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Nuclear New Build: Insights into Financing and Project Management


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The mission of the NEA is:

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– to provide authoritative assessments and to forge common understandings on key issues, as input to government decisions on nuclear energy policy and to broader OECD policy analyses in areas such as energy and sustainable development.

Specific areas of competence of the NEA include the safety and regulation of nuclear activities, radioactive waste management, radiological protection, nuclear science, economic and technical analyses of the nuclear fuel cycle, nuclear law and liability, and public information.

The NEA Data Bank provides nuclear data and computer program services for participating countries. In these and related tasks, the NEA works in close collaboration with the International Atomic Energy Agency in Vienna, with which it has a Co-operation Agreement, as well as with other international organisations in the nuclear field.

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Foreword

Nuclear new build has been steadily progressing since the year 2000, with the construction of 94 new reactors initiated and 56 completed reactors connected to the grid. Among these new reactors are some of the first generation III/III+ reactors of their kind. This period has been one of technological, structural and geographical change, and the experiences gained since the beginning of the 21^{st} century, as well the challenges that projects have faced and the solutions sought to overcome these challenges, have been gathered in this report to provide a valuable reference for policy makers and stakeholders concerned with nuclear new build. The report was written under the oversight of the OECD Nuclear Energy Agency (NEA) Working Party on Nuclear Energy Economics (WPNE) and the NEA Committee for Technical and Economic Studies on Nuclear Energy Development and the Fuel Cycle (NDC). Two well-attended international workshops in September 2013 on financing, and in March 2014 on construction, provided detailed information on a broad range of specific issues from highly regarded experts, and the present report draws extensively upon these discussions.

Using a combination of conceptual analysis, expert opinion and seven in-depth case studies, the report aims to synthesise experiences and provide insights into the principal challenges facing nuclear new build and to propose possible solutions to address and overcome them. It focuses on the most important challenges when building a new nuclear power plant, namely assembling the conditions for successful financing and managing highly complex construction processes and their supply chains. The report offers an instructive overall picture of the state of nuclear new build today, ongoing trends and possible ways forward.

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Executive summary

Nuclear new build has been steadily progressing since the year 2000, with the construction of 94 new reactors initiated and 56 completed reactors connected to the grid. Among these new reactors are some of the first generation III/III+ reactors of their kind. This period has been one of technological, structural and geographical change, and the experiences gained since the beginning of the 21st century, as well as the challenges that projects have faced and the solutions sought to overcome these challenges, have been gathered in this report to provide a valuable reference for policy makers and stakeholders concerned with nuclear new build. The report offers an authoritative overview of global trends in nuclear power plant (NPP) construction over the past two decades. The challenge of constructing NPPs is analysed from two principal perspectives: first, from the importance of revenue stability over time for high fixed cost projects; and second, from the potential for improvements in efficiency through the optimisation of project and supply chain management.

The report provides a snapshot of the current state of affairs in nuclear new build, demonstrating that today 68 nuclear reactors are under construction, while a further 159 projects are planned. The largest single market is that of the Peoples' Republic of China, with 27 reactors under construction and 56 reactors planned. These numbers should be compared to the current operating fleet of 435 reactors worldwide. While a majority of the reactors under construction remain generation II designs, an increasing number of new build projects concern generation III/III+ reactors. Due to first-of-a-kind (FOAK) issues, generation III/III+ projects can undergo experiences not encountered in other construction projects. At the same time, there is considerable potential to learn from such FOAK projects, and to decrease costs and the duration of construction.

The importance of electricity prices and revenue stability

The second part of the report focuses on the first of two key issues for successful nuclear new build (NNB), the importance of the long-term stability of electricity prices in order to ensure revenue stability and the financing of NNB projects. Based on the results of an economic model where different power generation technologies compete according to their variable costs in a market with daily dispatch, the present report shows that the high fixed costs of nuclear power make it more vulnerable than other dispatchable technologies such as gas to declines in average electricity prices. These price declines are far from a theoretical possibility. In Europe, for example, wholesale electricity prices are today more than one third lower than in 2007 with no perspective of an increase in the coming years. In uncertain markets, a gas-fired power plant, with its lower fixed costs, is exposed to considerably lower financial risks than a nuclear plant, even if both plants have comparable levelised costs of electricity (LCOE) over their operating lifetimes.

At the date of commissioning, investors in a gas plant commit a smaller portion of total lifetime costs in an irreversible manner than investors in a nuclear plant. In the case of a long-term decline in power prices, the gas plant can limit its losses by shutting down and temporarily or permanently leaving the market. The nuclear plant does not have this option, since up to 80% of its total lifetime costs have been irreversibly committed the day of commissioning. Long-term electricity price risk is thus a major deterrent against investment in nuclear power.

Experts and investors in nuclear power, as well as governments, normally have at least an intuitive understanding of this issue. However, the report shows that the differences in the net present value (NPV) of a nuclear plant and a gas plant, which have the same LCOE under price certainty, are significant in the presence of possible long-term declines in wholesale electricity prices. For a permanent 30% fall in electricity prices, the difference amounts to USD 1 billion, and this sum rises exponentially for larger price falls. Results such as these should be sufficient motivation to accelerate the search for economically efficient measures capable of reducing the gap in risk exposure. Options might include long-term contracts, feed-in tariffs (FITs) or contracts for difference (CFDs). Clearly, such measures should be available for nuclear power as well as for other low-carbon technologies, the great majority of which face similar issues. At stake is the ability to find convincing answers to the questions posed by the intrinsic capital-intensity of low-carbon technologies. OECD governments and the regulators within these countries have been slow to systematically react to the strategic divergence between electricity market liberalisation and investment in low-carbon electricity generation technologies such as nuclear energy.

The results unequivocally demonstrate that the competitive position of two technologies is affected by the level of price risk and consequently by the choice of market design. There is no technology-neutral market design. Due to the risk of a decline in the price level, a liberalised electricity market will generate results that are different from those of a regulated market in terms of the relative competitiveness of nuclear power. The often invoked level playing field could potentially mean very different things to different technologies because not all technologies depend on the regulatory environment in the same manner. The profitability of a gas plant varies far less in relation to the regulatory regime than the profitability of a nuclear plant.

This report is complemented by the results of a financial Monte Carlo model with symmetric electricity price risk, which also includes the financial risks pertaining to the costs of construction operations. Under the assumptions of the model, construction cost and electricity price risk are of comparable orders of magnitude and dominate the overall risk of an NNB project. Added to this is the differentiated risk exposure of bond and equity holders. Given the cost structure of nuclear power, risks are in effect relatively low for bondholders, since the low variable costs of NPPs would mean that production would rarely cease completely, even in the case of substantial price declines. Indeed, nuclear power is usually the last remaining dispatchable technology in the market. For debt ratios of up to 50% and permanent price declines of up to 40%, bondholders will be fully repaid as long as the cost of debt does not exceed 5.5% in real terms.

Financial risks are, on the other hand, comparatively high for holders of residual risk (i.e. equity holders), since, in the case of a price decline, they are unlikely to ever fully recoup their outlays, which has obvious implications when targeting government support for nuclear finance. The latter is traditionally geared towards bondholders, for instance in the form of loan guarantees. Due to the cost structure of NPPs, however, it is equity holders rather than bondholders that are the constituency most in need of support, as any change in electricity prices will mainly fall on equity holders. In the current long-term policy environment, this means primarily a downside risk. From this point of view, electricity price stability remains a decisive element for new nuclear projects.

Three case studies of NNB projects are included in the second part of the report, at Akkuyu (Turkey), Barakah (United Arab Emirates – UAE) and Vogtle (United States), as well as a presentation of the Finnish Mankala financing model. All four projects point towards arrangements for providing at least some degree of long-term electricity price stability. The latter include power purchase agreements (PPAs) with guaranteed prices, equity provided directly by the host country government, regulated tariffs or long-term contracts with commitments to take off electricity at average costs.

Managing complexity in a changing environment

Managing the complexities of constructing new NPPs, as well as of leveraging the potential benefits of an increasingly international supply chain is the focus of the third part of the report. This latter part of the report describes the current situation of the global nuclear industry, which is experiencing significant and discontinuous technological change as generation II NPPs are substituted by larger and more complex generation III/III+ plants. Two further elements are taken into consideration here. First, the loss of skills and human capital as a generation of engineers of the nuclear building boom of the 1970s and 1980s retire should be factored into the current situation. Second, the reconfiguration of the global supply chain of contractors and subcontractors, which is driven both by new possibilities in data management, externalisation and logistics, and by a fundamental shift of activity from the United States, Europe, Japan and Korea to China, Southeast Asia and the Middle East, should also be taken into account. While the latter constitutes a shift from OECD to non-OECD countries, many if not most major suppliers continue to have their headquarters in the OECD area.

The nuclear industry has undergone a major wave of consolidation among the main reactor vendors in the past two decades, a trend that may continue in the future. However, integration at the horizontal level does not preclude increased differentiation and co-operation with specialist suppliers along a vertical axis. A large section of the present report examines the evolving structure of the global nuclear supply chain and provides a detailed overview of the global nuclear industry, which combines consolidation at the horizontal level with the development of more differentiated profiles across the vertical value chain.

The key to efficient project management is finding the right balance between vertical integration and competitive procurement. The former is, of course, the traditional model for integrated vendors close to national authorities that in some cases are even able to include long-term fuel supply, maintenance and the removal of radioactive waste in their offer. This model has advantages that are recognised both in theory and in practice, such as the smooth integration of all parts and limited transaction costs through established command and control structures. Among the disadvantages, however, are inflexibility and the exercise of monopoly power.

Competitive procurement under an architect-assembler or a turnkey approach with an engineering, procurement and construction (EPC) contractor model is an alternative that holds promise but has yet to provide a sufficient number of convincing success stories. There is also some evidence that the hands-off, risk-off approach of working through EPC contractors is increasing overall costs as contractors, as well as several layers of subcontractors, hedge their respective financial exposure. This "pancaking" of financial margin on financial margin is partly responsible for continuing cost increases during the past decade.

When deciding on which financial and managerial model to choose, previous experience with NNB clearly matters. Less experienced customers will often go with relatively high-price, turnkey contracts, while customers with more experience go with multi-package approaches. However, experience also shows that NNB contains an element of residual, non-diversifiable risk related to technical, organisational and regulatory complexity. Not all risk can be diversified in a large construction project highly dependent on regulatory decisions. This brings new meaning to the seemingly old-fashioned notion of leadership, since at one point or another, someone needs to assume the residual risk and take responsibility for it.

Another major issue for the structure and efficiency of the global nuclear supply chain is the convergence and standardisation of industrial codes and quality standards. There are currently a number of private or public initiatives, such as the Nuclear Quality Standard Association (NQSA) in Europe, the Nuclear Procurement Issues Committee (NUPIC), which created the NSQ-100 standard, or the initiative on Co-operation in Reactor

Design Evaluation and Licensing (CORDEL) of the World Nuclear Association (WNA). Despite these initiatives, unification remains elusive, with the two big groups of codes, RCC-M/E and the American Society of Mechanical Engineers (ASME), continuing to exist in parallel. This co-existence impedes the emergence of a competitive global nuclear industry as it limits the scope of externalisation and co-operation between different companies. It also hinders benchmarking and an easy transferability of best practices across suppliers, which would constitute important stepping stones in the reduction of construction costs.

Regardless of the lack of global harmonisation in engineering and safety codes, the nuclear industry has nevertheless been adopting a number of technological and managerial improvements. Traceability of all components, 3D modelling or automatic welding are part of a number of incremental improvements that are nudging the industry towards higher levels of efficiency. On the management side, early involvement and training of suppliers, attention to the management of culturally diverse teams and explicit change management to prepare for unforeseeable mishaps are now part of the industry standard. Design completion before the start of production is also an important component of successful projects.

Nonetheless, it is safe to say that the global nuclear industry has not yet settled on a new equilibrium model and that different approaches that combine elements of the two reference models, the turnkey or architect-assembler model, are still being tested. The industry is clearly exploring different paths and has to some extent adopted a "wait-and-see" approach to determine if a new scalable business model will emerge from the surge in reactor constructions in Asia.

A dedicated section of the report examines the divergence between actual and estimated costs in large industrial and infrastructure projects. It asks whether "nuclear is special" and whether large cost and construction time overruns are confined to the nuclear industry, and concludes that this is not the case. "Megaprojects" in all industries are subject to similar challenges, although the past record of the nuclear industry remains slightly below that of its peers in other sectors of the energy industry in terms of building to time and budget, but this could well be a function of project size and complexity.

Design standardisation is of great importance. While there is some evidence for rising costs per MW of capacity over time across different reactor types, several studies provide encouraging evidence for cost savings as the number of completed reactors based on a particular design increases. Cases in point are France and Korea. In addition to the replication of a proven design, a key success factor is the existence of a stable regulatory and political environment with experienced stakeholders adopting a long-term view.

The third part of the report is rounded out by case studies of NNB projects at Shimane (Japan), Flamanville-Taishan-Hinkley Point (China, France, United Kingdom), Tianwan (China) and VC Summer (United States), pointing to change management and early supply chain planning, as well as "soft" features such as leadership, team building and trust, as key issues in the construction process.

Maintaining momentum

While different projects may have chosen different paths, these projects nonetheless share a number of features. On the financing side, financing capital-intensive NNB projects requires the long-term stabilisation of wholesale electricity prices, whether through tariffs, PPAs or CFDs. Empirical evidence also demonstrates that most nuclear new build projects occur in regulated markets or with the help of long-term contractual arrangements. Electricity market designs are not technologically neutral and if significant reductions in carbon emissions continue to be the objective of the electricity industry, a general rethink will be needed to determine how to finance capital-intensive, low-carbon generation technologies.

In construction, where the emergence of a competitive, global supply chain is not yet ensured, the convergence of nuclear engineering codes and quality standards remains a key step in promoting both competition and public confidence. In parallel, a number of smaller technological and managerial improvements keep the industry moving forward.

During a time of major technological, structural and geographical shifts, it is important that the global nuclear industry maintains a dynamic of continuous technological, logistical and managerial improvement at the level of the construction site, while preserving financial and regulatory stability at the level of the overall project. While it may be too soon to tell, there are sufficient promising developments under way to justify expectations for a new business model so that financially and economically sustainable new nuclear build projects can continue to emerge in the coming years.

PART I.

Introduction and overview of nuclear new build projects

Chapter I.1.

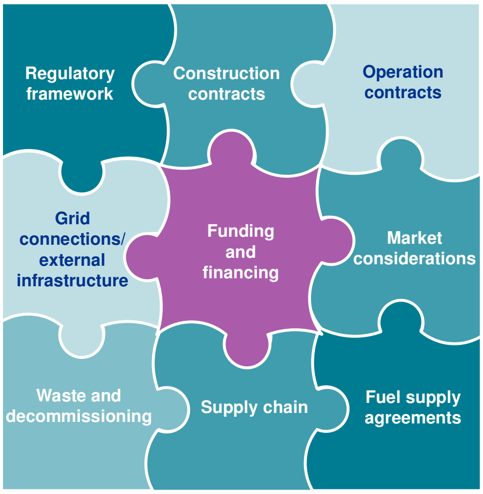
Introduction

The construction of a new nuclear power plant (NPP) is a major industrial undertaking involving a number of complex economic, technical and regulatory challenges, which also have political and social repercussions. Since the year 2000, the construction of 94 new reactors was initiated and 56 completed reactors were connected to the grid, among them the first generation III/III+ reactors. This report attempts to gather insights from a wide range of experiences that involve different countries and reactor types, as well as different legal, economic and financial arrangements. It is designed for policy makers, stakeholders and the broader public, and eadeavours to provide an overview of the principal challenges facing nuclear new build (NNB) projects, as well as with potential solutions to address and overcome them.

The report focuses on two of the most important challenges of building a new NPP: first, assembling the conditions for the successful financing of NNB projects and, second, managing highly complex construction processes and their supply chains. Using a combination of conceptual analysis, economic modelling, expert opinion and empirical case studies, this report, overseen by the Working Party on Nuclear Energy Economics (WPNE) and the Committee for Technical and Economic Studies on Nuclear Energy Development and the Fuel Cycle (NDC) of the Nuclear Energy Agency (NEA), outlines a number of key factors for successful NNB projects.

Figure 1 recalls that financing, construction and supply chain management are central pieces in the complex puzzle that needs to be assembled for a successful NNB project.

Figure 1: Nuclear new build relies on assembling a complex puzzle



Source: KPMG, 2013.

Any study of nuclear new build must deal with finance since it is at the centre of the puzzle. It is perhaps the most important and the most difficult of all the challenges that nuclear new build faces. The second part of this study focuses on the management of the construction process and the supply chain, referred to in the graph above as "construction contracts" and "supply chain". All other issues such as regulation, decommissioning, grid connection, fuel supply and operations are to different degrees connected to financing and the management of construction and the supply chain. While nuclear new build can be approached from different perspectives, this study has chosen to focus on two of the most pertinent issues.

It very quickly emerges that different pathways exist which can lead to successful nuclear new build projects under different political and economic circumstances. Thus the report does not exclude the possibility of drawing upon lessons from conceptual considerations, expert opinion or concrete project feedback. It underlines major strategic questions that can be identified, but finds that the specifics of the implementation of answers to these questions must be left to the individual project managers in countries where nuclear new build takes place.

With respect to financing nuclear new build, this study aims to demonstrate that due to its high fixed costs, a new NPP requires a stable, guaranteed level of electricity prices and hence a steady stream of revenue over a substantial period of its lifetime. Such stability is important for nuclear power to compete against other baseload technologies such as coal-fired power plants or combined-cycle gas turbines (CCGTs). It is exceedingly difficult for investors to absorb long-term electricity price risk when two-thirds or more of total lifetime costs need to be committed before the date of commissioning.

This is a cost and risk structure that nuclear power shares with other low-carbon technologies such as renewable technologies. Other low-carbon generating technologies such as hydroelectricity and renewable energies have ratios of fixed to variable costs that are even higher than those of nuclear. Variable renewables such as wind and solar, which produce energy based on the weather and not on demand, also generate a need for more flexibility in electricity systems. Technologies that could respond to this need, such as storage, demand-side management (DSM) or improved transport and distribution networks, have again very high ratios of fixed costs to variable costs. In all these cases, large upfront costs contrast with low or negligible variable costs, meaning that the long-term price risk will deter investors to a greater extent than in the case of fossil fuel technologies. Both nuclear energy and renewables have received considerable subsidies over the past decades, without these subsidies fundamentally altering their basic cost structure and economic characteristics.

This situates nuclear new build in the context of a larger question: to what extent are the two objectives of decarbonising power generation and financing fixed costs in liberalised electricity markets compatible? It is no coincidence that of the eight case studies presented in this report, seven are taking place under conditions of price guarantees or regulated tariffs and even the eighth power plant, the European pressurised water reactor (EPR) in Flamanville (France), is taking place in an environment where large shares of nuclear power production are sold at regulated prices.

This report not only makes an empirical point of the financing issue but also makes it a point of principle. In markets for non-storable commodities such as electricity, with volatile marginal cost pricing and large fixed costs, competitive markets will *not* constitute a level playing field. Volatile markets will discriminate against capital-intensive technologies even if on average their lifetime costs are lower, since the intrinsic volatility of their payoffs is higher. Financing the fixed costs of capital-intensive, low-carbon investments requires long-term electricity price stability in order to guarantee the revenue stability necessary to recoup the initial outlay.

This need for price stability should not be construed as a general contradiction between low-carbon power generation and liberalised electricity markets. Nuclear power, renewables, storage or DSM can all profitably compete on variable costs in short-term markets for dispatch (day-ahead, intraday, adjustment and balancing markets). However, it is very difficult or impossible to arrange for the long-term financing of the relatively high fixed costs of capacity in liberalised electricity markets, which holds true despite the existence of markets for the forward delivery of electricity that can offer a degree of price stability for future output. Such markets, however, trade forward for up to a maximum of three to five years, which is far too short for the amortisation of an NNB project. The present report therefore argues that nuclear new build requires coherent long-term solutions for financing.

In terms of the management of new build projects and their supply chains, the situation is different. No one single defining issue has arisen either from the conceptual analysis or the empirical case studies. However, there are a number of important developments under way that are shaping the future contours of nuclear new build. The issue for the industry is not so much whether to adapt to them or not, but rather how to find the appropriate trade-offs in a relatively fluid environment that is characterised by once-in-a-generation technological, structural and geographical change. The role of this report is to synthesise the different developments so as to provide the basis for a more informed discussion on these issues.

While technological improvements such as automated welding, 3D modelling of all design elements or advanced logistics are being progressively integrated by manufacturers, uncertainties and differences remain with respect to managing knowledge and experience, human capital and the integration of suppliers. Organising the transfer from one project to the next in order to realise the much hoped-for cost reductions in moving from first-of-a-kind (FOAK) generation III/III+ reactors to series production is a major task. Keeping experienced teams together and incentivising them appropriately is also an important issue. Reconfiguring or recreating supply chains, many of which require significant participation from domestic enterprises capable of delivering components to exacting standards is an additional issue. A major element in this context is the question of a global standardisation of engineering and quality codes, which would enable a better transfer of learning and co-operation between the major suppliers.

Although this report contains case studies of new build projects in Barakah (United Arab Emirates – UAE) and Akkuyu (Turkey), it does not focus on the specific challenges of newcomer countries in the spirit of the International Atomic Energy Agency (IAEA) Milestones document (IAEA, 2007). The report is aimed at policy makers and experts in the nuclear sector of NEA countries, most of which have a strong interest in lowering the greenhouse gas emissions of their power sectors. In many, the electricity sector is also liberalised and so the question of financing low-carbon technologies in the context of electricity price uncertainty remains pertinent. On the other hand, regulated prices prevail and objectives for greenhouse gas reductions are less stringent in many non-OECD countries.

In terms of technologies, this report provides case studies on seven pressurised water reactors (PWRs) and one boiling water reactor (BWR), which largely corresponds to their respective global market shares. Small modular reactors (SMRs) were not included in the case studies, although they constitute a benchmark model with respect to providing flexibility in financing in the face of uncertain demand. They may constitute a valid option in the future, but it is too soon to include them in a study on recently completed or ongoing construction projects.

Overall, the report aims to contribute to analysing the ability of the nuclear industry to successfully deliver NNB projects on time and on budget. It identifies a number of serious challenges, as well as a number of paths that offer promising perspectives to potentially overcome them. In assessing progress, one needs to keep in mind the long time frames involved. During a period of profound transition of the nuclear industry, it may be years before the industry re-establishes a new equilibrium configuration as a network of global competitors. An important area where OECD and NEA member countries could play a useful role is in the harmonisation of global engineering and quality standards.

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Chapter I.2.

Overview of the number, size and status of different nuclear new build projects

For a period of about 15 years following the Chernobyl accident in 1986, the construction of new NPPs was more or less on hold. The beginning of the 21st century, however, saw a renewed interest in nuclear power – particularly in economies with fast-growing electricity demand such as in China and India – widely considered a nuclear renaissance. The sometimes wildly optimistic expectations that resulted have since been lowered with the accident at the Fukushima Daiichi power plant following a major tsunami. Nevertheless, a substantial number of nuclear plant construction projects remain active all around the world. Data from the World Nuclear Association (WNA) database show 227 new NPP projects, of which 68 are actually under construction and a further 159 are being planned (see Table 1). The largest single market today is China, with 56 reactors planned and 27 reactors under construction.

Table 1: Reactors currently under construction or planned

Region	Under construction	Planned
Europe	4	19
Russia and Former Soviet Union	11	30
China	27	56
Rest of East Asia	10	10
West Asia (Middle East)	2	8
South Asia	7	24
South East Asia	--	4
Africa	--	1
North America	5	7
South America	2	--
Total	**68**	**159**

Source: Based on WNA database.

Most of the reactors under construction are pressurised water reactors (PWRs), in part reflecting the geographical concentration in China and the Russian Federation. Although the first generation III/III+ plants are starting to be built, the majority of those under construction remain generation II designs. The distinction between generation II and III/III+ plants is not completely clear-cut. One of the major differences is that generation III/III+ plants include more passive safety systems as opposed to systems that require active controls or operator intervention in the event of malfunction (NEA, 2008).

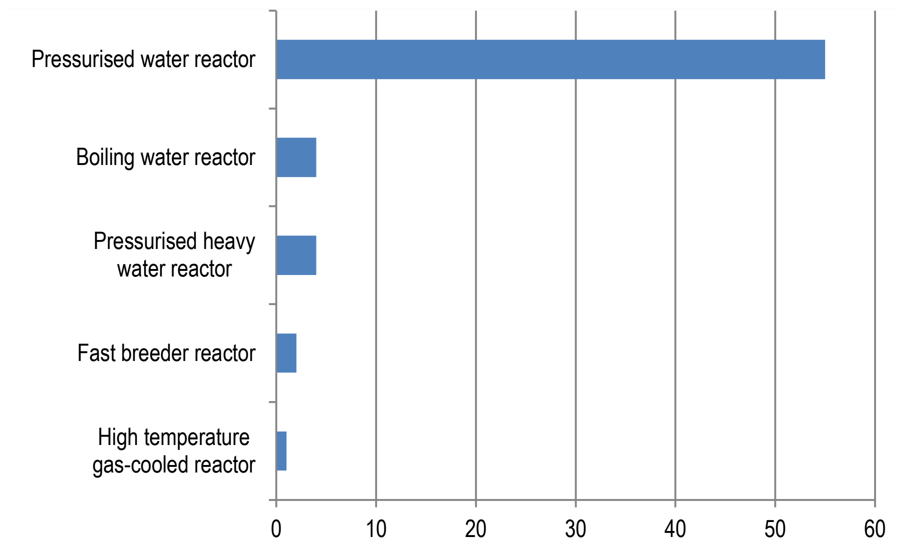
The WNA reports a further 159 plants that are planned or ordered, including 25 in Russia, 56 in China and 20 in India. Compared with the current operating fleet of 435 reactors worldwide, this represents a geographical shift from the United States and Europe towards Asia and especially China. The technologies for the plants that are planned but have not yet began the construction phase are not all selected, but it is likely that an increasing proportion will be of generation III/III+ design. The WNA estimates that the total value of planned new build is estimated to be approximately USD 1 200 billion.

The procurement and delivery models adopted by developers of new plants vary considerably. According to a survey by the consulting company Arthur D. Little, roughly half of all new projects where a delivery model has already been decided will adopt a turnkey contract approach (Arthur D. Little, 2010). There is also evidence that turnkey contracts are the favoured approach where the developer is either a new entrant to the nuclear market or is relatively inexperienced. However, in cases where the developer is more experienced, there is a mix of approaches. While there is relatively little variation in contracting approaches between different reactor technologies, there is a difference according to geography. Developers in Asia are comparatively more likely to favour multi-package approaches to procurement over turnkey contracts. This is discussed in greater detail in Section III.3.3.

For reactors currently under construction, the IAEA Power Reactor Information System (PRIS) database provides data on reactor new build that is very similar to the data provided by the WNA but with a slightly different geographical breakdown. Figure 2 starkly underlines the dominance of PWRs in recent nuclear new build.

Figure 2: Reactors currently under construction by type

Total number of reactors: 66

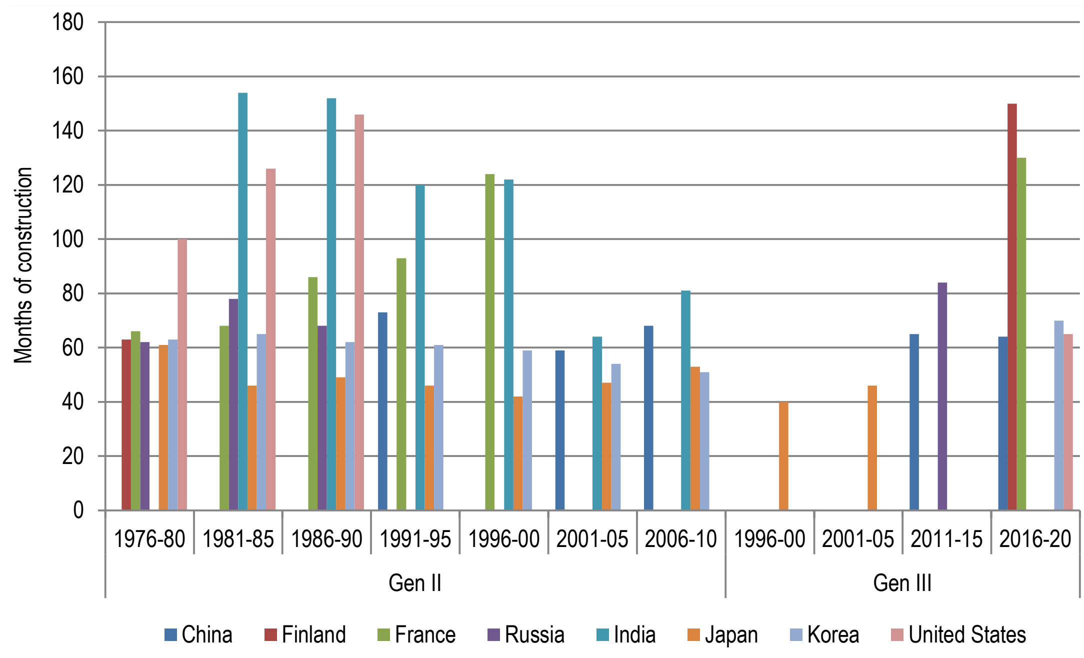


Source: IAEA, 2015.

In a study that is ultimately about the identification of factors that determine the success of NNB projects, an important question is the length of time that it takes to complete the construction of a new reactor. Figure 3, compiled by the NEA on the basis of the IAEA's PRIS databases and press reports, provides a complex picture that allows for three observations. First, there was a period lasting roughly from 1980 to the year 2000 during which construction times for new reactors in many countries actually declined. This concerns in particular India and Korea. It was also a time during which generation II reactors reached maturity and were able to exploit global economies of scale. Overall good performance during the 1990s was also the result of the numerous starts of reactors resulting from the new generation II nuclear construction projects during the 1970s and 1980s.

Important exceptions are France and the United States, both of which have very important new build programmes. In these countries, construction times increased considerably after 1980, to up to 90 months in France and to over 140 months in the United States, mainly due to heightened regulatory concerns. The reasons vary and are still subject to debate (see also Chapter III.3). In France, subsequent designs became more complex. In the United States, regulatory oversight tightened after the accident at Three Mile Island in March 1979.

Figure 3: Construction times for recently built generation II and generation III reactors



Source: Based on IAEA PRIS database and press reports.

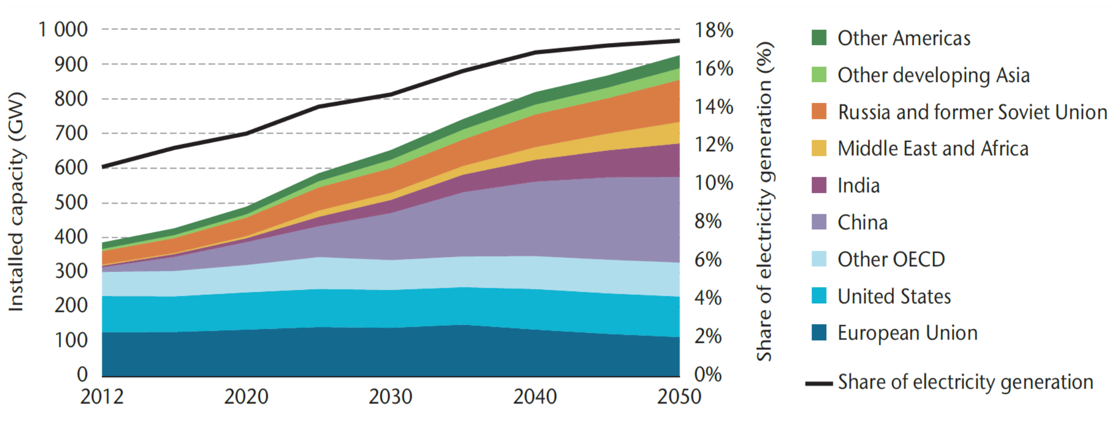
Generation III/III+ reactors offer a different picture, with two widely commented on outliers in Finland and France. This brings us to the second observation: economic cycles in nuclear new build are exceedingly long and can span two or three decades. The change from one generation of reactors to another is a very particular moment in the history of nuclear construction and any judgements about the economic success of the new generation are probably best withheld for another decade.

The third observation is that construction times in East Asia (China, Japan and Korea) have been on average lower than in other regions of the world. While technological choices may have played a role to some extent, for example in favour of generation III/III+ advanced boiling water reactors (ABWR) in Japan, the industrial performance is nonetheless impressive and will be reviewed in the case studies on the reactor projects at Shimane, Taishan and Tianwan (see Chapter III.5). East Asian markets have been more successful in capturing the learning effects from the construction of a series of plants. They have benefited from the scale of their programmes, with fleets of the same reactors being built rather than just one or two, and also from lower labour costs and concerted political support for their construction programmes. According to industry, East Asian projects have benefited from the adoption of improved project organisation, and in particular, from better relationships between the contracting parties that have a shared focus on the successful delivery of the project as a whole. An important element of this success is a much stronger emphasis on developing the design, both of the physical plant and of the construction process, to an advanced stage before construction begins. And once construction does commence, any changes to design or construction plans are vetted rigorously.

Following the numerous starts of new construction projects during the 1970s and 1980s with a record of 37 new reactor constructions having been started the world over in the year 1969, the period between 1985 and 2005 saw on average less than five new projects starting per year. The Chernobyl accident in 1986 is, of course, the most straightforward explanation for this change. Construction starts inched up to 15 units a year from 2005 to 2010 during a brief nuclear renaissance, until the accident at Fukushima Daiichi. Since then, there have been seven construction starts in 2012 and ten in 2013. The nuclear industry is thus very much on a knife-edge between an insufficient number of plants to gain significant economies to scale and a number that will allow it to grow to an economically sustainable size.

The slowdown in orders has been partly reversed and most projections of demand for NPPs suggest a period of growth, notwithstanding the delays and cancellations in some countries in response to the Fukushima Daiichi accident. The *Technology Roadmap: Nuclear Energy* (IEA/NEA, 2015) produced jointly by the NEA and the International Energy Agency (IEA), and based on limiting CO_2 emissions to contain global warming to a 2°C rise in average global temperatures, targets a nuclear capacity of 900 GW by 2050, up from 370 GW in 2011 (see Figure 4). Assuming that all reactors operating today are decommissioned by 2050, this would require a global programme of commissioning more than 25 reactors of an on average capacity of 1 GW for each year from 2010 to 2050. Taking into account the opportunity for life extensions of existing plants and the trend towards plants larger than 1 GW, this implies almost a doubling of the global construction programme up to 2020, with a proportionate expansion of the equipment supply chain.

Figure 4: Nuclear generation capacity in the 2-degree scenario (2DS) by region



Source: IEA/NEA, 2015.

The underlying rationale of such a significant increase in global nuclear new build is evident, namely the ability of nuclear power to contribute to the reduction of global greenhouse gas emissions. Nevertheless, attaining this ambitious objective would require addressing the challenges posed by the financing of the large fixed costs of new nuclear reactors, as well as by the management of the complex construction process and its supply chain. It is the purpose of this report to outline the possibilities for successfully mastering these two challenges.

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PART II.

The importance of long-term solutions for electricity price stability and financing as a condition for successful nuclear new build

Chapter II.1.

The value of electricity price stability for nuclear energy

In recent years, financing has proven to be one of the most important hurdles for nuclear new build. Aside from the high and rising overnight cost for new plants, a key issue in this context relates to nuclear energy being a technology with a high ratio of fixed costs to variable costs. High fixed costs constitute a challenge for investors in all industries. The need to mobilise large amounts of capital before first revenue is earned implies a high level of commitment since once the plant is completed the investment decision can no longer be adapted to the market environment. The costs are sunk. This is of particular concern in many NEA and OECD countries where the liberalisation of electricity markets and the introduction of large shares of variable renewable energy has reduced the level of electricity prices and has increased their volatility.

An earlier NEA report on *The Financing of Nuclear Power Plants* (2010) had constituted a first attempt to address the fact that nuclear power as a large, high fixed-cost technology was confronted with a number of specific issues. While many of the general conclusions of the 2010 study go beyond the issue of financing, they still remain valid today (Box 1).

Box 1: Main conclusions from *The Financing of Nuclear Power Plants* (2010)

Key actions to be considered by governments that wish to see investment in new NPPs include:

- Provide clear and sustained policy support for the development of nuclear power, by setting out the case for a nuclear component in energy supply as part of a long-term national energy strategy. Winning public acceptance of a role for nuclear power in meeting environmental goals while providing secure and affordable energy supplies must be accomplished at the political level.
- Work with electricity utilities, financial companies and other potential investors, and the nuclear industry, from an early stage to address concerns that may prevent nuclear investment and to avoid mistakes in establishing the parameters for new NPPs. The government will need to take an active role in facilitating nuclear projects, even where investment is to be made by commercial entities.
- Establish an efficient and effective regulatory system which provides adequate opportunities for public involvement in the decision-making process, while also providing potential investors with the certainty they require to plan such a major investment. A one-step licensing process with pre-approval of standardised designs offers clear benefits in this regard.
- Put in place arrangements for the management of radioactive waste and spent fuel, with progress towards a solution for final disposal of waste. For investors in NPPs, the financial arrangements for paying their fair share of the costs must be clearly defined. A stable framework for nuclear insurance and liabilities must thus be in effect.
- Ensure that electricity market regulation does not disadvantage NPPs. Long-term arrangements may be necessary to provide certainty for investors in NPPs, reflecting the long-term nature of nuclear power projects. Where reducing CO_2 emissions is to act as an incentive for nuclear investments, the government may need to provide some guarantees that policy measures will keep carbon prices at sufficiently high levels. Allowing nuclear projects to generate carbon credits could also provide incentive, provided the policy was sufficiently long term.

Source: NEA, 2010: 56.

The present study concentrates on the final point of the conclusions in the 2010 study. It thus tightens the focus on finance and deepens the analysis of the specific challenges that nuclear faces in this area. In particular, it provides quantitative estimates of the comparative disadvantage that nuclear energy faces in electricity markets with uncertainty about the long-term average level of electricity prices.[1] In the same framework, it also discusses the benefits of remediating instruments such as long-term contracts as well as the different risk implications of different ratios of fixed cost to variable cost for bondholders and equity investors. Based on recent data from European electricity markets, this has yielded new insights on:

- the importance of long-term electricity price stability, and hence revenue stability, for new nuclear projects in comparison with gas-fired power generation;
- the economic value of long-term pricing arrangements such as contracts for difference (CFDs) for risk-averse investors with and without mark-ups over market prices;
- the impact of different market designs on the technology choices of private investors;
- the financial impact of different price scenarios on the present value of new nuclear projects, taking into account taxation and different debt-equity splits;
- the specific risk exposure of debt and equity holders, if a nuclear project turns out to be worse than expected.

Apart from the large absolute size of NPPs which, in principle, should not pose an issue for the large and liquid global markets available for investment finance, the key issue for investors is the short-run and long-run volatility of electricity prices. Such volatility is due to the fact that electricity is a non-storable good and, at the same time, a vital necessity with low price elasticity. Non-storability implies that electricity systems require a high level of capacity able to cover even the most extreme peak demand but will be working most of the time at overcapacity with prices that equate to variable costs of the marginal technology. Due to the absence of electricity storage and the variability of demand, prices also vary considerably according to the time of day, the weekdays, the season, economic growth or the weather. The fact that electricity is a vital necessity means that demand is not very price-sensitive, in particular in the short-run, and can adjust only if demand-side management is available. An additional difficulty derives from the fact that all but the largest customers pay a fixed tariff which does not reflect the real conditions of supply and demand and thus the actual cost of electricity production.

Given the intrinsic difficulties of equating prices and costs due to non-storability, electricity in NEA and OECD countries was traditionally supplied by integrated monopolies under regulatory regimes, whose key objective was to devise electricity tariffs that would provide financial security for adequate, socially and politically determined, amounts of capital-intensive investments, so-called rate-of-return regulation. There is broad consensus among experts, that rate-of-return regulation works well with respect to investment levels and security of supply but that it can also lead to costly over-investment (gold-plating), operational slack and a lack of industrial dynamism.

1. If not indicated otherwise, the term "electricity price" refers to prices on the electricity wholesale market or to the wholesale tariff set by the regulator. In either case, the term "electricity price" refers to the bulk revenue obtained by producers for their sold output. It does *not* refer to the final end-use prices paid by households or commercial and industrial consumers.

The subsequent shift towards competitive electricity markets benefited from a general movement of market liberalisation in the 1980s but was primarily enabled by the advent of the CCGT. With total fixed costs measured in the low hundreds of millions rather than billions of US dollars for economically advantageous sizes and a ratio of fixed costs to lifetime variable costs about one-to-two (rather than about two-to-one for an NPP), CCGTs seemed to make free market competition in electricity a realistic alternative. In addition, gas as the marginal fuel was setting electricity prices under competition which provided CCGTs an automatic hedge against variations in the fuel price.

Combined with an increasingly complete transport infrastructure as well as new discoveries, notably in the North Sea, CCGTs constituted the technology of choice in OECD Europe and North America during the 1990s and early 2000s. Nuclear power, during this period, had not only to absorb the shock of the Chernobyl accident but also found itself an increasingly risky investment proposition on financial grounds, as far as new build was concerned. Already constructed nuclear plants continued reliably producing large amounts of electricity at comparatively low variable costs. Low variable costs imply stable output and sales. As long as average electricity prices held up, nuclear power was exposed to very little revenue risk even in liberalised markets with competitive dispatch. This allowed owners and operators to recoup their outlays and more over the decades largely independent of the market environment. Major accidents apart, it would be a challenge to find a commissioned NPP that has lost money for its owners.

However, the economics of NPPs are characterised by two very different phases with starkly contrasting risk features. While the operational phase is exposed only to modest risks pertaining to technical interruptions and variations in the fuel prices, it is the financial risk during the construction phase, with its high fixed costs, that currently constitutes the greatest barrier to nuclear new build in NEA and OECD countries. This study therefore concentrates on the comparison of nuclear plants with gas-fired CCGTs, an alternative in the production of dispatchable baseload electricity with very different cost characteristics.

Coal-fired power generation remains, of course, in principle an additional option in this context with its fixed costs lying squarely between those of a nuclear or a gas plant. Very recently, coal-fired power generation has even enjoyed somewhat of a comeback in European OECD countries due to the decline in coal prices following the shale gas boom in the United States and the collapse of the carbon price in the EU emissions trading system (EU ETS). Coal essentially depends on the carbon price. Without a price on carbon emissions, the levelised costs of electricity (LCOE) of coal are quite favourable in many different regions of the world. Its competitiveness, however, declines rapidly as soon as robust carbon-pricing with USD 20 per tonne of CO_2 or higher is introduced. Given long-term climate constraints and in the absence of progress on carbon capture and storage, increasing the share of coal is currently not considered a serious option for the electricity supply of NEA and OECD countries in the longer run. In a study of the competitiveness of nuclear as a dispatchable source of baseload power, today the proper comparison is with CCGTs.

For different reasons, comparing the financing challenge for nuclear new build with that for renewables would not have yielded any interesting insights either. With the exception of geographically constrained hydropower, the deployment of renewable energies for electricity production is still driven by subsidies, given their current high cost. This eliminates of course any financing challenge. In addition, the variability and dependence on local weather conditions of renewables such as wind and solar creates a number of supplementary system costs in terms of balancing, added transport infrastructure and back-up (see NEA, 2012). When it comes to supplying the bulk of around-the-clock, baseload electricity, the choice, as far as electricity systems operating under even a modest carbon constraint are concerned, remains essentially one between nuclear and gas.

The comparison of the net present value (NPV) of an NPP with a gas plant allows for a focus on the decisive issue of the vulnerability of technologies with different cost structures to changes in the average price level in liberalised electricity markets. A change in the level of electricity prices is equivalent to a change in revenue. Although a nuclear plant will presumably continue to produce the same amounts of output as before, its revenue will fall due to the decline in price.[2] The gas plant will continue to produce *only* during hours when prices are still higher than its already high variable costs but since this now happens only during a limited number of hours, its output and also its revenue will fall. Such load factor risk has been integrated in the model devised by the NEA through an explicit daily dispatch for conventional power plants (nuclear, coal, gas) over a five-year period. This allows modelling load factor risk explicitly as a function of different price scenarios.

In other words, both nuclear and gas will lose revenue but for different reasons. Nuclear will lose revenue because of lower average prices, gas because of a reduced number of load hours. The stabilisation of electricity prices would solve both issues. The decisive point, however, is that independent of the economics behind the drop in revenue, investors in an NPP will suffer more from the price drop than investors in an equivalent gas plant with identical levelised costs of electricity (LCOE). This is due to the relatively higher fixed costs of the nuclear plant, which constitute a high level of economic commitment. Investors in the gas plant retain a level of flexibility which is akin to having the option of partially or completely leaving the market when conditions have changed.

Due to its favourable cost structure, gas has been relatively successful in attracting finance and expanding capacity as far as NEA and OECD countries are concerned. In 1990, the capacity for nuclear and gas-fired power generation in these countries was almost at par, with gas-fired capacity at 254 GW and nuclear at 267 GW. Since then, gas-fired capacity has almost trebled to 695 GW in 2011, whereas nuclear capacity has increased only slightly to 307 GW (IEA, 2013).

This does not mean that gas-fired power generation is devoid of risks. Gas-fired power plants, for instance, have proven vulnerable to changes in demand and the influx of low-cost renewables. As the marginal units they are the first to fall out of the merit order when residual demand declines and are therefore exposed to load-factor risk. During the last two years, this has led to temporary shutdowns in Europe of about 35 GW of gas-fired capacity with considerable losses for the owners and concomitant risks for the security of electricity supplies.

Gas is also struggling to make a credible claim of constituting a low-carbon generating choice. While emitting only roughly half as much CO_2 per MWh as coal, at around 400 kg of CO_2 per MWh, gas is hardly a low-carbon fuel. Compared to nuclear, gas-fired power generation is also more import-dependent. There are few domestic sources of natural gas in OECD Europe and OECD Asia, which means gas-fired capacity is exposed to changes in international prices or even the occasional physical interruption. The recent tensions between the European Union and Russia over Ukraine have highlighted the extent to

2. It is possible to think of cases where nuclear power could be exposed to load factor or output risk. This would be the case when technologies with short-term variable costs *lower* than those of nuclear would produce output that is greater than residual demand once nuclear output is deducted from total demand. Only variable renewables such as wind and solar photovoltaic (PV), as well as hydropower, have short-term variable costs lower than nuclear power. However, to reduce the load factor of nuclear, these technologies would need to have very large shares of total electricity production. Even in countries with combinations of large amounts of renewables and nuclear such as Spain, Switzerland or Germany, the number of hours during which nuclear output is reduced due to renewable production is very limited. Instead, what affects the profitability of nuclear plants strongly in all three countries is the decline of average electricity prices induced by new wind and solar PV capacities.

which natural gas remains subject to geopolitical risks regarding security of supply. While there are hopes that an emerging global infrastructure for liquefied natural gas will reduce dependence on individual producers or transit countries in OECD Europe, this is a process that will need decades to fully play out.

The key advantage of gas-fired power generation is its more favourable fixed cost to variable ratio rather than overall lower LCOEs. This has overcome all other factors, which otherwise may have weighed against further increasing investment in gas-fired power plants. Its lower fixed cost to variable ratio provides gas with a distinct advantage over nuclear when facing the uncertainty surrounding future electricity prices. A break in the long-term level of average electricity prices will affect investors in both types of plants. However, the losses of a gas-fired plant will be lower than those of an NPP of the same size.

This report aims at assessing the size of this advantage and evaluating the impact of long-term pricing arrangements on the competitiveness of nuclear in this context. Chapter 2 examines the importance of long-term electricity price stability for new nuclear projects in comparison with gas-fired power generation and discusses the resulting impact of different market designs on technology choices. Chapter 3 looks at how different financing structures and investor groups are affected by these risks. Chapter 4 presents three case studies on recent NNB projects which assembled successful financing packages, and Chapter 5 concludes Part I with a number of policy conclusions.

II.1.1. Dealing with risk in the study of nuclear new build

Chapter 2 concentrates on the respective exposure of gas-fired and nuclear power generation to electricity price uncertainty.[3] Its key results concern the impact of a lack of long-term electricity price stability on the competitiveness of new nuclear projects and the economic value of long-term pricing arrangements such as CFDs for risk-averse investors with and without mark-ups over market prices. A concluding section reviews the impact of different market designs on the technology choices of private investors.

The analysis takes place in a framework of NPV comparisons. The NPV methodology is a simple, transparent and frequently used methodology for cost comparisons. It considers individual plants in isolation, summing up their discounted costs and benefits over their lifetimes. This allows for easily understandable results, which can provide a general understanding of the issues and orders of magnitude at stake for energy experts, policy makers or even future investors. This study also includes an analysis of the variability of NPV under different scenarios and shows how different technologies react differently to changes from the baseline scenario, amounting to different risk profiles for investors. These scenarios can be interpreted as representing different constellations of the demand for electricity from dispatchable technologies such as nuclear and gas, based on different levels of penetration by renewables with low marginal costs.

Nevertheless, such scenario analyses should not be confused with a simulation for a real-world nuclear investment project. In the latter case, many other issues, such as portfolio issues, would inevitably come into play. A diversified electric utility would thus

3. In the classic distinction introduced by Frank Knight, “risk” refers to random future events whose probability distribution is known, while “uncertainty” refers to future events whose probability is unknown. The distinction is economically relevant to the extent that risk can be priced and can be diversified through dedicated markets. Uncertainty, however, cannot be separated from the agent responsible for initiating and operating a project, referred to by Knight as the “entrepreneur”. In keeping with common usage, this report does not distinguish between “risk” and “uncertainty”. However, whenever relevant, it refers to non-diversifiable risk as “residual risk” or “residual uncertainty”.

look at the correlation of the specific financial risks of either nuclear or gas with those of all its other generation investments. Financial portfolio investors would do likewise at the level of the totality of the investment choices available to them (assuming that they are capable of understanding and managing them at the same level as the diversified utility). The simple NPV methodology considered here and in the following chapters does neither, but instead concentrates on a small number of clearly spelled out specific issues that in a real-world investment case would have to be combined with the country-, technology- and market-specific parameters of the project.

The simple, plant-level NPV methodology used here is comparable to the methodology of establishing the LCOE employed in several NEA reports. The key difference between the two methodologies is that, in NPV calculations, electricity prices are *exogenous* variables, while LCOE calculations establish the implicit price of electricity at which the NPV is zero.

Both methodologies are routinely criticised for being unable to appropriately value risk. This is only partly true. NPV and LCOE calculations work by discounting the annual streams of costs and benefits. The discount rate chosen will reflect the opportunity costs of capital, in other words the private or public cost of funds, which is the weighted rate of the interest rates demanded by debt and equity investors. If investments in the electricity sector are considered risky, a higher interest rate should be chosen to reflect this and, of course, careful studies should provide results for different levels of interest rates and risk perceptions.

This manner of considering the cost of capital as a composite measure of all risk pertaining to an investment project is an acceptable short-cut in studies that compare different technologies across different countries, which require simple, transparent and above all comparable parameters for their LCOE or NPV calculations. It is an unsatisfying measure, however, when more detailed answers to specific risk parameters are being sought. The following list provides a non-exhaustive overview of the different dimensions of risk or uncertainty that might be of interest in the context of a more complete evaluation of the attractiveness of an individual electricity generation project:

- Different technologies are exposed to different levels of losses in the case of a fall in long-term average electricity prices, which translates into higher or lower investor risk. This is due to technologies with a lower ratio of fixed costs to variable costs holding the option to exit an unattractive market with a relatively low share of total funds spent. Technologies with higher fixed to variable cost-ratios, which already spend a large share of funds before commissioning, do not hold such an option. This high level of pre-commissioning commitment adds to overall investor risk.
- While high fixed cost technologies are exposed to long-term price risk, high variable cost technologies are exposed to short-term changes in demand. Since they are the first to leave the merit order when demand declines, the load factors of high variable cost technologies such as gas-fired power plants can decline quickly if demand temporarily decreases such as, for instance, if there is an influx of large amounts of variable renewables.
- Future variable production costs depend on the uncertain and volatile prices of certain input factors, typically fuel. The importance of this particular dimension of risk depends on the share of fuel costs in total production costs. High variable cost technologies such as gas are more vulnerable in this respect than low variable cost technologies such as nuclear.[4]

4. The first three bullet points in this list demonstrate that one cannot make generalisations of the type “low fixed cost technologies are less risky than high fixed cost technologies” or vice versa. Technologies are exposed to particular risks, for instance electricity price risk under point 1,

- In the face of uncertainty about the evolution of electricity demand, there is value in the ability to scale projects in successive steps. Such flexibility can be provided by technologies that can be sub-divided into several smaller units with lower absolute fixed costs. A typical example is constituted by SMRs, which currently are still in the design and development phase, since investment commitments can be dynamically adapted to market conditions in this case. Of course, such flexibility advantages would have to be weighed against potentially higher per unit costs of investment.
- In liberalised electricity markets, prices reflect the costs of the technology with the highest variable costs plus a mark-up. This means that high variable cost technologies such as gas, usually set the electricity price and thus earn a relatively stable mark-up, whereas technologies such as coal and nuclear will be exposed to short-term variations in their revenue according to changes in the gas price and the level of electricity demand.
- Different technologies react differently with respect to accompanying measures designed to reduce long-term profitability risk, such as CFDs, feed-in tariffs (FITs) or regulated prices, which reduce in particular the risk of technologies with high fixed costs, or typically low-carbon technologies.
- Each accompanying measure will affect differently the specific risks to which different groups of investors are exposed. On a first level of analysis, this is obvious. Loan guarantees will thus primarily protect bondholders. On a second level of analysis, however, loan guarantees will be far more valuable in projects with an "all-or-nothing" profit profile (typically high variable cost projects such as gas that will leave the market if the market environment worsens) rather than projects such as those which will continue operations despite high overall profitability risk.

This study is particularly interested in evaluating the two dimensions of risk mentioned under point 1 (the value of being able to exit a market with declining prices), point 6 (the value of a fixed-price contract such as a CFD) and point 7 (the impact of a loan guarantee on borrowers and equity investors). All three points have thus far been little addressed in the literature.

Points 2, 3, 4 and 5 have already been discussed at different moments in economics literature. Point 2 (the vulnerability of short-term profits of high variable cost technologies due to reduced load factors) was discussed in NEA (2012: 103-155). Point 3 (the vulnerability of LCOE and NPV to changes in the cost of inputs) has been the subject of extensive sensitivity analyses with respect to changes in factor prices based on empirical data in IEA/NEA (2010: 105-139). Point 4 (the advantage of smaller absolute sizes in investment projects when demand is uncertain) has been discussed in Locatelli and Mancini (2011). Point 5 (the extent to which the variability of short-term profits depends on the position in the merit order) has been discussed in a series of papers by Roques, Newbery and Nuttal (2008: 1831-1849), which underline that the "automatic hedge" enjoyed by the profits of gas-fired plants reduce the diversification benefits of nuclear power.[5]

In developing points 1, 6 and 7, this study aims first and foremost to provide a fuller picture of the risks that project developers, utilities and investors are exposed to when undertaking new electricity generation projects in general and new NPPs in particular.

load factor risk under point 2 and fuel price risk under point 3. It is up to the investor to compare the different risk parameters in each case and choose the technology accordingly.

5. The "automatic hedge" argument has lost some empirical relevance as the influx of variable renewables has shown that the position of gas as the marginal technology constitutes a risk as much as a benefit. While the marginal technology is protected against changes in fuel costs, it is also the first to leave the merit order once low-cost alternatives come on the market.

When discussing contacts for difference (fixed-price contracts) and loan guarantees, the study assesses in a second step the value of such measures and the size of the contribution they can make to the successful financing of nuclear new build.

II.1.2. Long-term electricity price stability and the competitiveness of new nuclear projects

The key argument in this section is that in liberalised electricity markets where the long-term level of average electricity prices is uncertain, the ratio of fixed to variable costs is an important determinant of investment choices. This work can be considered an extension of the basic LCOE methodology that was used in a number of previous NEA studies (NEA, 2010, 2011 or 2013). The latter remains a valid tool for assessing the social resource costs of different technology options under price certainty. It is thus particularly useful in electricity systems where electricity prices are regulated. Without complementary analysis, however, it does not specifically reflect price risk.

The argument that the ratio of fixed to variable costs is an important consideration for investors is quite intuitive. Consider two generation projects that are equivalent in terms of capacity and electricity production and which, over a lifetime of 40 years, will accrue EUR 1 billion of total costs in present value terms. However, with project A, 80% of these costs, or EUR 800 million, need to be committed before the date of commissioning, while the remaining 20% will be spent over the next 40 years. With project B, only 20% of total funds, or EUR 200 million, will need to be committed before commissioning, while 80% are due to be spent over the next 40 years. If electricity prices remain stable over these 40 years, both projects will, net of tax considerations, yield the same amount of profit.

With even small amounts of uncertainty, investors will choose project B over project A. In a deregulated electricity market, the level of electricity prices is certainly the most important source of uncertainty. In addition, other than price risk, a myriad of other sources of uncertainty exist in real life. The latter can range from political, social or regulatory risks to natural disasters or technology risks (think of a cheaper source of electricity, for instance). In each of these cases, disbursing EUR 800 million rather than EUR 200 million means putting a higher share of total capital at risk early on.

The flexibility of the two projects in the face of uncertainty, or their response option, is thus not the same. If market conditions permanently deteriorated, say, by falling significantly below the variable costs of project B, the latter would leave the market. However, its losses would be limited to EUR 200 million. Project A, however, would have lost already EUR 800 million. Even though it could hope to regain some of these EUR 800 million during remaining operations, its total losses are likely to be higher than the losses of project B. Contrary to appearances, staying in a market with declining prices while competitors exit is not necessarily a sign of superior financial performance.

Technically speaking, Project B holds a real option (i.e. exiting the market if prices fall) that is more valuable than the equivalent option for project A.[6] The term “real option” was introduced independently but simultaneously by Arrow and Fisher (1974) and Henry (1974). It became a widely used concept in the wake of Dixit and Pindyck (1994). A real option provides the ability to react when new information, typically information about new price movements, is incoming. Possessing a real option means not being tied down

6. It is, in fact, very unlikely that project A will ever draw on its option to exit the market prematurely, which it possesses in theory. With its low variable costs, it will typically continue producing electricity even if prices have fallen permanently and it no longer harbours any hope of ever recouping its fixed costs. In other words, for a high fixed cost technology, the value of the option to exit is zero.

by irreversible commitments, typically a fixed investment that is sunk and can no longer be reversed.

Much of the real option analysis in the wake of Dixit and Pindyck is done by calculating the value of an option in the manner familiar to financial economists, i.e. by using the Black-Scholes formula for solving a partial differential equation on the basis of a continuous random walk (geometric Brownian motion) modelling the relevant underlying movement in prices (e.g. Rothwell, 2006). The present study takes a more pedagogic and far simpler approach. The value of the option to abandon a project, i.e. to exit the market either completely or partially, is not generated by a random walk but by a one-time, discrete decline in electricity prices. The fundamental principle remains the same: the value of the option to be able to exit the market is the difference between the NPVs of the projects with and without the option.

The price of a real option thus indicates the value of the flexibility it provides. Frequently, this value is also referred to as the "value of being able to wait". More correctly, a real option indicates the benefit of avoiding an irreversible action that would no longer allow reacting once the economic environment changes. Holding a real option means possessing flexibility or, equivalently, enjoying insurance. Just like a financial option which allows selling (put option) or buying (call option) an asset at a pre-agreed price, usually to insure against unfavourable movements in the price of the underlying asset, a real option provides the flexibility to reverse course if prices take an unfavourable turn. The difference between a financial option and a real one is that the latter is embodied in the physical or economic structure of a project rather than in a paper claim on a financial counterparty.

Project B, the project with the relatively lower fixed costs, thus possesses a real option in the sense that it is flexible in reacting once new information such as an electricity price decline comes in. Its option is that it can leave the market with limited losses, since only a small share of its total lifetime costs have been irreversibly committed. This option holds real economic value for investors in project B. They know that even under adverse circumstances, their losses will be limited.

As mentioned above, project A, the project with the high fixed costs, does not have the same option or, more precisely, its option to exit the market has no value, and thus it will never use it. Project A could of course leave the market once prices fell but it would never do so, as the vast majority of its funds have already been committed. Its low variable costs will enable it to eke out some positive revenue. However, the profits it will make over variable costs will never be enough to pay back its huge, initial investment costs that are irreversibly sunk. Despite staying in the market after the price-fall, losses for its investors will actually be larger than for the investors in project B.

This study assesses the difference in NPV due to the option value arising from a lower ratio of fixed to variable costs by comparing a nuclear plant with characteristics similar to project A to a gas plant with characteristics similar to project B. In a simplified framework, we determine the value of the flexibility that investors in the gas plant possess given that they have irreversibly committed only a relatively small amount of funds at the time of commissioning. In other words, we value their option to exit the market, fully or partially, by not producing and thus not incurring costs when prices are low.[7]

7. The option to exit the market is also referred to as the "abandonment option" by Min et al. (2012). In this exercise, the option to exit or abandon the market is modelled simply by the fact that the gas plant does not produce when electricity prices fall below its variable costs. The term "suspension option" of a plant was used in NEA (2011) however "an option for completely or partially exiting the market" constitutes a more complete indication of its function.

Once prices have dropped, the value of this option to exit the market is the difference between the decline in NPV of the technology with high fixed costs (nuclear) and the decline in NPV of the technology with low fixed costs (gas). In other words, the value of the option is the price investors in the nuclear plant would have been willing to pay to possess the same degree of flexibility.

In order to calculate the value of the option to exit the market for the gas plants with its small fixed costs in a simple and transparent manner, the model works with a small number of highly stylised assumptions:

- Both technologies possess the same LCOE and thus the same NPV in the absence of a price fall. In other words, if prices were guaranteed over the lifetime of the two plants, their NPVs would be identical. Under electricity price stability, the option to exit the market would have zero value. This refers to the point made above that a real option has value only as an instrument to react to newly incoming information, thus providing insurance if needed.
- For simplicity and clarity, it was assumed that a henceforth permanent fall in average prices of 30% would manifest itself immediately after the date of commissioning. The model can accommodate price falls at later stages of a plant's life or of different magnitudes but does not work with the moving averages typical for random walk processes. A 30% electricity price decline is comparable to the scenario currently playing out in European OECD countries due to the entry of significant amounts of subsidised renewables.
- The exit option can only be exercised after decommissioning. In fact, the value of the real option of the gas plant would be reduced if information of a price fall was forthcoming during construction, and further investment in the nuclear project could be stopped before the date of commissioning.
- In order to concentrate on the notion of option value, the only source of uncertainty modelled in Chapter II.1 was the electricity price. In the real world, other sources of uncertainty exist such as the cost of construction, fuels and operations or political risk. The financial model in Chapter II.2 also includes the impact of risk in construction, fuels and operations albeit without accounting for option value.

In the electricity sector, the most important irreversibility remains investment in fixed capacity. Again for reasons of simplicity, all investments in the fixed costs of a power plant were considered irreversible (see Box 2 for discussion). Fixed cost is the sum of expenses necessary before the date of commissioning. As spelled out in IEA/NEA (2010), this includes expenses for engineering, procurement and construction (EPC) as well as interest during construction (IDC).

Even if investment in fixed costs can be considered irreversible for all power generation technologies, its size varies considerably, and concerns not only the absolute size of a given technology. The latter may play a role in credit-constrained markets, but it is usually not of primary concern in NEA and OECD countries with large, liquid and sophisticated financial markets. Differences between technologies concern first and foremost the ratio of fixed to variable costs or the share of fixed costs in the total lifetime production costs of a given technology.

Box 2: Are the fixed costs of investment always irreversible?

Not all investments in fixed capacity are irreversible investments in the sense of being completely "sunk costs". Reversible investments are those that can be transferred at reasonable costs from one market to another. This is not only a theoretical consideration. The vast movement of liberalising formerly regulated markets in the 1980s and 1990s was accompanied by the influential theoretical body of work on "contestable markets" (see Baumol et al., 1982). The reversibility or transferability of fixed-size investments was the central assumption of the theory of contestable markets. The paradigmatic example of a contestable market was the airline industry, where airplanes, an airline's principal fixed investment, can be quite easily transferred from one market to another. In a nutshell, the theory of contestable markets maintained that even large fixed investments leading to (natural) monopoly would not lead to prices being higher than average costs as rival monopolists could always use "hit and run" tactics to extract short-term rents if prices were higher than average costs.

A key question in this context is to which extent electricity markets are contestable. Of course, power plants cannot be physically moved, but in principle their output – electricity – can be redirected from one market to another. Three very different considerations have bearing on this question. First, any shift of output from one market to another is likely to be imperfect due to limitations in interconnections. Second, to the extent that two markets are interconnected, competition will ensure that prices equal variable rather than total costs. Third, power plants cannot be moved but they can be temporarily closed or "mothballed", especially in times of overcapacity. While this can contribute to maintaining prices at average costs, all the while deterring new entry, mothballing obviously does not allow earning revenue in other markets. Taken together, these considerations would argue in favour of considering investments in electricity generation in the context of this work being irreversible, even though in practice this irreversibility might be less than absolute.

These shares vary considerably between technologies. Among baseload technologies, NPPs and CCGTs are at opposite ends of the spectrum in this respect. Even at 5% financing costs (which makes for relatively lower IDC and thus lower fixed costs), the share of fixed costs can reach up to 73% for the projected costs of a nuclear plant in Belgium, for example (IEA/NEA, 2010: 90).[8] At a 10% rate, this share would even rise up to 85% (IEA/NEA, 2010: 92).[9] The share of fixed investment costs in total lifetime generation costs of a combined-cycle gas plant in Italy instead can be as low as 8% at financing costs of 5% (IEA/NEA, 2010: 91). Even at 10% financing costs, the share of fixed investment costs in total costs would still remain at 13% (IEA/NEA, 2010: 93). While the precise shares vary from country to country as a function of specific investment costs, operating and fuel costs, capital-intensive technologies such as nuclear energy will by definition have higher shares of fixed costs in total costs than less capital-intensive technologies such as gas. This is quite independent of the respective levels of total costs habitually measured as the LCOE. In the examples provided above, for instance, the LCOE of nuclear is lower than the LCOE of gas at 5% financing costs and higher at 10% financing costs. Independent of whether capital costs are 5% or 10%, as long as differences in LCOE stay in a reasonable range, it is the difference in the fixed cost to variable cost ratio that crucially influences investor decisions.

8. Figures for the costs of capital in the IEA/NEA studies on the projected costs of generating electricity are real rather than nominal and pre-tax.

9. For renewables such as solar PV or wind, the shares of fixed costs in total costs are higher still. However, since they are subsidised through fixed feed-in tariffs the subsequently developed arguments around price uncertainty do not apply. Nevertheless, the moment that renewables have to fend for themselves without subsidies on liberalised markets, they would be exposed to price uncertainty to an even larger extent than nuclear energy. This is one of the reasons why discussions about "grid parity" have only very little bearing on the eventual economic viability of a technology.

As pointed out above, a lower ratio of fixed to variable costs provides greater value to the option to exit the market in case that electricity prices fall for a prolonged period of time. Assessing the advantage of technologies with relatively lower fixed costs of being able to extract themselves from the consequence of falling or permanently low electricity prices implies, accordingly, an assessment of the competitive benefit that nuclear energy derives from price stability. For a high fixed cost technology such as nuclear, the value of the predictability and stability of electricity prices is precisely equal to the lack of an option for exiting the market without the majority of funds having been spent in the case that prices should decline permanently.

Empirically, the link between the stability of electricity prices and nuclear new build is already obvious even in NEA and OECD countries with liberalised electricity markets. Whether regulated tariffs in France and the United States (at least as far as Georgia, North Carolina and Tennessee are concerned, where nuclear new build is taking place), at-cost off-take of electricity by major consumers in Finland or CFDs in the United Kingdom, only a stable long-term outlook for prices will allow new NPPs to be built. The case studies on the financing of the reactor project in Vogtle, GA (United States) and Akkuyu (Turkey) that are part of this study document the crucial importance of such long-term price guarantees. Price stability can be considered as a given in many non-OECD countries with nuclear new build such as China, India, Russia or the UAE, which do not operate with decentralised spot and forward markets for electricity.

While long-term electricity price guarantees play a decisive role in the commercial and financial sustainability of nuclear power, the issue has never received much analytical treatment. A rare counterexample is constituted by Rothwell (2006: 37-53) who pioneers the use of real options in the spirit of Dixit and Pindyck to assess the cost of a nuclear project in Texas facing uncertainty in terms of output prices, capacity factors and variable costs. The result is that a 10% decrease in capital costs would be required to compensate for profitability risk resulting from an increase in the variance of annual electricity prices of 0.9%. This underlines the importance of price stability for investors even in markets without the drastic and potentially long-lasting price falls currently observed in markets that are experiencing significant inflows of variable renewables in NEA and OECD countries.

Illustrating the vulnerability of nuclear to declines in the average price of electricity

Before estimating the value of the real option that a gas plant possesses and the resulting competitive disadvantage of nuclear in an unstable price environment with the NEA electricity market model, there could be some value in further developing an intuitive feel for the divergent impacts of decline in average prices on the profitability of gas and nuclear. Figure 5 presents NPV calculations under different price scenarios at discount rates of 3%, 5% and 7%. The horizontal axis shows different levels of price declines, the depth axis shows different years for the onset of the price decline and the vertical axis shows the NPV. The principal parameters of the underlying model can be found in Table 2.[10]

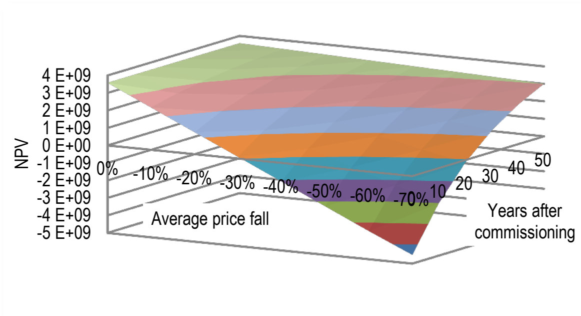
For all three discount rates, the NPVs for the nuclear and the gas plant have been normalised by adjusting the fixed costs of the nuclear plant. In other words, each time, at 3%, 5% or 7%, the nuclear and the gas plant would yield the same profit if the initial price level could be assumed to be stable during the lifetime of the plant. The beginning of the graph, in each case, is in the upper left corner. What distinguishes the two graphs is their

10. Without making an explicit comparison, this study argues that providing electricity price stability is even more important than lowering the cost of capital, which, of course, remains an important driver of the profitability of nuclear power plants. Government-backed nuclear bonds or attracting long-term investors such as pension funds are innovative concepts in this area which deserve to be explored.

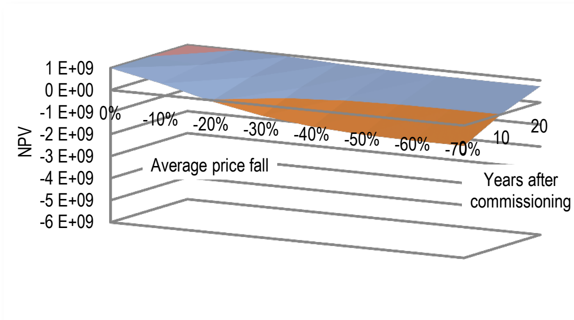
behaviour as prices fall. Compare the "flatness" of the gas graphs to the "steepness" of the nuclear graphs, which in a yet to be more precisely defined qualitative manner indicates investor risk. Without price risk, both graphs would be flat.

Figure 5: Net present value sensitivity to long-term declines in electricity prices for nuclear and gas

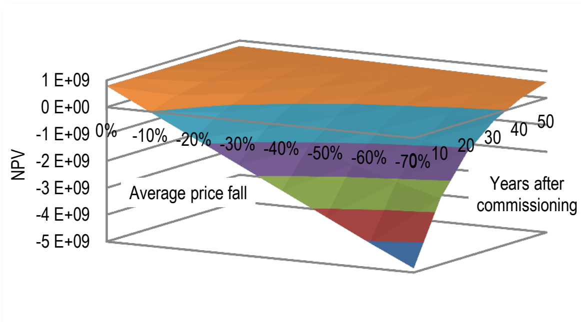
The NPV of an NPP based on a fall in electricity prices and the onset of the price fall years after commissioning (r = 3%)



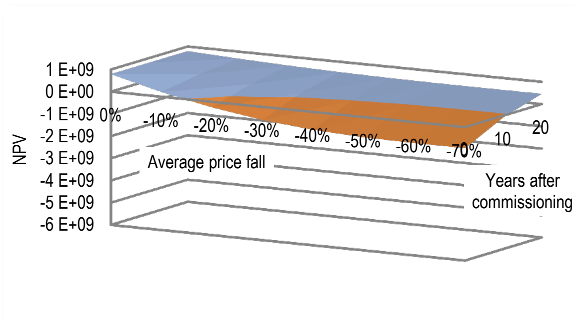
The NPV of a gas-fired power plant based on a fall in electricity prices and the onset of the price fall years after commissioning (r = 3%)



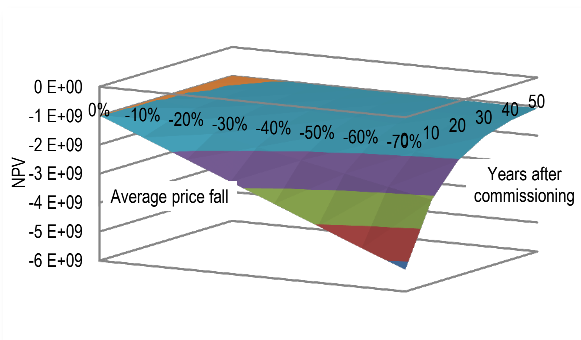
The NPV of an NPP based on a fall in electricity prices and the onset of the price fall years after commissioning (r = 5%)



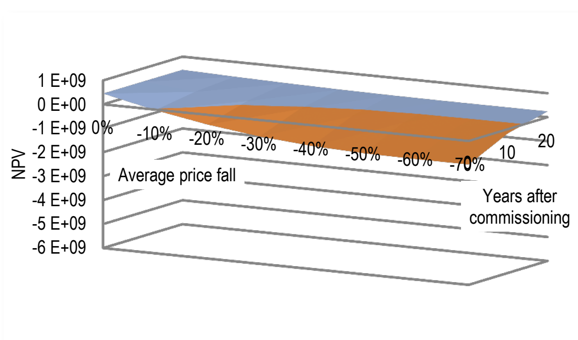
The NPV of a gas-fired power plant based on a fall in electricity prices and the onset of the price fall years after commissioning (r = 5%)



The NPV of an NPP based on a fall in electricity prices and the onset of the price fall years after commissioning (r = 7%)



The NPV of a gas-fired power plant based on a fall in electricity prices and the onset of the price fall years after commissioning (r = 7%)



How does gas achieve this relatively modest variability of its profit outlook, reflected by the "flatness" of the graph? It limits the impacts on its profits by exiting the market, ceasing production, when prices turn low. Given that most of its costs consist of expensive fuel, there are large savings to be made. It may never recover its fixed costs, but they were not very high to begin with. On the other hand, it is very unlikely that electricity prices would be below the variable costs of nuclear power and thus cause the shutdown of the nuclear plant, meaning that the option to exit has little value. The nuclear plant will instead continue producing with its relatively low variable cost, but it must bear the large fixed cost which drags down its NPV.

Comparing the graphs vertically, they confirm the well-known fact that the NPV of a nuclear plant is very much dependent on the cost of capital. Comparing them horizontally between nuclear and gas at identical interest rates, they underline the much stronger dependence of nuclear energy on the stability of electricity prices when compared with a gas plant of the same size. Intuitively, the greater the difference between nuclear and gas concerning the steepness of the decline in NPVs following a fall in prices, the more valuable the option to exit the market is for gas. The following section will determine more precisely the value of an option to exit the market for both technologies.

Determining the value of price stability for technologies with high ratios of fixed to variable costs

The basic methodology to determine the monetary value of the ability to exit a market suffering a permanent decline in average prices is based on the methodology already employed in *Carbon Pricing, Power Markets and the Competitiveness of Nuclear Power* (NEA, 2011: 51). This study uses real daily prices for gas, carbon and electricity in European markets over the period 2005-2010, as well as the cost data synthesised in IEA/NEA (2010) for construction, operations and maintenance (O&M), fuel and decommissioning costs (see Table 2). These values are then extended in series of five years over the lifetime of the project to establish the NPV of two alternative power generation projects of 1 000 MW, a nuclear plant and a gas plant.[11]

Establishing the NPVs of these two plants under historic conditions is, as usual, the sum of discounted costs and benefits, the latter depending entirely on electricity prices. The load factors of the two technologies depend on the underlying NEA electricity market model calibrated, for expositional purposes, on European electricity markets (see Annex to Part II). Clearly gas-fired plants with comparatively higher variable costs will see a far greater reduction in their load factors than nuclear. However, this option to exit the market for gas is ultimately less costly than being stuck with fixed costs that will never be recuperated, as is the case for nuclear, even though nuclear keeps on producing electricity and earning limited profits on a far greater number of hours.

The focus is on a permanent fall in the average level of the price of electricity, not on its short-term volatility. The latter is mainly an issue for gas-fired power plants, which as marginal producers are sensitive to the day-by-day interactions of their variable costs (fuel and carbon costs) with electricity prices. The long-term level of average prices is the key issue for NPPs. With its modest variable costs, nuclear power can see it through almost any form of short-term price volatility. However, due to the obligation to repay large fixed investments costs, nuclear depends on the level of average prices.

11. The carbon pricing study contains a discussion of the advantages and drawbacks of using empirical data rather than a full analytic formulation for modelling future prices (see NEA, 2011: 52).

Table 2: Assumptions on cost and technology (EUR)

	Nuclear	Gas
Technical assumptions		
Capacity	1 000 MW	1 000 MW
Construction years	7	2
Lifetime	60	30
Electrical conversion efficiency	n.a.	0.55
Gross energy content of fuel unit	n.a.	1 MWh
CO_2 emissions per MWh	0	0.37 tCO_2/MWh
Cost assumptions		
Overnight costs[1]	EUR 4 000 per kW	EUR 851 per kW
O&M	EUR 10.92 per MWh	EUR 3.54 per MWh
Fuel[2]	EUR 6.31 per MWh	Daily
Carbon (CO_2)[3]	0	EUR 14.44 per MWh
Decommissioning	EUR 600 per kW	EUR 43 per kW

1. Fuel costs for nuclear energy include cost for the back end of the fuel cycle.
2. The overnight costs for the gas plant are based on the median case in IEA/NEA (2010: 105). The overnight costs for the nuclear plant are based on NEA expert estimations.
3. Carbon costs in the NEA model correspond to the observed daily price in the EU emission trading system during 2005-2010. The table contains the average over the same period.

Source: IEA/NEA, 2010.

The NPV model used for this study can be parameterised for different price scenarios. For reasons of readability, the focus is on the impact of a permanent fall in average prices of 30%. In comparison, prices in European wholesale electricity markets have fallen in the past five years, largely due to the influx of variable renewables electricity, up to 50% below their 2008 peak.[12] In keeping with the basic set-up, daily prices were uniformly lowered by 30% to preserve the dynamics of the interaction between the different price series.

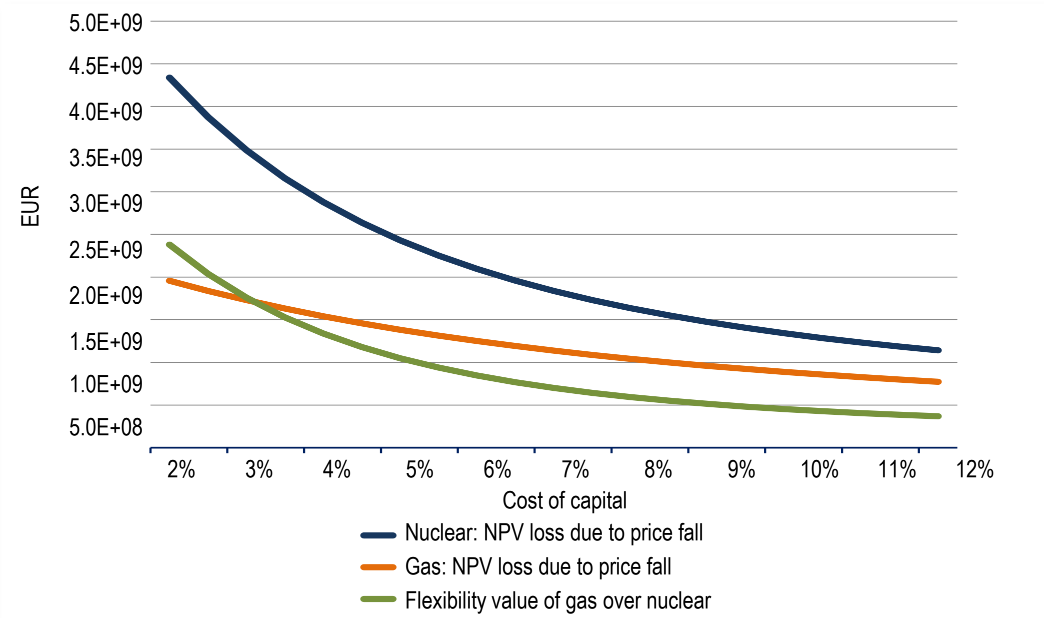
For the present analysis, focusing on the difference in profitability between technologies with high fixed costs and those with low fixed costs, it makes little difference whether the price fall is anticipated or unanticipated. Of course, if the price fall is high enough to push the NPV below zero and is anticipated, the investment will never be profitable, independent of a technology's cost structure. This is why it is intuitively easier to imagine the price fall as unanticipated or as associated with a sufficiently low probability so that investors in either technology will go ahead with their investments.

12. There is debate about whether current low prices in European electricity markets are permanent or transitory and whether they may rise again once conventional capacity retires and economic growth recovers. The final result will depend on the interplay between the share of subsidised renewables in electricity production and demand. In the very long-run, net investment in conventional capacity will also play a role. For investors, the decisive parameters are expected prices and profits, which are a combination of different outcomes with different probabilities. For ease of computation, it was also assumed that a price decline sets in right at the day of commissioning. In reality, they can appear at any time during the lifetime of a plant. The scenario of an immediate 30% fall in electricity prices must thus be considered an illustrative synthesis of different possible scenarios.

The flexibility value of gas, its option to leave a low-price market, is however unaffected by the question of whether the price change was anticipated or not.

Figure 6 shows the difference in NPVs between a situation with price stability and a situation with a decline in electricity prices. In order to allow for comparability, the two projects, gas and nuclear, will have the same total capacity and will yield the same NPV under price stability. The costs of a 30% price decline would be considerably higher for the nuclear plant (in blue) than for the gas plant (in orange). The difference between the two is indicated by the green line, which corresponds to the advantage in NPV terms of the gas plant in case of a price decline. This is equivalent to the value of the option that the gas plant holds due to its ability to exit the market, i.e. not to spend a significant share of the originally budgeted total lifetime costs. The green line also corresponds to the competitive advantage that nuclear would gain through any arrangement guaranteeing stable electricity prices throughout the lifetimes of both plants.

Figure 6: The flexibility value of gas with a 30% fall in electricity prices



NPV: Net present value.

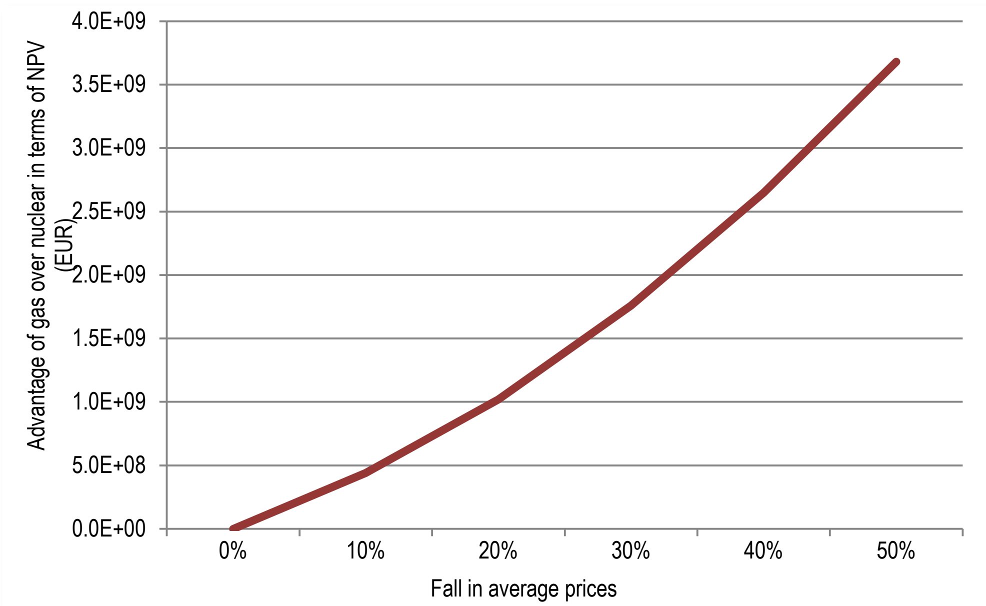
Under a scenario of stable prices, and using cost data from the *Projected Costs of Generating Electricity*, the NPVs for nuclear and gas are roughly equivalent at around EUR 800 million, if both face a real interest rate of 5%. However, in the case of a drop in electricity prices of 30% right after commissioning, the NPV of nuclear would fall in the NEA electricity market model from EUR 800 million to EUR -1.64 billion, while the NPV of gas would decline only from EUR 800 million to EUR -590 million. The difference is worth roughly EUR 1 billion.

Thus the NPV risk of the nuclear plant as a function of an electricity price decline is considerably higher than the NPV risk of the gas plant. This applies despite the load factor of the nuclear plant remaining considerably higher than that of the gas plant, *even in the case of a price decline*. The nuclear plant, with its low variable costs, will keep on producing at essentially unchanged load factors but remain saddled with its initial high fixed costs, which the new prices no longer allow to repay in full. The gas plant instead will reduce its overall risk exposure by stopping production at days when the now lower electricity prices no longer allow it to repay its high variable costs.

Following a 30% decline in electricity prices, the load factor of gas, as calculated by the NEA electricity market model, will reduce quite dramatically, from 84% to 39%. However, despite the ensuing loss in revenue, its overall loss will be smaller than that of nuclear due to its much smaller fixed costs. In other words, the gas plant exercises its option to exit the market. Nuclear does not possess an analogous option, since a far greater portion of its lifetime costs are already sunk.

This additional financial value conferred to a gas plant when electricity prices are uncertain rises very quickly with the size of the potential price fall. At around EUR 1 billion for a 30% decline, it is above EUR 2 billion for a 50% decline (see Figure 7).

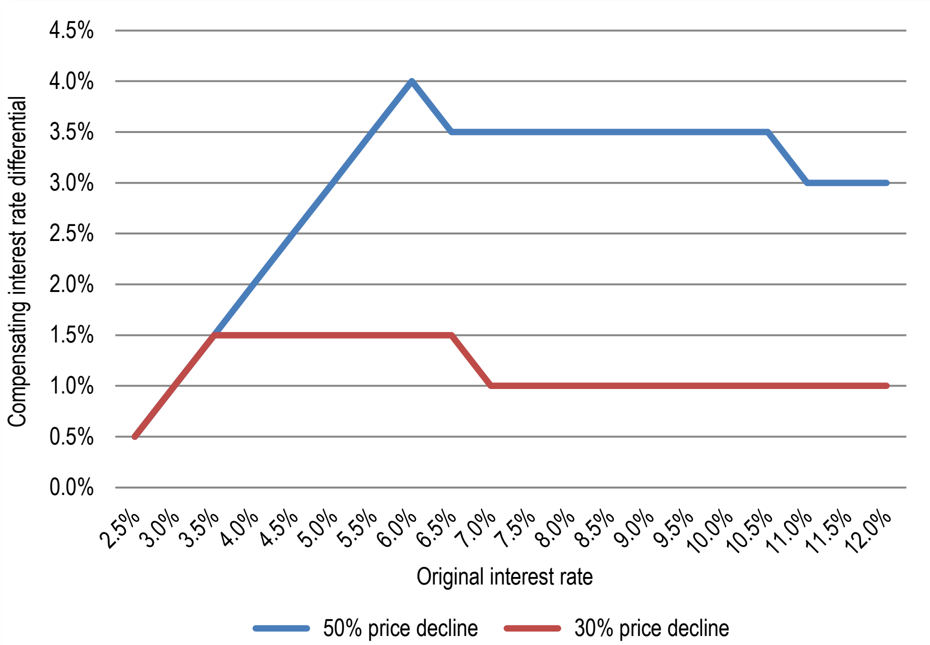
Figure 7: The NPV advantage of a gas plant at price declines of different sizes
(Difference in NPVs after price fall at 5% capital cost)



The cost of price uncertainty for NPPs can also be expressed in terms of an equivalent interest differential. In order to compensate for the difference in the face of a 30% price decline, NPPs would need to have access to funding at costs that are up to 1.5% lower than the funding costs for a gas plant. If the price decline was 50%, its capital cost advantage would need to be up to 4% to be competitive (see Figure 8).[13] The results show the disproportionate impact of price declines on high fixed cost technologies compared to technologies with lower fixed cost to variable cost ratios. They also show the increase of this disparity with the size of the long-term price decline. The difference between both technologies is relatively modest at price declines of 20% or less. However, the difference dominates all other considerations with a long-term price decline of 50% or higher. Even a low probability of such a massive price decline will push investors towards choosing technologies with low fixed costs such as gas.

13. The compensating interest rate differential is not uniform but depends on the underlying original interest rate assumed. As Figure 8 shows, it is highest with respect to the most likely costs of capital to be used by large firms, between 6% and 8% real. At very low rates, the relative capital cost advantage, even for small changes in interest rates, is considerable and so nuclear does comparatively well even in the face of a price decline. At very high rates, rather, the flexibility advantage of gas becomes less significant.

Figure 8: Differential in the cost of capital required to offset the competitive disadvantage of nuclear with price declines of 50% and 30%



The point is not that nuclear projects are inherently more risky than gas-fired projects. They are not. They are just much more heavily exposed to a fall in the average level of electricity prices, be it 30% or 50%. Such electricity price risk could be neutralised in a straightforward manner through the provision of price guarantees or outright price regulation. This is, of course, already the case in the vast majority of NNB projects. In particular, when large amounts of subsidised renewables, such as wind and solar photovoltaic with low variable costs, are being pushed into the market, investors will shy away from capital-intensive projects without price guarantees. This is *not* an effect of risk aversion. Even risk-neutral investors would prefer the less capital-intensive project which possesses the so-called "real option" to exit a market that is no longer attractive.

Electricity price uncertainty thus has a direct and significant impact on technology choices as well as on the environmental performance of the power sectors of NEA and OECD countries. Capital-intensive, low-carbon technologies such as nuclear or renewables require a comprehensive long-term approach to electricity price stabilisation. Currently, most NEA and OECD countries are attached to the triple objective of electricity market liberalisation, selective subsidisation of renewables and decarbonisation. However, the strategic mismatch between these three objectives has not been thoroughly discussed. Effective decarbonisation through low-carbon nuclear energy and renewables will require a fundamental re-think of the workings of the electricity sector in the coming years.

The remainder of Chapter II.1 addresses the benefits of avoiding price uncertainty and elaborates on the link between price uncertainty and nuclear new build in different regulatory environments.

II.1.3. The economic value of long-term pricing arrangements such as contracts for difference with and without mark-ups over historic market prices

The previous section showed the disproportionate impact of uncertainty about average electricity prices on technologies with high fixed to variable cost ratios such as nuclear energy. It illustrated this effect by contrasting a scenario of price stability with a scenario in which prices declined permanently by 30%. In both instances, the impact was measured in terms of NPV. This section takes the opposite perspective, namely it examines the value of price stability under different assumptions.

Price stability can be provided through a variety of measures that include regulated prices, long-term contracts, FITs or CFDs. While different instruments correspond to different legal and regulatory contexts, their economic and financial impact through the provision of price stability remains identical at this level of analysis. The positive impact of price stability goes beyond satisfying the demand for assurance of risk-averse investors. The previous section showed that the relatively larger costs of a price decline for a capital-intensive technology accrue independent of risk preferences.

That said, the more risk averse are investors, the higher the benefit of price guarantees. From the investor point of view, price guarantees corresponding to average expected future prices are unambiguously positive. The question is what are the costs of such agreements to consumers? Long-term price guarantees such as CFDs, which eliminate price risk for producers since consumers guarantee any short-fall of market prices, are not cost-free. With a CFD, risks in the costs of electricity production are not eliminated but transferred to consumers who provide in effect price insurance to producers.[14] On average, the latter will have slightly higher and more stable electricity bills as well as higher levels of security of supply.

Consumers, in particular, forego the potential advantages of upside risk. If one day newly invented technology promises to provide cheap and abundant carbon-free energy, then consumers locked in a long-term fixed-price contract for nuclear will be subjected to a large opportunity cost. On the other hand, foregoing long-term fixed-price arrangements could mean security of supply risks and significantly increased carbon emissions. These are trade-offs that a representative agent such as government must resolve in the best interest of its citizens. Given the "public good" issues involved, such as security of supply and climate change, economic theory cannot provide a simple straightforward answer.[15]

In theoretical terms, a significant carbon tax may constitute an alternative instrument to generate investments in low-carbon generating technology. However, the selective subsidisation of renewables with very low marginal costs does not allow, for the foreseeable future, electricity prices to recover to levels which would allow financing new investment on carbon prices alone. This holds for any dispatchable baseload technology but *a fortiori* for nuclear energy, which together with hydropower is the only nearly carbon-free source of energy.

Market purists will argue that leaving price risks with private investors will have benefits in terms of the dynamics of a competitive market environment that would force producers to reduce costs and develop strategies to better cope with risk. After 25 years of

14. The UK CFDs work on the basis of a levy on electricity supplies which will fund the government-owned CFD Counterparty Ltd. As its name implies, the latter is the financial counter-party for electricity producers eligible for payments under a CFD. Since the levy is based on electricity sales, its cost will be passed on directly to consumers as part of their per-MWh electricity tariff. Suppliers, and hence consumers, will also pay for all transaction costs including insurance for a "reserve fund" and an "insolvency fund".

15. This argument goes beyond the general argument that the public sector has advantages in dealing with uncertainty for large investment projects made in the Arrow-Lind theorem (Arrow-Lind, 1970: 364-378). To the extent that the risks of a given project are idiosyncratic, i.e. uncorrelated to the systemic, macroeconomic risk an economy is facing, the Arrow-Lind theorem maintains that a project should be financed publicly at the risk-free rate. This is motivated by risk spreading, the effect that if project costs are spread over a large population, an individual's cost of risk falls to zero.

experimenting with electricity market liberalisation and its peculiar cost recovery mechanisms, the verdict is still out on whether the priority of electricity sector regulation should be providing stability to ensure investment and security of supply or whether its priority should be inciting technological and organisational innovation. There is extensive literature on the respective benefits of *ex post* or rate-of-return incentive regulation and *ex ante* or incentive regulation, the former favouring investment, the latter efficiency (see for instance, Laffont and Tirole, 1993). It may well be that different moments in time and different countries require different answers. However, in 2014, the majority of NEA and OECD countries were facing an investment challenge requiring increased stability rather than overinvestment requiring a shake-up through stronger market dynamics.

Even when the conceptual argument for long-term price guarantees has been made, assessing their value for producers is not quite as straightforward as it seems. The economic value of an instrument for providing price stability is not just the inverse of the loss resulting from a sudden price fall. This is due to the fact that by accepting a long-term arrangement providing price stability such as a CFD, investors also forego any upside risk, i.e. the possibility that prices and profits may rise.[16] This requires assessing the value of a fair CFD, i.e. a CFD whose strike price corresponded to the expected average level of future electricity prices. A fair CFD would provide insurance against price uncertainty for risk-averse investors in a symmetric manner, eliminating both upside and downside risk. Eliminating only downside risk could be construed as constituting a subsidy, since it would raise an operator's average revenue above what it could hope to obtain in a free-market situation. The question becomes very difficult, however, if current prices are nowhere near a level that could support *any* investment in unsubsidised technologies. In such cases, the level of a "fair" price guarantee needs to be defined essentially on the basis of costs rather than on price.[17]

The first case this model analysed is a CFD that paid EUR 55 per MWh with certainty. This corresponded to the average price during the period from 2005 to 2010, which is the basis for the present modelling effort. For illustrative purposes, the study then confronted this case of price certainty with a risky scenario, in which there was an even chance of either a 30% rise or 30% fall in prices over the lifetime of the plants. In conceptual terms, the value of a CFD corresponds to the maximum amount investors would be willing to pay for an insurance that would guarantee them price stability in a market environment characterised by the risk of either a 30% fall or a 30% rise in electricity prices.

Risk aversion was modelled with the help of the concept of constant relative risk aversion (CRRA), a standard notion based on utility functions with declining marginal utility of wealth. A simple example may clarify the notion. A bet that offers an even chance of winning either EUR 10 or EUR 50 is worth EUR 30 to a risk neutral person. For a

16. In the following, we will use CFDs as the expression for long-term arrangements guaranteeing price stability, since they are probably the instruments most easily compatible with the continued existence of nominally liberalised electricity markets in NEA and OECD countries. CFDs have the particularity of letting producers sell their output into electricity wholesale markets but add or deduct any difference of the obtained price with an *ex ante* agreed upon "strike price". The recent agreement between the UK government and EDF Energy to allow for the construction of two new nuclear power plants at Hinkley Point C (Somerset) with the help of CFDs for electricity further underscores their current policy relevance. A recent state aid inquiry of the European Commission came away with a positive conclusion in October 2014 and allows the project to go ahead as planned.

17. The difficulty arises from the fact that in liberalised electricity markets prices that are formed on the basis of the variable costs of the marginal technology can diverge for very long periods from the full costs of generating electricity. The effect is significantly compounded by the entrance of subsidised renewables with zero short-term variable costs.

risk-averse person with a CRRA equal to one, the same bet would be worth only EUR 22. In case that a second person had a CRRA equal to two, this value would decline to EUR 17. In the present context, the NPV value of an electricity generation project can be interpreted as such a change in wealth. A CFD that *guaranteed* the expected average pay-off of EUR 30 would thus be worth an additional EUR 8 to the first person and EUR 13 to the second person (the difference between the value of the risky bet and the guaranteed pay-off).

Economists like working with a CRRA of one, for reasons of both empirical realism and mathematical tractability. On the first point, a CRRA of one is not far from what is observed in experiments. On the second point, a CRRA of one means that the relationship between wealth and utility collapses to the natural logarithm. A CRRA of two would only apply to highly risk-averse investors. CRRA has an additional advantage over the theoretical alternative of constant *average* risk aversion (CARA). With CARA, the change in utility following the gain or loss of a given amount is independent of the initial level of wealth. CRRA instead adapts the impact of a given change in wealth on utility to the level of wealth. Losing EUR 1 000 is far more painful for somebody earning a salary of EUR 1 500 than for somebody earning EUR 5 000. With CARA, the loss in utility would be the same in both cases.[18]

In assessing the value of a CFD to investor groups with different degrees of risk aversion, the question is to which extent the risk aversion of different investors is already captured in the cost of capital. Higher costs of capital correspond to higher levels of risk. One must, however, distinguish the intrinsic riskiness of a project, for instance its exposure to operational risk or input price risk, from the cost of that risk to different investor groups. The former, intrinsic project risk, will determine the cost of capital at which a risk-neutral investor will be willing to fund the project. The latter, risk aversion, will determine the *added* compensation investors with different degrees of risk aversion would demand.

A CFD that guarantees a fixed price of electricity will affect both, the intrinsic project risk and the cost of this risk to risk averse investors. In other words, a CFD holds value also for a risk-neutral investor. This is brought out in the previous section on the value of the flexibility of a gas plant facing deteriorated market conditions. The value of the latter's option to leave the market does not depend on risk aversion. Nevertheless, to bring out the value of a CFD it was useful to assume that a CFD would *not* affect the cost of capital, which is assumed to be exogenous, but would only affect the added value of the smoothed revenue stream for risk averse investors.[19]

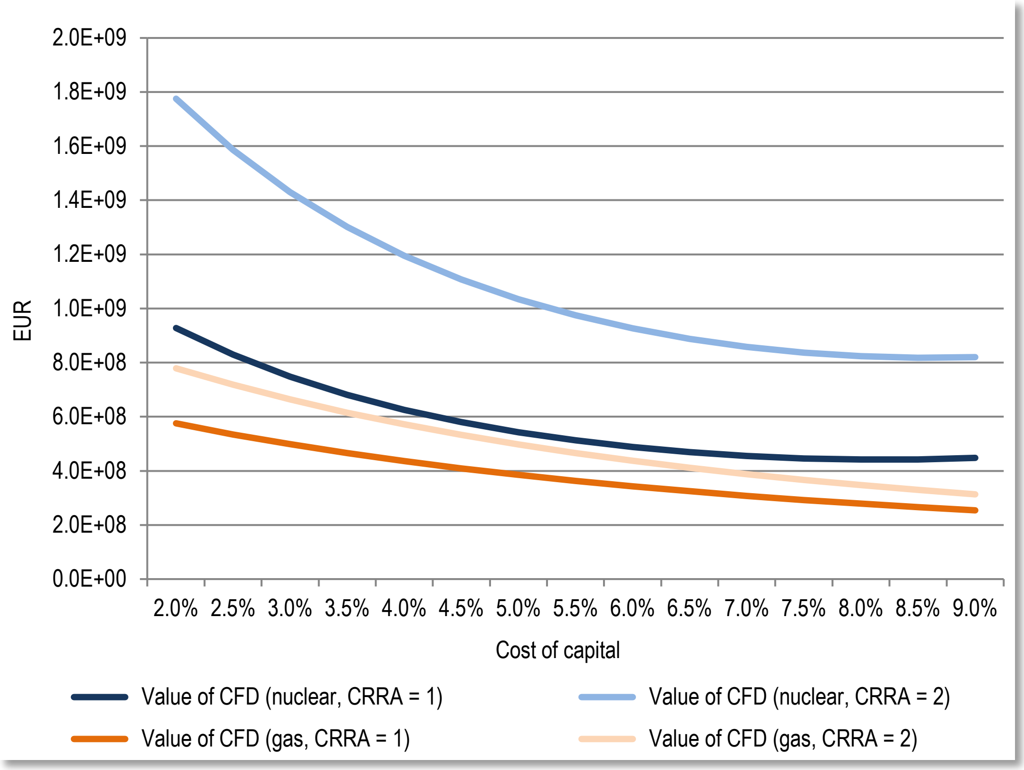
The value of a "fair" CFD is thus the difference between the value of a stable revenue stream and the value of a revenue stream with symmetric upside or downside risk

18. Following the work of Arrow (1970) and Pratt (1964), constant absolute risk aversion is defined as $\alpha = -u''/u'$, where u' and u'' are the first and the second derivative of a continuous and convex utility function. Constant relative risk aversion, which takes into account differences in the initial level of wealth (declining risk aversion for constant sums at risk with increasing income), instead is defined as $\rho = -W^*(u''/u')$, where W is wealth. As indicated above, a change in wealth corresponds to the NPV of an investment in the present context. The utility of an investment thus corresponds to $U = (NPV^{1-\rho})/(1-\rho)$, which collapses to $U = \ln NPV$ for $\rho = 1$.

19. To some extent, this assumption marks the difference between economic and financial analysis. In financial analysis, the cost of capital will be endogenously determined and rise with the level of risk. In much of economic analysis, the cost of capital is assumed to be exogenously determined and taken as given. A nuclear project situates itself at the borderline between the two logics. On the one hand, it is likely that a nuclear project will have access to some forms of financing whose cost is exogenously determined (export credits, government loan guarantees, construction cost recovery through regulated tariffs, corporate bonds of large utilities, investment tax credit). On the other hand, a successful project will always strive to attract additional private funding.

leading to a 30% change in electricity prices. This value is equal to the added compensation investors would demand if forced to accept price risk. In Figure 9, this compensation has been expressed in absolute terms on the vertical axis. It could also have been expressed in an interest differential and thus have been fed back into the cost of capital. The approach chosen provides results that allow an immediate intuitive grasp of the orders of magnitude concerned.

Figure 9: The value of a contract for difference (CFD) for nuclear and gas for different degrees of risk aversion (constant average risk aversion)



CFD: Contract for difference; CRRA: Constant relative risk aversion.

Figure 9 above shows the value of a fair CFD for two types of risk-averse investors. This value increases with the degree of risk aversion. It is also higher for nuclear than for gas, since the exposure of nuclear to changes in the price level is considerably higher than the exposure of gas. At realistic levels for the cost of capital, say 5% to 7% real, the value of such a CFD to normally risk-averse investors is slightly below EUR 500 million, which translates to about 11% of the overnight investment costs of an NPP.

A key question for a CFD is the choice of the reference price level. Needless to say, the higher the reference price level, the greater the value to investors. A straightforward reference would, of course be the current level of electricity prices. This reasoning, however, only holds true if market prices covered average cost. In many of today's electricity markets, wholesale electricity prices are no longer anywhere near the average costs of generating electricity. This is due to the fact that prices correspond to short-run variable costs, while only average costs (total costs divided by output) include the fixed costs of investment. In the past, gas-fired generation with its comparatively high variable costs usually set the prices with comfortable margins for all other producers. Any remaining differences between average and variable cost were covered through modest mark-ups due to transitory monopoly power.

However, to the extent that electricity markets are dominated by renewable energies with zero short-run variable costs, the gap between market prices and average costs has increased. Table 3 from a recent NEA study shows that this impact of variable renewables on prices and profits is high even at a relatively low share of renewable penetration of 10% of electricity.

Table 3: Load and profitability losses due to the integration of variable renewables

		10% penetration level		30% penetration level	
		Wind	Solar	Wind	Solar
Load losses	Gas turbine (open-cycle gas turbine)	-54%	-40%	-87%	-51%
	Gas turbine (combined-cycle gas turbine)	-34%	-26%	-71%	-43%
	Coal	-27%	-28%	-62%	-44%
	Nuclear	-4%	-5%	-20%	-23%
Profitability losses	Gas turbine (open-cycle gas turbine)	-54%	-40%	-87%	-51%
	Gas turbine (combined-cycle gas turbine)	-42%	-31%	-79%	-46%
	Coal	-35%	-30%	-69%	-46%
	Nuclear	-24%	-23%	-55%	-39%
	Electricity price variation	-14%	-13%	-33%	-23%

Source: NEA, 2012: 136, Table 4.6.

This means that today's prices are too low for new power generation equipment to finance itself on the basis of market prices in the electricity sectors of most NEA and OECD countries, independent of the choice of technology. It is impossible to finance *any* new capacity at EUR 55 per MWh, the average price in European electricity markets during the 2005-2010 period and all the more so at the even lower current prices. The only technologies being built in this environment are those receiving one form or other of support.[20] In other words, the true cost of electricity in any form is higher than current or even future expected prices.

A CFD, a feed-in tariff or a long-term contract might thus very well be above the market price and still be considered "fair". As long as the level corresponds to the least cost of producing electricity, any subsidy arguments would boil down to the risk reduction aspect discussed above.

Setting a strike price for a nuclear plant with an expected lifetime of 60 years is an exceedingly difficult affair. It involves, in particular, formulating expectations about future electricity generating costs and correspondingly expected future electricity prices.

20. It is primarily the cost structure of the new renewable capacity which is driving this evolution and not the fact that the latter are subsidised. Renewable capacity (the exception is biomass), by definition has predominantly low short-run variable costs since wind and sunshine are free, and this pushes prices downwards. Of course, their subsidisation is a necessary condition for such a result since renewables, even more so than other technologies, are very difficult to finance on the open market due to the very price falls they themselves induce.

The "no subsidy" argument, of course, holds only if the strike price corresponds to those expected future electricity prices. And although it was said previously that prices and average costs currently diverge considerably, theory maintains that scarcity pricing will ensure adequate returns in the long-run even in a free market environment (see Stoft, 2002). The trouble is that scarcity pricing corresponds to serving less than full load (brownouts) which is associated with a significant economic and social disutility. That is to say that some sort of anticipated average price will need to go into the setting of any strike price.

Even if the strike price is "fair", i.e. corresponds to expected average lifetime costs, it is obvious that a guaranteed strike price higher than the current market price makes the CFD attractive for the investor. Figure 10 shows an example of the difference between a CFD with a strike price corresponding to the historic average market price of EUR 55 per MWh (dark blue line) and the proposed strike price corresponding to the preliminary agreement between EDF Energy and the UK government for the construction of two EPRs at Hinkley Point (United Kingdom) first announced in October 2013 (light blue line). That agreement was based on a strike price of GBP 92.50 per MWh, which on the basis of an exchange rate of EUR 1.18 per pound corresponds to EUR 110 per MWh.[21] The graph also shows the NPV of building a nuclear plant. In the case of a strike price of EUR 55 per MWh, the NPV (net of tax considerations) will turn negative at real interest rates slightly higher than 5%. If the strike price instead corresponds to EUR 110 per MWh, the NPV stays positive for interest rates up to 11.5% with NPVs of around EUR 6 billion in the economically relevant range of 5% to 7% real.

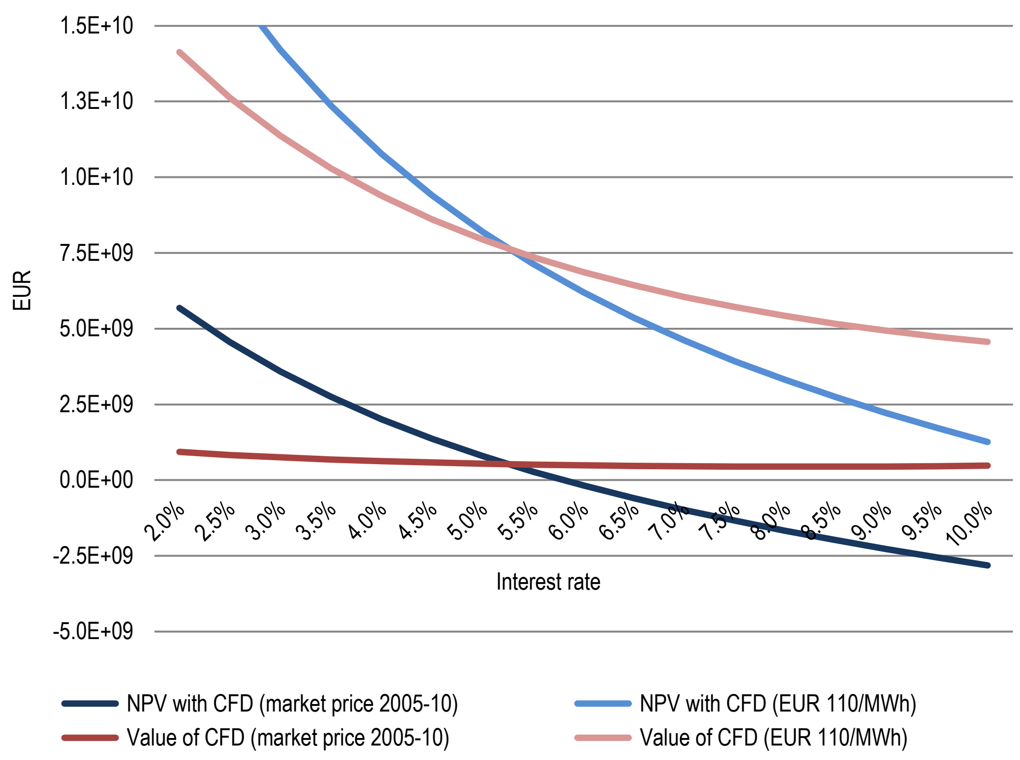
Of course, such results of a simplified economic model must not be taken as the "real value" of the agreement over Hinkley Point C, which reflects a number of real-world contingencies such as FOAK risk or the rebuilding of a nuclear supply chain in the United Kingdom. When comparing the two cases, it also should be kept in mind that the assumptions for investment and operating costs are identical in both cases. In particular, the overnight capital costs are assumed in both cases to be EUR 4 000 per kW. This is not an unrealistic assumption. However, it is entirely possible that the negotiations about the UK strike price have worked with different site- and country-specific capital costs. The results nevertheless show the magnitude of the impact of different strike prices.

In summary, guaranteeing the future level of electricity prices and thus eliminating long-term price risk is a valuable incentive for investment in electricity generation. It is particularly valuable for high fixed cost low-carbon technologies such as nuclear energy and renewables, which are disproportionately exposed to falls in the price level, as technologies with lower fixed costs have the option to leave the market with limited losses. Many renewables, of course, already receive such price support through the administration of FITs. A key question in this context is whether the guaranteed price on offer, for instance the strike price in a CFD, is based on the expected average market price or the average life-time costs of generating electricity. The latter choice can be justified if market prices are no longer a credible indicator for average generating costs.[22]

21. Of course, exchange rates can change, and have changed since an earlier version of this calculation. One should recall, however, that a CFD has a lifetime of 30 years or more. Over such time frames, it is impossible to provide a reliable value for the EUR/GBP exchange rate.

22. Stable pricing arrangements such as CFDs, feed-in tariffs or regulated prices based on average costs of production contain an implicit remuneration for capacity provision. They thus substitute for capacity payments for the technologies that are eligible for CFDs.

Figure 10: The value of a contract for difference (CFD) and the net present value of a nuclear plant at different strike prices



NPV: Net present value; CFD: Contract for difference.

II.1.4. Changing perceptions of electricity markets and competitiveness: The impact of different market designs on the technology choices of private investors

The policy implications of discussions in the previous sections confirm that nuclear power, due to its cost structure, is disproportionately exposed to the risk of a long-term decline in average electricity prices. Once more, this is different from its ability to deal with short-term price variations, which nuclear does very well. Independent of its total lifetime or average costs expressed in LCOE, it is the *cost structure*, its ratio of fixed to variable costs, which determines a project's risk vulnerability to long-term price risk. Different technologies are thus exposed to uncertainty about long-term electricity prices in very different ways. This, however, implies that a liberalised electricity market does not constitute a "level playing field". To the extent that market liberalisation implies uncertainty over long-term average prices, it provides incentives that are skewed towards technologies with low ratios of fixed cost to variable costs. Quite simply, the long-term price risk in electricity markets discriminate against technologies with high ratios of fixed to variable cost.[23]

23. Due to their very high ratio of capital costs to variable costs, which exceeds that of nuclear, most renewable energies are even less apt to deal with electricity price risk. However, benefitting from stable feed-in tariffs, which are akin to fixed-price contracts, makes them viable also in liberalised electricity markets. Even if technological progress will eventually achieve the "grid parity" of renewables, the equivalence of LCOE net of system cost with conventional technologies, it will be almost impossible to wean them off fixed-price support.

Almost by definition, low-carbon technologies are technologies with high ratios of fixed to variable cost. Liberalised electricity markets thus also display an inherent bias against low-carbon technologies. Whether nuclear, wind, solar, geothermal, marine technologies or even carbon capture and storage and electric storage, all incur the large majority of their costs *before* the date of commissioning. This is no coincidence. The comparatively high variable costs of carbon-emitting power generation technologies are precisely due to their use of carbon-intensive fossil fuels. This allows for a simple but powerful generalisation: there is an inherent strategic contradiction between electricity market liberalisation and carbon emission reductions. Of course, the issue could be addressed with the help of a substantial carbon tax. However, if for distributional and political reasons this option is foreclosed, liberalisation will inevitably tilt electricity markets towards investments in carbon-intensive technologies. Choices about electricity market design are invariably technology choices.

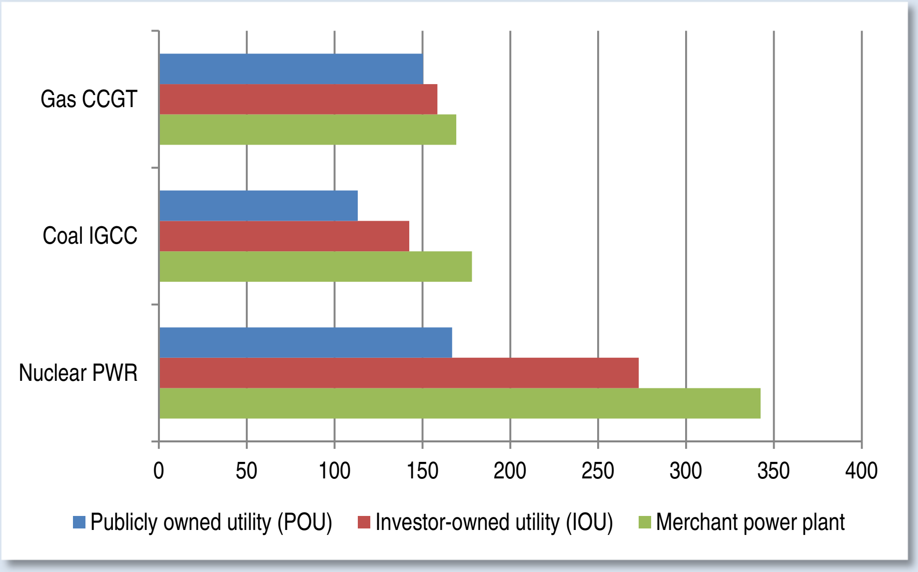
The competitiveness of nuclear energy under different market constellations

Different regulatory systems for the electricity sector imply different financing models, which imply different technology choices. In other words, the competitiveness of different technologies depends on the regulatory environment. A demonstration of this fact is provided by the 2010 study on the comparative costs of electricity generation by the California Energy Commission (CEC). Corresponding to three different regulatory environments, the study assumes three financing models, which each yield very different results for three standard power generation technologies: a CCGT, an integrated gasification combined cycle (IGCC) coal plant and a pressurised water reactor. Merchant power plants with a high share of equity are the typical financing model for deregulated electricity markets, while investor-owned utilities (IOUs) and publicly owned utilities (POUs) are typical financing models for regulated markets. In all three models, the CEC levelises the electricity generation costs over a twelve-year period (2006-2018). This is shorter than the depreciation period of capital-intensive technologies such as nuclear, and it results in comparatively higher LCOE.

In its average case, the CEC assumes for merchant power plants, a debt-equity split of 40/60 with a debt rate of 7.49% and an equity rate of 14.47% (gross, before tax) resulting in a net weighted average cost of capital (WACC) of 10.46%. For IOUs, the study assumes a debt-equity split of 48/52 with a debt rate of 5.4% and an equity rate of 11.85% resulting in a WACC of 7.7%. Finally, for POUs, the study assumes all debt-financing (no equity) with a debt rate of 4.67%, which, of course, results in a WACC of 4.67% (CEC, 2009: 51). These wide differences in capital cost assumptions correspond to different regulatory regimes and result in widely varying LCOE calculations (see Figure 11). Clearly, there is no such thing as technology-neutral decisions on financing and regulation. The lower investor risk, and hence the lower the cost of capital, the better capital-intensive technologies such as nuclear power will fare. This is typically the case in markets with regulated prices.

Not all technologies depend on the regulatory environment in the same manner. Regulation first and foremost impacts investor risk, while it cannot affect cost items such as fuel costs. Regulation thus primarily impacts the cost of capital. This implies in turn that capital-intensive technologies such as nuclear power are far more sensitive to changes in the regulatory environment than gas- or coal-fired power plants, whose competitiveness depends primarily on the globally or regionally determined costs of fossil fuels. In other words, the competitiveness of nuclear power does not exist; different levels of competitiveness exist only according to the different market environments. In contrast, decisions on the regulatory environment for electricity provision are not technology-neutral. Environments that leave investors exposed to price uncertainty will mechanically induce a bias against technologies with high ratios of capital costs to variable costs, such as nuclear or renewables. In either perspective, questions of electricity market design and technology choices need to be addressed together to ensure more sustainable low-carbon supplies of electricity in a cost-effective manner.

Figure 11: Levelised costs of electricity under different financing and regulatory arrangements
(USD/MWh)



CCGT: Combined-cycle gas turbine; IGCC: Integrated gasification combined cycle; PWR: Pressurised water reactors.

Source: CEC, 2010: 20.

Technologies with very low variable costs such as wind- and solar-based renewables and, to a lesser extent, nuclear have the added effect of coming early in the merit order of electricity market dispatch. Given that, in competitive markets, prices correspond to short-run marginal costs, this produces a tendency towards lower prices. Technologies with a high ratio of fixed to variable costs, including most low-carbon technologies, will hence erode the chances to ever fully recover their costs even if they have high load factors. Liberalising electricity markets and promoting market-based low-carbon technologies are ultimately contradictory objectives.

Disregard of this link, whether accidental or wilful, can lead to a disconnection between officially expressed public policy objectives and the reality on the ground. However, this does not so much concern nuclear energy, which is usually a well politicised issue. It concerns technologies such as carbon capture and storage or electric storage, as well as variable renewables such as wind and solar. The frequently invoked market maturity of the latter, for instance, will be utterly unattainable in deregulated electricity markets with uncertain prices.

Maintaining the competitiveness of low-carbon technologies, including nuclear power, thus requires addressing the issue of long-term electricity price stability. At current costs, it is difficult to imagine that nuclear power will be the chosen technology in markets without long-term price guarantees or commensurate compensating measures, although this has been done in cases such as the Finnish Mankala model or the CFD in the United Kingdom. Not addressing the issue in countries with liberalised electricity markets, which includes the majority of NEA and OECD countries, means confining nuclear power to markets without long-term price risk.

This is not just a question of regulatory arrangements. In the long term, countries without electricity price risk are those that have a stable or increasing willingness-to-pay for electricity over time. This means countries where the economy, the population and electricity demand are growing. A look at the geographical distribution of NNB projects (see Table 1) shows that this is precisely what is happening, with China and South East Asia in the lead.

However, the question is not closed for countries with mature economies and liberalised electricity markets. It only means that the impacts of price uncertainty on the energy mix need to be addressed. Not addressing the question of long-term vulnerability of unsubsidised low-carbon technologies may mean foregoing affordable low-carbon baseload technology. There is a real question in this context which is to what extent the flexibility of the alternative gas plant also has social and not only private value. The answer ultimately depends on the "framing" of the question and of politically determined priorities.

If the priority is to have liberalised electricity markets, the decision of private investors to go for gas plants even when their LCOEs are higher is, as John Parsons, MIT CEEPR, points out, also the socially optimal choice, precisely due to their higher flexibility. However, if the top policy priority is to provide electricity output at the lowest possible cost, i.e. with the lowest relative input of capital, labour and natural resources, things should be otherwise. In this case, private choices for more flexible technologies with overall higher LCOEs would indeed constitute a socially sub-optimal choice. Providing stable long-term contracts with regulated prices would increase welfare in this case. Needless to say, such arguments would come before externality considerations such as security supply, proliferation or environmental impacts, which may tilt any economic balance either way according to country-specific social preferences.[24]

Are liberalised electricity markets the exception or the norm?

The deregulation of the electricity sector in the United Kingdom, the United States and continental Europe that began at the end of the 1980s was the result of both the larger political context as well as new technological developments such as the advent of the CCGT. Deregulation at the time primarily meant the unbundling of vertically integrated monopolies overseen by regional or national regulators in combination with the competitive production of electricity negotiated through wholesale markets. The objective was to reduce costly "gold-plating" (over-investment), organisational slack and regulatory capture of regulated utilities, as well as to address a lack of technological dynamism.

Decentralised allocation of electricity through liberalised markets has both benefits and drawbacks. On the benefit side, electricity is, at least at a first level, an undifferentiated commodity with fairly low transport costs, at least over short distances. At a second level, quality issues, intermittency (the fact that variable technologies such as wind or solar technologies are only available at certain moments), the availability of reactive power and other factors, complicate this assessment slightly but not enough to make a fundamental difference as long as all technologies face equal responsibilities in maintaining adequate supplies at all times and system integrity. At a third level of analysis, however, electricity's benefit in this context is also its Achilles' heel: the inability to differentiate the product, the absence of transaction costs and pricing power makes short-run marginal cost pricing the norm. Under normal operations, this does not allow for the full inclusion of capital costs.

Substantial parts of capital costs are included in prices, as baseload and mid-load technologies with comparatively low variable costs gain "infra-marginal rents" during the operation of price-setting peak-load technologies with higher variable costs. However, full capital costs could theoretically only be recovered during scarcity periods, where electricity is priced at the value of lost load (VOLL) during periods of revolving brownouts.

24. Previous NEA studies (2011 and 2010) have dealt with the issues of greenhouse gas emissions and security of supply.

Since VOLL-pricing is politically and socially undesirable, there is a constant tension between socially and privately sustainable levels of capacity in liberalised electricity markets. This issue is frequently referred to as the "missing money" issue, which is technically wrong but intuitively correct in the sense that in liberalised electricity markets without special capacity mechanisms there is a financing gap between privately and socially optimal levels of capacity.[25]

There are further drawbacks for having electricity provided according to commercial logic in liberalised markets. For instance, outside of countries with abundant reserves of hydroelectricity, storing electricity is unprofitable. This means that production and consumption need to be equalised second for second. While the issue can be solved with some effort at the technical level, the absence of storage remains an issue at the economic level. The absence of storage makes for volatile prices as demand changes during the day, the week and the season. This in turn makes it difficult for market participants to aggregate volatile short-term prices (added to the risk of potential breaks in long-term trends) into long-term investment signals. While forward markets allow for some control of price volatility, they do not exist beyond three years. Dealing with price uncertainty in liberalised electricity markets is further complicated by:

- dependence on weather, climate and consumption patterns;
- inelasticity of demand, especially in the short-run;
- considerable length of investment cycles;
- dependence on the macroeconomic environment, regulatory and policy changes.

The superposition of different policy initiatives in nominally deregulated electricity markets, notably the selective subsidisation of variable renewables, very much increases price uncertainty in both the short and the long term. This cumulative uncertainty is detrimental to investment in general terms but affects in particular potential investments in technologies with high capital costs.

If unchecked and unaccompanied by off-setting measures such as capacity mechanisms, the subsidisation of variable renewables can also pose risks to the security of electricity supply. Subsidising a megawatt of variable renewable capacity contributes very little to the security of electricity supply. Its "capacity value", or its ability to contribute to peak demand, is in fact very low. However, the same megawatt of renewable capacity diminishes the economic viability of a megawatt of dispatchable capacity and increases the risk that the latter will be withdrawn from the market or not be substituted at the end of its technical life.

Another characteristic of deregulated electricity markets is the externalisation of costs generated at the plant level towards the system level. Such costs created, for instance, by the intermittency of production, are either not taken into account at all (resulting over time in a degradation of networks, operating conditions and security of electricity supply) or are taken into account (most likely through increases in transport and distribution tariffs) in a diffuse and non-transparent manner that eludes open and informed democratic debate about crucial choices in the electricity

25. The term "missing money" refers to the fact that markets with strict marginal cost pricing, such as electricity markets fixed costs, are inadequately financed. Electricity market theorists, however, maintain that utilities will recoup the outstanding balance of their capital costs during scarcity hours, at which time demand exceeds supply and prices reach the level of the "value of lost load" set by the regulator. Such periods of VOLL pricing are, however, rare and due to the fact that they correspond to periods of rolling brownouts are frowned upon by politicians and consumers. In practice, the number of VOLL hours is far below the level required for fixed cost financing, which is why most markets are introducing or have introduced dedicated capacity mechanisms. For a broader discussion of the issue see Joskow, 2007.

sector. This is due: *i)* to the vertical disintegration of electricity systems which no longer internalise interactions between production, transport and distribution; and *ii)* to the selective subsidisation of variable renewables.

In the long run, this leads to a lack of cost transparency and to a disconnection between the full costs of electricity generation and prices that, calibrated on variable costs, exclude system costs and parts of capital costs. In turn, this leads to a growing disconnect between private and social optimality with a tendency towards under-investment and the resulting security of supply risks.

During the past three decades, deregulated electricity markets have often worked without posing major issues in several OECD countries. Liberalised electricity markets also continue to optimise short-term dispatch successfully. Today however, their limited ability to attract sufficient amounts of investment, in particular investment in low-carbon generation capacity, is becoming apparent. This inability was masked for a long time by the ample reserve margins and structural overcapacity established during the generous rate-of-return regulation that preceded deregulation and the long life-times of existing equipment. In addition, where investment was needed, gas-fired power plants constituted a technology option that was comparatively well-suited for competitive markets due to low fixed costs and high variable costs.

Suddenly, however, it has become obvious that liberalised electricity markets are not very conducive to long-term investment. There are two principal reasons for this. First, competitive electricity markets will always set the price equal to variable costs and will thus, under normal conditions, struggle to generate sufficient revenues for financing fixed costs. Second, the volatility of electricity prices will deter risk-averse investors. This holds for all technologies. Low-carbon technologies with their high fixed costs will be particularly exposed to both issues. Finally, the question of adequate fixed cost financing has been dramatically amplified in European OECD countries, where the influx of substantial amounts of subsidised renewables has seriously dented the business case for all forms of dispatchable power generation (mainly nuclear, coal and gas) which remains, however, indispensable for guaranteeing the security of electricity supply.

Electricity market deregulation is also running up against the issue of numerous policy interventions due to the special social and economic nature of electricity in advanced industrial economies. The price signal coming from the production-side in the electricity market are thus overlaid with a number of different policy signals that explicitly or implicitly have an influence on the attractiveness of different investment options. Among them are:

a) carbon markets;
b) feed-in tariffs, feed-in premiums or CFDs;
c) out-of-market long-term power supply agreements;
d) tariffs or fixed-price production sharing obligations (e.g. the French NOME law);
e) renewable obligations or objectives;
f) energy efficiency objectives;
g) social objectives (social tariffs);
h) capacity remuneration mechanisms.

In addition, market operations in the electricity sector have always been constrained by technical realities such as the size and layout of internal and external grids, as well as the need for system services such as voltage and frequency stabilisation, and reactive power provision.

The idea of organising electricity provision exclusively around competitive markets has thus always been more of a conceptual blueprint for experts and policy makers rather than a concrete reality. While imperfections exist in every market, the special characteristics of electricity such as non-storability and inelasticity of demand on the one hand, and the inevitable attention and policy activism that it receives as an indispensable necessity for modern industrial societies, ensure that the question whether deregulated electricity markets are indeed the best allocation mechanism for electricity is posed with more urgency than elsewhere.

Ultimately, the answer whether liberalised electricity markets can work hinges on four different conditions. First, there is the capital-intensity of investments in new capacity, since technologies with high capital costs cope poorly with the price risks associated with deregulated electricity markets. This refers to the already discussed bias against low-carbon technologies. Second, there is the elasticity of demand response, as more elastic demand can provide flexibility to smooth price shifts. This area is currently undergoing significant technological, behavioural and economic change and may alleviate some of the constraints mentioned earlier.

Third, there is storage, on which defenders of added variable renewables (VaREN) deployment place much hope. So far, however, neither the required technological break-through, nor a viable economic model has been forthcoming. This is also due to the intrinsic characteristics of some renewables. For example, electricity production by solar PV reduces peak prices during the day and thus diminishes the day-night differential from which storage providers traditionally obtain their profits. It is a typical example of how the intermittency of renewables undermines the economical foundations of the electricity system on which they depend. Thus variable solar energy would require additional storage to be deployed, but its presence undoes the very economics on which hydro storage provision is based. Finally, there is the amount of subsidised renewables itself, as subsidised variable renewables such as wind and solar are currently denting the business case for conventional thermal technologies (nuclear, coal and gas) by lowering average prices and reducing load factors. The latter, however, continue to be needed to maintain the security of electricity supplies.

Truly liberalised electricity markets as envisaged in economics textbooks were only workable in NEA and OECD countries during a transitory period dominated by an overhang of largely amortised baseload capacity, which was a legacy of decades of generous rate-of-return regulation. Where new capacity was needed, the advent of CCGTs coupled with a maturing gas transport infrastructure revolutionised the structure of baseload operation and enabled market liberalisation. As the price-setting technology with comparatively modest fixed cost, CCGTs not only were able to support a certain degree of price uncertainty but also ensured sufficiently high prices for others to recoup their fixed costs.

The limits of the deregulated electricity market model in NEA and OECD countries have become more apparent as legacy plants reached the end of the operating lifetimes and new investment is required. Gas-fired power generation also displayed a number of vulnerabilities including load factor risk, CO_2 emissions and the security of supply. This situation was compounded by a massive dash for variable renewables, in particular wind and solar PV. The idea that market competition on variable costs would automatically translate into reductions of overall costs, wholesale prices and retail tariffs is tested by the system-level effects in a sector that, due to the non-storability of electricity and its socio-economic importance, is unlike any other. A systematic rethink of electricity market design has thus begun and is gathering momentum (see, for instance, the Regulatory Assistance Project [RAP], the ESAP project at the International Energy Agency or the Chaire European Electricity Markets [CEEM] at Université Paris-Dauphine). This goes beyond the selective subsidisation of desirable technologies and focuses on three main points:

- The long-term financing of capacity through dedicated capacity mechanisms, price guarantees, long-term contracts, generalised feed-in tariffs, CFDs or other means providing long-term electricity price security.

- A higher priority for integrated system management with an increased role of supervision, sanction and coercion for transport system operators (TSOs) and an increased role for distributors, who will be also responsible for demand-side management, at the expense of retail suppliers.
- A coherent and robust carbon policy providing a clear long-term signal to investors whether in the form of a carbon trading system of a binding constraint or a simple carbon tax.

Such a return towards a more long-term view of the design and operation of electricity markets will be welcomed by all market participants. It would have particularly positive effects for nuclear energy, which is very much a technology requiring a long-term perspective. Changes will not come overnight as the evolution of regulatory regimes is complex and laborious. Nevertheless, as the following chapter shows, those interested in nuclear power have everything to gain to stay lucid and active observers in this process.

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Chapter II.2.

Risk exposure of different investor groups in different price scenarios

This chapter addresses the financial risk associated with the development of a new nuclear project in a different manner. Compared to the previous chapter, it adds construction cost risk and operational risk to electricity price risk. Instead of analysing the impacts of a severe, unexpected one-off decline in electricity prices from historic levels, it models the NPV of a nuclear project on the basis of anticipated price volatility around a central assumed price of EUR 80 per MWh. While the previous chapter focused on the option value connected with low fixed costs in the face of price declines, this chapter focuses on the effects of the superposition of the impacts of different sources of volatility. The level of the fixed cost to variable cost ratio here affects NPV only in a minor way through the uncertainty in overnight construction costs. The finer representation of the risk structure, however, differentiates the impact of the combined risk on the expected payoff and shortfall risk of different investor groups, notably bondholders and shareholders. Sections II.2.1 and II.2.2 will discuss the impact of different scenarios for price volatility on investor risk and Section II.2.3 will consider the impact of such uncertainties on the risk for bondholders and shareholders respectively.

The first objective is to propose a realistic model of the payoffs that a private investor may expect, taking into account the capital structure of the investing company as well as the impacts of taxes and asset depreciation on investment choices. The second objective is to show how the financial risk for the two different investor groups of equity holders and bondholders varies in different ways when exposed to price volatility and NPV risk at the project level. The model thus provides quantitative estimates for the impact of financial leverage on the NPV of the project and assesses the risk exposure of bondholders and equity holders according to the leverage of the company. Investor risk is modelled by way of the dispersion of expected returns (standard deviation of the project NPV) and of shortfall risk, which takes into account only the potential negative outcomes for investors. This complements the analysis performed in the previous chapter, where risk was addressed by way of the risk aversion when facing price declines.

The policy implications of these two complementary approaches converge in as much as they both reveal the high value of long-term fixed-price contracts for investors in nuclear projects. This value varies, of course, with different electricity price levels. A nuclear project could be financially viable under many combinations of the parameters considered (cost of capital, gearing of the project, expectations and uncertainty about overnight costs, lead times and future electricity prices), and the present analysis is limited to a few of their possible combinations. However, the tendencies and phenomena shown have a general validity which goes beyond the specificity of the few scenarios selected.

For the present analysis, the NEA model for optimal dispatch and NPV calculation already used in the previous chapter was expanded to include corporate taxes, depreciation and the effect of the tax-shield on debt's interest. With the help of stochastic Monte Carlo simulations on the most relevant variables for the financial risk, the net cash flow to the firm as well as the relative shares going to debt and equity investors are obtained for different scenarios. The main technical, economic and financial assumptions used in the study are summarised in Table 4. A more detailed description of the model, the methodology and the assumption used is provided in the Annex to Part II.

Table 4: Main assumptions used in the model

Technical assumptions		
Plant size (MWe)	1 000	
Construction time (years)	7	Stochastic
Plant operation life (years)	60	
Load factor (%)	85%	Stochastic
Economic assumptions		
Overnight cost (real) (EUR/kWe)	4 000	Stochastic
Decommissioning cost (real) (EUR/kWe)	600	
Total O&M cost (real) (EUR/MWh)	10.57	
Fraction of fixed O&M costs	95%	
Fuel cost (real) (EUR/MWh)	4.72	
Back-end costs (real) (EUR/MWh)	1.58	
Average electricity prices (real) (EUR/MWh)		Stochastic
Financial assumptions		
Inflation rate	2%	
Increase in electricity prices	2%	
Opportunity cost of capital (real)	5% to 12%	Fixed
Cost of debt (real)	3% to 7%	Fixed
Debt ratio	30% to 80%	Fixed
Tax rate	30%	
Debt repayment (years)	60	
Depreciation length (years)	15 (MACRS)	

MACRS: Modified Accelerated Cost Recovery System.

The model allows for a parameterisation of the opportunity cost of capital, the cost of debt and the debt ratio (gearing of the project). In particular, the study considers six different debt ratios between 30% up to 80%. The cost of debt used in the simulations varies from 3% to 7% in real terms, and the opportunity cost of capital from 4% to 12%. With the help of a Monte Carlo simulation, the model analyses the most important sources of risk in a nuclear new build project – electricity price risk, construction risk and load factor risk. Construction risk, which encompasses both the amount of overnight cost and the duration of construction, is particularly important for capital intensive projects such as nuclear. The range of the construction costs considered is representative of ninth-of-a-kind (NOAK) projects, between EUR 3 200 per kW to EUR 4 800 per kW, while assumed construction time is between 3.5 and 10.5 years. The uncertainty of overnight costs and construction duration is modelled by normal distributions with a standard deviation of 16% and 38% respectively and with cut-offs at ±20% and ±50%. A correlation between overnight costs and construction duration reflects the fact that delayed projects also tend to be over budget as well.

Electricity market risk is treated in detail via a two-stage model that takes into account the short-term volatility of electricity prices, as well as long-term changes in the electricity price trend. Short-term variability of electricity market prices is modelled via a mean reversion model with parameters derived from real data observed in European markets from 2005 to 2010. In the base case, the long-term average price is set at EUR 80 per MWh in real terms. This value is clearly higher than the market prices currently prevailing in Europe, but it was chosen to allow for scenarios in which market-based private investment in nuclear power at realistic rates of interest might go ahead. Additional calculations are performed for alternative price scenarios ranging from EUR 40 to 120 per MWh for long-term average electricity prices. The results for different price scenarios are aggregated with different weights in three composite scenarios with increasing electricity price volatility and concomitant market risk (see Table 5). It should be noted that in all three composite scenarios, the mean price is EUR 80 per MWh. In other words, these three scenarios ensure the same average level of return and differ solely by the variability of future prices. They thus have the same expected return but different risk.

Table 5: Composition of the three composite scenarios with increasing risk
(Percentages indicate relative weights of sub-scenarios, average price EUR 80 per MWh)

		Change in electricity price					
		±50%	±40%	±30%	±20%	±10%	Stable
Scenarios	Low electricity price risk	0%	0%	1%	5%	20%	48%
	Medium electricity price risk	1%	2%	5%	10%	15%	34%
	High electricity price risk	3%	5%	8%	12%	14%	16%

In the “medium electricity price risk” scenario, for example, the market experiences either a price increase or a decrease of 50% with a probability of 1%. Furthermore, prices will increase or a decrease by 40% with a probability of 2%, while there is a probability of 5%, 10% and 15% that electricity prices change by 30%, 20% and 10% respectively. Prices stay constant at the level of EUR 80 per MWh with a probability of 34%. It should be noted that those probability distributions are symmetrical, so that the average price remains EUR 80 per MWh for all scenarios.

Operating risk is taken into account by representing the availability factor of the plant with a triangular distribution that has an average of 85% and extreme values of 75% and 95%. The model does not take into account the variability of the fuel cost nor the financial risk associated with the management of nuclear waste and decommissioning. However, these aspects constitute only a small fraction of the cost of nuclear generation and thus their impact on the total financial risk of a nuclear project is rather limited.[1]

The analysis does not consider the political risk, i.e. the change in governmental policies towards nuclear, which could result in new taxes, additional regulatory requirements during the lifetime of the plant, and also forced abandonment of

1. Total fuel cost represents only a small percentage of the total LCOE of nuclear, between 10 and 15%, depending on the discount rate chosen. Also, the pure uranium cost represents only a fraction of the total fuel cost, while remaining costs are due to enrichment, fuel fabrication processes and radioactive waste management. Also, decommissioning costs have a limited weight on the LCOE of nuclear, since these costs occur several decades after the commissioning date of a plant. For an investor having to decide on a nuclear new build project, the financial risk associated with decommissioning is once again limited.

construction or premature closure of operating plants. In case of a nuclear project, this risk, although difficult to express in a quantitative way, can be significant, as has been experienced in some OECD countries after the accident of Fukushima Daiichi.

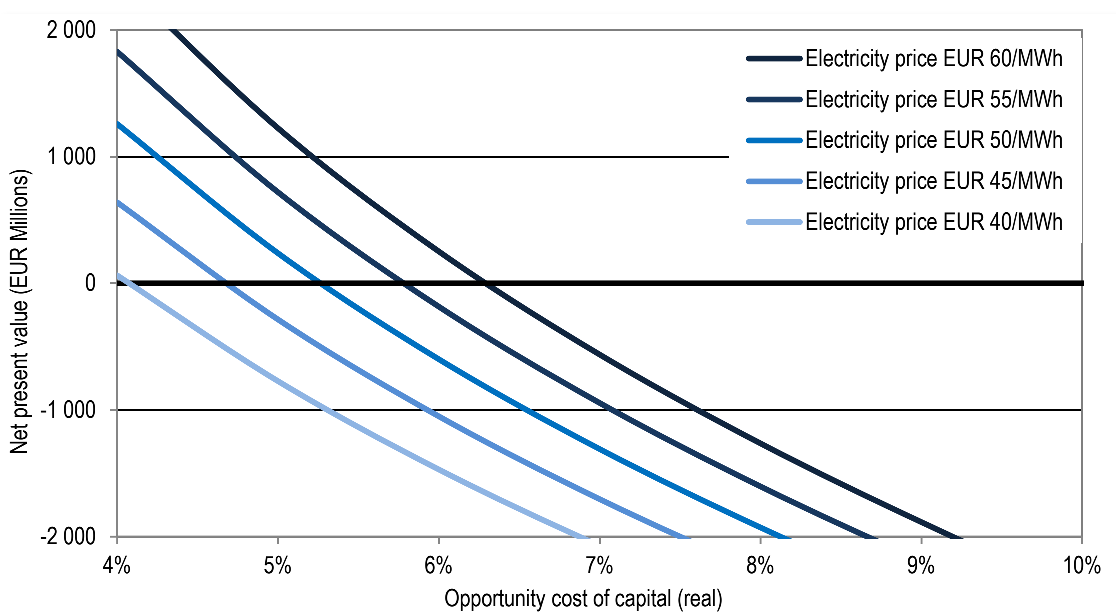
II.2.1. The financial impact of different price scenarios on the present value of new nuclear projects

Reduced electricity demand in Europe, a consequence of the severe financial crisis that has lasted for almost a decade, combined with the fast development of variable renewables such as wind and solar, has led to a severe reduction in the wholesale electricity prices across Europe. The downwards trend of electricity prices has been continuous over the last decade across all Europe. As an example, day-ahead prices in Germany were at an average level of EUR 30 per MWh during spring and summer 2014, and at EUR 40 per MWh in autumn 2014.

The current level of electricity prices thus does not support the financing and construction of a new NPP (and more generally of any new generation plant) in a competitive market environment without any form of governmental intervention. This is clearly illustrated by Figure 12, which shows the NPV of an NNB project as a function of the opportunity cost of capital at a debt ratio of 60% for several levels of average electricity prices that broadly encompass the price range seen in the European power markets during the last decade. Even at an average electricity price of EUR 60 per MWh, new nuclear new construction would be viable at an opportunity cost of capital of about 6.5%, which is still low compared to the requirements of large utilities in Europe. With the investment cost assumed in this study, a minimal market price of EUR 70-80 per MWh would be needed to attract investments in new nuclear on a pure market basis.

The future of nuclear new built in Europe relies on the following three factors: the level of average electricity prices, a progressive reduction in construction cost and lead times; and third, on the adoption of long-term pricing arrangements to reduce the financial risk of a nuclear project.

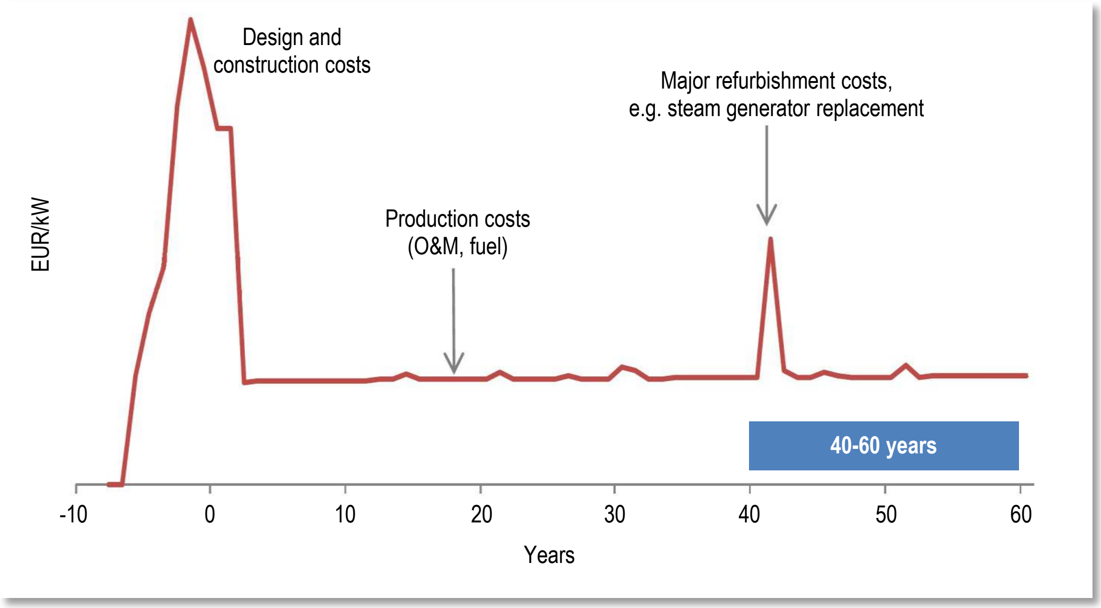
Figure 12: NPV of a nuclear new build project at different levels of electricity prices
(Overnight costs at EUR 4 000 per kW and debt ratio of 60%)



II.2.2. Determining investor risk as a function of net present value (NPV) variability and average net loss

The expenditure profile in an NPP project can be divided into two different phases that are characterised by a different risk profile from the investor viewpoint. During pre-construction and construction, large capital expenditures (CAPEX) must be made without expecting any revenues from the electricity generation. Once the plant is operational, nuclear power guarantees reliable electricity generation with low, stable and predictable production costs over a very long time frame. A schematic representation of the expenditures in an NPP project is given in Figure 13.

Figure 13: Expenditure profile of a nuclear power plant project



Source: Courtesy of EDF.

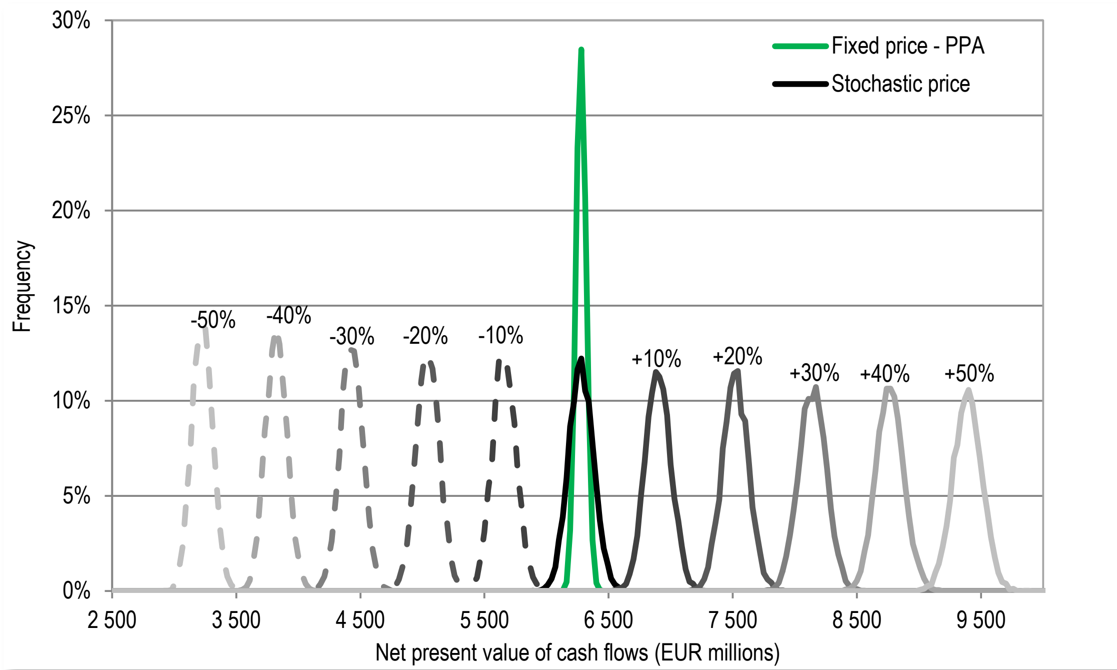
Investor risk also changes significantly over the lifetime of a nuclear project. In the first phase, the capital intensity and the length on the construction process, combined with uncertain construction costs and lead times, make for a significant investor risk. During the production phase, the low level of generating cost and the high availability factors of nuclear power gives a relatively stable net cash flow for the investor. During this phase, the variability of the net cash flow and thus the risk faced by an investor is significantly lower for nuclear than for most other generation options.

There is thus a case for changing the composition of investors when switching from construction to operations. The latter phase, in particular when coupled with fixed-price long-term contracts, should be attractive to long-term investors such as pension funds or sovereign funds interested in investments with stable and predictable rates of return over long time frames. Risk-seeking investors should instead be in charge of the development and construction of the infrastructure to subsequently transfer the ownership to the long-term investor once the riskiness of the project has been reduced. In the power sector, NPPs seem particularly attractive due to their long lifetimes, the correlation of their payoffs with inflation and the relative stability of their revenues even in environments with market risk. A long-term fixed-price contract would further reduce risk and enhance the attractiveness of an NNB project for such investors.

Due to this dichotomy of risk, it makes sense to also divide the financial analysis of an NNB project into two distinct phases. First the electricity market and operational risks are discussed in isolation by analysing the variability of the NPV of an NPP during operations. In a second stage, the analysis is complemented with the uncertainty of expenditures during construction. The calculations presented in the following pages assume, if not specified otherwise, a cost of capital of 7.5%, a cost of debt of 5% and a debt ratio of 70%.

Figure 14 shows the NPV distribution of net cash flows generated by an NPP after the beginning of operations for different average levels of electricity prices. Risk is represented by the uncertainty of future cash flows once the power plant has been constructed. Riskier projects are characterised by a wider range of possible outcomes and by a larger standard deviation. The variation of the NPV is due to the short-term volatility of electricity prices as well as due to annual variations in the availability of the NPP. The curve plotted in black corresponds to a base price of EUR 80 per MWh, while the grey lines represent the NPV with different electricity prices. The green curve shows the variability of revenues in the presence of a purchasing power agreement (or a long-term contract) at a fixed price of EUR 80 per MWh. In the latter case, the NPV distribution is much narrower since the variability of revenues is only due to uncertainty over the availability factor.

Figure 14: NPV of cash flow after commissioning at different electricity price levels
(EUR millions)

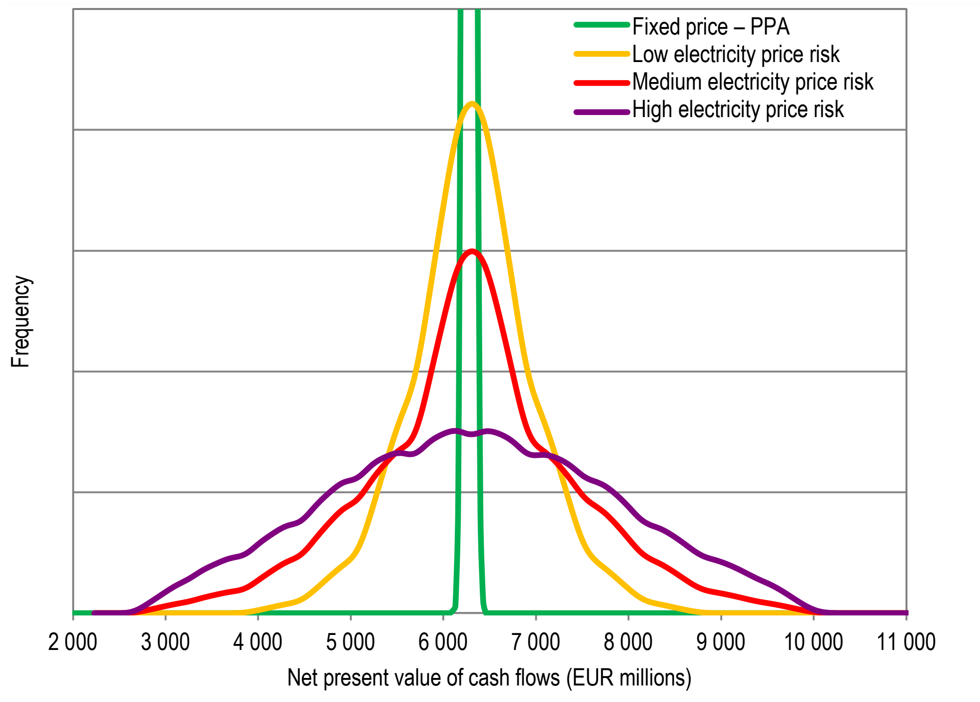


PPA: Power purchase agreement.

The results illustrate how nuclear, due to its low variable production costs, is not particularly affected by the short-term variability in electricity prices, but is much more vulnerable to long-term changes in electricity price trend (which are represented by the curves for different price levels).

The results show what would be the NPV given different electricity price levels. This analysis needs to be complemented by associating probabilities to each outcome. To take this into account, three scenarios have been established as shown in Table 5, corresponding to different levels of the electricity market risk. The results are provided in Figure 15, together with the NPV distribution in the case of a long-term contract or power purchase agreement (PPA). Table 6 contains the quantitative results for the different scenarios considered, as well as the NPV and standard deviation of construction costs.

Figure 15: NPV after commissioning for different electricity price scenarios
(EUR millions)



PPA: Power purchase agreement.

As expected, scenarios with higher electricity price risk show a wider spread in the NPV distributions and are therefore characterised by a larger standard deviation. The results show clearly the benefits of fixed-price PPAs (alternatively, one may think of a feed-in tariff or a CFD), as they reduce the variability of cash flows after commissioning. In this example, the standard deviation of NPV is reduced to 0.7%. This is a reduction by a factor of ten in comparison with the scenarios with price risk. It should be noted that, by construction, the average NPV remains the same in all scenarios with or without electricity price variations. This reflects the fact the PPA has been defined at the level of average future market prices. The PPA is thus "fair" and does not contain any form of subsidy.

Table 6: NPV of cash flows after commissioning

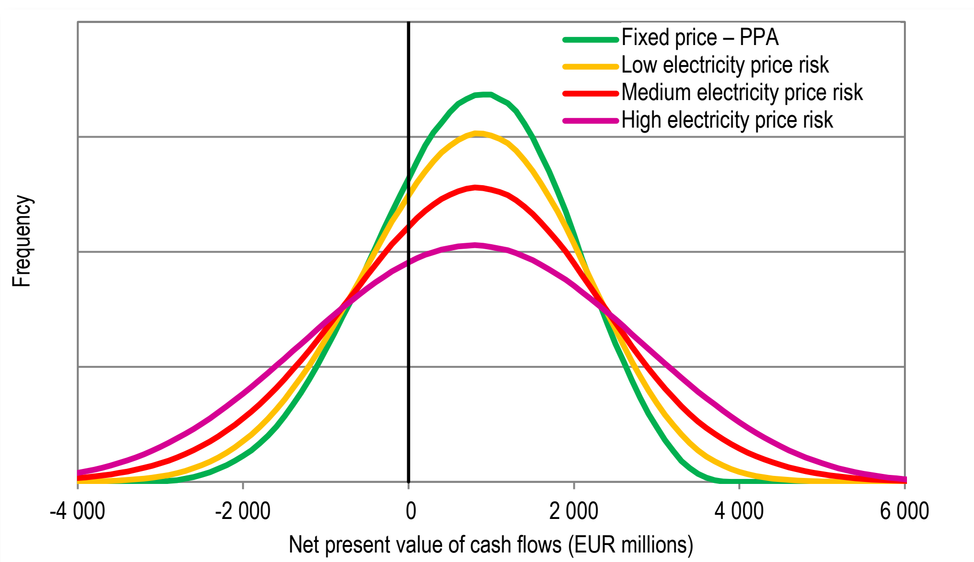
		Average	Standard deviation	
		EUR million	EUR million	%
Construction cost		5 500	920	16.8%
Scenarios	Fixed price – power purchase agreement	6 300	40	0.7%
	Low electricity price risk	6 300	620	9.9%
	Medium electricity price risk	6 300	1 100	17.5%
	High electricity price risk	6 300	1 490	23.6%

From an investor viewpoint, the risk reduction guaranteed by a fair long-term contract warrants a reduction in the required rate of return, which in turn enhances the competitiveness of a nuclear project. It is difficult to assess with precision the reduction in the rate of return that is required under price risk when compared to a fixed-price PPA. *Ceteris paribus*, however, risk is reduced for both electricity producers and consumers as both parties lock in their future electricity price and are therefore protected from variability.[2]

In a second step, the study also includes the risk during construction and thus considers the whole lifetime of a nuclear project, from construction to decommissioning. The final analysis thus includes the following four major sources of uncertainty in: *i)* overnight costs; *ii)* construction length; *iii)* operating performance; and *iv)* electricity prices. Both standard deviation, which measures the dispersion of net cash flows, and shortfall risk, are considered measures of investor risk. Shortfall risk is the probability that the NPV of the whole project is negative or, in other terms, that the rate of return obtained in the project does not meet requirements. Hence, while the standard deviation considers the whole spectrum of possible financial outcomes, shortfall risk and average shortfall focus only on the negative outcomes for the investor.

Distribution of cash flows are plotted in Figure 16 for all four scenarios considered (with and without electricity market risk). Standard deviations of the net cash flows over the lifetime of the plant are reported in Table 7 in absolute values as well as in percentage of the average NPV of construction costs. Estimations of the shortfall risk and of the average value of the shortfall are provided in Tables 8 and 9 for different combinations of debt leverage, capital costs and debt costs.

Figure 16: NPV distribution of cash flow for different electricity price scenarios
(EUR millions)



2. In principle, both parties profit from the reduction in their respective business risk due to a fixed-price agreement. Nevertheless, one may construct scenarios in which one or both parties would have benefit from remaining exposed to short-term electricity price volatility. For instance, a gas plant that faces volatile gas prices but sets the electricity price as the marginal producer has a more constant free cash flow (price minus variable cost) with variable electricity prices. Likewise, consumers exposed to macroeconomic shocks might benefit more from the lower electricity price during a slump than suffer from the added costs of a higher electricity price during a boom.

As expected, integrating the uncertainties of construction costs increases the maximal spread and variability of financial outcomes in all electricity price scenarios considered. With low electricity market risk, total financial risk is dominated by the uncertainties during the construction phase. For scenarios with more variable electricity prices, both construction and electricity market risk are important parts of the total financial risk of a nuclear project.

The benefits of long-term fixed-price arrangements remain significant also when the whole lifetime of a nuclear project is considered. Long-term contracts reduce the spread of possible financial outcomes as well as their variability. For instance, the maximal spread and the standard deviation of NPVs are reduced by a factor of two in comparison with the scenario with very high electricity market risk.

Table 7: NPV of cash flows in a nuclear project

		EUR million	%
Scenarios	Fixed price – power purchase agreement	980	17.9%
	Low electricity price risk	1 160	21.2%
	Medium electricity price risk	1 470	26.9%
	High electricity price risk	1 780	32.6%

The benefits of long-term contracts appear more clearly when considering only the negative outcomes from the investor viewpoint. For all projects that are financially viable (those with a positive expected NPV), long-term price arrangements significantly reduce the probability of having a negative financial outcome as well as the average extent of the financial loss (average shortfall). Clearly, such significant reductions in shortfall risk reduce the risk premium required for investments in nuclear projects and thus facilitate their realisation.

As an example, with a cost of capital of 7%, a debt cost of 5% and a debt ratio of 70%, a long-term contract on electricity prices would reduce the possibility of a shortfall by about one third and the average shortfall by about two thirds; in comparison with a scenario with high electricity price risk (see Table 8). Benefits are even more evident in scenarios with higher expected NPVs, such as the ones with a lower opportunity cost of capital presented in Table 9.

Table 8: Probability of shortfall and average shortfall (cost of capital of 7%, debt cost of 5%)

Capital cost 7% Debt cost 5%	Probability of shortfall			
	Fixed price	With market risk		
		Low	Medium	High
Unleveraged	40.9%	42.2%	43.8%	45.5%
30% Debt	32.0%	34.2%	37.1%	40.0%
40% Debt	29.2%	31.7%	34.9%	38.3%
50% Debt	26.9%	29.3%	32.9%	36.6%
60% Debt	24.4%	27.1%	30.9%	34.9%
70% Debt	22.1%	24.8%	28.9%	33.2%
80% Debt	19.7%	22.7%	26.9%	31.5%

Capital cost 7% Debt cost 5%	Average NPV Shortfall (EUR million)			
	Fixed price	With market risk		
		Low	Medium	High
Unleveraged	-316	-378	-492	-625
30% Debt	-223	-280	-389	-515
40% Debt	-197	-252	-358	-481
50% Debt	-173	-226	-329	-449
60% Debt	-151	-202	-302	-419
70% Debt	-131	-180	-276	-390
80% Debt	-113	-159	-252	-362

Table 9: Probability of shortfall and average shortfall (cost of capital of 6%, debt cost of 4%)

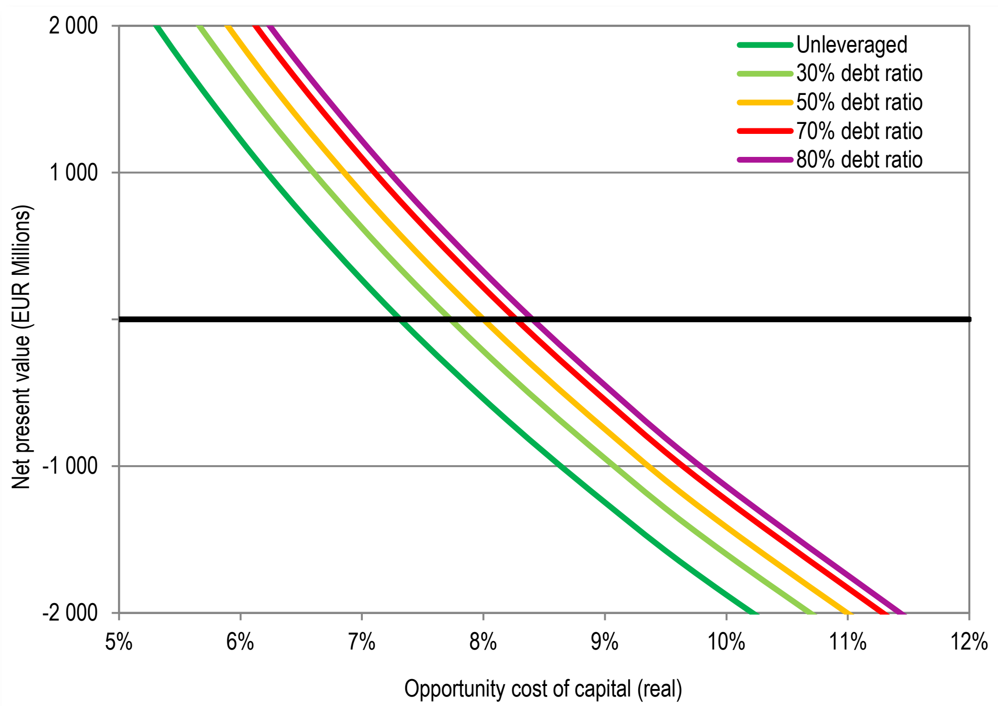
Capital cost 6% Debt cost 4%	Probability of shortfall			
	Fixed price	With market risk		
		Low	Medium	High
Unleveraged	11.3%	15.7%	21.7%	28.0%
30% Debt	7.4%	11.8%	17.9%	24.5%
40% Debt	6.3%	10.6%	16.8%	23.4%
50% Debt	5.5%	9.6%	15.7%	22.3%
60% Debt	4.6%	8.6%	14.6%	21.2%
70% Debt	3.9%	7.7%	13.6%	20.2%
80% Debt	3.3%	6.8%	12.7%	19.1%

Capital cost 6% Debt cost 4%	Average NPV shortfall (EUR million)			
	Fixed price	With market risk		
		Low	Medium	High
Unleveraged	-47	-97	-201	-326
30% Debt	-27	-67	-159	-269
40% Debt	-22	-59	-146	-252
50% Debt	-18	-52	-134	-236
60% Debt	-14	-46	-124	-220
70% Debt	-11	-40	-114	-205
80% Debt	-9	-35	-104	-191

II.2.3. The risk exposure of debt and equity holders in the case of a price decline and the role of loan guarantees

The capital structure of a company, i.e. its proportion of debt and equity financing, has a direct impact on the NPV and the attractiveness of a project. One reason is that the interest paid on debt can be deducted from taxes; hence higher leverage reduces the amount of taxes paid and thus increases the NPV of a project. This effect is illustrated in Figure 17, which shows the NPV of a nuclear project for different debt ratios of the company. At equal levels for the opportunity cost of capital, leverage increases the NPV of the project. However, an increase in the leverage of a company increases risks for debt holders as well as risks and required payoffs for equity holders.

Figure 17: NPV of a nuclear new build project as a function of debt ratio

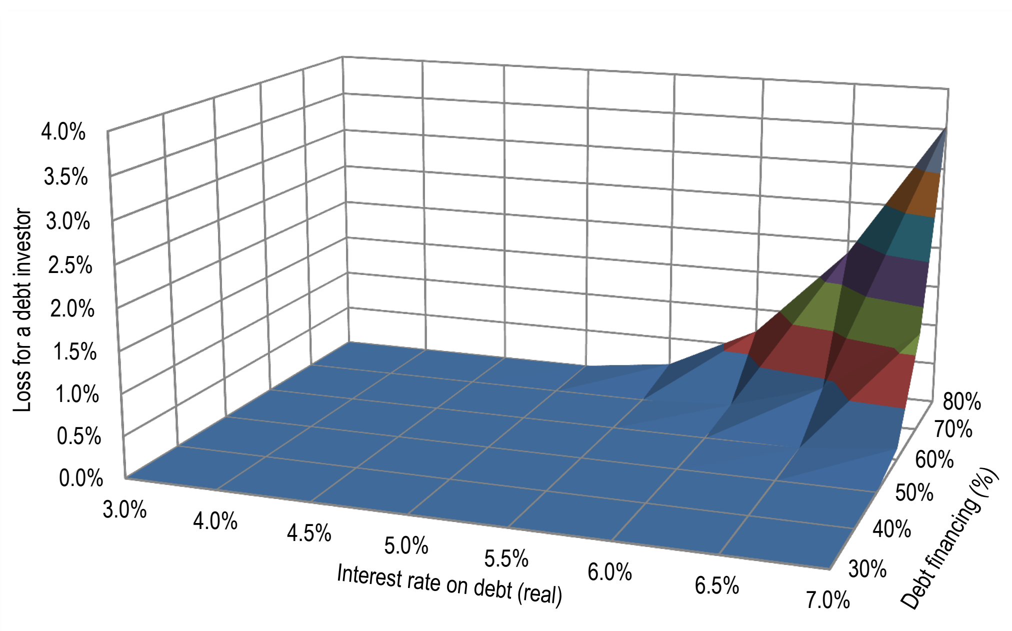


This section looks specifically at the financial characteristics of a nuclear project from the viewpoint of debt holders. The objective is to quantitatively assess the risk that debt holders are unable to recuperate their investment in the case of an unfavourable evolution of electricity market prices.

When electricity prices turn sharply lower, nuclear plant owners will experience a shortfall in their expected revenue. However, in all but the most extreme cases, a nuclear plant will keep on operating due to its low variable costs. This means that in almost all cases (even including financial restructuring under Chapter 11 of Title 11 of the US Bankruptcy Code) nuclear plants will continue producing some cash flow. While the cash flow may not be sufficient to repay the full investment costs, it will still cover part of it. However, due to the legal priority that bondholders have over equity holders, the remaining cash flow should go to debt holders. Whether it will be enough to cover all or just some bond payments depends of course on the specific financing structure of the company.

The model calculates the cash flow available to debt holders in case of an adverse evolution of electricity prices, taking into account the uncertainty in overnight costs, construction lead times and operational performance of the plant. Several combinations for the cost of debt and the debt ratio are considered, to illustrate how these parameters affect the risk for debt holders. The metric for risk is the average loss for the bondholder, expressed in percentage terms as the difference between the NPV of the committed capital and the NPV of the paid off debt. Thus, an average loss of 0% means that the cash flow going to debt holders is fully sufficient to repay the committed capital and accrued interests. A loss of 5% would mean that, on average, the repayment to debt holders covered 95% of the committed capital and interest. Results are provided in Figures 18 and 19 for declines in electricity prices of 30% and 50% respectively. Additional examples are provided in the Annex to Part II for different levels of electricity price drops.

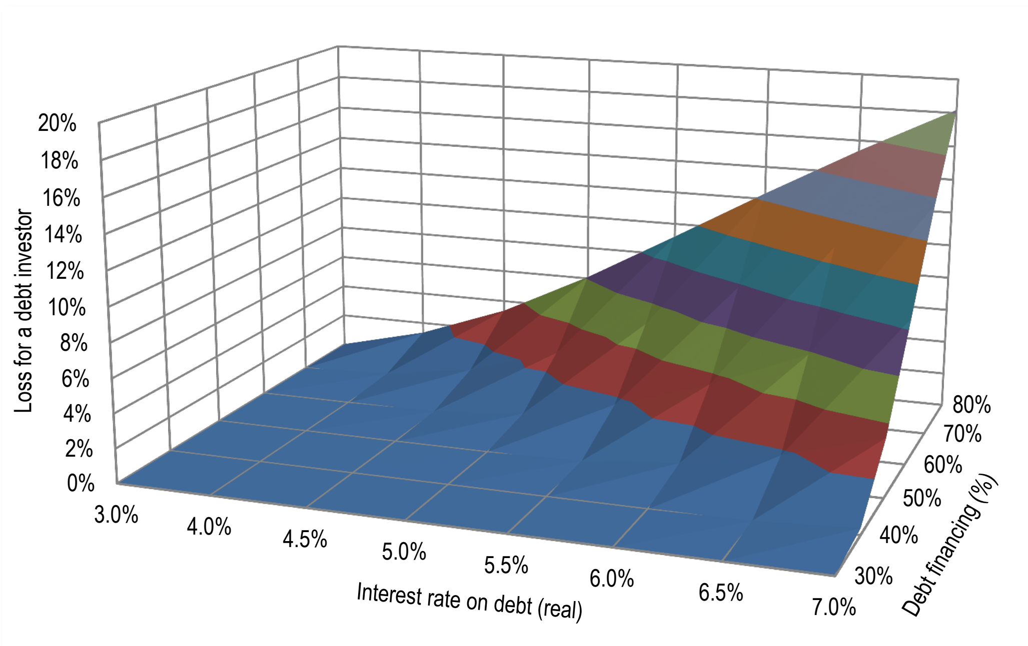
Figure 18: Average loss for a bondholder in case of 30% decrease in electricity market prices



Decreases in long-term electricity prices of less than 20% of the base case do not have any impact on the expected payoff for debt holders. Debt holders may incur financial loss only in case of a combination of high leverage (≥70%) and high interest rate (≥6.5%). Even then, however, the financial risk is rather limited. For all other financial arrangements, the nuclear project is able to fully service its debt (interest and capital) in all situations simulated.

In the case of more significant decreases in electricity prices between 30% and 40%, the financial risk for debt holders becomes significant for a larger range of financial arrangements. However, even in such adverse market conditions, the debt holders are fully repaid for debt ratios up to 50%. The average loss remains limited (less than 1% of the investment, on average) for debt ratios between 60% and 70% as long as the cost of debt is below 5.5%. Only for a combination of high financial gearing of the project and high required returns, the risk for bondholders becomes significant with a range of 3% to 10% of the expected pay back. Potential losses for debt holders increase substantially when long-term electricity prices decrease further (see Figure 19). If electricity prices decline 50% from their initial level, bondholders must expect losses even with a gearing of 50% except for ultra-low rates.

Figure 19: Average loss for a bondholder in case of 50% decrease in electricity market prices



The statistical analysis performed on nuclear project financing demonstrates a quantitative estimate of the financial risk for a debt holder and illustrates the interplay of long-term electricity price falls, financial gearing of the project and required rate of return.[3] At debt ratios below 60%, the risk for a debt-investor in a nuclear project is rather

3. It should be noted that the analysis has taken into account a limited number of causes that could affect the financials of a nuclear project, but it does not address some types of risks that are difficult to assess quantitatively. For instance, there is a possibility that the project is not completed or is shut down a few years after entering into operations due to changes in the political conditions. While political risk is not considered in the current analysis, it could impact the risk of a nuclear investment, especially from the perspective of a debt holder.

limited even for large electricity and permanent price falls. In such conditions, the risk premium required for investing in a nuclear project should be small. At higher gearing, however, the debt holder assumes a larger fraction of the project risk and thus the required interest rate will rise.

Although the definition of an optimal level of financial gearing requires a detailed analysis based on the individual characteristics of the shareholders, the present analysis indicates that a nuclear project could support a rather high level of financial leverage, in comparison with other generation technologies. This characteristic is ultimately a consequence of the low level of variable costs of nuclear. Even in very unfavourable conditions, a nuclear plant will experience some positive operating cash flow. Up to debt ratios of 60%, bondholders have only limited financial risk, even in the case of permanent large drops in electricity prices. However, debt holders are exposed to severe financial losses if the project is cancelled before completion due to political or economic reasons. In this case, debt holders can lose up to all capital committed.

This very robust result has important consequences for the choice of policy instruments to support the financing of nuclear new build. Traditionally, policy support has concentrated on the protection of debt holders, e.g. through government loan guarantees. Loan guarantees are effective in protecting debt holders from completion risk, but bring limited benefits once the power plant is completed. Due to the economic structure of nuclear power, i.e. its low variable costs, NPPs are extremely likely to always produce some positive operating cash flow even with much lower than expected prices. Any surplus over variable costs will go to bondholders.

The potentially more important question is whether the surplus will be enough to cover the totality of capital costs. The answer, provided by the two complementary analyses in Chapters II.2 and II.3 is negative. With volatile electricity prices, there exists a considerable risk that the totality of lifetime cost will not be covered. However, it is shareholders that must absorb this potential short-fall between operating cash flow and the full costs of operation.

Shareholders are of course supposed to be remunerated to take on such residual financing risks. However, the economic characteristics of nuclear power – high capital costs, low variable costs and long pay-back periods – make residual risk for shareholders high. This means that the core shareholders of an NNB project, which include most likely a large utility, will either demand very high rates of return or will reflect very carefully indeed before committing themselves. Innovative support measures that address such short-fall risk, including guarantees for prices and quantities, might thus ultimately be a superior way to provide financial support than loan guarantees, which are addressed at the financial constituency least exposed to risks once a power plant has begun to operate.

Chapter II.3.

Case studies on long-term solutions for electricity price volatility and financing

Previous chapters have set out the challenge for nuclear power of dealing with long-term uncertainty about electricity prices. They have also identified the value of long-term pricing arrangements. The results in these chapters provide the analytical and quantitative framework for an empirical fact observable in the real world: successful nuclear power projects rely on stable long-term arrangements for electricity prices. Whether at-cost take-off (Finland), long-term contracts (France), guaranteed tariffs (Turkey, United States) or CFDs (United Kingdom), capital-intensive nuclear power projects are only going ahead in countries that offer electricity price stability to investors. This holds true for countries with electricity price regulation as well as for those countries that have liberalised electricity markets.

The following three case studies of NNB projects that either take place in NEA and OECD countries or involve companies from NEA and OECD countries as primary contractors will highlight the importance of price stability and long-term finance in practice. The three case studies presented in the following chapter are:

- construction of a Russian VVER in Akkuyu, Turkey;
- construction of a Westinghouse AP1000 in Vogtle (Georgia), United States;
- construction of a Korean APR-1400 at Barakah, United Arab Emirates.

Box 3 presents the main features of the Mankala model in Finland, where currently a French EPR is being built. The case studies represent experiences of constructing NPPs with different technologies in different regions of the world under very different circumstances. Nevertheless, they converge over the fact that long-term financing arrangements were crucial in all three cases. Such arrangements can come under very different forms, ranging from long-term electricity supply agreements in a vendor-financed build-own-operate (BOO) structure over regulated tariffs to export finance. It is probably safe to say that these arrangements came due to the individual ad hoc financial considerations specific to each stakeholder rather than to any systematic conceptual framework as proposed in this study.

The purpose of the combination of conceptual analysis and empirical evidence presented here, however, is not to inform investors about the risks they are incurring when financing capital-intensive projects selling output into volatile markets, as they are likely aware of these risks. The purpose is rather to alert policy makers that nuclear finance requires a sustained and systematic approach to the management of financial risks over 60 years or more. This is all the more urgent in an electricity environment that has become ever-more volatile due to the introduction of large amounts of variable renewable technologies such as wind and solar PV. In the absence of effective actions to support long-term financing arrangements, the choice of nuclear power for electricity production will become the exception rather than the norm. This would mean that future electricity systems will either be more expensive, more carbon-intensive, or both.

Box 3: The Mankala model*

The Mankala model is an ownership arrangement of energy production companies that was developed in Finland in the 1930s by forest product companies that joined their resources to acquire a shared generation asset. The model became widespread in the 1960s and is now common in Finland.[1] Forest product companies such as pulp and paper producers are characterised by large around-the-clock electricity needs, which are usually provided by technologies with high capital and low variable costs. In 2010, the electricity generated by Mankala Companies reached 42% of total Finnish production and 61% of the production produced by the most capital-intensive technologies, nuclear, hydro and wind.

The companies based on the Mankala model are typically limited liability companies jointly owned by several parties such as energy wholesalers and distributors, energy-intensive industries and local municipalities. However, unlike standard companies, the purpose of a Mankala company is not to make a profit and pay a dividend to the shareholders but to provide them electricity at cost. The shareholders have the right and the obligation to purchase at cost an amount of electricity that is proportionate to their respective shareholdings. The electricity acquired can then be used by the owners to satisfy their own energy needs or can be sold bilaterally or through the Nordic Power exchange market. Figure 20 and Table 10 illustrate the shareholder's composition and operating principles of Teollisuuden Voima Oyi (TVO). TVO, a company which is based on the Mankala model, is currently financing the construction of the Olkiluoto 3 power plant by a consortium led by AREVA and Siemens. TVO has issued three different classes of shares, each one referring to specific assets. The composition of shareholders can vary for each class of shares.

Figure 20: Financial structure of TVO

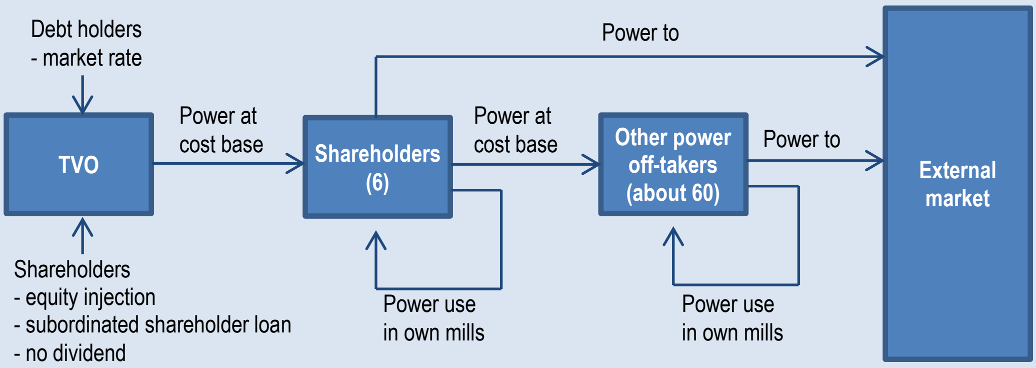


Table 10: Shareholders composition of TVO

		A-series (OL 1 and 2)	B-series (OL3)	C-series (Meri-Pori)
Etelä-Pohjanmaan Voima	Local utilities, others	6.5%	6.6%	6.5%
Fortum	Electric company	26.6%	25.0%	26.6%
Karhu Voima		0.1%	0.1%	0.1%
Kemira	Chemical industry	1.9%	-	1.9%
Mankala Ab	City of Helsinki	8.1%	8.1%	8.1%
Pohjolan Voima	Industry, local utilities, municipalities, others	56.8%	60.2%	56.8%

1. In the 1960s, the Supreme Administrative Court of Finland ruled that the owners of a Mankala company were not receiving any hidden dividends by obtaining electricity at a cost that was below the average market price.

Box 3: The Mankala model* (*cont.*)

The main objective of a Mankala structure is to allow shareholders to undertake and finance a project together that would be too large or too risky for any of them individually. This model is particularly suited for power generating technologies that require a large upfront capital investment but have lower and more stable operating costs and guarantee low long-term generation cost. In addition, such co-operative models facilitate the access to the market by new and small players and, more in general, ease the diversification of the generation mix for all shareholders, regardless of their size.

The experience of Finland shows that the benefits of Mankala structures are not limited to a reduction of financial risk via a simple diversification process. The Mankala structure also provides shareholders with the benefits of lower and more stable electricity costs and thus provides a hedge against electricity price volatility. This is particularly important for utilities, electricity-intensive industries and municipalities that cannot easily transfer the electricity price risk to customers.

From the viewpoint of the generating company itself, the Mankala structure virtually eliminates the electricity price and production risk, since it gives the certainty that all the energy produced will be acquired by the shareholders on a cost basis. Also, shareholders remain liable for the costs of operating the plant and repaying outstanding loans, even if the company would not be profitable at prevailing electricity market prices. These features allow for relatively high debt ratios compared to classical generating companies and to a lower cost of capital.[2]

Overall, Mankala companies have generally good creditworthiness and consequently a high credit rating, which contributes to reducing borrowing costs. As an example, the rating reports by Standard & Poors (S&P) on TVO underline that the company has a strong business risk profile thanks to its "protective business model including a full cost structure backed by long-term off-take agreements with the owners" deriving from the Mankala principle. Also S&P states that the shareholders "would have a strong interest in supporting TVO should any individual shareholder default, to protect their investment and output from a proven low-cost electricity producer" (S&P, 2012; S&P, 2013).

In conclusion, Mankala-like structures can effectively reduce electricity price and operation risk, which constitute an important part of the risk associated with electricity production. However, these structures on their own cannot provide protection for construction risk (over-cost and construction delays), which remains significant for all capital intensive technologies including nuclear.

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* This section benefited from discussion with Kaija Kainurinne (2014) from TVO. Material has been taken from Pirttilä, Mikko and Sarita Schröder (2011), *Mankala Energy Production Model Under Threat?*, International Law Office, May 2011.

2. The TVO Olkiluoto 3 project is financed to 75% with bonds (issued by TVO itself, by the shareholders and by French and Swedish Export Credit Agencies) and to 25% by equity (Barkatullah, 2014).

II.3.1. Case study of Akkuyu nuclear power plant

General background

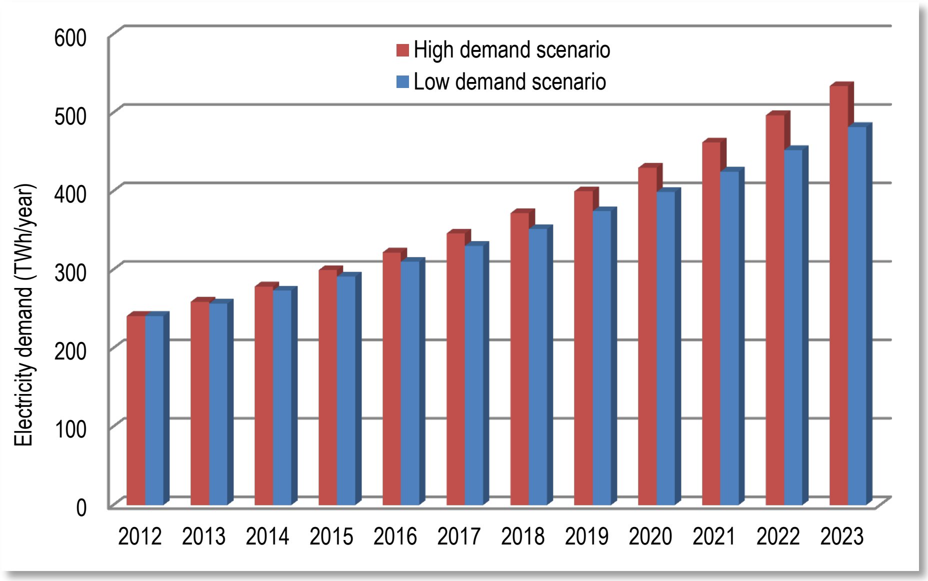
Turkey is the 17th largest economy in the world and has one of the fastest growth rates among the NEA and OECD countries. From 2002 to 2012, the real gross domestic product (GDP) growth rate averaged 5.1%, despite the global financial crisis in 2008 and 2009 and the economic slowdown that affected the European economy in 2012. According to Eurostat data, Turkish GDP per capita adjusted by purchasing power standard stood at 52% of the EU average in 2011. In 2012, the nominal GDP was current USD 734 billion and GBP per capita was current USD 10 067. According to the 2023 vision targets of the government, in 2023, it is planned that:

- GDP will be USD 2 000 billion;
- GDP per capita will be USD 25 000/capita;
- the export amount will reach USD 500 billion.

Turkey has a relatively young population, estimated at 75.63 million people in 2012. The population density is about 97 inhabitants per km^2. The average annual growth rate of the population was 1.4% between 2007 and 2012, and decreased to 1.2% in 2012. It is predicted that the population of Turkey will be 84.25 million in 2023. The population will increase slowly towards the year 2050, and it will peak at 93.48 million people in this year. After 2050, the population will start to decline, and it is expected to be 89.17 million in 2075 (Turkstat, 2014).

In the last decade, Turkey has become one of the fastest growing energy markets in the world concurrent with its demographic and economic growth, and it is rapidly gaining a competitive structure. In addition, the country aims to become a central energy hub for transporting oil and gas from the eastern Mediterranean to Europe and Asia. Total primary energy supply was 105.1 Mtoe in 2010, up 38% from the 2000 values and more than double from 1990. Compared with other NEA and OECD countries, Turkey relies heavily on fossil fuels, which accounted for about 90% of total primary energy supply (TPES). Also, Turkey does not have oil and natural gas resources and depends on imports for more than 72% of its total primary energy supply.

Figure 21: Electricity demand projection



Source: MENR, 2013.

Electricity consumption has grown very rapidly in the last two decades, reaching 241 TWh in 2012 from about 47 TWh in 1990. This trend is likely to continue in the near future: the Turkish Electricity Transmission Company estimates that Turkey's demand for electricity will increase at an annual rate of 6.5% in low demand and 7.5% in the high demand scenario between 2012 and 2023 (see Figure 21). The generation mix is based on natural gas (46%), coal (24%) and hydro (25%), while oil, geothermal and wind power contribute to the remaining 5% of the supply in 2012 (MENR, 2013).

Electricity market and industry structure

The Turkish electricity industry has been dominated by large, publicly owned and vertically integrated companies. However, since 2001 the Turkish electricity sector has been undergoing a gradual restructuring process, in particular since the enforcement of the 2001 Electricity Market Law which introduced free market conditions and liberalised the energy sector. The goal of this restructuring process is to move towards a decentralised market where state intervention is limited, especially with regard to investments and risks (EDAM, 2011). Starting from 2003, the government is progressively opening the electricity market for all customers and this process should be completed by 2014 for all industrial and non-industrial users. The Turkish government is also taking steps to create competitive wholesale and retail markets; by 2023 an energy stock exchange should be established.

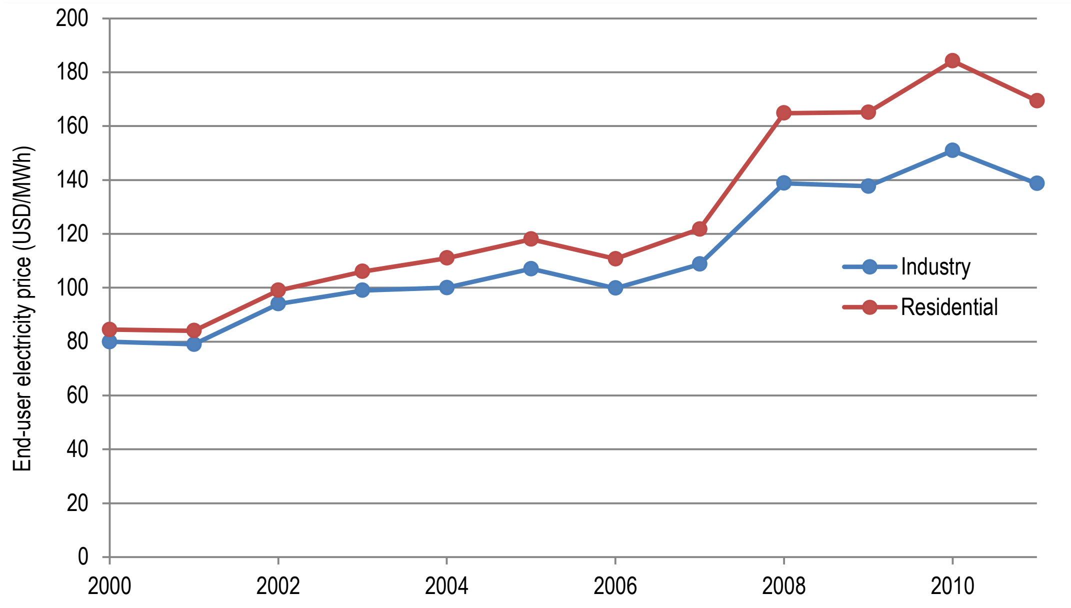
Since the enactment of the 2001 Law, Turkey has created an independent energy regulator (Energy Market Regulatory Authority, or EMRA) and has implemented a licensing regime. In the electricity sector, Turkey has unbundled the government-owned incumbents into different business activities: transmission (Turkish Electricity Transmission Company, or TEIAŞ), generation (Turkish Electricity Generation Corporation, or EÜAŞ), distribution (Turkish Electricity Distribution Company, or TEDAŞ) and wholesale trading and retail supply (Turkish Electricity Trade and Contract Corporation, or TETAŞ). The 2001 law decreed TEIAŞ as the sole transmission and market operator, and started to privatise the state-owned distribution and generation businesses.

Until 2001, the private sector was able to participate in generation, transmission and distribution through three different modes, namely build-operate-transfer (BOT), BOO and transfer of operating rights; private-owned companies generated about 22% of the total electricity in 2001. However, although the 2001 Law introducing market liberalisation abolished these models, the legal obligations arising from them still remain.

The largest generation company is the state-owned EÜAŞ which controlled around half of all installed capacity in 2009, while the rest of the generation is divided between independent producers, auto-producers and private ownership under BOO, BOT and transfer of operating rights (TOOR) agreements. Thus, the share of electricity generation produced by state-owned companies decreased from 78% in 2001 to about 46% in 2009. The only state-owned wholesale company is TETAŞ, with a market share of around 43% in 2009. By March 2010, there were 45 wholesale licence holders. By law, the market share of any privately owned company is limited to 15% of the total wholesale volume in the previous year.

Turkey has traditionally regulated end-user tariffs but, as part of its market reform policy, has gradually moved to a fully cost-reflective tariff system. The wholesale tariffs are already cost-based. A major step towards fully cost-reflective retail tariffs was the introduction of a cost-based pricing mechanism in July 2008. Retail tariffs had been kept largely constant from 2002 to 2007 (see Figure 22), despite a significant increase in gas prices and in generation costs, and limited improvements in reducing network losses and increasing collection. At times, tariffs were below generating costs. Nowadays tariffs are adjusted quarterly, on the basis of changes in input prices (coal and natural gas), inflation, and exchange rates. The transition to this system in 2008 was complemented by three large tariff increases which raised the average retail tariff by about 50%, thereby reaching fully cost-recovery levels. By international comparison, electricity prices to end-users in Turkey are close to the IEA median for industry and slightly below the IEA median for households.

Figure 22: End-use electricity prices in Turkey*



* Prices include 18% value added tax (VAT).

Energy plan for Turkey and the role of nuclear

In order to respond to the strong anticipated growth in power demand, capacity of all forms of power generation must increase substantially. Turkey's ambitious vision for 2023, the centennial foundation of the Republic, includes ambitious targets for the energy sector in Turkey, with total investments estimated at around USD 130 billion. These targets include upgrading the transmission infrastructure with more than 11 000 km of new transmission lines and doubling the installed generation power from 57 GW in 2012 to more than 100 GW in 2023. To reduce dependency on energy imports, the government of Turkey wants to develop mainly renewable and nuclear energy and to reduce the natural gas share from the actual 46% to 30%. Looking to 2023, Turkey plans to reach a 30% share of renewable energy by fully developing the hydropower and geothermal reserves, and by installing over 20 GW of wind power and 3 GW of solar. The government's target is to have a share of nuclear energy of almost 10% by 2023, and 15% before 2030. To meet the objectives for nuclear power, eight units must be constructed at the two sites of Akkuyu (4.8 GW of installed capacity) and Sinop (at least 4.5 GW) and four units should be constructed at a third site not yet officially declared (MENR, 2013).

History of nuclear projects in Turkey

Studies to build an NPP in Turkey were started in 1960s. Later, between 1967 and 1970, a feasibility study was undertaken by a foreign consultant company to build a 300-400 MW NPP. This NPP would have been in operation in 1977. However, the project could not come to fruition because of problems related to site selection and other issues. In 1973, the Turkish Electricity Authority (TEK) decided to build an 80 MW prototype plant. However, in 1974, the project was cancelled since this project could delay the construction of a greater capacity NPP. Instead of this prototype plant, TEK had decided to build a 600 MW NPP in southern Turkey.

Site selection studies were made in 1974 and 1975, and the Gülnar-Akkuyu location was found suitable for the construction of the first NPP. In 1976, the Atomic Energy Commission granted a site licence for Akkuyu. In 1977, a bid was prepared, and ASEA-ATOM and STAL-LAVAL companies were awarded the contract. Contract negotiations continued until 1980. However, in September 1980, due to the Swedish government's decision to withdraw a loan guarantee, the project was cancelled.

A third attempt was made in 1980. Three companies were awarded the contract to build four NPPs (one CANDU unit by Atomic Energy of Canada Ltd [AECL], one PWR unit by Kraftwerk Union [KWU] in Akkuyu, and two BWR units by General Electric [GE] in Sinop). Due to Turkey's request to apply the BOT model, KWU resigned from the bid. Although AECL accepted the BOT model, it insisted upon a governmental guarantee of the BOT credit. The Turkish government refused to give such a guarantee, and as a consequence the project was cancelled.

In 1993, the Supreme Council for Science and Technology identified nuclear electricity generation as the project of third highest priority for the country. In view of this decision, the Turkish Electricity Generation and Transmission Company (TEAS) included an NPP project in its 1993 investment programme. In 1995, TEAS selected the Korean KAERI as the consultant for the preparation of the bid specifications. The bid process started in 1996. Three consortiums (AECL, Nuclear Power Institute and Westinghouse) offered proposals in 1997. In July 2000, after a series of delays, the government decided to postpone the project.

With the continuous increase in Turkey's demand for energy, initiatives to build an NPP were given a new boost in the past decade. A new law on the construction and operation of NPPs was passed in 2007. This aims to facilitate private-sector investment in building NPPs and their subsequent operation by private-sector organisations, supported by PPAs. Furthermore, the law also allows the State to take part in nuclear power projects directly or indirectly by means of public-private partnership (MENR, 2013 and IEA, 2009).

In February 2008, the Ministry of Energy and Natural Resources (MENR) formally invited bids to build and operate an NPP. The tender, managed by state-owned electricity wholesaler TETAŞ, was to supply and operate a nuclear station of between 3 000 and 5 000 MW, to be built at Akkuyu. Financing for the project was to be arranged by the bidders, supported by a 15-year PPA with TETAŞ. Neither the government nor any state-owned entity would be directly involved in the financing, ownership or operation of the plant.

Only one group, a consortium led by the Russian state-owned nuclear vendor Atomstroyexport, participated in the tender. The offer made by the bidding group proved to be high with USD 211.6 per MWh. The bidding company then lowered this price to USD 150 per MWh. However, while the offer was evaluated, the State Council (Turkey's supreme administrative court) decided to suspend the execution of some articles in the relevant regulation and the tender was consequently annulled. Despite these difficulties, direct government-to-government discussions with Russia continued on the Akkuyu project, as part of broader discussions on energy and trade co-operation. The "Agreement between the governments of the Republic of Turkey and of the Russian Federation for Cooperation on the Establishment and Operation of a Nuclear Power Plant at Akkuyu in the Republic of Turkey", signed on 12 May 2010, was ratified by the parliaments of both countries.

The intergovernmental agreement (IGA) signed between the Turkish government and the Russian government envisages co-operation between the two parties in areas such as the design of the power plant, its construction, operation, the purchase and sale of the electricity produced by the power plant, nuclear fuel supply, dismantling of the power plant and the nuclear fuel cycle (MENR, 2013).

On the other hand, another study has started for the installation of NPPs in the Sinop province. A Joint Declaration was signed between state-owned utility EÜAŞ and Korea Electrical utility Korea Electric Power Co. (KEPCO) in Istanbul, on 10 March 2010, for the construction, commissioning, operation and decommissioning of Sinop NPP. However, during the negotiations, an agreement was not reached with Korea. Following that, negotiations with the Japanese government and Japanese companies started on 26 November 2010 for the Sinop NPP Project. After the Fukushima Daiichi event, negotiations with Japan were suspended. However, on 3 May 2013 the Turkish government and the Japanese government signed an "Agreement on Co-operation for Development of Nuclear Power Plants and the Nuclear Power Industry in the Republic of Turkey". Additionally, some other agreements such as the Host Government Agreement, Memorandum of Understanding and Shareholder Agreement of Feasibility Studies Special Purpose Vehicle will be signed.

EÜAŞ has been given the role of state operating organisation for NPPs in case the NPP will be owned and operated by the state (as whole owner or shareholder). EÜAŞ, a state-owned company and the largest electricity generation company in Turkey, operates the existing hydraulic and thermal power plants including the maintenance, repair and rehabilitation of the power plants under operation. EÜAŞ has applied to the Turkish Atomic Energy Authority (TAEK) to be recognised as the owner of the Sinop NPP. After being recognised as an owner by TAEK, the preparation of the site report for the Sinop NPP Project has been initiated by EÜAŞ to obtain a site licence in accordance with TAEK regulations.

According to the IGAs, EÜAŞ will be a shareholder of the Sinop Public Company together with the Japanese Consortium which consists of Mitsubushi, Itochu and GDF Suez Companies. Sinop NPP will have four units of ATMEA-1 type nuclear reactors, each units having an installed capacity of 1 120 MW (total capacity is 4 480 MW). The estimated cost of the Sinop NPP project is USD 22 billion.

Terms of the agreement for the Akkuyu project

The first NPP project of Turkey has begun at the Akkuyu site, in Mersin Province on the Mediterranean coast (Figure 23), with an IGA (Akkuyu IGA, 2010) signed on 12 May 2010 between the governments of Russia and Turkey. The IGA was ratified in Turkey and in Russia on 21 July 2010 and 13 December 2010, respectively. According to the IGA, Russian State Atomic Energy Corporation (ROSATOM) and the Turkish Ministry of Energy and Natural Resources are parties of the agreement on behalf of signatory countries. In the IGA, the responsibilities of the parties are outlined as:

Russian side

- engineering design;
- obtaining of all necessary licences and permits;
- funding engagement;
- construction, management and supervision;
- supply of equipment and materials including nuclear fuel;
- commissioning;
- training of Turkish staff of Akkuyu NPP;
- operating and maintenance;
- waste management;
- decommissioning the NPP.

Turkish side

- allocation of the plant site with its current licence to Akkuyu Nuclear JSC without any charge until decommissioning;
- grid connection of the plant;
- electricity purchase guarantee according to the PPA;
- facilitating the issuance of necessary licences and permits.

In addition, the IGA includes a take-back option given to the Russian party for reprocessing of spent fuel discharged from Akkuyu NPP in Russia.

Figure 23: Location of the Akkuyu site

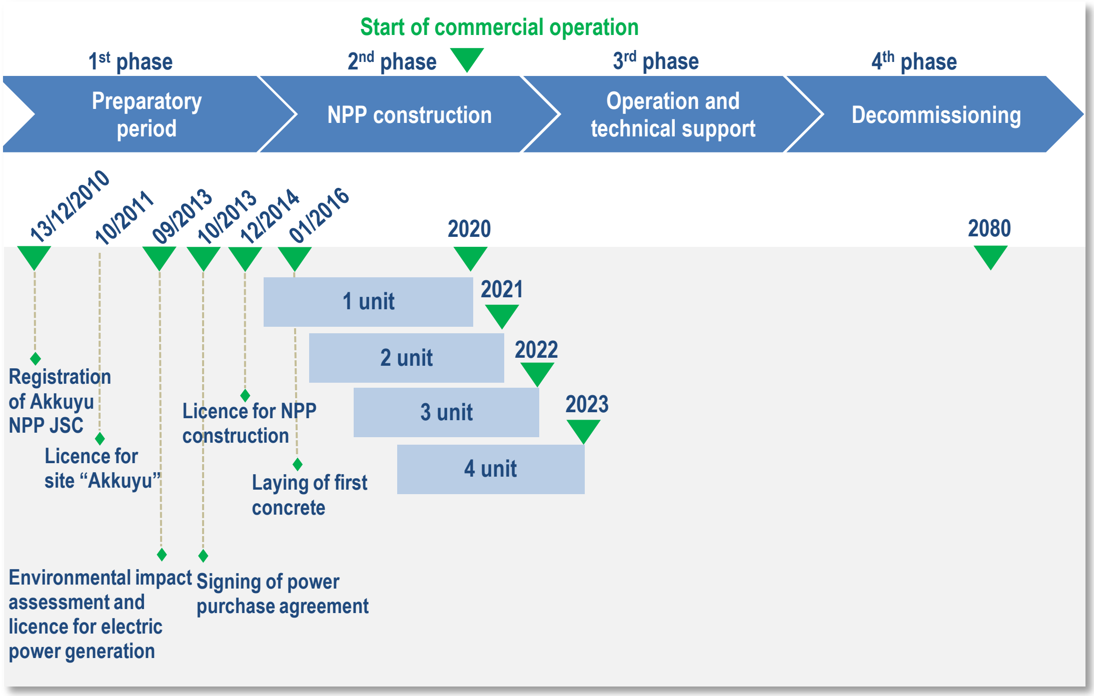
According to the IGA, the Akkuyu NPP will have four VVER-1200 (NPP-2006) reactors with a total capacity of 4 800 MW, based on the Novovoronezh NPP-2 (Russia, Voronezh region). The construction of the first unit should start in 2015 and it should be commissioned and connected to the grid at the end of 2020. The others should be commissioned in one-year intervals after the commissioning of the first unit. The anticipated lifetimes of the units will be 60 years, and each unit is expected to produce about 8.75 TWh per year. Table 11 provides some information about the Akkuyu NPP. Figure 24 shows the time schedule of the Akkuyu NPP project.

Table 11: Information about the Akkuyu NPP

Legal basis	Intergovernmental agreement with Russia on 12 May 2010
Project implementation model	Built-own-operate
Contractors	ROSATOM affiliates
General contractor	Atomstroyexport
Total capacity	4 800 MW(e)
Number of units	4
Reactor design	VVER-1200 (AES-2006)
CAPEX	ca. USD 20 billion
Total annual electricity generation	35 TWh (8.75 TWh from each unit)
Operating period	60 years
Location	Akkuyu site in Mersin Province
Construction period	2015-2020 (unit 1), 2016-2021 (unit 2), 2017-2022 (unit 3), 2018-2023 (unit 4)
Power purchase agreement period	15 years, average weighted price US cents 12.35/kWh (max. US cents 15.33)

Source: Based on Rosatom website.

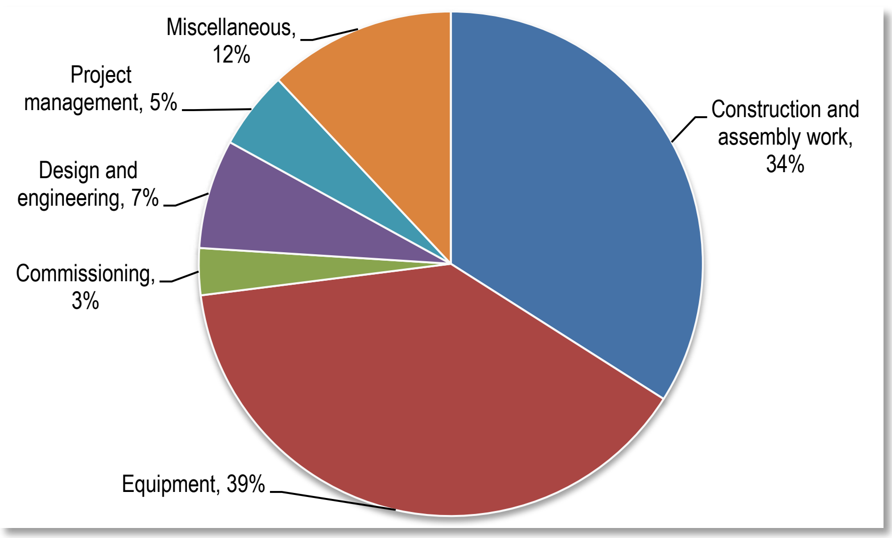
Figure 24: Time schedule for the Akkuyu nuclear power plant



Source: NEI, 2013.

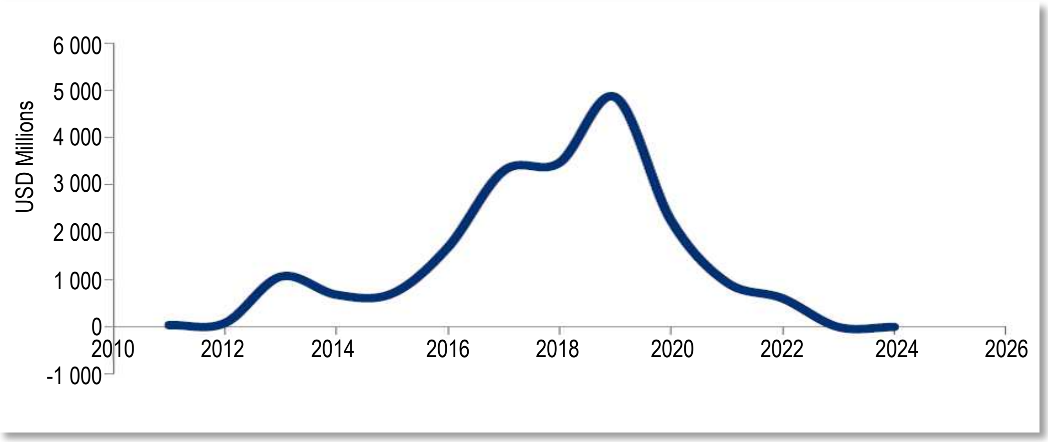
The capital expenditure of the Akkuyu NPP project, according to ROSATOM, will be around USD 20 billion. According to the IGA, the Russian party will be responsible for funding. Breakdown of capital expenditures and the capital expenditure profile are provided in Figure 25 and Figure 26, respectively.

Figure 25: Breakdown of capital expenditure for the Akkuyu project



Source: Smirnov, 2013.

Figure 26: Capital expenditure profile in the Akkuyu NPP project



Source: IEA/NEA, 2015.

Akkuyu nuclear JSC

The Russian side registered a project company called Akkuyu NPP JSC (Akkuyu Nükleer Güç Santrali Elektrik Üretim Anonim Şirketi) in Turkey on 13 December 2011. This established the Turkish company as the owner and operator of Akkuyu NPP which has 100% Russian capital. At the general shareholder meeting in September 2014, it was decided to change the name of the company to Akkuyu Nuclear JSC (Akkuyu Nükleer Anonim Sirketi). The shareholders of Akkuyu Nuclear JSC are the following companies:

- Rusatom Overseas JSC (64.96%)
- Rosenergoatom JSC (30.66%)
- Atomstroyexport JSC (3.17%)
- Inter RAO UES OJSC (1.15%)
- Atomenergoremont OJSC (0.03%)
- Atomtechenergo JSC (0.03%)

According to the agreement, a minority share of Akkuyu Nuclear JSC can be distributed into the market, provided that the Russian party in Akkuyu Nuclear JSC will not be less than 51%. The distribution of the remaining shares of the company and the "topics relating to company management" will be subjected to the consent of the Turkish party. In case Akkuyu Nuclear JSC fails, the Russian party will assume all relevant responsibilities for appointing a successor company that will fulfil its liabilities arising from the agreement.

- Akkuyu NPP JSC is the general customer and investor in the project.
- Atomenergoproekt JSC is the general designer of the plant.
- Atomstroyexport JSC is the general contractor for engineering, procurement and construction.
- Rosenergoatom Concern OJSC is the operation and maintenance contractor.
- Worley Parsons is the licensing and safety consultant.
- National Research Center Kurchatov Institute is the scientific supervisor of the Project.

- TVEL JSC is the fuel supplier.
- Gidrospress Design Bureau is nuclear island principal designer.
- VNIIAES JSC is system integrator, automatic process control system principal designer (MENR, 2013).

Electricity price arrangement

A PPA will be signed between Akkuyu Nuclear JSC and TETAŞ (fully owned by the Turkish state), based on the terms defined in the agreement between the Turkish government and Russia.

According to the agreement, TETAŞ will purchase 70% of the electricity to be produced from units 1 and 2, and 30% of the electricity to be produced from units 3 and 4 for 15 years once each unit becomes operational. Akkuyu Nuclear JSC will sell the remaining electricity directly to the electricity market or via retail energy suppliers.

At least one year before the start of commercial operations of unit 1, Akkuyu Nuclear JSC shall present the monthly electricity generation amounts for all the units and for the whole duration of the PPA. The IGA indicates USD 123.5 per MWh as the average electricity purchase price to be made by TETAŞ. The quantity and price trajectories over the 15 years that make up this average price are not public. However, the IGA specifically indicates that Akkuyu Nuclear JSC may adjust the annual variations of the electricity price, within an upper price limit of USD 153.3 per MWh, to ensure the payback of the project. After the PPA expiry dates, 20% of Akkuyu Nuclear JSC's net profit shall be given to the Turkish party on an annual basis throughout the lifetime of the plant (Akkuyu IGA, 2010).

According to the agreement, the first unit is to be activated within seven years following all approvals and permits required for the construction. The remaining units will be activated with an interval of one year between each unit (Akkuyu IGA, 2010).

The IGA gives a broad legal framework and specifically indicates that some details and arrangements should be further specified in the Power Purchasing Agreement contract signed by TETAŞ and the Akkuyu Nuclear JSC.

The IGA indicated the principles followed for establishing the PPA price (terms for reimbursing capital and operational expenditures, cost of debt and amortisation schedule).[3] The agreement mentioned clearly that "no change will be requested in the unit price throughout the PPA period" and that "no escalation shall be applied to the unit price components". However, the agreement indicated changes in costs incurred as a result of the amendments in the Turkish legislation will be reflected to TETAŞ at the rate corresponding to the amount of electricity purchased by TETAŞ. Apart from legislative amendments, the agreement is not very clear on the conditions at which the unit price may be changed. In particular, it indicates that Akkuyu Nuclear JSC can change the annual electricity price within a framework defined in the PPA to ensure the payback of the project, but no further details are available.

Also, the IGA indicates that contractual arrangements and responsibilities of the parties in case the units are activated earlier or later will be determined in the PPA and

3. In the agreement, the unit price was indicated to be calculated on the basis of the following principles: all capital expenditures required for four units to be operating commercially will be reimbursed within 15 years after the date the units become operational. In contrast, all operational costs will be financed "on the basis of realisation" once the units are activated. With regard to the activation of the units, the investments made directly or indirectly by investors into Akkuyu Nuclear JSC will be paid back within 15 years on the basis of the equal amortisation method.

will be reflected in the electricity price. The exact settlement of the risk relating to the construction time, which occupies a key place financially, is therefore not known. Also, in the case of a lack of electricity, Akkuyu Nuclear JSC will provide electricity from the private market. The liabilities in case of a delay related to the Turkish side were not mentioned.

Akkuyu Nuclear JSC is responsible for nuclear waste management and the decommissioning of the power station. Two separate funds will be established for financing each of these activities. As envisaged in the relevant law, the company will contribute to each of these funds with USD 1.5 per every MWh purchased by TETAŞ in the framework of the PPA. With regard to the electricity sold outside the framework of the PPA, Akkuyu Nuclear JSC will make the necessary provisions according to the applicable Turkish laws and regulations. The spent waste can be shipped back to Russia for reprocessing. In that case, the spent fuel fund can be used to finance this operation to be carried out by the Akkuyu Nuclear JSC. The cost of decommissioning is expected to be covered by the decommissioning fund. In the case that decommissioning fund sources are insufficient for these procedures, up to 25% of the sources collected for the decommissioning fund will be covered by the treasury, and by the company if this also proves to be insufficient (NEA, 2007).

According to the IGA between Turkey and Russia, third party liability for nuclear damage will be regulated in compliance with the international agreements and instruments that Turkey is and will be a party to, and by Turkey's national laws and regulations. Turkey is a contracting party to the 1960 Paris Convention on Third Party Liability in the Field of Nuclear Energy. Turkey has also signed and ratified the amending Protocols of 28 January 1964 and 16 November 1982. In 2004, the Amending Protocol was signed on 12 February 2004. The ratification process of the 2004 Protocol to the Paris Convention is underway. Turkey prepared a draft law on nuclear third party liability which will be presented to the Turkish Parliament. The responsibility of insuring the risks comprising the investment and operation periods of the project belongs to the Akkuyu Nuclear JSC, but the amount and details of this insurance[4] have not been specified in the agreement. Negotiations have been initiated with the Russian side to clarify this situation.

Principal financial structure

Based on preliminary calculations, the total estimated cost of the Akkuyu NPP construction is about USD 20 billion (calculated without taxes, in nominal prices for the corresponding periods). Project capital costs are considered to cover the complete construction of the plant, including training of operational personnel to safely operate the plant. The structure of financial resources is preliminarily envisaged to include about 30% equity and 70% debt.

According to the IGA, the Russian party is responsible for the financing of the project. Russia will give state support in the form of equity contribution for the construction of Akkuyu NPP. The volume of the total project demand for direct Russian financing is estimated at approximately USD 4 billion for the period of 2011-2015. In 2011, the first equity contribution from Russia was made. This contribution was included in the charter capital of Akkuyu Nuclear JSC.

The schedule of project financing with Russian federal budget funds envisages financing of the key activities at the initial phase of the project, including financing of high-priority activities, contracting of long-lead equipment and contract pre-payments.

4. Typically, a liability limit is determined which is naturally a parameter that affects insurance dues and hence the economics of power generation. If Turkey ratifies the Amending Protocol to the Paris Convention, operator liability must be regulated to cover at least EUR 700 million.

To comply with the project implementation schedule, the long-lead equipment will be ordered in advance.

The specified volume of state support for the Akkuyu NPP construction in Turkey will cover preparation activities (including excavation of the first unit foundation) in 2011-2015 before the main construction starts, as well as pre-payments on long-lead equipment contracts. The schedule and structure of state financing presented under the Russian programme "Development of Nuclear Power Complex" for 2012-2015, for the period until 2020, were revised according to the results of the project implementation schedule update. In addition, there are plans to involve additional sources of financing in the Akkuyu NPP project during 2017-2021.

In addition to ROSATOM's basic sources such as balance sheet financing and bank loans, there are other potential sources of financing, including:

- financing by an export credit agency (ECA);
- funds provided by outside investors.

Equipment and services for the project will be delivered by Russian and international suppliers. ECA financing may also be attracted. OECD rules are assumed to apply, i.e. ECA financing could be provided to up to 85% of the price of the exported goods from the respective countries. The precise conditions of ECA financing are still under discussion but were originally estimated to be at about USD 1.6 billion.

To ensure a positive short-term cash balance, payment of interest, and reduction of credit payment periods, there are plans to attract other sources of financing. These sources could be shareholders' debt funds, additional investments in the equity capital (including funds from new investors), or other financial instruments. Other forms of support may be explored once negotiations with potential lenders have been initiated.

In summary, the main source of the Akkuyu NPP Project financing will be the equity financing provided by Akkuyu Nuclear JSC in the amount of approximately USD 4 billion, and debt financing raised under the following conditions:

- funds are raised by several tranches (2015-2021);
- interest rates on loans are 7-8% per year (loans are assumed in USD);
- interest during construction is capitalised and is added to the project's fixed assets;
- loans are repaid by free cash flow, which will be available after the start of operation of the plant and will be generated by the revenue from electricity sales.

The above-mentioned conditions of financing are assumptions for financial modelling; the loan amounts and schedule are based on the estimated project needs.

In summary, the structure of financial resources is preliminarily envisaged to include 30% equity and 70% debt. The main source of the Akkuyu NPP Project financing will be the equity financing provided by Akkuyu Nuclear JSC in the amount of roughly USD 4 billion, and the remainder will be covered by debt financing. The IRR of the project is expected to be around 10%, and the pay-pack period of about 18 years.

Technology transfer and exchange of information

The IGA specifically indicated that co-operation between Turkey and Russia will include technology transfer and exchange of information and expertise in the fields of licensing and nuclear safety and security. In particular, Russia engaged in a training programme for Turkish citizens to be subsequently employed in the operation of the NPP. The agreement also indicated that Turkish companies should be part of the supply chain for the work in connection with the construction of the NPP.

A training programme for Turkish plant operators has been established at the Obninsk Branch of MEPhI (Moscow Engineering Physics Institute, Russia). In 2011 and 2012, 117 students were enrolled and it was envisioned that 80 more Turkish students would be enrolled in 2013, with about 600 operators being trained for the Akkuyu plant through on-the-job training at Novovoronezh NPP-2. After graduating from the University and completing their training at the Training Centres of Rosatom, they will become part of the operating staff at the Akkuyu NPP. In the future, Turkish experts will be involved in the NPP operation at all stages of the life cycle of the plant (MENR, 2013).

Comments

Power purchase agreement

The electricity purchasing price (USD 123.5 per MWh, value added tax excluded) is quoted in nominal terms and should be applied for a period of 15 years, almost two decades ahead. It is therefore necessary to calculate the value of the expected cash flow at the present time applying an appropriate discount rate. Table 12 gives the present value of the purchase agreement for discount rates in a 2-6% range and two possible price trajectories. First, it is assumed that the price is kept constant throughout the 15-year span of the PPA. In a second case, it is assumed that Akkuyu Nuclear JSC can maximise the present value of the future cash flow by applying the maximal electricity price (USD 153.3 per MWh) in the first seven years of electricity production while reducing the price in the last phase of the agreement[5] (this corresponds to the last line of Table 12). According to the calculations, the actualised electricity price varies between USD 53 and USD 92 per MWh, depending on the discount rate applied. The "price trajectory" value, i.e. the possibility to vary the annual price by Akkuyu Nuclear JSC during the 15 years of the agreement, can increase the present value of the cash flow by 1.8-5% at most, depending on the discount rate.

Table 12: Present value of the power purchase agreement at different discount rates
(USD/MWh)

	Value (in USD_{2011} per MWh) of the purchase price agreement at different discount rates								
	2.0%	2.5%	3.0%	3.5%	4.0%	4.5%	5.0%	5.5%	6.0%
Constant price trajectory	92.10	85.76	79.92	74.53	69.56	64.98	60.73	56.81	53.18
Maximal value	93.74	87.66	82.04	76.83	72.00	67.53	63.37	59.52	55.93

The present value of the average purchase price flow should be compared with the wholesale electricity prices in Turkey. The Turkish Energy Market Regulatory Authority has announced the country's average wholesale electricity price for the year 2010 as Turkish liras (TRY) 140.7 per MWh, which corresponds to USD 93.8/MWh using the official average exchange rate of TRY 1.5/USD in 2010 (EDAM, 2011).

The present value of the average purchase price flow is equivalent to the 2010 wholesale electricity price if a discount rate of 1.9% is used. When applying higher discount rates, the present value of the PPA is lower than the 2010 electricity price. In particular, if a discount rate of 2.5%[6] is used, the present value of future cash flow is about 8% lower than the 2010 wholesale electricity price.

5. This second assumption is based solely on the terms expressed in the intergovernmental agreement and does not take into account different arrangements expressed in the PPA.
6. The average increase of the consumer price in the United States has been 2.5% per year in the 2005-2012 period (OECD, n.d.).

Risk allocation

According to publicly available information on the Akkuyu model, a significant part of the risks associated with the NPP construction project are borne by the Akkuyu Nuclear JSC, and indirectly by the Russian state. The state-owned company TETAŞ and the Turkish government also share part of the risk of the Akkuyu project, the main risk for the Turkish side being related to the volatility of the electricity market price.

Construction and supply chain risk – financial risk – construction delay risk

The electricity purchasing agreement will not be adjusted to reflect potential cost overruns during construction or changes in the financial conditions for the Akkuyu Nuclear JSC. In this respect, construction, supply chain and financial risk are borne almost exclusively by the Akkuyu Nuclear JSC. However, it should be noted that the financial risk is minimised in the case of the Akkuyu project, since the companies participating in Akkuyu Nuclear JSC are state-owned.

As indicated in the agreement, the trajectory of the electricity prices (but not its average) could be modified by Akkuyu Nuclear JSC to compensate for cost overruns and transfered to TETAŞ. According to the information available, however, the financial value of this arrangement is limited.

The financial consequences of construction delays are particularly important for generating technologies with high capital costs such as nuclear. The IGA indicates that those costs will be borne by the parties responsible of the delay, but no further details are given.

A long construction period pushes up financing costs and therefore affects the economics. The first power unit in Akkuyu is scheduled to start commercial operation at the end of 2020, which implies six years of construction if construction starts at the end of 2014. The responsibility to insure risks to cover this period belongs to the Akkuyu Nuclear JSC. Furthermore, in case of failure, the Russian party has the responsibility to designate a successor that possesses all necessary competencies and capabilities. Accordingly, the financial risk on the Turkish side related to possible construction delays, cost overruns or credit downgrades are limited.

Operating and fuel supply risk

Operating risk is fully borne by the Akkuyu Nuclear JSC, which is engaged to supply a certain amount of electricity every month according to the schedule agreed one year prior to the start of the plant's commercial operation. If the production of electricity is less than the volumes planned, Akkuyu Nuclear JSC must purchase the lacking volume of electricity in the wholesale market. Akkuyu Nuclear JSC thus faces the additional risk of the electricity market price being higher than the price agreed in the PPA.

Design risk

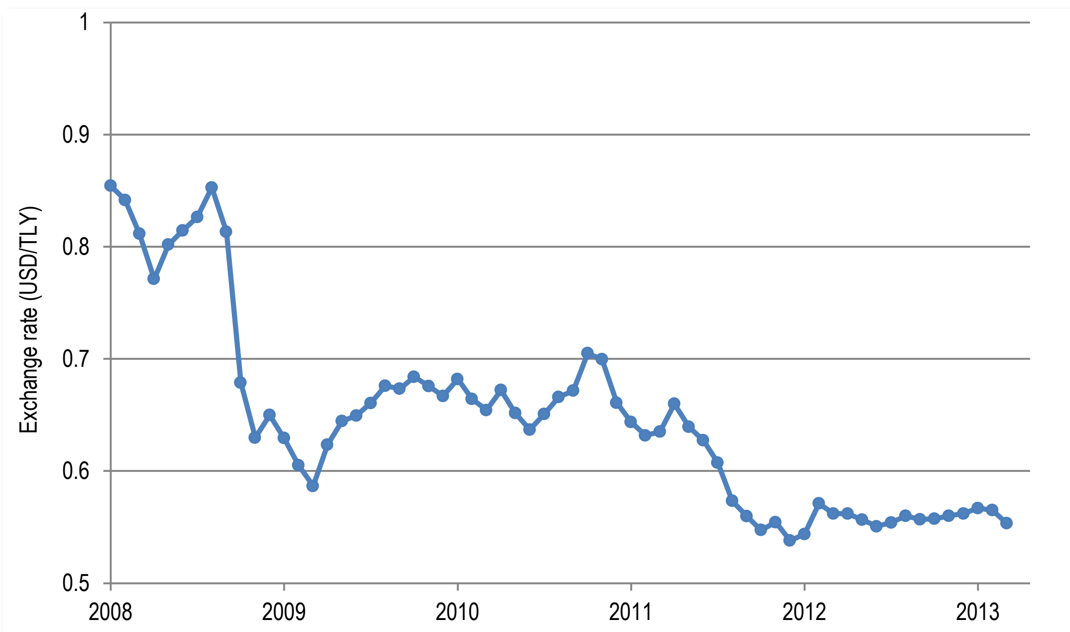
An additional source of project risk is related to the seismicity of Turkey and of the Akkuyu site. Based on the available studies on the seismic properties of the area, the plant design is envisaged to be earthquake safe up to a magnitude of nine on the Richter scale, and cost estimates reflect this assumption. The Russian subsidiary company has outsourced independent measurements of seismic activity and other essential indicators like temperature, humidity and air salinity to evaluate the site-specific design safety. In case of increased seismic activity, there could be a need for a modification in design, which would induce additional cost and affect the economics. Design risk is borne by the Akkuyu Nuclear JSC (EDAM, 2011).

Electricity market risk

The PPA is applied to 50% of the electricity produced by the Akkuyu NPP during the first 15 years of electricity production. The remaining production will be sold in the wholesale market.

Thus, Akkuyu Nuclear JSC will be exposed to market and exchange rate risks for half of the production in the first 15 years of operation and will be fully exposed to these risks thereafter. The PPA denominated in a foreign currency exposes the wholesale company TETAŞ to both exchange rate and electricity market risks. Exchange rate risk is particularly significant in a growing and developing economy such as Turkey. For instance, in five years, from the beginning of 2008 to the end of 2012, the Turkish lira has lost 33% of his value with respect to the US dollar (see official exchange rates in Figure 27).

Figure 27: Exchange rate between Turkish lira and US dollar



However, both of these risks appear to be low due to the present conditions of the Turkish economy and electricity market. Electricity demand has been and is expected to continue to increase rapidly in Turkey with economic development, and future electricity prices are expected to increase accordingly. The exchange rate risk appears to be limited for TETAŞ since electricity wholesale prices are strongly correlated to gas and coal prices (expressed in US dollars) and electricity tariffs are regularly adjusted to inflation and generation costs.

Waste management and decommissioning risk

Akkuyu Nuclear JSC is responsible for waste management and decommissioning of the power plant and thus bears the associated financial risk. For the electricity sold in the framework of the PPA, Akkuyu Nuclear JSC must provide USD 1.5 per MWh to each of two accounts set up specifically for those purposes. The price agreed seems in line with international estimates.

It should be noted that the Turkish state will also be responsible for contributing to the dismantling cost of the NPP if the decommissioning costs prove to be higher than the savings in the Decommissioning Fund. The contribution of the Treasury is however limited to the 25% of the amount accumulated in the fund and thus Akkuyu Nuclear JSC is bearing most of the financial risk.

Political risk

The specific nature of the Akkuyu agreement, with the direct involvement of the highest level of state representatives from the two countries, gives an implicit guarantee that Turkey will maintain its current political attitude towards nuclear energy and thus somehow minimise the political risk. However, the information publicly available does not explicitly cover this aspect.

The agreement between the two countries recognises that any increase in the construction costs due to changes in Turkish laws and regulations should be reflected in the price of the purchase agreement. Also, the Turkish government has engaged to take all the necessary steps to facilitate the timely licensing of the NPP, as well as to acquire all the required permissions for the companies involved in the construction. To this extent, TETAŞ (and indirectly the Turkish state) will be taking on some of the regulatory and licensing risk.

When considered in terms of risk sharing, the Akkuyu model is akin to an extreme "commercial power plant" model, in such a way that a very significant part of the financial risks listed in the previous sections remain the responsibility of the Akkuyu Nuclear JSC. However, the electricity company undertaking the risks related to the construction and operation of the power plant is not a true private company; it is a public company owned by the Russian state. Therefore, in the case that the project revenues fail to cover the project cost and the need for additional financing emerges, mutual understanding calls for the coverage of this financing by the budget of the Russian state as a last resort.[7] Whether or not the deal would have been possible without an IGA, as a stand-alone commercial treaty at the same terms, is questionable considering the economics and the risks taken up by the Russian party (EDAM, 2011).

The PPA between TETAŞ and Akkuyu Nuclear JSC will be able to be signed within one month following the issuance of the power generation licence by the Energy Market Regulatory Authority to Akkuyu Nuclear JSC in compliance with paragraph 1 of article 10 "Power Purchase Agreement" of the Intergovernmental Agreement. Pursuant to paragraph 8 of the same article (10), the alterations in the cost occurred due to the amendments to the legislation, would be reflected on TETAŞ accordingly as an increase or a decrease.

Project history (MENR and Schilito, 2013)

13 January 2010	Joint statement by the Russian Deputy Prime Minister, Igor Sechin, and the Minister of Energy and Natural Resources of the Republic of Turkey, Taner Yıldız, on co-operation in the construction of an NPP in Turkey. Bilateral negotiations begin.
12 May 2010	Signing of the agreement between the governments of Russia and the Republic of Turkey on co-operation in relation to the construction and operation of an NPP at the Akkuyu site in the Republic of Turkey.
21 July 2010	The Law ratifying the Intergovernmental Agreement enters into force in the Republic of Turkey (Law No. 27648 of 21 July 2010).

7. In the meeting held with the authorities of Akkuyu Nuclear JSC, this association between the financial risks of the company and the Russian budget was emphasised.

12 November 2010	Akkuyu Nuclear JSC shareholders identified by the Russian government.
13 December 2010	The law that ratifies the intergovernmental agreement enters into force in Russia (Federal Law No. 322-FZ of 29 November 2010).
13 December 2010	Registration of Akkuyu NPP JSC.
13 December 2010	Akkuyu Nuclear JSC, Akkuyu Electricity Generation JSC was established in Turkey.
26 May 2011	Start of full-scale site survey activities.
2011	Transfer of land plot for construction and operation of the AKKUYU NPP.
29 March 2012	The Ministry of Environment and City Planning holds public consultation on the Environmental Impact Assessment in the region of the Akkuyu NPP construction.
March 2012	Opening of the PIC (Public Information Center) on the atomic energy in Buyukeceli.
June 2012	Transfer of the Updated Akkuyu NPP Site Report to TAEK.
August 2012	TAEK accepted Novovoronezh NPP-2 as a reference plant for Akkuyu NPP.
November 2012	TAEK accepted the licence basis of the regulatory act, standards and regulations for Akkuyu NPP.
December 2012	Opening of the PIC on the atomic energy in Mersin.
End of 2014	Environmental impact assessment report.

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II.3.2. Case study of the Barakah nuclear power plant

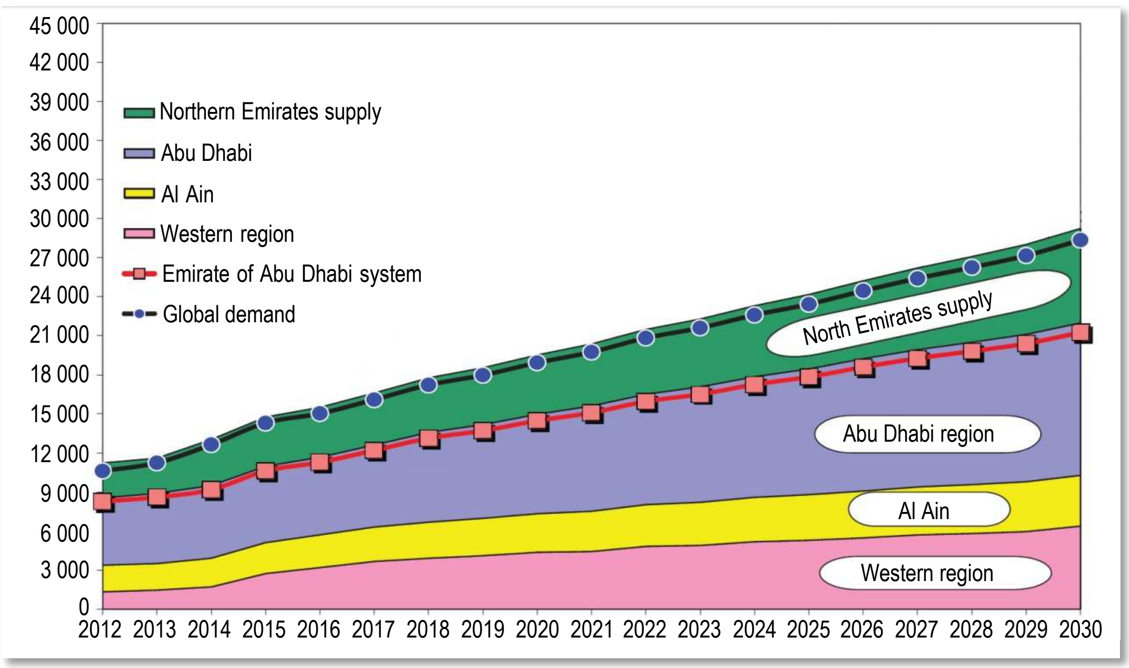
Introduction and general description

The United Arab Emirates (UAE) was founded in 1971 and comprises seven states including Abu Dhabi and Dubai. Its capital is Abu Dhabi. The Abu Dhabi emirate also accounts for 87% of the land area of the UAE and 95% of its oil (ADWEC, 2014; Business Monitor International, 2010). Dubai is the UAE's largest city.

The UAE's interest in nuclear energy is motivated by the need to develop additional sources of electricity to meet future electricity demand, which is projected to rise rapidly, and thus to ensure the continued growth of its economy (see Figure 28). In collaboration with other members of the Gulf Cooperation Council (GCC), the UAE has proceeded with plans to set up its own nuclear power programme aiming at bringing significant new capacity on line by 2020 (ENEC, 2013). In December 2006, the six member states of the GCC – Kuwait, Saudi Arabia, Bahrain, the UAE, Qatar and Oman – announced that the Council was commissioning a study on the peaceful uses of nuclear energy. The UAE nuclear project at the Barakah site is the first nuclear power project in the Gulf area (WNA, 2014).

Figure 28: Global electricity peak demand forecast 2012-2030 in UAE

(Global demand = Emirate of Abu Dhabi System + Northern Emirates supply)



Note: Northern Emirates supply includes electricity used for auxiliaries and pumping.
Source: ADWEC, 2014.

Together, the GCC countries produce 273 TWh per year, all from fossil fuels with demand rising between 5% and 7% per year. Their total installed capacity is about 80 GW, and they share a common grid. In a 2009 report, the WNA even projects the electricity demand of the GCC economies to increase annually by 10% until 2015.[8] This increase is driven in part by the demand for water and desalination, which is projected to increase at 8% per year. It implies important new capacity needs in the coming years, at 60 GW until 2015 alone (WNA, 2014).

In 2009, the UAE produced 88.2 TWh of electricity, 98% of it from gas, for which it relies partly on imports (ADWEC, 2014; GULF, 2012). Current capacity is about 19 GW and electricity demand is growing (ADWEC, 2014). In April 2008, the UAE published its own comprehensive energy policy on nuclear energy. It projected electricity demand to increase from 16 GW in 2008 to over 40 GW in 2020 (UAE, 2008). Half of this increase was expected to be covered by natural gas. Renewables would be able to supply about 7% of the required power (IRENA, 2013). Nuclear power, as an established low-carbon baseload technology, was chosen to supply the difference and thus to contribute to the economic development and energy security of the UAE. Concerning the competitive situation of nuclear, the still to be determined tariff for nuclear electricity is likely to be higher than that for gas-fired power plants. However, since it is planned to keep the feed-in tariff for electricity from NPPs stable in nominal terms over the whole contract period, it is expected that with time and rising gas prices nuclear will become more competitive than gas-fired power plants.

The Nuclear Power Programme in the UAE

The UAE nuclear programme was gradually planned and implemented over several years. In April 2008, the UAE published *The Policy of the United Arab Emirates on the Evaluation and Potential Development of Peaceful Nuclear Energy* (UAE, 2008). The policy paper found nuclear power to be a safe and environmentally friendly option that could supplement existing power plants in meeting growing energy needs. As a result of the study, the UAE began to pursue a peaceful, civilian nuclear energy programme. In particular, the UAE created a Nuclear Energy Program Implementation Organization, subsequently named the Executive Affairs Authority (EAA).

On 23 September 2009, the UAE issued a Federal Law through Decree No. 6 of 2009 on the “Peaceful Uses of Nuclear Energy”, which put in place a framework for nuclear regulation and formally established the nuclear regulatory body, the Federal Authority for Nuclear Regulation. The same year, on 23 December 2009, the president of the UAE, in his capacity as the ruler of Abu Dhabi, established by decree the Emirates Nuclear Energy Corporation (ENEC), the organisation charged with implementing the UAE nuclear energy programme. As well as overseeing and developing the nuclear programme, it acts as the investment arm of the government by making strategic investments in the nuclear sector, both domestically and internationally. In particular, ENEC is responsible for:

- overseeing the work of the prime contractor during design, construction and operations phases;
- working closely with the Abu Dhabi and the UAE federal government to ensure that the civil nuclear programme is aligned with the industrial infrastructure plans of the UAE;
- developing public communications and education programmes;
- operating the civil nuclear programme safely and securely.

8. Based on the IEA (2012) report *Energy Balance of Non-OECD countries*, the total electricity generation of GCC in 2009 was 415 546 GWh and 456 017 GWh in 2010, which is around a 10% annual increase.

After having invited bids from nine different consortia, three bidders were shortlisted, AREVA with Suez and Total proposing its EPR, GE-Hitachi proposing its ABWR, and a Korean consortium proposing its APR-1400 PWR technology (IAEA, 2013). The latter was led by KEPCO and included Samsung, Hyundai and Doosan, as well as Westinghouse, whose system 80+ design, which had originated with Combustion Engineering and was certified in the United States, was the basis for the APR-1400. ENEC announced on 27 December 2009 that it had selected a consortium led by KEPCO to design, build and assist in the operation and maintenance of four NPPs of 1 400 MW (KEPCO, 2013). KEPCO was to supply the full range of works and services for the UAE Civil Nuclear Project including engineering, procurement, construction, nuclear fuel and operations and maintenance support. The contract also provided for extensive training, human resource development, and education programmes as the UAE builds the capacity to eventually staff the vast majority of the nuclear energy programme with domestic experts.

The total value of the contract for the construction, commissioning and initial fuel loads for the four units is USD 20.4 billion, with a high percentage of the contract being offered under a fixed-price arrangement. The consortium expects to earn another USD 20 billion by jointly operating the reactors for 60 years. The total cost of the plant including infrastructure and finance is expected to approach USD 32 billion. Final cost estimates, however, are still under review (WNA, 2014).

In addition to Samsung, Doosan Heavy Industries and Westinghouse, the Korean consortium includes Hyundai Engineering and Construction as well as the KEPCO subsidiaries Korea Hydro and Nuclear Power (KHNP) and Korea Power Engineering (KOPEC, currently KEPCO E&C). KHNP will play a key role in engineering, procurement and construction as well as, at a later stage, as an operator. KOPEC will provide the design of the new NPP and engineering services. Korea Nuclear Fuel (KNF, currently KEPCO NF) will provide the fuel. KEPCO Plant Service and Engineering (KPS) will be involved in plant maintenance.

By August 2012, ENEC had also awarded six contracts relating to the supply of natural uranium, conversion and enrichment services as well as to supply a share of the enriched uranium. Several suppliers are involved at each stage of the front end of the fuel cycle. ENEC estimates the contracts to be worth some USD 3 billion and will enable the Barakah plant to generate up to 450 TWh of electricity over a 15-year period beginning in 2017. ENEC expects to return to the fuel market at various times to take advantage of favourable market conditions and to strengthen its security of supply position. The enriched uranium will be supplied to KEPCO Nuclear Fuels – part of the prime contractor consortium led by KEPCO – which will manufacture the fuel assemblies.

Table 13 provides an overview of the overall scope of the UAE contract, how different items have been allocated among the members of the consortium as well as some information on costs to the extent that they are publicly available (CERNA, 2011).

An IAEA Integrated Nuclear Infrastructure Review (INIR) mission to the UAE reported, in January 2011, that the UAE had followed its recommended comprehensive “milestones” approach for such countries. Also ENEC has joined the World Association of Nuclear Operators (WANO) to benefit from the outset from the latters’ peer review process to ensure the highest possible standards of safety. The United States signed a bilateral nuclear energy co-operation agreement with the UAE in January 2009 and Korea signed one in June 2009. In addition, the existing bilateral nuclear co-operation “123” agreement between Korea and the United States for co-operation with UAE has been extended in July 2013 to run for another two years until March 2016 (NEI, 2013). Also Japan and the United Kingdom have signed Memoranda of Understanding on nuclear energy co-operation with the UAE. Canada and France also have nuclear co-operation agreements with the UAE. Russia concluded an agreement in December 2012 and Argentina in January 2013. Australia and Canada also signed bilateral safeguard agreements with the UAE in August and September 2012.

Table 13: The role and share of Korean consortium members in the UAE tender

	Scope	Firms	Price (USD billions)
Construction/ management	NSSS, steam generator and other major components	Doosan (with Toshiba as a STG supplier)	3.9
	Civil engineering	Hyundai (prime constructor) and Samsung	3.1 and 2.5
	Technical assistance and licence	Westinghouse	1.3
	Engineering, procurement and construction	Korea Electric Power Co. (KEPCO) and Korea Hydro and Nuclear Power (KHNP)	Unknown
Training	Training of UAE staff	KHNP and Korea Advanced Institute of Science and Technology	Unknown
Design	Plant design and modification	Korea Power Engineering Company	Unknown
NPP launch and first two fuel loads	Nuclear fuel (two loads)	Korea Nuclear Fuel	1
	Initial O&M	KHNP and Korea Plant Service & Engineering	1.2
Cost of capital	Project financing	KEPCO	Unknown

Source: CERNA, 2011.

The Barakah nuclear power plants

The four NPPs planned in the UAE are advanced power reactors of 1 400 MW (APR-1400) and are to be built at a single site (ENEC, 2013). This site is located at Barakah (formerly Braka) on the coast – 53 km west of Ruwais and 300 km west of Abu Dhabi city – slightly closer to Qatar than to the capital (ENEC, 2013). The APR-1400 is an evolutionary advanced light water reactor (ALWR) developed in Korea in 2002. The design has evolved based on the experience gained throughout the development, construction, and operation of the 1 000 MW Optimum Power Plant (OPR-1000), the first standard pressurised water reactor plant in Korea. During the 1980s, Korea had developed as part of its policy of self-reliance all aspects of NPP construction on the basis of the OPR-1000. Currently, a total of twelve OPR-1000 units are operating in Korea with very good operating results. Standardising the construction and operation of the OPR-1000 reactors helped Korea to build an internationally competitive nuclear industry with respect to construction, operation and maintenance.

On the basis of the successful experience with its OPR-1000 fleet, Korea launched in 1992 the APR-1400 development project and completed a standard design in 2002. In addition to the OPR-1000 design, the APR-1400 also utilises advanced design features based on technologies of system 80+, whose design had been certified by the US Nuclear Regulatory Commission (NRC).

The APR-1400 is intended to constitute the next generation of NPPs in Korea, following the OPR-1000. In Korea, the first APR-1400 plants are located near the existing Kori site, where the construction project for the two twin units, Shin-Kori 3 and 4, is in progress. The construction periods for the Shin-Kori 3 and 4 reactors are scheduled to last 51 months from first concrete to first fuel, which is an ambitious objective, considering that these are FOAK plants for the APR-1400 design. Shin-Kori units 3 and 4 were slated to begin commercial operation in 2013 and 2014, respectively. However, with their operation delayed by the need to replace cables following forged test reports, the units are now expected to start up in 2015 and 2016 respectively (WNN, 2013). Other APR-1400 construction projects are either at early stages of construction, such as the Shin-Ulchin 1 and 2 units (commercial operation planned for 2016 and 2017) and the Shin-Kori 5 and

6 units (commercial operation planned for 2019 and 2020), or in the planning stage, such as the Shin Ulchin 3 and 4 units.

The design of the APR-1400 plant at Barakah is based on the design of the Shin-Kori 3 and 4 units that serve as reference plants. Nevertheless, there will be a number of design changes mainly related to site-specific environmental conditions, which are different from those at Shin-Kori. These include different seismic design conditions, ultimate heat sink temperature related to cooling, a much higher ambient air temperature, and a 50 Hertz electrical grid (compared to 60 Hz in Korea). Further adaptations relate to different safety and security issues in the global nuclear industry that arose in the years following the design certification of the APR-1400 such as aircraft crash and cyber security.

Advancement of the Barakah project

Back in 2009, ENEC had announced the following overall schedule (Table 14) for the four APR-1400 plants at Barakah.

Table 14: Overall schedule for NPPs at Barakah

Plant	Construction started	Start-up
Barakah 1	July 2012	May 2017
Barakah 2	May 2013	2018
Barakah 3	2014	2019
Barakah 4	2015	2020

In April 2010, ENEC lodged licence applications and an environmental assessment for the Barakah site. The application was assessed by the Federal Authority of Nuclear Regulation (FANR). This assessment, which included an environmental management plan, was vetted also by Abu Dhabi's Environment Agency and approval for the Barakah site was given in July 2012. In July 2010, ENEC had already received two licences from FANR: a site preparation licence for Barakah and a limited construction licence allowing manufacture of major components for four units. ENEC lodged a construction licence application for unit 1 and 2 in December 2010 to undertake full site works. The 18-month review involved more than 60 FANR staffs and three international consulting firms, as well as the IAEA. It also took in account changes resulting from the Fukushima Daiichi accident. The construction licence for units 1 and 2 was issued by FANR in July 2012. Construction of unit 1 followed almost immediately. Major milestones for the Barakah 1 unit include first concrete in July 2012 ahead of its scheduled date in late 2012, the setting of the reactor vessel by July 2014, obtaining the operating licence and fuel loading by October 2016, and commercial operation by May 2017. The Barakah unit 2 construction began on 28 May 2013 (The National, 2013). On 15 September 2014, FNAR approved the construction licence for units 3 and 4 at the Barakah NPP (WNN, 2014). The planned dates for the commercial operations of units 2, 3 and 4 remain 2018, 2019 and 2020, respectively.

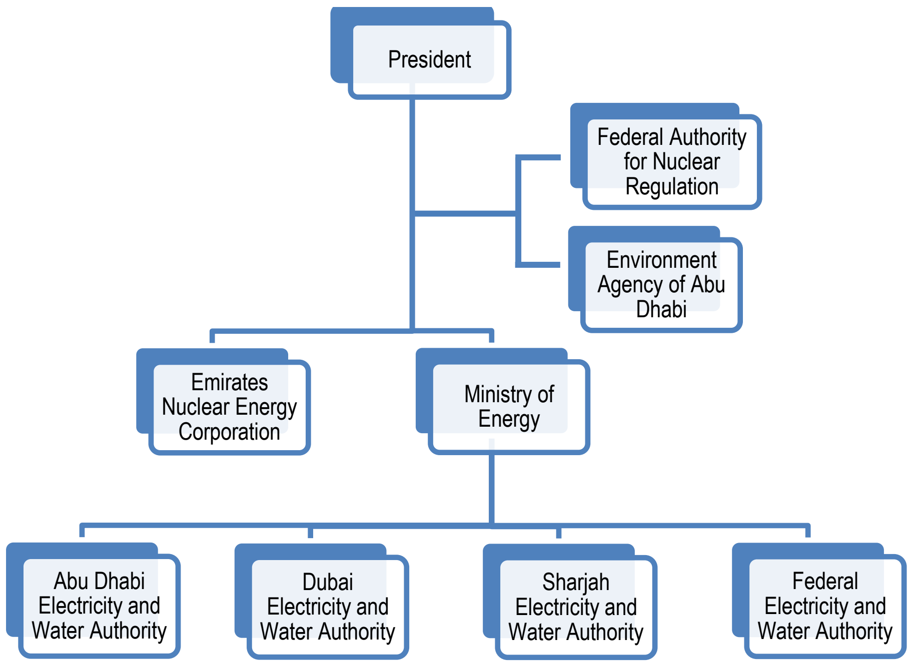
Project management at ENEC

The ENEC is the organisation charged with implementing all aspects of the UAE nuclear programme. ENEC developed an organisational structure that defines clear responsibilities for each functional unit. ENEC itself answers directly to the President of the UAE (see Figure 29). A key role is assumed by the ENEC Project Management Team, also called the Prime Contractor Oversight Management (PCOM), which reports to the ENEC Chief Program Officer (CPO). Its role is to supervise the activities of the consortium led by KEPCO, the prime contractor. This team has currently about 200 positions. After commissioning, about 50% of PCOM staff is likely to be transferred to NPP Operations, which reports to the ENEC Chief Nuclear Officer (CNO) (IAEA, 2011).

ENEC PCOM, with the technical support of KEPCO, is also responsible for overseeing all NPP licensing activities. The NPP construction licence application was thus reviewed by ENEC PCOM focusing, in particular, on any differences with the reference plant. The ENEC Project Management Information System (PMIS) was developed to ensure planning, execution and monitoring of all NPP project activities. The development of this integrated management system has benefited from the IAEA's *Management Systems for Facilities and Activities* (IAEA, 2011).

"Emiratisation", or the increased participation of UAE nationals in both the public and private sectors, is part of Abu Dhabi's objectives to achieve economic diversification and long-term sustainability. International corporations can opt to pay fines if they are unsuccessful at finding UAE nationals to fill the quota. The country's civil nuclear programme around ENEC, a government enterprise, is however obliged to comply with the Emiratisation requirement of 60%. Indeed, 67% of ENEC's more than 650 employees are UAE nationals (Nuclear Energy Insider, 2013).

Figure 29: Governmental organisation related to nuclear energy in UAE



The financing structure of the Barakah project

The methods and source of financing for the Barakah project in the UAE are not principally different from those used for other large power sector or infrastructure projects. Initially, the UAE announced that it would offer joint-venture arrangements to foreign investors for the construction and operation of the NPPs that were similar to the existing structures for water and power producers, which are owned 60% by the government and 40% by the foreign joint venture partner. As in other industries, in the management of its nuclear power programme, the UAE is thus also relying on the services of outside contractors rather than waiting for the establishment of domestic expertise.

The goal of any financing structure is to optimise the allocation of the risk so as to maximise the probability of the loans being serviced and repaid on time, in a manner that is consistent with an adequate return for the project investors. As mentioned earlier, the initial financial volume of the project to construct four APR-1400 at Barakah is USD 20.4 billion. A high percentage of the contract is offered under a fixed-price arrangement. In addition to the delivery of the four plants, ENEC and KEPCO have also agreed to the key terms under which Korean investors will have an equity interest in the project. On 8 November 2012, KEPCO and its affiliates decided to invest USD 1.04 billion in Barakah One Company, a special purpose company established to build and operate an NPP in Barakah, in exchange for an 18% equity interest (SEC, 2013). This was intended to further strengthen the incentives to make the necessary technology and skills available to achieve on-time and on-budget delivery of the plants.

The contract also provides for extensive training, human resource development, and education programmes as the UAE builds the capacity to eventually staff the vast majority of the nuclear energy programme with national talent, and develops the industrial infrastructure and commercial businesses to serve the nuclear energy industry.

In an early background article, Bloomberg News reported on 28 November 2011 that the total joint venture might be worth about USD 30 billion, with roughly one-third consisting of equity and two-thirds of debt. In this arrangement, Abu Dhabi would provide most of the USD 10 billion of equity. USD 10 billion of debt would most likely come from a Korean export-credit agency. The remaining USD 10 billion would be a mix of bank financing and sovereign debt (Bloomberg, 2011). Abu Dhabi may thus consider a direct government debt issue or a debt issue by ENEC backed by the government. In September 2012, the US Export-Import Bank approved USD 2 billion in financing for the Barakah plant, for US-sourced components from Westinghouse (including coolant pumps and instrumentation and control [I&C]) as well as for services from Westinghouse and two other firms.

Ultimately, the financing risk related to the Barakah project is limited as the Abu Dhabi government is willing to back the NPP project until its conclusion. Currently, ENEC is looking at various options for financing the programme, including equity investment from KEPCO and further loans from export credit agencies and commercial banks, to complement the equity investment by the owners. The Middle East Economic Digest (MEED) News reported on 31 May 2013 that sources close to the project said that they had hoped to get the deal signed before the end of 2012, but that the debt financing for the nuclear project being developed in Abu Dhabi had been delayed at the last minute.

Updating the information provided by Bloomberg, MEED News indicated that the financing package was to be split between a USD 10 billion loan from the Export Import Bank of Korea (Kexim), a loan of around USD 2 billion from the Export-Import Bank of the United States (USExim), USD 6 billion in direct funding from the government of Abu Dhabi, and just over USD 2 billion from commercial banks. The payback period of the debt would be 23 years. The commercial banks tranche of the financing is understood to be provided mainly by Abu Dhabi banks. In the process the UK's HSBC is advising ENEC and Standard Chartered is advising the KEPCO consortium. According to sources involved in the project, the amount that ENEC was to borrow to fund the scheme had been cut back over concerns about the size of the total interest bill due on the proposed USD 20 billion 23-year debt package (MEED, 2013).

Thus far, the content of the detailed agreement is unknown. Completing the financing process will require a full financial analysis of the programmes as well the due diligence process required by potential lenders. Both are still outstanding at this time.

Electricity price arrangements

By 2020, the UAE hopes to have four 1 400 MW nuclear plants running and producing electricity at a cost that is expected to be lower than producing the same electricity with gas-fired plants. Beyond satisfying its own quickly rising demand, it also plans to export electricity to Gulf neighbours via the regional power grid. In this context, a long-term PPA with the Abu Dhabi Water and Electric Company (ADWEC), which is overseen by the Ministry of Energy, is envisaged. The UAE government as well as its Regulator and Supervision Bureau (RSB) will be reviewing the PPA to issue the generation licence to Barakah NPP. This however will only happen once the financing is finalised. Given that its contents are not yet public, the details of electricity price arrangement are currently difficult to access. In any case, they are probably not decisive for the financing of the project as the latter primarily relies at all stages on the implicit and explicit support of the UAE government.

Conclusions

The Barakah nuclear plants are based on the design of the Korean APR-1400 reactor, which is itself an evolution of the design of the OPR-1000 reactor. It is financed by a mix of equity contributed by the UAE government through ENEC and debt. The latter is secured to a significant share by the Korean Export-Import bank (Kexim). Electricity price arrangements are still under discussion. However, they are unlikely to affect the financing in a major way as the project's financial viability ultimately relies on the implicit and explicit support of the UAE government.

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II.3.3. Case study of the Vogtle nuclear power plant

Introduction and general description

This case study provides an overview of the expansion of the Alvin W. Vogtle Electric Generating Plant in the United States and explores the financial, regulatory and market-related matters that have made it possible. "Plant Vogtle" is an NPP operating in the state of Georgia, in the south-eastern part of the country. Georgia has a population of 9.9 million people and produces a large amount of electricity mainly from coal, natural gas and nuclear power (EIA, 2012). Four nuclear units at the Vogtle and Hatch sites already provide electricity to Georgia consumers, and the current project to build two additional units will make Plant Vogtle the largest nuclear plant in the country with four reactors operating on the site.

The first new American nuclear construction in 30 years, Plant Vogtle is hoping to lead the way for a revitalised American nuclear energy sector. Since 2005, substantial federal incentives have been put in place for the development of advanced nuclear facilities. However, few electricity generating companies have so far taken advantage of them. Some of this can be attributed to the NRC's extensive review process, but not all. The capital intensity of nuclear power is the greatest hurdle facing new nuclear development and dealing with upfront costs is enormously challenging in most American electricity markets. Furthermore, on the state level, some states are more generous than others in supporting and approving nuclear projects. Plant Vogtle has benefited from a unique set of state-level regulatory conditions, and its future success could influence other utility companies to seek out advanced nuclear power's low marginal costs and carbon neutrality, despite its high initial investment costs. Each one of the four shareholders in Plant Vogtle has put in place a mix of measures for the long-term financing of large, capital-intensive power generation projects that limit the financial risks of construction. These include the possibility provided by the regulator to include construction costs into electricity rates as well as long-term power contracts under which customers will take off electricity at cost.

Location, technology, management

Plant Vogtle sits on 1 295 hectares and has been operating since the late 1980s, with unit 1 coming on-line in 1987 and unit 2 in 1989. Named after a former executive of The Southern Company, Plant Vogtle is located in Burke County, Georgia, approximately 34 miles (55 km) southeast of the city of Augusta. The site's two Westinghouse pressurised water reactors have a rated net capacity of approximately 1 150 megawatts (IAEA, 2014).

The plant is jointly owned by four electricity companies, with varying ownership shares: Georgia Power, 45.7%; Oglethorpe Power Corporation (OPC), 30%; Mutual Electric Authority of Georgia (MEAG), 22.7%; Dalton Utilities, 1.6%. Note that this ownership arrangement is the same for the forthcoming units 3 and 4. Plant Vogtle is operated by Southern Nuclear Operating Company. Southern Nuclear was established in 1991 and holds the NRC licences to operate Plants Vogtle and Hatch in Georgia, as well as Plant Farley in Alabama. Units 3 and 4 under construction will also be operated by Southern Nuclear. Georgia Power, the plant's largest shareholder, and Southern Nuclear, are both subsidiaries of the Southern Company.

Box 4: Information on the co-owners of Plant Vogtle

Georgia Power
Units 3 and 4 ownership: 45.7%

Georgia Power Company is an investor-owned utility, a subsidiary of the Southern Company, and the largest electricity generation and distribution company in Georgia. Georgia Power provides electricity for approximately 2 million residential and over 300 000 commercial, industrial and "other" customers, with residential customers accounting for 37% of annual revenues. The company also co-owns approximately 27 000 km of transmission lines with MEAG and Dalton Utilities under Georgia's integrated transmission system (GPC, n.d.). Georgia Power operates as a vertically integrated utility providing the bulk of Georgia's urban electricity needs. It is regulated by the Georgia Public Service Commission (GPSC), which approves all of its rates and new generation projects.

Oglethorpe Power Corporation (OPC)
Units 3 and 4 ownership: 30%

Oglethorpe Power Corporation is a non-profit membership-based electricity company that provides electricity to 38 out of 42 electric membership corporations (EMCs) in Georgia. EMCs are local electricity retail companies which operate in 151 out of Georgia's 159 counties, serving approximately 4.1 million people. OPC provides for the majority of its members' electricity needs and does so under long-term wholesale power contracts, the majority of which last until 2050 (OPC, 2013). Each EMC owns and is accountable for a share of each piece of generation that is agreed upon by 75% of members. Some EMCs enter into ownership arrangements with other generation facilities independent of majority participation. Under this framework, OPC naturally insulates itself from risk, because there must be a 75% agreement to take on projects that require significant debt, ensuring that all EMCs will be involved in the financing to some extent (OPC, 2013). Oglethorpe is the generating body of three independently operated but interconnected electric service companies, with Georgia Transmission Company providing transmission services and Georgia Systems Operations Corporation managing the grid for the EMCs.

Mutual Electric Authority of Georgia
Units 3 and 4 ownership: 22.7%

MEAG Power was established in 1975 by the Georgia General Assembly to provide municipal electric utilities with reliable electricity at stable prices. Forty-nine non-profit municipal electric utilities are currently part of the MEAG Power system. These utilities differ from EMCs based on historical territory distinctions. MEAG participants own electricity production and distribution independently, and many sell part of their shares of MEAG power production on the wholesale market to consumers in other states. MEAG Power shares the state's Integrated Transmission System with Georgia Power (MEAG, 2013a).

Dalton Utilities
Units 3 and 4 ownership: 1.6%

Dalton Utilities is a small municipal electric utility company that provides electricity for the city of Dalton, Georgia. It is one of the few municipal electricity companies that operates outside of MEAG Power. Dalton's 1.6% stake in Vogtle units 3 and 4 gives it exclusive ownership of more than 20 MW of power.

Contractors

In April 2008, as an agent on behalf of the co-owners, Georgia Power entered into an engineering, procurement and construction agreement with Westinghouse Electric Company (WEC) and Stone & Webster, Inc. for the development of the two AP1000 nuclear units at Plant Vogtle, the Shaw Group (TSG). In the years since the EPC agreement, these contractors have gone through multiple acquisitions by larger companies. Stone & Webster, at the time was an operating company of the Shaw Group LLC, a Louisiana-based infrastructure company. In 2012, the Shaw Group was acquired by Chicago Bridge

& Iron (CB&I), a larger infrastructure and energy conglomerate. In addition, Westinghouse, which in 2008 was partially owned by the Shaw Group, as of 2013 is 87% owned by Toshiba (WNN). Therefore, today, CB&I promotes the nuclear build at Plant Vogtle as one of its largest current projects. The key subsidiary working at the Vogtle plant is the former Shaw Modular Group, which is now called CB&I Lake Charles Facility. The changes in ownership have not changed the nature of the agreement between the contractors and Georgia Power on behalf of the co-owners.

Permitting

In order to begin construction of Plant Vogtle, the co-owners and contractors complied with the Nuclear Regulatory Commission's permitting process. The NRC has handed down design certification for the Westinghouse AP1000 reactor since 2002, with 19 revisions since then. The design certification for the AP1000 units to be installed at Plant Vogtle was affirmed in December of 2011. As for the on-site development of the project, the co-owners and operators sought a combined licence (COL), which authorises the construction and operation of a plant under conditions specified by the NRC. COLs are valid for 40 years of operation, though they can be renewed. To issue a COL, the NRC must comprehensively review all aspects of an applicant, particularly concerns relating to safety and the environment. Southern Nuclear Operating Company sent its COL application for units 3 and 4 to the NRC on 28 March 2008, and received its licence on 10 February 2012. Plant Vogtle also sought and received an early site permit (ESP) from the NRC, which approved the site for a nuclear power facility but did not approve construction of the facility itself. This kind of permit allows for preliminary construction, expediting the overall nuclear build process. In August 2006, Southern Nuclear applied for its ESP, which was approved in August 2009 (NRC, 2014) (see Table 15).

Legal challenges

The permitting process has caused an ongoing legal dispute between the plant owners and the contractors. Delays in the permitting relating to the design certification and subsequently the COL have generated added costs. While the contractors claim that the co-owners are responsible for covering these expenses based on the EPC agreement, the co-owners dispute their responsibility. On 1 November 2012, the co-owners filed suit in the US District Court of Southeast Georgia to deny their responsibility for the costs. The contractors responded immediately by suing the co-owners in the US District Court of the District of Columbia. The litigation had not been resolved as of August 2013 and leaves open many questions relating to escalating costs for the project. This will be addressed in more detail in the "cost and financing" section of this chapter.

Table 15: Timeline of important dates for Plant Vogtle 3 and 4 construction

Southern Nuclear submits application for early site permit	15 August 2006
Southern Nuclear submits Vogtle 3 and 4 application	31 March 2008
NRC completes deficiency review	30 May 2008
NRC issues Vogtle early site permit and limited work authorisation	26 August 2009
NRC issues draft environmental impact statement	26 August 2010
NRC Issues last advance safety evaluation report (SER) material	2 December 2010
NRC affirms AP1000 design certification	22 December 2011
NRC issues Vogtle COLs	10 February 2012

Source: NRC, 2014 and GPC, 2013b: 9.

Costs and financing

Overview of costs

The costs of building a nuclear plant can be broken down into two primary categories: overnight costs and financing costs. Overnight costs subdivide into EPC costs and owner's costs. EPC costs are effectively the bare price for the elements of the nuclear facility. Data for Plant Vogtle indicate that EPC costs are clearly identified but that their level may change between the date of the estimate and the date of actual construction. Owner's costs are less clearly specified, however, and account for all extraneous costs, from costs relating to project management to the cost of implementing transmission lines. In the case of the construction of Vogtle units 3 and 4, these costs have accounted for a large percentage of cost increases. Financing costs, finally, are the interest and other costs that the owners of the plant incur in raising the capital needed for the project completion.

Overnight costs

In 2009, the Public Service Commission of Georgia certified the overnight costs for Georgia Power to be about USD 4.4 billion (45.7% of total) with the reactors expected to supply electricity by April 2016 for unit 3 and by April 2017 for unit 4. This certification is part of the GPSC's required "Integrated Resource Plan" for Georgia Power, which requires that the most economical options for power generation be sought to meet future demand. Table 16 shows the overnight costs for all of the co-owners based on the GPSC's certification for Georgia Power (these figures are based on the hypothesis that co-owners have equally distributed shares of cost according to their ownership percentage).

Table 16: Georgia Public Service Commission certified costs in 2009

	Cost estimates (USD millions)				
	Total	Georgia Power	OPC	MEAG	Dalton
Percentage ownership	100%	45.7%	30.0%	22.7%	1.6%
EPC base	6 818	3 116	2 046	707	33
EPC escalation	1 490	681	447	155	7
Owner's costs	1 359	621	408	141	7
Total overnight costs	9 667	4 418	2 900	1 003	46

MEAG: Municipal Electric Authority of Georgia; OPC: Oglethorpe Power Corporation; EPC: Engineering, procurement and construction.

Source: Based on GPC, 2013a.

EPC base represents the originally estimated costs for the construction of the plant, encompassing the costs associated with engineering, procurement of important plant parts such as generators and turbines, and construction carried out by contractors on-site. EPC escalation shows the potential increase in EPC between the date of the original estimate and the actual date of construction. Note that the GPSC agreed to certify almost USD 1.5 billion worth of these costs. In contrast, owners' cost is the residual term for any other costs associated with construction. These are listed as "Quality assurance, compliance and operations and EPC scope change", "ad valorem", "test fuel offsets", and "transmission interconnection". These costs are the most vulnerable to overruns (based on GPC, 2013a).

Cost increases

According to the latest report from Georgia Power (GPC, 2014b), the overnight costs of the project are higher than the original certification of 2009, rising from a total of USD 9.7 billion to USD 10.5 billion (see Table 17). Although offset by reductions in forecasted EPC cost escalations, owners' costs increase by more than USD 1 billion. These owners' costs can be mainly attributed to the delays in the project's forecasted completion, which has been revised for the fourth quarter of 2017 for unit 3 and the fourth quarter of 2018 for unit 4. Georgia Power's eight Vogtle construction monitoring report (VCM) explains the costs that have resulted from delays:

> Costs for actual engineering, procurement, and construction of the main power block and support structures (i.e. bricks and mortar) remain stable and represent a less than 1% increase in the certified capital costs. Changes in the capital cost forecast also include known and expected costs to implement NRC regulatory changes, increased taxes, costs necessary for operational readiness, quality and compliance during construction, transmission costs, and legal and environmental permitting costs (GPC, 2013a: 4)

The 9th/10th Vogtle construction Monitoring Report (GPE, 2014a) notes that the total construction and capital cost forecast remains unchanged, while the financing costs are reduced by USD 91 million due to more favourable conditions in capital markets.

Table 17: Project forecast in June 2014

	Cost estimates (USD millions)		Cost increase (%)
	2009	June 2014	
EPC base	6 818	6 829	0.2%
EPC escalation	1 490	1 274	-14.5%
Owner's costs	1 359	2 398	76.5%
Total overnight costs	**9 667**	**10 501**	**8.6%**

EPC: Engineering, procurement and construction.

Source: Based on GPC, 2014a.

Litigation as a result of overruns

On 1 November 2012, both operating parties of the Vogtle units 3 and 4 construction (Georgia Power and the Contractors) began litigation to resolve a dispute related to cost overruns due to delays. Since the delays were primarily caused by delays in approval of the design certification and COLs, Georgia Power claims that the contractors are responsible for these costs, which are in excess of USD 425 million for Georgia Power.[9] The contractors dispute this based on the terms of the original agreement. The results of this litigation are pending.

Project financing methods

Each owner of Plant Vogtle finances its share of the project in a unique way. The four entities are different in terms of their business models and operating structures, and this weighs heavily on the manner they have chosen to approach financing.

Georgia Power

As a large scale electricity generator and retailer, Georgia Power uses complex financing methods to cover the costs of its numerous utility construction projects. This includes issuances of long-term bonds for specific projects, as well as short-term bonds for immediate cash needs. In addition, Georgia Power relies on large revenue streams from electricity sales as well as various methods of equity financing.

9. The co-owners are collectively seeking damages in the lawsuit, meaning that the total damages are approaching USD 1 billion, appropriated based on ownership share.

In February 2014, Georgia Power and the US Department of Energy (DOE) signed a loan guarantee agreement, for an estimated amount of USD 3.46 billion, corresponding to 70% of capital costs. Georgia Power estimates that the loan guarantee agreement would provide a benefit to customers of approximatively USD 250 million[10] in interest costs over the life of the loan (GPC, 2014a). In the last Vogtle Construction Monitoring Report [ibid.], Georgia Power has also estimated the added benefit of participating in the production tax credit programme to USD_{2018} 800 million (see Box 5 for further information).

Box 5: US federal financing incentives for nuclear power

Loan guarantee programme

Under Title 17 of the 2005 Energy Policy Act, the Federal government established loan guarantees that would aid financing the construction of advanced nuclear power facilities. The government will guarantee loans for up to 80% of the costs of construction. In addition, the Federal Financing Bank can provide the loans to borrowers in lieu of a private institution. Should a borrower default on a loan, the Federal government will reimburse the lender to the amount of both principal and interest. In exchange for providing a loan guarantee, DOE is authorised to charge sponsors a fee that is meant to recover the guarantee's estimated budgetary cost on a market basis. In February 2014, the DOE has finalised the process to grant USD 3.46 and USD 3.07 billion as loan guarantees to Georgia Power and Oglethorpe Power, respectively, while the decision for a third loan guarantee of USD 1.8 billion to the Municipal Electric Authority of Georgia (MAEG) is still in progress.

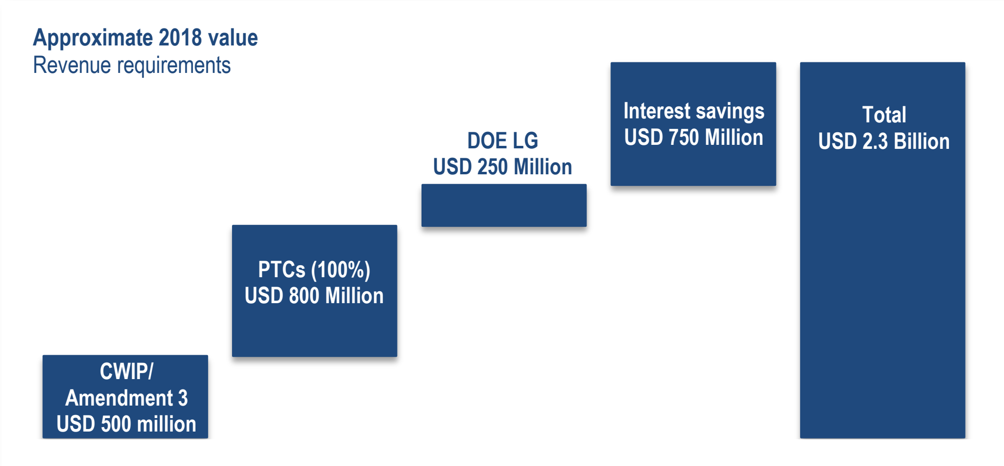
Production tax credit

Under Title 13 of the 2005 Energy Policy Act, the Federal government established an USD 18/MWh production tax credit for the first eight years of operation of an advanced nuclear facility. This plan is limited to the first 6 000 megawatts of installed generation in the United States and is linked to the double condition that construction work starts before 2014 and the power plants are brought into service before 2021. Production tax credits work similar to a subsidy per unit of output and will provide significant cash returns for the first advanced nuclear facilities once they commence operation.

On the state regulatory level, Georgia Power has reduced its financing burden with the help of a construction work in progress (CWIP) tariff to charge customers for the financing costs of construction over time. Specifically, the Nuclear Construction Cost Recovery (NCCR) Tariff was established in the Georgia Nuclear Energy Financing Act, Georgia Code Section 46-2-25, and for FY 2013 it guarantees that an amount equal to 7.58% of customer base bill calculations will be allocated towards paying the financing costs of the units 3 and 4 construction (GPC, 2012). According to Georgia Power, this plan reduces the capital costs of the plant by up to USD 500 million (GPC, 2014a). This tariff is very effective because it reduces the reliance on *Allowance for Funds Used During Construction* (AFUDC) costs incurred through financing. AFUDC is an accounting term which refers to the income from long-term bonds, which is then used to finance short-term debt. This ultimately is more costly because of numerous factors including interest on AFUDC, the possibility of inflation and more (Pomerantz and James, 1975). Under the CWIP model with the NCCR tariff, Georgia Power is able to continually pay off their debt through their rate plans, imposing minor additional costs unto costumers in the present but reducing long-term future costs associated with AFUDC financing. The overall benefits for customers, according to Georgia Power estimates, are reported in Figure 30.

10. On a 2018 present value basis.

Figure 30: Summary of customer's benefits
(USD_{2018})



CWIP: Construction work in progress; PTCs: Production tax credits; DOE LG: US Department of Energy loan guarantees.

Source: GPC, 2014a: 33.

Oglethorpe Power

As a co-operative, Oglethorpe has a different relationship with its customers than Georgia Power, and is exempt from many of the state-level regulatory processes that Georgia Power faces. A statement says:

> We operate on a not-for-profit basis and, accordingly, seek only to generate revenues sufficient to recover our cost of service and generate margins sufficient to establish reasonable reserves and meet certain financial coverage requirements. (OPC, 2013: 69)

Much of past funding for Oglethorpe has come from the Rural Utilities Service loan Guarantee Programme that provided loans from the Federal Financing Bank. However, there is concern that this programme is shrinking due to budget concerns and will not be sufficient to support Oglethorpe's future projects, including its share of the new Vogtle units (OPC, 2013). In the same mode as Georgia Power, on the 20 February 2014 Oglethorpe has signed a final agreement with the DOE to guarantee USD 3.1 billion of Oglethorpe's costs towards the Vogtle 3 and 4 construction.

However, given the uncertain nature of this contract, throughout the early stages of construction, Oglethorpe has met many of its long-term financing requirements using traditional capital market methods, focused on issuing bonds in both taxable and tax-free markets. This, along with numerous credit lines, has given Oglethorpe what it sees as "sufficient liquidity to cover normal operations and interim financing needs, including financing for the new Vogtle units under construction" (OPC, 2013: 83). A significant portion of Oglethorpe's Vogtle financing costs are being met using variable rate debt. To minimise risk associated with this, Oglethorpe purchased interest rate options covering USD 2.2 billion of debt that will finance the plant. These options, which are LIBOR "swap options", give Oglethorpe the option of enacting the floating LIBOR rate if it proves to be financially advantageous. Oglethorpe paid an up-front premium of 100 million for these options, and has scheduled the options' expiration dates to match the borrowing schedule for the new Vogtle units (OPC, 2013).

Oglethorpe has not reported any use of a Construction work in progress tariff comparable to Georgia Power's Nuclear Construction Cost Recovery plan. Given Oglethorpe's closer relationship with its customers through its non-profit arrangement, they may have included such a financing provision in their rates with the understanding that it is directly beneficial to customers under the bylaws of the company. In addition, Oglethorpe is not required to report such a rate increase to the GPSC.

Mutual Electric Authority of Georgia (MEAG)

MEAG's plan for electricity generation at Plant Vogtle has been divided into three "projects". "Project M" will provide power for the municipal consumers of Georgia, and will consume 7.7% of Plant Vogtle units 3 and 4's power (with MEAG's total being 22.7%). "Project J" is an out of state PPA with the city of Jacksonville, Florida, and will account for 9.3% of Vogtle 3 and 4 generation, and "Project P" is a PPA with the city of Andalusia, Alabama, consuming 5.7% of Vogtle 3 and 4's capacity. Each of these projects is financed separately, with its own set of bond issuances. These are each 20-year PPAs (MEAG, 2013a).

MEAG has been in talks with the DOE to acquire loan guarantees under the same programme as the other constituents of the Vogtle construction, but a final decision has not yet been taken. DOE and MEAG continue to work on the remaining conditional commitment for an additional USD 1.8 billion loan guarantee.

Dalton utilities

As a small electric utility, Dalton does not publish a public report of its finances, and the company did not provide information for this study. It is assumed that Dalton will cover its share of the construction costs by issuing long-term bonds.

Financing costs

Georgia Power

As of 31 December 2013, the projected financing costs, and total costs of the project for Georgia Power, are the following:

Table 18: Georgia Power costs
(USD millions)

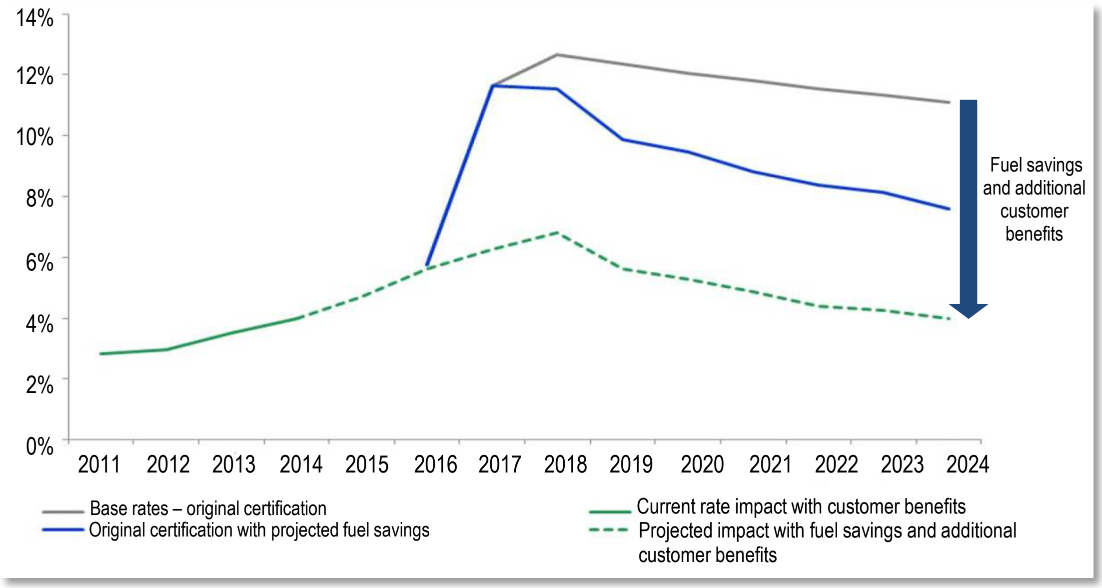
	GPSC certified 2009	Current forecast	Change (%)
Total overnight costs	4 418	4 799	8.6%
Return on CWIP in rate base	1 545	1 796	16.2%
Total construction schedule financing	1 695	1 905	12.4%
Total capital costs and financing	6 113	6 704	9.7%

CWIP: Construction work in progress; GPSC: Georgia Public Service Commission.

Source: Based on GPC, 2014b.

The financing costs for this project account for the largest projected cost increases for Georgia Power resulting from construction delays. As the company has shifted mostly to the CWIP tariff to pay for financing costs, the AFUDC burden has been reduced. Georgia Power states that the CWIP programme will be beneficial to rate paying customers due to its reduction of interest on financing costs. As seen in Figure 31, the CWIP tariff along with "relative fuel benefits", and federal production tax loans (PTC, USD 18 per MWh from the DOE) have significantly reduced the long-term customer rate burden.

Figure 31: Projected cumulative rate impacts



Source: GPC, 2014b: 7.

Oglethorpe Power

Oglethorpe Power has not published long-term cost projections in the same detail as Georgia Power; it is not required to report such projections to the GPSC. However, based on information from credit rating agencies, as well as the overnight costs shared by Oglethorpe, we can determine its financing costs. Standard and Poor's provided the estimation that as of April 2013 the project will cost USD 4.5 billion, increasing from the initial estimation of USD 4.2 billion taken before delays in construction (S&P, 2013). Given that the current overnight cost projection is USD 3.15 billion and the initial projection was USD 2.9 billion (see Table 16), we can determine that the financing costs have accounted for 31% of initial total costs and 30% of current total costs, slightly higher than the burden for Georgia Power, which was 28% initially and is now rated at just below 30%. It is unclear exactly how Oglethorpe amortises its financing costs and whether it incorporates them into its current rates.[11]

MEAG

According to MEAG's 2012 financial statements, its projected costs to put the plant in service are USD 3.9 billion. The overnight costs for MEAG's share are about USD 2.4 billion, which indicates that financing costs account for 38% of total costs. In addition, MEAG points out that with the addition of some reserve funds they require, the total cost is actually USD 4.2 billion. The financing costs for MEAG appear to be higher than the other co-owners. This could be because of different accounting methods in reaching their total cost estimation, higher interest rates for MEAG, or different methods of financing (MEAG, 2013b).

Total costs

Together with the costs incurred by Dalton utilities, the following table summarises the total cost for the Vogtle Plant.

11. Oglethorpe Power declined to provide information outside of what is currently available from its annual reports.

Table 19: Combined total cost of Vogtle Plant[12]
(USD billions)

Total	Georgia Power	Oglethorpe Power	MEAG	Dalton utilities
15.5	6.9	4.5	3.9	0.2

MEAG: Municipal Electric Authority of Georgia.

Electricity markets and price arrangements

Overview of market players and regulation

The electricity market in Georgia is dominated by three major electric utility companies and their constituents, each of which have their own set of regulations that they are subject to. The three dominant market players are also the three largest share owners of the Plant Vogtle. The power companies' markets are defined by a central piece of Georgia state legislation, the Territorial Electric Service Act of 1973.[13]

Georgia Power

Georgia Power is the largest power generation and distribution company in Georgia. Territorial rights aside, Georgia Power dominates commercial and industrial electricity production above 900 kW, and given its size has developed market power for this kind of generation. Therefore, it is heavily regulated by the GPSC. The GPSC determines the electricity rates for Georgia Power through a rate making process, which varies in length of time. For example, with regard to base rate cases, the GPSC maintains oversight over a six month period of implementation (GPSC, 2014a). Furthermore, the GPSC is involved in all aspects of the company's activities, including financing of new power plants, environmental compliance, and auditing. The GPSC has continually supervised Georgia Power throughout the development of Vogtle units 3 and 4, requiring the company to submit regular forms documenting the progress and expenses of the project. Therefore, while Georgia Power has control over generation, transmission and retail in many areas, the GPSC regulates it to ensure fair pricing.

In addition, Georgia Power is one of the national leaders in real-time pricing (RTP), a pricing model that constantly adjusts prices based on demand and cost of generation. Georgia Power gives its high load customers the option of purchasing electricity at either day ahead or hour ahead prices and mainly commercial and industrial customers use this service. These customers are also assigned an amount of maximum load, and any fluctuations above that level incur extra costs. The advantage of RTP is that with hour ahead pricing Georgia Power can rarely be undercompensated for electricity. The day-ahead market poses a risk that unexpectedly high demand will result in unexpectedly high prices, high prices that Georgia Power would not anticipate. Hour-ahead pricing eliminates this risk. Also, the act of binding consumers to a load ceiling keeps demand more stable and makes electricity consumption more predictable (EEI, 2001).

12. These estimates have been generated by adding the total costs for each company as reported by the companies, with the exception of Dalton Utilities, which has been estimated based on its ownership percentage.

13. The Georgia Territorial Electricity Services Act, enacted in 1973, defines the areas in which utility companies can operate and sell electricity within Georgia. Large loads (above 900 kW) have a one-time option of choosing their electricity provider regardless of location, but all other customers, including residential consumers, are locked into the services of their regional electricity provider. This act is the cornerstone of Georgia's electricity markets, and under this framework, the electricity retailers in Georgia operate under localised monopoly conditions in their designated areas.

Oglethorpe Power

Oglethorpe Power's market environment is defined by the EMCs that buy Oglethorpe's electricity. These EMCs are self-regulated for the most part, receiving little oversight from the GPSC, other than some requirements such as approval of EMC financing for new plants. Thirty-nine of the EMCs are partial owners of Oglethorpe, a non-profit organisation, so the electricity rates from EMCs are based on consumer interests and the EMCs' financial demands, and do not require regulation from the GPSC.

The rates that the EMCs pay to Oglethorpe power for wholesale electricity are based on long-term PPAs. Rates are determined as those sufficient for Oglethorpe to recover all costs of generation, while yielding "a minimum 1.10 margins for interest ratio under [Oglethorpe's] first mortgage indenture". In other words, Oglethorpe determines its wholesale price contracts based on maintaining a 1.10 "margins for interest ratio" when selling electricity to customers (OPC, 2013: 3). This margin, which would be looked at by some as a profit, is maintained to ensure Oglethorpe's financial solvency in case of unexpected, disruptive circumstances. EMCs' rates are also increased by transmission costs associated with Georgia Transmission Corporation, which, also independently operated but owned by the EMCs, would charge rates to uphold similar margins as those of Oglethorpe Power.

MEAG Power

MEAG Power supplies electricity for the majority of municipal electric companies in Georiga, with some exceptions such as Dalton Utilities. Providing retail electricity only to their municipalities, these utilities are self-regulated with minor oversight from the GPSC. And, in a similar way as the EMCs, they set prices based on financial needs and consumer interests. Wholesale contract prices are determined by the ownership share of the municipal utility of MEAG's generation facility, and the municipalities are required to pay a sufficient share to cover the costs of generation plus any debt amortisation requirements (MEAG, 2013a).

Electricity price implications

Tables 20 and 21 show the average residential electricity prices for each type of retailer.

Table 20: Average residential electricity prices, summer 2012
(US cents/kWh)

	500 kWh	1 000 kWh	1 500 kWh	2 000 kWh
Georgia Power	12.53	12.92	13.58	13.92
Electric membership corporations	13.14	11.62	11.32	11.18
Municipal utilities	11.71	11.47	11.59	11.73

Source: GPSC, 2014b.

Note that in the summers, Georgia Power's rates increase for customers with greater load, unlike the other two groups of retailers. Overall, however, the data show that regulation, external for Georgia Power and internal for the EMCs and municipal utilities, keeps prices relatively even among the three electricity retail groups. With a couple exceptions, most fluctuations are minor, and EMCs and Municipal organisations in particular are mostly within a few percentage points of each other.

Table 21: Average residential electricity prices, winter 2013
(US cents/kWh)

	500 kWh	1 000 kWh	1 500 kWh	2 000 kWh
Georgia Power	11.94	10.51	9.91	9.61
Electric membership corporations	13.22	11.38	10.58	10.18
Municipal utilities	12.09	11.00	10.53	10.29

Source: GPSC, 2014b.

Another trend of note is that while Georgia Power's rates increase in the summer for higher load customers, EMCs and municipal utilities' electricity prices are stable. Since Georgia Power services the majority of large load customers, it most likely would be under strain during points of peak load to meet the high demands. Smaller electricity retailers who service predominately low load customers would not be as dramatically affected by demand spikes.

Effect of local market power on market conditions

Given that each of the electric utilities operates in absence of competition, which is guaranteed by state legislation, each utility company has a consistent revenue stream from its consumers in a given region, subject to a few variables such as fluctuations in demand stemming from external (e.g. weather-related) causes, and regulatory lag that prevents utilities from adjusting pricing models swiftly. While regulation keeps prices low and prevents the negative aspects of market power, long-term contracts among consumers and retailers ensures that most company decisions will focus on maintaining long-term stability, particularly since the self-regulated utilities are non-profit enterprises. This creates a market with low volatility, since customers have relatively predictable demand.

Georgia compared to other US markets

To understand the way the markets in Georgia have affected the Vogtle project, it is fundamentally important to understand the way that Georgia's electricity markets compare to those of other areas of the country. Georgia is a regulated electricity market. With policies such as the Territorial Electric Services Act, the structure of electricity generation and distribution is rigid, since they are typically controlled by the same entities. However, in the majority of the highly populated areas of the country, including California and the Eastern Seaboard north of Washington, D.C., electricity markets are deregulated, resulting in separate distribution and generation companies, which compete with each other to achieve the lowest prices and highest profit margins. These regions' electricity markets are controlled by Independent System Operators, non-profit organisations that co-ordinate the transactions of generation companies selling wholesale electricity to distribution companies. In this deregulated environment, the intense competition that many companies undergo (except those with PPAs) results in a greater emphasis on short-term economic gains to ensure solvency among competitors. Therefore, capital intensive technologies such as nuclear power are less attractive in these volatile deregulated markets, because they entail much more risk than other options with lower up-front costs, such as gas-fired power plants (UCAL, 2004).

Comparisons to other nuclear markets worldwide

The electricity market in Georgia, and thus the electricity market that defines nuclear power within the state, is effectively a dual system with opposite sides representing different understandings of electricity market structures. On one side there is Georgia Power, a vertically integrated utility that has the ability to take on capital intensive projects due to its insulation from competition. On the other side, there are Oglethorpe and MEAG, both of which are controlled or owned by their customers. The reason for this duality is the historic divide of electricity retail rights affirmed by the 1973 Territorial Service Act, and its implications are significant for nuclear power in the state.

The vertically integrated utility model can be loosely compared to a system like that in France overseen by EDF, absent the direct government subsidies that support it. Without any major competitors either for generation or retail (in this case within Georgia Power's service regions), both EDF and Georgia Power are able to support capital intensive projects including nuclear power.

The community ownership model exhibited by OPC and MEAG is reminiscent of the system in Finland, which supports nuclear power by directly tying the consumer's financial interests to the long-term success of the project. This causes prudence of investment, and the decision by co-operative ownership entities to develop nuclear power indicates their belief in nuclear over time as source of electricity with stable long-term pricing (FV, 2011).

Interaction of electricity price arrangements and financing

Financing an NPP requires long-term market stability and a reasonable assurance that the power produced will be cost effective over time. With little competition among electricity generators and retailers in Georgia, the state is well suited to developing nuclear power from a market standpoint. With absence of regional competition against the plant's co-owners, the co-owners will be selling Plant Vogtle's electricity for many years to come, provided that the marginal cost of producing electricity (which includes numerous factors) remains competitive enough to prevent project's abandonment by the companies that built it. Oglethorpe for example has PPAs with its EMC customers that last until 2050, so there is no risk of an outside competitor seizing the market. Furthermore, MEAG's municipal consumers own their share of the electricity generated that they consume, so they are also bound to their interests in Plant Vogtle for a long time.

Georgia Power, with its market share comprising 62% of total electricity and more than 70% for industrial and commercial customers, will be the dominant for-profit retailer of electricity for the foreseeable future, and its customers will remain tied to their current contracts, since Georgia Power is vertically integrated. Benefitting from its vertically integrated structure, Georgia Power will sell its electricity to its consumers, and since it has agreed with the GPSC that its long-term electricity needs will be serviced in part by nuclear power, Plant Vogtle is guaranteed to be providing electricity as long as its marginal operating costs are lower than competing electricity sources such as natural gas or clean coal technology.

With all of these elements in place, the project appears promising for potential investors, as stable, long-term revenues mitigate risk. This carries positive implications for plant financing, because the co-owners will be able to show the long-term viability of Vogtle units 3 and 4 as a source of electricity that will remain competitive over time, despite its high initial costs. Factors that could be a concern in other states are avoided by Georgia's market and regulatory conditions:

Outside Competition: Due to the stringent regulations imposed by the Georgia Territorial Services Act and the long-term power agreements between generators and retailers, outside retailers would not find an opportunity to compete selling electricity in Georgia. The vertical-integration of Georgia Power and the long-term contracts of the EMCs and municipal utilities guarantee that the status quo of electricity generation will remain for many years to come.

Fuel Prices: Although there is speculation that nuclear power is not cost competitive with gas prices at their post 2010, fracking-era levels, the barrier on outside competition will prevent this from posing an eminent threat to Plant Vogtle, as outside companies cannot seek out this competitive advantage.

Concluding remarks on the financial and economic viability of the project

Although Plant Vogtle has been featured in the media because of its cost overruns, the market and regulatory conditions in Georgia appear to be favourable to this project, regardless of how economically unviable it may seem in the short term. The stability of demand and low-risk environment arising from the state's electricity market structure indicates that the plant's owners can predict their long-term revenues better than they could in other states. Furthermore, Georgia Power's CWIP tariff under the Nuclear Energy Financing Act is a very beneficial regulatory policy to reduce financing cost escalation during construction. As a result, Plant Vogtle, despite its high capital costs, can foreseeably be able to support its financing.

Of course, many issues come into this discussion. First and foremost is the question of the DOE's loan guarantee programme, because if the co-owners do not receive their loan guarantees, they will be required to raise capital on their own. Furthermore, the greatest risk to the co-owners of Plant Vogtle is the unlikely possibility of the deregulation of the markets through the elimination of the Territorial Electric Services Act. Also, the outcome of the legal dispute between the contractors and the co-owners will affect the outcome of the project, not only because of damages paid to either party, but also because of possible future delays.

Ultimately, as of 2013, the co-owners are optimistic that the project is on track for a successful completion in 2017 and 2018. However, the status of loan guarantees and litigation is uncertain, and could potentially bring challenges. Nonetheless, Plant Vogtle and its co-owners benefit greatly from the regulated Georgia markets and their lack of volatility.

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ANNEX TO PART II

Description of the economic and financial model

The economic and financial model used in Part II has been developed from the model employed in the NEA study on *Carbon Pricing, Power Markets and the Competitiveness of Nuclear Power* (NEA, 2011). The model calculated the NPV of the cash flows for an NPP and for a gas power plant assuming real discount rates of 3%, 5% and 7%. Main technical and economic assumptions for the two generating technologies have been derived from the IEA/NEA study on the *Projected Costs of Electricity Generation* (IEA/NEA, 2010) and are reported in Table 2. Future electricity, gas and carbon prices are based on historical daily data observed in European electricity, carbon and gas markets over five years between June 2005 and May 2010.

For electricity prices, the key parameter, a daily synthetic electricity price, was constructed as a weighted average of day-ahead, monthly, quarterly and annual forward prices. Historic prices have then been taken as a basis for assumptions about future prices. During the course of its operations, a gas power plant with a lifetime of 30 years will thus face the same electricity, gas and carbon prices that prevailed during the 2005-2010 period, in six five-year increments. The model allows the possibility to suspend electricity production when the daily electricity price is insufficient to cover the variable costs of generation.

From this reference case, several scenarios have been constructed. In order to assess the flexibility value of a gas plant compared to a nuclear plant, the impacts on NPV of a permanent variation of electricity prices (by ±10%, ±20%, up to ±70%) as well as the timing of this variation after commissioning (immediately after commissioning, 10 years later, 20 years later or anywhere from 20 to 50 years later) were taken into account. The comparison of the resulting NPV under different price scenarios illustrates the sensitivity of the two technologies to long-term decline in electricity price.

Based on the economic model described above, several adaptations have been made to model the choices, challenges and risks faced by private investors for the financial analysis presented in Chapter 2. This allows the flexibility to define multiple values for the key financial parameters: the opportunity cost of capital, the cost of debt and the debt ratio. The analysis has been performed for six different values of debt ratio, from 30% to 80%, and for eight values of cost of debt, ranging from 3% to 7% in real terms. Eight values for the opportunity cost of capital have also been used in the calculations, with values from 5% to 12% (real). This approach allows for an analysis of a broad range of investment arrangements and of different investor profiles. However, the main difference refers to the estimates of future electricity price via a mean reversion model instead of using historical values (more details will be given at the end of this section).

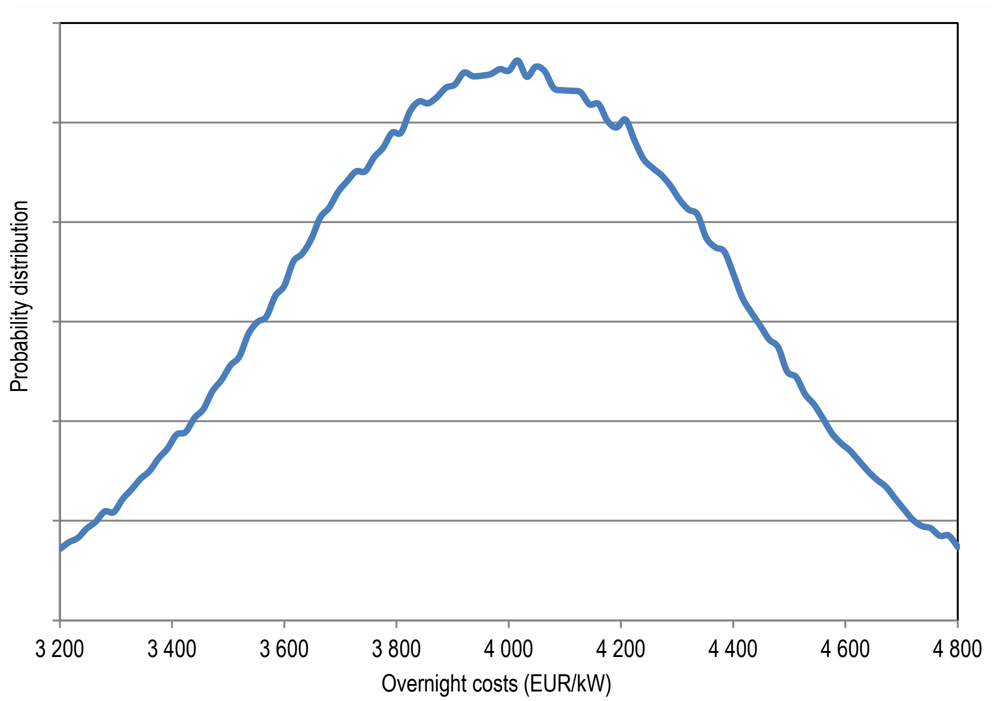
Concerning the basic NPV calculations, the basic cash flow model takes into account the corporate taxation, the depreciation of existing assets and the tax shield on the interest paid on debt. The modified accelerated cost recovery system (MACRS) has been adopted for tax deductions on companys' assets, with a depreciation length of 15 years. Concerning the treatment of debt, the model assumes that the debt repayment occurs over the lifetime of the plant (60 years), with constant payments in nominal terms.

Finally, a tax rate of 30% is assumed on corporate profits. In the case of negative tax returns, the model allows for both an indefinite carry-forward of tax losses (that could thus be compensated in the successive years) and for their immediate compensation. The former would be the case for a project-financed entity, while the latter would be representative of a large utility with a reasonable certainty to produce (as a whole) a net benefit in the future. The results presented in the study, however, refer to the latter situation. An inflation of 2% is assumed throughout the lifetime of the NPP, and the same value is used for escalation of variable costs (fuel, O&M and back-end costs) as well as for the increase of electricity prices.

With regard to the economic data, the study assumes an average overnight cost of EUR 4 000 per kW (in real terms), including the contingency, and a construction time of seven years on average. O&M costs and front-end and back-end fuel costs do not differ from those used in the previous analysis and are reported in Table 4. However, it should be noted that 95% of the O&M costs are considered as fixed, and 5% variable. Decommissioning occurs the year after the shutdown of the plant; the relative costs, equal to 15% of overnight costs, are fully allocated in the first year of decommissioning. With respect to operational parameters, the nuclear plant has a lifetime of 60 years and has an availability factor of 85% on average.

The financial model treats explicitly, via a Monte Carlo analysis, the most important sources of risk in a nuclear new build project: construction risk (which includes both uncertainty related to the overnight costs and the length of the construction), uncertainty in the availability factor, and electricity market risk.

Figure 32: Probability distribution of overnight costs
(EUR/kW)



The probability distribution of overnight costs (shown in Figure 32) is represented by a normal distribution with a mean of EUR 4 000 per kW, a standard deviation of 16% and a cut-off at ±20%. Overnight costs thus range from EUR 3 200 to 4 800 per kW. Also, the statistical distribution of construction length is represented by a normal distribution, with a mean of seven years and a standard deviation of 38%,[1] as well as a cut-off at ±50%. Thus, the construction length spans from 3.5 to 10.5 years. Finally, a correlation between these two independent variables has been introduced in the model: the correlation coefficient assumed is 0.5. Operational risk is taken into account by representing the annual availability factor of the plant with a triangular distribution having an average of 85% and extreme values of 75% and 95%.

The electricity market risk is treated with great detail via a two-stage model that takes into account the short-term volatility of electricity prices as well as long-term changes in the electricity price trend. Short-term variability of electricity market prices is modelled via a mean reversion process:

$$\boldsymbol{P_{t+1} = P_t + \propto (\mu - P_t) + \varepsilon_t}$$

Where:

- P(t) is the market price at the time t;
- μ is the long-term average electricity price;
- ε is a random component (with a zero mean);
- α is the rate of mean reversion.

In the base case, the long-term average price is set at EUR 80 per MWh, in real terms. The values of ε and α have been obtained from real data observed in European markets over the 2005-2010 period. For each year of operation, two independent series of electricity prices have been modelled representing the price level during peak and off-peak hours (each of them with 240 points), to calculate the stochastic average price. It should also be noted that the model assumes that the power plant stops production when the electricity market price is below its variable cost of production.

A set of additional calculations have been performed for different values of long-term average electricity prices, ranging from EUR 40 to 120 per MWh (and representing a variation of ±50% of the base-case value) to assess the effect of changes in the long-term average price of electricity. These variations are assumed to occur when the power plant starts operations, after the plant has been constructed and financed.

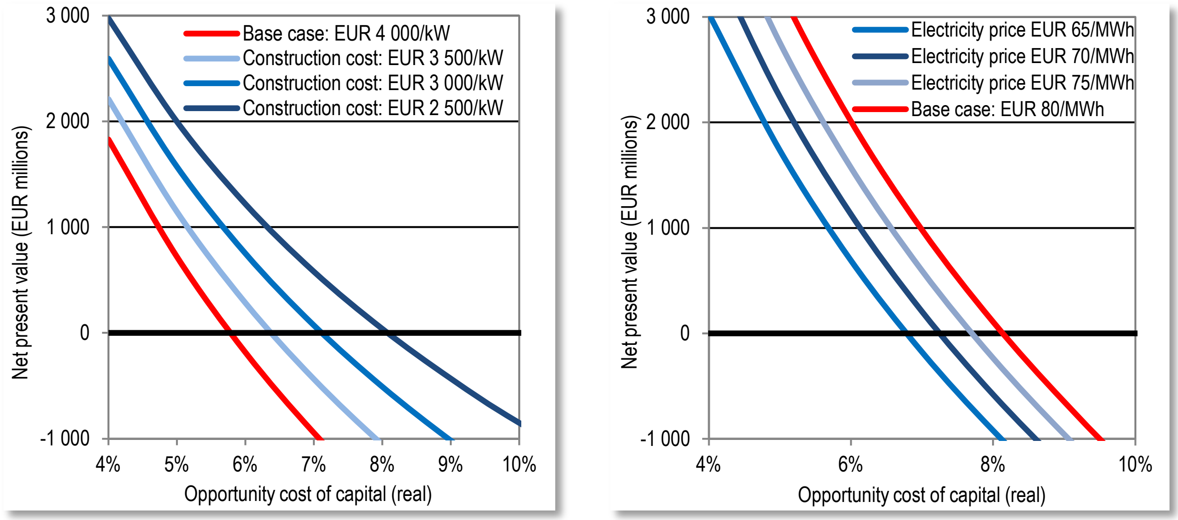
Sensitivity calculations on NPV

Figure 33 shows several sensitivity calculations of NPV as a function of overnight costs and different electricity price levels.

1. If one considers nuclear projects completed from 2000 to 2012 in the four countries that have most recently built NPPs (China, India, Japan and Korea), the average construction time is 5.8 years and the standard deviation is 38%. However, an average construction time of seven years has been maintained in the current analysis for consistency with previous NEA analyses.

Figure 33: NPV of a nuclear new build project as a function of construction costs (left) and electricity prices (right)

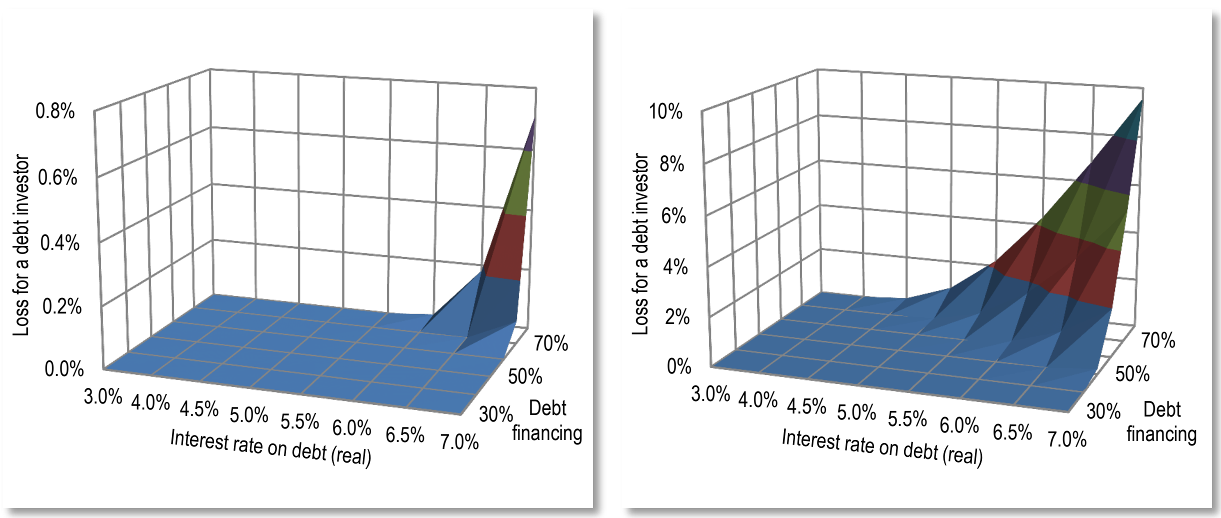
(Base case assumptions: Electricity price = EUR 55 per MWh, construction costs = EUR 4 000, debt ratio = 60%)



Bondholder average losses

Figure 34 shows the average losses of bondholders in case of the adverse evolution of electricity market price.

Figure 34: Average losses for bondholders with 20% (left) and 40% (right) declines in electricity prices



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PART III.

Project management and logistics in nuclear new build

Chapter III.1.

Project management and logistics: The basic challenges

The challenges for NNB projects extend beyond financing to project management and procurement, as the two are clearly linked. Other things being equal, a poorly managed project can end up being more expensive. However, the two challenges remain distinct and therefore must be separately addressed. Even a project with a superior management team in place will not come off the ground without adequate long-term finance and, of course, even well-financed projects can be mismanaged. Part II is thus dedicated to identifying the key challenges for good project management as well as promising perspectives for how best to address them.

Good project management is vital for the nuclear industry to maintain nuclear energy as a credible option for electricity generation in the marketplace. Building to time and to budget will be a crucial prerequisite to allow investors, including public investors, to commit themselves, as they are being watched by a sceptical public. The fact that a new generation of reactors poses first-of-a-kind (FOAK) issues is widely understood but cannot serve indefinitely as an excuse for time and budget overruns. The record thus far is patchy. The *World Nuclear Industry Status Report* claims in its 2014 edition that 49 of the 68 projects that are currently under way the world over have encountered construction delays. Even in China, 21 of the 27 projects under way are said to have experienced delays ranging from several months to two years. "The average construction time of the last 37 units that were connected to the grid since 2004 was 10 years", although this average is heavily skewed by a number of outliers with "construction times" of 20 years or more (Schneider and Froggatt, 2014). Clearly, in such extreme cases it is the political environment rather than commercial project management that is the primary cause for the delay.

Accounting for the length of construction times or even deciding whether a project is still ongoing, suspended or abandoned is not an exact science. Different sources arrive at slightly different results. However, it is evident that the nuclear industry is confronting a challenge when trying to convince future investors that construction times of five to seven years can be respected (see also Chapter III.4 on the question of whether the nuclear industry may be different in this respect from other "megaprojects"). Building a new NPP is a large and complex industrial project at the best of times. Even without considering the financing issues addressed in Part I, there are a number of challenges that are specific to nuclear new build:

- Massive and discontinuous technological change as generation II NPPs are substituted by larger and often more complex generation III plants with new rounds of licensing and regulatory change.
- Loss of expertise and human capital as projects are, with the exception of China, few and far between.
- A complex supply chain with quality control issues at all levels of externalisation.
- Long time frames at all levels of the value chain. From design and licensing to construction, operations and decommissioning, changes in nuclear new build can take a decade or more until all contributing factors have adjusted and they have

found a least-cost equilibrium constellation that can be replicated and allows reaping economies of scale.

- Shifts in political and social support after the Fukushima Daiichi accident. While only a small number of countries have actually decided to phase out nuclear, their decisions have created uncertainties that go far beyond their national boundaries.

The last point raises a particularly important question, as it is essential to know to what extent the nuclear industry will strive to become competitive provider of low-carbon electricity and to what extent implicit and explicit governments at different levels will remain an essential feature of successful NNB projects. Governments, of course, define the legal and regulatory framework, including the permission to build and operate nuclear plants and the rules for waste disposal, decommissioning and accident insurance.

As shown in Part I, due to their high capital-intensity, nuclear energy and other low-carbon providers will also require a form of long-term electricity price guarantee to remain competitive with fossil fuel-based generators. Another key issue is, of course, national carbon emission reduction objectives that translate into implicit or explicit carbon prices. Carbon prices remain decisive drivers of the competitiveness of low-carbon technologies. Due to the economic stability that nuclear requires, especially in terms of electricity prices, political and social support will always be vital. However, such support is earned by proposing an option for power generation that is safe and economically attractive over the long run. Part II examines how the nuclear industry is working on delivering new NPPs on time and on budget. This is an essential complement to the electricity price stability on which all new build projects currently rely, even in otherwise liberalised electricity markets.

Both the conceptual analysis and the case studies presented in the following chapter show that the successful management of a nuclear construction project and its supply chain turns on three issues:

- Finding the right balance between outsourcing (externalisation) and vertical integration. The adoption of a common set of engineering codes could be a driver of efficiency in this area.
- Finding the right balance between standardisation and scale economies on the one hand and adaptation to local conditions on the other hand.
- Developing competences in handling "soft" issues such as team, trust and confidence building as well as a systematic approach to learning and change management.

The following chapters develop these issues from both a conceptual and an empirical point of view. Chapter III.2 will consider from the point of view of economic analysis the respective merits of vertical integration and competition global procurement. Chapter III.3 will consider the evolving structure of the global nuclear supply chain and its ability to contribute to successful NNB projects. Chapter III.4 asks "What is special about nuclear?" by comparing the history of cost overruns in the nuclear industry to those in other industrial and infrastructure projects. Chapter III.5 will present case studies of successful new build projects with different reactor types at Shimane (Japan), Summer (United States), Tianwan (China) and Olkiluoto-Flamanville-Taishan (Finland, France and China).

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Chapter III.2.

Vertical integration versus competition: What does economic theory have to say about the organisation of large industrial and infrastructure projects?

III.2.1. The theory of transaction costs

The large scale, long time frames and complexity of nuclear new build in changing technological, regulatory and political environments has always required different forms of co-operation of varying duration and varying degrees of commitment. In order to allow for a more analytical treatment, the question of which form of co-operation is the most appropriate can be rephrased as what are the respective drawbacks and advantages of vertical integration as compared to procurement in competitive markets. We will approach the question both from a theoretical (Chapter III.2) and a practical (Chapter III.3) level.

At its most abstract level, the question of the optimal degree of vertical integration was posed by R.H. Coase (1937) in his classic and immensely influential article on the "Nature of the Firm" in terms of the respective "transaction costs" created by either integrating an economic activity into an existing enterprise or by externalising it to another enterprise in the market. This allows for the elegant analytical statement that the optimal size of a firm has been obtained as soon as the marginal transaction costs of internalising an additional economic activity are equal to the marginal transaction costs of procuring the same economic activity on the open market.

While Coase's work provides important insights, it also neatly sidesteps the issue from the point of view of the analyst trying to understand the actual and, possibly, ideal structure of an industry. This is due to the term "transaction costs" eluding easy definition and codification. Transaction costs concern all those elements related to delivering an economic good that are not immediately quantifiable as goods or services themselves. They constitute a residual category that includes all the unspoken and unquantifiable hassle of running around, telephoning, preparatory work, negotiating and information gathering, as well as dealing with the political, regulatory and administrative pressures that is necessary to get the action moving.[1]

One of the most important components of transaction costs is the cost of monitoring and enforcing the quality and the precise technical specifications of goods that have been outsourced to other companies. Given the very high quality requirements for all technical components in the nuclear industry as well as the absolute necessity for different elements to fit together seamlessly, this issue is of considerable importance in the present context.

The economist Oliver Williamson has provided a fuller picture of what transaction costs might consist of and what might be the appropriate institutional arrangements to

1. Incidentally, transaction costs also include value added tax (VAT) or any other transaction tax. Not coincidentally, VAT is routinely waived for firm-to-firm (or B-to-B) transactions.

deal with them.[2] He concentrated, in particular, on the possibilities of opportunistic behaviour between the two sides engaging in a contract. Such opportunistic behaviour is enabled by two major factors:

- Contracts cannot be permanently renegotiated since negotiation itself is costly. In many ways, contracts have economic characteristics akin to irreversible capital investment. They engage participants over an extended period. There is thus an inevitable tension between the ex-ante investment in the contractual relationship and its ex post performance due to what economists refer to as moral hazard.[3]
- Information is costly and asymmetric. Neither side knows exactly what the other side is really doing or capable of. Verifying whether the shiny new valves contain hidden structural flaws is again the source of added transaction costs.

These two factors combine to create a third one. Since information is costly and the future is uncertain, contracts are always incomplete. No contract can possibly specify conditions for all possible future contingencies. In addition, both monitoring and enforcing contract performance are costly. This state of affairs provides both sides with the possibility of "hold up", the ability to interpret, exploit or even deform the contractual relationship in a manner that lowers its cost or increases its profits up to the point at which the other side is willing to pay for monitoring and enforcing the original contract.

These are serious issues, in particular in the global nuclear industry, for two reasons. First, the deep roots the nuclear industry maintains in many instances with a country's social, institutional and political fabric can make contract formulation, monitoring and enforcement more difficult than in other industries. Both parties to a contract need to take into account a number of cultural, social or political contingencies that are neither of a technical nor of a commercial nature, which may be difficult to negotiate or even to convey to their counterpart.

III.2.2. The advantages of integrated companies in creating a "common vision"

In general, economists are sceptical of vertical integration as it limits the extent of the market and it can be used as a means of leveraging monopoly power from one market to another. Consider, for instance, the example of a vendor with a national monopoly in the construction and sale of the nuclear island that vertically integrates itself with a supplier of steam generators or steam turbines. This would extend the monopoly from the nuclear

2. Two of Williamson's numerous contributions are "The Vertical Integration of Production: Market Failure Considerations" (1971) and "Markets and Hierarchies: Analysis and Antitrust Implications" (1975). A good summary of the literature on vertical integration and, in particular, Williamson's contribution is provided in Joskow (2008).
3. Moral hazard refers to a situation in which an economic agent acts on behalf of a principal in a complex environment characterised by asymmetric information and opportunistic behaviour. A typical example would be a manager who is contractually required to act in the interest of shareholders, who have limited means to verify whether he always acts as stipulated in the contract. Contracts are also necessarily incomplete. This framework can also be applied to situations of bargaining between, say, an EPC contractor and a supplier. Both sides will know something that is relevant to the cost of the contract that the other side will not know. Either side will try to formulate the contract in a way that maximises its upside risk and minimises its downside risk. Such negotiations are inevitable if one wants to operate in a market environment, but they also constitute both a considerable transaction cost and a source of risk. To some extent, there is an internal trade-off between transaction costs and risk; making contracts less risky is possible but only at the cost of massive documentation, detailed legal stipulations and costly monitoring. In principle, vertical integration would do away with both the transaction cost and the risk but it would, of course, also forego the opportunities connected with working through specialised outside suppliers.

island to the steam generator and the turbine, even if these two markets were, in principle, competitive. The mechanism works both upstream and downstream.

Of course, the benefits of vertical integration (smooth integration of all parts, maintenance of quality, reduction of transaction costs) continue to apply even in the context of such a transfer of monopoly power. The question thus remains legitimate as to whether, given the high transaction costs in an industry as complex as the nuclear industry, the vertically integrated model of industrial organisation that has been behind the vast majority of reactors that are in operation today remains appropriate. Hierarchical, vertically integrated structures save on negotiating costs, avoid the problem of post-contractual "hold ups" and can lower information costs due to consistent internal protocols of codifying, transmitting and using information. Of course, one must not idealise the performance of vertically integrated institutions as opposed to contractual market arrangements. Anybody who has ever worked in hierarchical or bureaucratic structures knows full well that transaction costs, moral hazard and the tactical use of information also exist where contracts are unwritten.

However, the literature on transaction costs would be of little use if it limited itself to justifying the existence of vertical structures. Its true value resides in the ability to provide concepts that allow for approaching the boundary at which the specific division of labour between markets and hierarchies ensures the most efficient use of scarce resources as well as the highest levels of economic output and customer satisfaction. The most important point in this context is that this efficiency boundary is permanently moving as a function of ongoing technological, organisational and structural change.

Three examples may illustrate this point. The explosion of computing power allows not only for new ways of project management through the complete traceability of all parts and 3D-modelling but also for the use of specialist logistics, design and engineering companies. The adoption of one single global product code rather than the currently co-existing RCC-M/E and ASME codes would allow for increased competition among specialist suppliers. Commercial pressures, as well as the gradual emancipation of the civil nuclear power industry from national strategic considerations, allows for new industrial configurations. This is exemplified in the origins of the two dominant nuclear reactor suppliers in NEA and OECD countries. AREVA has thus emerged from a history that involved Siemens, AEG, Babcock and Wilcox, Framatome and Kraftwerk Union, whereas the history of Toshiba Westinghouse involved ABB, British Nuclear Fuels Limited (BNFL), General Swedish Electric Company (*Allmänna Svenska Elektriska Aktiebolaget* – ASEA), Combustion Engineering and Brown, Boveri & Cie (BBC). It would be rash to assume that their respective corporate histories are complete.

A key issue in this context is information and the ability to act on it. While established vertically integrated combines may be more efficient at using existing information, they may be less efficient at generating and absorbing new information as well as adequately incentivising superior performance. Paul Joskow (2008), at Massachusetts Institute of Technology (MIT), summarises these two points in his exhaustive entry on the Chapter "Vertical Integration" in the *Handbook of New Institutional Economics*:

> While internal organization is likely to be better at removing certain kinds of internal informational asymmetries in the short run, it may be an inferior structure for obtaining, processing and using external information about prices, cost, quality, and technological change in the long run compared to repeated market transactions … Competitive market prices [for instance] convey a tremendous amount of information that is difficult to reproduce using internal accounting cost and auditing information … The potential shirking problems resulting from low power internal compensation incentives are also likely to become more significant as monitoring becomes more difficult in large organizations. (pp. 29-30)

At the same time, one may credit vertical institutions with an accumulation of knowledge through time in areas where trust, reputation and informal relationships are important. This may concern relations with regulators or other stakeholders, including public relations or parliamentary lobbying. Overall, however, Joskow deplores the current state of research on the determinants of the efficiency of non-market transactions:

> There is still much to learn about vertical integration, alternative market contracting structures and various hybrid forms. In my view, we have made more progress in understanding and measuring the hazards and associated costs of market contracting in the presence of alternative transactional attributes than we have about the costs of internal organization and how these costs are affected by different internal organizational and incentive structures. (p. 43)

While Joskow intends his remarks to be general, one is tempted to see them directed at the nuclear industry in a more specific manner. Partly due to a history of close relations with government, vertical integration is to some extent the historic default mode of organisation in the nuclear industry. There are good reasons for this. It is only with governments absorbing the high costs and large uncertainties connected with fundamental research in particle physics as well as the construction of the first generation of reactors that the nuclear industry was able to come into being. The same logic was subsequently extended to the construction and operation of NPPs. The global nuclear industry originates either directly in government-sponsored national champions or, as in the United States and China, from government-sponsored programmes that facilitate the emergence of more than one large specialist supplier. As technologies, corporate structures, the size and sophistication of both financial and power markets have evolved, the question is to which extent the original rationales of risk management, strategic considerations and infant industry promotion still hold true.

The superior efficiency of hierarchical organisations such as large, vertically integrated combines, when compared to the market mechanism, depends on the existence of *implicit* structural principles that aid and co-ordinate the myriad of individual daily and hourly decisions that need to be taken from the shop floor to the highest reaches of management. Terms such as "enterprise culture", "*esprit de corps*", "our way of doing things" or "entrepreneurial spirit" point towards these all-important but little theorised internal organising principles, which, ultimately, provide the edge of the hierarchical firm over the transaction costs in the market. They also point towards the limits of the firms as soon as the structuring power of these principles wanes with the distance from the centre.

In the age of the instantaneous transmittal and processing of information, it holds evermore true that as soon as a commercially or technologically relevant aspect of an economic transaction can be explicitly codified, it can be outsourced. The advantage of a hierarchical institution is not so much that the hierarchical superior can tell his or her employee what to do and how to do it without having to renegotiate a labour contract every day. Many customer-supplier relationships allow for similar interactions. The advantage of a hierarchical institution comes into being when an employee does at every single point what he or she *assumes to be what the hierarchical superior would want*. In return, any manager will necessarily provide a certain degree of autonomy (monitoring costs are also important inside the firm, and not only outside the firm). This reciprocity is part of the trust or common purpose required among different members of the same firm.

At the point where these unwritten, uncodified and uncodifiable relationships no longer perform, one has reached the perimeter of the firm, where its efficiency advantage over the transaction costs in the market comes to an end. Time is important here. Learning such implicit structures takes time and the latter can also become subject to inertia, at which point they risk outliving their economic usefulness. Nevertheless, no enterprise can subsist for any meaningful length of time without them.

This was also brought out at the international NEA Workshop on "Project Management and Logistics in Nuclear New Build" in March 2014, which brought together almost 70 experts from industry, academia, consulting and international organisations. Several speakers emphasised the importance of institutional stability as well as trust, for instance between project managers and regulators, and team-building for successful new build projects. This concerns the stability of the relations of the project managers with regulators and suppliers as well as the stability of established construction teams through time. The possibility of repeat projects, for instance, is a very powerful incentive in this context.

The stability of relations and organisations is also important to codify implicit, institutional or tacit knowledge so that it can be transferred and made useful for other projects. Stability, however, must not mean rigidity. There needs to be sufficient leeway for technical innovation, new supply relationships to evolve or new construction techniques to be adopted. While stability has its merits, so does competition. Getting the balance right depends also on the social and cultural environment. The Japanese practice of sharing specific work teams between otherwise competitive nuclear construction companies seems difficult to transfer to an American or a European context, where the perimeter of the individual firm is conceived in a far less elastic manner. However, independent of cultural invariants, the global nuclear industry needs to address the question of managing both institutional relationships and change in a proactive and systematic manner. A systematic distinction between core activities which require relatively high degrees of stability and more peripheral activities which can benefit from a more competitive environment would certainly be part of that.

Related to the question of the stability of relationships is the question of what kind of knowledge is most needed for successful NNB projects. "Knowing what to do is easy; knowing how to do it is difficult", resumed one participant. The global nuclear industry, with tens of thousands of well-educated engineers, does not suffer from a knowledge deficit. It has, however, not always been able to demonstrate in a consistent and convincing manner that it can translate and implement that knowledge into timely and cost-efficient projects. This comes back to some extent to the distinction between codifiable knowledge and the much more elusive "institutional knowledge".

Successful projects require a number of principles that need to be shared by all stakeholders, including suppliers, public authorities and regulators. These include a common vision with shared values and clearly stated goals, a collaborative attitude and culture as well as appropriately designed contracts and incentives. A homogeneous culture can help but may be elusive in multi-national project teams. To some extent, it is up to the project leaders to create a more project-specific common culture. "Beat the date", for instance, can be a motivating principle if coupled with unrelenting quality standards and appropriate incentives at all levels. Repeat interactions with suppliers and regulators over time can also shape attitudes and a common understanding. They also build trust by establishing a track-record, while at the same time providing incentives to do well in the expectation of follow-up business. Much value was seen in established teams and keeping them together under a leadership capable of inspiring confidence.

There was a surprisingly widespread recognition among participants that much work remains to be done in this often over-looked area of "soft" issues. Notions such as "trust", "experience", "mutual understanding" on the one hand but also "shared vision" and "leadership" came up repeatedly. They were seen as critical, in particular, for infusing the necessary flexibility to handle the unforeseen events that inevitably arise in complex industrial projects, all the while maintaining exacting standards of nuclear quality. In short, the nuclear industry, like other high-tech industries with high public visibility, needs men and women at all levels willing to assume that incompressible residual responsibility that is commonly associated with the term leadership; a quality that is, of course, only acquired by demonstrated competence over time.

III.2.3. Cost savings due to externalisation, modularisation and standardisation

In order to structure the tension between provision by competitive markets and provision by vertically integrated combines, Williamson introduced two key concepts – the frequency of transactions and asset specificity (a third point, uncertainty, is closely related to the latter). Asset specificity can relate to the site of the project, the non-transferability of the equipment used, the specialised skills of the work-force or the reputation of the primary partner that is associated with the project. All other things being equal, in particular price, the more frequently two parties interact and the more specific and complex are the assets they transfer, the stronger is the case for vertical integration.

Other than pure market sourcing or vertical integration, there exist a multitude of hybrid features such as long-term out-sourcing, minority share-holdings, joint project companies or joint ventures. Many NNB projects involve the creation of a dedicated joint venture owned wholly or in part by the client, usually the future operator, or the reactor vendor. Needless to say, each particular corporate structure will bring its own transaction cost and dynamics with it. Over time, the form of collaboration between two enterprises may and frequently does change. This may happen for instance when domestic subcontractors gradually acquire the skills to provide components of nuclear quality.

AREVA thus reported, for instance, at another recent NEA Workshop on the Financing of Nuclear New Build (September 2013) how at the Taishan 1 reactor project, the pressuriser, steam generator, control rod drive mechanism (CRDM) and the reactor cooling pump were all provided by AREVA itself. At the identical Taishan 2 project, however, those same elements were either provided wholly by Chinese suppliers or, in the case of the CRDM and the reactor cooling pumps, by Chinese-French consortia (Beutier, 2014).

Higher degrees of externalisation are also enabled by new technologies. The full traceability of all processes and components with sophisticated computer tools is now standard throughout the industry and allows for more complex supply chains. On the other hand, increasing the number of layers of subcontracting is not without risks of its own. In principle, a company externalises the supply of goods or services that it would otherwise produce in-house once the external supplier provides the same good or service at a lower cost. Table 22 provides some examples for organising the supply chain in an NNB project according to the criteria of asset specificity and frequency of transaction.

Table 22: Examples of different contractual arrangements in nuclear new build

		ASSET SPECIFICITY		
		Low	Medium	High
FREQUENCY	Low	Spot market provision (building services)	LT outsourcing/tender (construction of headquarters)	Joint venture (building of power plant in specific country)
	Medium	Spot market provision (IT supplies)	LT outsourcing/tender (NPP maintenance)	LT outsourcing/tender (provision of specialised valves and pumps)
	High	LT outsourcing/tender (NPP maintenance)	Vertical integration (human resources management)	Vertical integration (fabrication of the reactor vessel)

The question that poses itself at this point is, “how does the external supplier manage to cut costs without cutting corners either in terms of quality or environmental and social performance?" The standard case would be that the subcontractor is a specialist provider that benefits from the economies of scale of providing the same product to multiple companies that the client company itself would not possess. Frequently, however, the first items to be externalised are services such as maintenance where there are few economies of scale. In these cases, external providers might have an advantage only in terms of labour costs due to less advantageous and shorter-term contracts, environmental performance, or lower liabilities and reputational losses in the case that anything should go wrong. With multiple layers of subcontracting, the difficulties of monitoring quality and performance increase and become a source of risk for the ultimate client. A greater perception of these risks has led companies building new NPPs, such as EDF, to reduce and limit the level of layers of subcontractors.

Closely related to questions of subcontracting and externalisation is the question of modularisation. The latter implies the off-site fabrication of large components of an NPP, possibly including even large building structures such as fuel pools, on dedicated assembly lines for a number of different plants and has been a much discussed concept of late. Prefabrication of modules in an off-site environment which are then brought onto site for assembly includes:

- Structural modules, consisting of steelwork for elements of the building such as steel reinforcing units into which concrete is then poured on-site, or other steel structures such as stairways and platforms.
- Equipment modules for mechanical and electrical equipment including piping, cabling and supports.

In particular for producing multiple SMRs, modularisation promises cost reductions through economies of scale as well as through standardised and guaranteed quality. In principle, this reinforces the argument for subcontracting. Modularisation is a specific form of externalisation and is an important element in the quest of the nuclear industry to optimise nuclear new build.

Fabrication of modules can be done in factories remote from the site or specially constructed adjacent to it. Factory production can reduce costs and improve standardisation and quality. It can allow equipment to be assembled in a safer, more controlled environment than on-site, allowing for round the clock production rather than being limited by the weather and availability of daylight. By reducing the amount of work that must be done on-site it can relieve resource pressures and limit the complexity of work that can only be carried out on-site.

Modularisation and pre-fabrication were, for instance, used to good effect in the overall very successful ABWR projects in Japan, which were built on time and on budget. It has also proven its potential in other industries such as shipbuilding in Korea. Nevertheless, a number of industry observers warn of overblown expectations regarding modularisation. First of all, modularisation can generate its economies of scale only if there is sufficiently high demand. There is no use building a dedicated assembly line for one or two reactors. This requires the building of multiple units by the same project manager or at least that partially standardised units are being built by several project managers. There is thus a link between modularisation and the harmonisation and eventually standardisation of engineering codes and standards in the nuclear industry.

Modularisation also creates a requirement for transport of the modules and potentially for specialist facilities to handle them, depending on their size. It may require construction of specialist infrastructure to enable the modules to be transported. Some new reactor technologies, notably the ABWR and the AP1000, are explicitly designed for modularisation.

Modularisation and off-site manufacturing also offer no absolute guarantees for quality. For instance, the VC Summer project in South Carolina in the United States recently experienced quality issues with the off-site manufacturing of two large modules

(CA20, CA01). As a consequence, production had to be shifted from off-site to on-site causing delays and USD 200 million in cost overruns. Certain reactor vendors, such as AREVA, also remain cautious about modularisation and prefer to stay with a stick-built approach for the time being. They point towards the increased engineering requirements, the potential difficulties of organising the interface with specialist subcontractors and transporting the often very large sub-components. In addition, modularisation requires sizeable up-front investments in design, procurement and fabrication not only several years prior to commissioning but also prior to start of construction, which can raise financial risks and overall financing costs.

The question is, of course, at which point the cost advantages of scale economies are outweighed by the added set up and market transaction costs. A project developer will have recourse to modularisation only if it creates efficiency gains in construction. A key point is scale and hence standardisation. Modularisation is likely to prove beneficial if standardised components can be used across a large number of suppliers and projects.

In any case, the opposition between modularisation and a stick-built approach should not be overplayed. The difference is one of degree. All projects will use pre-fabricated modules to some extent and will fabricate others on-site. Hinkley Point C, a project in which AREVA participates together with EDF, as well as China General Nuclear Corporation (CGN) and China National Nuclear Corporation (CNNC), will thus, for instance, have its fuel pools built off-site. There thus remains an attractive potential for off-site production. However, without a harmonisation of engineering and quality codes across the global nuclear industry, modularisation is unlikely to become a game-changer in the effort to bring down the costs of nuclear new build.

III.2.4. Standardisation and benchmarking

Closely related to the question of modularisation is the question of standardisation and benchmarking. Only closer co-operation between reactor vendors and their principal suppliers on common codes and quantity standards could really initiate a structural shift towards widespread modularisation. While the movement towards harmonisation has begun, it is still lagging behind comparable industries (aerospace or oil and gas, for example) and much remains to be done in this respect.

One issue is that the nuclear industry is expected to meet enhanced standards of quality and performance, which also applies to the supply chain in accordance with the nature of equipment to be supplied and its role in the plant. As indicated in Table 23, the components for an NPP and the requirements for quality assurance can be divided into three categories.

Unlike some other industries, there is no general quality assurance standard specific to the nuclear sector. Depending on the country and the vendor, the standards adopted for nuclear grade components might be American ASME (NQA-1) codes, French RCC-M and RCC-E codes or International Organization for Standardization (ISO) codes. An increasing number of industry observers consider that the nuclear industry could reduce its costs and improve its safety reputation by moving towards more standardisation, harmonised quality management and benchmarking. Standardisation does not imply the convergence towards a single reactor type. It could imply, however, the adoption of a common set of standards and indicators that would allow comparison and benchmarking for quality and cost across the industry.

This requires co-operation between industry and regulators. Kaser, from the WNA, for instance maintains in Davies (2014a) that "the harmonization of codes and standards will generate benefits for the nuclear industry… WNA is [therefore] analysing the degree to which regulatory requirements may be aligned for licensing and permitting… and documenting good practice to help… promote the convergence of standards." Variations in regulatory requirements, even where they are intended to secure essentially the same level of quality assurance, pose challenges for supply chain companies. This can be additionally challenging where the regulatory system is non-prescriptive because companies do not have the certainty of knowing which specific product design will be acceptable prior to approval. The NEA Multinational Design Evaluation Programme (MDEP) therefore promotes the convergence of regulatory criteria across countries for individual reactor types but does not yet consider the convergence of standards across types.

Table 23: Classifying nuclear components according to quality assurance requirements

Nuclear grade components		Industrial grade components
Safety-related items	Safety-significant items	
Enhanced quality assurance programme is mandatory.		Quality assurance programme may be required.
Production process subject to inspection, verification or testing. Defects or non-compliance must be reported and corrected.	Reasonable assurance that the component will perform safely.	Good commercial practice required. Analysis of past performance required.
Performance testing according to specified codes or standards.	Performance testing according to special codes or standards.	Performance testing according to specified codes or standards may be required.

A recent note by *Nuclear Energy Insider* looked at the transferability of experience with common quality insurance standards in other industries (Davies, 2014a). Helped by active government encouragement, the US aerospace industry thus developed in the National Aerospace and Defence Contractors Accreditation Program (NADCAP) a shared quality standard, the AS 9100, based on the widely used ISO family of codes. Like the aerospace industry, the nuclear industry is characterised by risks that have low probabilities but high impacts. This particular risk structure creates strong reputational externalities, an insight captured in the truism that “an accident anywhere is an accident everywhere”.

This in turn makes reputation, safety and quality control industry-wide public goods or, technically speaking, club goods characterised by strong reputational externalities. The safety performance of the nuclear industry in one country, in particular a negative performance, will immediately affect attitudes towards nuclear power in all other countries. Trial and error by individual industry members is not an option. Things are different, for instance, in the car industry where frequent accidents with localised impacts prevail. A recall due to a quality issue by company A is usually a commercial benefit for company B. This is the opposite in the nuclear industry. The Fukushima Daiichi accident has thus reverberated heavily in Germany, Switzerland and Belgium and has induced world-wide adaptations in nuclear safety.

To some extent, the nuclear industry already recognises this and experiments with different formats for industry-wide standardisation without that the latter have yet converged towards a global initiative. AREVA and Bureau Veritas, for instance, established the Nuclear Quality Standard Association (NQSA). In the United States, the Nuclear Procurement Issues Committee (NUPIC) developed the NSQ-100, a further development of the ISO 9001 standard.

The Co-operation in Reactor Design Evaluation and Licensing (CORDEL) initiative by the WNA and the MDEP initiative by the NEA both aim at the convergence of codes, standards and safety objectives. So far, a single global system of standards and indicators proves elusive as even the RCC-M/E and ASME codes continue to exist in parallel, which prevents the sharing of data and benchmarking. The latter is already common practice, for instance, in the oil and gas industry, which shares several important characteristics with the nuclear industry such as the size, complexity, capital intensity and long lifetimes of its projects, as well as its global reach and economic significance. In comparison with the oil and gas industry, however, the nuclear industry is still very protective of its proprietary information, even when it does not touch on strategic concerns.

While industry-wide benchmarking remains elusive, the transfer of good practices between projects inside a single industrial entity is now an established part of a culture of continuous improvement. EDF thus makes every effort to improve processes for the construction of a new EPR at Hinkley Point (United Kingdom) by learning from other EPR construction projects at Flamanville 3, as well as at Taishan 1 and 2 (see the case study on EPR projects in Chapter III.5). This includes the creation of dedicated processes for defining, assessing and implementing lessons learnt, with the appointment of pilots responsible for the transfer of specific lessons.

In addition to benchmarking there is the issue of certification for the complete nuclear supply chain, which can be a time-consuming and expensive investment for supplier companies. Certification extends to:

- the company's management system, including the system for quality assurance which must go beyond compliance with benchmark standards;
- the company's production process, which must ensure the products meet performance specifications under all design basis situations for the life of the plant;
- the company's personnel, who must be suitably qualified and experienced in nuclear environments.

Companies must also be able to demonstrate a nuclear safety culture, which means that the overarching priority of safety permeates the whole organisation from its senior leadership to individual employees and there is an understanding that nuclear is special. Nuclear safety culture recognises nuclear operations as special, from design through construction, operation and decommissioning. It encompasses conventional safety and excellence of working practices in a truly integrated approach. It requires a high level of professionalism and attention to detail in execution of all works on a nuclear plant. These requirements are a significant commitment from supply chain companies and entail investment and up-skilling for countries that are developing their nuclear capability.

Moving towards benchmarking and common quality and certification standards in the global nuclear industry will not be easy. It would however constitute the appropriate measure for reducing reputational externalities and increasing efficiency. This would include both the establishment of a robust and easily communicable safety standard and the pooling and exchange of best practice in the construction of new nuclear reactors. At stake are both the reputation and the cost efficiency of the global nuclear industry.

The sequence externalisation, modularisation, standardisation and benchmarking defines one of the most important issues facing the nuclear industry today, i.e. how to structure the trade-offs between in-house and external production. Given the long time frames of the nuclear industry, it is too soon to say where precisely a sustainable equilibrium of industrial organisation will be located. This is not to say that things will always been in flux. Considering the growing maturity of generation III/III+ reactors, the initiatives on standardisation mentioned above, the integration of post-Fukushima lessons, a better view of the potential of SMRs and a stabilising framework for nuclear new build, there is good reason to believe that the nuclear industry will define its future *modus operandi* in the coming five years. While full modularisation is likely to remain a vision rather than a reality, improved standardisation and flexible co-operation among different vendors, regulators and suppliers are likely to play significant roles in the future.

Cost is now clearly a key driver of the restructuring of the global nuclear supply chain, as well as the nuclear industry in general. In a recent survey by *Nuclear Energy Insider* in 2014 involving 200 executives in the nuclear industry, 73% of the respondents stated that they had recently experienced budget cuts (Davis, 2014b). For 62% of respondents, cost efficiency strategies were by now the most important trend in supply chain management. This leads to a situation in which 80% of nuclear procurement engineers are reconsidering their relationships with suppliers and shifting towards an internationalised supply chain at a much faster rate than initially thought. Unsurprisingly, the share of international procurement for at least 50% of the supply chain is expected to rise from 17% to 42% during the next ten years. This still leaves some room for further internalisation. However, for an industry with decades of tight vertical integration and national procurement, this is a very significant development.

III.2.5. Beyond standardisation and externalisation: Change management and supply chain management

Not all issues facing companies engaging in nuclear new build concern optimising the degree of standardisation and outsourcing. Other important issues in this context are managing relations with suppliers, at any given level of externalisation, as well as dealing with unanticipated events during the construction phase.

Much of the success of a new build project is, in fact, decided *before* first concrete is poured. Most importantly, the reactor design and all engineering studies need to be completed for all critical components. From the start, designs also need to integrate constructor methods and constructability with robust and realistic specifications. Work should not be undertaken until all specifications and configurations are stable. The supply chain also needs to be in place well in advance. This will enable early contractor involvement to improve interface management and establish a common language and a common safety culture. The latter must be stringent for the crucial elements of the nuclear and the generator islands but reasonable for less critical components, which requires a careful grading of the safety significance of different components and work steps.

There are also advantages to leaving considerable lead time between the authorisation to proceed (ATP) and first concrete date (FCD). Early contract involvement (ECI) and early work agreements (EWA) with suppliers must precede the final signature. Similarly, the project management organisation should be set up early on. Despite the latter's importance, it should have a philosophy of not managing but supporting the on-site teams at later stages of the process. EPC and logistics should thus be on-site to have first-hand experience of what is going on. A solid governance structure with the ability to resolve conflicts and to adapt, when necessary, the project baseline, is a key component of success. There also needs to be a "single source of truth" that synthesises and centralises incoming information and is the only authoritative voice for general as well as outgoing information.

Procedures for change management need to be put in place, even in the case of strict change control. Regardless of whether organisations try to limit uncertainty, they need to be ready for the unexpected. The ability, for example, to take corrective action in a proactive manner when required is important. This would avoid issues that have hampered the construction of NPPs for decades such as increases in initial quotations due to configuration changes as well as insufficient control of contractual milestones. New technologies such as automatic welding or temporary four-season shelters, which create a factory-like environment for working around the clock, also lead to a an improvement in quality.

Change management is also important in the relations between project managers and nuclearregulators. "Trust" is a key ingredient as not everything that is happening or supposed to happen on a nuclear construction site can be put down in codified specifications. Not only can overly prescriptive regulation make construction difficult but the flexibility of regulatory authorities can be vital in avoiding delays. The US Department of Energy thus recently reported an example from the VC Summer new build project in

South Carolina, where the original spacing and depth of the rebar was not in conformity with the design documents (Crozat, 2014). Due to the flexible approach of the regulator, as well as the good performance of the formal and informal dispute resolution mechanisms between South Carolina Electric and Gas and the contractor CB&I-Westinghouse, delays could be limited to six months. The alternative, a confrontational approach, would have stalled the project far longer.

A focus on collaboration between all the parties towards the shared goal of successful delivery and a single integrated project structure is becoming increasingly important throughout the industry as it experiments with structures other than vertical integration. This helps improve communications, reduces the complexity of scheduling activities and multiple layers of contractor responsibilities, and eliminates costs of adversarial disputes between clients and contractors.

An important underlying principle behind collaborative working is that it ensures that project risks are managed and mitigated by all parties collectively, rather than seeking to transfer them from one party to another, which can in any case prove illusory. This can be underpinned by pricing incentives that enable all the parties to share in the rewards from on-time delivery and cost reduction, as well as sharing the downside of cost overruns. This must be built on a high level of trust and a culture of collaboration, which is reflected in and supported by the terms of contracts, rather than being wholly dependent on them.

Although these principles of international best practice are understood and generally accepted in the nuclear industry, it is not always straightforward to transfer them from one region of the world to another or from other market sectors into nuclear. First, collaborative working can create difficulties for the regulatory body if it blurs the lines of accountability for the safe construction and operation of a plant. In addition, the involvement of contractors in aspects of design and construction planning of the plant can introduce modifications to the design, which means that it evolves after approval.

Secondly, there are cultural, legal and commercial differences between the East Asian markets and other regions. Most western countries have developed contractual relationships around traditional contractual forms of the *Fédération Internationale des Ingénieurs-Conseils* (FIDIC) suite of contracts, which are generally built on the formalised separation of roles and clear lines of accountability between different parties. These contractual forms have evolved, with, for example, the NEC3 contract template in the United Kingdom seeking to reflect collaborative principles. But it can be expected that in western countries there will still be a role for commercial and competitive tensions between parties, blended with varying degrees of collaboration according to the preferences of the client in the circumstances.

One consequence of the global integration of the nuclear industry is that developers and principal contractors are familiar with working together in different commercial environments and are conscious of the challenges of applying the project organisational principles in their home markets to other environments. In the best of cases, major players from both East and West will seek a synthesis of different approaches appropriate to the particular circumstances of each project.

A review of the lessons learnt on nuclear projects in China and Europe conducted by a group of professional institutions in the United Kingdom, with the purpose of informing the UK new build programme, emphasised the importance of good project management, effective leadership by client organisations, collaborative relationships with contractors and of improving quality in the supply chain (RAENG, 2012). The review also underlined the importance of "soft issues" such as skills, project organisation and quality control. Major points were:

- The impact of shortages in expertise and skills, especially among subcontractors.
- The requirements for new competencies among individuals and subcontractors.

- The requirements to "teach" aspects of nuclear quality and safety culture to subcontractors. Even companies familiar with working in other industries with high regulatory standards may find it difficult to adapt to the particular requirements of NPP construction.
- Anticipating and absorbing the implications of the variation in regulatory practice across national boundaries.
- The implications of new approaches such as automated welding, and making allowance for the learning of such approaches.
- The importance of selecting manufacturers and subcontractors on the basis of quality rather than price.

Whatever the form of project organisation, it is clear that complex projects such as the construction of a new nuclear plant requires more than ever a very high level of effective project management and leadership. The good news is that the nuclear industry is conscious of the challenge and is working to overcome it.

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Chapter III.3.

The evolving structure of the global nuclear supply chain

The current structure and ongoing reconfiguration of the global nuclear supply chain offers both opportunities and challenges for nuclear new build. The challenges concern the efficient management of construction, cost control and public acceptability. However, these have much in common with other major technologically advanced, capital-intensive programmes (see Chapter III.4 on "Is nuclear special?"). Many other comparable industries, including large scale infrastructure programmes, process engineering and advanced manufacturing, have improved their performance and can offer examples of best practice.

The nuclear industry, arguably faces particular challenges in incorporating these best practices into the construction of new nuclear plants, for a number of reasons:

- High levels of regulation which can lead to regulatory interference and design changes. This is compounded by the possibility of political change, even with construction under way.
- The capital-intensive nature of nuclear projects, which means higher risks as funds are committed before uncertainties have played out.
- The hiatus in nuclear construction in many countries, which means that the supply chain is learning how to build nuclear plants again or for the first time.

However, nuclear is not unique in facing additional and special challenges. The aerospace industry in particular must meet extremely demanding design and manufacturing standards, such that all components perform fully from the moment they are used and throughout their lifetimes, and also to ensure that all materials and components are fully traceable. Similarly, the offshore oil and gas industry has had to make demonstrable improvements in quality and safety standards, even while operating in extremely challenging environments, including political and regulatory uncertainty.

III.3.1. The current structure of the global nuclear supply chain[1]

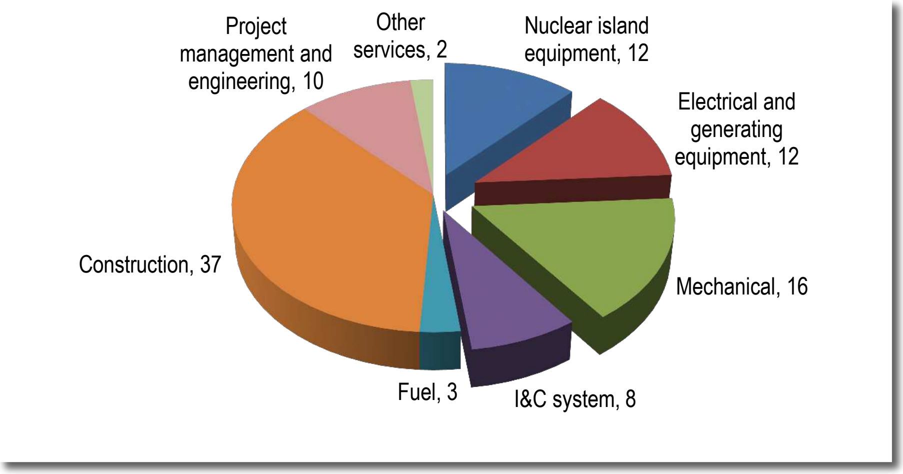
The significance of the supply chain for the overall economics of nuclear power follows from the very high contribution that capital costs make towards levelised costs of power generation in the case of nuclear, relative to other sources of power, and the large share of capital costs that is accounted for by the supply chain.

There is no single correct measure of the breakdown of costs for an NPP, which vary according to the reactor technology, location, timing and specific contractors as well as the way the costs are broken down. Figure 35 gives a summary of various industry sources, where equipment supply, for example, is shown to constitute around 48% of overnight costs (i.e. the cost of construction excluding financing costs).

1. This case study was prepared by Chris Savage, World Nuclear Association and Vanbrugh consulting.

Broken down in an alternative manner, namely by the area of the plant, and thus including construction and installation costs in addition to equipment supply for each part of the plant, the nuclear island accounts for around 28% of total costs, the conventional (turbine) island around 15% and the balance of plant 18%, with civils works across the plant accounting for 20% and the remainder being design, engineering and commissioning costs.

Figure 35: NPP percentage cost breakdown



Construction and civil engineering account for about one third of total costs, depending on their precise break-down. Along with mechanical and electrical installation, virtually all of this activity must take place locally near the site where the plant is being built. Equipment supply by contrast is an international business and can be procured through globally competitive markets. The capability, capacity and competitiveness of the equipment supply chain can therefore have a major impact on the economics of new plants.

Major players

Construction and operation of nuclear plants involves the interaction of a number of key players. The principal ones are the following:

- **Government**: The national government sets the policy framework for the role of nuclear power within overall energy policy. This includes a legislative framework, some of which is determined through international treaty obligations. The government may also own utilities and set the policy conditions for industrial participation and the skills required to construct and operate nuclear plants.
- **Regulator**: The regulatory authority is responsible for setting objectives for the safe operation of nuclear plants and for enforcing them. The regulation of nuclear power is a national prerogative and there are differences between how regulation is applied. However, according to IAEA principles, the regulator must have effective independence of government and industry, must have the capability to assess nuclear safety and must be able to enforce its decisions.
- **Owner/operator**: The owner/operator procures the plant and is the licensee for operating it. Typically it is either a utility (publicly-owned or private) or a consortium including a utility. It is the owner/operator's responsibility to demonstrate to the regulator that it has the necessary management, organisational and financial resources to safely operate a nuclear plant.

- **Vendor**: The technology vendor owns the reactor design. They usually also have manufacturing capability for the major nuclear steam supply system components such as reactor pressure vessels (RPVs), reactor core internals (possibly including the first fuel core), steam generator and pressuriser (for a PWR). In addition, they will usually have the engineering capability to translate high-level reactor designs into the detailed design and delivery schedule for construction of a plant. Conversely, they may supply the reactor design under licence and leave the engineering and construction to a third party.
- **EPC contractor**: An EPC contractor will take overall responsibility for construction and delivery of a power plant. In practice, there is a range of contractual arrangements for risk sharing among the parties.
- **Equipment suppliers**: There are certain major components of an NPP, some of which may be heavy engineering components that are critical to the design and construction of an NPP. These may be supplied by the vendor or by third parties although there are often strategic relationships in view of the criticality of these components.

Organising principles of industrial structure

A question that cannot be conclusively answered, at least in the scope of the present discussion, is one that goes to the heart of industrial policy: what, if anything, is the organising principle that determines the industrial structure for NPP construction and that enables certain segments of industry, or countries, to capture the value that it creates.

As demonstrated in discussions below, it is evident that some countries have made it a national priority to build the industrial capability to manufacture and supply some of the major heavy components that characterise nuclear plants. The capacity to supply heavy industrial components, especially large forgings, and the efforts to promote localisation of the supply chain are examples of these efforts. Even where such policies are not pursued, public debate around industrial policy often bemoans what is seen as the absence or loss of this manufacturing capability.

Alternatively, there is an assumption behind national policy in many countries that the priority must be to develop and retain an independent reactor design. Assuming that this is more than simply national engineering pride, the argument would be that the real value of NPP construction lies in the intellectual property of the design, the owner of which can capture value by licensing the design even if they do not carry out the construction of the plant themselves.

It is notable, however, that at least two of the countries that were early movers in nuclear power, the United States and the United Kingdom, have not, despite all the debate on public policy around these issues, been persuaded to treat it as a national priority to recapture whatever manufacturing or design leadership they have lost.[2] Many former manufacturing companies in both countries have successfully redefined themselves to focus on aftermarket and services work rather than on ownership of capital intensive facilities.

The provision of finance could be an alternative organising principle for power plant construction, but as noted in the discussion below, the development of project finance for nuclear power is limited at best, and the financing of new plant construction will rely heavily on the balance sheets of owner/operators and their partner companies. Vendor

2. A focus on electricity market restructuring and a maturing gas infrastructure might have contributed in both countries to a hands-off attitude on this issue.

financing is more of an opportunity to secure contracts and a share of work rather than an attractive commercial opportunity in its own right.

The purpose of posing these questions here is not to answer them conclusively, but rather to suggest that the conclusion is not as self-evident as is implied in much of the popular political debate. The issues they raise are implicit through much of the discussion that follows.

Market structure and main suppliers for key components

This section summarises the main components for an NPP, their performance characteristics and manufacturing requirements, as well as the nature of the market for each component.

Reactor pressure vessel (RPV)

The RPV is a thick-walled, high integrity, pressure vessel which contains the reactor core and the nuclear fuel elements. This is where the nuclear fission reaction takes place, creating heat which is then used to generate steam for the turbine. The RPV operates at very high pressures and temperatures. In a PWR, the pressure will be around 175 bar and the temperature will be in excess of 300° Celsius. In a BWR, the pressure and operating temperature are lower.

The RPV in a 1 300 MW PWR is about 12 m in height, the inner diameter is 5 m and the wall of the cylindrical shell is about 250 mm thick. In a BWR, the RPV is considerably larger for an equivalent output, allowing for the fact that steam generation takes place within the RPV. The RPV consists of cylindrical ring forgings at the bottom and mid-section, and a single dome at the top or head. Both the ring forgings and closure head are manufactured from high quality ferritic steel, specially developed to give the necessary tensile strength and toughness, which are then welded together. The welds are designed to facilitate reliable inspection by ultrasonics. The inside is lined with stainless steel cladding to protect against corrosion.

As well as enclosing the reactor core and fuel elements, the RPV contains the CRDM, which inserts or withdraws the fuel assemblies, the primary loop pipework (in the case of a PWR) and the steam dryer and separator (in a BWR). The basic building blocks of a RPV are large and ultra-large forgings, which can be manufactured in only a few places around the world. The following companies can manufacture RPVs using large forgings that may be supplied from elsewhere (see also the section below on "A special issue: Large forging suppliers" below):

- Ansaldo (Italy)
- AREVA (France)
- Doosan (Korea)
- IHI (Japan)
- Mitsubishi Heavy Industries (Japan)
- OMZ (Russia)
- Skoda (Czech Republic)

RPV Internals

RPV internals are high precision, high quality components. In a PWR, they can be divided into two types: support for the fuel assemblies, including machined rods, tubes and plates, as well as shielding and reflectors to reduce radiation from the core onto other parts of the RPV. In a BWR, they also include the steam separator and dryer. Manufacture of RPV internal components involves precision-machining of tightly specified materials.

The metallurgical composition of all materials is very important. The components must then be assembled and tested to nuclear grade standards.

Companies must therefore be able to combine strong metallurgical knowledge with experience of procurement and manufacture to nuclear grade standards. They must also have gantry handling capacity with about 25 m of headroom to allow for machining and assembly. RPV suppliers typically take responsibility for assembly of the package as a whole and testing of equipment, but there is an internationally diverse and competitive market for supply of components.

Steam generator

In a PWR, steam is generated in a secondary loop in a steam generator outside the reactor pressure vessel. The steam generator is a form of heat exchanger which takes heat from the primary (pressurised) loop to convert water to steam. The steam generator is a large pressure vessel which can measure up to 25 m in height. The interior consists mainly of heat exchange tubes welded into a thick tube plate, along with steam dryers and separators. These are contained within a pressure vessel of large ring and hemispherical forgings (large forgings exist in many other product markets; the distinctive features in nuclear are both the scale of the pressure vessels required and the integrity of materials and manufacturing quality. See the section below on “a special issue: Large forging suppliers”).

Depending on the design, there may be two to four steam generators per RPV. Manufacturing of the components for the steam generator and assembly into a complete unit is a complicated process requiring some specialist machining, welding, fitting and inspection operations. The tubes are of special material and must be manufactured to tight tolerances. Because of the scale and complexity, there are only a few companies that have the capability to manufacture complete steam generators. Very often they will be supplied by the reactor vendor. Among the companies that can supply complete steam generators are:

- AREVA (France)
- AtomEnergoMash (Russia)
- Babcock and Wilcox (United States)
- Doosan (Korea)
- ENSA (Spain)
- Larsen and Toubro (India)
- Mangiarotti (Italy)
- Mitsubishi Heavy Industries (Japan)
- Shanghai Boiler Works (China)

Pressuriser

In a PWR, the reactor coolant in the primary loop is maintained at very high pressures to avoid boiling. This is achieved by a pressuriser which is located outside the RPV but is connected to the primary loop containing the coolant. Pressure is maintained at the appropriate level by varying the temperature of the coolant, through a combination of heaters and water sprays. These are contained within a medium-sized pressure vessel, not as large as the steam generator and not as heavy as the RPV itself.

The facilities required for manufacturing pressurisers are not as restrictive in terms of scale as for the RPV and steam generator, although a manufacturer must still demonstrate handling capability for products of up to 150 tonnes and compliance with the highest quality standards for these nuclear-grade vessels. This means that there are a larger number of companies that can supply the pressuriser as a whole or components for it, and the market is quite diverse and competitive. Pressuriser internals, in particular the heaters, could be supplied by numerous component manufacturers and then assembled by the final supplier.

Valves and pumps

In a nuclear plant, there may be over 100 major safety-related and balance of plant pumps. And there may be over 1 500 major valves in the nuclear island, with a further 300 in the turbine or conventional island. All of these need to be of high quality and reliability and are subject to considerable stresses. They must be capable of safe operation throughout the lifetime of a plant, or to be ready to operate at any time from a stand-still state.

In a PWR, the reactor coolant pump circulates pressurised water to the steam generator and the primary circuit and is fitted with a number of specialist safety-related valves. In a BWR, circulation of water in the reactor is achieved by a reactor recirculation pump which regulates the power output of the reactor as well as cooling. All of these require extensive environment and seismic testing and qualification before installation.

The high-grade, class 1 pumps and valves in the nuclear steam supply system are supplied by specialist companies capable of manufacturing and testing to nuclear standards and operating on a global basis. They are mostly centralised around the established nuclear markets. Most of the lower-grade, safety class 2 and 3 pumps and valves, on the other hand, can be manufactured by regional or localised supply chains. Major suppliers include:

Pumps

- AtomEnergoMash (Russia)
- AREVA JSPM (France)
- Curtiss-Wright Flow Control (United States)
- EBARA (Japan)
- Flowserve (United States)
- Hayward Tyler (United States)
- HMS Pumps (Russia)
- KSB AG (Germany)
- Mitsubishi Heavy Industries (Japan)
- Shanghai Electric (China)
- SPX Flow Technology (United States)
- Teikoku Electric Manufacturing (Japan)
- Weir Group (United Kingdom)

Valves

- AtomEnergoMash (Russia)
- AUMA (Germany)
- Armatury Group (Czech Republic)
- Dresser (United States)
- Emerson Process Management (United States)
- Flowserve Corp. (United States)
- KSB AG (Germany)
- Larsen & Toubro (India)
- Oka Ltd (Japan)
- Okano Valve Manufacturing (Japan)
- PK Valve (Korea)
- Samshin Ltd (Korea)
- SPX Flow Technology (United States)
- Toa Valve Engineering (Japan)
- Toshiba (Japan)
- TyazhPromArmatura (Russia)
- Tyco Flow Control (United States)
- Weir Group (United Kingdom)
- Westinghouse (United States)
- Velan Inc. (Canada)

Primary containment vessel

The primary containment vessel encloses the reactor pressure vessel, other primary components and piping. In the very unlikely event of an accident, this shielding prevents the release of radioactive substances. The ABWR uses a reinforced concrete containment vessel (RCCV). Its reinforced concrete outer shell is designed to resist pressure, while the internal steel liner ensures the RCCV is leak-proof. The compact cylindrical RCCV integrated into the reactor building enjoys the advantages of earthquake-resistant design and economic construction cost. The design of containment building in a PWR varies between reactor designs; the AP1000 utilises a steel containment vessel which must be manufactured off-site and lifted into place in sections which are then surrounded by reinforced concrete. The EPR has a large, domed, pre-stressed concrete containment vessel which is constructed *in situ*.

In all cases, construction of the containment vessel requires specialist construction expertise and manufacturing capability. It is the major construction item in the nuclear island. Many of the resources can be provided by local suppliers but it will be led by internationally experienced companies.

Control and instrumentation

The instrumentation and control system monitors physical parameters and performance and makes automatic adjustments to plant operations as necessary. It also responds to failures and non-normal events, to ensure that safe and reliable power generation are maintained. New NPPs require a large amount of plant instrumentation and control equipment for the reactor, generating plant and all ancillary equipment. This includes control and monitoring of the reactor, turbines, alternators, fuel handling, security and access. There are specialist requirements for such equipment on nuclear plants due to the necessity to integrate the equipment and software with the safety case and safety systems.

Earlier generations of nuclear reactor instrumentation and control systems used analogue or integrated solid state equipment. The current generation uses digital equipment for both instrumentation and control functions. The progressive shift towards digital systems has been driven by several factors, including the high performance characteristics and enhanced features of digital systems, and also the ageing of analogue equipment and the difficulty in finding replacement components.

Design of the control and instrumentation system requires a detailed knowledge and experience of the reactor design that is being controlled. For this reason, the control and instrumentation system is often provided through strategic partnerships with the reactor vendor or in some cases by the vendors themselves. Siemens AG withdrew from its specialist business providing instrumentation and control systems for nuclear plants, and this decision followed the earlier sale of its stake in AREVA NP, through which it had jointly developed the EPR. Companies supplying control and instrumentation systems to NPPs include:

- AREVA (France)
- AtomEnergoMash (Russia)
- Doosan (Korea)
- GE Hitachi (United States/Japan)
- Invensys (United Kingdom)
- Lockheed Martin (United States)
- Mitsubishi Electric Corp. (Japan)
- Rolls Royce (United Kingdom)

- Skoda JS (Czech Republic)
- Toshiba (Japan)
- Westinghouse (United States)

Pipework

A nuclear plant contains many tens of kilometres of pipework and associated pipe supports, covering safety-related and auxiliary functions. In a PWR, the reactor coolant or primary loop pipework contains the pressurised coolant and connects this to the steam generator where heat is transferred to the secondary loop. Primary loop pipework consists of high integrity thick-walled pipe made from forgings. Straight sections of pipe are forged and bends are formed by induction bending of the forgings. There is a limited amount of prefabrication. There is a small number of welds which must be of high integrity and capable of ultrasonic inspection.

Primary loop pipework is a specialised activity and there are a relatively small number of companies that can undertake the fabrication of the base pipe, its manufacture into spool pieces and site installation of these spools. Typically, it is supplied by an established partner of the reactor vendor, although it has also been one of the areas for localisation initiatives in, for example, China (Shandong Nuclear Power Equipment Manufacturing Company/Westinghouse and Shanghai Electric Heavy Industries/AREVA) and India (Larsen and Toubro/Westinghouse).

Throughout a new nuclear plant, there is a wide range of safety-related pipework associated with power generation or safeguard protection. These may be designed to nuclear design codes and, according to the design and the requirements of regulatory approval, may need to be qualified to operate under defined environmental, radiological and seismic conditions.

In addition, there is a large volume of auxiliary pipework which may be designed, manufactured and installed using robust quality managements systems and experienced personnel, but which may not need to meet class 1 or 2 nuclear-grade requirements. Some of this pipework will be integrated into modules to be constructed off-site while other pipework will be supplied in spools and installed on-site. A large number of companies today are capable of designing, manufacturing and installing auxiliary pipe spools or modules, and these will often be supplied from the host country for a new plant.

Turbine and generator

The steam turbine and generator in an NPP is in principle no different in conceptual or engineering terms from those that operate in other thermal power plants. However, the combination of a large steam mass-flow and the low initial steam pressure means that steam turbines in nuclear plants require longer blades and operate at lower rotor speeds. In a BWR, the steam also contains a small amount of radioactivity, and so there must be additional screening for personnel. This is also a factor in the selection of construction materials.

The turbine in a nuclear plant is designed for baseload operation, which means it must be designed for more or less continuous operation with limited downtime and this affects thermal stress analysis, life cycle evaluations and the selection of materials. On the other hand, the turbine in an NPP does not involve superheated steam or the high pressures characterised by the turbine cycles in a fossil fuel plant.

For reasons of economy of scale and access to the distribution network, the designs for modern NPP typically call for a single turbine generator per reactor. In the case of a current generation GW-scale nuclear plant, this means the power output is very large by comparison with other thermal power plants. The manufacture and supply of steam turbines for nuclear plants is therefore a discrete market sector that is dominated by a number of major players. The supply of turbines is closely associated with the reactor design and vendor.

Turbine manufacturers have, however, located production near to their nuclear markets, and there are a number of examples of joint ventures (for example Mitsubishi Heavy Industries/UTZ and Alstom/AEM in Russia). The main suppliers of steam turbines and generators include:

- Alstom (France)
- Bharat Heavy Electricals (India)
- China First Heavy Industries (China)
- China Dongfang Electric Corp. (China)
- Doosan /Skoda Power (Korea)
- GE (United States)
- Hitachi (Japan)
- Mitsubishi Heavy Industries (Japan)
- OMZ (Russia)
- Siemens (Germany)
- Silmash (Russia)
- Toshiba (Japan)

Balance of plant

The radioactive (radwaste) plant and management system consist of tanks, process pumps and other processing equipment for the handling of liquid, gaseous or solid radioactive waste. It is located within the reactor containment building along with the nuclear steam supply system. The radwaste plant is part of the reactor vendor's design although it is also heavily influenced by national government policy and regulatory objectives, for example whether and for how long radioactive waste should be stored on-site and at what stage it should be transferred to centralised facilities for long-term storage and management.

There are a number of specialist companies with experience of designing and supplying equipment for radwaste plant. In many cases, these have gained experience in decommissioning and waste management for legacy nuclear projects and tend to be located in established nuclear markets (France, North America and United Kingdom). In addition to these specialist companies, there are many firms globally that could manufacture and supply a radwaste plant. The manufacturing facilities and skills required are for stainless and carbon steel vessel and pipework fabrication, manufacture of a general mechanical plant and manufacture of stainless steel containments.

There are two types of heating, ventilation and air conditioning (HVAC) systems in a nuclear plant: nuclear and conventional HVAC. Nuclear HVAC is required within the reactor, fuel, nuclear auxiliary and radwaste processing buildings. It is designed as part of the nuclear safety regime to provide containment of radioactive material so as to minimise operator exposure to airborne radiation and discharges to the environment. The nuclear HVAC system is typically an integrated system consisting of air supply and building extraction elements, made up of safe-change filters, high-specification fans, dampers, ductwork and high integrity control systems. Conventional HVAC is required in office and other accommodation and is comparable to that supplied for other power stations. The supply of both nuclear and conventional HVAC equipment is diverse and competitive and much of it will be localised in the host market.

A special issue: large forging suppliers

For the current generation of new NPPs, with power output in excess of 1 000 MW, a critical supply chain issue is the availability of capacity to manufacture the large forgings required in pressure vessels. Reactor pressure vessels are typically constructed of two or three ring forgings at the side and a closure head, each of which is machined from a single forging, and then the parts are welded together. Because of the size of the RPV in a generation III/III+ plant, this is likely to require a manufacturing facility with a forging press of around 15 000 tonnes and with the capability to handle hot steel ingots of 500-600 tonnes.

Such forging presses exist in only a few places in the world, notably Japan (Japan Steel Works), China (China First Heavy Industry and China Erzhong) and Russia (OMZ Ishora). This creates significant pressures on the available capacity. Japan Steel Works alone claims to be supplying 80% of the global nuclear market for large forgings at the moment. Japan Steel Works is expanding its capacity, and new capacity is also being built by JCFC (Japan), Shanghai Electric Corp. (China), Doosan (Korea), Creusot (France), Pilsen (Czech Republic) and OMZ and ZiO-Podolsk (Russia).

Table 24: Capacity for the construction of pressure vessels

Country or region	Company	Heavy forging press, mid-2009	Heavy forging by 2013	Max. ingot – tonnes 2013
Japan	Japan Steel Works	14 000 t	14 000 t x 2	600 (650)
	Japan Casting and Forging Corp.		13 000 t from 2010	500
Korea	Doosan	13 000 t	17 000 t from 2010	540
China	China First Heavy Industries	15 000 t, 12 500 t	Same	600
	Harbin Boiler	8 000 t	Same	
	Shanghai (SEC)	12 000 t	16 500	600
	China Erzhong and Dongfang	12 700 t, 16 000 t	Same	600
India	Larsen and Toubro	9 000 t	15 000 t	600 (in 2011)
	Bharat Heavy Electricals		10 000 t	
	Bharat Forge		14 000 t	
Europe	AREVA, SFARSTEEL	11 300 t	Same	250
	Sheffield	10 000 t	Same	
	Pilsen Steel	100 MN (10 200 t)	12 000 t	200 (250)
	Vitkovice	12 000 t	Same	
	Saarschmiede	8 670 t	12 000 t (in 2010)	370
United States	Lehigh	10 000 t	Same	270
Russia	OMZ Izhora	12 000 t	15 000 t	600

Source: Based on Savage, 2014 and WNA, 2015.

One of the striking features of the market is the shift in capacity from North America to Asia and Russia (see Table 24). Much of the new capacity in Asia is targeted at domestic markets, including India and, for now, China. The exception is Korea, which has ambitions to become the third largest exporter of nuclear technology. China too, although currently focusing on delivering its domestic programme, has ambitions to become a leading nuclear exporter.

In the past, a general shortage of capacity for large forgings limited the number of RPVs that could be supplied to around five to seven reactors per year and has obliged the reactor suppliers to reserve capacity on a long-term basis (*The Engineer*, 28/04/2010). The additional capacity installed by Japan Steel Works alone will allow that company to increase its capacity to 12 reactors per year. An important question for the Asian and especially Japanese manufacturers of large forgings is how the industry responds to the slowing of the market that has taken place since the Fukushima Daiichi accident. There are some concerns about excess capacity arising in the Japanese market.

Concluding remarks on current market structure

It can be seen from the above discussion that most areas of equipment supply for a new nuclear plant are relatively open to competition and new entrants, and there is great diversity in the range of companies in the market. There are a few specific items, mainly in the nuclear island, where the technological and manufacturing capability required constitutes a significant barrier to entry, namely the reactor pressure vessel, reactor coolant pump and steam generator (in a PWR) and the associated very large forgings.

The supply of these critical components is restricted to a few companies in the world with manufacturing facilities on the necessary scale and the required experience in the nuclear market. Reactor vendors typically will take responsibility for supplying these items themselves or will procure them from strategic partners. Vendors are also likely to take responsibility for the assembly of reactor internals and instrumentation and control equipment, although most of the components can be supplied by a somewhat wider range of companies both locally and internationally.

Outside the nuclear island, the manufacture of turbine/generators is a relatively discrete market, in part because of their size compared with the steam turbines required in other types of thermal power plants. It is dominated by a small number of suppliers, in most cases closely linked to reactor vendors through established working relationships or formalised into partnerships.

Beyond this relatively small number of critical components, however, there is a very large part of the scope of supply for a new nuclear plant where the technical barriers to entry are low and where there is a more diverse range of suppliers. These include some technologically advanced components such as equipment for the nuclear island, as well as a large volume of equipment for the conventional island that does not need to be manufactured to nuclear grade quality standards, which provides opportunities for the supply chain both for localisation and for international competition.

III.3.2. The evolution of the global nuclear supply chain

Cost trends

As noted earlier, the supply chain makes up a very significant part of the overall costs of an NPP. Capital costs for construction of new nuclear plants have risen in recent decades, but understanding the reasons behind this rise is complicated by several factors:

- First, there are large variations between countries, in particular between the emerging industrial economies of East Asia and both North America and Europe.
- Second, there are also variations between reactor technologies and project management structures.
- Third, there are large differences between project estimates and outturn costs.

The NEA and the IEA in their report on the *Projected Costs of Generating Electricity: 2010 Update* provide a range of estimates of the costs of nuclear power in OECD and selected non-OECD countries. Table 25 shows marked differences between countries ranging from Korea, at below USD 2 000 per kW, to Western Europe and the United States, where costs were between USD 3 400 and USD 5 900 per kW.

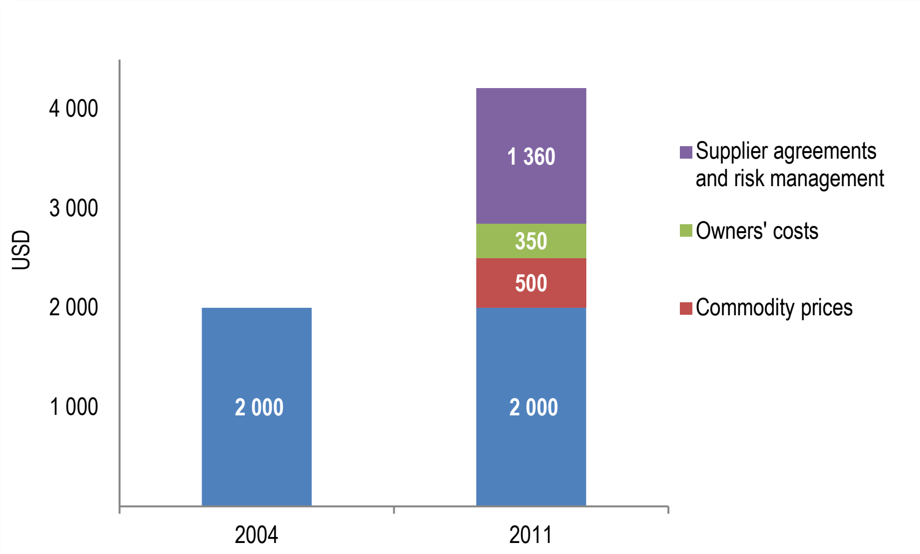
Table 25: Overnight costs and levelised costs of electricity of nuclear power plants

Country	Technology	Net capacity	Overnight costs[1]	Investment costs[2]		Decommissioning costs		Fuel Cycle costs	O&M costs[3]	LCOE	
				5%	10%	5%	10%			5%	10%
		MWe	USD/kWe	USD/kWe		USD/MWh		USD/MWh	USD/MWh	USD/MWh	
Belgium	EPR-1600	1 600	5 383	6 185	7 117	0.23	0.02	9.33	7.20	**61.06**	**109.14**
Czech Rep.	PWR	1 150	5 858	6 392	6 971	0.22	0.02	9.33	14.74	**69.74**	**115.06**
France[4]	EPR	1 630	3 860	4 483	5 219	0.05	0.005	9.33	16.00	**56.42**	**92.38**
Germany	PWR	1 600	4 102	4 599	5 022	0.00	0.00	9.33	8.80	**49.97**	**82.64**
Hungary	PWR	1 120	5 198	5 632	6 113	1.77	2.18	8.77	29.79/29.84	**81.65**	**121.62**
Japan	ABWR	1 330	3 009	3 430	3 940	0.13	0.01	9.33	16.50	**49.71**	**76.46**
Korea	OPR-1000	954	1 876	2 098	2 340	0.09	0.01	7.90	10.42	**32.93**	**48.38**
	APR-1400	1 343	1 556	1 751	1 964	0.07	0.01	7.90	8.95	**29.05**	**42.09**
Netherlands	PWR	1 650	5 105	5 709	6 383	0.20	0.02	9.33	13.71	**62.76**	**105.06**
Slovak Rep.	VVER 440/ V213	954	4 261	4 874	5 580	0.16	0.02	9.33	19.35/16.89	**62.59**	**97.92**
Switzerland	PWR	1 600	5 863	6 988	8 334	0.29	0.03	9.33	19.84	**78.24**	**136.50**
	PWR	1 530	3 681	4 327	5 098	0.16	0.01	9.33	15.40	**54.85**	**90.23**
United States	Advanced gen III+	1 350	3 382	3 814	4 296	0.13	0.01	9.33	12.87	**48.73**	**77.39**
Non-OECD members											
Brazil	PWR	1 405	3 798	4 703	5 813	0.84	0.84	11.64	15.54	**65.29**	**105.29**
China	CPR-1000	1 000	1 763	1 946	2 145	0.08	0.01	9.33	7.10	**29.99**	**44.00**
	CPR-1000	1 000	1 748	1 931	2 128	0.08	0.01	9.33	7.04	**29.82**	**43.72**
	AP-1000	1 250	2 302	2 542	2 802	0.10	0.01	9.33	9.28	**36.31**	**54.61**
Russia	VVER-1150	1 070	2 933	3 238	3 574	0.00	0.00	4.00	16.74/16.94	**43.49**	**68.15**
Industry contribution											
EPRI	APWR, ABWR	1 400	2 970	3 319	3 714	0.12	0.01	9.33	15.80	**48.23**	**72.87**
Eurelectric	EPR-1600	1 600	4 724	5 575	6 592	0.19	0.02	9.33	11.80	**59.93**	**105.84**

1. Overnight costs include pre-construction (owner's), construction (engineering, procurement and construction) and contingency costs, but not interest during construction (IDC).
2. Investment costs include overnight costs as well as the implied interest during construction (IDC).
3. In cases where two numbers are listed under O&M costs, numbers reflect 5% and 10% discount rates. The numbers differ due to country-specific cost allocation schedules.
4. The cost estimate refers to the EPR in Flamanville (EDF data) and is site-specific.

Another study by the University of Chicago (2011), looking specifically at costs in the US market, suggests that overnight capital costs for a FOAK plant more than doubled from USD 2 000 to USD 4 210 per kW between 2004 to 2011 (Figure 36). The Chicago study concluded that rising commodity prices contributed an additional USD 500 per kW to overnight costs and owners' costs a further USD 350 per kW. However, the largest contributing factor was in design maturation (the additional costs of translating designs to US requirements), vendor and supplier agreement and risk management.

Figure 36: Factors for increases in overnight capital costs
(Overnight costs, USD per kW)



Source: University of Chicago, 2011: 5.

The study did not fully quantify the breakdown of design maturation, vendor and supplier agreements and risk management, but it quotes outside expert views attributing the bulk of these rising costs to fixed or firm price EPC contracts, which were seen as the number one reason why nuclear capital costs have escalated. While such contracts provide a degree of certainty for the plant owner, this comes at the price of a significant premium due to caution on the part of EPC contractors. This is exacerbated by the fact that EPC contractors then seek to pass on risk by negotiating similar contracts with their own suppliers, creating an effect of pancaking cost contingencies with margins built on margins.

Notwithstanding the general tendency of costs rising over time in nuclear, costs have been driven by a number of competing factors, many of them applying upward pressure but some of them tending to reduce the costs, and these have varied over recent decades. A working paper for the UK Energy Research Centre identified an escalating trend in costs for new nuclear plants until around 1990, followed by a period in which costs appeared to fall during the 1990s and early 2000s, and a subsequent return to rising costs from the mid-2000s to the present (Greenacre, 2012).

Upward cost pressure during the period through the 1960s to the 1980s appears to have been largely driven by environmental and safety concerns, which dominated public debate about nuclear energy and which were accentuated sharply following the 1979 Three Mile Island accident and the 1986 Chernobyl accident. This drove up regulatory standards but also meant that the rules for nuclear design, construction and operation were subject to constant change, causing project times to overrun and costs to escalate, with knock-on effects on financing costs. In the United States, new plants built before 1979 took an average of five years to license and build, but after Three Mile Island, this rose to nearly 12 years. Addition cost drivers during this period included:

- lack of standardisation due to multiple reactor design variants;
- disappointing economies of scale due both to the absence of mass production benefits and to disproportionately increasing complexity at larger scales;

- failure to achieve the anticipated learning effects due especially to excessively rapid deployment, excessive design variants and complexity.

By the 1990s, the development of more advanced designs with enhanced safety and environmental standards improved confidence that nuclear plants could be operated safely. A more stable regulatory environment for plant constructors contributed to downward pressure on costs, reinforced by lower labour and material costs and shorter construction times.

Construction times were an important factor in driving down costs. Nuclear plants under construction from the early 1990s, especially in Asia, were built in shorter periods and with less cost variability than had previously been experienced in the United States and Europe. The average construction time for new plants in the United States up to the late 1970s was nearly ten years. By contrast the global average for plants beginning construction between 1993 and 2001 was just over five years.

The reduction in cost pressures was in part explained by the fact that construction of new nuclear plants was taking place largely outside the United States and Europe. Almost all construction activity from 1990 to 2005 took place in the lower cost markets of South America, Eastern Europe and Asia. Among the factors contributing to cost reductions in these countries were:

- lower input costs, especially labour, in part due to a slowing down of the world economy;
- reduced cost-forcing regulatory pressures;
- greater incidence of construction in command-and-control type economies likely to ensure stable electricity prices which therefore lowered the risk premium on capital financing.

The period from 2005 was then characterised by a return to rising costs for new nuclear construction. First, the costs of construction materials on global markets, especially steel and aggregates, were rising sharply over this period. Secondly, growing demand for power generation, and competition with rising demand from other sectors such as oil and petrochemicals, were leading to pressures on manufacturing capacity. For large components such as specialist forgings with long lead times, this also led to supply chain bottlenecks. Costs have been further driven up by:

- skills shortages and management problems;
- poor cost estimates revealed only late in the life of projects;
- delays and cost overruns due to lengthy gaps in nuclear construction experience.

Drawing on its analysis, the UK Energy Research Centre (UKERC) study concluded that the nuclear construction industry had a fairly consistent record of appraisal optimism. Cost estimates have not taken full account of or built in sufficient contingencies for the uncertainties arising from the regulatory instability surrounding nuclear, combined with the technical and construction difficulties that have been faced. In addition, the industry's cost estimates have given insufficient weight to the challenges presented by a profusion of different reactor types and sizes.

A second overall conclusion is that the nuclear industry has not captured the learning effects that might normally be expected from several decades of construction experience. Potential benefits have tended to be overwhelmed and largely negated by other cost drivers. The increasing scale of nuclear plants over this period has led to disproportionately cost-increasing complexity, with economies of scale more than outweighed by the resultant increases in construction times and component and labour costs. The intrinsically large-scale and site-specific nature of nuclear energy means that it cannot easily benefit from mass production of equipment, while opportunities to benefit from multiple unit construction at the same site are likely to be relatively limited.

Compounding this, the long gaps that have been experienced in nuclear construction in individual countries has resulted in a loss of collective knowledge and organisational memory of how to manage projects successfully. Even where a series of plants is planned, excessively fast roll-out might compromise the ability to incorporate learning into successive units.

The additional costs that apply to the first of a particular technology design are referred to as FOAK costs. This covers the fixed cost of the reactor design, taking it from conceptual design to a detailed engineering design. The 2004 Chicago study indicated that FOAK costs may amount to around 30% of the overnight costs for the first reactor. Depending on how many reactors of a particular design are built and how the utility owner accounts for these fixed costs, they may be amortised over multiple units (University of Chicago, 2004).

FOAK costs are specific to each reactor design. This means that if a series of plants are constructed in different parts of the world from a standardised design, a large part of the FOAK costs will already have been met. This holds even if there is additional fixed costs to allow a generic design to be adapted to each particular country's regulatory requirements and to obtain the different construction and operating licences.

A related, but distinct, issue is the potential to reduce costs for a series of plants by capturing the learning from previous construction and manufacturing experience. The Chicago study indicates that savings from such learning may lie between 5% and 7% for each doubling of the number of plants of a specified type built. Uncertainties are large, however.[3] It identifies three elements of this learning-by-doing:

- in the factory: learning ways to produce components in shorter times and with less waste;
- on-site replication: retaining the experience and teamwork by keeping an engineering and construction team together on the same site;

3. *Ad verbatim*, the Chicago study states the following:

> Studies of nuclear plants built in the 1960s and 1970s report evidence of learning rates of 5 to 7% with doubling of plants constructed. Extending the sample of plants to those built in the 1980s weakens the ability to identify construction learning effects. Studies have found lower costs on plants built in-house by a utility itself rather than by a contractor, as much as 25%; but an earlier study found a 30% higher cost on in-house construction. It is possible that the in-house effect is the result of contractors in a market with limited competition.
>
> A plausible range for future learning rates in the US nuclear construction industry is between 3 and 10%. Three per cent is conservative. It is consistent with a scenario involving low capacity growth, reactor orders of a variety of designs spaced widely enough apart in time that engineering and construction personnel cannot maintain continuity, some construction delays, and a construction industry that can retain internally a considerable proportion of learning benefits. A medium learning rate of 5% is appropriate for a scenario with more or less continuous construction, with occasional but not frequent cases of sequential units built at a single facility, a narrower range of reactor designs built by a more competitive construction industry, with delays uncommon. A 10% learning rate is aggressive. It would necessitate a continuous stream of orders that keep engineering teams and construction crews intact, a highly competitive construction industry, and streamlined regulation largely eliminating construction delays (University of Chicago, 2004: 4-1)

- between-site replication: through standardised procedures which can be transferred from one site to another even though the engineering and construction staff may change.

Cost reduction over a series of plants might also be achieved through the ability to schedule activities and the deployment of construction equipment across multiple units, either on the same site or between sites. Experience reported in the study, supported by a review of international experience by the NEA, suggests that savings from multi-unit construction have averaged around 15% of the overnight costs of a single-unit plant (University of Chicago, 2004: 3-12-13).

Consolidation trends in the global nuclear supply chain

In the early days of nuclear power development, the design and construction of NPPs was led by consortia in each country. These consortia were typically built around industrial boiler makers on the one hand and electrical turbine generator manufacturers on the other. Although these were specific to each country, there was a degree of competition from the very early days. In the United Kingdom, one of the first movers in nuclear power, there was a deliberate policy of creating separate commercial consortia which were invited to tender for the design and construction of plants on the basis of a high-level design specification determined by the UK Atomic Energy Authority, which acted as both the design authority for nuclear facilities and adviser to the state-owned generating utilities. In the United States, competing designs were developed by Westinghouse and General Electric, with both PWR and BWR technologies being developed respectively.

According to the WNA, there were some 32 such companies active in nuclear plant construction in ten countries in these early years. Most of these were not exclusively focused on nuclear and were active in other areas of power engineering and process plant construction. They were supported by other major construction and engineering companies, capable of manufacturing the heavy forgings and castings for power plants and of carrying out the site works and mechanical and electrical installation.

By the 1970s, a process of industrial restructuring had reduced these to a smaller number of companies with more focus on nuclear plant engineering as indicated by Table 26.

Table 26: Nuclear power plant vendors in the 1970s

North America	Western Europe	Asia
Atomic Energy of Canada Ltd, Canada	Swedish/Swiss group ABB (from 1988)	Hitachi, Japan
Babcock & Wilcox, United States	Framatome, France	Mitsubishi, Japan
Combustion Engineering, United States	Kraftwerk Union (Siemens), Germany	Toshiba, Japan
General Electric, United States	National Nuclear Corp, United Kingdom	Nuclear Power Corp. of India, India
Westinghouse, United States		

Source: Based on WNA data (2012).

Further consolidation occurred from the 1980s, in part because of the slowdown in nuclear plant construction, with a series of mergers and partnerships developing. This took on an increasingly international pattern, with significant mergers and partnering between the United States, European and Asian companies to take advantage of economies of scale and sharing of technology, during which time the former UK and Swiss/Swedish champions were absorbed into other players. Key developments included:

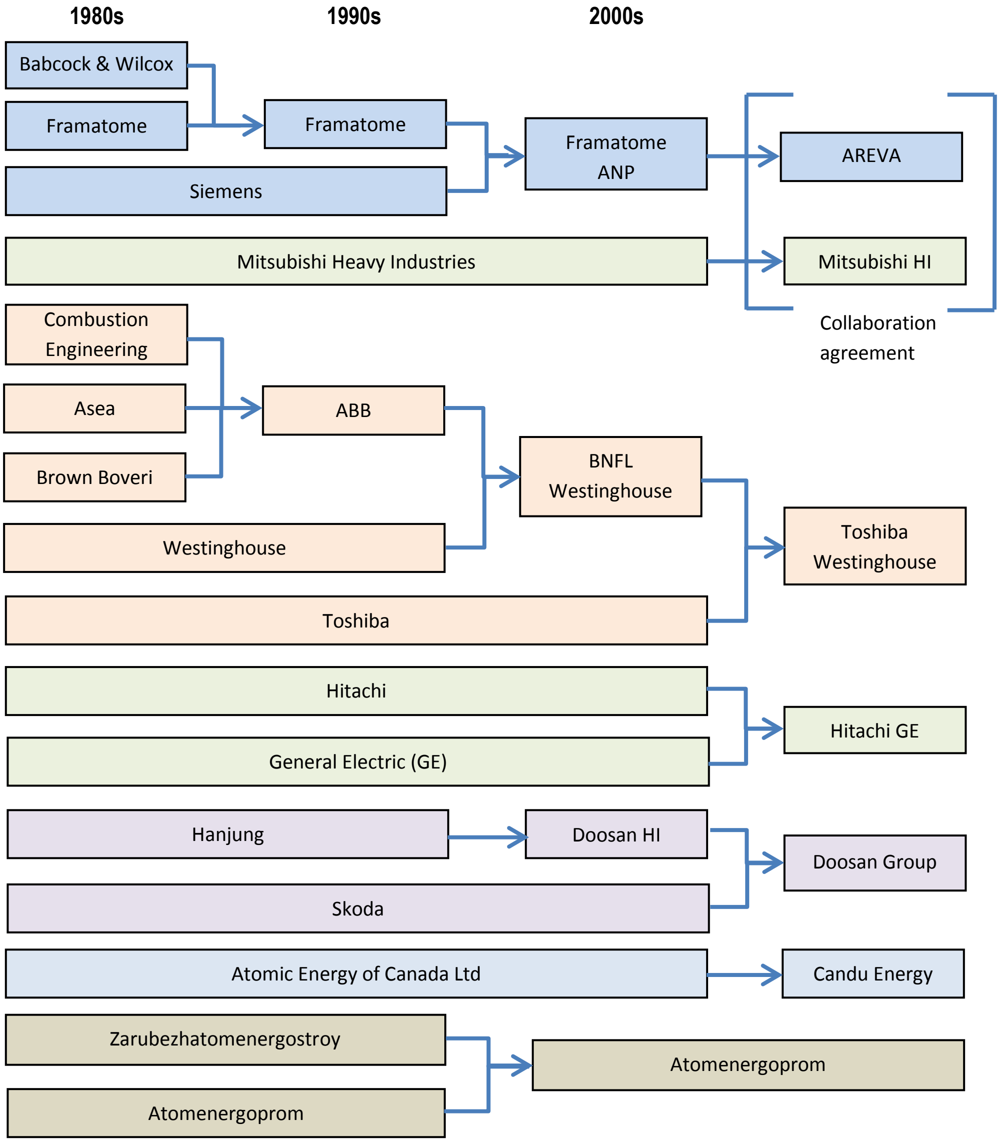
- Merger of Construction Engineering (United States) into the Swedish/Swiss group ABB; the nuclear businesses of both companies were absorbed into Westinghouse, which at the time was owned by British Nuclear Fuels Limited. Westinghouse was then acquired by Toshiba in 2006.
- The nuclear fuel and services business of Babcock & Wilcox was acquired by Framatome of France. Framatome and Siemens' nuclear businesses were then merged to form AREVA NP.
- GE and Hitachi formed a strategic alliance to develop BWRs in 2007, forming GE Hitachi Nuclear Energy (GEH) and Hitachi-GE Nuclear Energy (H-GNE).
- The Russian nuclear industry has been integrated under the leadership of Atomenergoprom (AEP), bringing together 80 former civil sector enterprises, to build NPPs in Russia and overseas.
- Doosan, which took over Korea Heavy Industries and Construction on privatisation in 2001, acquired Babcock Energy in the United Kingdom (2006) and Skoda Power in 2009.

The resulting consolidated groups of AREVA, Toshiba/Westinghouse, GE Hitachi and AEP are responsible for 222 of the 434 nuclear plants currently operating globally and 27 of the 56 plants built since 2000 or currently under construction.

The focus of this discussion is on the evolution of the equipment supply chain. However, it should be noted that the industrial consolidation described here also featured, and was in part driven by, consolidation of the market for fuel fabrication. The major fuel fabricators are also vendors of NPPs, and the consolidation among these companies was partly driven by overcapacity in fuel fabrication and the need for investment in R&D. Thus the creation of AREVA involved the merger of Siemens' nuclear fuel operations with Framatome-Cogema Fuels, the fuel fabrication business of ABB-CE was merged with Westinghouse into British Nuclear Fuels, before the acquisition of Westinghouse by Toshiba, and GE, Hitachi and Toshiba formed Global Nuclear Fuels for the supply of BWR reactors, incorporating Japan Nuclear Fuels, their previous joint venture for the Japanese market (see Figure 37).

Emerging from this process of industrial consolidation, and also from the very high costs and long lead times for designing NPPs, was the important role of the reactor technology vendor. The customer for a new plant buys not so much the manufacturing capacity of such companies as the design and engineering capability to develop and license a reactor design. Vendors will normally carry out the manufacturing of at least some of the critical components in their own facilities, allowing them to integrate design and manufacturing, but they will also subcontract manufacture as necessary. This may include large and technically sophisticated components such as ultra-large forgings, pressure vessels and CRDM.

Figure 37: Consolidation in nuclear reactor manufacture



While vendors are traditionally strong in their domestic markets, they are also able to market and license their technologies internationally. The characteristics of various designs attract different governments according to local circumstances and needs. According to the WNA, there are now nine consolidated vendors offering their technology and services globally (see Table 27).

Table 27: Characteristics of leading nuclear reactor vendors

Company	Reactor type	
AREVA NP	EPR	Manufacturing capability for reactor pressure vessel including the Le Creusot forgings facility and nuclear steam supply system components.
	ATMEA	Front end fuel supply and reprocessing facilities as well as decommissioning.
	KERENA ABWR	Co-operation agreement with Mitsubishi HI to develop ATMEA technology.
Candu Energy	ACR 1000	Design and construction of NPPs, supply of specialised equipment and plant life support.
GE Hitachi	BWR	Two subsidiary partnerships offer fuel cycle services.
	ABWR	Engineering, procurement and construction management of NPPs.
China National Nuclear Corporation	CNP-1000 CAP 1400	Subsidiary companies covering nuclear construction, fuel supply and fabrication.
Doosan	APR-1000 APR-1400	Partnership with KEPCO to supply nuclear and turbine components and engineering, procurement and construction management of NPP construction.
Mitsubishi Heavy Industries	APWR	Joint venture with AREVA to develop ATMEA.
	ATMEA	Fuel fabrication. Manufacture of reactor pressure vessel and nuclear steam supply system components.
Nuclear Power Corporation of India	PHWR-220 PHWR-700	Reactor pressure vessel and turbogenerator manufacture (with Larsen & Toubro). Architect engineer and engineering, procurement and construction management for NPP construction.
American Electric Power	VVER	Construction and operation of NPPs, fuel supply.
Toshiba/Westinghouse	ABWR AP1000	Reactor pressure vessel internals. Steam turbine generators. NPP modular construction. Fuel fabrication. Engineering, procurement and construction management.

Source: Based on WNA data (2012).

Consolidation affects not only the reactor vendors and the suppliers of heavy engineering components for NPPs; it is felt down through the supply chain. At the end of the 1980s, in the United States, there were over 400 companies supplying nuclear components and over 900 nuclear stamp certifications from the American Society of Mechanical Engineers (ASME N-stamp). Two decades later there were fewer than 80 nuclear suppliers in the United States and the number of ASME N-stamp certifications had fallen to fewer than 200.

The trend towards consolidation was driven by a combination of rising costs of designing and developing new nuclear plants, and the slowdown in orders for nuclear plants from the 1980s. Most of the growth in nuclear new build that is projected, however, will be taking place outside the OECD area. This has implications both for capacity in the supply chain and for the pressures for consolidation discussed above. There are also important trends mitigating and potentially outweighing the pressure towards consolidation.

Localisation trends

There is strong pressure from host markets towards localisation and technology transfer to maximise economic opportunities from a new build programme, especially through a move towards manufacture of higher value components, engineering and design. The effectiveness of localisation strategies over the long term can be seen in France and Japan, two countries that have made the transition to being established nuclear players. Both countries started their nuclear development on the basis of technology transfer agreements with the United States, and in both countries there was a conscious long-term policy to use the expansion of nuclear power to build an indigenous nuclear industrial capability.

In France, the French industrial group Empain Schneider worked with Westinghouse to build PWRs at Chooz in 1969 followed by Tihange in Belgium in 1975. The companies established Framatome to supply the RPVs for the two plants, with the company then also winning orders for plants in Switzerland and the United States. The licensing agreement between Framatome and Westinghouse was extended in 1972 to cover all components associated with the reactor core and vessel design. France undertook a major programme of investment in nuclear power in the 1970s (the Messmer plan named after then Prime Minister Pierre Messmer) and Framatome went on to develop a French standardised reactor design during the 1970s and 1980s, supported by EDF.

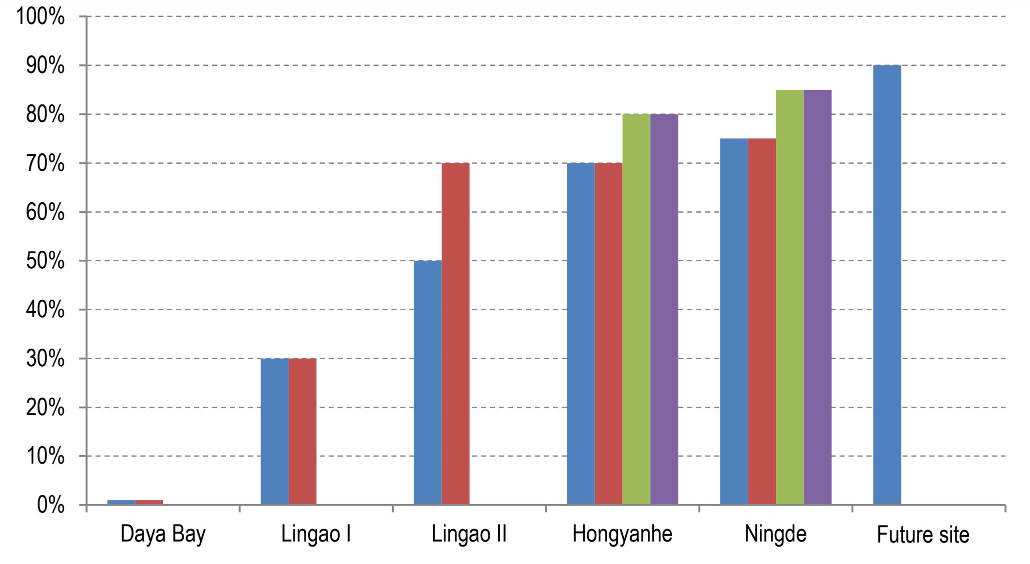
In Japan, the Ministry of International Trade and Investment undertook a plan in 1967 to establish "total engineering capability" for NPPs. PWRs were built by Mitsubishi Heavy Industries under licence from Westinghouse. BWRs were developed through collaboration between GE and Hitachi starting in 1966. Local content for the early PWRs and BWRs was around 60% but by the time of construction of the Shimane 1 BWR in the 1970s, it had risen to 93%. The Advanced BWR was developed between GE, Hitachi, Toshiba and Tokyo Electric Power Company (TEPCO) during the 1980s and, by the time of the first ABWR commissioned in 1996, Toshiba supplied the complete nuclear steam supply system.

The recent experience of Korea is also instructive. When the first nuclear plants were purchased from Westinghouse and Framatome in the early 1970s, local content ranged from 8% to 29% of equipment. A localisation policy was adopted in 1979. By the early 2000s, when the Yonggwang plants 5 and 6 were built, local content had reached 79%. Korea aimed for 90% local content by the early 1990s. A technology transfer agreement with Westinghouse was signed in 1987, aimed at enabling Korea to achieve technical self-reliance over a ten year period. Korea developed an indigenous nuclear steam supply system design which was to become the Korean standard NPP, now marketed for export as the OPR-1000. The Korea Power Engineering Company has also developed a generation III/III+ APR-1400, which is being supplied to the UAE.

China has also pursued a vigorous policy of localisation, building on licensing arrangements and technology transfer from the start of the Daya Bay project in the late 1980s, which was developed jointly with AREVA and EDF. AREVA retained the intellectual property rights to the first CPR-1000 technology, with local content being steadily increased (see Figure 38). The development of the project was led by CGN, which established a nearly complete supply chain in China.

Over time, Chinese companies have developed the capability to supply the reactor pressure vessel, steam generator, reactor internals, CRDM, primary coolant pump and main turbine. Different strategies of mixing and matching indigenous designs with those of foreign suppliers were pursued at different times and locations.

Figure 38: Local content of different Chinese CPR-1000 reactor



Note: Each bar indicates a reactor's share of local content.

The Qinshan PWR was thus an indigenous Chinese design, initially at 300 MW, that was scaled up to a 600 MW twin loop design. The phase III Qinshan units used a Candu PHWR design that was provided by AECL on a turnkey contract. The State Nuclear Power Technology Corporation (SNPTC) signed a technology transfer agreement with Westinghouse in 2007, with the AP1000 selected as the technology basis for four reactors at Sanmen and Haiyang. The agreement covered transfer of the designs, development of a standardised design for Chinese application and its mass manufacture. The agreement was subsequently extended to include co-operation in overseas markets. In parallel, the then China Guangdong Nuclear Power Group (now CGN) entered into an agreement with AREVA and EDF to develop two EPRs that are now being constructed at Taishan. Both CGN and CNNC are potential partners for EDF's project at Hinkley Point C in the United Kingdom.

China is now self-sufficient in basic nuclear design and manufacturing capability and is looking at exporting technology. Each wave of new countries entering the nuclear market and localising its supply brings new entrants into the supply chain that are able to compete in the global nuclear market.

Looking beyond these examples, where localisation has been pursued vigorously by national governments, the experience of the global nuclear supply chain is more mixed. Not every country can achieve localisation in a comprehensive way, in the sense of moving, through technology transfer and licensing, towards establishing a full indigenous capability to design and build NPPs and to manufacture the heavy industrial components to nuclear grade standards.

Some countries, notably the United Kingdom and to some extent the United States, which were early movers in nuclear development, have abandoned the goal of complete self-reliance. In the United Kingdom, there was a long history of seeking to develop independence in reactor design, backed up by industrial capability to manufacture and deliver power plants, for reasons of engineering pride as much as industrial competitiveness. But this floundered on a failure to standardise designs and to develop an export market for the United Kingdom's chosen advanced gas-cooled (AGR) reactors. By the time the United Kingdom built its most recently completed nuclear plant in 1995, it was already reliant on an imported Westinghouse PWR design and a RPV built by

Framatome in France. The United Kingdom is now embarking on a new programme of NPP construction, based on competing reactor technologies provided by non-UK owners and vendors.

Other countries have focused on a segment of the supply chain where they have established a comparative advantage, such as the Czech Republic, Italy, Spain, Sweden and the Ukraine. Even where a comprehensive policy of localisation is not pursued, new entrants can be brought into the market through partnerships with companies that are already part of the vendor's supply chain. This can create opportunities both for companies from the host market and for international companies to enter the nuclear market. The vendor's existing suppliers can bring knowledge of the vendor's quality requirements and an established working relationship with the client. Local partner companies can bring not only additional delivery capacity but also knowledge of the local regulatory, commercial and stakeholder environment. In this way, partnerships can be an effective way for local companies to acquire knowledge and experience of supplying the nuclear market and also satisfy political desire to maximise local content.

According to the WNA, in markets that are open to international competition, local content is likely to be in a range from 30 to 70%, with even mature industrial countries such as the United Kingdom and France achieving only 50 to 70%. There are powerful pressures for consolidation in the nuclear industry because of the very high costs of investment in design and manufacturing capability. But there is not a single direction of travel. There are also pressures for localisation and the geographical expansion of the nuclear market brings new entrants into the supply chain.

An important feature of the development of the market has been the shift towards east-west partnerships, whether formalised through ownership or through strategic partnering. This allows established western companies not only to enter eastern markets, but also to benefit from the experience of actually delivering projects, which has often been more successful, especially in East Asia, than in North America or Europe. Thus, consolidation and partnering is driven not only by the benefits of scale economies and investment, but increasingly by learning and the transfer of best practice on project delivery.

Barriers to global competition

The very heavy investments that are made in developing the designs for nuclear reactors create a barrier to entry for new competitors. It can take many years to develop the conceptual design for a nuclear reactor and further investment is required to translate this to the regulatory and commercial requirements of a given market. The most likely source of new entrants to supply new nuclear plants for the foreseeable future is companies that have developed an independent capability as a result of a licensing or technology transfer arrangement with an existing supplier, as had happened with Japanese and Korean companies and is likely to take place with Chinese companies. This places the reactor vendor in a relatively strong market position relative both to their own customers (utilities, developers, governments) and to their supply chain.

Despite these formidable barriers to entry and the factors that should favour the major players, a review by the NEA a few years ago concluded that the market for the supply of new nuclear plants was in fact reasonably competitive (NEA, 2008). Competition between the major players appeared quite vigorous and the Hirschman-Herfindahl Index (HHI) which gives a measure of market concentration as indicated in Table 28, did not show over-concentrated markets.[4]

4. The HHI of concentration measures diversification by calculating the sum of the squares of the percentage shares multiplied by 100 of the different constituent elements ($HHI = \sum_i (share_i * 100)^2 \ with \ \sum_i = 1$). A perfectly diversified set would have an HHI of zero, while a set consisting of

Table 28: The historic shares of different NPP vendors and their HHI scores

Company	No. of NPPs	Share (%)	HHI
Toshiba/Westinghouse (including ABB and C-E)	120	27.6	765
AREVA (including Framatome, Siemens)	96	22.1	489
General Electric (GE) Energy	54	12.4	155
Atomenergoprom	52	12.0	144
Atomic Energy of Canada Ltd (AECL)	34	7.8	61
Mitsubishi Heavy Industries (MHI)	19	4.4	19
Nuclear Power Corporation of India Ltd	16	3.7	14
Hitachi	10	2.3	5
Skoda Praha	10	2.3	5
Doosan Heavy Industries	9	2.1	4
Babcock & Wilcox (B&W)	7	1.6	3
China National Nuclear Corp. (CNNC)	7	1.6	3
Total	**434**	**100.0**	**1 666**

Source: NEA, 2008.

A comparable exercise for current competition in NPP construction would be difficult to undertake since different projects are at different stages of completion. Nevertheless, it is quite obvious that Russian, Korean and, in particular, Chinese reactor vendors would significantly increase their market share in comparison to those of historic suppliers such as Toshiba/Westinghouse, AREVA/Framatome, GE, Hitachi or AECL.

In general, abstract measures such as the HHI provide an imperfect picture of market competition in nuclear as elsewhere. In practice, a myriad of specific structural or administrative features can have a bearing on the state of competition, the possibility for incumbents to enjoy situational rents and the ability of newcomers to enter a given market (see text Box 6 for further details).

one single element would have an HHI of 10 000. The HHI is frequently used as a first approach for measuring the degree of competitiveness of a market. Markets with HHIs below 2 000 are usually considered not to give rise to competitiveness concerns. This does not mean that under particular circumstances, producers cannot engage in anticompetitive behaviour in such markets. Another crucial question is, of course, the size of the relevant market. The NEA (2008) study assumed a global market for nuclear reactors, which is increasingly a reality but was not necessarily the case in the past.

Box 6: Factors determining the competitiveness of nuclear-related markets

1. Market concentration

A widely used measure for concentration is the HHI, defined as the sum of the squares of the percentage market shares of all market participants.

2. Degree of vertical integration

A high degree of vertical integration in a market can be a sign of market foreclosure, i.e. companies with a strong position in an upstream sector can use this to maintain or increase their share in downstream sectors.

3. Proportion of long-term contracts

Where a market is mainly conducted through long-term contracts, this can also be a sign of market foreclosure as suppliers can tie up their customers for long periods, limiting the opportunities for new market entrants.

4. Barriers to entry

There can be many different types of barriers to market entry. They may include the existence of patents and other restrictions on the required technology or know-how, the need for large capital investments, etc.

5. Transaction costs and market segmentation

Transaction costs (such as costs for transport, communication and information) can lead to market segmentation and thus reduced competition. Cultural, legal and linguistic factors can also play a role.

6. Product differentiation

In a perfect market, the products of all suppliers are equivalent and substitutable (e.g. uranium supply). In other market segments, such as NPP construction, differences in design and quality limit competition.

7. Balance of capacity and demand

Overcapacity is generally conducive to competition (a "buyer's market"). Conversely, markets with insufficient capacity (perhaps as a result of rapidly growing demand) can lead to reduced competition (a "seller's market").

8. Market alliances and supplier co-operation

Regulators have powers to punish collusion or cartel-like behaviour such as price fixing. Other forms of co-operation may be permitted but require careful monitoring.

9. Protection of public goods

Governments seek to protect the environment or public health through appropriate measures. While such protection is indispensable, unnecessarily burdensome measures can restrict market competition.

10. Trade barriers and restrictions

Other legal or administrative requirements can, unintentionally or by design, limit market competition. These include import tariffs as well as other less obvious measures that disadvantage foreign suppliers.

Source: Adapted from NEA, 2008: 19-21.

III.3.3. The importance of the supply chain for successful nuclear new build projects

Construction of an NPP is a highly complex undertaking requiring the co-ordination of a wide range of activities including the development of the design according to detailed technical assessments and regulatory requirements, procurement of equipment, civil engineering and construction, testing and installation of components, commissioning of the power station and the co-ordination of numerous contractors and subcontractors. All of this must be carried out to the most exacting of standards of quality and safety and in a cost effective manner.

The way in which the project's equipment, materials and services are procured and the relationships with contractors have significant impacts on the development of the supply chain. There exists a wide spectrum of different options for sharing the responsibilities between the ultimate operator of an NPP and the principal supplier. The IAEA and NEA have nevertheless identified three main categories of contracts that are used for the construction of new NPPs (IAEA, 2012 and NEA, 2008):

1. **The turnkey approach**, where a single contractor or a consortium of contractors takes the overall responsibility for the construction work. A turnkey approach to NPP contracting involves a single large contract between the customer and an NPP vendor (or a consortium led by such a vendor), covering the supply of the entire plant. This will include design and licensing work, supply of all equipment and components (including a first core of fuel and often several reloads), all on-site and off-site fabrication, assembly and construction work, and testing and commissioning of all systems and the entire plant. The vendor or consortium will subcontract any elements of the project which it is not able to supply itself. Thus, the contractor takes full responsibility for delivering a complete and fully working plant to the customer. There are several variations on this pure turnkey approach. For example, the construction of some support facilities may be excluded from the main turnkey contract, and customers with in-house nuclear expertise may wish to retain some involvement in design decisions. Nevertheless, as the overall responsibility for the construction and integration of all important plant systems remains with the main contractor, this may still be considered a turnkey contract.
2. **The split-package ("island") approach**, where the overall responsibility is divided between a relatively small number of contractors, each coping with a large section of the plant. In the split-package approach, the project is divided into a few major systems, each of which is the subject of a separate contract. At its simplest, this approach divides the plant into two packages: the nuclear island (essentially, the reactor containment building and all systems within it) and the conventional or turbine island (the turbine generator and associated systems and buildings). More complex split-packages can separate the civil construction work on the whole plant from the contracts for the nuclear and turbine systems, and can also separate out other major electrical and mechanical systems into individual contracts. In such an approach, it is necessary to allocate overall responsibility for design and licensing, and for integrating the various packages to ensure that all the plant's systems work together correctly. Such overall responsibility could be taken by the plant's owner (where sufficient in-house expertise exists), or this role could be taken by one of the main contractors (usually the main nuclear island contractor).
3. **The multi-contract approach**, where the owner or its architect/engineer (AE) assumes the overall responsibility for detail engineering and constructing the plant. The architect engineer typically issues a large number of contracts. This approach gives the customer the maximum influence over the design and construction of the plant, but also the most responsibility for the success of the project. Only a few large nuclear utilities have this expertise in-house, so often where this approach is adopted an external architect/engineering company will first be contracted to manage the overall project. The architect/engineer (in-house or external) is responsible for the overall design and for licensing, for inviting bids and selecting contractors for each of the plant's systems, for managing the actual construction work as well as for testing and commissioning. In addition to the architect/engineer key contributing actors are: *(i)* the nuclear steam supply system (NSSS) supplier; *(ii)* the turbogenerator supplier; and *(iii)* the construction contractors. While some

major contractors, such as the nuclear systems supplier, will also have a significant on-site presence, many other contractors supply pre-fabricated systems or components with little or no on-site presence. There are many variations within this overall approach, in particular as to exactly how many separate contracts are issued. Breaking the project into a large number of separately supplied components and systems can maximise the choice of supplier as well as competition, but is likely to make the architect/engineer's task of co-ordinating the project more onerous.

The role of EPC contractors

The use of turnkey contracts is often associated with the services of EPC contractors to provide a single point of management for contracts, although this is, strictly speaking, a separate question. An EPC contractor will manage the procurement and delivery of the construction project as a whole, assuming responsibility for all phases of the project and managing all contractors and subcontractors.

The EPC contractor may be a single company with project management expertise or a consortium of companies bringing experience across the disciplines required for the construction of a nuclear plant. EPC contractual structures emerged from other sectors of major infrastructure development, often at the instigation of investors. They can be attractive as a way of managing the risks of construction in such a way that it is effectively transferred from the customer to a contractor able to take on and manage the risk. However, this is complicated in a market such as nuclear where engineering risks are high and where the predominant role of regulation means that they cannot be known or controlled with certainty. This means that there will be boundaries to the risk that an EPC contractor in a nuclear context will be willing or in practice able to take on.

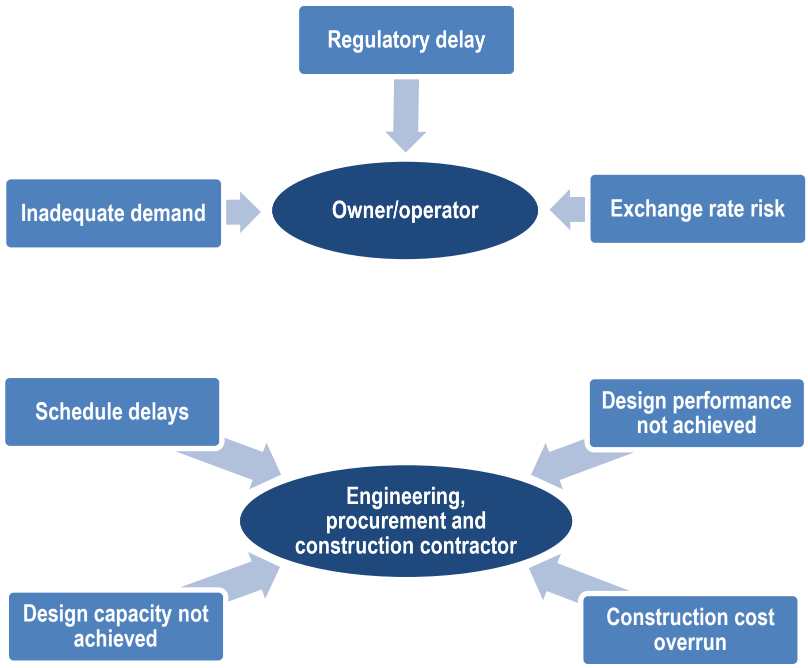
The role of EPC contractors does not, therefore, fall into a single definition but can best be viewed as a spectrum along which risk may be transferred between client and contractor, typically involving one or more of the following pricing structures:

- **Fixed pricing** – meaning that the stated price is fixed for some portion of the work throughout the term of the agreement (subject to typical change orders, such as those based upon changes to the facility requested by the owner, force majeure events or changes in applicable legal requirements).
- **Indexed pricing** – meaning that the stated price for some portion of the work (which is also subject to typical change orders) is subject to adjustment over the course of the project based on the change in one or more indices.
- **Target pricing** – meaning that the contractor is reimbursed for all costs it incurs plus a fee (profit), subject to a sharing mechanism where the contractor receives a bonus if the final project costs are below a pre-established target price, or alternatively where the contractor's fee is reduced or eliminated if the final project costs are above the target level. Significantly, target pricing often includes an absolute limit on the contractor's exposure to project cost overruns regardless of fault.

Even where an EPC contract is the chosen form of procurement, therefore, it does not follow that the terms of the contract will seek to transfer risk from the customer to the contractor. It is possible that customers will seek to negotiate a menu of contracts with the degree of risk transfer or risk sharing varying according to the package (nuclear island, turbine island, balance of plant, associated works), the nature of the risks to be managed and agreement on which parties are best placed to manage them.

Figure 39 gives an illustration of the potential allocation of risk between the owner/operator and the EPC contractor. This allocation may be underpinned by contractual terms providing that, for example, the EPC contractor will make payments in respect of construction or schedule delays above a given threshold or for delays caused by design or quality performance not achieved.

Figure 39: Illustrative risk allocation

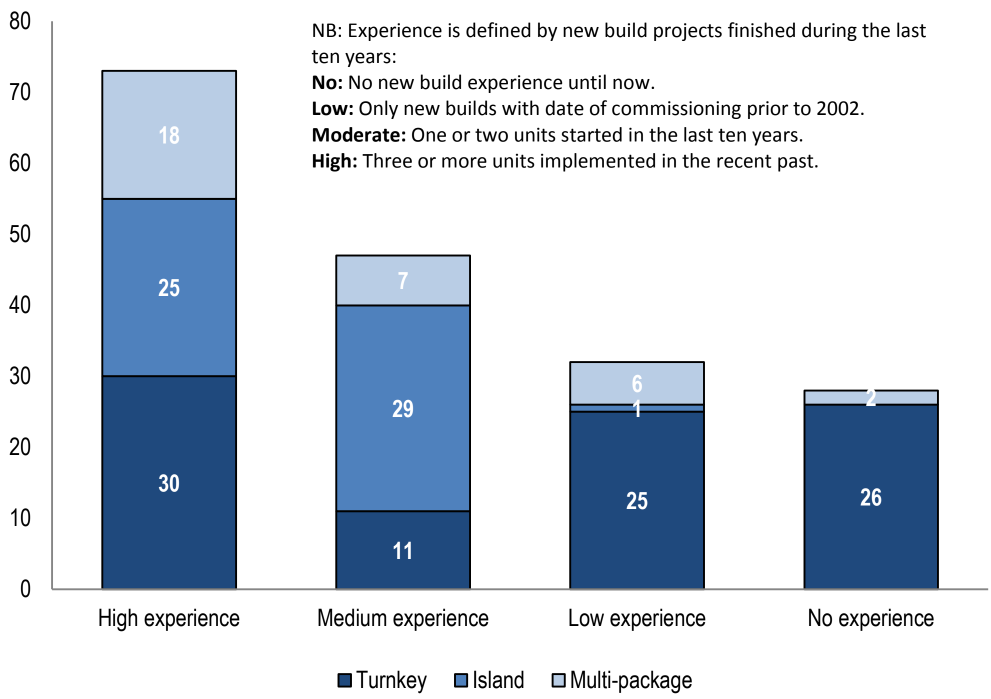


Source: IAEA, 2013.

A study by Arthur D. Little (2014a), found that of 61 plants under construction in 2010, 19 had chosen to utilise a turnkey form of contract, compared with 5 utilising split package or island contracts and 22 choosing a multi-package or component approach. The study also found that less-experienced customers tend to choose either an EPC-turnkey or an island approach, particularly for the first projects in a programme (see Figure 40). That said, EPC contracts were also in evidence among experienced customers as well as new entrants. More detailed findings included:

- All five current new build projects in the United States, covering three different owner operators, have used or are planning to use EPC contracts.
- In countries with several technologies, and therefore vendors, different approaches apply according to the owner and vendor:
  - In the United Kingdom, three technologies are currently being considered for the new build programme. Hitachi and Toshiba/Westinghouse are proposing to use EPC contracts whereas EDF Energy is employing a multi-package approach.
  - In China, there are four major EPC contractors employed on nuclear projects, although in practice these are co-ordinated strongly by the state apparatus, which effectively carries the risk.
  - In Turkey, the government has chosen a contract with Rosatom for the first nuclear project at Akkuyu on a build, own, operate basis. For the second project at Sinop, the reactors are of the ATMEA design supplied by Mitsubishi and AREVA and will be operated by GDF Suez. Both projects include long-term PPAs.
- EDF, as the largest owner and operator of NPPs, has a standardised model of procurement based on a largely multi-package approach, in which it acts as its own architect/engineer. It applies this approach globally and does not encourage new entrant countries to delegate their risk to a contractor, as EDF fulfils all the prerequisites for managing such risk itself.

Figure 40: Choice of contract form according to experience



Source: Arthur D. Little, 2014b.

The obligations of the owner-operator to retain a capability as an intelligent customer places important limits on the extent to which risk and responsibility can be transferred to contractors. Principle 1 of the IAEA fundamental principle of safety specifies that "the prime responsibility for safety must rest with the person or organisation responsible for facilities and activities that give rise to radiation risks" and that "this responsibility cannot be delegated" by the licensee.

The IAEA Guidelines for *Project Management in Nuclear Power Plant Construction* go on to specify that both the owner/operator and the vendor must have:

- project management and quality management skills;
- experience from management of a large construction project;
- knowledge and experience in all technical areas relevant for nuclear safety: civil, mechanical, electrical, and I&C engineering, and nuclear technologies (water chemistry, nuclear fuel, reactor physics, thermo-hydraulics, and safety analysis);
- skills and arrangements to verify achievement of required quality;
- arrangements to control and correct non-conformances;
- experienced designers-engineers who have a realistic view on the actual challenges involved in construction and manufacturing;
- access to manufacturers and constructors who have proven capability to meet the designer's intent and related specifications.

Financing as a driver of project organisation in nuclear new build

The structure of the financing arranged for an NNB project is not only a major issue in itself (see Part I of this study) but will also affect the procurement and project management of the project. Traditional mechanisms for financing new nuclear plants have either relied on the balance sheet of the owner-operator or on the guarantees that were underwritten by rate payers or by national governments through their ownership of utilities or through explicit guarantee schemes.

Project finance or limited recourse financing mechanisms, in which debt finance is raised against the assets of a project – principally, in the case of a power plant, its future revenue stream – have not proven practical for recent nuclear projects, in view of the risks associated with construction costs, regulation and revenues. The NEA and IAEA have published guidelines on the financing of new nuclear plants, including recommendations to reduce or manage regulatory or revenue risk, through:

- clear and sustained policy support for the role of nuclear power as part of a long-term national energy strategy;
- a robust framework of regulation that commands public and political support, with adequate opportunities for public involvement in the decision-making process;
- electricity market regulation that provides long-term certainty for investors in nuclear plants.

Even following these suggestions, however, it is unlikely that project finance will be forthcoming for nuclear plants in the foreseeable future. Commercial financing of new plants will rely on the balance sheets of owner-operators. In a number of projects in recent years, owner-operators have sought to share the risk to their balance sheets by bringing in other equity partners.

In the case of the Olkiluoto 3 project in Finland, the majority of shares in the utility TVO are owned by a group of major industrial customers who contract to take power at cost over the lifetime of the project. The financial structure of TVO is shown in Box 3 on *The Mankala Model*. The purpose of a Mankala company is not to make a profit and pay a dividend to the shareholders but to provide them electricity at average costs. The shareholders have the right and the obligation to purchase at cost an amount of electricity that is proportionate to their respective shareholdings.

Also in Finland, downstream industrial customers for electricity have formed a new company Fennovoima, to develop a new nuclear plant at Hanhikivi (to be built by Rosatom) that will supply power to its shareholders at a price corresponding to average costs. In most cases where equity is shared, though, it is with contractors rather than with the downstream customers for electricity. So even in the Hanhikivi project, Rosatom has taken a 34% equity share, alongside the company's industrial customers.

In China, CGN and AREVA established a joint venture owned 55% by CGN and 45% by AREVA to develop EPR technology first in China and, in the future, overseas. In the United Kingdom, EDF Energy has agreement in principle from CGN and CNNC, with AREVA, to participate in equity in the project at Hinkley Point C in Somerset, while continuing negotiations with other potential equity partners.

Elsewhere, vendors have gone further than taking equity stakes in projects. Rosatom in particular has led its export growth strategy through Atomstroyexport on a BOO basis. In the Turkish Akkuyu project (see the detailed case study in Part I) Rosatom will initially hold 100% of the equity. Turkish companies, including the state generating company EÜAŞ, will take stakes only as the project develops. The BOO arrangement is underpinned by a 15-year PPA with TETAŞ covering 70% of the output of the first two plants and 30% of units three and four. The Turkish authorities have sought a similar BOO arrangement for the country's second nuclear project at Sinop where Mitsubishi and AREVA will develop four Atmea 1 reactors.

Rosatom has also offered to supply Jordan with two AES-92 reactors on a BOO basis, with Russia contributing at least 49% of the USD 10 billion cost. This arrangement could be extended to an additional fleet of reactors in the future. In Hungary, Rosatom has secured an agreement to build the Paks 5 and 6 plants on a BOO basis, providing 80% of the finance for the project to be repaid over the life of the project by the Hungarian government through the utility Magyar Villamos Művek Zrt (MVM).

Such financing arrangements have important impacts on the supply chain in two areas. First, investors who are also contractors will expect to secure a share of work in a project. Second, by providing projects with at least a degree of protection against market risk, they reduce the incentive to make a selection of contractors on purely commercial grounds. The latter may be mitigated by risk sharing agreements where contractors share in the benefits of cost reduction as well as in the losses from cost overruns. Nevertheless, it is too early to judge what the impact of these financing arrangements will be as there are for now too few examples of working reactors built under vendor finance to draw any firm conclusions.

Regulation and international collaboration as potential drivers of supply chain development

Regulation of the nuclear industry has impacts not only on the owner operator but also on the supply chain. The issue has gained in importance due to the internationalisation of the industry as designs need to be adapted to meet different regulatory regimes and suppliers must accredit their products for different customers. The regulation of nuclear power is a national prerogative in the system of international relations and there are differences in the way that regulation is applied in different countries. While the regimes for nuclear regulation have certain common standards for the objectives of regulation, the way these objectives are achieved differs.

Prescriptive systems of regulation set down deterministic requirements and the standards that licensees must follow. For the supply chain, this offers clear rules and certainty although it may stifle innovation. Technology vendors tend to design their products and components to meet the regulatory body's requirements. The US NRC is generally considered to be a prescriptive system, although it has moved in recent years towards a more risk-informed approach. Nevertheless, prescriptive systems have tended to predominate in the nuclear industry and, according to the WNA, have led to significant design variations in new nuclear plants.

Non-prescriptive regulatory regimes, such as those that prevail in the United Kingdom or in Sweden, do not determine what is acceptable or specify which industrial codes and standards the operator must adopt, but place a responsibility on the licensee to demonstrate that they can operate a plant safely. Operators must demonstrate that they have competences and management systems in place to control risks. This is sometimes referred to as a risk-informed approach to safety regulation.

As noted above, one of the fundamental principles of nuclear regulation is that the licensee has the responsibility for safe operation of a plant and this cannot be delegated. Even if it procures the construction of an NPP from contractors, the licensee must retain sufficient knowledge of what is going on throughout its supply chain that it can effectively take responsibility for all aspects of the delivery of the plant.

Under the international conventions governing civil liability for nuclear accidents, the operator has strict and exclusive liability for any injuries or costs to third parties. This gives clarity for the victims of any incident. It also means that operators cannot transfer liabilities to third parties such as their suppliers. Some countries with NPPs are not signatories to these conventions, which may affect the willingness of vendors and other suppliers to enter these markets. India, for instance, despite being a signatory, introduced legislation in 2010 in response to the Bhopal gas release accident in 1984 that gives operators some recourse to their suppliers' liability. This has created uncertainty for suppliers as to whether they might be exposed to claims in the event of an accident.

The WNA argues that there would be benefits from greater regulatory harmonisation based on a more collaborative, less prescriptive regime which it believes would facilitate the development of a global nuclear market while at the same time enhancing safety, security and environmental protection. It argues that regulatory consistency would be improved and the burden on vendors of complying with numerous nationally prescriptive regulatory regimes would be reduced, while their responsibilities for assuring that their designs were safe over the plant's lifetime would be greater.

This is, for instance, the objective of the Multinational Design Evaluation Programme (MDEP), whose Secretariat is hosted by the NEA in Paris. It was established in 2006 to leverage and share the resources and knowledge of the national regulatory authorities charged with reviewing designs for new generation III/III+ reactors. MDEP comprises the nuclear regulatory authorities of ten industrialised countries. China, India and South Africa are also members, while Turkey and the United Arab Emirates are associate members.

A complementary effort is to enhance the regulatory capability of emerging and developing economies that wish to develop nuclear power for the first time. The IAEA Regulatory Cooperation Forum, a group of senior industry regulators from 19 IAEA member states, has identified and implemented a pilot programme with Jordan to help the country establish an effective nuclear regulatory body. These programmes are too recent to have made an impact on reactor design and development. However their initiators clearly aim to contribute to a safer, more transparent, and hence more competitive, global nuclear supply chain.

Concluding remarks on the evolution of the global nuclear supply chain

The global nuclear supply chain is still searching for its equilibrium constellation. This is due to a combination of political, technical and structural factors. Politically, the industry is recovering from the shock of the Fukushima Daiichi accident and the announced phase-outs in Germany and Belgium, mindful that no nuclear construction project has been cancelled and new projects are being announced. July 2014 saw the announcement of an agreement to build two new NPPs in Romania and the expression of interest for building an additional nuclear plant by the CEO of Southern Company, which is currently building two reactors at Southern in the United States.

Technically, new techniques such as automated welding or 6D modelling (3D modelling integrating time, cost and facility management) still need to be digested by the complete supply chain. While improvements in information technology allow for less vertically integrated logistics, such differentiation also highlights the need for all elements of the supply chain to perform to nuclear quality standards. This reorganisation is taking place in the context of a once-in-thirty-years change from one generation of reactors to another. FOAK issues are rife and have led to widely publicised overruns in cost and construction times. Structurally, the hiatus of new constructions outside of China and Russia has meant that skills and experience have been dormant, are difficult to resuscitate or have been lost altogether.

Organising and managing supply chains in a technically, logistically and politically complex industry such as nuclear new build require dedicated skills and expertise. What is very encouraging is that the industry has taken the measure of this difficulty and major suppliers and customers are actively investing funds and management time into the issue. Ultimately, the incentives provided through supply-push and demand-pull need to come together. Of course, industry must provide its customers an assurance concerning its capability of building new nuclear plants in a variety of environments. On the other hand, the global nuclear supply chain will only be stabilised once a sustained demand for new nuclear plants provides the time, competitive pressure and funds for achieving an equilibrium configuration.

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Chapter III.4.

The divergence between actual and estimated costs in large industrial and infrastructure projects: Is nuclear special?

Large capital-intensive projects such as NPPs have had in recent years a poor record in delivering on budget and on time in most NEA and OECD countries. On the plus side, the nuclear industry has long been counting on the learning effects of building a series of given reactor types to bring costs down. Recently, however, researchers have questioned whether the costs for new build are increasing rather than decreasing (Grubler, 2010; Locatelli and Mancini, 2012). Assessing whether potential cost reductions from learning over the course of constructing several units are in fact outweighed by other factors such as increases in resource costs or regulatory uncertainty, is made difficult by the fact that there are relatively few projects from which to draw conclusions. Although there is a reasonable roll-out of broadly comparable generation II designs across the globe, there are substantial differences in the economic, political and regulatory environments in which plants are built. And the variations to standardised designs to allow for local regulatory conditions mean that there is limited experience in reality of building to standardised designs.

Westinghouse believes that the experience of building PWRs in Korea between 1995 and 2005 shows reductions in both costs and construction times that are consistent with estimates that series build of a standard design can obtain cost reductions of around 30%. They attribute the cost savings to standardisation and also currency stability resulting from localisation of equipment supply (Matzie, 2005).

Whether this experience can be replicated in western markets is subject to a wide-ranging debate. A study of the French nuclear programme, while considering it to be the most successful scaling-up of a complex, large-scale technology in the recent history of industrialised countries, examined the causes of cost escalation over the programme (Grubler, 2010: 5174-5188). Despite the favourable institutional setting of centralised decision making and regulatory stability, the cost of PWR units constructed in the mid-1990s were considerably higher than those built at the beginning of the programme two decades earlier. The study considers that several intrinsic characteristics of nuclear construction, such as their size and complexity limit the opportunities to achieve cost improvements through the classical mechanisms of standardisation, large series and repetition of experience, i.e. economies of scale production over several reactors.

Subsequent studies however pointed out that the Grubler study failed to distinguish between different series of reactors with sometimes considerable technical differences. At a recent workshop organised by the NEA, presenters both from AREVA and the French École des Mines agreed that when comparing like with like, learning-by-doing and cost reductions do exist in the French nuclear industry (Jannet, 2014; Berthélemy and Escobar Rangel, 2013). When considering each technological series separately, the French nuclear programme thus achieved, according to AREVA, construction cost reductions between the first and last unit of each series that vary between 2% (CP0, 6 units) 26% (CP1, 18 units) with an average of 16% (calculations based on the widely recognised *Cour des Comptes* [2012] report).

As far as more recent experience is concerned, construction at the EPR at Taishan (China) boasts a 60% reduction in engineering hours, a 50% reduction in months of civil work, a 40% reduction in the months of manufacturing of heavy components and a 30% reduction in months of welding of primary loop when compared to the EPR at Olkiluoto 3 (Finland). EDF reported similar progress between the construction of the EPR at Flamanville (France) and the Taishan project as the pouring of the raft of the nuclear island was reduced from 4.5 months to 1 month and putting the liner cup on the base slab from 47 to 10 weeks (see also the full case study on Flamanville 3, Taishan 1 and 2 and Hinkley Point C 1 and 2 in Section III.5.1).

The reasons for these reductions lie both in technical improvement (one-batch pouring for the base slab, reduced steps for the pouring of the containment base) and organisational advances such as the reduction of management interfaces. A key question that was left unanswered is, of course, whether this impressive progress is a technological series effect or a country effect. The planned EPR at Hinkley Point (United Kingdom) is thus expected to have similar lead times but higher costs.

This points towards the wider issue of how to account for learning-by-doing. Shall the series be constructed by technology (as do AREVA and EDF) country, company or even team? Research by the French École des Mines for instance is based on companies and show that on average there is a 12% decrease in construction costs when moving from a FOAK reactor to a second reactor, with a FOAK premium varying between 10% and 40%. The main reasons are better co-ordinated supply chains and reduced risks of regulatory intervention. This gives a premium to less diversified nuclear fleets and the authors have calculated that a 10% decrease in the logarithmic HHI index of diversification will reduce costs by approximately 22%. The relevant metric might even be the team rather than the company.

The IAEA Secretariat thus pointed out that the CANDU project at Quishan, for instance, one of the few major nuclear projects to be completed *ahead* of schedule, was built by a team that had immediately preceding experience with two other CANDU reactors (Moore, 2014). This stability of the teams was also a factor in the overall very satisfying construction performance of the ABWRs built at Shimane, Kashiwazaki and Hamaoka in Japan according to CH2MHill (Worker, 2014).

Despite this encouraging evidence, the overall impression remains that nuclear projects are often delivered behind schedule and above budget to the extent that cost overruns and delays seem inevitable features of the industry. However, cost overruns for large and technically complex projects exist also in other industries. In fact, 70% of the costs of a nuclear reactor project are due to civil works, the conventional island and project management, with only 30% due to the nuclear island itself. And some conventional "megaprojects" do well, although cost overruns are typically larger in the energy industry (plus 80%) than in other industries according to the authors of the eponymous study.

This begs the question "Is nuclear different?", in particular from its peers in the energy industry such as the oil and gas industry. The latter needs also deal with multi-billion energy projects in often difficult political and regulatory environments, although it may constitute a more homogenous industry at the global level, thus facilitating both competition and benchmarking. Arguably, the oil and gas industry is also submitted to a level of public scrutiny that is comparable to that of nuclear, at least as far as its operating performance in NEA and OECD countries is concerned. This has led the IAEA to conclude that while series for individual reactors types are typically small, nine out of ten issues in nuclear new build remain the same as in other industries.

What can the nuclear industry learn then from other industries, whether the oil and gas industry, the aerospace, the automotive or the logistics industry? One area is project management and logistics. EDF has thus hired as a project manager for its reactor project at Hinkley Point the person who was responsible for the London Olympics as these were widely regarded as a logistical and financial success. The complete traceability of components for more efficient delivery, installation and eventual replacement is another area where the nuclear industry can learn from other industries. Benchmarking and the pooling of industry experience (see the section on project management) is a third area. Overall, the distinct impression has emerged from discussions that the global nuclear industry is slowly becoming more "normal", in the sense of having to deal with the challenges of new build under conditions very similar to those of its peers. While a "special" status might have protected national nuclear champions from economic efficiency pressures in the past, today cost concerns rather than safety concerns are driving change in the nuclear industry. In this, the nuclear industry is already very similar to its peers. The next section will look at this question in the particular context of the EU megaproject programme.

III.4.1. The overall performance of megaprojects[1]

A megaproject (sometimes called a large or major project) is an extremely large-scale physical investment project of at least USD 1 billion and having considerable impacts on communities, the environment and shareholder value. They include:

- civil infrastructure projects such as railway lines, bridges, tunnels or airports;
- oil and gas projects such as refineries, pipelines or liquefied natural gas plants;
- power plants, in particular NPPs.

More often than not, megaprojects are characterised by cost overruns and delays. Several scholars have attempted to identify the reasons for such dismal performance. Bend Flyvbjerg and his group have thus studied megaproject performance in the transportation sector (Flyvbjerg, 2006) and Cantarelli has analysed 806 large projects benchmarking the performance of Dutch infrastructure vs. the rest of the world (Cantarelli et al., 2012). A study by Ansar relied on a database of 245 large dams, built between 1934 and 2007 on five continents (Ansar et al., 2014), while 318 megaprojects distributed all around the world costing more than USD 1 billion was the database used by Merrow (2011).

A common conclusion of these studies is that large infrastructure projects are characterised by large cost overruns. Flyvbjerg thus shows an average budget overrun of 44.7% for rail, 33.8% for bridges and tunnels, and 20.4% for roads. Cantarelli reports mean cost overruns of 19.8%, 34.1%, 30% and 35.5% for road, rail, bridge and tunnel projects, respectively. For dams, three out of every four large dams suffered cost overruns and actual costs were on average 96% higher than estimated costs with a median value of 27%. The Ansar study also shows that large dams take significantly longer than planners forecast. About 80% of the projects suffered a schedule overrun and construction times were on average about 44% (corresponding to two years and four months) higher than the estimate. An important conclusion from these analyses is that the accuracy of predictions, whether for cost estimates, construction schedules or even road and rail traffic forecasts, has not improved over time. Whether due to the bias introduced by tendering procedures or due to the inherent complexities of megaprojects, there is apparently little learning from past mistakes.

Ansar's research also suggests that there is no correlation between regions and cost or schedule overruns. Large dams built in every region of the world suffer systematic cost

1. This next two sections are based on a synthesis of Locatelli and Mancini (2010), Locatelli and Mancini (2012) and Locatelli et al. (2014a and 2014b), as well as on the results of the unpublished study for E-COST "The Effective Design and Delivery of Megaprojects in the European Union" by Mauro Mancini, Giorgio Locatelli and Tristano Sainati.

and schedule overruns. The analysis by Merrow shows a strong dichotomy: few projects are very successful, several unsuccessful.

> The 35% of the projects that succeeded were genuinely excellent projects. On average, they underran their budgets by 2% while delivering highly competitive (96% of industry average) costs. They were completed on time with schedules that were only slightly (4%) slower than the long-term industry average. Their average production was well ahead of the plan. By contrast, the failures are truly miserable projects: they averaged a 40% constant currency overrun while being very expensive in absolute terms. They slipped their execution schedules by an average of 28% while being 15% slower than a competitive schedule. (Merrow, 2011)

Thus far, research on analysing and comparing nuclear projects with other large infrastructure projects is limited to the work by Mancini, Locatelli and Sainati (n.d.) on "The Effective Design and Delivery of Megaprojects in the European Union", that is based on a network of about 80 researchers from more than 20 European countries. Their dataset is composed of 43 megaprojects including 20 transportation megaprojects and 12 energy projects, of which 4 are nuclear. The latter include the EPR new build projects Olkiluoto 3 (Finland) and Flamanville 3 (France), the completion of the Mohovce 3 and 4 units (Slovakia), and the upgrade of the reactors in Oskarshamn (Sweden). The overall picture is consistent with the results reported by Flyvbjerg and Merrow: megaprojects in Europe tend to be over budget and late. Although the nuclear database consists only of a very limited number of cases and all of them can be considered as FOAK projects, results show the budget overrun of nuclear projects even exceeds the overruns of other large infrastructure projects.

Reasons for cost and budget overruns in megaprojects

In explaining the budget overruns and delays in the delivery of megaprojects, the project technology (NPPs apart), location and construction date have little influence. There are, however a number of recurring features that are identified by different researchers.

Optimism bias and strategic manipulation

Wachs interviewed government officials, consultants and planners in charge of different projects and noted that their estimations were biased (Wachs, 1990). They manipulated forecasts to achieve values that were not justified in technical terms, but acceptable for their superiors to be able to implement the project. Cognitive biases and organisational pressures push managers to provide optimistic forecasts. Flyvbjerg (2006) adds optimism bias inducing promoters to consider each assumption positively. The authors point out, however, that such optimism is misleading for the promoters themselves, and not an intentional error.

Stakeholders mistakes and project characteristics

Merrow (2011) identifies seven "key mistakes" and provides a statistical analysis of the correlations between project characteristics and project performance. The seven "key mistakes" made by the key megaprojects stakeholders are: greed, schedule pressure, poor bidding phase, reductions in upfront cost, poor engineering and design, unrealistic cost estimations and poor risk allocation.

Regarding the statistical analysis, the author also shows that the following parameters have strong correlations with project performance: regulatory climate and stability, clear and coherent business objectives, quality and reliability of basic data, radical new technology, project team characteristics, quality of the front-end loading, engineering and design, remoteness of site, contractual forms, incentives, supportiveness of government, risk management, labour availability and project governance.

Project governance

Focusing on the governance of megaprojects, van Marrewijk et al. (2008) argue that the failures of megaprojects are also promoted by scope ambiguity, technical complexity and the involvement of a large number of partners with different cultures and different ways of working. According to the authors, it is possible to improve project performance through better governance and a better definition of the responsibilities of the key stakeholders involved. In particular, they refer to the so-called "control versus commitment dilemma". When the project organisation exercises dominant control, the partners lose commitment to the project. They feel that they do not have autonomy to make decisions and consider their role focused only on accomplishing the tasks they are in charge of. However, commitment is fundamental to achieve success, so it is necessary to find an optimal compromise between control and freedom.

Intrinsic complexity

Another research stream explains the cost overruns and delays of megaprojects by way of their intrinsic complexity and the complexity of the environment in which they are delivered. Compared to a "simple project" (e.g. a primary school building), megaprojects are often delivered in a project environment characterised by:

- rapid technological change and increased risks of obsolescence;
- interoperable and interdependent systems;
- emphasis on cost reduction;
- tight schedules without quality or scope reduction;
- integration issues as a high number of system parts, and organisations involved;
- combining multiple technical disciplines;
- competitive pressures.

These seven elements are typical of "complex project environments". Another metric defines a project environment as "complex" if it has at least one of the following characteristics:

- several distinct disciplines, methods or approaches involved in the project;
- strong legal, social, or environmental impacts of the project;
- the use of a high share of a partner's resources (absence of redundancy);
- strategic importance of the project to the organisation or organisations involved;
- stakeholders with conflicting needs regarding the characteristics of the project;
- a high number and variety of interfaces between the project and other organisational entities.

It is clear that these parameters often apply to megaprojects, in particular the construction of NPPs.

III.4.2. New nuclear power plants as megaprojects

Quite obviously, the construction of a new NPP is a megaproject. A typical generation III/III+ reactor will use 6 000 m^3 of concrete only for the base-mat, 61 000 tonnes of steel and 4 000 tonnes of forgings. To this must be added 5 000 valves, 200 pumps, 210 km of piping, more than 2 000 km of cabling and more than 50 000 welding seams. However, there are other large industrial projects. In this perspective, does nuclear remain special?

Assessing cost reductions and the ability of the nuclear industry to keep up with its peers over time remains a work in progress. Representatives of the EU funded Megaproject research study, who study cost and time performance of a large number of sizeable industrial projects, even dispute on the basis of their statistics that FOAK is a relevant metric. One must also be cautious with ascribing all observable impacts to the internal economies or diseconomies of the reactor builder. As pointed out by Vanbrugh consulting, reactor costs really did come down during the 1990s in many countries. As far as the subsequent cost increases during the first decade of the 21st century are concerned, external factors such as increases in the price of steel, specialised labour and energy played a significant role. Not everything can be controlled. Only two thirds of the costs can be considered as firm at the time of signing the contract; the rest is variable. Fortunately, external influences can go either way. The US DOE thus reported that current outlays at the AP1000 project at the VC Summer plant in South Carolina are *below* projections due to lower than expected financing costs. The current cost of debt is thus 5.7% on average, with a latest tranche of USD 400 million having been placed at 4.6% in June 2013, more than compensating a slight increase in overnight costs. The industry also no longer experiences serious bottlenecks in key components. Even in the area of high-value segment of large forgings such as the reactor vessel, global supply is currently sufficient, with Japan alone being able to satisfy three quarters of global demand.

The research of Flyvbjerg, Merrow and the Megaproject group mentioned above, however, suggests that cost escalation in the nuclear sector might be even higher than elsewhere, in particular looking at the two new European projects Olkiluoto 3 and Flamanville 3. On the other hand, the history of the Korean nuclear programme until its recent brush with quality control issues can be considered an unqualified success. Nuclear programmes seem to display a dichotomy of performance that is stronger than with other type of megaprojects.

Several factors make the projects of building new nuclear reactors unique. Comparing the construction of nuclear reactors with other megaproject (e.g. a new defence system or an international high-speed railway) point to a number of peculiarities, including:

- The “safety issue”. A failure/accident in a solar, wind or even coal plant has very local “short-term” consequences, while a nuclear accident can cause a major disaster with a long time-scale. The design and construction of safe reactors is possible, but requires very high quality standards. They also require extreme specialisation with bottlenecks in particular for FOAK projects.
- The variety of disciplines and provenance of the workforce. The design and construction of an NPP include virtually all kinds of hard engineering skills (from civil to mechanics) and managerial skills (finance, project management, health and safety). Moreover, the design and construction involves thousands of people from multiple countries on the site. The blend of disciplines, cultures, languages (and even standards and certifications) represents an extraordinary challenge for organisation. This was a critical aspect at Olkiluoto 3.
- Stakeholder scrutiny. Compared to a large offshore wind farm, the construction of an NPP will attract much more attention from safety authorities, but also the press, political or environmental groups.

The following section focuses on the cost and schedule performance of NPPs. It provides three case studies of nuclear new build at Shoreham (United States), Olkiluoto and Flamanville (Finland and France) and in Korea, and discusses the key lessons learnt.

Shoreham nuclear power plant

The Shoreham NNP was a 820 MW BWR located adjacent to the Long Island Sound in East Shoreham, New York. The plant was built between 1973 and 1984, commissioned, but never operated. The cost famously escalated from USD 75 million to USD 5.5 billion, a factor of roughly 70. Ross and Staw (1993) identify some of the reasons behind this spectacular cost overrun:

- Objective difficulty to estimate the real cost of such a complex and innovative project, in particular as scope creep set in due to legislation changes.
- Sunk cost trap: cost estimates rose exponentially during the project. The US dollar value of each increase was a relatively small percentage of previous expenditures. In addition, most of the expenditures took place when the plant was already 80% completed. Having a nearly completed physical structure probably increased the willingness to invest additional funds.
- Investment lock-in: greater and greater percentage of owner and bank capitals were tied to Shoreham, the plant and the future of the utility became intertwined. The project turned into a "bet-the-company" proposition.
- Psychological determinants included optimism bias, "winner will always win" attitude and a blame culture in which abandoning the project would be shameful for the project team.
- Social determinants may have included cultural factors such as the fact that American society reserves special praise for those who stay a course in the face of hardship, or mimetic behaviour: the company that owned Shoreham was one of the few major utilities in the United States not to have a nuclear power component. They wanted an NPP.
- Organisational determinants: the decision to embark on the construction of an NPP mainly involved people whose primary asset was expertise with nuclear power. Increasingly, the company placed all its hopes in the nuclear basket.
- Contextual determinants: The decision to construct a nuclear plant became larger than the organisation itself, involving forces beyond the organisation's boundaries, such as political supporters. The role of these external parties and their alliances with the owner cannot be overemphasised.

European new build: Olkiluoto and Flamanville

Locatelli and Mancini focus their analysis on the EPR new build projects Olkiluoto 3 and Flamanville 3 (Locatelli and Mancini, 2012). By examining Olkiluoto 3 and Flamanville 3 for points of similarity, it is possible to posit that the causes of cost over budget and delay can be grouped into the two meta-themes of: *(i)* FOAK effects in a highly regulated environment; and *(ii)* over-optimistic forecasts.

FOAK effects for megaprojects

It may seem strange to define two EPR construction projects using the same technology of FOAK projects. However, even if the technologies are the same, the two projects are executed by separate supply chains, parts of which were unfamiliar with the regulatory context, and each one of which experienced its own significant FOAK issues.

In nuclear engineering projects, the architect/engineer plays a key role in the performance of a project particularly in terms of managing project information. In the case of Olkiluoto 3, AREVA was, for the first time, the architect/engineer of a nuclear construction project. In the case of Flamanville 3, EDF has a long history of having built and commissioned 44 GW of nuclear capacity. The last unit built in France however started commercial operations in 2002, although construction had been completed in 1999. The EPR is a new technology and caused many FOAK issues even for an experienced architect/engineer such as EDF. Furthermore, EDF used a new and untested supplier network. FOAK effects in the supply chain were thus in evidence in both cases. In Flamanville 3 and in Olkiluoto 3, the regulatory authorities (the Nuclear Safety Authority [ASN] and Finnish Radiation and Nuclear Safety Authority [STUK] respectively) held up construction because of the insufficient quality of the work undertaken by inexperienced contractors (Ruuska et al., 2009).

Over-optimistic forecasts

In both projects, the original estimates were significantly below the actual time and resources required. Grubler argues that the initial 2005 forecast for the EPR at Flamanville was too optimistic if compared to the previous costs of reactors built in France, in particular considering that an increase in size increases construction time, and the EPR is the largest reactor ever built. Moreover, the EPR is based both on the German Konvoi reactor and the French N4 reactor. Already, building the N4 reactor had proven difficult as it faced numerous technical difficulties, substantial delays, and by French standards, significant cost overruns. Looking at the values for the N4 reactor in Table 29 and in Figure 41, it becomes clear that the initial forecasts were too optimistic. The previous reference reactors had been completed in about ten years during an era in which dozens of reactors had been built, when the entire project delivery chain was experienced and FOAK effects had been minimised.

The new EPRs are bigger, more complex and built by inexperienced supply chains. Nevertheless, the initial estimation forecasted a 50% reduction in the construction schedule. The forecasts for both Flamanville 3 and Olkiluoto 3 clearly demonstrated optimism bias. EDF Energy (a UK company owned by EDF) has now advanced plans for the construction of two EPRs in Hinkley Point (Somerset, England). EDF Energy applied for consent to construct and operate the two EPRs in October 2011. In October 2013, the government announced that initial agreement had been reached with EDF Energy on the key terms of a proposed GBP 16 billion investment contract for the Hinkley Point C nuclear power station. The sum of GBP 16 billion corresponds to EUR 20 billion, a number not very far from the current and possibly final estimates for the total combined costs of Olkiluoto 3 and Flamanville 3. The new cost estimates are thus consistent with a "reference class forecast" approach.

Table 29: Cost and construction times of N4 and Konvoi reactors

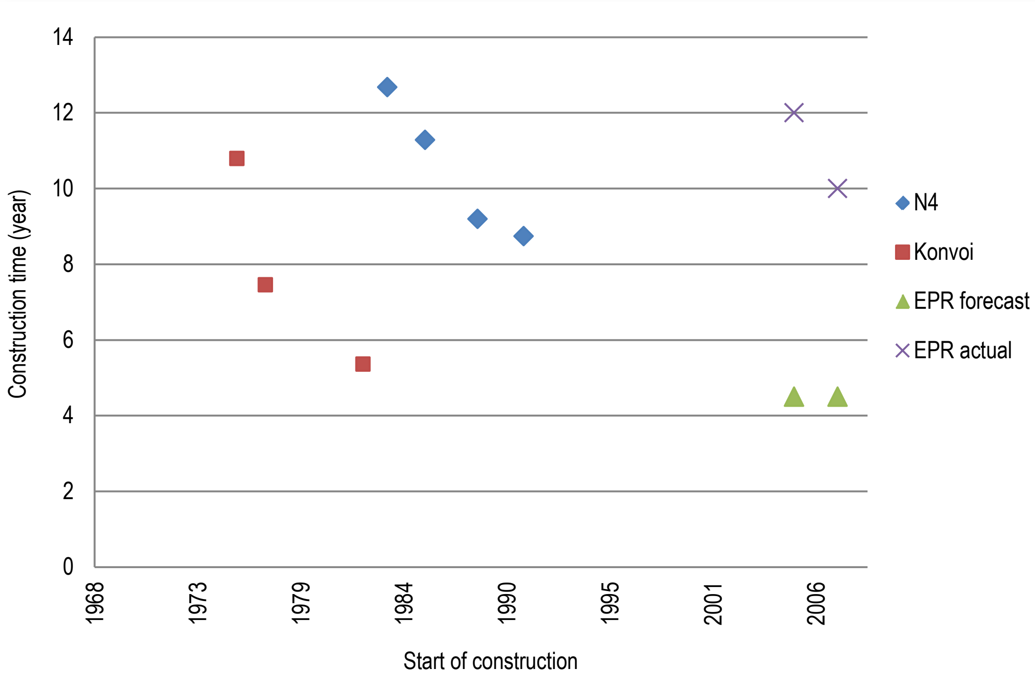
Type	Location	Net capacity (MW)	Construction started	Connected to grid	Commercial operation	Constr. time (years)	Cost[1]	Cost[2]
N4	Ardennes	1 500	01/1984	08/1996	05/2000	12.7	2.41	5.01
N4	Ardennes	1 500	12/1985	04/1997	09/2000	11.3	2.56	5.32
N4	Vienne	1 495	10/1988	12/1997	01/2002	9.2	2.56	5.32
N4	Vienne	1 495	04/1991	12/1999	04/2002	8.7	4.82	10.02
Konvoi	Brokdorf	1 410	01/1976	10/1986	12/1986	10.8	n.a.	n.a.
Konvoi	Philippsburg	1 402	07/1977	12/1984	04/1985	7.5	n.a.	n.a.
Konvoi	Isar	1 410	09/1982	01/1988	04/1988	5.4	n.a.	n.a.

1. Historic, EUR billions.

2. EUR billions in 2011.

Source: IAEA, 2014 and Grubler, 2010.

Figure 41: Construction times in comparison



The Korean experience

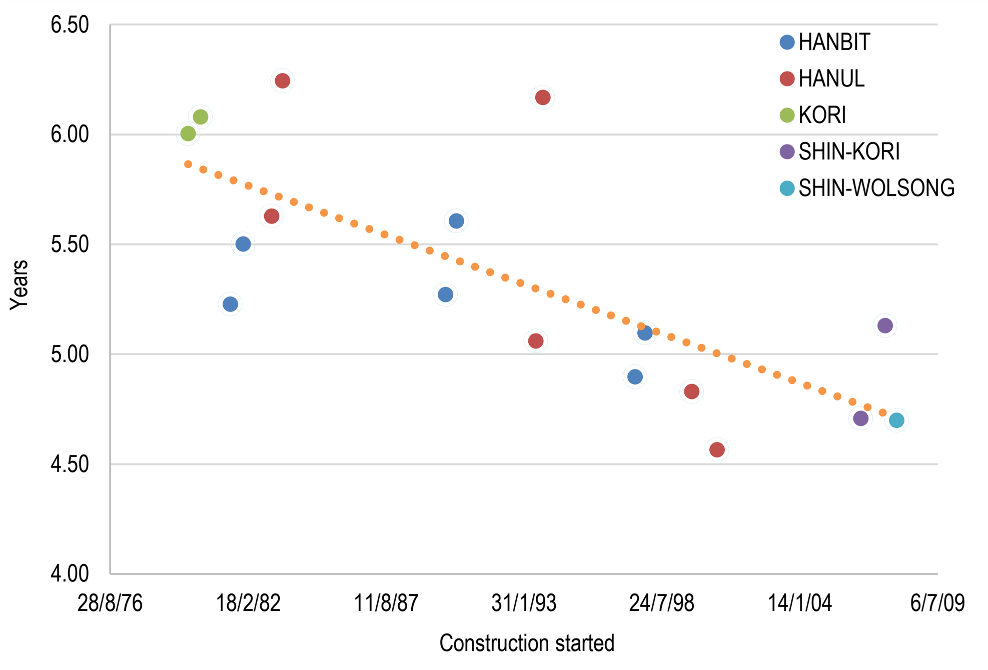
Nuclear experts agree that the (pre-2000) French and Korean NNB programmes are success stories. In both countries, a cohesive group of organisations constituted the project delivery chain and, after the definition of a standard design, successfully delivered several power plants. These countries established network relationships to deliver a "nuclear programme" (i.e. several, almost identical, reactors) rather than individually commissioned power plants. Most of the time, the architect/engineer and the subcontractors were able to deliver the reactors on time and on budget, the French N4 reactors being an exception.

In large projects, especially in the nuclear field, a key strategy to achieve good performances appears to be the standardisation of the project delivery supply chain and reactor design (Locatelli et al., 2014b). This is an insight that applies well to the Korean new build programme. Figure 42 shows the very good performance in terms of construction times of the Korean nuclear programme (IAEA, 2014).

In addition to standardisation, Choi, et al. (2009) summarise a number of lessons to explain the success of the Korean experience:

- integration of extensive knowledge and experiences;
- strong national commitment to the nuclear power programme;
- continuous investment in the infrastructure with government leadership;
- localisation through technology transfer (as discussed above);
- clear definition of responsibilities and rights in the NPP construction.

Figure 42: The Korean pressurised water reactor programme



Concluding considerations on delivering successful megaprojects

In order to enable the realisation of complex systems, such as an NNB project in multidimensional environments, multidisciplinary approaches such as system engineering are required. The latter provides a somewhat broader approach to classic project management and includes aspects such as shared leadership, social competence and emotional intelligence, communication, skills in organisational politics and the recognition of the importance of visions, and values. The modern origins of system engineering can be traced to the 1930s, but the first significant developments were in the early 1950s when the US Department of Defence needed to deliver large, complex projects respecting time, budget and quality.

To achieve these ambitious targets, standard project governance was no longer enough and "project governance" had to evolve into "system governance". The focus of system engineering is in particular on the earlier project stages. These stages are the project definition (scope management), project stakeholder management and project planning (all aspects related to the project governance). These are key aspects in the nuclear field, and include the decision on the reactor size (a multidimensional problem requiring the evaluation of several aspects), the definition of the best supply chain configuration for the local culture and political configuration (including all external stakeholders), or the realistic overall plan without biases from personal or ideological interests.

The nuclear sector presents the highest level of technical complexity compared to other industrial sectors such as oil and gas, pharmaceuticals or food manufacturing, which makes paying attention to managerial topics particularly important. When analysing both the past performance of nuclear projects and nuclear incidents, most of them can be traced back to managerial mistakes, not to technical ones. In the past, these considerations were addressed by giving managerial positions in the nuclear delivery chain to very good managers coming from other sectors. However, the peculiarities of the nuclear industry cannot be fully appreciated with just theoretical training. On-hand experience remains a fundamental asset.

Increasing the organisation and managerial quality of the nuclear sector must remain a long-term objective, even if it is not a simple and quick process. The managerial evolution of the military and aerospace supply chain can be considered as a benchmark, since they are from an organisational point of view comparable to the nuclear industry.

However, very clearly there is no magic bullet. Megaprojects are frequently over budget and late all over the world in many different sectors. There has been little or no improvement over the decades. Project performance today is roughly similar to ten, twenty and thirty years ago. On the other hand, even if public opinion and the press are focusing on nuclear projects being over budget and late, such poor performance is not a fatality. The Korean and the (pre-2000) French experience shows that it is possible to deliver nuclear projects on time and budget. Key success factors are the replication of existing reactors, a relative monoculture, a stable environment with experienced stakeholders and a long-term view. Some of these factors may no longer be replicable and the most promising way forward may be to start learning from other high technological sectors such as aerospace or oil and gas, where a number of major companies have evolved from national champions to global competitors.

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Chapter III.5.

Case studies on logistics and project management

III.5.1. Case study of Flamanville 3, Taishan 1 and 2, and Hinkley Point C 1 and 2[1]

Presentation of EDF group

EDF group is the French leader in energy production, transport and supply. Since 2004, the group has become a publicly listed joint-stock company with 84% of its shares still held by the French government. EDF manages a broad portfolio of electricity generation technologies with a large share of its production stemming from nuclear energy. According to 2012 data, EDF is the global leader in nuclear power generation.

EDF manages all French NPPs which are located in all French regions, except in Brittany. Table 30 provide an indication of the distribution of French NPPs and their capacity.

Table 30: Distribution of French nuclear power plants and their capacity

Class	Reactor	MW net each	Commercial operation
900 MWe	Blayais 1-4	910	12/81, 2/83, 11/83, 10/83
	Bugey 2-3	910	3/79, 3/79
	Bugey 4-5	880	7/79-1/80
	Chinon B 1-4	905	2/84, 8/84, 3/87, 4/88
	Cruas 1-4	915	4/84, 4/85, 9/84, 2/85
	Dampierre 1-4	890	9/80, 2/81, 5/81, 11/81
	Fessenheim 1-2	880	12/77, 3/78
	Gravelines B 1-4	910	11/80, 12/80, 6/81, 10/81
	Gravelines C 5-6	910	1/85, 10/85
	Saint-Laurent B 1-2	915	8/83, 8/83
	Tricastin 1-4	915	12/80, 12/80, 5/81, 11/81
1 300 MWe	Belleville 1 and 2	1 310	6/88, 1/89
	Cattenom 1-4	1 300	4/87, 2/88, 2/91, 1/91
	Flamanville 1-2	1 330	12/86, 3/87
	Golfech 1-2	1 310	2/91, 3/94
	Nogent-sur-Seine 1-2	1 310	2/88, 5/89
	Paluel 1-4	1 330	12/85, 12/85, 2/86, 6/86
	Penly 1-2	1 330	12/90, 11/92
	Saint-Alban 1-2	1 335	5/86, 3/87
N4-1 450 MWe	Chooz B 1-2	1 500	12/96, 1999
	Civaux 1-2	1 495	1999, 2000
	Total (58)	63 130	

Source: EDF.

1. This case study was prepared by Philippe Leigné and Valérie Levkov, EDF Group (2014a, 2014b).

Nuclear power in France has a total capacity factor of around 77%, which is comparatively low due to load following. However, availability is around 84%, indicating very good overall performance of the plants. EDF is currently anticipating the potential renewal of its NPPs in the 2020s as several PWRs will reach the end of their originally anticipated lifetimes.

The contribution in this case study is based on the experience feedback ("REX" in French) from ongoing PWR conception and operation processes. Several years ago EDF had in fact taken the decision, approved by government, to launch a generation III/III+ power plant at an existing site in Flamanville (Manche), close to Cherbourg. Two existing units on the same site had started production in 1985 and 1986. Earthworks would be minimal because the site was already laid out to receive two additional units. The initially planned date of commissioning of the Flamanville 3 EPR was 2012, but completion at the date of publication was scheduled for 2017. An additional EPR was planned for the Penly NPP, but this project has now been abandoned. EDF is currently in the process of deciding whether to go ahead with the construction of two new EPRs at Hinkley Point C in the United Kingdom.

Presentation of the EPR

The EPR is a new generation III/III+ PWR with a power generation capacity of 1 650 MW, which places it among the most powerful reactors in the world. It was previously called the European pressurised reactor or evolutionary power reactor, but now it is simply referred to as the EPR. The EPR was developed by AREVA on the basis of the last models manufactured by EDF in France, the N4, and the Konvoi by Siemens in Germany. The EPR is thus an evolutionary design based on well-established technologies and principles.

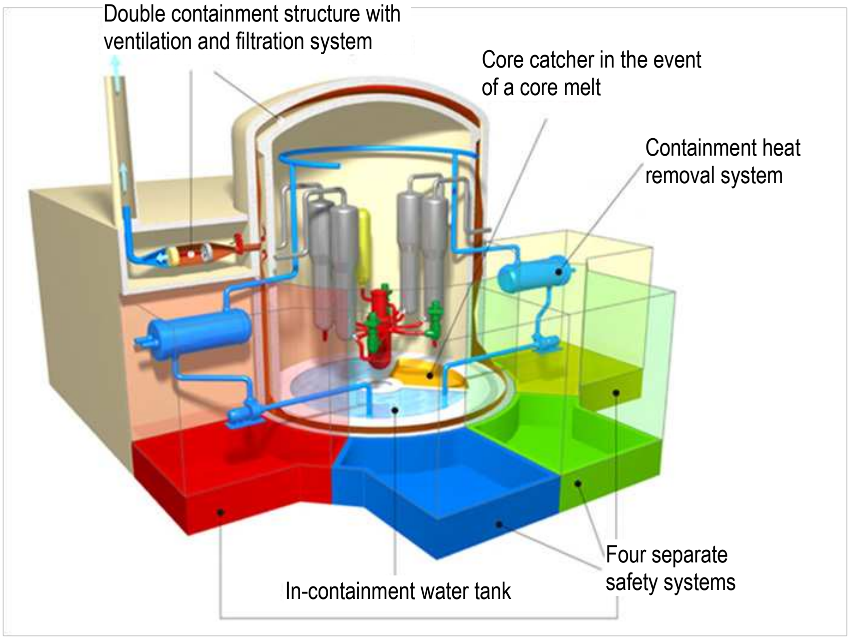
From a safety point of view, the EPR ensures a very high level of safety thanks to diversified, redundant, active and passive safety systems to drastically reduce the probability of severe accidents compared to existing generation II reactors, while ensuring that there is no impact on the surrounding area. In particular, it is highly resistant to external incidents (e.g. a large commercial airplane crash) and features multiple protected power sources and water reserves. Through an improved thermal efficiency of 37%, the EPR also achieves a reduction in uranium consumption of about 15% per MWh compared to older generation II reactors and a concomitant reduction in the production of long-lived radioactive waste. The EPR has 241 fuel assemblies, compared to an average of 264 assemblies in previous designs, and can use both uranium or mixed oxide (MOX) fuels. Its technical availability is expected to be at 92%.

The main design objectives of the generation III/III+ EPR design are increased safety and enhanced economic competitiveness through improvements to previous PWR designs. As shown in Figure 43, the EPR design has several active and passive protection measures against accidents:

- four independent emergency cooling systems, providing the required cooling of the decay heat that continues for one to three years after the reactor's initial shutdown (i.e. 300% redundancy);
- leak-tight containment around the reactor;
- an extra container and cooling area if a molten core manages to escape the reactor (see containment building);
- two-layer concrete wall with a total thickness of 2.6 m, designed to withstand impact by airplanes and internal overpressure.

The EPR has a design maximum core damage frequency of 6.1×10^{-7} per plant per year.

Figure 43: Reactor building design



Source: EDF.

Supply Chain

EDF is well known for NPP construction management. Its EPR projects aims at working with industrial partners capable of working to the highest standards. Moreover, EDF is committed to collaborate with local, regional and national companies to generate new competencies at all levels around its reactor projects.

Flamanville 3

EDF uses the established skills of French companies, both local and multinational in Flamanville 3. Key supply companies are:

- AREVA NP for the nuclear boiler as well as monitoring, control and command systems;
- DTP for preparatory works;
- Bouygues for civil engineering;
- Alstom for the turbo generator group;
- Endel/Boccard for nuclear piping;
- Spie/Cegelec for electrical installations;
- Vinci/Soletanche for seaworks.

Taishan

EDF is working closely with French companies that have established know-how in the Taishan project. Numerous joint-ventures allow for co-operation with local companies. Key elements of the supply chain and the construction process for the EPRs at Taishan 1 and 2 are:

- AREVA NP subcontracted EGIS Industries for the design of civil works for the first two units of the plant.

- Sany supplied the crawler crane for the plant's construction.
- Vinci Construction is providing technical assistance in construction.
- The reactor pressure vessel was manufactured by Mitsubishi Heavy Industries (MHI), which delivered the vessel to AREVA in February 2012.
- The internal parts for the EPRs are being manufactured by Skoda (now Doosan Skoda) under a subcontract with AREVA signed in July 2009.
- The heat exchangers for phase I are supplied by DCNS, under a contract awarded by the Chinese Nuclear Power Engineering Company (CNPEC) in 2008.
- Baosteel was contracted by Dongfang in August 2010 to supply 510 t of high value-added steel plates for manufacturing the turbine generators.
- ABB Xiamen Switchgear Company and ABB Xiamen Low Voltage Equipment Company are involved in the design and supply of the switchgears and circuit breakers for the plant.
- Seven Trent Services will supply its chlorine dioxide generator for the water purification system of the plant to avoid algae and slime growth in the cooling system.

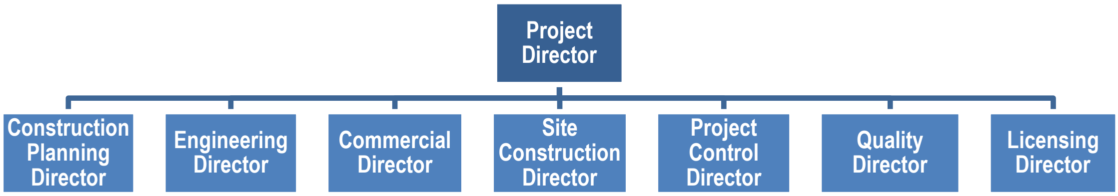
Hinkley Point C

The Hinkley Point C projects will benefit from the experience of both British companies such as Kier Bam and Laing O'Rourke, and French companies such as AREVA and Bouygues. The UK supply chain brings knowledge of the national regulatory and construction environments, along with recent proven experience of delivering large infrastructure projects such as the Olympic Park. French companies have extensive experience and expertise in EPR technology and nuclear construction projects from all over the world. Many other companies, including small and medium-sized enterprises in both countries, are also gearing up to participate in the project. Working together, companies based in the United Kingdom and France could potentially gain more than 80% of the value of the construction project.

Management structure

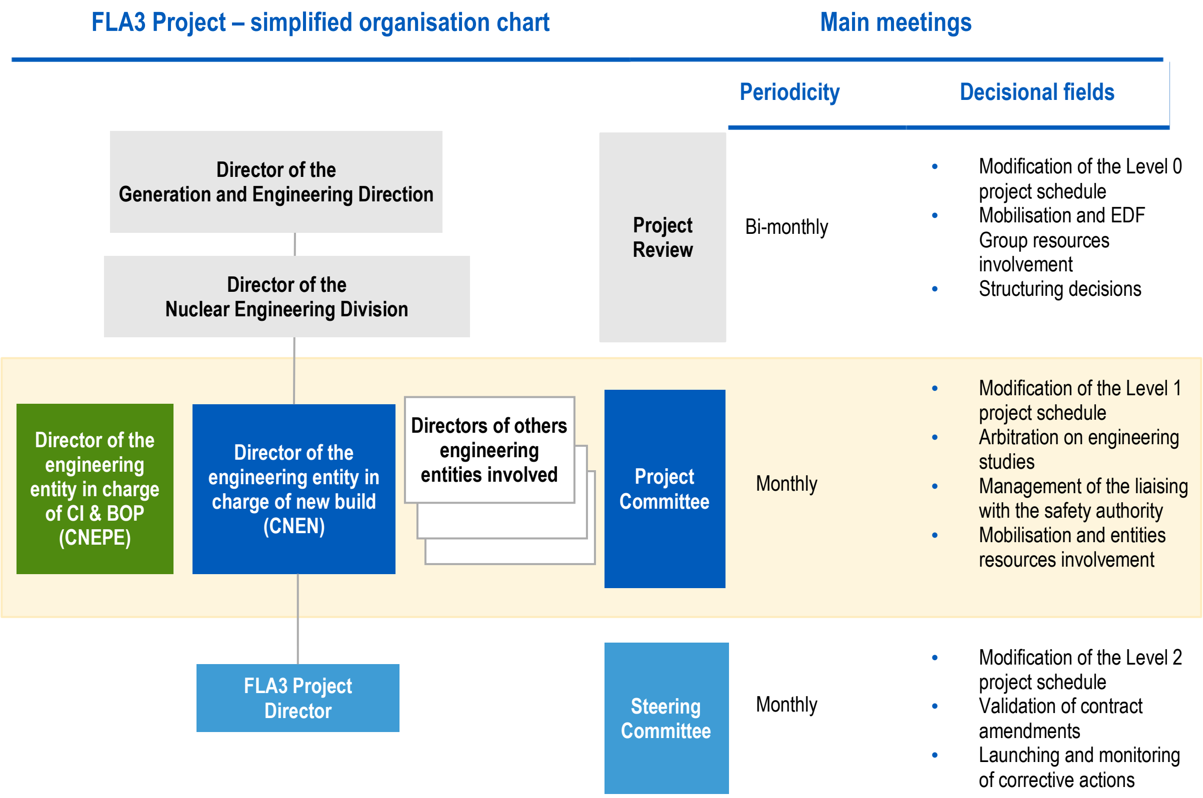
Figures 44, 45 and 46 show the management structures of the three projects reflecting their different needs and institutional environments.

Figure 44: Hinkley Point C project leadership team



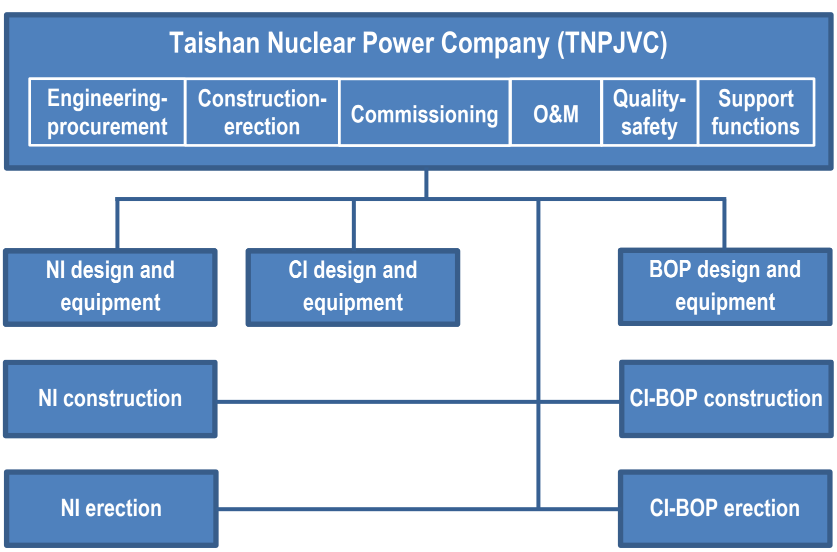
Source: EDF.

Figure 45: Flamanville 3 project organisation chart



BOP: Balance of plant; CI: Conventional island.
Source: EDF.

Figure 46: Taishan 1 and 2 project department



BOP: Balance of plant; NI: Nuclear island; CI: Conventional island.
Source: EDF.

ISO 9001 and 14001

ISO 9001 is an international quality management system (QMS) standard. It presents fundamental management and quality assurance practices that can be applied by any organisation. On their own, few practices demanded by ISO 9001 would be considered world-class. However, the requirements represent an excellent foundation for planning, control, and improvement. EDF is ISO 9001 certified.

The ISO 14000 family addresses various aspects of environmental management and provides tools for identifying and controlling environmental impacts and improving environmental performance. ISO 14001 is an environmental management standard. It specifies a set of environmental management requirements for environmental management systems. As EDF is committed to respect the highest norms and standards for its NPPs, the EPR is certified ISO 14001.

Licensing, design, pre-construction, logistics and procurement

Flamanville 3

First concrete was poured in December 2007. Before preparatory work, the basic design was prepared for the licensing process. The EPR project co-operates with a qualified industrial supply chain. Flamanville 3 collaborated with more than a hundred subcontractors in various domains. There were 150 main contracts; the 20 biggest subcontractors (AREVA, Bouygues) represent 80% of the total budget issued by EDF. Procurements were made according to the components' delivery time; EDF anticipated deliveries in a manner that had them arrive at the appropriate moment in order to allow project advancement. The same processes are used for each EPR project, as shown by the examples below. In May 2006, forged components had been delivered before the project's first concrete in December 2007.

Taishan

The Taishan project was scheduled in two parts. The first part is dedicated to design and preparatory work including basic and detailed design. Its duration was estimated at 24 months. Following preparation, the date for first concrete was 1 September 2009 for the conventional and the nuclear island.

In June 2009, several months before first concrete, procurements for 30% of total CNPEC supplies and 70% of total AREVA supplies had been completed to ensure a smooth start of the project.

Hinkley Point C

The Hinkley Point C project began when the authorities of Somerset approved site preparation in 2011. Two years later, in 2013, the project received administrative approval from the UK government and construction could begin. On 6 May 2014, preparatory works began on the Hinkley Point C project. In autumn 2014, the European Commission accepted the principal elements of the agreement between EDF Energy and the UK government for the CFD based on a fixed strike price of GBP 92.50 for the output of the first reactor at Hinkley Point C. The final investment decision by EDF is expected before the end of the year 2015.

The Hinkley Point C project is beginning preparatory work. Subcontractors were chosen by competitive processes, except for the nuclear steam supply system where AREVA was chosen as supplier. The goal was to ensure reliability of components and supplies for improved overall efficiency. Each supplier provides its own quality programme, approved and regularly monitored by EDF.

Workforce management

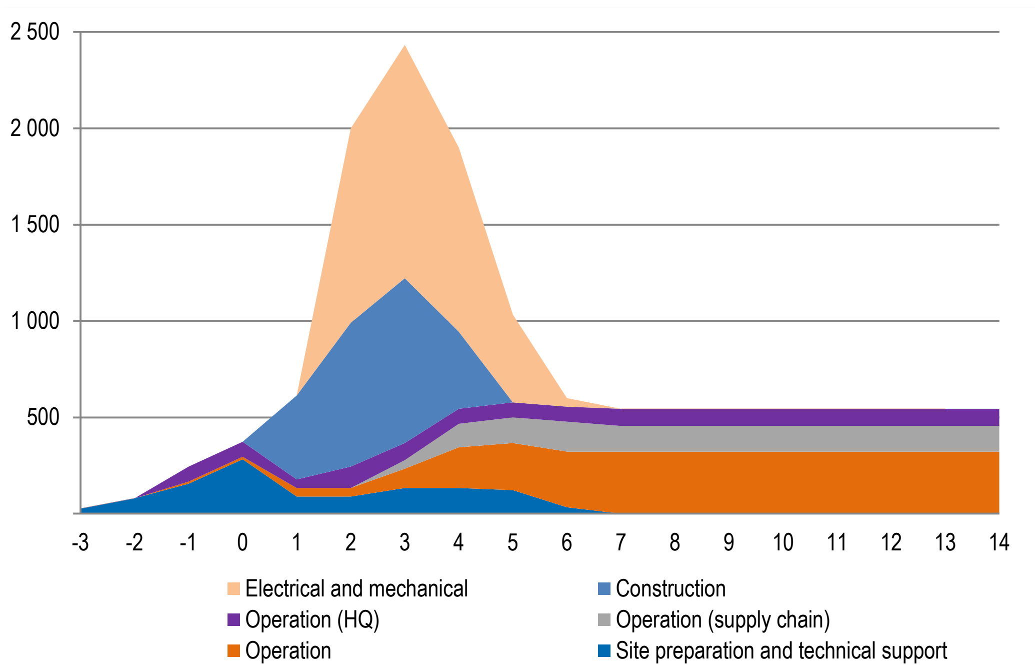
EDF-EPR capitalises skills from everywhere in the world. However, when the company launches such a project, local workers are trained to benefit from NPP construction. EDF is committed to transfer knowledge, training and information to local workers and inhabitants.

EPR Flamanville will employ over 3 500 employees at its peak. Knowledge and benefit transfer is expressed in this area as 40% of total workers in the project being local staff with appropriate training. Moreover, indirect jobs will be created. According to the lower estimation of EDF in 2016, the plant will employ about 900 people for operations and maintenance, as well as hundreds of indirect and induced jobs created by the NPP's daily operations (accommodation, catering).

Hinkley Point C will employ 25 000 people during the course of its construction with 5 600 employees on-site at its peak and 900 after completion for operations and maintenance. More than 1 200 firms from Somerset and 550 British companies have registered a formal interest in working on the project.

New nuclear construction projects, in particular for EPRs, require careful attention to manpower management over time due to their sheer size. The total number of worked hours at the Flamanville 3 project up to 2014 for instance was about 27 million man-hours (see Figure 47).

Figure 47: Required man-hours for different tasks during construction
(in thousands per year)



Source: EDF.

Institutional issues

The construction of the EPR at Flamanville is conducted under the supervision of the French nuclear regulatory body, the Nuclear Safety Authority (Autorité de Sûreté Nucléaire or ASN), with technical support from the French Institute for Radiation Protection and Nuclear Safety (Institut de Radioprotection et de Sûreté Nucléaire or IRSN).

These institutes organise regular evaluations of the advancement of the Flamanville 3 project and they can, if necessary, halt construction and force EDF to change its construction process. Site layout, concrete works and steel containment layers were criticised several times by the regulator, and these partly explain the delay of the project.

Before the start of construction at Flamanville 3, a public debate was organised so as to inform the public about the EPR project and its benefits. As part of this debate, 21 public meetings were organised between October 2005 and February 2006, both nationally and locally.

Experience feedback

Experience feedback consists of improving methods and processes to enhance safety and efficiency. Thanks to this approach, EPR construction today benefits from 30 years of experience feedback from previous NPP construction and operations.

In the case of the EPR, experience feedback covers design, engineering and construction. Safety was the top-priority in EPR design. While an accident for a classical NPP would be less likely than a meteorite fall, it would be ten times less so for an EPR. The reactor building was designed so as to prevent core meltdown reaching the containment building. Even in the case of a rupture of the sealing, an unlikely event in itself, the melted combustible cannot escape from the reactor.

This approach of continuous improvement has been extended to construction where experiences with problems or good practices are transferred from the Flamanville EPR site to Taishan and Hinkley Point. It also includes a continuous monitoring of the existing fleet to make sure that the likelihood of any event affecting safety or productivity is kept as low as possible.

Lessons learnt from Flamanville 3

EDF has created a dedicated experience feedback project from Flamanville 3, with three key objectives:

- the analysis of encountered difficulties during detailed design, manufacturing and construction processes;
- after analysis, the issuance of feedback sheets providing information on the situation for Flamanville 3 and proposed solutions for the future project;
- modifications assessed to simplify the EPR design and improve the construction methods.

This has allowed both an assessment of aspects that worked well in the Flamanville 3 positive project as well as those that need to be improved in future EPR projects.

What worked well in Flamanville 3 include:

- the complete use of 3D mock up to manage the entire layout interfaces (civil, piping, cabling, ducts);
- the development of a simulator for validation of the process and the operation documentation;
- in-factory surveillance of off-site manufacturing;
- the involvement of local companies and the recruitment of local workers.

Aspects that require further improvement include:

- the degree of specialised experience and competence in the nuclear field of the workforce such as the knowledge of codes and standards;
- beyond the selection of suppliers, a need to organise the subcontracting chain;

- completion of basic design and a significant part of detailed design before the beginning of construction;
- the improvement of individual construction processes such liner erection or anchor plates.

Lessons learnt from Taishan 1 and 2

The reference design for the Taishan EPRs is the Flamanville 3 plant currently under construction in France. At the very early stage of the project, EDF had taken the lead in the licensing process with the Chinese regulatory authorities and today the current process between the Taishan Nuclear Power Company (TNPJVC) and the National Nuclear Safety Administration of China (NNSA) can still benefit from the licensing process for this reactor design in Europe (both in Finland and France) and the experience gained from Daya Bay and Lingao.

Early phases of construction have also benefited from the European experience. AREVA has provided experience feedback and analysed more than 1 000 lessons from its ongoing and previous projects – most of them coming from Finland – and has been able to leverage these lessons by employing staff with prior experience. As part of the experience feedback process, it was ensured that in the Taishan 1 and 2 projects a significant part of Taishan employees had already worked for the Olkiluoto 3 or the Flamanville 3 project.

Base-mat concrete pour was thus successfully completed in a single pour on unit 1, halving the time from two months to one month in comparison with previous EPR projects (Olkiluoto 3, Flamanville 3). Moreover, the time taken for initial pouring was reduced between the two units, going from 80 hours for unit 1 to 68 hours for unit 2, showing ongoing improvement one project to the next due to the increased experience of the workforce.

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III.5.2. Case study of the Shimane-3 and Kashiwazaki-Kariwa 6 and 7 nuclear power plants in Japan

General description

Before the Fukushima Daiichi accident in March 2011, nuclear energy in Japan accounted for almost 30% of the country's total electricity production of 47.5 GW of capacity (net). There were plans to increase this to 41% by 2017, and 50% by 2030. Today, Japan has 48 reactors totalling 42 569 MW that are in principle operational. An additional three reactors, Shimane-3, Ohma-1 and Higashidori-1, with a combined capacity of 4 141 MW, are under construction. One reactor (Monju, a fast sodium-cooled reactor) is in indefinite shutdown, and twelve reactors with a combined capacity of 16 532 MW are planned. In 2010, the first of those now operating reached their 40-year mark (when it was presumed that it would close down). Some licence extensions have been approved. For example, the licence for Fukushima Daiichi was extended in early 2011. In March 2011, units 1-4 of the Fukushima Daiichi plant were seriously damaged in a major accident, and were hence written off and are being decommissioned, which removed 2 719 MW from the country's system (WNA, 2014a).

Following the Fukushima accident, 17 out of Japan's 50 remaining NPPs were operating, but this number steadily dwindled to zero. In October 2011, the government published a White Paper proposing that "Japan's dependency on nuclear energy will be reduced as much as possible in the medium-range and long-range future". In September 2012, an Energy and Environment Council set up by the cabinet office as part of the National Policy Unit, released the "Innovative Energy and Environment Strategy", recommending a phase-out of nuclear power by 2040. In December 2012, after a decisive victory in national elections for the Diet's Lower House, the Liberal Democratic Party took a more positive view of restarting idled NPPs and a nuclear policy than its predecessor. The new government said it would take responsibility for allowing reactor restarts after the Nuclear Regulatory Authority issues new safety standards and confirms the safety of individual units. As a result, construction of the new NPPs of Shimane unit 3 and Ohma unit 1 was approved to continue (WNA, 2014a).

Unit 3 at the Shimane Nuclear Plant Station (hereafter Shimane-3) has been under construction. It will be one of the largest plants (1 373 MW) and the 5th advanced BWR in Japan. After issuance of the first construction licence in December 2005, the excavation of main buildings started in 2006, and construction had been progressing smoothly. Shimane-3 was planned to enter commercial operation in December 2011, but this was delayed to March 2012 because the CRDM had to be returned to the manufacturer for modification and cleaning. In March 2011, after the Fukushima accident, the construction was suspended and the start-up date was then deferred until evaluation of the Fukushima accident could be undertaken. The Chugoku EPCO finished building a 15 m high sea wall in January 2012, and planned to extend the seawall by 2013 to a total length of 1.5 km so as to also protect Shimane units 1 and 2. On 15 September 2012, the Ministry of Economy, Trade and Industry (METI) approved the construction and restart of nuclear plants, including Shimane-3 (94% complete) and Ohma (38% complete), but plans to start commercial operation have not yet been announced.

The Chugoku EPCO plans to build two Kaminoseki ABWR nuclear power units on Nagashima Island on the Seto Inland Sea Coast in Kaminoseki Town, Yamaguchi Prefecture. Some site work commenced but then halted after the Fukushima accident – 40% of the site is to be reclaimed land. The small island community of Iwaishima a few kilometres away has long opposed the plant. In October 2012, the Chugoku EPCO confirmed its intention to proceed (WNA, 2014a).

The development of the ABWR started in 1978 as an international co-operation between five BWR vendors: GE of the United States, Hitachi and Toshiba of Japan, and European BWR vendors. This conceptual design was received favourably by TEPCO and other Japanese utilities, and as a result, the ABWR was included in the third standardisation programme of Japan from 1981. Preliminary design and numerous development and verification tests were carried out simultaneously by Toshiba, Hitachi and GE together with six Japanese utilities and the Japanese government. From 1987, GE, Hitachi and Toshiba started project engineering, detailed design and preparation of licensing documents for the Kashiwazaki-Kariwa nuclear power station units 6 and 7, which were then ordered by TEPCO from this international consortium (ICONE 17, 2009).

Four ABWRs are already operational at NPPs in Japan. TEPCO's Kashiwazaki-Kariwa units 6 and 7 were the first ABWRs (of 1 356 MW), which started up in 1996-1997 and are now in commercial operation. Two further ABWRs – Hamaoka 5, Shika 2 – are also operational. Hamaoka 5 (Chubu Electric Power Co., Inc.) started construction (first concrete) in July 2000 and commenced commercial operation in January 2005. Shika 2 (Hokuriku Electric Power Co.) started construction (first concrete) in August 2001 and commercial operations in March 2006. Two more are currently under construction, the Shimane-3 Nuclear Power Station of the Chugoku EPCO and the Ohma Nuclear Power Plant of Electric Power Development Co., Ltd. The commercial operation and annual outage experience of ABWRs have been very satisfactory.

Through a competitive bidding process, Taiwan Power Co. (TPC) selected the ABWR for its two unit Lungmen project. GE designed and provided the scope of supply for the two 1 350 MW ABWR. Construction began in 1999 and commercial operation for the two units was scheduled originally for 2006 and 2007. When the two reactors were one third complete, a new cabinet cancelled the project, but work resumed the following year after a legal appeal and a government resolution in favour of resuming the work. A date for completion of the first unit was to be announced early in 2012 – in June it was undergoing pre-operation testing, with the second unit about a year behind. Commercial operation was expected in 2012, but the Chinese Taipei government has ordered Lungmen unit 1 to be put on hold until safety checks are complete and before loading fuel, and construction of unit 2 (90% complete) to be halted. A referendum on the future of the plant is to be held (WNA, 2014c).

While a number of advanced reactor designs have now been approved as standard designs, the ABWR is the first advanced reactor developed to meet the common goals set by the Japanese electric utilities and BWR manufacturers (GE, Hitachi and Toshiba), based on design, construction, operation and maintenance experience of NPPs (IAEA, 1997). The most significant point is standardisation, which consists of design standardisation, document standardisation and quality management standardisation. The scope of design standardisation is standardisation of system design, layout design in the reactor building and the turbine building, and embedded level of the reactor building and the turbine building. Initially the ABWR is derived from a General Electric design in collaboration with Toshiba and Hitachi, but the ABWR is now offered in slightly different versions by GE Hitachi, Hitachi-GE and Toshiba. Though GE and Hitachi have subsequently joined up as Hitachi-GE Nuclear Energy, Ltd. (or GE Hitachi in the United States), Toshiba retains the rights of the design.

The Hitachi UK-ABWR has similar features, and has a similar size to the other Japanese units. Toshiba is promoting its US-ABWR for American markets and its EU-ABWR of 1 600 MW class with core catcher and passive containment cooling systems for European markets. Hitachi-GE and Toshiba have had responsibility for the construction of other ABWR plants in Japan. Since the ABWR is a standardised reactor, Simane-3 benefited from the experience of the previous ABWRs in terms of construction and commissioning of earlier projects. Since Shimane-3 is also located close to Shimane units 1 and 2, operating since 1974 and 1989 respectively, it has benefited from being able to construct on an existing site where the necessary technical and social infrastructure already exists.

Using the same basic design means that specific details can be defined at the start of the project. This enables more possibilities in cost reduction through further improvement in the construction methods and the procurement of separate equipment systems based on well-defined interface design information. In this report, general information on the project management of the ABWR construction came from the previous studies of the Kashiwazaki-Kariwa units 6 and 7 (IAEA, 1998; IAEA 1999; IAEA, 2000; IAEA, 2004). Some recent publications are available for Shimane-3 related to advanced design and construction features, but the information was limited because it is still in the construction stage (ICONE 17, 2009; Kajiyama et al., 2009; ICONE 18, 2010; Fushiki et al., 2008).

Synthesis of ownership, corporate responsibility and financing structure

For any nuclear power project, the type of contracts – such as the turnkey contract, split-package contract and multi-package contract – influence all aspects of the project implementation, from siting, design, construction and commissioning to commercial operation. In the case of Kashiwazaki-Kariwa units 6 and 7 construction, TEPCO assumed the overall management of the project in a split package contract approach (IAEA, 2000). The main design and construction was carried out by a joint venture of manufacturers (Toshiba, Hitachi and General Electric):

- The civil work (land forming, intake and discharge structure) was done by a joint venture of civil construction companies.
- Building work (main building) was done with a Building Joint Venture.
- Mechanical work (piping/equipment/commissioning) was done by Hitachi-GE.
- Radioactive waste management was assigned to a manufacturer joint venture.
- Separate contracts were conducted for equipment and structures having fewer interfaces with main equipment work and for which a competitive market existed.

In the case of Shimane-3, the owner is the Chugoku EPCO. The Chugoku EPCO co-ordinates all contractors in civil, building and mechanical fields, and oversees the work undertaken by each contractor. Hitachi-GE is responsible for installation and applies construction methods, such as larger block modularisation to the plant. There are three divisions generally organised for the construction of Shimane-3, and each one places orders to each contractor.

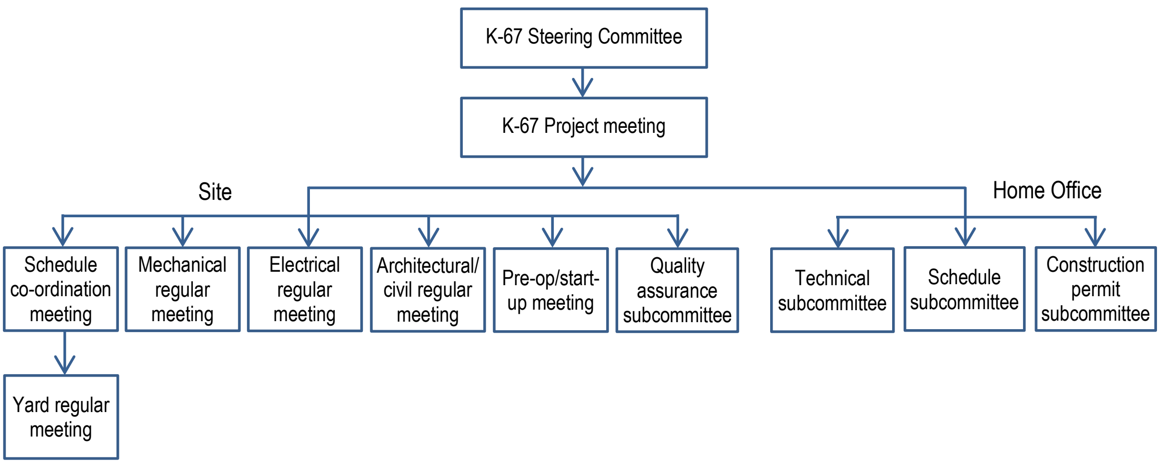
The Chugoku EPCO has a plan to delegate a part of maintenance to its subsidiary companies to reduce maintenance cost after starting operation. Therefore, they have been involved in the project as the prospective support from its construction phase to acquire knowledge and skill for maintenance (ICONE 17, 2009).

Management structure

Project management is primarily concerned with the definition, direction, co-ordination and overall control of project implementation activities. Project management activities start with initiation of the nuclear power project and end with turnover of the completed and commissioned plant to the operating organisation. The project management is responsible for the cost, schedule and technical performance of the project and is in control of project activities such as design, engineering, procurement, manufacture, construction and commissioning.

There are many activities in project management for project planning and scheduling: design schedule, construction schedule, control of project progress, management of information and methods to subcontract material and construction work. A hierarchical committee organisation was established including a steering committee, project meeting, and subcommittee in the case of the Kashiwazaki-Karaiwa 6 and 7, as shown in Figure 48, in which TEPCO and the plant suppliers participated in discussions of engineering issues to control the engineering and construction schedule, to co-ordinate various activities such as quality assurance and licensing and to review the progress of the project (IAEA, 1998). To advance the whole construction efficiently and smoothly, Chugoku EPCO organises regular meetings in case of necessity, manages information on schedule progress and site situation and instructs each contractor. The "Top Management Meeting for Construction Schedule" is situated as the highest-level meeting. Top management from Chugoku EPCO and contractors attend these meetings (ICONE 17, 2009).

Figure 48: Project organisation for TEPCO's Kashiwazaki-Kariwa 6 and 7 project



Source: IAEA, 1998.

At a lower level, there are several meetings such as the "construction yard co-ordination meeting", "Unloading schedule co-ordination meeting" and so on. Securing the safety of work is the top priority for the owner. The Chugoku EPCO manages safety and health over the entire site. The Chugoku EPCO organises meetings for safety and health and promotes these not only among its employees but also among all workers on-site. The "monthly safety meeting" is situated as the highest-level meeting. At a lower level, safety meetings for each contractor are held. Communication between the Chugoku EPCO and workers is one of the important factors to prevent problems and industrial accidents. Progress in contact and discussion between Chugoku EPCO and workers is built by communicating with each other closely on a regular basis. It is important to consolidate information and clarify instructions for proceeding with civil, building and mechanical work in a same period smoothly.

The quality assurance (QA) programme is an interdisciplinary management tool that provides a means for ensuring that all work is adequately planned, correctly performed and assessed. The QA programme is a set of documents that describes the overall measures established by an organisation to achieve management goals and objectives. The plant owner is responsible for establishing and implementing an overall QA programme to ensure that all project activities and processes are described in detailed plans and procedures, implemented by prescribed methods and techniques, and documented in exhaustive records and reports. The QA programme also includes organisational structures, functional responsibilities, levels of authority and interface for those managing, performing and assessing the adequacy of work and qualification requirements for personnel, equipment and procedures. In the case of the Kashiwazaki-Kariwa 6 and 7, TEPCO established basic requirements for QA, based on extensive experience in NPP construction, which include: establishment of organisations and basic schemes for QA; systematic quality control (QC) for design, drafting, transportation, installation, etc., according to the degree of importance of each component; systematic procurement control and auditing the manufacturer's QC. There were a total of 286 government and 3 718 TEPCO (system-wise) inspections. Out of TEPCO's inspections, 657 were at the factories and the balance on-site (IAEA, 2004).

Licensing, design, pre-construction, logistics and procurement

The licensing process is an ongoing process, starting from concept, site preparation and continuing through design, construction, commissioning and operation of the NPP. The licences include, in addition to the site authorisation, the construction permit and operation licence. These licences are directly requested by the plant owner to start construction and operation of an NPP, and they are issued by the regulatory body.[2]

In 1987, when TEPCO announced its decision to proceed with a two-unit ABWR project at its Kashiwazaki-Kariwa nuclear power station, the ABWR standard safety analysis report (SSAR) was completed, after the basic design study for ABWR had been done from 1981 to 1985. On 29 September 1987, GE applied for certification of the US ABWR standard design with the US NRC. The NRC staff issued a final safety evaluation report (FSER) related to the certification of the US ABWR design in July 1994 (NUREG-1503). The FSER documents the results of the NRC staff safety review of the US ABWR design against the requirement of 10 CFR Part 52, Subpart B, and delineates the scope of the technical details considered in evaluating the proposed design. NRC adopted as final this design certification rule in May 1997 (WNA, 2014b). Both Toshiba and GE-Hitachi have applied separately to NRC for design certification renewal. The initial application for the ABWR design certification was submitted in 1997 and in 2011 the NRC certified it. Hitachi had applied for a UK Generic Design Assessment for its version of the ABWR.

In the case of Kashiwazaki-Kariwa 6 and 7, after the governmental approval, construction of units 6 and 7 began in September 1991 and February 1992 respectively. The operation licence was issued before the commercial operation of units 6 and 7, in November 1996 and July 1997 respectively. The basic design was complete before applying to the government for the pre-construction establishment licence and the design details were finalised before applying for the construction permit. Since the ABWR design is standardised, the Shimane-3 has benefited from engineering/licensing experiences of the previous NPPs. Up-front licensing, in which the regulatory requirements are agreed between the regulatory body and the plant owner in advance of construction, reduces the potential for regulatory induced construction schedule delays. By having the early engineering and the licence acceptability in advance of the construction, the financial risk of the nuclear project is also reduced.

In case of the Kashiwazaki-Kariwa 6 and 7, as the first ABWR units, many FOAK engineering equipment and systems were adopted in the design. There are reactor internal pumps, fine motion CRDM, reinforced concrete containment vessel, three-division emergency core cooling system, high efficiency BOP system with a large capacity turbine generator, full digital control system with advanced man-machine interface and so forth (IAEA, 1997). ABWR also has many new technical features, which have a significant bearing on the construction scheme including the use of RCCV structurally

2. Before the Fukushima Daiichi accident, the principal nuclear regulatory body was the Nuclear and Industrial Safety Agency (NISA) overseen by the Ministry of Economy, Trade and Industry (METI). After reorganisation, the nuclear regulator is now the Agency for Nuclear Regulation (ANR) overseen by the Ministry of the Environment (MOE). The technical support organisation Japan Nuclear Energy Safety Organisation (JNES) has also been integrated into the ANR as of the beginning of 2014.

integrated with the reactor building and a reduction in the building volume through the rationalisation of the layout design. Hence, one of the priorities placed on the project was the design change control (IAEA, 1998). To minimise the risks associated with design changes, every small deviation from conventional design is carefully evaluated from the view point of performance, reliability, transient behaviour, side effects on their systems and so on. TEPCO has established a rule of design change control, and has successfully reduced the occurrence of trouble with new units, with design review, design verification tests, and production verification tests. As a result of overall efforts, the Kashiwazaki-Kariwa 6 and 7 had been completed as scheduled with good management over the FOAK design.

A detailed procurement programme is to be established early enough to enable the smooth construction of an NPP. The programme includes procurement of the following:

- necessary engineering documents in advance;
- items, especially long-lead-time components, in advance;
- services such as civil, mechanical, electrical and I&C services in accordance with the project master schedule.

Material management is to ensure that the variety, quantity and quality of materials meet site construction requirements and are available according to schedules or when urgently requested. A material management system usually relies on a computerised database, which maintains material inventory and controls inventory location (IAEA, 2004).

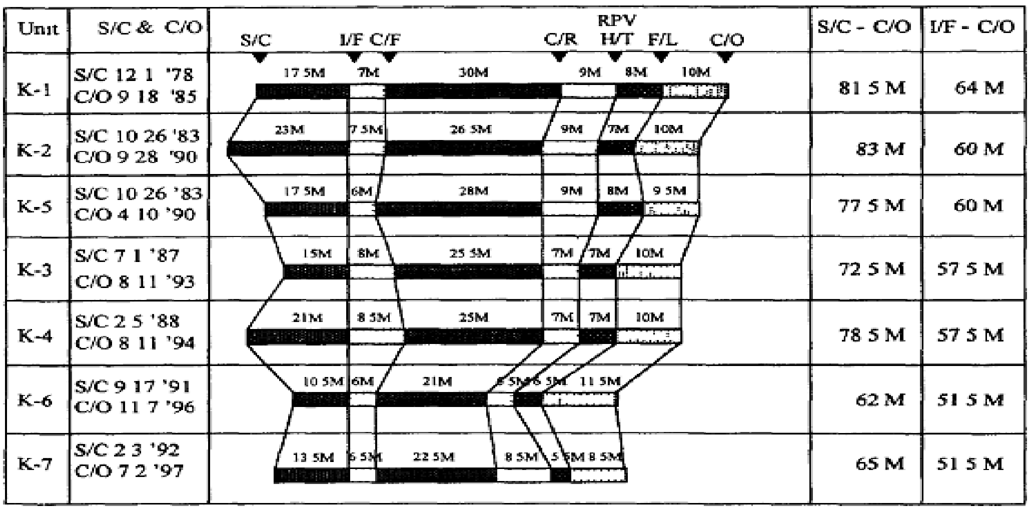
Organisation of construction and subcontracting

During the construction of an NPP, civil, building and mechanical construction activities take place in a same period to shorten the construction time, with rationalised construction methods, making overall construction management complicated. The term "pre-construction period" or "pre-construction duration" refers to the time from the inspection of the foundation and the start of environmental assessment to the start of the pouring of "first concrete" and the construction duration from "first concrete" to the start of commercial operation. The construction duration of the Kashiwazaki-Kariwa 6 and 7 was 51.5 months (IAEA, 2004). TEPCO expected that if some conditions unique to the Kashiwazaki-Kariwa 6 and 7, such as additional tests for the FOAK projects, had not been included in the schedule, it could have been shortened to about 48 months. For the next project, TEPCO has estimated that the duration can be shortened up to 35 to 40 months by changing the holiday schedule to be four days per month (IAEA, 2004). Figure 49 shows the comparison of construction periods of the Kashiwazaki-Kariwa Nuclear Power Station, where the improvement of the duration of the plant construction of the Kashiwazaki-Kariwa 6 and 7 was realised by:

- design features of ABWR for better plant constructability;
- prudent design change control with a principle of "test before use";
- advanced construction technology;
- detailed engineering at early stages of the project;
- good construction management.

Construction methods have been improved based on the experience accumulated through the continuous construction of NPPs. Unit 1, whose construction began in December 1978 and was completed in September 1985, thus took 81.5 months from start of construction to commercial operations. Of this, a total of 64 months were spent to go from the inspection of the foundation to commercial operations. The complete construction of unit 6 instead lasted only 62 months due to learning effects.

Figure 49: Comparison of the construction times (months) of units K-1 to K-7 at Kashiwazaki-Kariwa nuclear power station



S/C: Start of construction; I/F: Inspection of foundation; C/F: Completion of foundation mat; C/R: Completion of refuelling floor; H/T: First hydrostatic test; F/L: Fuel loading; C/O: Start of commercial operation; M: Month.

Source: IAEA, 1998.

In the case of the Kashiwazaki-Kariwa 6 and 7, there are two key methods that determine the outline of the construction schemes. One is called "all-weather construction method" applied to unit 6 and the other is "large block construction method" employed in unit 7. The former originally came from Kajima/Toshiba, and the latter originated with Hitachi. The large block construction method was designed to expand scopes of factory fabrication and concurrently execute site work. Components and structures are assembled or integrated into large block modules either at factories or at an assembly space on the site, and then they are installed so that construction work can be efficiently conducted. Following the major block module at unit 7 were the RCCV centre mat rebar module, the RCCV linear plate module, the RPV pedestal module, the RCCV upper drywell internal module, and the RCCV top slab composite module of rebar, liner and built-in-piping. The modularisation was applied to the maximum extent to the RCCV and its internals to shorten the critical schedule in the RCCV erection (IAEA, 1998).

In the construction of the Shimane-3, the concept of large-block modular construction was extended further to room-type modules. Major modules in the Shimane-3 are:

- reactor water clean-up system (CUW);
- reinforced concrete containment vessel (RCCV);
- condensate demineraliser (CD);
- reactor pressure vessel (RPV);
- off gas (OG).

A room-type module was applied to the hydraulic control unit (HCU) room. HCU room modules are installed in the under-most layer in the reactor building, one on the north side, the other on the south side. The room-type module consists of products prefabricated and assembled like a room and minimises the work on the construction site. The building contractor is in charge of designing the installation of walls, floors and ceilings in rooms that belong to an architectural structure. The mechanical contractor is in charge of designing the installation of structures in a room such as equipment and piping. Hitachi uses a dedicated factory for module production that was completed in 2000. Construction at the Shimane-3 will use about 190 modules, and about 100 modules are to be used at the Ohma 1 (ICONE 17, 2009; Kajiyama et al., 2009).

A large crane plays a key role in Hitachi's construction techniques. The large crawler crane (lifting capacity: 930 tonnes) was introduced in 1984 and is used to lower large equipment and modules directly into position at the site. This expanded the scope for using modular construction. Shimane-3 uses a large crawler crane to unload goods directly from ships, because the Shimane-3 construction yard is located next to a wharf (Kajiyama et al., 2009).

To ensure the delivery and installation of the huge number of components required in the construction of an NPP, Hitachi uses concurrent construction methods called parallel construction to deliver and install equipment while building construction is still in progress. Not only has the range of the components installed in advance at Shimane-3 been expanded, efficiency is also being improved by bringing work forward or optimising work procedures by, for example, carrying out work such as installing operating pulpits or performing basic set-up for equipment, panels, and racks while construction of the building is still in progress. Even in adverse conditions such as heavy snowfalls and strong seasonal winds, this method has been designed to create a factory-like environment under such situations, which is similar to the all-weather construction method in Kashiwazaki-Kariwa 6 and 7. This involves erecting the permanent steel frame to the height of the roof before installation of the floors and walls so that a removable temporary roof can be placed on the top to keep out the rain and snow.

Traditionally, the hydro-static pressure test in a completed power plant needs to be implemented after the completion of system construction, which inevitably causes workload peak at or near the end of construction. Hitachi developed a new concept for this issue, called "floor package method", which allows partial hydrostatic pressure testing for each floor of the building before the completion of whole system construction. The aim is to spread the workload more evenly by bringing work forward and optimising work procedures (ICONE 17, 2009).

Construction support technologies that use the latest information technologies, such as three-dimensional computer-aided design (CAD) system and radio-frequency identification (RFID), are also used to improve safety and reliability, to keep construction on schedule and to ensure that construction work is spread smoothly. A nuclear plant consists of a huge number of components. Examples include the approximately 30 000 on-site pipe welding points and a total cabling length of about 2 000 km. Advanced design and construction management technologies are required to install all these components efficiently and accurately.

To take advantage of information technology (IT) in the management of plant construction, Hitachi has developed an integrated on-site construction system for nuclear plants to ensure that work planning is carried out reliably and that associated work is done efficiently. The integrated on-site construction system is structured in a way that allows the planning, execution, measurement, and corrective steps of the project management cycle to be performed. It has links to three-dimensional CAD and other design data to cover everything from the installation work plans for the equipment, pipes, panels to racks and other components so as to assist in the organisation of the work and on-site inspection (Kajiyama et al., 2009).

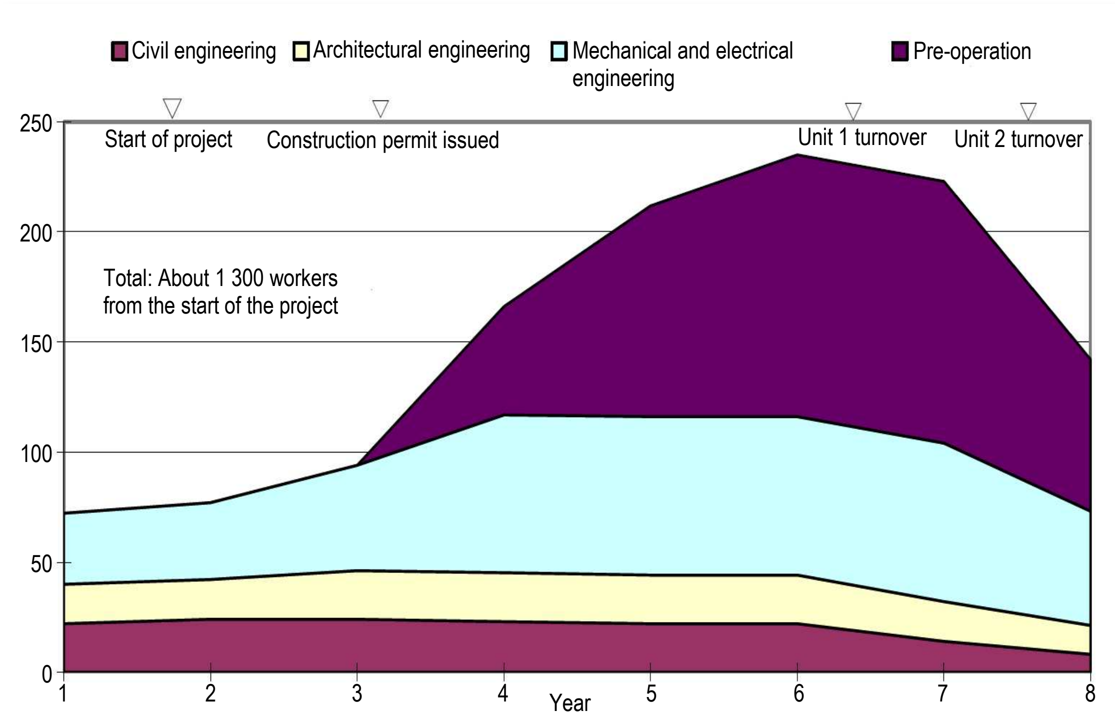
Hitachi has developed and implemented the construction management methodology and associated system using mobile personal computers (PCs) and RFID for warehousing and delivery management, installation work record management, and cable connection work. Hitachi is also building an integrated system covering factory production through to on-site installation and preventive maintenance using RFID. RFID is a technology for identifying objects automatically or by people via radio using a dedicated reader. It works by attaching an integrated circuit (IC) tag to the object being identified. The IC tags have a chip that contains data identifying the objects or person to allow contactless authentication (Kajiyama et al., 2009).

Workforce

Because of the complexity of an NPP project, a huge amount of resources (man-hours/staff, material, etc.) must be managed to get the project completed. Figure 50 shows the owner's human resources needs in case of the Kashiwazaki-Kariwa 6 and 7. Other resources utilised are given below (IAEA, 2004):

Manpower – construction (man-hours):	
Unit 6 (including U6 and U7 common facilities):	14 400 000
Unit 7:	10 800 000
Materials:	
Piping (tons):	
Unit 6 (including U6 and U7 common facilities):	11 000
Unit 7:	6 000
Valves (pieces):	
Unit 6 (including U6 and U7 common facilities):	11 000
Unit 7:	8 000
Concrete (m^3):	
Unit 6 (including U6 and U7 common facilities):	200 000
Unit 7:	167 000

Figure 50: Owner's project management team in the Kashiwazaki-Kariwa 6 and 7 project



Note: For the twin ABWR plant: about 1 300 workers-year, out of which: mechanical and electrical (average 57, max. 72); architectural (19, 22); civil (20, 24); administration (61, 82).

Source: IAEA, 2004.

The ease, efficiency and cost effectiveness of construction of an NPP are key factors in improving quality and reducing the gestation period and cost. Computer modelling can be a very effective tool for both designers and constructors. The use of these tools has not only improved the quality of design and construction by identifying errors and weaknesses in advance, but it has also resulted in great savings in materials and man-hours to reduce the project construction time and cost. The integrated design tools known as CAD, computer-aided design and drafting (CADD) or computer-aided engineering (CAE) are broadly used in the design and in the construction and commissioning stages. Three-dimensional CAD (3D-CAD) has been developed and customised by Hitachi. The system contains a centralised engineering database, which includes small tubes, pipes and supports, enabling wide and effective data applications for things such as preventive maintenance, accessibility, construction work planning or installation procedures.

Institutional issues

Shimane-3 was planned to enter commercial operation in December 2011, but this was delayed to March 2012 because the CRDM was returned to the manufacturer for modification and cleaning. In March 2011, after the Fukushima Daiichi accident, the construction was suspended and the start-up date was then deferred until evaluation of the Fukushima Daiichi accident could be undertaken. At that time, the construction progress was 94% complete. In September 2012, the Ministry of Economy, Trade and Industry admitted the restart of construction of Shimane-3, but the current status of commissioning is not known.

Concluding remarks and lessons learnt

- The first ABWR construction project, the Kashiwazaki-Kariwa 6 and 7, was accomplished as scheduled, fulfilling every development target without major trouble. The construction duration was shorter than a conventional BWR in Japan by nearly one year.
- The standardisation of ABWRs in Japan allows new construction projects to benefit from the positive experience in the construction and project management of the previous ABWR projects and to build on them for further improvements.
- The Shimane-3 project employs advanced technologies in construction and project management.

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III.5.3. Case study of the Tianwan nuclear power plant in China

General description

Tianwan nuclear power plant (*田灣核電站*) is an NPP near Lianyungang city, Jiangsu province, China. It is located on the coast of the Yellow Sea approximately 30 km east of Lianyungang city, 250 km north of Shanghai (see Figures 51 and 52). For the time being, Tianwan NPP consists of two pressurised water reactor units each rated at 1 000 MW capacity with two more units of the same size under construction (IAEA, 2014). With four more units planned for construction, Tianwan NPP has the potential to become the largest NPP in China (WNA, 2014).

Figure 51: Tianwan NPP in China

Figure 52: Tianwan NPP 1

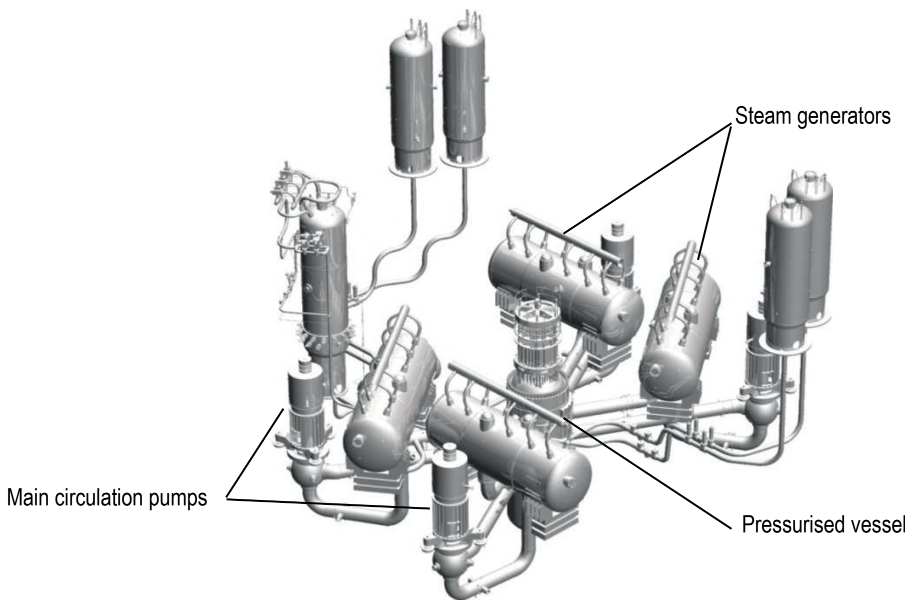
Source: Atomic Energy, 2012

Construction of the first reactor unit started on 20 October 1999 and construction of the second one on 20 October 2000. The first reactor went critical on 20 December 2005; it was connected to the grid in May 2006. Commercial operation of the first reactor unit was started a year later, in May 2007. The same month, the construction of the second unit was also completed and its commercial operation began in August 2007 (see Table 31).

Table 31: Tianwan reactors in China

Unit	Reactor type	Net capacity	Gross capacity	Construction started	Commercial operation
Tianwan-1	VVER-1000/428 (AES-91)	990 MW	1 060 MW	October 1999	May 2007
Tianwan-2	VVER-1000/428 (AES-91)	990 MW	1 060 MW	October 2000	August 2007
Tianwan-3	VVER-1000/428M (AES-91)	1 050 MW	1 126 MW	December 2012	2018
Tianwan-4	VVER-1000/428M (AES-91)	1 050 MW	1 126 MW	September 2013	2019

Figure 53: VVER pressurised water reactor



Source: Gidropress, 2014.

Both units use VVER pressurised water reactor technology supplied from Russia. The units are the Russian standard reactor type VVER-1000/428 (AES-91) (Figure 53) adapted specifically for China. Distinctive features of the VVER reactor unit (OKB GIDROPRESS design) are as follows (Gidropress, 2014):

- horizontal steam generators;
- hexagonal fuel assemblies;
- no bottom penetrations in the pressure vessel;
- high-capacity pressurisers providing a large reactor coolant inventory.

The AES-91 model unit adopted for Tianwan NPP is based on the design, building and operating experience of VVER-1000/320 units performing at the Balakovskaya, Kalininskaya, Rostovskaya NPP in Russia (8 units), Khmelnitskaya, Rivenskaya, Zaporizhskaya, South Ukrainian NPP in Ukraine (11 units) and Temelin NPP in Czech Republic (2 units) (IAEA, 2014).

The AES-91 model unit was improved both in terms of safety and performance in accordance with current international nuclear industry regulations. Its key characteristics are as follows (Atomstroyexport, 2014):

- a reactor with double containment;
- a pre-stressing tension system of the containment vessel that uses a reverse-U model with 50-cable tension;
- safety system with wholly independent safety facilities;
- the physical separation of smelt filter and a cooling system to relieve the impact of severe accidents;
- a uranium-zirconium gadolinium-wide integrated advanced fuel module;
- fully digitalised instruments and control systems.

Reactors also received additional protection from earthquakes. The other important safety feature is the core confinement system. The “catcher” is installed for retention and cooling down of the melt core. It is provided for the melt core to fill the “catcher” in case of an emergency, and it does not destroy the basement under the vessel and the building of the reactor. The “catcher” is an original technical solution, which does not have any analogues in the world practice of NPP construction. China became the first country to have such a device. The “catcher” design was successfully tested by the Russian and Chinese regulatory authorities and was approved by IAEA (Atomstroyexport, 2014).

Institutional issues

The NNSA, under the China Atomic Energy Authority, is the licensing and regulatory body which also maintains international agreements regarding safety. It was set up in 1984 and reports to the State Council directly.

The NNSA is responsible for licensing all nuclear reactors and other facilities, safety inspections and reviews of them, operational regulations, licensing transport of nuclear materials, waste management, and radiation protection including sources and naturally occurring radioactive materials. It licenses staff of nuclear manufacturers through to reactor operators. It is responsible for environmental impact assessments of nuclear projects. The 2003 Law on Prevention and Control of Radioactive Pollution passed by Congress is supplemented by a number of Regulations issued over 1986 to 2011 with the authority of State Council.

Nuclear power plant licences issued by the NNSA progress from siting approval, then construction permit (12 months before first concrete), fuel loading permit, to operation licence.

China has shown unprecedented eagerness to achieve the world's best standards in nuclear safety (as in civil aviation). It has requested and hosted 12 Operational Safety Review Team (OSART) missions from IAEA teams to October 2011, and each plant generally has one external safety review each year, either OSART, WANO peer review, or CNEA peer review (with the Research Institute for Nuclear Power Operations – RINPO). In December 2013, the NNSA, with its Japanese and Korean counterparts, agreed to form a network to co-operate on nuclear safety and quickly exchange information in nuclear emergencies. The NNSA is also part of the ASEAN+3 Forum on Nuclear Safety.

In 2013, the China Atomic Energy Authority (CAEA) signed a co-operation agreement with the NEA, confirming China as a “key partner” with the OECD.

Following the Fukushima Daiichi accident in Japan in March 2011, the government suspended its approval process pending a review of lessons which might be learnt from it, particularly regarding siting of reactors with plant layout, and control of radiation release. Safety checks of operating plants were undertaken immediately, and review of those under construction was completed in October 2011. Resumption of approvals for further new plants was suspended until a new nuclear safety plan was accepted and State Council approval given in October 2012.

The major laws regulating nuclear energy application in China are:

- the Law of the People's Republic of China on Prevention and Control of Radioactive Pollution;
- the Law of the People's Republic of China on Environmental Protection;
- the Law of the People's Republic of China on Environmental Impact Assessment.

In addition to these laws, the Safety Regulation for Civilian Nuclear Installations and Emergency Management Regulations for Nuclear Accidents of Nuclear Power (ANSN, 2010) also applies.

The Chinese government is working towards regularising and promoting public participation on different stages of nuclear new build including the site selection process. Information on construction projects is released to the public via internet, newspaper, etc. Conclusions and related information on environmental impact evaluations are transmitted to the public as well (ANSN, 2010).

In 2007, it was announced that three state-owned corporations in China had been approved by the NNSA to own and operate NPPs: CNNC, CGN and China Power Investment Corporation (CPI). Any other public or private companies are to have minority shares in new projects (WNA, 2014).

Site characteristics

The NPP approvals process in China has three stages:

- siting and feasibility study, with project approval from the National Development and Reform Commission (NDRC);
- construction, first requiring a construction permit and later a fuel loading permit from the NNSA;
- commissioning, leading to the NNSA operating permit.

China's growing nuclear expansion began with the NDRC 10th Economic Plan for the years 2001-2005. It incorporated the construction of eight NPPs. The 11th Economic Plan for the years 2006-2010 set even more ambitious goals and marked a watershed in China's commitment to third-generation reactors, as well as the maturing of CPR-1000 technology. The 12th Five-Year Plan (2011-2015) included construction starts on phase II of Tianwan, Hongyanhe, Sanmen and Haiyang, as well as phase I of inland sites: Taohuajiang, Xianning, and Pengze (WNA, 2014).

For NPP siting, the following aspects are taken into consideration (ANSN, 2010):

- effects of external events occurring in the region of the particular site (these events could be natural or of man-made origin);
- characteristics of the site and its environment which could influence the transfer of released radioactive substances to populations;
- density and distribution of the population and other characteristics in the zone around the site needed for evaluating the possibility of implementing emergency response measures and the risks to individuals and the population.

Workforce

Construction of the first phase of Tianwan NPP (units 1 and 2) involved about 400 Russian specialists who were housed nearby. Operating personnel for Tianwan NPP were trained by OJSC Atomtekhenergo, at the special training facility in the Novovoronezhskaya NPP (the reference plant for VVER-1000/320 design) in Russia. The Novovoronezh training facility specialises in training operational personnel for VVER NPPs, both domestic and foreign, and has all the necessary full-scale simulators, required classrooms and auditoriums, and highly qualified training staff.

In total, OJSC Atomtekhenergo's training facilities have trained 5 397 specialists for foreign NPPs. For further personnel training, including units 3 and 4 staff, a special training facility was built at the site of Tianwan NPP.

Tianwan NPP Phase I

Synthesis of ownership, corporate responsibility and financing structure

The joint construction contract between China and Russia was signed in December 1997. The contract was signed by AO Atomenergoeksport (AEE) and VPO Zarubezhatomenergostroy (ZAES) of Russia (both were later merged into JSC Atomstroyexport [ASE]) and the Tianwan Nuclear Power Corporation of China (the latter has since become Jiangsu Nuclear Power Corporation [JNPC]). Russian and Chinese officials signed a new protocol in January 1999. The Russian side is responsible for providing general technology, project design, as well as supplying, installing and calibrating equipment, and personnel training. The major contractor and supplier is JSC Atomstroyexport.

JSC Atomstroyexport is an engineering company of Rosatom, a state-owned enterprise (SOE) specialising in the construction of nuclear power facilities abroad. At present, JSC Atomstroyexport is the company implementing construction contracts, including "turnkey" ones, for five nuclear power units outside of Russia. The company's project management system is in full compliance with ISO 9001:2008, ISO 14001:2004, and OHSAS 18001:2007 standards.

The Chinese side is responsible for project construction management, construction engineering, equipment purchases from third-party countries and the provision of auxiliary services, as well as most of the installation work on the NPP. The operator of the plant is the JNPC.

The JNPC was established on 18 December 1997, and is mainly responsible for the construction and operation of Tianwan NPP. The corporation consists of the following three shareholders: China National Nuclear Corporation (50% share), China Power Investment Corporation (30%) and Jiangsu Guoxin Group (20%) (Dynabond Powertech Service, 2014). Project cost was originally estimated at USD 2.5 billion, but finally reached USD 3.2 billion, including the USD 1.4 billion cost of the contract with JSC Atomstroyexport.

The main grid systems in China are operated by the State Grid Corporation of China (SGCC) and China Southern Power Grid Co (CSG). It is sophisticated and rapidly growing, utilising ultra-high voltage (1 000 kV AC and 800 kV DC) transmission (SGCC, 2014). Tianwan NPP is connected to the grid by a high-voltage direct-current transmission (HVDC) line. Jiangsu Power Systems is in charge of the HVDC power line engineering and peak modulation facilities.

Organisation of construction and subcontracting

Unit 1 of Tianwan NPP poured its first concrete on 20 October 1999. On 18 October 2005, it started fuelling for the first time and reached critical mass on 20 December 2005. On 17 May 2007, unit 1 was put into commercial operation.

Unit 2 of Tianwan NPP poured its first concrete on 20 October 2000 and reached critical mass on 1 May 2007. Unit 2 was put into commercial operation at the end of 2007 as planned (Atomtechenergo, 2014) (see Table 32).

Table 32: Tianwan NPP construction time frames

Unit	Tianwan-1	Tianwan-2
Construction started	20 October 1999	20 October 2000
Fuel loaded	18 October 2005	16 March 2007
Criticality reached	20 December 2005	1 May 2007
Connection to the grid	12 May 2006	7 May 2007
Commercial operation	17 May 2007	16 August 2007

Source: Based on data from Atomstroyexport, 2014; Atomtechenergo, 2014.

The Tianwan NPP uses third party parts. While the reactor and turbogenerators are of Russian design, the control room was designed and built by an international consortium (including Siemens). According to the contract, the scope of JSC Atomstroyexport's obligations included technical responsibility for the project as a whole, NPP designing, delivery of equipment and materials from Russia and Rosatom-owned facilities abroad, delivery of fresh nuclear fuel for the first core of each power unit, training of Chinese personnel, transfer of design computer codes, performance of installation works in four basic buildings of the "nuclear island", performance of commissioning works for all Tianwan NPP systems, putting the plant into operation, provision of guarantee operation of the power units and delivery of spare parts.

More than 150 Russian enterprises and organisations took part in Tianwan NPP construction. Russian experts also supervised the manufacturing of main reactor equipment, including pressurised vessel, main circulation pumps, steam generators, pipelines, high-pressure pre-heaters and other equipment. Atomstroyexport also handled the assembly process.

The facility was taken over for operation in 2007. On 12 September 2009, the two-year guarantee operation of both power units was finalised. All stages of Tianwan NPP units 1 and 2 construction were successfully completed. The operation guarantee period has shown reliable and safe operation of the station.

Subsidiary companies of CNNC performed various tasks during the construction of Tianwan NPP, including engineering survey, excavation, reactor layout and installation build-out.

The major subcontractors were the following:

- China Nuclear Engineering Geotechnical Institute (engineering survey).
- China Nuclear Industry Zhongyuan Engineering Company (large equipment assembly and part of the site's excavation work).
- China Nuclear Industry Huaxing Construction Company (nuclear island engineering for unit 1).
- China Nuclear Industry 22nd Construction Company (nuclear island engineering for unit 2).
- China Nuclear Industry 23rd Construction Company (nuclear island installation for units 1 and 2).

Tianwan NPP Phase II

Synthesis of ownership, corporate responsibility and financing structure

The general contract for the construction of Tianwan NPP Phase II (units 3 and 4, 1 126 MW each) was signed in 2010 between JSC Atomstroyexport and, acting jointly, China Nuclear Power Engineering (CNPE), JNPC and China Nuclear Energy Industry Corporation (CNEIC). It came into force after the signing of a final agreement in June 2011, defining commercial terms and payment details.

The engineering, procurement and construction contract has been signed for the second phase of the Tianwan NPP by two CNNC subsidiaries. The contract was signed by JNPC and China Nuclear Power Engineering Co (CNPE) in Beijing on 11 October 2011 (WNN, 2011).

On 19 December 2012, the State Council of China approved the construction of units 3 and 4 at Tianwan NPP, by submitting to the NNSA the documents needed for obtaining a licence for the construction of the new units.

Tianwan Phase II units are similar to the first stage of the Tianwan plant, comprising two Russian-designed VVER-1000 pressurised water reactors. While JSC Atomstroyexport is supplying the nuclear islands for the new units, JNPC and CNPE are responsible for the design and supply of non-nuclear components and equipment.

CNPE was set up by CNNC in 2006 to rationalise design work for new nuclear plants, as well as to help win overseas orders for nuclear plants. It is responsible for the construction, equipment procurement, trial testing and operational maintenance of NPPs. The project cost is estimated at USD 6.0 billion, of which USD 1.8 billion is the size of the contract with JSC Atomstroyexport. In August 2013, China Development Bank signed a loan agreement with Jiangsu Nuclear Power Co. for CNY 16 billion for phase II (WNA, 2014).

Organisation of construction and subcontracting

According to the preliminary agreement signed with JSC Atomstroyexport in October 2006, the construction of Tianwan NPP Phase II with two 1 060 MW AES-91 reactors was planned to start when units 1 and 2 were commissioned, and in November 2007 a further agreement was signed by CNNC. Preliminary approval from the NDRC was received in August 2009. Protracted discussion on pricing for the Russian components of the plant delayed the project. Eventually, a contract for the engineering design of two further Tianwan units was signed in September 2010 between JNPC and Atomstroyexport, and the general contract was signed in November 2010 and came into force in August 2011 with the protocol signed by China Atomic Energy Authority and Rosatom.

After the Fukushima-1 nuclear accident in Japan in March 2011, China introduced a moratorium on new NPP projects. The ban lasted for nearly two years, until the Russian project to build a second stage of the Tianwan NPP was finally cleared after strict checks for compliance with the post-Fukushima safety requirements.

In late 2012, China's National Nuclear Safety Administration approved the construction of the third and fourth units. In December 2012, the first concrete was poured for the foundations of unit 3 (WNN, 2012). Construction of unit 4 started in September 2013 (WNN, 2013).

Atomstroyexport is providing 30% of the VVER units for USD 1.8 billion, including nuclear island equipment (reactor, steam generator, pressurisers, primary piping, etc.) and some related equipment. It will not act as the principal contractor, though it retains intellectual property rights. The JNPC is responsible for about 70% of the project, namely, the civil work, turbine island with equipment and related infrastructure on the site.

Final approval from the NDRC was received in January 2011; the EPC contract with CNNC's China Nuclear Engineering and Construction Group (CNEC) was signed in October 2011 and a civil engineering contract concluded with China Nuclear Industry Huaxing Construction Company (HXCC) in May 2012 and China Nuclear Industry 23rd Construction Company for component installation in July. Both are CNEC subsidiaries.

The turbine generator sets will be sourced from Dongfang Electric, using Alstom Arabelle low-speed technology. AREVA I&C systems will be used. CNNC lists them as V-428M reactor units. The EPC contract with CNNC's CNEC was signed in October 2011. Commercial operation is due in 2018 and 2019.

Meanwhile, Iskorskiye Zavody, part of OMZ, started making the major components covered by the Russian USD 1.8 billion part of the phase II plant. It will manufacture two VVER-1000 reactor pressure vessels with internals and upper units. Delivery should be completed in 2014. The company already took part in making the major equipment for Tianwan 1 and 2, including reactor pressure vessels.

Concluding remarks and lessons learnt

Tianwan NPP is a joint project of Russia and China with significant localisation. First phase (units 1 and 2) was completed in 1999-2007. Units 3 and 4 are under construction. They are similar to the first two units, comprising Russian-designed VVER-1000 pressurised water reactors, with the JNPC taking responsibility for the design and supply of non-nuclear components and equipment.

The Chinese side, gradually gaining experience in construction, procurement and overall management, was able to increase its share of construction work up to 70%, with the Russian side being responsible for the nuclear island and technology supervision.

Russian experience in reactor design and procurement, economy of serial VVER manufacturing as well as Chinese experience in construction work and third-party equipment procurement allowed them to keep the project cost under USD 3 000 per kW.

The experience gained through the construction of the first unit at Tianwan NPP also allowed a significant reduction in the construction time of unit 2. Construction of Tianwan NPP Phase II is on schedule.

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III.5.4. Case study of the VC Summer units 2 and 3 in the United States[3]

Summary

South Carolina Electric and Gas Company (SCE&G) and the South Carolina Public Service Authority (Santee Cooper) are in the process of jointly constructing two new AP1000 reactors in South Carolina, United States at the Virgil C. Summer nuclear power station (known as "VC Summer"). A constructive regulatory environment in South Carolina supports new nuclear construction by allowing SCE&G to apply for periodic rate increases to recover financing costs during construction. Among the first new NPPs to be constructed in the United States in 30 years, the project has experienced both institutional and operational delays; beginning with the licensing process and currently in the fabrication of modular components. These delays have caused the completion dates for the reactors to be set back more than a year, with further delay announcements expected. Yet the delays experienced by the VC Summer project (and the nearby Plant Vogtle) are not wholly unexpected given that it involves a new reactor design, built using a new modular construction method, and coupled with a lack of contractors and skilled workers with recent nuclear reactor construction experience in the United States. But foresight in the Public Service Commission of South Carolina's approval of the project, allowing for an 18-month construction schedule contingency period without needing Commission approval, has kept the project progressing forward thus far. These challenges have impacted the schedule, but the effect on project cost has been very modest to date and more than offset by lower than expected interest rates, although recently revised schedule and cost estimates may require a reassessment. Overall, SCE&G and the South Carolina Public Service Authority (known as "Santee Cooper") bear the burden of being among the "first movers". It is likely that lessons learnt from the VC Summer construction process will serve to build skills and experience within the industry, resulting in an improved and streamlined process for subsequent reactor construction that will more readily realise the benefits of modular construction.

1. Background

In March 2008, SCE&G submitted a combined operating licence application to the US NRC to build two Westinghouse AP1000 advanced passive pressurised-water reactors at the currently operating VC Summer nuclear power station site in Jenkinsville, South Carolina (known as VC units 2 and 3) (NRC, 2014). The currently operating VC unit 1 is a 966 megawatt pressurised water reactor that entered service in 1984 and is licensed to operate through 2042 (IAEA, 2014). The VC Summer nuclear station is owned by two South Carolina utilities, SCE&G and Santee Cooper. Construction of the new units is managed through a consortium between WEC and CB&I (SCE&G, 2013). The original consortium was WEC and the Shaw Group, the latter was acquired by CB&I in February 2013 (South Carolina Office of Regulatory Staff, 2013a).

Until the VC Summer and nearby Plant Vogtle nuclear construction projects commenced in 2013, the last new nuclear reactors built to completion in the United States began construction in 1978 (South Carolina Office of Regulatory Staff, 2013c).

2. Ownership and financing

2.1 Ownership

SCE&G is the majority owner and operator of VC units 2 and 3. SCE&G began the project with a 55% stake, partnered with Santee Cooper, which held 45% (South Carolina Public Service Commission, 2009). SCE&G is the principal subsidiary of SCANA Corporation, an

3. This case study was prepared by Erica Bickford and Matthew Crozat, US Department of Energy, Office of Nuclear Energy.

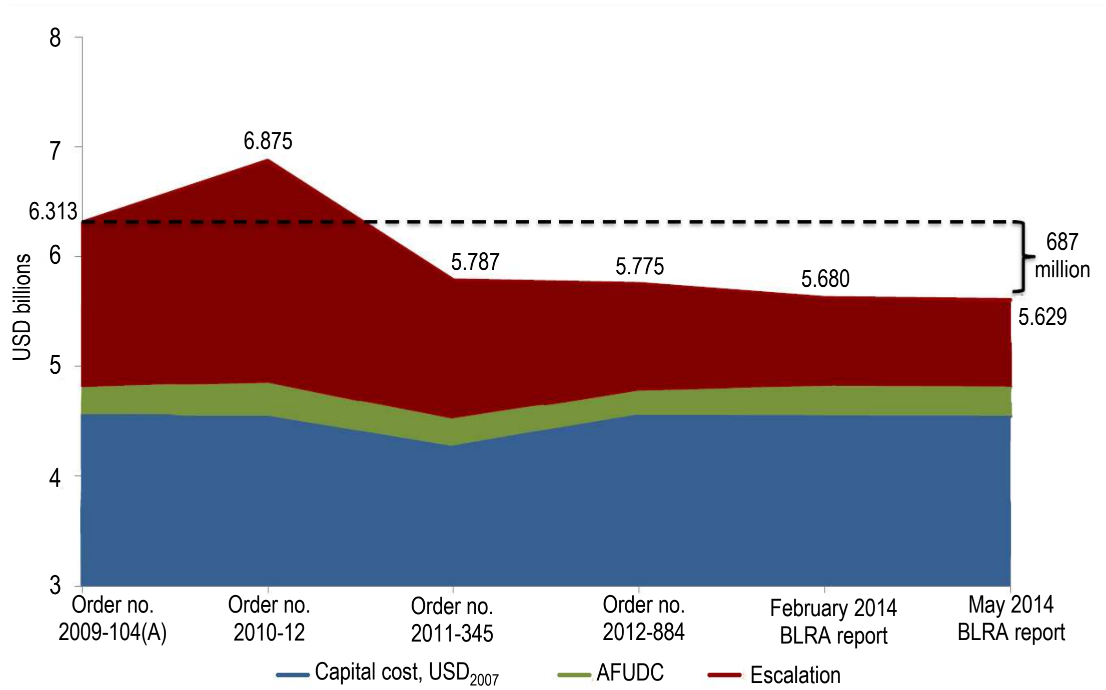
investor-owned utility company involved in regulated electric and natural gas utility operations. SCE&G owns two-thirds of VC unit 1, and operates the reactor (NRC, 2002). Santee Cooper, created in 1934 as the South Carolina Public Service Authority, owns the other one-third and is South Carolina's state-owned electric and water utility, and the state's largest power producer.

In January 2014, SCE&G agreed to acquire an additional 5% (110 MWs) ownership interest from Santee Cooper after the reactors are operational, which will increase SCE&G's stake to 60% and decrease Santee Cooper's to 40% (South Carolina Office of Regulatory Staff, 2014a). The new agreement and specific terms are subject to South Carolina Public Service Commission (PSC) approval and until construction is complete, the project is governed by the ownership responsibilities established in the approved EPC agreement.

2.2 Project costs

In December 2008, the combined total nuclear construction cost for both units was estimated at USD 9.8 billion in nominal dollars (SCE&G, 2011). The current approved base construction cost for SCE&G's 55% share is USD 4 548 billion (in 2007 USD) (South Carolina Office of Regulatory Staff, 2014b). The approved gross construction cost of SCE&G's share of the project is USD 5.755 billion (South Carolina Office of Regulatory Staff, 2014b). As of 30 June 2014, due to current escalation rates, the forecasted gross construction cost of the plant was USD 5 607 billion, representing a decrease of approximately USD 148 million (South Carolina Office of Regulatory Staff, 2014b). Figure 54 shows projected costs for SCE&G's 55% share of the VC Summer project over time, as of May 2014. The figure does not reflect the newest (June 2014) slightly lower cost projection.

Figure 54: SCE&G new nuclear project costs (at 55%) share*



Note: Reflects new nuclear projected costs as filed May 2014 in the Base Load Review Act's (BLRA) quarterly report; SCE&G 55% share. AFUDC: Allowance for funds used during construction.

* SCE&G's additional 5% ownership interest in the new nuclear project does not impact the BLRA projected cost calculation.

Source: SCANA, 2014e.

2.3 State government support and financing

South Carolina is in a regulated electricity market region of the United States; the state's PSC governs energy production and retail electric pricing and allows a rate of return on capital investment. The Base Load Review Act (BLRA), passed in South Carolina in 2007, enables SCE&G to recover financing costs during power plant construction to mitigate rate shock when power plants become operational (South Carolina General Assembly, 2007). This mechanism allows SCE&G to apply for annual rate increases and use those funds to cover some financing costs. The average annual rate increase was 2.15% as of the May 2014 Annual Request for Revised Rates (SCANA, 2014a). By using rate increases to pay off financing costs during construction, SCE&G expects to reduce overall project costs by USD 1 billion during construction and USD 4 billion over the life of the units (SCANA, 2009).

SCE&G plans to finance construction with earnings, corporate debt and additional equity (SCE&G, 2011). Planned equity sales are USD 725 million over the 2014-2016 period through public common stock offerings (USD 425 million) and the dividend reinvestment and 401k plans (USD 300 million), and debt financing of USD 1.6 billion (South Carolina Office of Regulatory Staff, 2014a). Due to a constructive state government regulatory environment, and the ability to use their own earnings and balance sheet to cover costs, the project owners have not sought a loan guarantee from the US Department of Energy even though such a guarantee has been given for the Plant Vogtle expansion in nearby Georgia, which is also building twin AP1000s (US Department of Energy, 2014).

In addition to allowing financing costs to be recovered during construction, South Carolina's BLRA requires that the PSC establish contingencies to apply to the plant construction schedule approved under its terms. Schedule contingencies reflect the fact that that there are inevitable risks and uncertainties involved in a construction project as complex as nuclear reactors, especially when they are new designs. In their application, SCE&G requested a construction schedule contingency of 30 months that would apply to the substantial completion dates of each unit as well as major schedule milestones (South Carolina Public Service Commission, 2009). However, the PSC felt that 30 months was too long a period to grant without their review of the delay circumstances. The PSC granted an 18-month contingency, and SCE&G will need to seek the PSC's approval if delays exceed that period (South Carolina Public Service Commission, 2009).

3. Licensing

3.1 US Nuclear licensing process

Prior to the 1992 Energy Policy Act, licensing new nuclear reactors in the United States involved a two-step process. First, the NRC issued a construction permit based on a preliminary nuclear reactor design. The power plant was built and then a licence to operate the plant was sought from the NRC. This process enabled design changes to be made as the plants were built, but it meant that safety issues would often remain unresolved until the end of the licensing process. This created significant regulatory uncertainty after substantial financial investments had been made. It was possible that a power plant could be built to completion and then fail to receive a licence to operate (Nuclear Energy Institute, 2013).

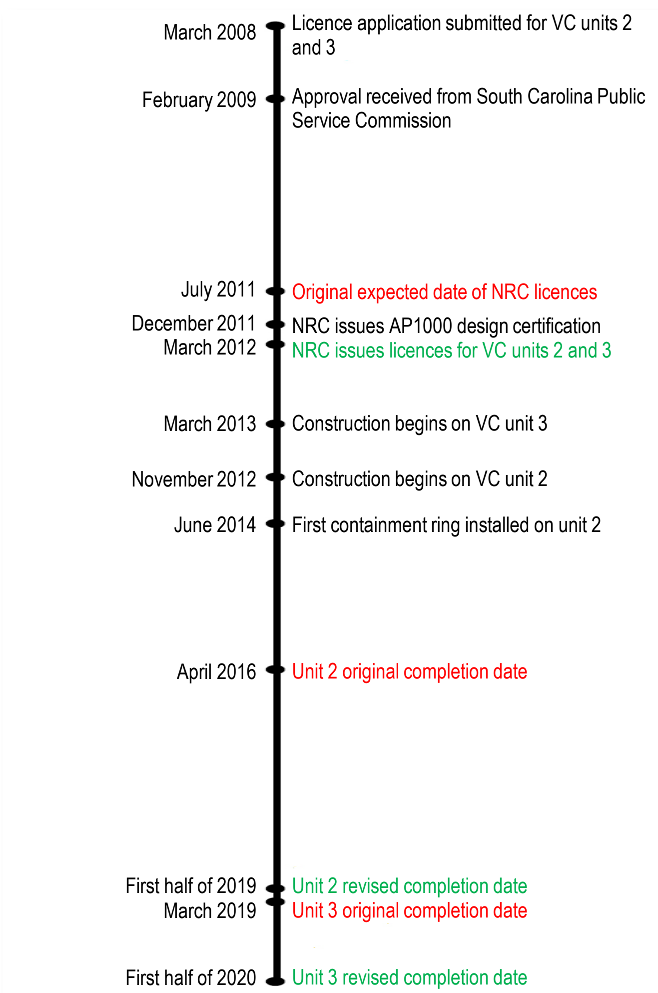
After 1992, the NRC licensing process was changed to also allow for a streamlined process to license power plants before they are built. Under this approach, reactors and associated components and structures must receive a design certification from the NRC independent of applications to construct and operate power plants, which attempts to ensure design safety issues are addressed prior to any construction. For construction of new plants, a prospective licensee submits a combined operating licence application to the NRC to construct and operate an NPP using an NRC certified reactor design. It takes an estimated two years to develop the combined operating licence application, and an estimated three years for the NRC to review it (Nuclear Energy Institute, 2013). After the

NRC issues the COL, NRC staff continues to monitor construction and carry out inspections, overseeing start-up testing before the plant becomes operational. If during construction, design issues arise that vary from the licensing basis in the COL, the licensee must file a licence amendment request with the NRC and receive approval to modify the design before construction continues. The revised licensing process shifts issue resolution to the front end of the design and construction processes to improve downstream efficiencies and mitigate regulatory uncertainty.

3.2 VC Summer Licence and Construction Schedule

Figure 55 illustrates the current timeline for VC Summer's principle licensing and construction activities. Licence applications for VC units 2 and 3 were submitted to the NRC in March 2008 (NRC, 2014). While expected to take three years for licence review and issuance, the simultaneous evaluation of the new Westinghouse AP1000 design undoubtedly affected the licensing schedule. The Westinghouse AP1000 Reactor and associated components and structures received final design certification from the NRC in late 2011 (NRC, 2013). Combined licences for VC Summer were issued in March 2012 (NRC, 2014). The pouring of concrete for the basemat commenced in March and November 2013, for units 2 and 3 respectively (SCANA, 2013a and 2013b).

Figure 55: Timeline for VC Summer principle licensing and construction activities, as of October 2014



Source: DOE, 2014.

3.3 Engineering procurement and construction

EPC has been contracted to WEC and CB&I, collectively “the Consortium” (South Carolina Office of Regulatory Staff, 2014a).

WEC has overall consortium responsibility and is responsible for:

- AP1000 design authority, including design, licensing, systems integration, configuration management, change control and basic plant design;
- detailed design of 32 systems and containment vessel, shield building and auxiliary building;
- construction of the containment vessel;
- procurement of major components and start-up support for nuclear systems.

CB&I is responsible for:

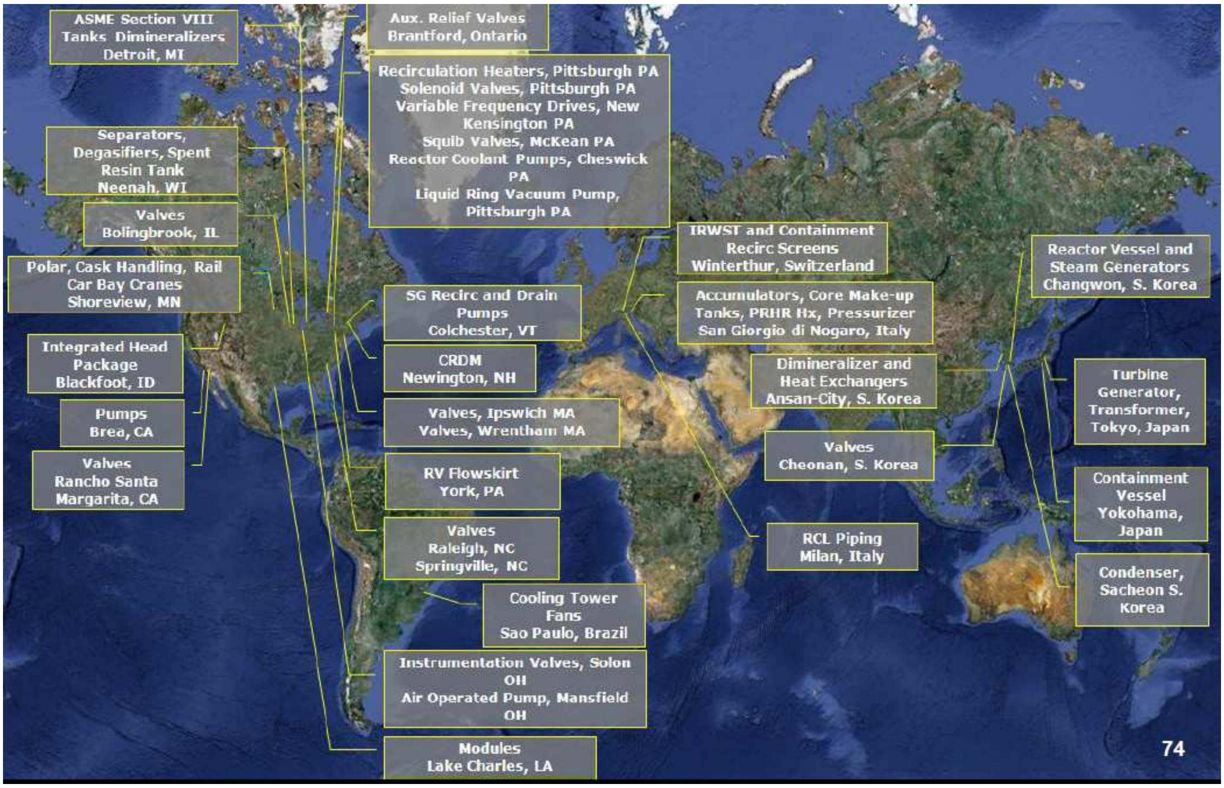
- detailed design of 29 balance-of-plant systems;
- site-specific systems and structures;
- balance of plant buildings, radioactive waste, diesel generator, annex and turbine buildings;
- fabrication of structural and mechanical modules;
- procurement of commodities and selected equipment;
- site specific design, construction and start-up support (SCANA, 2013c).

As of June 2014, approximately 2 500 WEC/CB&I and subcontractor personnel were on-site (SCANA, 2014b). The site is expected to peak at about 3 000-3 500 workers during various points of construction (SCANA, 2014b). The project is open shop, i.e. without a project-wide labour union, and works mostly, but not exclusively, with non-unionised labour.

3.4 Modularity and supply chain

The construction process for units 2 and 3 utilises modular components fabricated in various factories and transported to the VC Summer site for final assembly. The modular approach was employed in an attempt to ensure consistent quality, and diminish build times and costs. Figure 56 illustrates the global supply chain for components for VC Summer.

Figure 56: Global supply chain for VC Summer components



Source: SCANA, 2011: 6.

Note: Abbreviations are explained in the table below.

Component	Location	Continent	Component	Location	Continent
Condenser	Sacheon, Korea	Asia	Instrumentation valves	Solon, OH, US	North America
Containment vessel	Yokohoma, Korea	Asia	Integrated head package	Blackfoot, ID, US	North America
Demineraliser	Ansan City, Korea	Asia	Liquid ring vacuum pump	Pittsburgh, PA, US	North America
Heat exchangers	Ansan City, Korea	Asia	Pumps	Brea, CA, US	North America
Reactor vessel	Changwon, Korea	Asia	Reactor coolant pumps	Cheswick, PA, US	North America
Steam generators	Changwon, Korea	Asia	Reactor vessel flowskirt	York, PA, US	North America
Transformers	Tokyo, Japan	Asia	Recirculation heaters	Pittsburgh, PA, US	North America
Turbine generator	Tokyo, Japan	Asia	Selonoid valves	Pittsburgh, PA, US	North America
Valves	Cheonan, Korea	Asia	Separators	Neenah, WI, US	North America
Accumulators	San Giorgo, Italy	Europe	Steam generators recirculation and drain pumps	Colchester, VT, US	North America
Containment recirculation screens	Winterthur, Switzerland	Europe	Spent resin tank	Neenah, WI, US	North America
Core make-up tanks	San Giorgo, Italy	Europe	Squib valves	McKean, PA, US	North America
IR water storage tank IRWST	Winterthur, Switzerland	Europe	Tank demineralisers	Detroit, MI, US	North America
Pressuriser	San Giorgo, Italy	Europe	Valves	Bolingbrook, IL, US	North America
PRHR Hx heat exchanger	San Giorgo, Italy	Europe	Valves	Rancho, St. Marg., CA, US	North America
Reactor coolant loop piping	Milan, Italy	Europe	Valves	Ipswich, MA, US	North America
AP1000 modules	Lake Charles, LA, US	North America	Valves	Winchester, MA, US	North America
Air operated pump	Mansfield, OH, US	North America	Valves	Raleigh, NC, US	North America
Auxiliary relief valves	Brantford, ON, Canada	North America	Valves	Springville, NC, US	North America
Control rod drive mechanism	Newington, NH, US	North America	Variable frequency drives	New Kensington, OA, US	North America
Cranes	Shoreview, MN, US	North America	Cooling tower fans	Sao Paulo, Brazil	South America
Degasifiers	Neenah, WI, US	North America			

IR: In-containment refuelling; PRHR: Passive residual heat removal.

3.5 Challenges and delays

The project has faced several delays beginning with an eight-month delay in issuance of NRC's combined licences for both units. In the construction process, the biggest challenge to process and schedule has been significant delays in fabricating and delivering the key structural sub-modules (CA20 and CA01, both very large steel-reinforced concrete structures) by CB&I at their Lake Charles, Louisiana facility (South Carolina Office of Regulatory Staff, 2014a). Though the CA20 module for unit 2 was put in place in May 2014, these setbacks have resulted in the estimated completion date for both units 2 and 3 to be delayed at least nine months and likely longer according to more recent estimates (South Carolina Office of Regulatory Staff, 2014c; SCANA 2014c). Regarding the order issued by the state regulator, overall construction is still considered to be on schedule if it is not delayed more than 18 months (South Carolina Public Service Commission, 2009).

In response to the challenges at the Lake Charles facility, CB&I has shifted work for other modules to fabricators both at the VC site and at other locations. Yet even this move has not fully resolved fabrication and delivery schedule problems. SCMI in Lakeland, Florida was assigned the fabrication of unit 2 sub-modules for CA03 and unit 3 module CA04, and had yet to deliver as of 1 September 2014 (South Carolina Office of Regulatory Staff, 2014a).

Problems of fabrication quality have also contributed to the schedule delays. In September 2012, the NRC raised issues with *i)* design and compliance of t-shaped connections being used to terminate the floor rebar wall connection, *ii)* quality related to the bend radius of the fabrication rebar, *iii)* spacing of the rebar to ensure adequate shear strength of the basemat and *iv)* rebar design surrounding the Nuclear Island elevator pit and sumps. SCE&G remedied the first two issues but had to file two licence amendment requests (LARs) for the others resulting in a six-month delay (South Carolina Office of Regulatory Staff, 2013b). In addition, shipment of squib valves for the units are being held due to manufacturer anomalies uncovered during qualification testing of the valves and deficiencies identified by the NRC in document packages related to work performed by subcontractors (South Carolina Office of Regulatory Staff, 2013c).

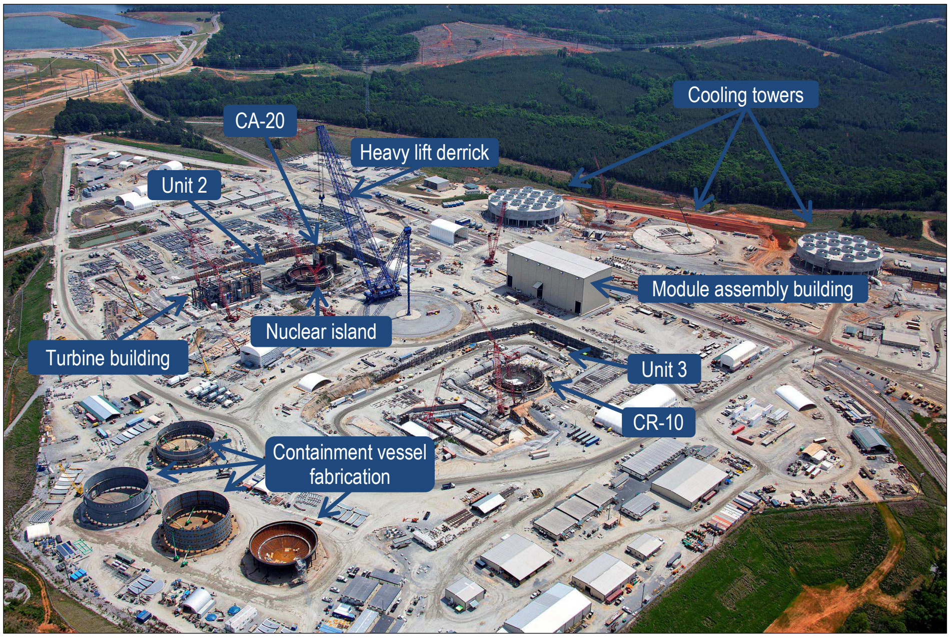
In early October 2014, the Consortium released updated preliminary cost estimates due to delays. The estimated cost to SCE&G, based on their 55% share, is approximately USD 660 million (in 2007 USD) (SCANA, 2014c). Total project cost overruns include Santee Cooper's 45% project share, putting the overall delay cost estimate at USD 1.2 billion (in 2007 USD). This amount is subject to escalation, and excludes any owner's costs amount associated with delays, which could be significant. The amount also does not account for the liquidated damages provisions of the engineering, procurement and construction contract, which would partly mitigate delay-related cost increases (SCANA, 2014c). Allocation of financial responsibility for overrun costs due to delays has not yet been determined. The Consortium's preliminary schedule and cost estimate information are being reviewed by SCE&G and Santee Cooper, with a revised schedule and cost estimate to be finalised at a future date.

While the current schedules from SCE&G indicate delays remain within the 18-month contingency period, SCE&G anticipates that a revised schedule will be finalised in the fourth quarter of 2014 (SCANA, 2014d). It is possible that a number of milestones in the revised schedule will exceed the 18-month contingency window and therefore require SCE&G to file with the PSC to review the project and approve the adjustments to the schedule. The current preliminary revised construction schedule released by the Consortium puts substantial completion of unit 2 in late 2018, or the first half of 2019, and substantial completion for unit 3 approximately 12 months later (SCANA, 2014c). However, SCE&G has not accepted this schedule and it may change as project evaluation and negotiations continue.

4. Site characteristics

The VC Summer Nuclear Station is on the east side of the Broad River in western Fairfield County, South Carolina (see Figure 57). The unit 1 power block area is on the south shore of the Monticello Reservoir. Units 2 and 3 are approximately 1 mile (1.6 km) south-southwest of unit 1. The closest population centre (more than 25 000 residents) is Columbia, South Carolina. Columbia is located approximately 30 miles (48 km) southeast of the site. The closest community is Jenkinsville (population 46), approximately 3 miles (5 km) southeast of the site (NRC, 2010).

Figure 57: Aerial view of the VC Summer construction site



Source: SCANA, 2014e.

5. Preliminary conclusions

In evaluating the VC Summer nuclear construction plan and process, several unique aspects of the project and its location stand out as having a significant impact on the successes and failures of the construction progress to date.

5.1 State regulatory support

South Carolina's regulated electricity market and support from the state government via the BLRA made taking on the financial burden of nuclear construction much more viable. The BLRA enables SCE&G to recover financing costs during power plant construction through annual electric rate increases to mitigate rate shock when power plants come online, reducing total project costs by an expected USD 1 billion during construction.

5.2 Project delays associated with licensing and sub-module fabrication

For VC Summer, both the federal regulatory process and supply chain arrangements created challenges resulting in significant project delays. Though the US licensing process for nuclear construction is generally expected to take about three years, VC Summer's licensing process took four years – likely due to the NRC's simultaneous certification of amendments to the AP1000 reactor design, which was approved three months before the VC Summer project combined operating licence was issued.

Like its twin AP1000 construction project at Plant Vogtle, VC Summer employed a modular construction method. While the intent of modularity is to streamline construction, reducing production times and costs, the combination of a new reactor design and an absence of skilled and experienced nuclear construction contractors and workers has in practice resulted in several schedule delays. The lack of institutional skill and experience is the limiting factor. Supply chains for first movers face difficulties no matter what build methodologies are used. It is likely that lessons learnt from the VC Summer construction process will serve to build skills and experience within the industry, resulting in an improved and streamlined process for subsequent reactor construction that will more readily realise the benefits of modular construction.

5.3 *Flexibility and contingency planning*

While VC Summer and Plant Vogtle have struggled similarly with sub-module fabrication delays, VC Summer has been less hampered by the alteration of its construction schedule. This is in part because of the 18-month milestone contingency that the South Caroline Public Service Commission established pursuant to the BLRA for the plant construction schedule due to the complex nature of constructing VC Summer units 2 and 3. Foresight of the BLRA framers recognised that FOAK projects need flexibility, as they are likely to encounter supply chain issues.

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PART IV.

Lessons learnt and policy conclusions

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Lessons learnt and policy conclusions

With 227 nuclear new build (NNB) projects at different stages of realisation - 68 of which are under construction - the industry is today allowing for a wide variety of experiences in nuclear new build. Following the enthusiasm of the nuclear renaissance, as well as the deception after the accident at Fukushima Daiichi, the global nuclear industry is entering a new phase of cautious optimism that is both aware of the opportunities, particularly with respect to renewed ambitions to reduce global greenhouse gas emissions, and heedful of the challenges of global nuclear new build. It is thus an appropriate time to draw together observations and lessons on nuclear new build.

However, it is also a special period in the history of nuclear development for reasons internal to the industry. In the midst of a once-in-a-generation technological, geographical and structural transition, the nuclear construction industry currently does not operate along a well-defined equilibrium path. It is instead exploring different avenues related to financing, the supply chain and project management. While the old domestically based, vertically integrated model no longer seems appropriate for today's sophisticated customers interested in reliable and cost-competitive low-carbon electricity, no definite new model has yet to emerge.

The future, not the past, counts

In assessing the current performance of the global nuclear industry, the success or failure of a nuclear project needs to be appropriately defined. For instance, if exogenous regulatory changes cause cost overruns, the latter cannot be blamed on inefficient management. Nevertheless, the global nuclear industry will rise or fall based on its overall ability to deliver reactors ready for grid connection on budget and on time. What ultimately matters is that a dynamic of continuous technological, logistical and managerial improvement is maintained at the level of the construction floor, while financial and regulatory stability is ensured at the level of the overall project. Lessons learnt in these two areas are outlined in the following paragraphs.

IV.1. Conclusions in relation to electricity prices and financing

Part II of this report on the importance of long-term solutions for electricity price stability and financing conditions for successful new nuclear build projects mobilised both economic modelling and empirical analysis to provide justification for three interlinked key conclusions with high relevance for energy policy making. These conclusions are:

- market design, technology choices and carbon emissions from the power sector are intrinsically linked;
- the greater the long-term electricity price risk, the greater the bias against high capital cost technologies such as nuclear power;
- the more stable electricity prices are, the more stable net present values (NPVs) are, and the lower are the interest rates, making nuclear energy more competitive.

On the first point, energy policy makers need to understand that there is no technology-neutral market design. Liberalised electricity markets that set prices according to the variable costs of marginal technology will inevitably introduce a bias against capital-intensive technologies. In the absence of compensating measures such as carbon taxes, this will primarily favour carbon-intensive fossil-fuel technologies such as gas and coal. It is the nature of technologies with low-carbon emissions such as nuclear, hydro or renewables to have high investment costs and low variable costs. Without carbon pricing, capital-intensive, low-carbon technologies such as nuclear and renewables will be disadvantaged in liberalised electricity markets. This is due to investors in capital-intensive technologies being exposed to greater financial risk than investors in less capital-intensive technologies when there is a positive probability of a break in the long-term average level of electricity prices.

With two-thirds or more of total lifetime costs spent before the day of commissioning a nuclear power plant (NPP), investors have very little financial flexibility to react to changes in the price environment. The key point is that capital-intensive, low-carbon technologies require long-term price stability. Politicians have been willing to accord such stability in the form of guaranteed feed-in tariffs (FITs) to renewables, in particular wind and solar photovoltaic. The same logic is behind the UK Energy Market Reform and its cornerstone, the provision of contracts for difference (CFDs) to low-carbon technologies. These FITs and CFDs should be made available to all low-carbon technologies so that they can compete on cost.[1] CFDs, similarly to FITs, provide price guarantees that are financed as soon as the market price drops below the agreed "strike price" through a levy to electricity consumers; when the market price is higher than the strike price, the operator has to return the difference. The compatibility of this model with EU competition law has been questioned but the offer of a CFD for two new NPPs to be built at the existing site of Hinkley Point by the UK government was accepted by the European Commission in October 2014.

As soon as price risk is introduced, the general idea that "competitive markets create a level playing field for all technologies" no longer holds. Price risk is, of course, an intrinsic feature of markets for non-storable commodities with their extreme short-run inelasticity of demand. Even for minor changes in demand and supply, prices react discontinuously with large differences. The idea that competitive markets in industries for non-storable goods create a level playing field that optimises social welfare is fiction, since investors will not choose the technology with the lowest possible average lifetime costs but the technology that minimises their overall investment risk.[2]

The second point, which would indicate that the disadvantages of nuclear power rises with the size of the price risk, repeats this message but contains an additional

1. Questions that arise in relation to the financing of renewables such as wind and solar PV through FITs and the impact on electricity markets are not due to the provision of price stability for low-carbon technologies. They are rather due to the intermittency of these technologies, which introduces significant "system costs" and thus adds implicit subsidisation and security of supply risks to explicit subsidisation (see NEA, 2012 for a more detailed discussion on the issue of system cost). The discussion about the nature, magnitude and allocation of such system costs is still ongoing.
2. The intuition that risk does not fundamentally alter the conclusions reached for risk-free investments does not hold in markets for non-storable goods with their extreme short-run inelasticity of demand. Even the standard theoretical models require extreme price spikes when demand reaches capacity limits (VOLL pricing) to finance fixed costs. Due to such discontinuous price formation in markets for non-storable goods, price risk is of a different order than in standard markets for storable goods with elastic demand. Given the additional impacts from policy interventions in a politically and socially sensitive sector such as electricity, as well as the intrinsic inertia of generating capacity, high price risk both in the short run and the long run is a fact in electricity markets.

perspective. Without out-of-market guarantees for electricity prices, nuclear energy will remain confined to markets in which the risk of a long-term price decline is very low. These are essentially markets which can expect stable long-term growth in electricity demand, population and economic output. Not many OECD member countries can guarantee this. In other words, relying on variable electricity prices alone would confine nuclear power to a relatively small subset of countries, such as emerging economies in Asia.

The third point, that stable electricity prices may lower capital costs and thus make capital-intensive technologies more competitive even if all technologies benefit from price stability, is correct but potentially controversial. To what extent the transfer of risk from private investors to either consumers or to the public sector, and by extension, to tax payers, is a sensible policy proposition is part of a wider debate. It is not the purpose of this study to make a definitive statement about tariff regulation in network industries. At all times, the benefits of stability, visibility, and consequently the option of being able to undertake high-capital investments, must be weighed against the drawbacks of asymmetric information, rent seeking, gold-plating and lack of technological dynamism.

One reoccurring theme continues to arise in the current context of policy discussions about electricity market design: low-carbon technologies require out-of-market finance to enter into liberalised electricity markets. This can take the form of electricity price stabilisation, as discussed in Part II, or other forms of finance that limit investor risk with regard to the volatility of electricity prices. The latter may include loan guarantees or still-to-be-developed support schemes that target the fixed cost proportion of new nuclear projects rather than their lifetime costs as in the case of CFDs. Anything that limits the negative financial impact of the combination of high fixed costs and volatile prices is helpful, such as accelerated depreciation schedules (possibly offset by higher corporate tax rates once amortisation has run its course to stabilise tax revenues) or direct capacity payments, whether determined by auction or regulatory decision.

Electricity price stabilisation need not imply a return to vertically integrated monopolies. Nor does it imply the provision of long-term fixed-price contracts for 100% of electricity output. In a broader vision of electricity market design, a combination of energy-only electricity markets for day-ahead and intraday dispatch, coupled with mechanisms for long-term capacity remuneration, is an appropriate model for baseload power provision. Successful nuclear new build in the advanced market economies of NEA countries would require either long-term electricity price stability, support for fixed capital investment or both.

IV.2. Conclusions in relation to project management and logistics

As underlined, the global nuclear industry is in a phase of transition that is forcing vendors, builders, project managers, investors and regulators to adapt, and to some extent, to reinvent the reflexes of an established “best practice” in building new NPPs. The technological break between generation II and generation III/III+ plants and the geographical shift of the point of gravity of nuclear new build towards Asia constitute significant challenges. Also to be noted is the loss of expertise and human capital due to the deferred but massive hiatus in nuclear new build following the Chernobyl disaster and the recent decline in political support following the Fukushima Daiichi accident, as well as the difficulties introduced by the liberalisation of electricity markets for the financing of capital-intensive, low-carbon power generation technologies.

The liberalisation of electricity markets in most OECD countries, coupled with the introduction of significant amounts of variable renewable energies (wind and solar), has affected the financial position of utilities that would normally be the first in line to invest in new NPPs. Subsidised renewable energies lower not only the average price of electricity in the short run (given the existing structure of generation) but also the load factors of dispatchable power providers, in particular gas, which heavily weighs on their profitability (NEA, 2012).

Whether the financial crisis created issues for nuclear new build is open to debate. The lid placed on expectations for electricity demand growth certainly discouraged investment in new generation capacity. However, the record low financing cost that it brought in its wake greatly improved the competitiveness of nuclear power versus fossil fuel-based generation. The ability of NPPs to produce large amounts of low-carbon baseload electricity makes it reliable, and continuing concerns about carbon-induced climate change have sustained interest in nuclear new build in recent years. The complete picture nevertheless provides the impression of an uphill struggle, a struggle that the global nuclear industry is engaged in with resilience and inventiveness to overcome challenges.

By analysing, assembling and synthesising experiences in nuclear new build, this report provides a common way forward. The report examines conceptual considerations and feedback from experts, as well as four empirical case studies on project management and logistics. It concentrates primarily on the lessons learnt from the point of view of the policy maker who is interested in providing framework conditions in which nuclear new build can proceed, rather than examining industrial practice. Focus is given in particular to nuclear safety and electricity market regulation (see Part I). Due to the size and complexity of nuclear projects, however, in many cases governments go beyond simply setting the framework conditions and assume the roles of active stakeholders or even shareholders. Mindful of this double role of governments, one can identify three major areas in which promising developments could be supported, where there is a will to improve the conditions for nuclear new build:

- Advance the convergence and standardisation of engineering codes and quality standards in the global nuclear industry, which is lagging behind both the airline industry and the global oil and gas industry. The current balkanisation between ASME and RCC codes, and the lack of integration with the widely used International Organization for Standardization (ISO) quality codes is not an optimal situation. Initiatives such as the World Nuclear Association's (WNA) Cooperation in Reactor Design Evaluation and Licensing (CORDEL) project or the NEA's Multinational Design Evaluation Programme (MDEP) initiative should be supported and strengthened. Convergence towards common global engineering, and quality and regulatory standards would have three major effects. First, the emergence of a credible quality and safety standard would enhance trust and public confidence in nuclear new build, in particular in newcomer countries. Second, a common safety standard might, to some extent, internalise reputational externalities among operators. Not unlike the airline industry, the nuclear industry must cope with low probability but high impact accidents. According to a nuclear safety aphorism "an accident anywhere is an accident everywhere". Stringent national safety regulations are a necessary although perhaps not always sufficient condition. Third, shared engineering and quality standards will enable the emergence of more flexible and more competitive supply chains. Reactor vendors, as well as specialist suppliers, would be obliged to measure themselves against their peers and to compete on cost, while adhering to the same high quality. Such cost competition would constitute a short-run constraint on suppliers and builders. However, it is also the best and perhaps the only way to contain the current high costs of nuclear new build and to create the scale necessary for the industry as a whole to thrive.
- The second promising area in which efforts to improve the conditions for nuclear new build may make a difference consists of change management and supply chain management. In terms of change management, it is clear that successful projects are undertaken on the basis of wholly completed designs. Since each new build project will have its own particular features, it can never exclude minor

changes at the margin. However, in these cases, strict and rigorous change management, and keeping changes from the original design to a minimum, must be enforced. In all cases of conflict, there must be a single point of contact for conflict resolution – at the site itself. Once construction is underway, the concerns of the site must have priority over those of headquarters. In supply chain management, much progress has been accomplished by working with suppliers early on, sometimes several years before first concrete. This has been made a virtue of necessity given that in many recent new build projects the supply chain had to be completely reconfigured. In these cases, getting to know one's suppliers, certifying and assisting them in upgrading their skills, is as important for the managers of nuclear new build projects as getting to know their customers. Depending on the circumstances, governments may have no direct role in these two processes. However, insisting on completely finalised designs and facilitating the construction of an early interface with the industrial fabric of a region or a country are tasks where governments, not necessarily always at the central level, can play a very useful accompanying role.

- There is a third point in managing successful new build projects that may surprise those who consider successful project management only a matter of engineering prowess and financial acumen. "Soft issues" were consistently mentioned in discussions as important factors. These include leadership, the development of cross-cultural understanding, team building, the creation of appropriate incentive structures and trust. Bringing together and motivating large, multicultural construction teams on a nuclear site is a task in itself. Incentive schemes, promising bonuses for completing the work before schedule rather than just meeting the schedule, have proven to be enormously motivating in some cases. Spending money on the maintenance of established teams with experience on the ground is frequently a sound investment. Finally, trust established by successful repeat transactions can vastly reduce transaction costs in relation to suppliers and regulators. While no single one of these observations may come as a surprise, taken together they make the case for devoting specific resources to management, education, accompaniment and follow-up, and to working with numerous specialised workers and engineers interacting on the construction sites of new nuclear power plants.

References

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Appendix 1.
Participants at the two International WPNE Workshops

"The Role of Electricity Price Stability and Long-term Financing for Nuclear New Build"
19 September 2013

"Project and Logistics Management in Nuclear New Build"
11 March 2014

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Appendix 2. List of abbreviations and acronyms

ABWR	Advanced boiling water reactor
AECL	Atomic Energy of Canada Ltd
ASME	American Society of Mechanical Engineers
BLRA	Base Load Review Act
BOO	Build-own-operate
BWR	Boiling water reactor
CB&I	Chicago Bridge & Iron
CCGT	Combined-cycle gas turbine
CFD	Contract for difference
CGN	China General Nuclear Corporation
CNNC	China National Nuclear Corporation
COL	Combined licence
CRDM	Control rod drive mechanism
CWIP	Construction work in progress
DOE	US Department of Energy
EMC	Electricity membership corporation
ENEC	Emirates Nuclear Energy Corporation
EPC	Engineering, procurement and construction
EPR	European pressurised water reactor
FIT	Feed-in tariff
FOAK	First-of-a-kind
GPSC	Georgia Public Service Commission
GE	General Electric
HHI	Hirschman-Herfindahl Index
IAEA	International Atomic Energy Agency
I&C	Instrumentation and control
IEA	International Energy Agency
IGA	Intergovernmental agreement

ISO	International Organization for Standardization
JNPC	Jiangsu Nuclear Power Corporation
KEPCO	Korea Electric Power Co.
LCOE	Levelised costs of electricity
MDEP	Multinational Design Evaluation Programme
MEAG	Mutual Electric Authority of Georgia
NDC	NEA Committee for Technical and Economic Studies on Nuclear Energy Development and the Fuel Cycle
NEA	Nuclear Energy Agency
NNB	Nuclear new build
NNSA	National Nuclear Safety Administration of China
NPP	Nuclear power plant
NPV	Net present value
NRC	US Nuclear Regulatory Commission
OECD	Organisation for Economic Co-operation and Development
O&M	Operations and maintenance
OPC	Oglethorpe Power Corporation
PPA	Power purchase agreement
PRIS	Power Reactor Information System
PSC	Public Service Commission
PV	Photovoltaic
PWR	Pressurised water reactor
RCC-M/E	Règles de Conception et de Construction des Matériels Mécaniques des Ilots Nucléaires
RCCV	Reinforced concrete containment vessel
ROSATOM	Russian State Atomic Energy Corporation
RPV	Reactor pressure vessel
SCE&G	South Carolina Electric and Gas Company
SMR	Small modular reactor
TEPCO	Tokyo Electric Power Company
TETAŞ	Turkish Electricity Trade and Contract Corporation
TVO	Teollisuuden Voima Oyi
UAE	United Arab Emirates
VOLL	Value of lost load

WEC	Westinghouse Electric Company
WNA	World Nuclear Association
WPNE	Working Party on Nuclear Energy Economics

Units

GW	Gigawatt
kV	Kilovolts
kW	Kilowatt
Km	Kilometre
m	Metre
MWh	Megawatt-hour
Mtoe	Million tons of oil equivalent
TWh	Kilowatt-hour

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Nuclear New Build: Insights into Financing and Project Management

Nuclear new build has been progressing steadily since the year 2000, with the construction of 94 new reactors initiated and 56 completed reactors connected to the grid. Among these new reactors are some of the first generation III/III+ reactors of their kind. Drawing on a combination of conceptual analysis, expert opinion and seven in-depth case studies, this report provides policy makers and stakeholders with an overview of the principal challenges facing nuclear new build today, as well as ways to address and overcome them.

It focuses on the most important challenges of building a new nuclear power plant, namely assembling the conditions necessary to successfully finance and manage highly complex construction processes and their supply chains. Different projects have chosen different paths, but they nonetheless share a number of features. Financing capital-intensive nuclear new build projects requires, for example, the long-term stabilisation of electricity prices whether through tariffs, power purchase agreements or contracts for difference. In construction, the global convergence of engineering codes and quality standards would also promote both competition and public confidence. In addition, change management, early supply chain planning and "soft issues" such as leadership, team building and trust have emerged over and again as key factors in the new build construction process. This report looks at ongoing trends in these areas and possible ways forward.

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