratio of world GDP to U.S. GDP. In 2015, U.S. GDP was $18,036.65 billion (in U.S. dollars) compared to global GDP of $74,188.70 billion (World Bank 2017). This means that the United States accounted for 24.3% of the world's economic output in 2015. We used 24.3% to scale our results for U.S. nuclear process heat potential in non-refinery industrial applications to the rest of the world.

WORLD-WIDE NUCLEAR PROCESS HEAT CAPACITY

Using the above-defined scaling factors, we estimate the worldwide potential for nuclear process heat applications, assuming the use of

Table F.32: Estimate of worldwide nuclear process heat potential assuming 300-MW_{th} reactors

Category	Scaling Factor	Number of Reactors	Supplied Heat Load
Power Plants – Cogeneration	0.243	1136	340,800 MW
Refineries – Stand Alone	0.204	162	48,600 MW
Refineries – Petrochemical	0.204	94	28,200 MW
Chemicals – Ethylene Glycol	0.204	50	15,000 MW
Chemicals – Vinyl Chloride	0.204	30	9,000 MW
Chemicals – Nylon	0.243	42	12,600 MW
Minerals – Soda Ash	0.243	29	8,700 MW
Pulp and Paper	0.243	173	51,900 MW
Other - Food	0.243	157	47,100 MW
Other – Cellulose Acetate	0.243	9	2,700 MW
Other – Specialty Chemicals	0.243	9	2,700 MW
Other – Brine	0.243	9	2,700 MW

300-MW_{th} reactors, at 570,000 MW_{th} (Table F.32). This is roughly five times the estimated magnitude of the potential domestic U.S. market.

FUEL MARKETS

While the industrial sector accounts for a significant share of total primary energy use in the United States, its energy use is less than that of the transportation sector (21.4 quadrillion Btu in 2014, compared to 27.0 quadrillion Btu for transportation) (Figure F.3). The use of nuclear power to supply transportation sector energy demand could dramatically expand nuclear energy's role in the overall energy mix and the potential for associated CO_2 reductions.

We examine this potential for three scenarios that assume a major paradigm shift in the transportation sector, which is currently nearly 100% dependent on liquid petroleum fuels. The three scenarios assume full replacement of current transportation-related fossil energy consumption by electrification, hydrogen fuels, and biofuels, respectively. We do not consider other potential synthetic fuel options, such as gas-to-liquids and CO_2-to-liquids. Our methodology compares the efficiency of these non-petroleum fuels (i.e., electricity, hydrogen, biofuels) to current conventional transportation fuels to estimate total transportation energy requirements under each scenario:

$$\textit{Energy Required by New Fuel} = \frac{Eff_{\textit{New Fuel}}}{Eff_{\textit{Combustion}}}\ \textit{Energy Required by Combustion}$$

Other assumptions used for this analysis are detailed in Table F.33.

ELECTRIFICATION

Electrifying the transportation sector would involve replacing internal combustion engines and fuel tanks with electric motors and batteries. A number of auto manufacturers have recently released all-electric models (e.g., the BMW i3, Nissan Leaf, and GM Bolt). Electric cars are much more efficient than internal combustion cars, with an average efficiency of 60% (Office of Energy Efficiency and Renewable Energy 2015). If electric cars were to become the norm in the United States, they would require 2,640 TWh of electricity per year to operate.

HYDROGEN

If hydrogen were to emerge as the preferred path to zero-carbon transportation, new methods for producing hydrogen would be needed, since the current method—which relies on steam methane reforming—generates CO_2 emissions. We considered two alternative hydrogen production methods: electrochemical splitting of water and thermochemical splitting of water.

Table F.33: Transportation fuel market assumptions

Assumption	Justification	Implication
Average efficiency of the current transportation fleet is 20% (Office of Energy Efficiency and Renewable Energy 2015).	This is the average efficiency of an internal combustion engine.	Does not consider the diversity of the transportation fleet (e.g., trucks vs. cars). However, it should give an adequate first order approximation.
Heat to electricity conversion efficiency is 35%.	This is an average heat to electricity conversion ratio.	35% is considered low for higher temperature heat processes.

At 50%, the average efficiency of hydrogen fuel cells is much higher than that of traditional internal combustion engines. This means that replacing the current U.S. vehicle fleet with hydrogen-powered vehicles would require 3,164 TWh per year of hydrogen gas. Hydrogen gas has a lower energy value of approximately 121.5 megajoules per kilogram (MJ/kg) meaning that using hydrogen to power the U.S. transportation fleet would require 9.375×10^{10} kilograms (kg) of hydrogen per year (DOE 2006).

Electrochemical Splitting of Water (Electrolysis)

In electrolysis, an electric current is run through water to decompose the water into hydrogen and oxygen gas:

$$2H_2O \longrightarrow 2H_2 + O_2$$

Common industrial-scale electrolysis has an efficiency of around 70% for converting electricity to hydrogen gas. However, significant research efforts are underway to develop new technologies that would improve this efficiency. Using current electrolysis technology, approximately 574 GW of electric generating capacity would be needed to produce enough hydrogen to run the U.S. vehicle fleet. This level of electrical generation corresponds to a thermal heat load of 1,630 GW or 5.461 300-MW nuclear reactors.

Thermochemical Splitting of Water

In contrast to electrolysis, where an electric current is used to split water, thermochemical splitting uses a chemical looping process to separate the hydrogen and the oxygen. Currently the most developed process is the sulfur-iodine process, which has a thermal conversion efficiency of approximately 50%. This process has the added benefit transforming the heat directly into hydrogen chemically without electric power input, which allows for efficiency gains. As a result, this hydrogen production pathway requires significantly fewer reactors than electrolysis. However, the thermochemical cycles that have been proposed all present technical issues that must be overcome. In particular, the sulfur-iodine process involves the use of sulfuric acid at approximately 830°C meaning that associated material problems have to be overcome.

Table F.34: Electrification reactor requirements

Category	Number of 300 MW Reactors	Required Heat Load	Required Electricity Load
Electrification	3,186	956 GW	335 GW

Table F.35: Hydrogen – Electrolysis reactor requirements

Category	Number of 300 MW Reactors	Required Heat Load	Required Electricity Load
Hydrogen – Electrolysis	5,461	1,630 GW	574 GW

Table F.36: Hydrogen – Thermochemical reactor requirements

Category	Number of 300 MW Reactors	Required Heat Load	Required Electricity Load
Hydrogen – Thermochemical	2,676	803 GW	—

BIOFUELS

There are two major types of biofuels that involve different production methods: bioethanol and biodiesel. Bioethanol is produced by fermenting sugars from biomass feedstocks, typically sugar cane or corn, whereas biodiesel is produced by reacting lipids with an alcohol to produce a fatty acid ester. Biofuels are notoriously energy intensive to make due to the energy required to extract the necessary components from the cells, which involves breaking down the cell walls. The 'energy returned on energy invested' (EROEI) for conventional biofuels is currently only 1.3, meaning that for every 1 Joule (J) of biomass energy used to make biofuels, only 0.769 J are available afterwards.

Biofuels are used in internal combustion engines; a full transition to this transportation fuel source in the United States would therefore require 7,910 TWh of biofuel energy per year. Applying an EROEI of 1.3 and assuming that all invested energy is supplied in the form of heat from a nuclear reactor, we estimate that 1,305 GW of nuclear capacity would be required to produce enough biofuels to run the U.S. vehicle fleet.

COMPARING DIFFERENT TRANSPORTATION OPTIONS

Our analysis of different pathways to zero-carbon transportation clearly indicates that thermochemical splitting of water results in the lowest overall energy requirement. This is due to the high efficiency of hydrogen fuel cell cars and the high efficiency of converting heat into hydrogen. However, it should be noted that our analysis did not consider a number of potentially important technical issues, for example, materials issues with the thermochemical splitting of water and land-use issues with biofuels. There may be other underlying technical or social issues that discourage or favor one technology choice over another.

An important observation from Table F.38 is that the order of magnitude of the heat loads associated with using nuclear energy to supply different zero-carbon transportation fuels is roughly ten times that of potential process heat applications in the industrial sector (roughly 1,000 GW compared to 100 GW). This suggests that the transportation sector offers a much larger potential market for expanding the role of nuclear power in the future.

Table F.37: Biofuels reactor requirements

Category	Number of 300 MW Reactors	Required Heat Load	Required Electricity Load
Biofuels	4,348	1,305 GW	—

Table F.38: Comparison of nuclear reactor requirements for different transportation energy options

Category	Number of Reactors	Required Heat Load	Required Electricity Load
Electrification	3,186	956 GW	335 GW
Hydrogen – Electrolysis	5,461	1,630 GW	574 GW
Hydrogen – Thermochemical	2,676	803 GW	—
Biofuels	4,348	1,305 GW	—

CONCLUSION

Our analysis of U.S. industrial facilities that could be suitable for nuclear process heat applications suggests that only 16.5% of the entire domestic industrial heat market could be supplied using nuclear energy. This is largely because many industrial sites use fuel gas by-products and waste streams as energy sources and because commercial production of hydrogen currently requires higher temperatures than nuclear reactors can provide. Imposing a carbon constraint on industrial sector emissions would discourage the use of internally produced fuel gas as an energy source at industrial sites. It would also require the process heat industry to re-engineer many existing processes to enable greater integration with carbon-free energy sources—with the net effect of creating a larger market for nuclear energy.

Another potential future market for nuclear energy is the production of electricity or synthetic fuels for the transportation sector. This potential is substantial—and could be more than an order of magnitude larger than the potential in the industrial heat market.

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Appendix G

Results from a Survey of Development, Demonstration, and Deployment Paradigms in Other Industries

To gain insight into issues surrounding the commercialization of a new generation of nuclear energy technologies, we surveyed the development, demonstration, and deployment paradigms followed by other industries in introducing a diverse set of new technologies and products. Specifically, we conducted a series of surveys with experts from similarly technology-intensive industries in the United States, including chemical plants, coal plants, offshore oil and gas, jet engines, pharmaceuticals, automobiles, satellites, and robotics. The goal was to compare the deployment of nuclear energy technologies with deployment patterns in other industries, identify similarities and differences, and ascertain if there are strategies that could be adopted by the nuclear energy industry to reduce the long timescales and high costs of new product deployment. (Not all interviewees answered all questions, but the list of questions was broad enough to elicit information relevant to our study.) Based on the interviews, we grouped various technologies and identified ranges of cost and deployment timescales for the different industries surveyed. We summarize our findings and synthesize important characteristics of these industries in the last sections of this appendix.

TECHNOLOGY GROUPINGS

We grouped the industries in our survey using the following criteria and characteristics:

- **Large scale (LS)**—Industries that produce technologies that are physically large and that often have to be assembled on site for this reason; in other words, comparable in size to nuclear plants.
- **Extensive R&D and Regulation-Driven Testing (ERD)**—These industries spend a disproportionally large amount of time building models, testing modules, or conducting demonstrations; performing extensive testing; and working closely with regulatory bodies.
- **High Returns (HR)**—Industries whose products' marginal cost is far lower than their market price and industries that sell a high volume of products. These tend to be the commercial industries and the industries with the most freedom for innovation.
- **Factory Fabrication, Modular Construction, and Strong Supply Chains (FF)**—Industries that are able to optimize cost by minimizing the need to build on site; in other words, industries that have achieved some of the deployment efficiencies that are important for the success of advanced nuclear technologies.

TIME AND COST RANGES FOR TECHNOLOGY DEPLOYMENT

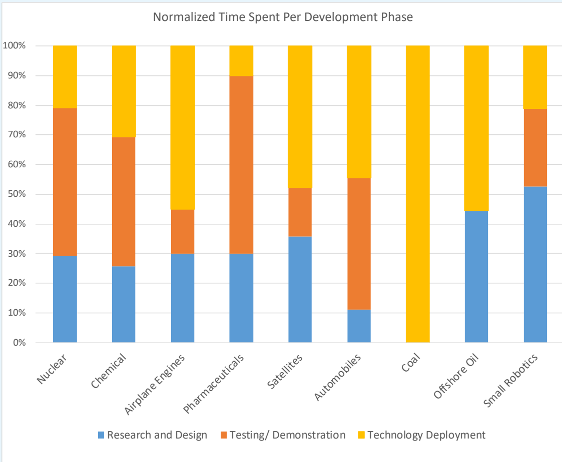
Based on interviews with industry experts, the time and cost ranges[1,2] needed to deploy new technology in different industries are shown in Table G.1 and pictured in Figure G.1. Figure G.1 shows the results of a deeper analysis of cost and time trends for the three major phases—research and design, testing/demonstration, and deployment—across all the technologies surveyed.

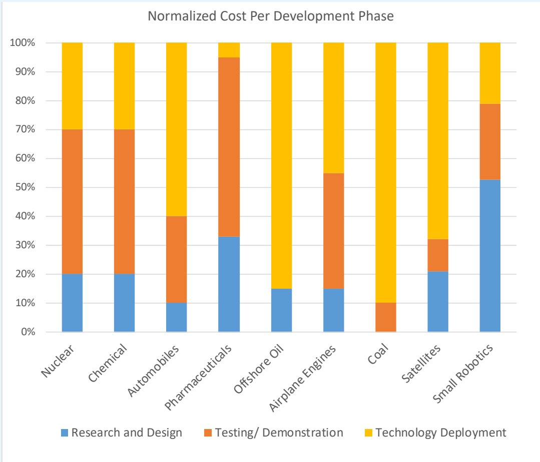
Table G.1: Time and cost ranges for new technology deployment in different industries

Industry	Time (years)	Cost ($B)
Nuclear	18–30	10–16
Chemical	10–15	3–10
Airplane Engines	10–15	3–5
Pharmaceuticals	9–15	1.6–2
Satellites	9–10	1–3
Automobiles	3–5	1–1.5
Coal	3–5	1–1.25
Offshore Oil	3–4	0.01–1
Small Robotics	2–3	0.03–0.04

The industries with the longest development times (nuclear, chemical, airplane engines, pharmaceuticals) all spend proportionally very little time in the technology deployment phase. Instead they focus most of their time in the testing/demonstration phase. This correlates with the fact that these are also the industries that must answer most extensively to external regulators (excluding the chemical industry). The nuclear industry works closely with the U.S. Nuclear Regulatory Commission (NRC), airplane engine manufacturers work with the Federal Aviation Administration (FAA), and the pharmaceutical industry interacts heavily with the Food and Drug Administration (FDA). The chemical industry is a unique case in that it is mostly self-regulated, although chemical companies must interface with the U.S. Environmental Protection Agency (EPA). Nonetheless, the chemical industry undertakes a complex, multiphase testing process that often involves building a string of small-scale, but fully functional and producing, demonstration facilities.

Figure G.1: Proportional amount of time (left) and budget (right) that different industries spend in each phase of new technology development.





[1] Values and ranges as predicted from interviewed experts.

[2] The large ranges of costs are correlated with industries that produce highly varied products, such as satellites, chemicals, and offshore oil.

The need to build these small-scale facilities is reflected in the disproportionately large amount that chemical companies spend in the testing/demonstration phase of new product deployment.

Most of the new product deployment expenses incurred by the more cost-intensive industries are not all associated with the same development phase. The chemical industry accrues large expenses to construct demonstration plants (testing/demonstration); the automobile industry spends much of its product development budget on developing new production lines (technology deployment); most of the cost of deploying new pharmaceuticals is associated with the many rigorous and expensive clinical trials needed to verify the performance of new drugs (testing/demonstration); and the bulk of the cost of deploying a new offshore oil rig is purely driven by capital costs for rig construction (technology deployment).

SUMMARY OF ALL INDUSTRIES SURVEYED

Chemical Facilities (LS)

Chemical facilities vary enormously depending on the nature of the product(s) they produce. Therefore, the cost to develop one of these facilities is also very variable, ranging between $3 billion and $10 billion. Large chemical projects are always built using existing technology; new designs are usually derivative or copy existing technologies to reduce cost and the probability of an accident.

Deployment Phases

- Research can take up to 2–10 years.
- Demonstration consists of building small-scale facilities. Pilot scale facilities ($5–$50 million capital investment; 2 years to construct, operated for 2–4 years) and market development facilities (larger sites to demonstrate cost and scale; 2–4 years of construction). Major blunders tend to occur only in the smaller, pilot-scale projects.
- Deployment consists of building a commercial-scale facility (6 years to construct).

Regulations and Safety Assurance

This industry is largely self-regulated, but EPA, local ordinances, and other parties regulate a facility's environmental impact (e.g., emissions). Permits are required to install and operate these facilities.

Airplane Engines (LS, ERD)

New engine designs are based on a prediction of what airlines will need 10–15 years into the future; the engines can only be created if the industry is confident there will be an aircraft for it to go on. Quite often, the aircraft design is incomplete, which necessitates an iterative design process with the engine framer. This deployment paradigm can be quite restrictive to innovation, because the airplane frame places physical shape and size constraints on the engine.

Airplane engines are sold to airframe makers at prices that are lower than cost of constructing the engine. Engine manufacturers only begin to make net positive profits by servicing and maintaining the engines. This unique business model has seen a recent paradigm shift.

Deployment Phases

- The research and development (R&D) phase involves establishing a new idea, convincing executives and airplane makers that the idea is worthwhile, and flying a demonstration model (the demonstrator is a proof-of-concept engine). The demonstration model falls just short being a prototype in that it displays only the unique and new components of the engine (2–4 years, $150–$250 million).
- Individual components and subsystems are tested years in advance as well. Prior to the construction of the demonstrator, engine makers run simulations (computer models based on first principles) to test various concepts.

- Testing and demonstration: Flight testing (1–2 years)
- Technology deployment: Companies incorporate the engine into the airframe (1–2 years), and develop the final product, including detailed engineering and certification (5–6 years).

Budget

- Idea development costs: ~$100–$200 million
- Construction of demonstrator: ~$50 million
- Detailed engineering and certification: ~$1 billion

Regulations and Safety Assurance

Certification is gained through the FAA. The FAA requires manufacturers to build a set of approximately 15 engines on which they can conduct tests. Manufacturers need to demonstrate that the engines can (a) operate for an extended period under a set of conditions and (b) operate safely under destructive failure situations

Pharmaceuticals (ERD, HR)

Developing a new drug and bringing it to market takes, on average, about 14 years (Schuhmacher, Gassman, and Hinder 2016). Within the market there is a large amount of competition, but also simultaneous camaraderie, amongst companies. The venture capital model is one of the most prevalent in the pharmaceutical industry. Because smaller companies tend to have more freedom to innovate, larger companies often purchase a new product after a patent has been issued. Smaller companies benefit from this dynamic because they need the resources, expertise, market, and brand name of larger companies to deploy their innovations.

Deployment Phases

- R&D: Discovery and development (4.5 years) covers the period during which research into a new drug begins in the laboratory. This early work is often carried out by universities or public research organizations. It is often preceded by a pre-discovery stage, when researchers work to understand a particular disease. The pre-discovery stage is often followed by drug discovery phase, in which scientists identify a way to combat the disease. Scientists may look at thousands of options before finding one that is effective.
- Testing/demonstration: New pharmaceuticals undergo an intensive, multi-stage series of tests that begin with preclinical research (1 year), during which the drug undergoes lab testing (in vitro) and animal testing (in vivo) to determine its safety. Preclinical trials are followed by clinical research, during which the drug is tested on human subjects. Typical clinical trials consist of three stages that progressively increase in size, complexity, and time (1.5, 2.5, and 2.5 years respectively).
- Technology deployment (18 months): In this phase, the manufacturer submits an application to the FDA requesting permission to market a drug. The FDA review process takes approximately 6–10 months.

Budget

- Drug discovery and preclinical development: 33%
- Clinical development: 63%
- Submission to FDA: 5% (Schuhmacher, Gassman, and Hinder 2016)

Regulations and Safety Assurance

This entire drug development process is carefully monitored and reviewed by the FDA. Before companies can progress from preclinical to clinical trials, they must submit a detailed application to the FDA. The review of this application takes about 30 days. Because the testing/demonstration process for this industry is extremely rigorous and costly, only about 1 in 5,000 drug candidates makes it to the licensing phase.

Following approval of a new drug application (NDA), the FDA also monitors drug safety once the drug is available for use by the public and conducts inspections on the facilities that manufacture the drug. At any point, the drug developer can ask for help or technical assistance from the FDA. The FDA also consults with companies to determine the best methods of conducting trials.

Satellites (FF)[3]

Costs to deploy satellite projects are extremely variable due to the large differences in project type and complexity. Typical costs range from $10 million to $1 billion. The deployment of new satellites tends to take approximately 10 years from concept to launch, with wide variations.

Deployment Phases

- R&D: The National Aeronautics and Space Administration (NASA) has coined the term 'project formulation' to describe the two phases in which a project's requirements, including estimates of cost and schedule, and system designs are defined. In the first phase, Phase A ('concept and technology development'), new technologies are identified and plans for their development, the use of pre-established technologies, and plans for risk-mitigation and testing are formulated. In Phase B ('preliminary design and technology completion'), more detailed plans are developed regarding various program requirements. This two-phase project formulation period concludes with a preliminary design review, in which the project must demonstrate that it can meet all system requirements within cost and schedule constraints.
- Testing/demonstration: A major review, the Key Decision Point C (KDP-C), is conducted to assess the preliminary design and make a determination concerning the project's readiness to proceed to the next phase. This review is completed by independent experts who provide an assessment of the project's technical and programmatic approach, project risks, and progress. Following this review, the project proceeds to Phase C, during which the design is finalized, test units are fabricated, and components are tested. A second design review occurs in the latter half of Phase C.
- Technology deployment: In Phase D, systems are integrated and other supporting infrastructure is completed. System assembly, integration, test, and launch activities are also part of Phase D. Phases E and F consist of operations and sustainment and project closeout.

Budget

Costs are variable and typically range between $1 and $3 billion depending on the scope of the project and requirements for the satellite. Research and design can take approximately one-third of the total time, and testing another 25% of the time, with the remainder used for actual demonstration.

Regulations and Safety Assurance

Most of the satellite development process is internally regulated, and there are not many externally imposed regulatory requirements (only radio frequency (RF) spectrum allocation, RF interference, and nuclear safety if radioisotopic power sources are used). There are a variety of hold points in the project development process, as specified in NPR 7120.5, as well as NASA Space Flight Program and Project Management Requirements (2012), milestone reviews, and key decision points where projects or programs can be cancelled, not confirmed, restructured, etc.

[3] Data and information pertaining to research satellites.

Similar to the nuclear industry, satellites are also subject to requirements for workmanship, electronic components, materials, and technical processes to determine the flight-quality of hardware and software. These stringent requirements increase the time and cost necessary for project completion, but are necessary to ensure the success of the satellite.

Automobiles (HR, FF)

The automobile industry is a leader in mass production. One of the methods it uses to facilitate mass production is maximizing the standardized components of a vehicle. Components that customers do not see are simplified and made uniform within a company, and only externally visible features are modified. This approach facilitates mass production and reduces development costs.

Deployment Phases

- R&D: Research is considered to be anything conducted 10 or more years before a car reaches the dealership. During this phase, the concept of the car is being developed. Advanced engineering is the work conducted to bring the concept to reality 3–5 years prior to completion. In this phase, individual vehicle components are being developed.
- Testing/demonstration: Preproduction, which occurs in the last two years prior to manufacturing, describes the period when the entire vehicle has been integrated and built. This is also the period when the manufacturer conducts testing and qualification at the vehicle level.

Budget

- Research: 5%–10%
- Testing/demonstration: 30%
- Fabrication: 60%

Regulations and Safety Assurance

During the preproduction phase, safety, emissions, and crash testing and safety compliance begin. Self-testing of components occurs prior to this point. Although some standards are defined at the federal level, different regions have different sets of requirements. Within the United States, there are specific official testing locations that normalize the testing done to demonstrate compliance with industry regulations. Because of the regionality of these requirements, manufacturers often have to modify their car designs for different regions; therefore, the supply chain is often formed locally as well. Most testing does not begin until the entire car is fully assembled. Additionally, all manufacturing facilities must comply with Occupational Safety and Health Administration (OSHA) regulations.

Coal Plants (LS)

Budget

The coal-fired power plant industry benefits from the maturity of the technology and the predominant use of a standard design (this industry has little need for first-of-a-kind technology). Thus, the vast majority of deployment costs occur in the procurement and construction phase, a three-year process, in most cases, that demands roughly $1 billion of investment. Coal plant designs also include elements of modularity. Engineered equipment such as turbines and generators are catalog items, and pieces of large equipment are often prefabricated at the vendors' facilities. In some cases, full standardization is not possible because of site-specific adaptations for a particular application.

Regulations and Safety Assurance

This industry mostly works with the EPA and local regulatory commissions, which monitor and regulate air and water quality. In addition to federal regulations, each state has its own set of environmental regulations.

Offshore Oil Platforms (LS, HR)

In the offshore oil industry, there is little innovation regarding the technology used at the surface, and every effort is made to use existing technologies in an effort to reduce cost. Additionally, rig design can be heavily influenced by previously completed rigs located in similar environmental settings, and the industry can rely on the research and construction abilities of the well-established ship-building industry. Within this industry, offshore projects tend to be declared finished on time, though they are often only partially complete when this occurs (this tendency is likely a result of the high pressure to begin producing immediately). In these cases, costly offshore work is often required to finish the project. The tendency to rush declarations of project completion is problematic because, once the rig is out of the shipyard, it becomes much more difficult and expensive to continue working on its construction.

Deployment Phases

- R&D: This phase includes concept selection, FEED ('front end engineering design'), and detailed design. During concept selection, a concept is developed for the best general approach to producing the oil (6–8 months). The design requires a look from end to end—that is, from the reservoir to the market. Then, in FEED, the primary goal is to narrow down options and better define the project. A FEED package may include 500–1,000 drawings and reports that address all the major parts and systems of a facility. A typical FEED may last 8–18 months. Finally, in detailed design, the company completes all the work needed prior to construction (e.g., prepares operations manuals, writes commissioning and test procedures, settles on final design). The detailed engineering phase occurs in the 6–9 months before construction commences.
- Technology deployment: Typically, the construction of offshore rigs involves the use of an engineering, procurement, and construction (EPC) contract, with the owner's engineering and operations team providing oversight and insight (24–36 months). The construction process is largely modularized, and many activities occur in parallel to facilitate the rapid construction of such large-scale projects. Large platform hulls are constructed and assembled in drydock or dockside. Other modules are built in a separate yard, and are lifted onto the completed hull and connected afterward.

Budget

- From end to end, engineering is only about 15% of the total budget.
- Project management expenses account for ~20% of the total cost.
- Remaining costs are associated with facility construction.

Regulations and Safety Assurance

Oversight organizations focus on both environmental safety and personnel/facility safety. The offshore oil industry is regulated in the United States by the Bureau of Ocean Energy Management (BOEM), which oversees the management of resources and the collection of royalties and which manages the government's leasing process for awarding drilling rights. The industry is also regulated by the Bureau of Safety and Environmental Enforcement (BSEE).[4] Different regulations apply in different parts of the world. Therefore, depending on where the rig is to be built and located, the company must consider different limitations and approaches. Testing is conducted at the vendor/factory level to ensure component quality and functionality. Following hull assembly, further tests are performed to validate the functionality of the completed unit as well as material and welding tests.

[4] Following the Deepwater Horizon spill of 2010, the MMS (Minerals Management Service) was renamed the Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE) and separated into three groups: the Office of Natural Resources Revenue, the BOEM, and the BSEE.

Small Consumer Robotics (HR, FF)

Because of the small scale of consumer robotics technology, this industry is able to take a vastly different approach to deploying new products. From the outset, product development can be completed in a more integrated and dynamic fashion and because the level of complexity involved is more manageable, operations and engineering can be merged earlier in the process. This integrated systems approach is advantageous because it facilitates a shorter deployment period and allows for early detection of any incongruities between systems.

Deployment Phases

- R&D (12–24 months): This phase involves conducting market research and testing ideas by building many prototypes. A few whole, functional robots may be built, but only to conduct testing of specific ideas.
- Testing/demonstration (12 months): In this phase, prototypes are continuously being constructed, but with better materials. Validation of a final prototype and integration tests are completed. The construction process is slowly moved to a factory.
- Technology deployment and manufacturing ramp process (3 months): The volume of products produced is incrementally increased over the course of 3–5 weeks. Products are shipped out.

Budget

- The budget allocated to each phase is roughly proportional to the time it takes.

Regulations and Safety Assurance

Consumer products are generally regulated by individual government agencies (unique to the country they are being sold in) and (in the United States) at the state level to assure safety, reliability, and performance. Manufacturers usually begin submitting material for regulatory approval 3–6 months ahead of production.

SYNTHESIS OF RESULTS

Our interviews with experts from other industries helped us identify a number of key attributes that could help accelerate the development, demonstration, and deployment of new nuclear energy technologies and increase the commercial attractiveness of these technologies. They are summarized here.

Increase Intrinsic and Extrinsic Value of Product

When a higher value is associated with a given project there is greater incentive to complete the project as quickly as possible and greater incentive for investors to provide funds. Payment of a premium for electricity generated from nuclear energy might be mandated by CO_2 reduction policies and the potential for additional energy applications could also add value to the watts produced by nuclear facilities.

Reduce Product Size and Complexity

Scale-backs in complexity correlate with reductions in the amount of labor required to complete a project and with reductions in the possible contingencies/failure points that can occur. Passive safety features in many advanced reactor designs are conducive to smaller and simpler designs.

Modularize Technology

Modularity permits increased construction in efficient, controlled, and predictable environments (factories)—all of which should reduce cost and potential for failure. The technologies included in the FF group provide an indication of the scale required for advanced nuclear systems to be effectively modularized.

Standardize Design (Nth-of-a-Kind Technology)

It is interesting to note that coal-burning electricity generation is one of the most cost- and time-efficient industries we surveyed, even though it does not fit into the trends that describe the deployment effectiveness of other industries.

Because this industry has been able to test and deploy a well-established design, there is no longer much incentive to innovate or reimagine the technology. Thus, the resources usually allocated to R&D and testing/demonstration are not needed. The coal industry is a clear example of the benefits of working with nth-of-a-kind technology.

Formalized Effective Project Management Structure

Many of the low-cost industries were able to identify adherence to strong project management techniques and the use of strong developmental benchmarking as primary contributors to deployment cost reductions. Because the deployment of a new technology often involves large and complex projects, an imposed structure assists with efficiency, organization, and clarity.

Construction of Small Demonstrator Facilities

Although the cost, timescale, and physical size of chemical facilities is comparable to that of nuclear facilities, the chemical industry is still able to construct physical, small-scale demonstrator facilities that allow for expedited testing and regulation (often, these smaller facilities are even able to generate a small amount of revenue through sales of their product outputs).

Regulatory Reform

None of the individuals we interviewed regarded their industry as being subject to overly burdensome regulation—indeed, some even confessed to thinking that the regulatory system they operated under was lacking. This contrasts with common industry opinion regarding the regulation of nuclear energy facilities. Strong relationships between the industry and regulatory authorities and regulations that are relevant to specific technologies and do not preclude innovation/development are critical to minimizing the resources that are devoted to the testing/demonstration phase.

There is a potential flaw in a deployment model that aims to design systems that can answer for all potential eventualities. The risk is that this model diverts the focus from the primary objective: producing a functional product. Therefore, it is imperative for the nuclear energy industry to find an optimal balance in new reactor designs that do not compromise either safety or development and that successfully reduce facility size, cost, and complexity.

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Appendix H

Measuring the Cost of Recent New Nuclear Power Plant Builds

This appendix provides additional background and detail concerning factors behind the high cost of recent new nuclear power plant builds.

Before discussing specific projects, a note on handling cost numbers is in order. 'Overnight cost' is a standard industry metric for quoting the capital cost of electric generating plant alternatives. This is the cost of building the plant as if it could be built instantly—that is, using current prices and without the addition of finance charges related to the time required for construction. Another metric is 'investment cost,' which includes the effect of inflation and finance charges up to project completion. Finally, the 'levelized cost of electricity' (LCOE) is a unit cost metric, which allocates the capital cost to electricity output over the life of the plant and adds in operating and maintenance costs, including the cost of fuel. We focus primarily on overnight cost, denominated in U.S. dollars and qualified by the year for which it is quoted, because we find this metric sufficient for understanding and addressing the issues at hand. When we mention another metric, it is only to tie back to how the figure was originally reported in the source material. While construction delays add costs on top of the overnight cost, in the form of inflation and financing charges, we address that by simply noting the reality that delays occur.

Many public sources report cost figures in a sloppy fashion, without distinguishing clearly between overnight or investment costs or even assuring consistency in the items included. For example, some sources report just the cost of the contract between the vendor and the buyer/owner, where a proper economic evaluation should include the additional construction-related costs incurred directly by the owner. Indeed, reported figures for the cost of constructing comparable nuclear plants can vary by a factor of two or more (Du and Parsons 2009) (Deutch, Moniz, et al. 2003). Therefore, we avoid reporting some headline figures for which definition is lacking, and we focus instead on the smaller set of sources that provide clearly detailed figures.

We begin by anchoring our discussion with a figure from the 2009 update of the MIT 2003 *Future of Nuclear Power* study. The 2009 update estimated the "plausible, but not yet proven" overnight cost of a Gen-III+ nuclear plant in the United States at $4,000 per kilowatt (kW) in 2007 dollars, which is roughly $4,900 in 2017 dollars. Emphasizing the conditional nature of the estimate, the 2009 study stated:

> The challenge facing the U.S. nuclear industry lies in turning plausible reductions in capital costs and construction schedules into reality. Will designs truly be standardized, or will site-specific changes defeat the effort to drive down the cost of producing multiple plants? Will the licensing process function without costly delays, or will the time to first power be extended, adding significant financing costs? Will construction proceed on schedule and without large cost overruns?

The first few U.S. plants will be a critical test for all parties involved.[1]

The actual experience with the first few builds of the new Gen-III+ designs in the United States and Western Europe failed that test spectacularly. The projects have experienced long delays and large cost overruns. We discuss this recent experience, providing cost information, construction duration information, and a few historical details. Table H.1 summarizes the key data. These are the data that are summarized in Figure 2.3 in Chapter 2.

In reviewing reported costs, we translate all data to an overnight cost quoted in 2017 dollars. Our review is organized by the major reactor vendors and designs.

One of the earliest Gen-III+ designs to begin construction in the west is the EPR (originally the European Pressurized Reactor, and now simply the EPR), which was developed by the French state-owned company Areva together with the German firm Siemens.[2]

- In 2003, a deal was struck to build the EPR at Olkiluoto, Finland with a 4.5-year construction schedule set to begin in 2005 and be completed in 2009. While construction did begin in 2005, the project has experienced a seemingly unending series of delays, with the completion date last reported to be 2019, a full decade later than originally planned.[3] In 2003, the reported cost of the deal was €3.2 billion ($3.8 billion). As of December

Table H.1: Overnight cost of recent Gen III+ builds versus benchmark

	As Reported				Equivalent Overnight Cost					2017 $	
	Year	$ Total	$/MWh		Year	Months Constr.	Overnight Share	$/MWh		Inflation Factor	$/kW
Benchmark from MIT Update					2007			4,000		1.219	4,900
EPR											
Olkiluoto	2012	11.12	6,822		2003	174	55%	3,769		2.122	8,000
Flamanville	2007	12.60	7,636		2007	126	79%	6,042		1.219	7,400
Taishan											
Hinkley C	2012	26.01	8,128		2012	72	93%	93%		1.104	8,400
AP1000											
Vogtle 3&4	2007	19.19	8,591		2012	104	91%	7,800		1.104	8,600
V.C. Summer 2&3	2007	11.77	5,265		2007	94	100%	5,265		1.219	6,400
APR1400											
Shin Kori 3											
Barakah (UAE)	2010	18.60	3,457		2010	54		3,457		1.149	4,000

[1] In employing the “plausible, but not yet proven” description, the 2009 “Update” was reinforcing an assessment first established in the original MIT *Future of Nuclear Power* study (Deutch, Forsberg, et al. 2009).

[2] Siemens eventually sold its stake to Areva. Recently, Areva was reorganized and the nuclear power plant business was made a part of the French state-owned company Électricité de France (EDF) and rebranded as Framatome.

[3] All construction start and completion dates reported here are as reported in the IAEA’s PRIS database, and where their “commercial operation date” is used here as the completion date. Actual expenditures on the development of a nuclear plant can begin years before major construction expenditures, sometimes even including certain bits of construction on auxiliary buildings or facilities. A canonical metric for the start of the project is the first pour of concrete for the reactor building which usually initiates the intensive investment schedule.

2012, the reported cost had been updated to €8.5 billion ($11.12 billion), or 2.6 times the original estimate. For comparability purposes, we translated this figure to an overnight cost, backing out the effect of the construction schedule and an assumed inflation rate. We then translated this overnight cost to 2017 dollars for comparability with the MIT benchmark. The last reported cost projection is approximately equal to an overnight cost of $8,000/kW quoted in 2017 dollars, far above the MIT benchmark.[4] Recall that this dramatic increase in the forecasted overnight cost does not incorporate the increased financing cost created by the decade-long construction delay. Moreover, the latest public cost estimate is from 2012, and a recent figure is certainly much greater.

- In 2004, the second project was announced for a plant in Flamanville, France, which is being constructed by Électricité de France (EDF). Construction began in 2007 and was originally to be completed in 2012. However, this project, too, has experienced enormous delays and is now scheduled to be completed in 2018 at the earliest, six years late. The original reported cost was €3.3 billion ($4.2 billion). As of January, 2018, the reported cost had been updated to €10.5 billion ($12.6 billion), or approximately three times the original estimate. Once again translating this yields an overnight cost of $7,400/kW quoted in 2017 dollars, again far above the MIT 2009 update benchmark.[5]

- In 2007, a deal was struck for construction on two units at Taishan, China.[6] Construction began in 2009, with the first unit originally scheduled to be completed by the end of 2013 and the second by the end of 2014. This project, too, has experienced significant construction delays totaling at least four years, with the first unit now scheduled to be completed sometime in 2018 and the second in 2019. While there are press quotes on the cost of the original deal, there is no information about what is included in the accounting, so we cannot reliably translate the available numbers to a comparable overnight cost figure.

- In 2016, the long discussed Hinkley Point C project, in the United Kingdom was approved both by the contractor, EDF, and by the British state. The two-unit facility would be two-thirds owned by EDF and one-third by the China General Nuclear Power Group (CGN). Much preparatory work had been done prior to that date, but the official start of construction was then scheduled for 2019 with completion of the first of two units in 2025 and the second 15 months later, in 2027. In 2013, when EDF and the British government signed a power purchase agreement for the project, the overnight cost of the project was reported to be £16 billion ($26 billion) in 2012 currency, or $8,100/kW. Translating this yields an overnight cost of $8,400/kW quoted in 2017 dollars, once again far above the MIT 2009 update benchmark. The contract provided a firm, inflation-indexed purchase price for the first 35 years of generation, equal to £92.50/MWh ($150/MWh). A price that high is consistent with a $7,000/kW overnight cost quoted in 2012 dollars, depending on assumptions about capacity factor, fuel and other operating and maintenance costs, and discount rate.

Westinghouse, then a subsidiary of Toshiba, created one of the earliest Gen-III designs with its AP600 reactor, but the design was never built. The

[4] The reported figures are from press reports based on Areva releases. The original figure is taken from a Reuters report, August 17, 2017, and the latter from the Finnish paper Helsingen Sanomat, December 13, 2012. Information on how costs are quoted is from the report of the French auditor, Cours des comptes, January 2012, The costs of the nuclear power sector. We have made our own assumptions on inflation based on the MIT 2009 Update through 2007 and 2% thereafter.

[5] The reported figures are from press reports based on EDF releases. The two figures are taken from Dow Jones reports on April 11, 2007 and January 8, 2018. Translation to overnight cost uses the same methodology and additional assumptions as for the Olkiluoto plant, adjusting for plant data.

[6] The plant owner is a joint venture of EDF and China Guangdong Nuclear Power Corporation, now China General Nuclear Power Group (CGN).

company followed up with a Gen-III+ design, the AP1000, which was approved by the U.S. Nuclear Regulatory Commission (NRC) in 2005 and selected for a number of U.S. new reactor projects and many elsewhere. Most have not moved forward, but there is experience with two projects in China and two in the United States.

- The first two projects to begin construction were in China. Both units of the two-unit Sanmen project were begun in 2009, and completion was originally anticipated to be in 2014. The two units of the Haiyang project were begun in 2009 and 2010, and completion was originally anticipated to be in 2014 and 2015. Completion of both projects has regularly been delayed, and as of the start of 2018, only Sanmen Unit 1 is now operational. That is a delay of more than three years. No reliable cost data are available.
- In the United States, the Southern Company's subsidiary Georgia Power proposed two AP1000s as Units 3 & 4 of the Vogtle plant. Georgia Power would own 45.7% of the two units, with three other public power companies owning the remainder. The proposal was approved in 2008 by the Georgia Public Service Commission. As originally conceived, construction would begin in 2011, with completion of the first unit in 2016 and the second in 2017. After various other proceedings were completed, construction actually began in 2013. As of the start of 2018, construction is running more than three years behind schedule with a projected completion date for the first unit in late 2021 and the second unit in 2022.[7] The original costs quoted for the project translated to an estimated overnight cost of approximately $4,300/kW quoted in 2007 dollars. The most recently updated cost projection shows an updated cost of $8,591/kW in 2012 dollars. Putting these costs on a comparable basis yields a revised overnight cost of $8,600/kW quoted in 2017 dollars.[8] It bears repeating that this near doubling of overnight cost does not incorporate the added financing costs produced by the lengthening of the construction schedule.
- Throughout early 2017, Westinghouse's parent company, Toshiba, was facing a number of problems from the cumulative losses on its various nuclear builds as well as financial problems in other businesses. Mid-year, it decided to cap its losses and exit the nuclear construction business and to harvest what it could by selling the engineering and design component that is the Westinghouse subsidiary. It put Westinghouse into bankruptcy and opened negotiations with the project owners. Confronted with this, Southern Company decided to take over responsibility as the general contractor for the project and negotiated financial terms with Toshiba. The Georgia Public Service Commission approved the decision to continue. Westinghouse has subsequently been purchased by Brookfield Asset Management, a private equity firm.
- The other U.S. AP1000 project was for Units 2 & 3 at the V.C. Summer plant owned by SCANA Corporation's subsidiary, South Carolina Electric & Gas Company (SCE&G). SCE&G would own 55% of the project with the state's public corporation, known as Santee Cooper, owning the minority interest. Approved in 2008 by the Public Service Commission of South Carolina, construction was to begin in 2011, with completion of the first unit planned for 2016 and the second in 2019. The U.S. NRC's approval of a construction license came through in 2012 and the first unit's completion

[7] Original dates from Georgia Power's application for certification of the units and its updated integrated resource plan, filed with the Georgia Public Service Commission in August 2008. Revised completion dates from Georgia Power's Vogtle Construction Monitoring Report, August 2017.

[8] Du and Parsons (2009) had estimated $4,700/kW based on partially redacted numbers in Georgia Power's 2008 submission. Georgia Power's 2017 filings separate out construction and financing costs in the original submission, which yields the original figure here. Georgia Power's 2017 filings give a revised construction cost figure of approximately $8,591/kW but including inflation during the period of construction which should not be included in an overnight cost number.

was accordingly adjusted to 2017.[9] This project, like the others, ran into cost overruns and construction delays. In 2016, the latest in a series of schedule revisions moved completion of the first unit to 2019 – a cumulative delay of approximately two years. Problems continued to mount, however. In mid-2017, when Toshiba put Westinghouse into bankruptcy, the pair of buyers ultimately decided to abandon the project despite considerable sunk costs. The original costs quoted for the project translated to an estimated overnight cost of approximately $3,400/kW quoted in 2007 dollars. The most recently updated cost projection shows a doubling of costs, including inflation over time. Putting these costs on a comparable basis yields a revised overnight cost of $6,400/kW quoted in 2017 dollars. This is a stale cost estimate that does not include the update, which precipitated the project's abandonment.[10]

The joint venture GE-Hitachi Nuclear Energy produced the Gen-III+ 'economic simplified boiling water reactor' (ESBWR) design. This design is a successor to General Electric's Gen-III 'advanced boiling water reactor' (ABWR) design, which was used in a series of four builds in Japan between 1996 and 2006, including units 6 and 7 of the Kashiwazaki-Kariwa plant, unit 5 of the Hamaoka plant, and unit 2 of the Shika plant. These earlier builds had been completed in a timely fashion and at costs that informed the original MIT study's conclusions that cost reductions were plausible (Deutch, Moniz, et al. 2003).[11] The ABWR and the ESBWR had both been selected as a design for one or more prospective builds in the United States when industry forecasts had many new builds on the drawing boards, but none of those projects advanced to the actual start of construction. To date, construction of the ESBWR has not begun anywhere in the world. The GE and Hitachi joint venture had been in negotiations with a site in India for the ESBWR, but so far nothing has gone ahead.

The state-owned Korea Electric Power Company (KEPCO) developed the Gen-III+ Advanced Power Reactor 1400 (APR1400), which builds on the success of the construction program for its Gen-II Optimum Power Reactor (OPR).

- The first APR1400, the Shin Kori plant's Unit 3, had been scheduled for completion in 2012, but a string of problems with certifying important pieces of equipment and other issues delayed final completion until 2016. However, reliable cost information is not available.
- KEPCO won the competitive bidding to provide four reactors of this design to the United Arab Emirates at the Barakah site. The first of the four units is nearing completion with minimal delay, and the others are in process. The reported price for the reactors is $3,457/kW, although it is difficult to be sure what is included in this number. We include the figure in Table H.1 because it is a very important data point given KEPCO's discipline in construction and its competitive ability to win the Barakah tender. However, in Figure 2.3 we color that data point differently to signify uncertainty about the number.[12]

[9] Original dates from SCE&G's application for certification of the units. Revised dates from the Wall Street Journal, March 31, 2012.

[10] Du and Parsons (2009) had estimated $3,800/kW based on partially redacted numbers in SCE&G's 2008 submission to the Public Service Commission. However, subsequent filings show an even lower number. The latest reported figures are based on a 2016 order. Both the original and the latest reported values are very low compared to other projects.

[11] Two other ABWR units began construction but were interrupted for non-economic reasons: at Lungmen, Taiwan and Shimane, Japan.

[12] KEPCO, December 2016, Investor Presentation, reports a total cost of $18.6 billion. Dividing this by the total 5,380 GW capacity of the 4 units yields the $3,457/kW figure. The presentation provides no detail about what is included in this figure or the quotation convention. For example, it probably excludes owners' costs which could add another 20% in order to be comparable to other figures. Press reports variously report the deal to be worth $20 billion, $25 billion, $30 billion, or even $40 billion. This latter figure is from the Korea Herald, June 20, 2015.

- KEPCO filed an application to have the APR1400 design certified with the U.S. NRC, but the design has not yet been a candidate for a specific project in the United States.

The results for the U.S. and Western European designs, regardless of where constructed, have been abysmal. We see cost overruns wherever good cost data are available, and we see extensive construction delays at most projects. This is in contrast to the earlier history of disciplined construction of the ABWR in Japan. As far as demonstrations go, the cost of building certain of these new Gen-III+ designs has been much higher than originally estimated and projected.[13] In contrast, the recent APR1400 build in the United Arab Emirates shows experience in keeping to the promised construction schedule, and may show the needed cost reductions, although the publicly available data are not yet sufficient to say so with confidence.

We must also take note of the other locations for active construction of new Gen-III+ designs, which are in Russia and China. Both countries are pursuing a domestic construction program and exports. Neither makes available any reliable cost data.

[13] In engineering it is common to distinguish between the cost of a first-of-a-kind (FOAK) plant, and the cost of an nth-of-a-kind plant. The first build of a new design is likely to have extra costs. Many costly aspects of the build process will shakeout with experience. The Gen III+ designs discussed above all included some FOAK plants. It can be tempting to excuse some of the cost overruns on this basis, and to insist that the NOAK plants might have a cost in-line with the original benchmark. In retrospect there is, by definition some truth to this: each of the vendors and contractors is now re-examining the design and the construction process looking for improvements that can be made to reduce the cost going forward. While there have been reduction in cost in Asian plants, this excuse is at odds with the historical record of Western builds. It ignores the facts about particular estimates made at the time. Take for example, the AP1000 reactors sold for the Vogtle and Summer sites. Estimated costs for those builds were presented to the respective state public utility commissions in official filings. Those estimated costs were represented as all inclusive, meaning that they incorporated any anticipated FOAK costs. Those official filings were part of the basis informing the benchmark reported in the MIT 2009 Update.

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Appendix I

Influence of Country-Specific Labor Costs on the 'Overnight' Cost to Construct a Light Water Reactor

One of the chief obstacles to the deployment of large, Gen-III+ nuclear plants is the inherent inefficiency of fabricating, assembling, testing, and commissioning these large and complex plants on site. While some advances have been achieved in construction methods and fabrication techniques since the 1970s and 1980s, the delivery of a light water reactor (LWR) remains a very labor-intensive, hands-on effort requiring many years to complete. Thousands of workers are deployed at the reactor site during construction, and total labor requirements correspond to 20–30 million person-hours for a gigawatt-scale LWR.

Given these large labor demands, regional or country-specific labor costs and labor productivity were assumed to have a significant effect on overnight plant construction costs. This hypothesis was based in part on the labor-rate data shown in Figure 2.4 of Chapter 2. However, these labor rates are not specific to the nuclear industry. This appendix discusses an independent assessment of nuclear-specific labor costs and the impact of productivity for four reference countries: the United States, the Republic of Korea, France, and China.

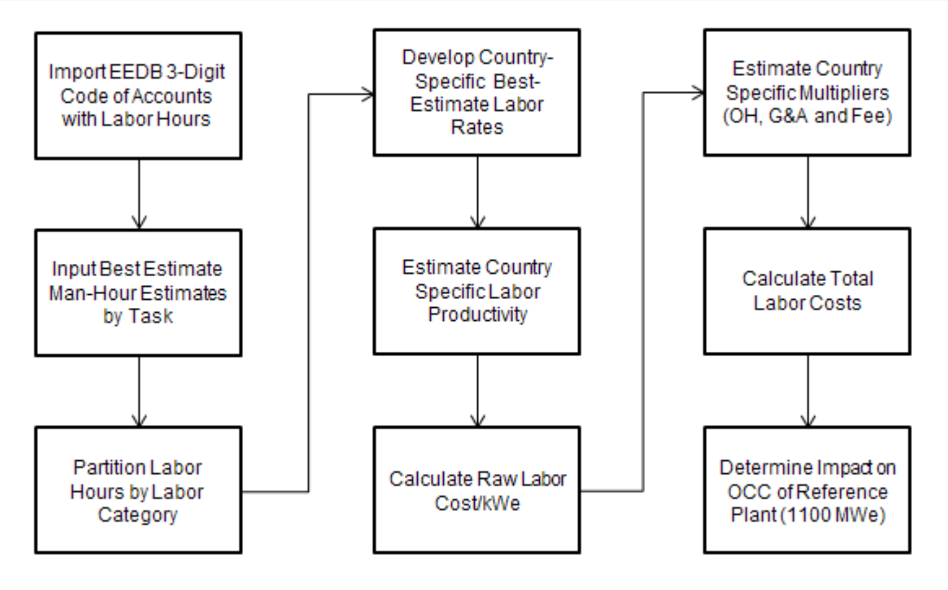
The evaluation was limited to the construction of a pressurized water reactor (PWR) for simplicity and was performed using the methodology mapped out in Figure I.1.

The evaluation included the following specific steps:

Definition of a Reference Plant – The first step in the evaluation was to decide if the country-specific evaluations would be performed using a country-specific reactor design (e.g., AP1000 for the United States and China; OPR1000 or APR1400 for Korea; EPR for France). Alternatively, we could select a hypothetical single unit reference design. Because of significant differences among current LWR designs, we opted to use a common reference design corresponding to a conventional Gen-III LWR, with an electric generating capacity of 1,100 megawatts (MW_e), as a more appropriate baseline for assessing relative labor cost and productivity effects. This approach had the added advantage of being consistent with the reference design used in the Oak Ridge National Laboratory (ORNL) Energy Economic Data Base (EEDB) evaluations from the 1980s, from which the Code of Accounts (COAs) discussed below were extracted.

Adoption of a Labor Cost Methodology – Various approaches for estimating labor costs were considered including bottom-up estimates and top-down estimates, where the top-down estimates were generated by applying multipliers to equipment costs to estimate labor requirements (for construction, equipment installation, and testing and commissioning), with added multipliers for home office costs, engineering, quality assurance, and management.

Figure I.1: Overview of country-specific labor cost analysis (OH = overhead, G&A = general administrative expense, OCC = overnight construction cost)



This approach was judged to be too simplistic. Instead, the Code of Accounts (COA) used by the EEDB, which is similar to that developed by the international Generation IV Program, Economic Modeling Working Group (EMWG), was used.

Estimation of Labor Hours Required by Activity/Task/Account – Once the labor cost model was developed using the EEDB COAs, person-hour estimates by discipline (craft, supervision, management, QA, home office, etc.) were taken from the EEDB reports, Electric Power Research Institute (EPRI) reports, other sources of information (e.g., public disclosures for projects such as Vogtle Units 3 and 4), and, to a lesser extent, estimates for overseas projects. Eight categories of labor were used (structural; mechanical; electrical/I&C; construction services, including carpenters; engineering; field supervision; quality; and "other," such as administration).

Labor Categories and Job Title – We determined early in the process that reported nuclear-specific salaries/labor costs were not always consistent with the eight categories used in the cost assessment model. For the analysis, eight general categories of labor similar to those in the model were used, but a total of 28 labor rates were compiled for each country. For example, craft labor costs were developed for 11 separate job titles.

Labor Costs and Averaging/Extrapolation – Once the labor categories and job titles were defined, the rates for each country were developed from: (a) published information; (b) interviews with utilities, nuclear steam supply systems designers and large construction subcontractors actively working at plant sites in the United States, France, and Korea; and (c) other sources such as data published by unions. Data for China were taken from published sources as well as from the China Quote System for power plant construction as of 2016. A stepwise change (increase) in Chinese labor rates for power plant construction was reported to have occurred in 2016 but information on this change was not available at the time of the analysis. In those cases where a specific wage was not available for a country, an extrapolation was made.

Estimation of Indirect Costs and Multipliers – Once the model was populated with labor costs, total direct labor costs were calculated for the reference plant. Indirect costs such as overhead, general and administrative (G&A) expense, and fee were estimated on a country-specific basis and then used to calculate the loaded costs. These indirect multipliers ranged depending on the country: a factor of 3 for Korea, 3.4 for the United States, 3.7 for France, and 5 for China.

Estimation of Country-Specific Productivity – Because it is expected that the number of hours required to perform a specific task at the plant construction site is directly proportional to worker productivity, an adjustment could be made to labor costs after the analysis. Alternatively, this adjustment could be made earlier in the analysis by scaling labor-hour requirements by task for a given country. With little quantitative data, no such changes were made here.

Calculation of Labor Costs for Reference Plant – As a last step, we calculated overall overnight labor costs for the hypothetical 1,100-MW_e plant.

Sensitivity studies were also completed to evaluate the effect of: (a) potential learning curves (especially in countries such as Korea and China), (b) number of workers on site (e.g., excess workers on site for training purposes), and (c) potential labor cost reductions associated with multiple-unit construction sites.

Overall, as shown in Figure 2.6 in Chapter 2, labor costs accounted for 15%–35% of plant overnight costs, depending on the country. Labor costs were lowest in China and highest in the United States. The labor cost difference between these two countries was approximately \$900/kW_e relative to an assumed (country-independent) average overnight cost of \$4,000/kW_e. The results for France and Korea were similar, with differences in labor costs accounting for about approximately \$400/kW_e.

Appendix J

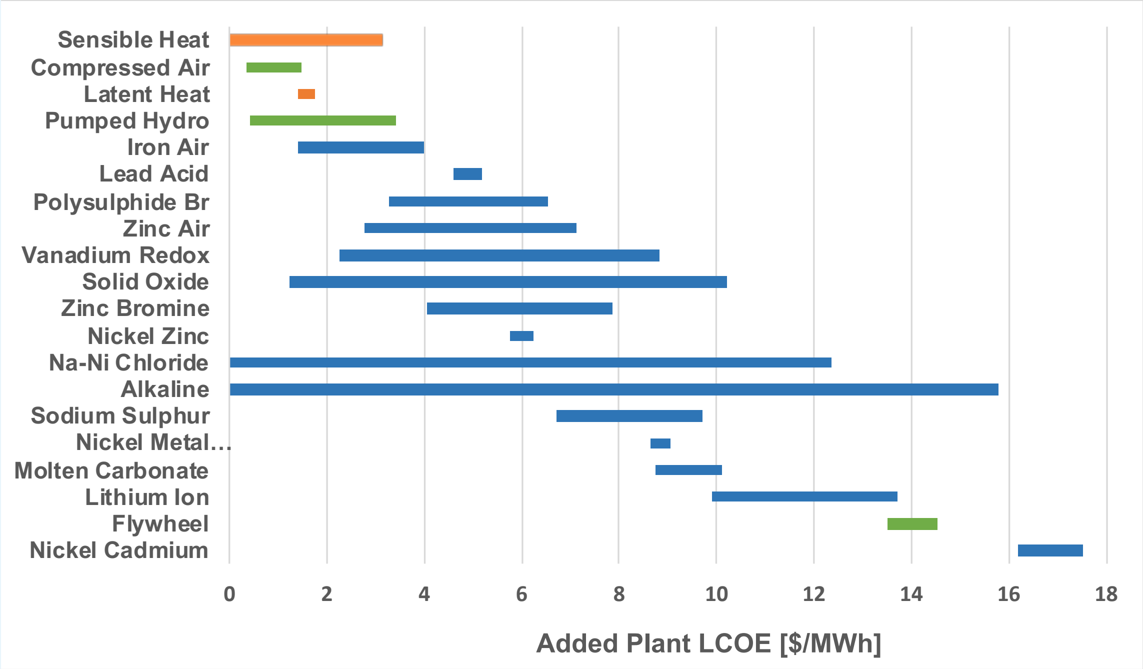
Energy Storage

Energy storage technologies offer potential to enhance revenues from the operation of baseload nuclear power plants because they make it possible to store energy when the price of electricity is low, and sell that energy when demand—and price—are high. In essence, energy storage opens up new peaking markets for nuclear beyond traditional baseload operation.

We examined a broad range of energy storage technologies (Forsberg 2017) including electrical storage (capacitors and electromagnetic devices), mechanical storage (pumped hydro, compressed air, and flywheels), batteries (including a range of static and flow types), and thermal storage (of both sensible heat and latent heat). A plot of projected storage costs, expressed in terms of added plant levelized cost of electricity (LCOE) at the scale necessary for integration with a nuclear reactor, is shown in Figure J.1.

The overall economics of energy storage systems has not been extensively studied yet. Furthermore, each storage technology has different characteristics with respect to rate of charging, rate of discharge, roundtrip efficiency, and readiness. As a consequence, the preferred option will depend on the electricity market.

Figure J.1: Added nuclear power plant LCOE ($/MWh) for different energy storage options (The color of the bars signifies the type of storage: green is mechanical, orange is thermal, and blue is electrical.)



The methods used to value storage technologies are not always well established nor are they always applied consistently. Typically, the cost of such systems is given by the following equation:

$$C = \frac{E \cdot \mu_E}{\eta_{RT}} + P \cdot \mu_P$$

Where

C = the capital cost [$];

E = the desired capacity [kWh];

μ_E = the capacity cost [$/kWh];

η_{RT} = the roundtrip efficiency, which captures the marginal energy losses induced by adding the storage cycle (typically expressed as the ratio of energy immediately out of the device to energy in);

P is the desired power [kW]; and

μ_P is the power cost [$/kW].

The analysis used to generate the results shown in Figure J.1 assumes 1 gigawatt hour (GWh) of storage and 100 megawatts (MW) of discharge power based on Westinghouse estimates for a pressurized water reactor (PWR) retrofit. By contrast, the analysis in Chapter 1 assumes battery storage with 2 megawatt hours (MWh) of energy storage capacity and 1 MW of charging or discharging power in the GenX simulations. Furthermore, the analysis here is based on current costs whereas the discussion in Chapter 1 uses projected costs in 2050 to account for potential reductions in the cost of storage technologies over the next three decades.

For a more accurate comparison between energy technologies, it is best to calculate the total capital cost of the energy storage system using the formula given above and then convert this capital cost into an estimate of 'added LCOE' for the specific storage technology being considered. It should be noted that the cost of a given energy storage technology could be different when paired with other energy generation technologies because of different scale and storage capacity needs.

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Appendix K

Economic Calculations for Advanced Nuclear Energy Concepts

This appendix discusses the basics of estimating power plant costs and provides a simple example, using a light water reactor (LWR), for the reader. Then, we apply the equations used in this example to estimate costs for advanced reactors and compare the economics of different advanced power conversion systems.

BASICS OF COMPONENTS OF POWER PLANT COST

There are three basic components to the cost of a plant that produces electricity (or any other energy product):

- **Capital Cost**—This is the largest cost component; it comes from the cost of building the plant and is composed of two parts. The 'overnight cost' of the plant is the cost to build it including the equipment, construction materials, and labor. The second part of capital cost is the cost of the interest that must be repaid for borrowing the money to construct the plant. Interest costs are affected by the construction time and the interest rate that applies to the borrowed money, which is known as 'interest during construction' (IDC) or 'accumulated funds during construction' (AFDC).
- **Operating and Maintenance Cost**—This cost component is the cost of operating and maintaining the power plant; it depends in part on the staffing needs associated with running the plant.
- **Fuel Cost**—This is the cost of the fuel used to produce the electricity.

Capital costs (including overnight construction cost and interest costs) can be considered fixed costs that are incurred whether the plant produces electricity or not. Operating costs have a variable portion. The fuel cost is only incurred when the plant is operating. Capital cost typically makes up more than 80% of the cost of a nuclear plant; the remainder of the cost is divided typically between the operating cost (15%) and the fuel cost (5%).

The levelized cost of electricity (LCOE) is then given by:

$$LCOE = \frac{1000}{8766{*}L}\left[\Phi\frac{I}{K} + \frac{O}{K}\right] + FCC$$

$$\Phi = \frac{(A/P,\chi,N)}{(1-\tau)} - \frac{\tau}{(1-\tau)}\left(\frac{1}{N}\right)$$

where,

$LCOE$ = levelized cost of electricity, mills/kWh$_e$;[1]

K = power plant size [kW$_e$];

L = annual capacity factor [actual kWh$_e$/rated kWh$_e$];

I = capital cost of the power plant including AFDC or IDC [$];

O = annual operating & maintenance cost [$/yr];

Φ = levelized fixed charge rate [yr^{-1}], accounting for both taxes and depreciation;

N = assumed plant economic life [years];

χ = discount rate $\{\chi = f_s r_s + f_b r_b (1-\tau)\}$;

f_s = fraction debt;

f_b = fraction equity;

r_b = rate on debt (bonds) (%);

r_s = rate on equity (stock) (%);

τ = composite tax rate;

$1/N$ = straight-line depreciation fraction;

$(A/P,\chi,N)$ = Capital Recovery Factor = $[\chi(1+\chi)^N]/[(1+\chi)^N - 1]$;

FCC = fuel cycle cost;

and 8,766 is the number of hours in a year. The nuclear fuel cycle cost is given by:

$$FCC = 1000{*}C_f/(24\eta B)$$

where:

C_f = total [net] fuel cycle cost [$/kg], including enrichment, conversion, fabrication and disposal;

B = fuel burnup at discharge [MWD$_{th}$/MTU] [megawatt-days-thermal/metric-ton-uranium]; and

η = plant thermal efficiency [kW$_e$/kW$_{th}$].

SIMPLE LIGHT WATER REACTOR (LWR) CASE

As a simple example, we consider an idealized AP1000 reactor assuming the cost inputs listed below:

Factor	Value
L= capacity factor [actual kWh$_e$/rated kWh$_e$]	0.85
Φ = annual fixed charge rate, yr^{-1}	0.10
I/K= specific capital cost, $/kW$_e$	5000
K = Plant capacity, MW$_e$	1100
O/K= annual operating cost, $/yr-kW$_e$	70
C_f = total [net] fuel cycle cost, $/kg	2500
B = fuel burnup at discharge MWD$_{th}$/MTU	50,000
η = plant thermal efficiency, kW$_e$/kW$_{th}$	0.33
N = assumed plant economical life (years)	30

We would then calculate that the LCOE = 67.1 + 9.4 + 6.3 ~ 82.8 mills/kWh$_e$ (or $/MWh$_e$), which is very similar to the value of 83.5 mills/kWh$_e$ calculated under similar assumptions by the U.S. Energy Information Administration (EIA) in its 2015 *Annual Energy Outlook*.

Advanced Reactor Cost Estimates

Advanced reactor costs are more difficult to estimate because of the lack of design detail and historical basis for construction of these systems, and because different sources use varying assumptions about key cost components. Open sources for overnight capital cost estimates were used to establish the costs presented in Table K.1. They are compared to cost estimates for U.S. pressurized water reactors (PWRs) from the Energy Economic Data Base (EEDB) (United Engineers and Constructors 1986) both for the best plant, as described by Ganda, et al. (2016), and for the median plant, as described by Lucid Strategies (2018). Costs listed in these sources for each labor component and materials are escalated to current dollars. (Values are rounded to the nearest dollar in this appendix, but to the nearest hundred dollars in the main text.)

[1] A 'mill' is equal to one-tenth of one cent, or $0.001. Note that 1 mill/kW (or 1 mill/kWh) is equal to $1/MW (or $1/MWh).

Table K.1: Comparison of cost estimates for different reactor types

Comparison of Reactor Cost Estimates ($/kW$_e$) for Different Reactor Types							
Cost Categories	**PWR Median Experience from Lucid Strategies**	**PWR 1100 MW$_e$ Best Experience from 1988 to 2014 using ANL escalation approach**	**HTGR 2400 MW$_{th}$/1000 MW$_e$ (2009) (from INL)**	**1100 MW$_e$ SFR/ANL (2014) from ANL**	**AHTR 3400 MW$_{th}$/1350 MW$_e$ (2011) based on 1100 MW$_e$ PWR w using ANL Escalation basis for PWR 1100 MW$_e$**	**12x242 MW$_{th}$ FHR with NACC (142 MW) from UCB thesis**	**ORNL 1000 MW$_e$ MSR Scaled to 2014 Based on PWR Scaling of Lucid Strategies but indirect costs similar to other advanced reactors**
Unit/Size	1	1	4x600 MW$_{th}$	4x840 MW$_{th}$	1	12x242 MW$_{th}$	1
Pre-Construction Costs			91				
Structures and Improvements	574	476	331	470	412		659
Reactor Plant Equipment	694	719	1083	1254	719		870
Turbine Plant Equipment	487	531	478	418	381	Detailed breakdown as shown here is not provided	440
Electrical Plant Equipment	217	193		157	154		266
Miscellaneous Plant Equipment	126	111	473	209	97		159
Main Cond Heat Reject System	103	116			101		61
Special Materials					220		
TOTAL DIRECT COST	**2201**	**2146**	**2456**	**2508**	**2085**	**2316**	**2455**
Owner's Cost			273				
Construction Services	739	538	494	355	270		
Home Office Engin & Service	895	505	381	1254	467		
Field Office Engin & Service	819	263	231		698		
TOTAL INDIRECT COST	**2453**	**1306**	**1379**	**1609**	**1436**	**1343**	**1669**
Indirect Costs as % of Direct	111%	61%	56%	64%	69%	58%	68%
TOTAL BASE COST	**4654**	**3452**	**3835**	**4117**	**3520**	**3659**	**4125**
Contingency		10%	20%	20%	30%	30%	30%
Contingency		345	767	823.4	1056	1098	1237
TOTAL OVERNIGHT COST	**4654**	**3797**	**4602**	**4940**	**4576**	**4757**	**5362**
IDC Rate		84%	20%	20%	20%	20%	20%
IDC	1500	3189	644	692	641	666	751
TOTAL	**6154**	**6986**	**5246**	**5632**	**5217**	**5423**	**6113**

Our cost estimates are based on traditional 'stick-built' construction in the United States for an 'nth-of-a-kind' (NOAK) plant. The NOAK plant is identical to the first-of-a-kind plant supplied and built by the same vendors and contractors with only the site-specific scope altered to meet the NOAK plant site's needs. Costs for NOAK plants are achieved only after many such reactors have been constructed for a particular nuclear system design.

Cost estimates for a high-temperature gas-cooled reactor (HTGR) (Gandrik 2012) and sodium-cooled fast reactor (SFR) (Ganda 2015) are the most current estimates openly available. They are based on conceptual designs. Cost estimates for the fluoride-salt-cooled high-temperature reactor (FHR) (large and small) and molten salt reactor (MSR) are based on pre-conceptual designs. Indirect costs for the small FHR (Andreades 2015) are based on those assumed for the HTGR. Costs for the large FHR (Holcomb 2011) were escalated to current costs based on the work of Ganda, et al. (2016). Costs for the MSR (Engle 1980) are based on early-1980s vintage pre-conceptual designs and were escalated using LWR direct costs from Lucid Strategies; to allow for a fair comparison, however, we used the large FHR indirect cost percentage for consistency. The scaling factors used to escalate costs are found in Table K.2. Overnight costs include capital costs, indirect costs, and a contingency factor, as discussed below.

Table K.2: Scaling factors used to escalate costs in the analysis

	Scaling for AHTR based on escalation approach by Ganda	Scaling for MSR based on Lucid Strategies
Pre-Construction Costs		
Structures and Improvements	1.24	5.23
Reactor Plant Equipment	1.19	4.84
Turbine Plant Equipment	1.19	4.40
Electrical Plant Equipment	1.21	4.93
Miscellaneous Plant Equipment	1.21	
Main Cond Heat Reject System	1.21	4.32
Special Materials		
TOTAL DIRECT COST		
Owner's Cost		
Construction Services	1.19	
Home Office Engin & Service	1.19	
Field Office Engin & Service	1.19	
TOTAL INDIRECT COST		

Capital Costs

Capital costs in Table K.1 were obtained from estimates developed by the teams working on different advanced reactor designs. These costs were binned into the traditional code of accounts for reactor systems:

- Pre-construction costs
- Structures and improvements (site preparation, excavation etc.)
- Reactor plant equipment (cost of the nuclear steam supply system or NSSS)
- Turbine plant equipment (cost of the turbine island)
- Electrical plant equipment
- Miscellaneous plant equipment
- Main condenser heat rejection system
- Special materials (for example, molten salt, which, depending on the salt, can be very expensive)

Indirect Costs

Given limited experience in the construction of advanced reactor systems, indirect costs (installation, home and field engineering, and construction services) are expressed as a percentage of direct costs. Indirect costs include the following sub-categories:

- **Construction services –** including but not limited to costs for construction management, procurement, scheduling, cost control, site safety, and quality inspections.
- **Home office and engineering services –** including but not limited to costs for estimating, scheduling, project expediting, project general management, design allowance, and project fees.
- **Field office and engineering services –** including but not limited to costs for the field office, field engineering, field drafting, field procurement, and field administrative and general expenses.
- **Owner's costs –** including but not limited to project fees, taxes, and insurance; spare parts and other capital expenses; staff training and startup costs; and administrative and general expenses, but not interest during construction.
- **Design costs –** preconstruction engineering, design, and layout work associated with the site.

An indirect cost multiplier of 57% was used for the HTGR and 64% for the SFR. (No escalation was done for these two cost estimates.) Indirect costs are collectively a large part of the overall cost. Estimates of actual indirect costs as a percentage of direct costs from the historical LWR fleet span a large range. Some have been as low as 20%, but a best practices value from the LWR fleet is about 40% whereas the fleet average is 50%. The U.S. Department of Energy's cost estimation methodology (1980) (1988) recommends 51% based on reactors built prior to Three Mile Island and 77% for reactors built after Three Mile Island. The International Atomic Energy Agency (IAEA)

(International Atomic Energy Agency 1978) recommends a value of 52%. Thus, the values used here are considered reasonable.

Contingency

We provide a variable contingency for these estimates to reflect cost uncertainty. The contingency is based on the maturity of the designs, associated technology development, and supply chain considerations. Mature conceptual designs approaching the level of preliminary design (HTGR and SFR) were thus assigned a 20% contingency, while early conceptual designs were assigned a 30% contingency to reflect the lower level of technical detail in these designs. While some may consider these percentages to be low, they are reasonable for comparison purposes.

Financing Costs

All systems were assumed to have construction times of 60 months. We assumed 50% debt/50% equity (6% debt and 12% equity), and a tax rate of 38%. This yields a discount rate, x, of 0.0786, a capital recovery factor of 0.088, and a levelized fixed charge rate, Φ, of 0.121, which are used in all of the calculations presented here. The discount rate of 7.86% was used to calculate interest during construction (IDC) as a multiplier of the overnight capital cost using the formula:

IDC (also known as *AFDC*) = $(1+N^{*}x/2)$

Overnight Costs and Total Capital Investment

The overnight costs in Table K.1 are all very similar: between \$4,600/kW$_e$ and \$5,400/kW$_e$. This is essentially the same value given the uncertainties involved, as discussed in Chapter 3. For comparison, the overnight cost for NuScale, a small LWR, is projected to be approximately \$5,000/kW$_e$. Adding in interest cost during construction results in a total capital investment of between \$5,200/kW$_e$ and \$6,100/kW$_e$. Shorter construction times can reduce the total capital investment shown here.

Estimates of the Levelized Cost of Electricity

Table K.3 shows capital cost, operating and maintenance costs, and fuel cycle costs for several advanced reactor concepts following the LCOE equation given earlier. Direct costs were taken from Table K.1. Annual capacity factors were assumed to be 0.9 for all reactor types.

Operating costs for the advanced concepts were either provided in total dollars (and then converted to \$/kW$_e$ by dividing by the thermal power and capacity factor) or were provided directly by the advanced reactor team.

For the FHR with the air Brayton combined cycle, the estimates assume operation with natural gas 50% of the time. This mode of operation boosts the thermal power for an individual unit operating at 100 MW$_{th}$ and 53% efficiency in reactor-only mode to 242 MW$_{th}$ and 70% efficiency in the reactor and natural gas firing mode. The estimates also include the cost of natural gas associated with the air Brayton cycle, which is assumed to be \$3.37/MWh$_e$ or only about 10% of O&M costs. Higher O&M costs for this design are driven by large staffing needs at each of the individual units.

Fuel costs for HTGR (TRISO fuel) and SFR (metallic fuel) reactors are significantly larger than fuel costs for current LWRs, in part because these advanced reactor fuels require higher levels of enrichment but also because they involve different fabrication methods. Neither design has been deployed yet on large scale so fuel fabrication cost reductions might be possible in the future. Additional details were not available for SFR fuel costs. HTGR fuel costs were based on enrichment and fabrication costs and the anticipated discharge burnup for the design. For FHR designs, original cost assumptions for both small and large systems that use TRISO fuel were underestimated and were corrected based on the HTGR cost estimate, which comes from vendor quotations. For MSRs, a detailed estimate was not available, but a nominal value was used based on the level of uranium enrichment provided for this system.

Table K.3: Details of LCOE calculations

Levelized Cost of Electricity Estimates						
		HTGR 2400 MW_{th}/1000 MW_e (2009) (from INL)	1100 MW_e SFR/ANL (2014) from ANL	AHTR 3400 MW_{th}/1350 MW_e (2011) based on 1100 MW_e PWR using ANL Escalation basis for PWR 1100 MW_e	12x242 MW_{th} FHR with NACC (142 MW) from UCB thesis	ORNL 1000 MW_e MSR Scaled to 2014 Based on PWR Scaling of Lucid Strategies but indirect costs similar to other advanced reactors
Plant size (MW_{th})		2400	4108	3000	2904	2275
Plant size (kW_e)	K	1.01E+06	1.51E+06	1.35E+06	1.33E+06	1.00E+06
Annual capacity factor	L	0.9	0.9	0.9	0.9	0.9
Total Direct Cost $		2.46E+09	3.79E+09	2.81E+09	3.08E+09	2.46E+09
Indirect Multiplier		1.58E+00	1.64E+00	1.69E+00	1.58E+00	1.68E+00
Contingency		1.20E+00	1.20E+00	1.30E+00	1.30E+00	1.30E+00
IDC		1.20E+00	1.20E+00	1.20E+00	1.20E+00	1.20E+00
Capital Cost including AFDC	I	5.57E+09	8.92E+09	7.40E+09	7.57E+09	6.42E+09
OVERNIGHT COST (does not include IDC)		**4619.62**	**4947.42**	**4579.52**	**4748.03**	**5356.36**
Levelized fixed charge rate	phi	0.121	0.121	0.121	0.121	0.121
Economic Plant life	N	30	30	30	30	30
Tax rate	tau	0.380	0.380	0.380	0.380	0.380
Discount rate	x	0.079	0.079	0.079	0.079	0.079
Capital recovery factor		0.088	0.088	0.088	0.088	0.088
Conversion factor (1000/8766*L)		0.127	0.127	0.127	0.127	0.127
SPECIFIC CAPITAL COST (I*phi/K) (mills/kW_ehr)		**84.74**	**90.75**	**84.00**	**87.10**	**98.25**
Annual O&M cost	O	9.96E+07		1.03E+08	3.12E+08	
Annual O&M cost ($/kW)		98.81		76.13	233.79	
SPECIFIC O&M (O/K) (mills/kW_ehr)		**12.52**	**8.34**	**9.65**	**33.00**	**12**
Fuel Cycle cost	$/kg	22373			16500	
Burnup	MWD/MTU	132000			100000	
Plant efficiency	kW_e/kW_{th}	0.42	0.37	0.45	0.46	0.44
Fuel Cycle Cost (mills/kW_ehr)		**16.81**	**14**	**17.54**	**14.98**	**9**
TOTAL LCOE	**mills/kW_ehr**	**114.08**	**113.10**	**111.19**	**135.08**	**119.25**

Operational costs range between 8 and 13 mills/kWh_e (or $/$MWh_e$) except for the small FHR, which is a 12-module plant for which costs were derived by scaling from the HTGR. Had a common cost for O&M been used, all of the systems would have an LCOE of approximately $110–$120/MWh_e. These values are slightly greater than the values for advanced LWRs provided by the U.S. Energy Information Administration (2016) ($92–$100/MWh_e) and NuScale estimates (Surina 2016) ($96–$106/MWh_e). Lower interest rates and shorter construction times can reduce the LCOE values presented here.

Comparison of Advanced Power Conversion Options

As part of our assessment of crosscutting technologies, we evaluated advanced power conversion systems to determine if an increase in thermal efficiency improves the overall economics of the plant for two cases:

- An HTGR at 950°C with a helium Brayton cycle compared to the conventional HTGR at 750°C with a superheated Rankine cycle.
- An SFR with a supercritical CO_2 cycle compared to a conventional SFR with a Rankine cycle.

Because of the increase in thermal efficiency, all cost components of the LCOE are affected in the calculation.

For the HTGR independent bottom-up cost estimates were developed for each option from Gandrik (2012). As shown in the Table K.4, the helium Brayton cycle and the higher outlet temperature increase the efficiency of the system from 42% to 50% but these design choices also increase the capital cost. Comparing the two cases indicates very similar LCOEs for these two reactor designs.

For the SFR, the use of supercritical CO_2 increases the efficiency from 37% to 50%. However, a detailed assessment of the design that integrates the supercritical CO_2 cycle was not available. Instead, we performed a top-down type of analysis and increased the capital cost until the LCOEs are equal, which corresponds to an additional \$825/kW$_e$. Because a traditional Rankine cycle costs about \$500/kW$_e$ (McKellar 2010) (Ho, et al. 2015), the supercritical option with the change in heat exchanger breaks even with the conventional system at a cost of approximately \$1,325/kW$_e$. Cost projections for the nth-of-a-kind supercritical CO_2 cycle are in the same range: between \$1,000/kW$_e$ and \$1,200/kW$_e$ (Ho, et al. 2015).

Thus, despite gains in efficiency, these advanced power conversion cycles do not change the overall economics significantly.

Table K.4: Comparison of HTGR and SFR LCOEs with different power conversion cycles

		HTGR 2400 MW$_{th}$/1000 MW$_e$ (2009) (from INL)	HTGR 4x600 pack 950 C Brayton (from INL)	1100 MW$_e$ SFR/ANL (2014) from ANL	1000 MW$_e$ SFR with SCO_2 (assuming \$825/kWe extra for SCO_2 changes)
Plant size (MW$_{th}$)		2400	2400	4108	4108
Plant size (kWe)	K	1.01E+06	1.20E+06	1.51E+06	2.05E+06
Annual capacity factor	L	0.9	0.9	0.9	0.9
TOTAL DIRECT COST $		2.46E+09	3.28E+09	3.79E+09	5.48E+09
Indirect Multiplier		1.58E+00	1.58E+00	1.64E+00	1.64E+00
Contingency		1.20E+00	1.20E+00	1.20E+00	1.20E+00
IDC		1.20E+00	1.20E+00	1.20E+00	1.20E+00
Capital Cost included AFDC	I	5.57E+09	7.44E+09	8.92E+09	1.29E+10
OVERNIGHT COST (does not include IDC)		**4619.62**	**5192.79**	**4947.42**	**5252.04**
Levelized fixed charge rate	phi	0.121	0.121	0.121	0.121
Economic Plant life	N	30	30	30	30
Tax rate	tau	0.380	0.380	0.380	0.380
Discount rate	x	0.079	0.0786	0.079	0.0786
Capital recovery factor		0.088	0.088	0.088	0.088
Conversion factor (1000/8766*L)		0.127	0.127	0.127	0.127
SPECIFIC CAPITAL COST (I*phi/K) (mills/kWhr)		**84.74**	**95.25**	**90.75**	**96.34**
Annual O&M cost	O	9.96E+07	9.96E+07		
Annual O&M cost ($/kW)		98.81	83.17		
SPECIFIC O&M (O/K) (mills/kWhr)		**12.52**	**10.54**	**8.34**	**6.12**
Fuel Cycle cost	$/kg	22373	22373		
Burnup	MWD/MTU	132000	132000		
Plant efficiency	kW$_e$/kW$_{th}$	0.42	0.499	0.37	0.5
Fuel Cycle Cost (mills/kWhr)		**16.81**	**14.15**	**14**	**10.248**
TOTAL LCOE	**mills/kWhr**	**114.08**	**119.95**	**113.10**	**112.71**

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Appendix L

Delivering Nuclear Megaprojects On Time and On Budget: Challenges and a Potential Solution

Megaprojects are defined as projects with large budgets (above $1 billion) and a high level of complexity. Typical gigawatt-scale nuclear power plant construction projects fit this definition. Megaprojects present substantial technical and financial risks and are often implemented after a sub-optimal planning phase that underestimates their costs and overestimates their short-term benefits (Flyvbjerg 2006).

An analysis of data from 318 industrial megaprojects shows that most may be considered a failure from the point of view of meeting schedule and budget targets and delivering promised benefits in operation (Merrow 2011). Cantarelli, et al. (2010) summarize the likely causes of this poor performance record:

- **Technical challenges**—These can include forecasting errors with regard to the price escalation of materials, or incomplete estimates of cost and uncertainty, changes in project scope, and inadequate organizational structure.
- **Psychological factors**—The well-documented tendency of project proponents, including project executives and officials, to display optimism bias in their assessments of cost and performance.
- **Commercial incentives**—The tendency of vendors/contractors to intentionally underestimate cost and overestimate benefit in order to 'sell' a project.
- **Political factors**—The manipulation of cost and benefit forecasts by decisionmakers for unethical reasons, for example, to gain support in upcoming elections or obtain a personal benefit (see also Locatelli, et al. 2017).
- **Organizational challenges**—These can arise when a project (or major subcontract) is awarded to the lowest "turn-key" bid without proper consideration of the contractor's ability to manage project risks.

Merrow (2011) submits that the most common causes of budget overruns and delays in megaprojects are stakeholders' greed; pressure to reduce estimates of construction time and increase the expected net present value of the project; an ineffective bidding phase; pressure to reduce upfront costs, which leads to poor quality 'front end loading' (FEL) and 'front end engineering and design' (FEED); unrealistic cost estimates; and ineffective risk allocation among project partners.

Several empirical studies (Ansar 2014) (Sovacool, Gilbert and Nugent 2014) have shown that the larger the megaproject, the greater the likelihood that it will experience cost overruns and delays. Locatelli, Mancini and Romano (2014) investigated the role of complexity (technical and organizational) in megaprojects and found that underperforming projects are often delivered in an environment characterized by interoperable and interdependent systems; emphasis on reducing costs and tightening schedules without the reductions in project scope needed to make these cost and time parameters feasible; integration issues (i.e., high number of system parts and high number of organizations involved, often from multiple technical disciplines); competitive pressure from other technologies within the same market (e.g., natural gas or renewable generators in the case of nuclear power plants) or from alternative systems using the same technology (e.g., different nuclear reactor designs).

The nuclear energy industry in Western Europe and the United States has experienced chronic problems with budget overruns and schedule delays in power plant construction projects—in fact, these issues seem to be systemic and there has been no apparent improvement over time. This has fostered '*tolerance for deviation*' (Pinto 2014)—that is, when members of a business community become so accustomed to a deviant behavior that they do not consider it to be deviant anymore. Decisionmakers play the necessary 'political games' to ensure support for a project despite a poor record of project management (Pinto and Patanakul 2015) but ultimately consistent poor performance is not sustainable. The Korean nuclear program is one of few exceptions to the general trend. The standard Korean 1-gigawatt power plant design has been consistently built on budget and within a reasonable schedule (five to six years), and the existing fleet of Korean reactors has had good operational performance. The Koreans established a 'supply chain for construction' to deliver a series of plants based on replicating a standardized reactor design rather than building individually-designed plants. In megaprojects, especially in the nuclear energy industry, a key strategy for achieving good performance (where performance is measured by adherence to budget and schedule), appears to be standardization—both of the project supply chain (i.e., the same stakeholders involved in delivering a project that is replicable multiple times) and of the product or project deliverable itself (in this case, the same power plant design duplicated over and over again) (Choi 2009). Small modular reactors (SMRs) naturally lend themselves to both supply chain and product standardization, thus one of the potential advantages of this technology is that it could improve project management performance in the nuclear sector. SMRs face a number of deployment challenges, from licensing to maturity of the supply chain to financing of early projects (Sainati, Locatelli, and Brookes 2015), however the potential rewards are great.

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Abbreviations and Technical Terms

ABWR	advanced boiling water reactor
AC	alternating current
ACRS	Advisory Committee on Reactor Safeguards
ACI	American Concrete Institute
AEA	Atomic Energy Act
AEC	Atomic Energy Commission
AFDC	accumulated funds during construction
AP1000	Westinghouse pressurized water reactor with improved use of passive nuclear safety
APR1400	Korean advanced pressurized water reactor
ARC	an advanced sodium fast reactor concept
ASLB	Atomic Safety and Licensing Board
ASME	American Society of Mechanical Engineers
BWR	boiling water reactor
CCGT	combined cycle gas turbine
CCS	carbon capture and sequestration
CFR	Code of Federal Regulations
CNS	Convention on Nuclear Safety
CO_2	carbon dioxide
COL	combined operating license
COLA	combined operating license application
COP21	21st yearly session of the Conference of Parties
CP	construction permit
DC	design certification
DOE	U.S. Department of Energy
EEDB	Energy Economic Data Base
EIA	U.S. Energy Information Administration
EPA	U.S. Environmental Protection Agency
EPC	Engineering, Procurement and Construction
EPR	evolutionary power reactor
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
EROEI	energy return on energy invested
ESBWR	economic simplified boiling-water reactor
ESP	early site permit
FAA	Federal Aviation Administration
FDA	Food and Drug Administration
FEED	front end engineering and design
FHR	fluoride high temperature reactor
FLiBe	molten salt containing lithium fluoride and beryllium fluoride
FOAK	first-of-a-kind
GDA	generic design assessment
GE	General Electric
GFR	gas-cooled fast reactor
GHG	greenhouse gas
GT-MHR	gas turbine modular helium reactor
HALEU	high-assay low-enriched uranium
HTGR	high temperature gas-cooled reactor
HTSE	high temperature steam electrolysis
I&C	instrumentation and control
IAEA	International Atomic Energy Agency
IDC	interest during construction
IEEE	Institute of Electrical and Electronics Engineers
IEO	International Energy Outlook
IGCC	integrated gasification combined cycle
INL	Idaho National Laboratory
INPO	Institute for Nuclear Power Operations
ITAAC	inspections, tests, analyses and acceptance criteria
KEPCO	Korea Electric Power Corporation
LCOE	levelized cost of electricity
LFR	lead fast reactor
LNT	linear no threshold hypothesis

LWR	light water reactor
MSR	molten salt reactor
NAICS	North American Industry Classification System
NOAK	nth-of-a-kind
NGNP	Next Generation Nuclear Plant
NNSA	National Nuclear Safety Administration
NRC	U.S. Nuclear Regulatory Commission
NSSS	nuclear steam supply system
O&M	operations and maintenance
OCGT	open cycle gas turbine
ODS	oxide dispersion strengthened
OECD	Organisation for Economic Cooperation and Development
OL	operating license
ONR	Office of Nuclear Regulation
ORNL	Oak Ridge National Laboratory
PRA	probabilistic risk assessment
PRISM	Power Reactor Inherently Safe Module
PV	photovoltaic
PWR	pressurized water reactor
RAI	request for additional information
SDA	standard design approval
SFR	sodium fast reactor
SMR	small modular reactor
SPC	steel plate composite
SSC	system, structure or component
SWU	separative work unit
T-B-T	Tianjin, Beijing, and Tangshan
TRISO	tri-structural isotropic
U	Uranium
UHPC	ultra-high performance concrete
VHTR	very high temperature reactor
WNA	World Nuclear Association

Units

Btu	British Thermal Unit
°C	degrees Celsius
°F	degrees Fahrenheit
g	gram
GW	gigawatt (10^6 kW)
GWh	gigawatt-hour
J	Joule
kg	kilogram
km	kilometer
kW	kilowatt
kWh	kilowatt-hour
MMBtu	million British Thermal Unit
MT	metric ton
MW	megawatt (10^3 kW)
MWh	megawatt-hour
TWh	terawatt-hour (10^9 kWh)

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