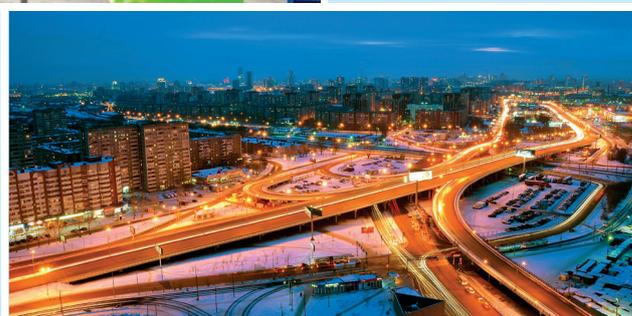
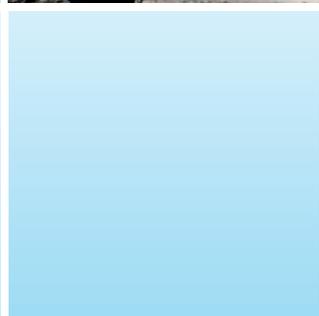
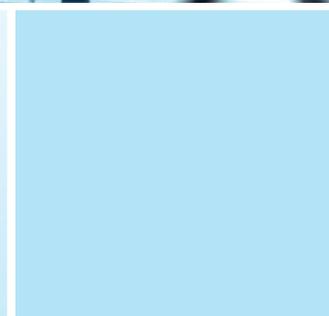
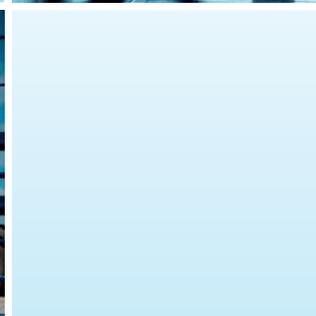


# Financing Nuclear Power

## in Evolving Electricity Markets



**IAEA**

International Atomic Energy Agency  
*Atoms for Peace and Development*

# Financing Nuclear Power in Evolving Electricity Markets

*Electricity market liberalization and increasing deployment of variable renewable energy for power generation have contributed to long term electricity price uncertainty. This created a challenging environment for new investment in capital intensive projects, such as nuclear power. In response, investors and decision makers are employing a range of ownership structures and financing mechanisms across different market environments to support construction of new large scale baseload nuclear generation projects.*

## NUCLEAR POWER IN TODAY'S ELECTRICITY MARKET

As of April 2018, there were 450 operational nuclear power reactors in 30 countries, representing 393 gigawatts of electrical capacity (GW(e)). These plants provide reliable baseload power at a stable and affordable price. Nuclear power plants (NPPs) produce virtually no greenhouse gas (GHG) emissions during their operation and emit the lowest quantity of GHGs per unit of electricity over their entire life cycle compared to other power generation technologies.<sup>1</sup> The nuclear power industry additionally supports advanced manufacturing, technology development and a highly trained workforce.

Despite these benefits, deployment of new NPPs faces a number of challenges. Financing the high upfront capital investment costs of a new plant represents a major hurdle, and projects are sensitive to interest rates, construction and lead times, and political risks. This challenge, combined with uncertain demand growth and competition from other electricity generation sources, means the future role of nuclear power remains uncertain as illustrated by the wide range of projections for the next three decades for installed nuclear capacity (Fig. 1).

In recent times, a changing electricity market environment has contributed to additional uncertainty for NPP investment. Market liberalization that started in the developed world in the 1990s has increased competition and reduced direct government involvement, while a large influx of variable renewable

energy (VRE) sources has disrupted traditional operating paradigms in some markets. At the same time, low natural gas prices and lower-than-expected growth in electricity demand have created further price and demand uncertainty in some markets. For construction of new NPPs, this new market environment requires innovative financing and structuring approaches to NPP construction projects that can mitigate the risks associated with these uncertainties.

*Nuclear power projects face new uncertainties requiring innovative financing approaches*

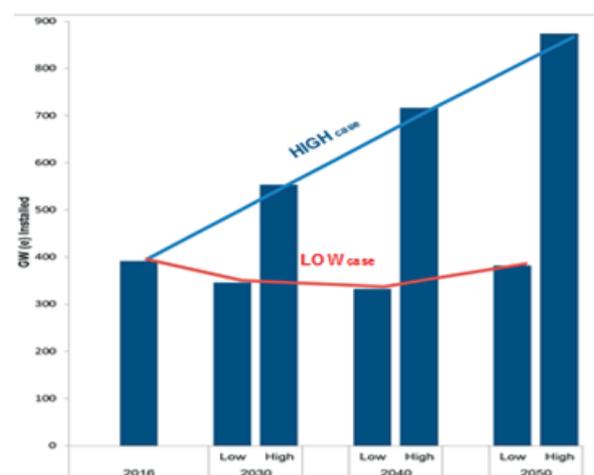


Figure 1. Nuclear electrical generation capacity projections, in GW(e)<sup>2</sup>

## ELECTRICITY MARKET REFORM AND CLIMATE CHANGE POLICY

While construction of NNPs has always been a lengthy and expensive process, in the 1970s and 1980s, most of the markets were regulated by the governments, meaning that the cost of construction were paid through tariffs.

Over recent decades, many countries have implemented electricity market reforms to establish a competitive market in order to reduce prices for consumers and promote efficient investment. At the same time, additional measures have been introduced to reduce the effect of the electricity sector on climate change.

Electricity market reforms implemented included market restructuring, deregulation, privatization and increasing consumer choice. 4

- **Market restructuring:** disaggregation of generation, transmission, distribution and retailing to increase competition (Fig. 2)
- **Deregulation:** reducing direct government regulation of the power industry, and opening the market to independent power producers (IPPs)
- **Privatisation:** reducing the conflict of interest from governments being both owners and regulators of utilities; transferring costs (and risks) of electricity production from taxpayers to the private sector (operators, investors)
- **Consumer choice:** an option for consumer to select the supplier from multiple providers (wholesale and retail competition).

The market reform typically had four main stages:

- disintegration of vertically integrated monopolies
- IPPs getting into the market

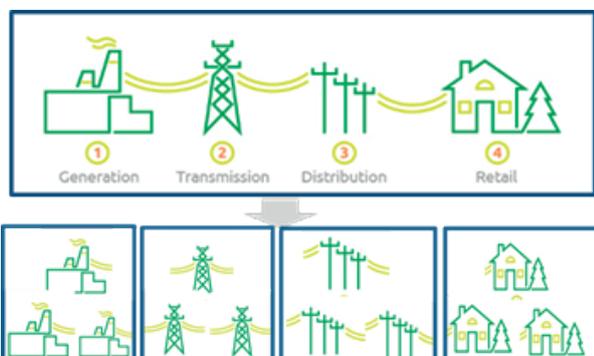


Figure 2. Disaggregation of vertically integrated monopoly into several companies

- competitive wholesale production of electricity
- competitive retail production of electricity

Many jurisdictions have implemented only some of these elements, for example only market restructuring and deregulation, without competitive wholesale and retail markets (Fig. 3). This is partly because countries have sought to achieve different goals via market reform (Table 1). In some cases this has led to re-regulation or government investment where deregulated markets have been unable to respond to longer term or social objectives such as energy supply security or grid reliability.

### Electricity market reform varies worldwide in terms of approach, goals and impacts

Figure 3 shows the status of market reform and the status of nuclear power reactors under construction and planned. As seen, reactors are under construction in states with different levels of market liberalization, and many are in regulated states or with mechanisms assuring revenue certainty.

In developing and emerging markets, where market reform has progressed more modestly, goals have often included overcoming electricity shortages, improving supply quality, meeting rapidly rising demand, and encouraging foreign investment in electricity infrastructure.

As a result, reforms have tended to be relatively less disruptive to traditional investment approaches and risks.

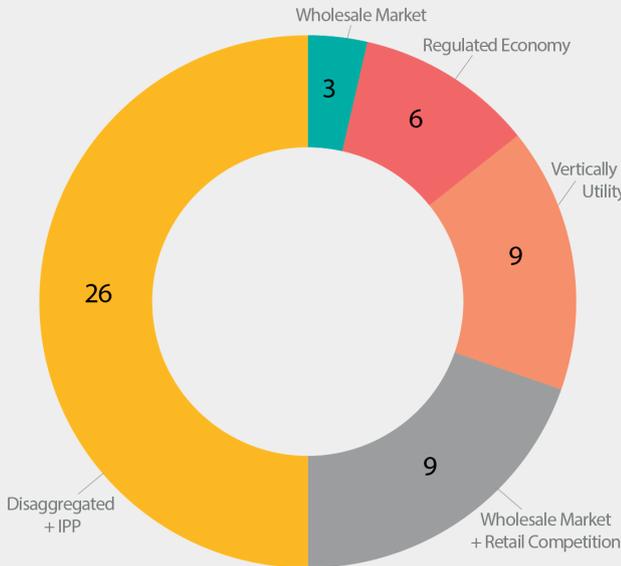
The success of some aspects of market liberalization has been tempered by the short-term focus of competitive (spot) markets. So far, many competitive electricity markets have failed to demonstrate that they can provide the incentives (market signals) necessary to ensure sufficient long term investment in new generation capacity. Investment cycles for new generation are long and upfront capital expenditure financing requirements are significant, while future prices and hence returns are uncertain.

### Current electricity markets do not provide market signals for long term investment

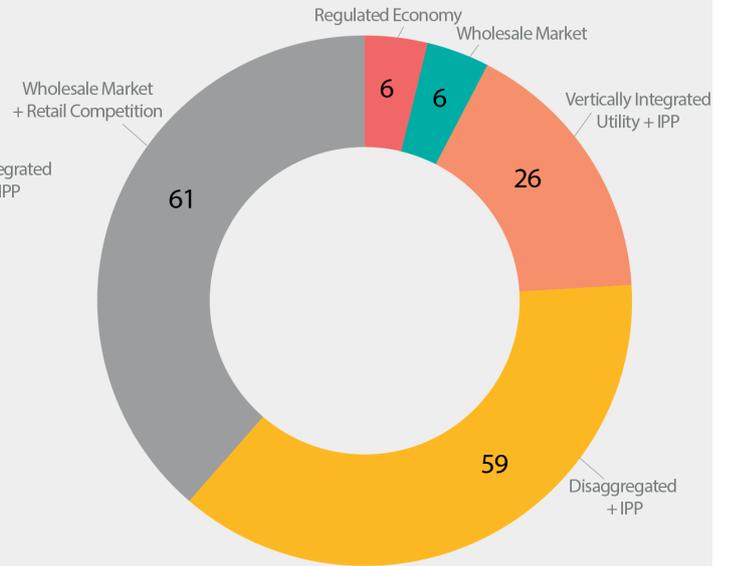
# Which Markets?

Figures as of 3 April 2018

Which markets are NPPs under construction in?



Which markets are NPPs planned in?



Level of Market Liberalization

Regulated Economy	Vertically Integrated Utility + IPP	Disaggregated + IPP	Wholesale Market	Wholesale Market + Retail Competition
Armenia Belarus Iran Republic of Korea	Bangladesh Canada Egypt Indonesia Slovakia South Africa United Arab Emirates United States of America* Vietnam	China India Pakistan	Argentina Brazil Romania Ukraine	Czech Republic Finland France Hungary Japan Poland Russia Turkey United Kingdom

\*In the USA, reactors are in operation and planned in both regulated and unregulated markets.

Figure 3. Electricity market reform status<sup>11</sup> and nuclear power reactors<sup>10,13</sup>

<b>Efficiency, costs and prices</b>
Improve productivity
Improve economic efficiency
Provide lower electricity prices
Provide customer choice and better service
<b>Sustainability and reliability</b>
Promote demand side management
Reduce environmental impacts
Improve electricity supply reliability
Remove price anomalies
<b>Investment and capital market</b>
Enhance investment in new capacities
<b>Social welfare</b>
Enhance affordability

Table 1. Rationale for market reforms<sup>4</sup>

*How has climate change policy interacted with electricity market reform?*

In a number of countries the process of electricity market reform closely followed or coincided with efforts to reduce GHG emissions for climate change mitigation. These efforts include additional government interventions in the electricity market, often supporting low carbon renewable electricity sources such as solar, wind, hydro and geothermal. Although nuclear power is a low carbon technology, in many countries GHG abatement policies have preferentially supported VREs with measures including direct regulation, governmental financial support, subsidies (including

feed-in tariffs paid to renewable generators), certificate based schemes, portfolio standards and emissions trading. In some markets, the scale of government intervention has substantially reduced or almost eliminated investment risks for VREs.

As a result of these climate change mitigation and renewable policies, combined with market liberalization, VREs are being deployed on a large scale in several countries. This has created a number of challenges to the electricity market and other generators. Firstly, large scale deployment of low marginal cost renewables has further depressed wholesale electricity prices, discouraging investment in dispatchable generating technologies (see Box *Electricity pricing and investment in liberalized markets*).

Secondly, the need to balance the intermittency of some renewable technologies — such as solar and wind — has increased the competitiveness of more flexible technologies (such as storage and natural gas generation), compared to technologies better suited to baseload operation (such as nuclear power and coal). The increase in intermittency in the European grid has also imposed additional requirements on baseload generators, including the need for more flexibility (maneuverability) capabilities of NPPs and other power plants to balance fluctuations due to unexpected large and rapid modulations of the power supply and demand.

*Market reforms and support for renewables have lowered electricity prices but increased supply volatility*

**Pricing and investment in liberalized electricity markets**

In liberalized electricity markets, the spot market price is usually determined by the marginal variable cost of the most expensive unit of generation required to meet demand. In other words, under marginal cost pricing generators are operated according to a ‘merit order’ from lowest to highest marginal cost (Fig. 4).

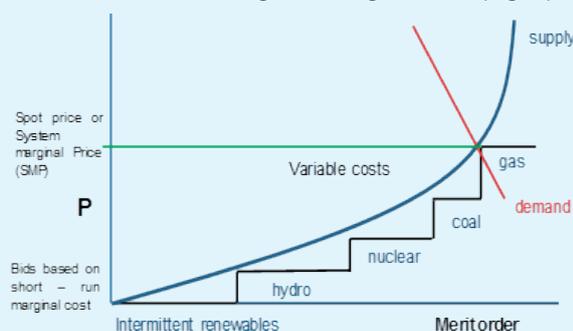


Figure 4. Merit order and marginal cost pricing

Some renewable technologies have almost zero marginal costs, with incremental increase for nuclear power, coal and natural gas. This means that gas technologies often set the electricity spot price and thus earn a relatively stable mark-up (margin), with variations in the gas price passed through to the electricity price. For other technologies, the mark-up will fluctuate according to short term changes in the gas price. However, if demand is lower the spot price will be set by a technology with lower variable costs and revenues may be insufficient to cover the fixed costs of some generators.

The net effect of uncertain demand, intermittent renewable generation and gas price variability is that marginal cost pricing can lead to volatile and low electricity prices that do not guarantee the recovery of investment costs.

## MARKET CHANGES AND THE IMPACT ON NUCLEAR POWER

Viewed objectively, nuclear power can support many of the economic and social objectives of market reform and climate change mitigation, along with other aspects of sustainable development. However, market reforms have increased future electricity price and demand uncertainty in some countries. This in turn has been particularly detrimental to investment in long-lived capital intensive technologies with large upfront costs and long construction times, such as nuclear power. While VREs also have high costs, NPPs have a larger scale of costs, longer payback period, and much longer construction time.

The situation has been quite different in transition and emerging markets, in which the state is still heavily involved in supporting capital intensive projects and only the initial stages of reform have been implemented. Demand growth is also more reliable in these markets, providing additional certainty for large capital intensive projects.

*NPPs face more financial uncertainty in liberalized markets compared to regulated markets*

In addition to the financial uncertainty in liberalized markets, NPPs face new operational requirements to balance the intermittency of VRE technologies. The need for greater flexibility is challenging for NPPs, where operation at a constant power level is less demanding on the plant's equipment and fuel. By contrast, flexible load following operations — i.e. rapidly ramping production up and down to match demand (Fig. 5) — increase maintenance needs and create additional challenges to fuel management. Compared to nuclear power, natural gas generation is better suited both technically and economically to load following. In particular, fuel costs account for a significant share of gas generation costs, so a decrease in output results in a substantial decrease in costs, unlike nuclear power, which has high fixed costs. While nuclear generators can achieve lower levelized costs than gas if operated at high capacity factors, gas generators are more cost effective at lower capacity factors.

*Load following is technically possible for NPPs*

Load following with nuclear plants is technically possible. For instance, NPPs in France and in Germany operate in load following mode, contributing to primary

and secondary frequency control and variable load management — some reactors vary daily output by up to 50% of rated power<sup>16</sup>. However, this requires proper planning to minimize additional operating costs.

These requirements for increased flexibility, together with the financial uncertainty, affect nuclear power at all stages: operations, extensions/replacements and new investment.

In the case of NPPs in operation, utilities and regulators have responded to lower and more uncertain energy prices in various ways. At one extreme, in the deregulated US market, a number of NPPs have been shut down due to reduced profitability. There are also NPPs being shut down for political reasons, such as in Germany.

On the other hand, France introduced in 2010 a dual pricing system to support operating NPPs, in which consumers can buy nuclear power at a regulated tariff based on the production cost as an alternative to purchasing electricity at more uncertain prices linked to the European wholesale market<sup>18,19</sup>. Countries have also introduced capacity payments which support reliable (dispatchable) generation sources, including nuclear power.

While these measures support operating plants, for **NPPs approaching the end of their operating lifetime** utilities face the choice between lifetime extension, replacement with either new nuclear or other generation capacity, and/or decommissioning. This choice is influenced by low gas prices, continued rapid decreases in renewable technology costs and climate change policies, including subsidies to renewables.

The UK government has decided to support the replacement of several ageing and retiring nuclear power reactors with new ones, while in other markets lifetime extension is seen to be attractive. In the USA many NPP operators/owners have requested lifetime

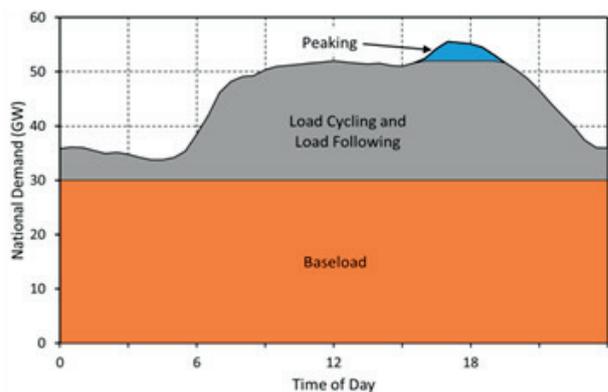


Figure 5. Illustration of load following

extensions from 40 to 60 years, with extension up to 80 years under discussion. France and the Russian Federation also plan extensions to 60 years for newer reactors. While this option is relatively low cost compared to building new plants, significant upgrades and capital expenditure will nonetheless be needed. This is also driving research to ensure both safety and reliability of plants in operation.

These initiatives to support the continued use of NPPs in liberalized markets recognize the technology's contribution to broader policy considerations, such as energy supply security, stability and reliability, and climate change mitigation.

## MECHANISMS TO ENABLE NEW NUCLEAR INVESTMENTS

Electricity price uncertainty remains a significant risk for new investment in long lived capital intensive NPPs. This and other risks can be mitigated through a range of financing options and other mechanisms, including a mix of incentives, government support and guarantees, and contract provisions<sup>3,13,17,20</sup>.

### What are the financing and ownership options for new NPPs in regulated and deregulated markets?

In regulated and deregulated markets there are two main ownership models: government and corporate (with project financing model being discussed but not used so far), which substantially influence the specifics of debt and equity financing.

**Government financing** has been the traditional approach to funding NPPs, with governments also involved in owning and operating energy utilities. While less common in deregulated markets, in regulated markets governments continue to directly and indirectly finance new nuclear and other power generation plants. Examples of direct government financing — in which projects are financed directly from the government budget — include the Qinshan 1 and 2 projects in China. Indirect financing includes sovereign loan guarantees, and accumulated reserves and cash flow from wholly or partially state owned companies. Examples include the Barakah NPP project in the United Arab Emirates (UAE) — see *Box United Arab Emirates — traditional model of an NPP in a regulated market*.

*Government financing support of nuclear power remains important*

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**Government-to-government** financing is also used in nuclear procurement, often taking the form of an intergovernmental loan. The lending government usually has a stake in a state-run NPP vendor, so this arrangement provides a market for its plants. For the borrowing country, this model offers a valuable source of foreign funding and vendor experience in the nuclear sector. In many cases, the goals of government-to-government financing go beyond the specific project, and include establishing long term bilateral relationships. The nature of this relationship may ultimately determine the conditions and repayment of the government-to-government loans.

This type of financing is provided by China to Pakistan, and by the Russian Federation to a number of countries, such as Bangladesh, Belarus and India.

**Corporate financing** describes investment by public or private companies financed from the corporate balance sheet, which can include debt and equity. In this model, the corporation takes on the full risk of the project.

Although in the past corporate financing represented one of the main financing models, the high cost and risk of a new NPP creates challenges for all but the largest companies (or groups of companies) with strong balance sheets. Corporate financing includes vendor financing (see below) and utility financing. Examples of countries in which corporate financing of NPPs is significant include China, Finland, France, India, Japan, the Republic of Korea, the Russian Federation and the USA. Where there is significant state ownership of nuclear utilities (such as in China, France, India, the Republic of Korea and the Russian Federation), the distinction between government and corporate financing is blurred.

**Vendor financing** covers a variety of financing options, including corporate financing via equity or loans provided from the balance sheet of the NPP vendor. Vendor loans are often short term, with vendors recently required by project owners to take an equity stake which provides a share of the future project income.

One way of corporate or government financing is financing by the vendor, where the vendor arranges credit from associated banks and export credit agencies. Examples of vendor financing include many projects constructed by the Russian Federation's Rosatom and China's corporations with vendor loans ranging from 50 to 90% of project costs. Since vendor companies are often state owned enterprises (such as Rosatom, China National Nuclear Corporation CNNC, China General Nuclear Power Group CGN, Electricité de

### Case Study: United Arab Emirates — traditional model of financing an NPP in a regulated market

The UAE Barakah NPP is an example of a traditional project approach in a regulated market, combining **government and vendor finance, loan guarantees** and a **power purchase agreement (PPA)**. The project is supported both politically and financially by the governments of the UAE and the Republic of Korea. The host government is directly financing most (66%) of the project, and provides a sovereign loan guarantee for the remaining finance and a guarantee for the PPA covering the full output of the plant. The vendor — Korea Electric Power Corporation KEPCO — provides a fixed price engineering, procurement and construction contract, as well as contributing equity (Fig. 6).

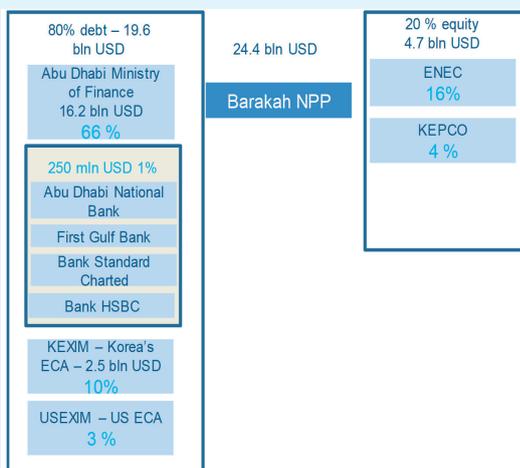


Figure 6. Approximate financial structure of Barakah NPP, based on public information (ENEC and KEPCO Announce Financial Close for Barakah Nuclear Energy Plant; ENEC 20.10.2016; WNA information library, UAE).<sup>12,25</sup>

France EDF) vendor financing can also be considered a form of government financing or guarantee.

Given the challenges of corporate financing, a widely discussed alternative is **project financing**, in which a special project vehicle (SPV) is set up by investors solely for the project. Lenders to the SPV then have recourse only to the revenues and/or assets of the project itself, and not to any other revenues and/or assets of the project investors/owners. This allows investors to segregate the risk of an NPP investment from other assets. On the other hand, few lenders may be willing to finance an entity whose only asset is a power plant they may deem as a risky investment and whose only revenue is from future power sales. So far, project financing has not been used for NPPs, although it has been employed in other power projects, such as in natural gas generation.

Project finance is suitable in following cases<sup>21</sup>:

- Construction risks are “controllable and limited”,
- Technology is well established,
- Rate of return is “predictable and motivating”,
- Project can be taken over or finished or operated in case of default.

Nuclear generation does not fit the abovementioned criteria because many of the NPP projects are first of a kind due to constantly changing technology design, construction risks are hardly controllable, and due to cost and schedule overruns for recent projects rate of return is not predictable.

### Can investors use other revenue assurances mechanisms to manage the risk of investing in a new NPP?

These financing options can be coupled with other mechanisms to guarantee revenues and redistribute some of the risks away from investors and lenders. **Long term contracts** have traditionally been used to guarantee future revenue, and continue to be employed in both liberalized and regulated markets. **Regulated tariffs** also provide a price guarantee for the investor. Most NPPs under construction are either covered by long term contracts or are in markets with some kind of price regulation.

Currently the most widely used mechanisms for guaranteeing long term revenue are **power purchase**

### Case Study: Finland — corporate financing by power intensive customers in a liberalized market: Mankala

A typical ownership model for energy production companies in Finland is the ‘Mankala’ model. This cooperative **corporate finance** model allows power users to participate in large, capital intensive projects. The idea is that a group of power users provide equity finance for the construction of an NPP and receive power at cost in proportion to their shares in the project.

The Mankala model **shares and balances risks** faced by power consumers and producers, improving the confidence of lenders. The shareholders nonetheless retain the risk of project failure.

The Mankala cost-price operating model also boosts competition by supporting the entry of new investors into the market, and encourages the sharing of competencies and financial resource.

## Case Study: Turkey – a new build with vendor finance under a build, own and operate (BOO) model

Turkey's Intergovernmental Agreement (IGA) with the Russian Federation provides an example of NPP financing in a market undergoing liberalization<sup>23</sup>.

The Akkuyu NPP combines vendor finance from Rosatom, which will build, own, and operate (BOO) the plant, and a PPA covering the project costs (Fig. 8). The PPA has an average price of US¢ 12.35/kw.h and runs for 15 years, with the Turkish power wholesaler (TETAS) agreeing to purchase 70% of the output of the first two units and 30% from units 3 and 4. After 15 years the full output will be sold on the market with 20% of any profits accruing to the Turkish government. Turkey also benefits by developing the domestic capacity for nuclear power, personnel training, equipment localization and advanced technology development.

While initially owned fully by Rosatom and related companies, the security provided by the PPA opened the way in mid 2017 for a consortium of three large Turkish electricity companies to potentially take a 49% equity stake in the project. Hence the negotiations were postponed and, so far, Rosatom is the only owner of the project. Akkuyu project

remains the only application of the BOO model for an NPP project.

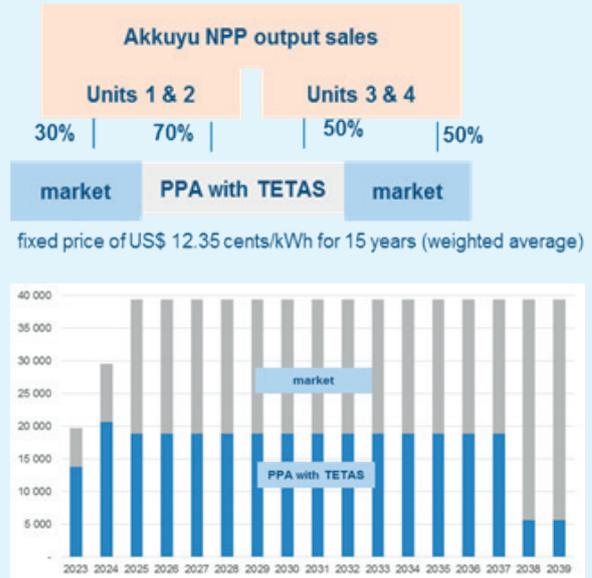


Figure 7. Electricity sales in accordance with terms of Akkuyu PPA, based on Akkuyu IGA information<sup>23</sup>

**agreements** (PPAs). In recent PPAs for NPPs, the purchaser agrees to take a contracted amount of electricity at a fixed price covering the full cost of the project plus margin, or pays a penalty. In the case of the Akkuyu NPP project in Turkey (see *Box Turkey – a new build with vendor finance under a build, own, operate (BOO) model*) a PPA with an electricity wholesaler is used without a host government guarantee (see below), while the PPA for the recent Barakah NPP project in the UAE (discussed above) includes a government guarantee.

Other options providing long term revenue certainty include **contracts for difference** (CFDs). With a

CFD, the generator is paid the difference between the contracted 'strike price' for electricity – reflecting the cost of the project plus margin – and the actual market price for electricity (or 'reference' price). It provides the investor with certainty and stability of revenues, with the risk transferred to the counterpart to the CFD, which is generally a government (and hence taxpayers). On the other hand, this counterpart benefits from the difference, if electricity market prices exceed the strike price (Fig. 9).

A CFD has been agreed for Hinkley Point C NPP in the UK (see *Box United Kingdom – returning to nuclear*), and it is expected that the same mechanism will be used for subsequent UK projects.

*Long term contracts such as power purchase agreements and contracts for difference can share the risks of investing in a new NPP*

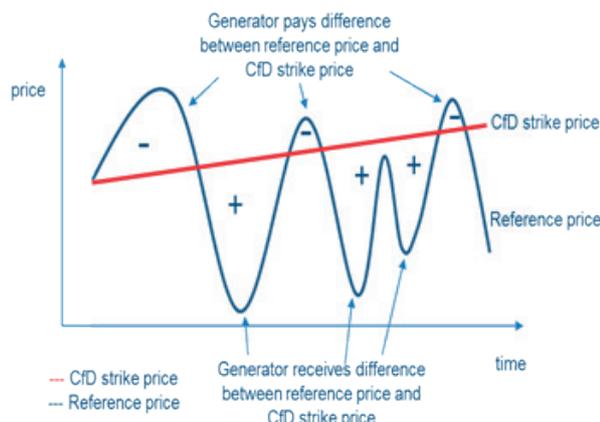


Figure 8. Operation of contracts for difference

## How can governments encourage investment in deregulated markets?

The guarantees provided by CFDs and some PPAs are examples of **host government guarantees**. Governments can also provide **loan guarantees** to assure lenders that they will be reimbursed in the event of default by a borrower. This allows an NPP

developer to increase leverage and reduce financing costs (via lower interest rates). In the USA, federal loan guarantees and other incentives outlined in the US Energy Policy Act<sup>22</sup> of 2005 are available for up to 80% of project costs for advanced nuclear reactors and other low carbon technologies, and were used to finance the Vogtle NPP. Similar schemes are available for new projects in the UK (see Box *United Kingdom – returning to nuclear*).

*Governments can share risks with investors and lenders or create additional markets that value reliable baseload generation*

Aside from supporting new investment by taking on investment and market risk, governments can also provide revenue support that is not directly related to the energy and finance markets. This includes supporting markets for services beyond energy output (i.e. kW·h) to also provide **capacity remuneration** for capacity availability (i.e. MW), which can ensure a more predictable flow of income well suited to covering fixed costs. Capacity markets exist in several countries and support existing baseload generation including

### Case Study: United Kingdom – returning to nuclear

The UK was among the pioneers of electricity market liberalization. While not directly involved in the ownership of utilities, the UK government is planning around 16 GW(e) of new nuclear capacity by 2030. To facilitate financing for large infrastructure projects, including nuclear power, the government is using **CFDs** to provide increased revenue certainty and **loan guarantees** to create a competitive and liquid bond market.<sup>12, 26</sup>

The first new project supported under these measures is the Hinkley Point C (HPC) NPP, financed by a state-backed utility and vendor (EDF Energy). The UK Guarantee Scheme may guarantee up to £10 billion (£2 billion approved) of loans to HPC, while a CFD has been agreed with an indexed strike price of £92.50/MW.h (2012 prices) for 35 years from the end of construction reducing to £89.50/MWh (2012 prices) if EDF take a final investment decision on their proposed Sizewell C project. In case of a substantial construction delay, the CFD would be cancelled leaving the owner reliant solely on revenues from the market. The HPC CFD also includes several additional mechanisms to protect the UK government, including a construction gain share and an equity gain share.<sup>12</sup>

nuclear. Usually, they are not used for investment in new generation because new generation investments require long term agreements for sale and purchase of power output than ones usually used in capacity markets. However capacity payments allow utilities to secure financing for new generation.

Other mechanisms include **carbon taxes or emissions trading** – which increase the cost of electricity from fossil sources and thus increasing the competitiveness of nuclear power – and **tax incentives** to reduce the burden on new nuclear builds. For example, the US Energy Policy Act of 2005 provides a production tax credit of 1.8–2.1 US¢/kW·h for the first 6000 MW(e) of new nuclear capacity constructed, available for the first eight years of operation.

### Small Modular Reactors – a way to reduce costs?

The world's first nuclear power plant that generated electricity for commercial use was a small reactor (5 MW) built in the Soviet Union in 1954. Many reactors were initially built small, but with evolving technology and increasing demand, GW-scale nuclear power plants were developed, taking advantage of economy of scale – larger reactors offering smaller per unit cost (per MW of installed capacity, or per MW·h of generated electricity). Small and medium sized reactors (up to 500 MW) were quite popular in countries where the demand was not very high and the transmission grid was not in a position to support large reactors.

Many countries started to consider small and medium sized or modular reactors (SMRs) as an alternative to large reactors for several reasons but mainly for expectations that small size and modularity would mean smaller upfront investments due to smaller scale, faster construction and shorter payback period. The modularity would allow building a first module and then adding new ones when there is need or funding available. Additional advantages of SMRs include the ability of load following, lower grid requirements in terms of capacity throughput (small grid), lower requirement for access to cooling water, ability to be used for co-generation, such as desalination, ability to remove reactor module or in-situ decommissioning at the end of the lifetime. They can be built and used in remote areas with low demand requirements.

Over 50 SMR designs (water, gas and liquid metal cooled) are under development for immediate and near term deployment. Many technological innovations were introduced to simplify plant design, reduce construction period, improve plant safety, and increase operational performance. Three SMRs are in advanced construction stages: the 27 MW(e) CAREM-25 in

Argentina, the 250 MW(th) HTR-PM in China and the 35 MW(e) KLT-40S in Russian Federation.

SMRs ready for industrial demonstration are the prototypes with very low capacity (except for those in China) thus it is difficult to compare them with large size reactors. At least 10 SMR designs are being developed for potential near term deployment.

It is too early to say whether SMRs will be cost competitive compared to existing, large reactors, and other technologies for power generation. Levelized cost of electricity (LCOE) for a first-of-a-kind (FOAK) SMR will be 30% higher than the LCOE of an n<sup>th</sup>-of-a-kind (NOAK) large reactor. Modularization, and serial, in-factory, fabrication could result in a decrease in capital expenditures (5 to 10% for each cumulative doubling of production)<sup>24</sup>. LCOE parity with a NOAK large reactor could be achieved at 5 GW(e) of deployment. Operational efficiencies could offset the higher operating costs expected for SMRs.

## **KEY POINTS: NUCLEAR FINANCE IN CHANGING MARKETS**

Electricity market reform varies worldwide in terms of approach, goals and impacts. In mature economies, reforms have generally involved disaggregation and deregulation aimed at increasing competition, reducing prices and promoting efficient investment. In emerging economies, reforms have sought to promote investment in generation capacity to meet rising demand. Many emerging markets remain regulated, with new generation paid through regulated tariffs. In deregulated markets, reforms have increased price uncertainty and have generally failed to provide incentives for long term investment, particularly in capital intensive generation.

Almost all markets retain a degree of government intervention, sometimes to provide long term price certainty to support investment, but also to achieve other goals such as climate change mitigation. In some countries significant support is provided to renewable technologies. Combined with market liberalization, support for renewables has reduced electricity prices and increased supply volatility, creating additional

technical and financial challenges for existing and new NPPs.

government financing of new NPPs is often used in regulated emerging markets. Direct or indirect Government financing, corporate financing and vendor financing are still the main models for building new NPPs in other markets, while project financing for nuclear power is yet to be demonstrated. A promising option in some deregulated markets is for large electricity consumers to finance new projects as both owner and customer.

Mechanisms to support investment by managing the risks associated with price and revenue uncertainty in deregulated markets include power purchase agreements (PPAs) and/or contracts for difference (CFDs), government financing or guarantees (PPA guarantees, loan guarantees, acting as CFD counterpart), capacity remuneration, tax incentives, and carbon pricing and trading.

Together, these financing and support mechanisms provide a range of options to investors and governments to support the construction of capital intensive baseload NPPs, across various markets. These mechanisms can go some way to overcoming the limitations of electricity market reform to promote efficient investment in reliable, long lived, low carbon generation capacity.

Although new mechanisms of financing and ownership are beginning to be used, including mechanisms used in other power industries, such as the B-O-O ownership model, Mankala financing model, or CFDs) it is rather early to evaluate their success. New nuclear power projects, including those built in regulated environment and even in liberalized markets, require measures and mechanisms to ensure revenues and secure financing.

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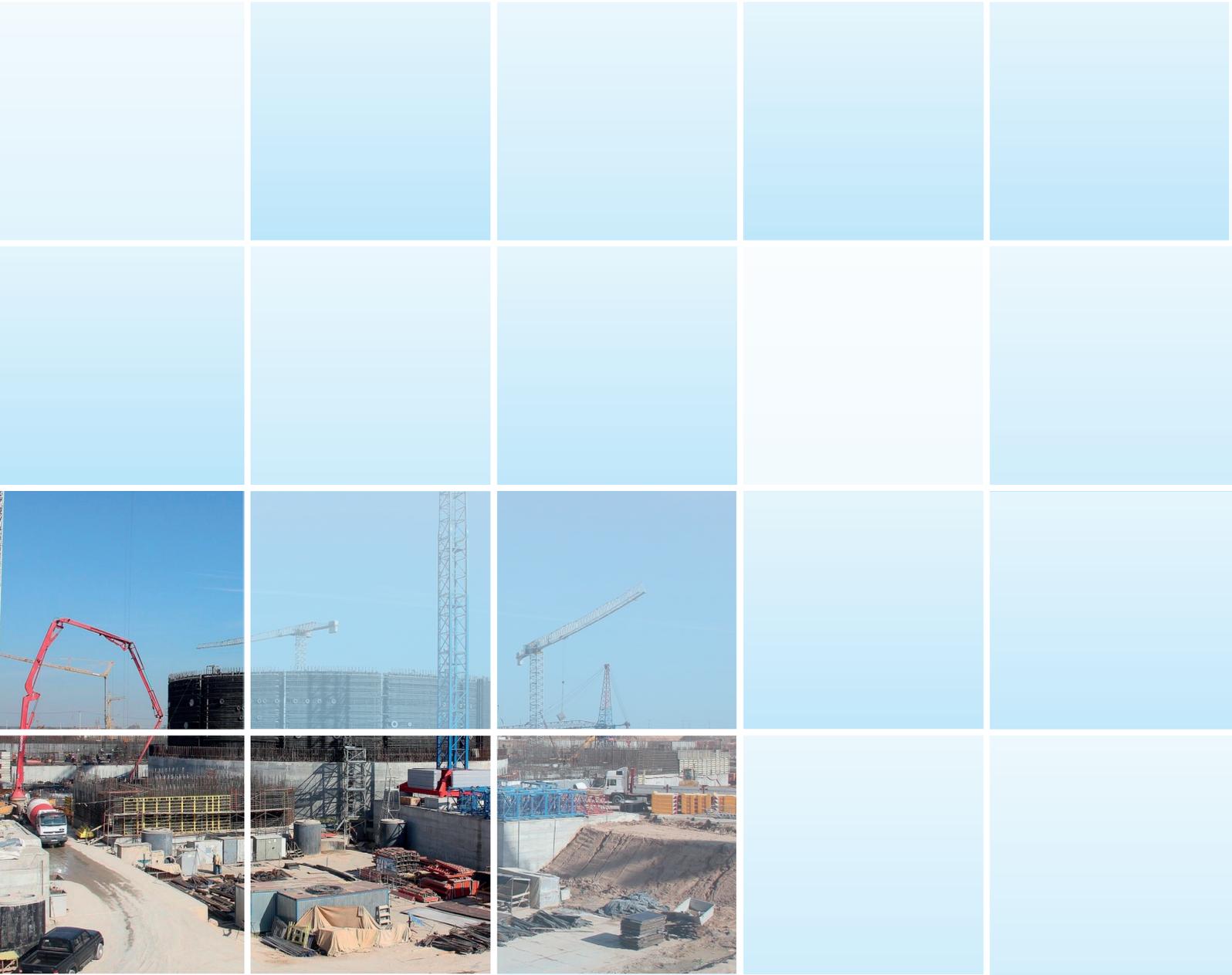
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April 2018