Nuclear asset shutdown under uncertainty

by

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M.S., Massachusetts Institute of Technology (2011)

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Abstract

The restructuring of the power sector that began in the 1990s created acute competition for nuclear power plants. While merchant reactors benefited from this change in the early years, recently they started to retire for economic reasons well before the expiration of their operating licenses. This unexpected wave of premature shutdowns has severe implications for energy and climate policy. It invites us to re-assess the viability and role of nuclear in a transitioning energy sector.

The thesis first develops two new tools aimed at measuring nuclear competitiveness and informing retirement strategies: (1) a structural model of electricity markets based on supply and demand equilibrium and (2) a long-term asset valuation framework accounting for stochastic price dynamics and flexible retirement options. We employ these tools to analyze the challenges facing nuclear energy in two countries: the United States and Japan. After evaluating the drivers and likelihood of premature retirements, we discuss a range of technological innovations and regulatory options that could help nuclear bring value to future competitive markets.

We show that low natural gas prices and stagnant electricity demand have been responsible for the drop in nuclear plant revenue in the United States. We measure that renewable wind and solar PV impact nuclear operations only for penetration levels above 15% and 30% respectively. We also find that spot price volatility, a feature of competitive markets, defers nuclear retirement decisions rather than precipitates them.

In this context, nuclear must adapt. Greater operational flexibility can prevent financial losses in areas where renewables are being deployed on a large scale. In the medium-term, heat storage technologies would protect plants’ profitability while enabling deep decarbonization of the energy sector. Finally, a few plants may be able to reach niche markets by diversifying their output beyond electricity.

We recognize that the carbon-free attributes of nuclear energy are not valued in competitive markets. Yet, even a moderate price on carbon would save most reactors. If not possible, states may adopt nuclear subsidies to meet their policy objectives. As a last resort, the exercise of a new mothballing license could prevent the irreversible loss of nuclear assets.
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Nomenclature

\( \alpha \) \quad \text{Short-term risk-adjusted average}

\( \chi_t \) \quad \text{Long-term component of spot price at time } t

\( \kappa \) \quad \text{Mean-reversion rate}

\( \mu \) \quad \text{Equilibrium drift rate}

\( \pi_n \) \quad \text{Net pre-tax cash flow for the time interval } n

\( \rho \) \quad \text{Correlation in stochastic increments}

\( \sigma \) \quad \text{Volatility}

\( \bar{\mu} \) \quad \text{Risk-adjusted equilibrium drift rate}

\( \xi_t \) \quad \text{Short-term component of spot price at time } t

\( C_n \) \quad \text{Total cost of generation for the time interval } n

\( \text{Cap}_n \) \quad \text{Average capacity price for the time interval } n

\( f(t) \) \quad \text{Seasonality component of price}

\( P_n \) \quad \text{Average price of electricity for the time interval } n

\( q_n \) \quad \text{Total electricity generation for the time interval } n

\( s_i \) \quad \text{Amplitude of } i^{th} \text{ seasonal factor}

\( S_t \) \quad \text{Spot price (day-ahead price typically) of electricity at time } t
$ZEC_n$ Average zero-emission credit or equivalent subsidy for the time interval $n$
Introduction

Problem statement

The electric power industry has undergone fundamental restructuring over the past 20-30 years in the United States and Europe [78, 135]. As electricity generation became competitive in the 1990s, the vertically integrated utilities lost their monopolies over the entire value chain of the electricity business (Figure 0-1). The utilities regulated on the basis of cost of service were replaced by independent companies competing on the short-run marginal cost of production of their assets. Electricity markets, previously “regulated”, became “liberalized” or “deregulated”.

The commercial nuclear power plants in operation today were all built during this earlier monopolistic business environment. In that era, the steep capital investments and their associated risks were passed on to the consumers through their electricity bills, thereby paying back the utilities. The nuclear plants affected by the 1990s market reform — the so-called “merchant” plants — were enjoying their new competitive environment at first. Electricity prices were relatively high and growing from the late 1990s to the late 2000s [78]. In addition, the plants’ performance (capacity factor) was improving significantly. Owning a merchant nuclear plant was very profitable. The operating licenses of nuclear plants were systematically extended when

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1 Note that the term “deregulated” is incorrect: competitive markets are still organized by a large set of market rules with oversight of several regulatory bodies.

2 The last units to be commissioned in the U.S. were Limerick in 1990, Comanche Peak in 1990 and 1993, Seabrook in 1990 and Watts Bar I in 1996. Watts Bar II was commissioned in 2016 by the regulated public power company TVA. In western Europe, plants are under construction in France and Finland but are not yet completed.

3 A merchant plant is a plant that solely relies on competitive markets for its revenue.
Figure 0-1: The colored States represent the States that have partially or completely restructured their electric power industry. About half of the U.S. nuclear capacity (dots on the map) lies in these regions.

legally possible. In the mid-2000s, new reactor construction projects were initiated in regulated, as well as deregulated, markets (the so-called “nuclear renaissance”).

However, economic conditions worsened in the late 2000s, and most new reactor projects were abandoned. In the early 2010s we started to observe the first retirements of legacy nuclear plants in the United States — Kewaunee in 2013 and Vermont Yankee in 2014. These closures that occurred before the end of the reactors’ operating licenses were largely unforeseen. Since then, many other reactors have shutdown. Today, many are at risk of a similar fate. Merchant reactors are struggling to recover their fixed operating costs and could retire prematurely. This unexpected phenomenon has severe implications for energy policy and climate change mitigation, as nuclear represented 20% of the total U.S. electricity and 60% of its carbon-free generation in 2015.

Existing reactors in other countries also face market pressure, albeit to a lesser extent due to higher electricity prices in those places. In Europe, the substantial cost of nuclear license renewal and the aggressive penetration of renewable energy
sources expose nuclear to new challenges in liberalized markets [109]. In Japan, all nuclear reactors were forced to shut down after Fukushima, and are required to undertake costly safety upgrades in order to restart. The upcoming restructuring of the Japanese power sector in 2020 raises uncertainty about the recovery of these investments in what will be a newly competitive setting.

All over the world competitive markets challenge nuclear assets. Plants have very long lives and minimal operational flexibility, which makes them risky enterprises in the face of uncertain and volatile electricity prices. Plant owners face a recurrent question: continue operations and invest in the expectation of future profits, or shut down forever.

**Thesis objectives and plan**

This thesis addresses questions that are central to the future of the commercial nuclear fleet in competitive market environments.

- First of all, how do nuclear plant owners make the decision to retire an existing nuclear asset? In particular, how do they deal with price uncertainty? How do they time their decision optimally?

In Chapter 1, we will see that classical decision methods have shortcomings when it comes to appreciate the full value of merchant nuclear power plants. We therefore develop two instruments aimed at better measuring historical and potential future retirements: an fundamental model of electricity market and a long-term valuation tool of nuclear asset under uncertainty.

Chapter 2 uses these tools to answer the following questions:

- What are the fundamental drivers of nuclear competitiveness?

- What are the determinants of nuclear asset retirements? What is the role of spot price uncertainty in early closure decisions?
• What is the outlook for nuclear energy in liberalized electricity markets? What are the consequences on energy policy?

Chapter 2 looks at the situation of existing nuclear plants in two specific countries where nuclear economics are particularly challenged by competition and market reform: the United States and Japan. The drivers of nuclear retirements and their consequences are identified, measured, and discussed.

Chapter 3 discusses solutions:

• How can the nuclear industry adapt to increasingly competitive environments? Is the large scale deployment of renewables a threat to nuclear economics?

• Are the attributes of nuclear energy correctly valued by markets and aligned with policy objectives? If not, what market rules could be proposed to effectively remunerate these attributes?

• Are there promising technological innovations that could help existing nuclear assets?

This last chapter proposes a set of technological innovations and regulatory options that could help maintain nuclear power in competitive markets.

**Contribution to the existing literature**

This paper contributes to the existing literature in several ways. First, we find that the topic of nuclear retirement economics has drawn little attention from the academic and research community. Most authors have focused on new nuclear economics, for instance [116, 115, 112, 98, 121]. However very few have focused on existing plants. The recent paper by Davis and Hausman [85] is an exception. The authors quantify the consequences of the closure of the San Onofre Nuclear Generating Station in California using econometric techniques. They calculate the impact on the energy mix, cost of generation, transmission constraints and market power. Their analysis,
though, is limited to California and to a past decision. They do not look at the nation-wide picture nor at future prospects.

   As the nuclear retirement crisis intensified in the U.S., other authors started to investigate the cost and benefit of existing nuclear power plants. Roth and Jaramillo calculate the cost of maintaining nuclear power based on data from the industry [140]. They conclude that preserving the nuclear fleet through policy support mechanisms is a cost-effective way to avoid carbon emission. In another paper, Tsai and Güllen [155] focus on the subsidies given to Illinois and New York plants. They question the rationale of local carbon emission reduction caused by zero-emission credits by stressing the existence of potential carbon leakage.

   Other papers, mainly from the banking and financial service industry, look at the financial health of the U.S. nuclear reactor fleet and try to forecast future closures [151] [139]. They focus on the short-term cash-flows of the reactors but often lack long-term policy analysis and rigorous model description.

   The nuclear community itself investigated the topic of early nuclear retirements and issued policy recommendations [50] [59]. Again, the methodology is not explained in detail which prevents the reproduction of the results. They unanimously conclude on the urgency of legislators to act to preserve nuclear assets.

   In this thesis we try by contrast to adopt a neutral, rigorous and broader approach to the topic of existing nuclear plant economics. We try to develop methods and draw conclusions that are applicable to not only a few plants in the United States but potentially to any merchant nuclear plant. The two cases studies we choose — the United States and Japan — are meant to cover economic environments that are sufficiently different in order to offer universal tools and conclusions.

   Second, the two tools we develop in this thesis contribute to a finer analysis of nuclear retirements.

   The first tool, a model of competitive electricity market, gives insights about the fundamentals of nuclear power plant revenue. By modeling the operation of the market, we are able to reproduce the behavior of spot wholesale electricity prices
in several regions of interest and to quantify the drivers of nuclear economics. We can also simulate the hypothetical revenue of nuclear plants in future markets. The model formulation is not new by itself, as many of such “economic dispatch” model already exist (see for instance [148, 86, 109]). It is optimized for the study of the energy sales from nuclear plants and it does not try to model unnecessary features such as coal plant startups or ancillary services. Our model is nevertheless powerful in that it is relatively accurate despite its simplicity. It is fast to run and adequate to conduct sensitivity analysis. The quality of our model inputs results in a satisfactory replication of historical price shocks, and consequently helps measure the drivers of nuclear profitability in competitive markets.

The second contribution in the methodology domain is the model of stochastic electricity price. Our model is a two-factor stochastic price process that include two volatility components: one for short-term mean reversion and another long-term dynamics. Such models were developed for commodities such as copper and oil for instance in [145, 130]. They were later applied to spot electricity prices by adding a seasonality component and then demonstrated superior fit to observations, notably in the Scandinavian electricity markets [122]. Differentiating short- and long-term volatility is important as the short-term variations prices can accelerate the decision to retire a nuclear plant losing money, whereas the long-term variations are crucial to apprehend the value of a plant over its entire lifetime (up to 10-20 years in the future if necessary). Both timescales are essential when it comes to make operating decisions today. More sophisticated models can be found in the literature such as those modelling seasonal price jumps and supply stack [81], but our problem did not clearly justify this added complexity.

The calibration of the two-factor stochastic model for electricity price enables to fit the futures curve of electricity price. It gives access to both the expected spot price of electricity and the price of risk associated with spot price stochastic behavior. It is therefore a naturally meaningful model for nuclear plant valuation, for which energy sales represent the largest source of risk. The extrapolation of the true futures curve with its volatility characteristics improves the long-term valuation of a nuclear plant.
The plant owner can explicitly calculate the risk-neutral expectation of price instead of relying on a default risk-adjusted discount factor.

The nuclear asset valuation technique we adopt incorporates the value of *real options* and calculates the optimal retirement decision. It is a net improvement as opposed to the Net Present Value (NPV) rule, which can prescribe the sub-optimal retirement of an asset. The approach we use is built upon a legacy of financial engineering and real option valuation literature. It is for the first time applied to a nuclear power plant in the midst of its life, with a stochastic process that embraces the credible dynamics of future electricity prices. Previous work have indeed either focused on infinite lifetime assets (such as in a copper mine valuation by Schwartz [145, 146]), or finite life assets with unrealistic price processes. Almost all real option literature adopts the simple geometric Brownian motion (GBM) with drift because it results in analytical solutions [87].

Real option valuation has been applied to nuclear plants by other authors. Rothwell [142], Jain et al. [113], Gollier et al. [83], Takizawa and Suzuki [153] compute the option to invest in new nuclear plants, but again they all assume a GBM process for price and infinite-life assets. Takashima et al. [152] analyze the mothballing option of nuclear power plant but again, considered a simple Brownian motion and an infinite plant lifetime. Our model by constrast captures a realistic behavior of electricity prices to optimize the retirement of ageing nuclear plants. A recent review of real option models applied to the electricity sector [90] confirms that such study is missing in the literature. We compute not only the option to retire a nuclear plant before the end of its operating license, but also the option value of mothballing and of lifetime extension. Our methodology is tractable and the exercise not purely academic. It is meant to be used by the industry. We provide a step-by-step example with the Fitzpatrick plant.

These tools generate results that are original. In particular, they allow a quantification of the drivers of nuclear plant revenue and of the factors affecting nuclear retirement decision. Other authors have identified the same drivers [51] but the quan-
itive dimension is missing in the literature. Many sources have for instance implied that the deployment of renewables was the primary cause of nuclear retirement in the United States (see for instance the interview of Exelon’s CEO in [156]). We demonstrate here that it is a secondary factor. Natural gas and low electricity demand growth have had a largest impact on nuclear plants revenue than renewables penetration. In the Midwest, the effect of wind on price was even offset by coal power plant retirements. A few plants (some of them owned by Exelon) could be locally affected by wind in case of power line congestion but it is far from being a nationwide problem as suggested. Our analysis also shows that nuclear economic drivers differ in magnitude from one region to another, as revealed by our analysis of the US Midwest, the US Mid-Atlantic and the Japan Tokyo region. Our description of Japan’s power sector characteristics highlights fundamental differences and invites cautiousness about applying US diagnostics and solutions to Japan.

As in other reports before us (Bloomberg in 2016 [151], R Street Institute in 2016 [139], SNL in 2017 [124]), we provide an assessment of the financial health of the US commercial nuclear fleet. Our main differences are: a more granular accounting of nuclear costs (we use the plant- and yearly specific cost estimates of SNL instead of fleet average numbers), the measurement of the impact of subsidies (ZECs), and the inclusion of regulated nuclear plants in the country-wide picture. Unlike others, our analysis is completely open and transparent\textsuperscript{4} which allows readers to reproduce results and comment them.

Our analysis of the perspectives for existing nuclear plants in deregulated Japan corroborates other studies. Komiyama and Fujii for instance use a sophisticated capacity expansion model to analyze long-term scenarios of Japan’s energy mix [119]. They show that a nuclear phase out would cause generation costs to quadruple by 2050. They assume fixed fuel price scenarios however, which we show is the critical factor of nuclear plant profitability in Japan. They project a steady increase of fossil fuel price regardless of the generation mix, whereas history shows that the power sector impacts fuel demand. Fossil fuel prices show important long-term volatility in

\textsuperscript{4}The calculation spreadsheet is available online at \url{ceepr.mit.edu}
Japan (see for instance [92]) and our sensitivity analysis demonstrates that in cases prices go down nuclear restart investments may not be fully recovered in competitive markets, which puts existing nuclear reactors at risk and together with them the energy policy goals of the country.

The impact of spot electricity price uncertainty on nuclear plant investments has been studied by some authors using the real option pricing framework. Real option valuation leads without surprise to a higher value of nuclear assets as compared to the classical DCF/ NPV method. Optionality creates value, a result that is consistently demonstrated in all real option problems (see for instance a review in [89]). What is new in this thesis is the measurement and the confirmation of these options values in the case of real nuclear retirement. The method we use is tractable and we hope to contribute to its wider use among nuclear plant owners. We acknowledge it is more complex but we believe this extra complexity is compensated by the additional information it carries compared to the DCF/ NPV method. The absolute option value is sensitive to assumptions and should not be blindly trusted, but the method has the merit of providing a measure of optimal retirement timing in very uncertain situations.

Nearly zero papers study the impact of price uncertainty on nuclear retirement decisions. Rothwell [142] evaluates the risk premium associated with revenue uncertainty of new nuclear power plants. He calculates the option value of waiting and delaying the investment decision. The calculation for an ABWR plant in Texas shows that the value of this option is significant — up to 25% of the total investment cost. He accounts for the uncertainty caused by electricity price, generation cost and capacity factor. Takashima et al. [152] quantify the option value of mothballing but not the option value of early retirements. The reason is that they use an infinite life asset. Dixit and Pindyck in their book [87] show that increased volatility increases the option value of waiting and defers irreversible abandonment decisions. We find that their result, obtained with a geometric brownian motion, applies as well to real nuclear plants subject to more complex stochastic price dynamics. Our study also
reveals the importance of nuclear fuel cycles in optimal retirement timing. This result has not been formally underlined in previous literature. We also show that the option value of extending the operating license has little impact in the closure decision of a reactor such as Fitzpatrick. Finally we identify a factor that may have precipitated Entergy’s decision to shutdown the facility: a mild 2015/16 winter causing unexpectedly low wholesale electricity prices.

Unlike Rothwell and Rust [143], we do not study the impact of unexpected problems affecting the plant and their associated consequence on optimal retirement. This is a limitation of our analysis. The differentiation of idiosyncratic (i.e. unhedgeable) risk vs. tradable risk and its impact on real option is one of the latest addition to the real option literature. In incomplete markets, risk can not be rigorously accounted by risk-neutral expectations, and the risk preference of the decision-maker matter. Henderson in 2007 [107] and Grasseli in 2011 [101] propose to use an exponential utility function to reflect risk aversion. Their approach is applied to an investment decision with uncertain payoff (infinite life asset in Henderson’s and finite life asset in Grasseli’s case). They show that instead of deferring investment, “risk-aversion and idiosyncratic risk erode option value and lower the investment threshold”, “a sharp contrast to the conclusion of standard real option model”. Our methodology did not allow us to verify this result in the case of nuclear retirement.

Finally, we contribute to the existing literature through our list of potential solutions for maintaining nuclear power in competitive markets. We try to discuss policy solutions that are innovative and/or have not been quantitatively evaluated.

The impact of large-scale renewables — wind and solar PV — deployment on the electrical grid is a common topic of the literature. The MIT future of solar study [42] and Hirth [108] for instance identify the same decline in the system value of renewable electricity as wind and solar PV are deployed. Here we show their particular impact on nuclear plant revenue in the Tokyo and Midwest grid. We observe that price

\footnote{Idiosyncratic risk in our case would be for instance the risk related to nuclear cost escalation, capacity payments or to generation disruption. By opposition, electricity price risk is tradable and is hedgeable.}
suppression is exacerbated by feed-in-tariff programs.

Nuclear load-follow capability has been studied from the nuclear system point of view [34, 80] but few papers compute the market opportunities created by this mode of operation. We characterize the domain where the benefit of nuclear flexible operation exceeds its cost (when subsidized renewables reach a certain threshold). We also discover a potential source of market power created by load-follow capability, which nobody described previously.

We confirm that little revenue is to be gained from the ancillary service, heat and radioactive isotope markets. They can provide substantial benefits in a few specific cases that we identify but will never substitute the wholesale electricity and capacity markets as the main source of revenue of nuclear plants — especially in a world of cheap fossil fuels. It is therefore not surprising that nuclear output diversification has been a neglected subject in the recent literature.

Heat energy storage coupled to nuclear however is a novel topic that has drawn substantial attention, as demonstrated by active research at MIT and elsewhere [67]. Our contribution to this field is to exhibit its market benefits, although in a simplified way. We explore how a system such as FIRES\(^6\) with infinite storage capabilities can accelerate the deployment of renewables without compromising nuclear plant revenue, enabling a cost-effective transition to a low-carbon world. Research is ongoing and the technical details of heat storage systems still need to be worked out [84] but our preliminary results are encouraging.

On the policy side, the benefits of nuclear energy in favor of climate policy and energy security have been recognized in many studies. See for instance recent reports in the US by the Brattle group [129], the DOE [50], or Roth and Jaramillo [140], and in Japan by the Ministry of Economics, Trade and Industry [37]. More specifically, the relationship between carbon price and nuclear competitiveness was studied by the OECD in 2011 [33] but was limited to Europe and LCOE comparisons. Here we provide a system analysis of the impact of carbon price in the US. The IEA [61], Rothwell [141] and Kee [38, 39, 118] more broadly looked at the market design

\(^6\)Firebrick Resistance Heated Energy Storage
problems facing nuclear in competitive markets and try to propose solutions as we do.

The zero-emission credits have created a passionate debate and generated abundant comments [17]. It is however hard to find a neutral analysis of their pros and cons in the literature. We hope this thesis helps re-centre the debate. Our other regulatory proposals — low-carbon capacity mechanism and low-carbon portfolio standards — enrich similar proposals made by others such as [59]. The last one — the low-cost mothballing — was briefly suggested by Kee [102]. Here we discuss in length the conditions for its applicability.
Chapter 1

Methodology and tools

The premature retirement of a nuclear power plant is a consequential decision for its owner. Nuclear reactors are multi-billion dollar capital investments and their shutdown is irreversible once the decommissioning process has been engaged. One of the objective of this thesis is to develop quantitative tools that can be used by plant owners and policy-makers to study the economics of existing nuclear power plants in competitive markets. We present in this chapter three instruments that are applied later in the thesis to investigate nuclear power plant retirements.

The first tool is a traditional asset valuation method based on Discounted Cash Flows (DCF) and the Net Present Value (NPV) rule. It is similar to the method that power plant owners classically use to appraise their assets. We use it as a reference. The cash flow of the plant over the future years is based on an expected price trajectory. In this thesis we use the futures price curve but in theory we could use any price forecast to estimate expected future cash flows. A discount factor is then applied and the sum of expected discounted cash flows equal the net present value of the plant. Finally, the Net Present Value (NPV) is compared to the cost of decommissioning to make a decision.

The second quantitative tool is a fundamental model of the electricity market, or “economic dispatch” model. It attempts to reproduce the supply and demand
curves for every hour of the year while taking into account the physical constraints of the generators and of the grid such as available installed capacity, ramping capabilities of the generator, and storage. As a result, we obtain the dispatch of the generators and the system marginal cost, that is the spot price of electricity for every hour of the year. The model requires a fairly detailed description of the supply curve to reproduce historical prices adequately. This approach gives fundamental insights about the underlying phenomena that impact prices and consequently nuclear power plant revenues from the wholesale electricity market. It can also be used to evaluate the outcome of possible new market rules (e.g. carbon price), of generation capacity withdrawal and/or capacity addition.

The third tool is an asset valuation framework based on a stochastic process for electricity price and on the option value of flexible retirement decision. The dynamics of the spot price are modelled by a stochastic price process which represents the foundation of the valuation method. The option to mothball, to extend the lifetime and to retire the asset early are then introduced to reflect the range of key operating strategies the plant owner can adopt depending on the range of possible cash flow outcomes. This “real option” framework provides quantitative information about the role of uncertainty in decision making, and about the optimal timing for nuclear asset retirements.

1.1 Classical asset valuation and decision rule

The classical asset valuation approach calculates the net present value (NPV) of the nuclear asset based on its total forward cash flows. This NPV is then used to inform business decision. In particular, if the NPV of retiring the plant is higher than the NPV of continuing operation, the plant should be retired immediately. This is the “NPV rule” that we find in all corporate finance textbooks such as [76]. It is the method frequently employed by the utilities because it is simple and easy to understand. The calculation is straightforward (an Excel spreadsheet is sufficient).
However the complexity lies in the estimation of risk which is integrated into the discount factor. We recall in this section the main steps of the valuation and explain how it can be applied in practice for a nuclear plant valuation exercise in the US and in Japan.

### 1.1.1 General formulation

A nuclear power plant is an asset that provides payoffs equal to its net revenue (income minus cost) over its lifetime. The value $V$ of the plant at time $t = 0$ is given by its expected discounted cash flow:

$$V = \mathbb{E}\left[\int_0^T \pi_t e^{-\rho t} dt\right] \quad \text{(continuous time formulation)} \quad (1.1)$$

$$= \mathbb{E}\left[\sum_{t=0}^T \pi_t e^{-\rho t}\right] \quad \text{(discrete time formulation)} \quad (1.2)$$

where $\pi_t$ is the net revenue at time $t$, $\rho$ is the discount rate, and $T$ the end of the lifetime of the asset.

The Net Present Value (NPV) rule states that a project should be undertaken if its NPV is greater than that of the status quo. In the case of decommissioning, the plant should be retired if the NPV of its continued operation $V_t$ is less than the NPV of its decommissioning $D$, that is if $(V_t - D) \leq 0$

Albeit simple, the NPV rule exhibits three major difficulties: the calculation of the net revenue, the choice of the probability measure to compute the expectation, and the determination of the discount factor.

Net revenues are the sum of energy sales (electricity price times generation) and costs. Over a given time interval $s$, the net revenue is

$$\pi_t = q_t S_t - C_s \quad (1.3)$$

with $S_t$ spot price of electricity, $q_s$ electricity production and $C_t$ cost of production. In case capacity payments and subsidies exist they are added to the cash flow.

In a nuclear power plants, costs and generation are in general well known. Price
is by far the largest source of uncertainty (and risk) nuclear plant owners face when valuing their assets in restructured electricity markets. Plant owners use the best of their knowledge to draw price scenarios. They can develop their own forecasts, use third-party projections (EIA for instance) and/or adopt the price of traded electricity futures contracts as an substitute for expected future spot price. This latter approach is commonly used by utilities and we will explain how to use it to value nuclear plants in the US in the next subsection. Futures are limited to the market horizon (3 to 5 years typically) though and therefore the decision maker must always rely on alternative forecasts for longer term valuations.

Nuclear generation and costs cannot be directly linked to traded financial assets and therefore the risk-neutral expectation cannot be computed for these components as they are for the spot price (in subsection 1.3.2 we show how to compute risk-neutral expectation for spot price). There is no market price for generation and cost risk. An alternative way to take risk into account is through the discount factor $\rho$. $\rho$ then incorporates the time value of money and the risk of the project. The risk-adjustment of discount factors is the preferred approach used in corporate finance. In practice, companies tend to use firm-specific discount factors (such as the weighted cost of capital, WACC) rather than project-specific discount factors (see [100] survey). $\rho$ is chosen such as it equals the expected payback of the company’s financial resources (debt from banks and equity from investors):

$$\rho = \frac{D}{D+E}r_d + \frac{E}{D+E}r_e$$  \hspace{1cm} (1.4)

with $D$ and $E$ debt and equity levels respectively, $r_d$ expected return of debt and $r_e$ expected return of equity. The Capital Asset Pricing Model (CAPM)\footnote{The CAPM model assumes market equilibrium between asset and market portfolio.} is classically used to compute $r_e$:

$$r_e = r_f + \beta (r_m - r_f)$$  \hspace{1cm} (1.5)

where $r_f$ is the risk-free rate of return, $r_m$ the expected return from the market.
portfolio and \( \beta \) a coefficient expressing the company’s equity return correlation with that of the market.

We now show more precisely how to perform the classical valuation of nuclear plants in the U.S. The results of the valuation are discussed in Chapter 2 where we provide a estimate of the US nuclear reactor fleet.

### 1.1.2 Valuation in the United States

In the U.S., the cash flow of nuclear power plants is the sum of a) the energy sales, b) the capacity market revenue, c) the policy support (subsidies if applicable) minus d) the cost of generation. Both historical (from 2013 until 2016) and future (2017-2019) market data are used to compute the expected future cash flows. The availability of the futures price data vary by location. Market prices are usually not available beyond a few years into the future and therefore the valuation we describe here is limited to 2019 and therefore incomplete because nuclear assets have a longer lifetime (most operating licenses end beyond 2030 in the U.S.). The valuation we perform in the beginning of Chapter 2 is therefore a short-term valuation only.

The historical generation of each facility in MWh is obtained from EIA survey forms 923 \[22\]. For future estimates, we take the average over the 2012-2015 period (4 years, \( \sim 2.7 \) fuel cycles).

The power sales are approximated as the product of the average of the day-ahead Locational Marginal Price of wholesale electricity (LMP, in \$/MWh) at the plant location, and the total generation for the time period considered. The hourly historical LMPs come from the market operator (ISO) websites when such an organization exists. The name of the nodes are extracted from the SNL mapping tool \[16\]. For future LMPs, we summed the nearest hub forward price and the historical spread between hub and LMP at the plant location. The forward price is the “fair value price” of electricity given by Bloomberg \[2\] and retrieved from a Bloomberg terminal. These

\[2\text{We realized afterwards that Bloomberg fair value price is very close (1-2\% difference) to futures}\]
forward values exist for every month in the future and for every major electricity hub of the United States. Bloomberg indicates that they are “calculated through a proprietary model that uses future prices, historical spreads, spot prices and other factors”. The historical spread is the average over the last two years, which is long enough to smooth seasonal variations but short enough to incorporate recent structural changes in the locational spread (caused by the recent large introduction of renewables and associated flow congestion in some areas for instance as in [1-1]).

Figure 1-1: The spread in day-ahead price can be significant and evolves with time due to congestion between nodes. In this thesis, we typically take the latest 2-year average spread for projections into the future. In Byron (IL), the spread in the Fall season is caused by a combination of high wind energy production and low electricity demand in West Illinois, as well as limited transmission capacity to the Chicago hub.

In the “cost-of-service regulated” Southeast of the country, in the absence of an ISO, the bilateral contract values of day-ahead electricity price in the Southern and Florida “hubs” are used in lieu of the LMP. These historical values are reported by Platts and SNL and provide a price signal for our profitability estimate. The price index is therefore similar for all the nuclear plants in the zone (15 plants, 28GW of

---

price. The only major difference is that Bloomberg price is posted between trading hours and that they make projections up to 10 years in the future. We therefore could have used the futures curve in our exercise without significant difference.
capacity) and is less granular than in the other U.S. zones. The forecasted price is the sum of the closest hub - Indiana for the South East - forward price and the historical spread between this hub and the zones. A similar approach was used for Columbia Generating Station in the Northwest.

Capacity market revenues are known once capacity auctions have been cleared. Preliminary auctions results when they exist are used to forecast future capacity revenue (PJM, ISO-NE, NYISO and California). For MISO, where preliminary auctions do not go as far into the future, we extrapolated the latest capacity clearing price.

The policy support is the potential subsidy that the plants receive for their zero-carbon attribute. If confirmed, these subsidies will apply to 5 plants in the US, in the form of Zero Emission Credits (ZEC): Nine Mile Point, Fitzpatrick and Ginna in New York and Clinton and Quad Cities in Illinois starting in 2017.

Finally, the cost of generation is taken from the SNL Financial database [16]. SNL provides plant-specific estimates of annual generation cost, based on IEA, FERC, and RUS survey forms (which include fuel cost reporting in particular) and/or a proprietary model when the data are incomplete. The SNL model is based on a three-year regression of a "large enough sample". The regression formula is based off net generation, age of plant and operation capacity. The total costs comprises fuel, fixed operating and maintenance as well as non-fuel variable operating and maintenance cost. The fleet-average cost of generation closely matches the number disclosed by the industry (see NEI 2016 and Table [1.1]). The O&M cost of future years is simply the O&M cost of the latest year augmented by the expected inflation.

Again, beyond the market horizon, a plant owner would need to develop a long-term forecast of cash flows. The next two tools described in this chapter can fulfill this role.
Table 1.1: The plant-average cost of generation from SNL is lower but close to the one reported by NEI.

<table>
<thead>
<tr>
<th></th>
<th>2012</th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
</tr>
</thead>
<tbody>
<tr>
<td>SNL estimates (61 plants)</td>
<td>34.1</td>
<td>33.4</td>
<td>34.4</td>
<td>33.9</td>
</tr>
<tr>
<td>standard deviation</td>
<td>5.3</td>
<td>6.4</td>
<td>6.5</td>
<td>4.6</td>
</tr>
<tr>
<td>NEI (reported fleet average, in 2015 $)</td>
<td>39.7</td>
<td>36.9</td>
<td>36.4</td>
<td>35.5</td>
</tr>
<tr>
<td>adjusted to nominal $</td>
<td>38.5</td>
<td>36.3</td>
<td>36.3</td>
<td>35.5</td>
</tr>
</tbody>
</table>

### 1.1.3 Valuation in Japan

In Japan, electricity markets are still “cost-of-service” regulated, with no real competition for electricity generation. The best available electricity price signal comes from the Japan Electric Power Exchange (JEPX), the trading platform for power. However this price signal has severe limitations. The volume of exchange is still low: only a few percent of the total electricity supply is traded via JEPX. The ten Electric Power Companies (EPCos, the regional electricity companies) participate marginally. In addition, JEPX only publishes a single price for the entire country, whereas locational marginal pricing would be needed to inform about local congestion and optimal location for investment, market entry and market exit. In addition, it has been shown that the price formation in JEPX was “inefficient and opaque” \[131\], in that it did not reflect the cost of electricity generation nor other economic indicators such as demand. Finally, the futures contract market is not very developed; the delivery dates do not go beyond one week in the future.

Classical valuation of a nuclear power plant in Japan therefore can not be executed reliably with the information gained from market as done in the U.S. because of unsatisfactory price signals from JEPX. Price trajectories must therefore be developed on fundamentals, all the more that the electricity market of Japan is expected to change significantly after re-structuring. The electricity market model developed in the next section serves this purpose. It reproduces price formation and can inform us about the expected revenue and value of Japanese nuclear power plants.
1.2 Electricity market model

Our wholesale electricity market model is designed to evaluate the dispatch of the power generators and the price of electricity under different market conditions. In this thesis, the model is used for different purposes:

- Identify the fundamental drivers of wholesale electricity prices and therefore the drivers of nuclear competitiveness,
- Quantify the consequences of nuclear power plant withdrawal from the grid,
- Evaluate the impact of new market rules (carbon price in particular),
- Assess the market value of technological innovations such as thermal energy storage or nuclear load-follow capability.

The basis for the model is a short-term supply-demand equilibrium, or “economic dispatch” model. Such type of model is commonly used in the power industry, and notably by the grid operators who dispatch the available generators to meet the electricity demand at minimal cost. These models can take different levels of complexity, and can be costly in computation time. The developer therefore needs to find a compromise between accuracy (complexity) and computation time for the specific problem she/he is trying to solve. For an exhaustive description of the different types of electricity market models, see [71] and [137].

In our case, we want a model that is quick to solve - 30 seconds at most - in order to run a large number of simulation cases with different market assumptions. This naturally leads us to opt for a linear formulation of the problem.

1.2.1 Model description

Our wholesale market is a simple economic dispatch model of the generators in a given zone spanning one year (8760 hours). The model takes in the hourly demand for electricity, the hourly generation profile of renewables (wind), the installed generation capacity, and its marginal cost in order to dispatch the generation and meet
the demand at minimal cost. The price of electricity for each hour is determined by
the marginal unit that serves the load (the price is the system marginal cost\(^3\)). The
transmission line constraints inside the zone are ignored, as well as the transmission
losses (“copper plate” approximation), and the power exchanged with the neighboring
regions is treated as an addition (export) or reduction (import) of the total demand
for the zone\(^4\). The constraints introduced in the optimization problem are: the load
demand constraint, the constraints on the maximum output of each generator, and
the flexibility constraint (ability to power up and down each generator). The cost
of not meeting the demand is equal to the value of lost load, whose default value is
set at $500/MWh\(^5\). The formulation of the problem leads to the solving of a linear
optimization problem, which is faster to compute than if binary constraints had been
introduced. The generators of a given class are aggregated when their characteristics
are similar. Typically, the coal plants, and the gas power plants in each state (region
for Japan) are grouped together.

The formulation of the economic dispatch problem is as follows.

Find:

\[
\min_{q_{i,n},VOLL,n} \left( \sum_{\text{generator } i, \text{hour } n} q_{i,n} (c_i + cc_i) + q_{VOLL,n}c_{VOLL} \right)
\]

(1.6)

with

- \(c_i\) marginal cost of production for generator \(i\) in $/MWh,
- \(cc_i\) cost of carbon for generator \(i\) in $/MWh (carbon price times carbon intensity of
  the generator),
- \(q_{i,n}\) power output of generator \(i\) during hour \(n\) in MW,
- \(c_{VOLL}\) value of lost load (cost of non-served energy) in $/MWh, and

---

\(^3\)The system marginal cost is rigorously defined as the cost of serving one more unit of load. In
other words, it is the “dual variable” of the demand constraint.

\(^4\)Net imports are as reported by the EIA or other sources. The total demand is equal to the total
supply in the zone. The “internal” demand is defined as the difference between the total demand
and the net exports of electricity in the zone.

\(^5\)In the cases we run there is almost always enough capacity available so this assumption is not
very important in practice.
\( q_{\text{VOLL},n} \) lost load during hour \( n \).

**Subject to:**

- Power demand constraint

\[
\sum_{\text{generator } i} q_{i,n} + q_{\text{VOLL},n} = d_n, \text{ for all } n
\]  

(1.7)

with \( d_n \) total electricity demand during hour \( n \) in MW.

- Minimum and maximum power output constraint for each dispatchable generator

\[
q_{i,\text{min}} < q_{i,n} < q_{i,\text{max}}, \text{ for all } i, n
\]  

(1.8)

- Minimum and maximum power output from renewables during each hour of the year (curtailment is allowed)

\[
0 < q_{\text{wind},n} < q_{\text{wind,max}}, \text{ for all } n
\]  

(1.9)

- Minimum and maximum ramping rate (change in power output of the generator between two consecutive hours)

\[
q_{i,n} - q_i < q_{i,n+1} < q_{i,n} + \overline{q}_i, \text{ for all } i, n
\]  

(1.10)

with \( q_i \) and \( \overline{q}_i \) maximum hourly change in output ramping down and up respectively (MW) for generator \( i \).

The solving of the cost minimization procedure yields the hourly dispatch of the generator as well as the hourly wholesale price of electricity.
1.2.2 Assumptions

We assume that the bids of the generator are equal to their marginal cost of production. In theory such bidding strategy is optimal in a perfectly competitive market, where no generator uses its market power to make extra profit [135].

The source of the input data are described in Table 1.2 for the U.S. electricity market model. We tried to use the most reliable public data available.

Due to the fact that we do not model plant outages, we apply a correction factor to the installed capacity of the generators to reflect their actual availability over one year. The availability factor is applied to the nameplate capacity installed in order to obtain the actual average available capacity. For nuclear, the capacity factor is assumed to be equal to the availability factor (no unexpected outage). For peaking units, the availability factor is set at 100% such that they are always available when needed (during scarcity periods).

We do not model unit commitment and therefore allow most generators to reach zero power output when needed ($q_{i,\min} = 0$). Nuclear power plants are an exception and unless otherwise specified, they run steadily at maximum capacity by default ($q_{nuc,\min} = q_{nuc,\max}$).

Table 1.2: The input for the electricity market modeling of the U.S. competitive markets come from different sources.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Reference</th>
</tr>
</thead>
<tbody>
<tr>
<td>Historical load profile</td>
<td>ISO websites (hourly demand) [9, 14]</td>
</tr>
<tr>
<td>Total demand, supply and imports/exports</td>
<td>EIA (by state and year) [22, 21]</td>
</tr>
<tr>
<td>Installed capacity</td>
<td>EIA (by state, year, and resource type) [22]</td>
</tr>
<tr>
<td>Fuel prices seen by electric power sector</td>
<td>EIA (by state, year, and fuel type) [23, 21]</td>
</tr>
<tr>
<td>Non-fuel variable cost (O&amp;M)</td>
<td>SNL (by plant and year) [16]</td>
</tr>
<tr>
<td>Ramping capabilities</td>
<td>Komiyama (by resource type) [119]</td>
</tr>
<tr>
<td>Availability factor</td>
<td>Nuclear: NEI capacity factor (yearly fleet average) [13]</td>
</tr>
<tr>
<td></td>
<td>Fossil: NERC (by resource type and time period) [12]</td>
</tr>
<tr>
<td></td>
<td>Hydro: adjusted to reflect EIA yearly generation [22]</td>
</tr>
<tr>
<td>Wind generation profile</td>
<td>ISO website (hourly profile) [9, 14]</td>
</tr>
</tbody>
</table>
Again, the generators that share the same characteristics are grouped together to simplify the formulation and accelerate computation. The value of the input parameters for the U.S. case are given for reference in Appendix.

For the Tokyo area in Japan, the inputs are different from the U.S. and their origin is summarized in Table 1.3.

Table 1.3: The input for the electricity market modeling of the Tokyo electrical grid.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Reference</th>
</tr>
</thead>
<tbody>
<tr>
<td>Historical load profile</td>
<td>TEPCO (hourly demand)</td>
</tr>
<tr>
<td>Total demand, supply and imports/exports</td>
<td>TEPCO</td>
</tr>
<tr>
<td>Installed capacity</td>
<td>TEPCO (by resource type)</td>
</tr>
<tr>
<td>Variable cost (O&amp;M + fuel)</td>
<td>Komiyama</td>
</tr>
<tr>
<td>Ramping capabilities</td>
<td>Komiyama (by resource type)</td>
</tr>
<tr>
<td>Solar generation profile</td>
<td>Meteorological agency of Japan, following the methodology of Esteban (hourly profile)</td>
</tr>
</tbody>
</table>

1.2.3 Solving

The model is implemented in Julia, and solved by calling the Gurobi optimization solver. It takes ten second at most to reach the exact solution because the optimization problem is linear (the objective function and all constraints are linear). If there were binary variables (unit commitment for instance), the model would take much longer to run. Note however that the problem is non-convex, due to constraints on minimum power output and ramping capabilities.

1.2.4 Validation

For validation purposes, we compare the simulated mix and prices with their actual, historical values for the Midwest and Mid-Atlantic regions in 2008 and 2015 (see Figure 1-2). The generation mix (share of total generation from each resource type) is in reasonable agreement, except for the Mid-Atlantic region in 2015. This is
due to the close marginal cost of power production from CCGT and from coal. The two technologies are very close in the merit order of the supply stack and a small change in marginal cost impacts the dispatch and the relative share of coal versus natural gas in the generation mix. It would require a more granular modelling of the CCGT and coal units in the region to reproduce the actual mix. However this is not needed to reproduce the actual price of electricity, which is simulated accurately. Another simulation discrepancy is the price in the Midwest region in 2008. The price is very sensitive to the coal power plant flexibility and availability assumptions, which we may have overestimated. It seems that the price is low because cheap coal is too much available for dispatch.

Figure 1-2: The simulations are in reasonable agreement with the historical prices and energy mix despite the simplicity of the model.

Overall, the model reproduces fairly well the price drop that happened in the two regions (35-45% drop in electricity price). The model is considered satisfactory as we are more interested in the relative changes in price than in their absolute values. Matching the actual values would require a more complex model that accounts for congestion (transmission constraints), unit commitment, uplift payments and a more granular modelling of the generators.
The model could be improved to account for the transmission network constraints. This feature would capture congestion in the lines and create different locational prices of electricity within the zone. This modeling approach requires more granular data and a realistic description of the transmission network. As a first step one could build a model where each state is modeled as one node. The supply and demand in each state would be needed, as well as the transmission network between the nodes. We did not complete this modeling by lack of time in this thesis but we consider this approach feasible. The transmission line map of SNL [16] is a good basis for building a model of the transmission network between States.

1.3 Long-term stochastic asset valuation

1.3.1 Purpose

The traditional approach of asset valuation exposed in section 1-1 relies on the net present value of the future cash flow. The forward price of electricity is the base of the cash flow calculation. Although this approach is appropriate in most asset valuation problems, it has serious limitations when it comes to long-term nuclear power plant valuation:

- It calculates the value of the plant for a fixed, assumed forward scenario. The price dynamics are not captured. The volatility and uncertainty of the revenue of the plant are not explicitly modeled. Hence the need for a risk-adjusted discount rate.

- It does not account for the option to shutdown the plant before the end of its operating license. The plant owner can updated its operating strategy during the 40- to 80-year lifetime of the plant, which modifies future cash flows and augments the value of the asset.

Forward electricity prices are highly uncertain, and the futures curves constantly adjust over time as market agents access new information about the market. The
The goal of the proposed methodology is to capture both the cash flow uncertainty and the operational flexibility in the valuation of nuclear power assets.

The method we are developing here and that we will test is based on several advancements in real asset valuation made in the past decades. The real-option approach is one of these relatively new approaches. It is derived from the financial option pricing theory and has been implemented with some success. It was for instance applied to the long-term valuation of a copper mine by Brennan and Schwartz [79].

Valuing a nuclear power plant as a real option requires to model the underlying electricity price process. This is the first step toward valuing the nuclear asset and the topic of the next subsection.

### 1.3.2 Stochastic process of electricity price

Electricity prices are highly volatile due to short-term variation in supply and demand, lack of large-scale energy storage technologies and shape of the supply curve. Figure 1-3 exhibits the daily average, day-ahead, spot price of electricity at the Western Hub (Mid-Atlantic PJM market). We notice the large volatility of daily prices. Weekly and yearly variations are also significant, as influenced by the cyclical load demand, the weather, and technology, notably transmission and generators availability.

The futures and forward price curve, unlike that for more storable commodities like oil and metals, shows strong seasonal variations as well (Figure 1-3). As we will demonstrate, the futures curve tells us about both the expected value of the spot price of electricity and the risk premium of the forward contract. It is an essential instrument of our price process calibration and validation. Typically, the futures are structured in peak and off-peak monthly contracts.

An adequate electricity price model for nuclear plant valuation captures:

**Seasonal patterns** Seasons change load demand and the price of electricity. Thus they impact asset valuation, and the timing of operation decisions.
Price jumps Prices can reach very high values for short period of times due to extreme weather or system outage.

Mean reversion Electricity price can differ from predictions but they quickly revert to an expected long-term mean.

Drift Technological advances on the supply side (e.g. storage technologies, plant efficiencies), structural change in load demand (e.g. electric vehicles, energy savings), and fuel price evolution contribute to a long-term evolution of the equilibrium electricity price\(^6\).

Market risk premium Market agents account for risk in electricity derivatives pricing. The risk premium is the compensation the risk taker (seller of the forward contract) requires for the risk associated with price change until delivery. Ideally, we want to quantify this risk adjustment to later use it in our nuclear power plant valuation.

In this section we will denote by \( S_t : \mathbb{R} \rightarrow \mathbb{R} \) the day-ahead spot price of electricity.

---

\(^6\)Note that seasonality, jump characteristics and mean reversion are also potentially affected by these changes.
It is defined as an Itô stochastic process as in Duffie [88]. We will introduce several models, calibrate and test them against observations.

**One-factor model**  The one-factor model states a price of the form

\[ S_t = f(t) + \chi_t + \xi_t \quad (1.11) \]

with \( f(t) \) a deterministic function that reflects the seasonality of electricity price, \( \xi_t \) a deterministic drift function and \( \chi_t \) a stochastic process. We assume that \( \chi_t \) follows a mean-reverting (Orsntein-Uhlenbeck) Itô process, of the form

\[ d\chi_t = -\kappa \chi_t dt + \sigma dZ \quad (1.12) \]

while

\[ d\xi_t = \mu dt. \quad (1.13) \]

where \( \kappa > 0 \) is the rate of mean reversion, \( \chi(0) = \chi_0 \), and \( dZ \) represents an increment of a standard Brownian motion \( Z_t \) of mean 0 and standard deviation \( \sqrt{dt} \).

\[ \mathbb{E}_0[dZ] = 0 \quad (1.14) \]
\[ \text{Var}_0(dZ) = dt \quad (1.15) \]

The process followed by \( \chi_t \) and \( S_t \) can be expressed as the solution of stochastic differential equations such that \( \chi_t \sim \chi(t, Z_t) \). A solution of the form

\[ \chi_t = A(t) \left( X_0 + \int_0^t B(s) dZ_s \right) \quad (1.16) \]

satisfies the stochastic equation with \( A(0) = 1, A(t) = \exp(-\kappa t) \) and \( B(t) = \sigma \exp(\kappa t) \). Therefore a solution for equation (1.12) is

\[ \chi_t = \chi_0 e^{-\kappa t} + \sigma \int_0^t e^{\kappa(s-t)} dZ_s \quad (1.17) \]
and

\[ S_t = f(t) + \chi_t + \xi_t \]
\[ S_t = f(t) + \chi_0 e^{-\kappa t} + \sigma \int_0^t e^{\kappa(s-t)} dZ_s + \xi_0 + \mu t \]  \hspace{1cm} (1.18)

The previous integrals are Itô integrals. The distribution of \( S_t \) is normal with mean and variance given by

\[ \mathbb{E}_0[S_t] = f(t) + \xi_0 e^{-\kappa t} + \xi_0 + \mu t \]  \hspace{1cm} (1.19)
\[ \text{Var}_0[S_t] = \sigma \int_0^t e^{2\kappa(s-t)} dZ_s \]
\[ = \frac{\sigma^2}{2\kappa} (1 - e^{-2\kappa t}) \]  \hspace{1cm} (1.20)

The spot price tends to the mean value \( f(t) + \xi_0 + \mu t \) in the long run. Its variance decreases and converges toward the fixed value \( \frac{\sigma^2}{2\kappa} \).

Our objective is to price derivative securities (forward price, physical assets) of \( S_t \). The price of these derivatives includes a risk premium, which can be accounted for by expressing the price process under the risk-neutral measure. The absence of arbitrage guarantees the existence of this risk-neutral measure called an equivalent martingale measure [88].

Girsanov’s theorem\(^7\) states that under the risk-neutral measure (denoted by upper script letter \( Q \)), the Brownian motion \( d\tilde{Z} \) defined as the standard Brownian motion \( dZ \) (in physical measure) adjusted by the constant and deterministic drift rate \( \lambda \) is a martingale.

\[ d\tilde{Z}_t = dZ_t + \lambda dt \]  \hspace{1cm} (1.21)

This implies that

\[ \mathbb{E}_0^Q[d\tilde{Z}_t] = 0 \]  \hspace{1cm} (1.22)

\(^7\)with constant risk-free rate
Substituting \( dZ_t \) by \( d\tilde{Z}_t - \lambda dt \), the risk-neutral process for \( \chi_t \) is then given by

\[
d\chi_t = \kappa (\alpha - \chi_t) \, dt + \sigma d\tilde{Z}_t
\]  

(1.23)

with \( \alpha = -\lambda \sigma / \kappa \).

Following the same solving procedure as previously, a solution of (1.23) is

\[
S_t = f(t) + \chi_0 e^{-\kappa t} + \alpha (1 - e^{-\kappa t}) + \sigma \int_0^t e^{\kappa(s-t)} d\tilde{Z}_s + \xi_0 + \mu t
\]  

(1.24)

The mean and variance of \( S_t \) under the risk-neutral measure are

\[
\mathbb{E}_Q^0 [S_t] = f(t) + \chi_0 e^{-\kappa t} + \alpha (1 - e^{-\kappa t}) + \xi_0 + \mu t
\]  

(1.25)

\[
\text{Var}_Q^0 [S_t] = \frac{\sigma^2}{2\kappa} (1 - e^{-2\kappa t})
\]  

(1.26)

Let’s now denote by \( F_t(S_t, t) \) the value at time \( t \) of a forward contract on the spot price \( S_t \) maturing at time \( T \). According the fundamental theorem of asset pricing, in a complete market a derivative’s price (the forward contract in this case) is the discounted expected value of the future payoff under the unique risk-neutral measure. The future payoff at expiration time \( T \) is \( S_T - F_0(S_0, T) \), and since the price of the forward contract at time 0 is zero, we have:

\[
0 = \mathbb{E}_Q^0 [(S_T - F_0(S_0, T)) e^{-rT}]
\]  

(1.27)

if the riskless rate is constant and equal to \( r \). This implies that the forward price is the risk-neutral expected spot price of electricity:

\[
F_0(S_0, T) = \mathbb{E}_Q^0 [S_T] = f(T) + \chi_0 e^{-\kappa T} + \alpha (1 - e^{-\kappa T}) + \xi_0 + \mu t
\]  

(1.28)

\( \alpha (1 - e^{-\kappa T}) \) represents the risk premium that results from our adjustment to the risk-neutral measure. It can be seen as the market price of risk.
The price of $F$ at an arbitrary time $t = T - \tau$ is

$$F_t(S_t, T) = \mathbb{E}_t^Q[S_T] = f(t + \tau) + \chi_t e^{-\kappa\tau} + \alpha (1 - e^{-\kappa\tau}) + \xi_t + \mu\tau \quad (1.29)$$

**Two-factor model**  Two-factor models are models that include two volatility components, such as a short-term volatility and a long-term volatility. It was demonstrated that in a number of cases such as oil and copper prices, two-factor models perform significantly better than one-factor models to replicate the volatility of futures and forward prices \[145, 130\]. They also fit forward electricity prices better \[122\].

A major shortcoming of one-factor models is that they imply that changes in spot prices and futures prices at all maturities are perfectly correlated. In other words a change in the spot price would result in an immediate shift of the futures curve. This behavior is proven wrong by observing the data. The notice that long-term futures price is loosely correlated with spot price (see also \[122\] for observations in Europe). This makes sense if you consider that spot price variations are linked to events that do not necessarily reproduce and are by nature unpredictable such as plant outage or extreme weather. The downside of two-factor models is their complexity - they need to be estimated with advanced techniques because the two volatilities are not observable directly. The number of parameters to be estimated is also larger, which makes them more difficult to estimate with accuracy.

In our case, a model that differentiate short- and long-term volatility is important because the short-term structure of prices can impact the decision to retire a nuclear plant losing money right now, whereas the long-term variation component is important to catch the value the plant over its entire lifetime (10-20 years in the future if necessary). Both timescales are essential when it comes to make operating decisions today. Also, the strong seasonality of prices must be maintained as a plant is more likely to retire (or undergo maintenance) in spring or fall rather than in winter when prices are at their highest\[8\].

---

\[8\] Some authors discuss the benefit of introducing season-specific volatilities \[81\] but in this thesis we keep volatilities constant.
The two-factor model we propose is an extension of the previous one-factor model. It takes the form

\[ S_t = f(t) + \chi_t + \xi_t \]  

with \( f(t) \) deterministic seasonal function, \( \chi_t \) short-term deviation in prices and \( \xi_t \) the long-term, or “equilibrium” dynamics. The short-term component is similar to the one-factor model; it follows a mean-reverting process. The long-term component follows an arithmetic Brownian motion (constant drift). They are mathematically expressed by

\[ d\chi_t = -\kappa \chi_t dt + \sigma_\chi dZ_\chi \]  
\[ d\xi_t = \mu dt + \sigma_\xi dZ_\xi. \]

The two Wiener processes \( dZ_\chi \) and \( dZ_\xi \) are in the general case correlated through:

\[ \mathbb{E}[dZ_\chi dZ_\xi] = \rho dt. \]

A solution of the stochastic differential equations for \( \chi_t \) and \( \xi_t \) are obtained in the same way as for the one-factor model:

\[ \chi_t = \chi_0 e^{-\kappa t} + \sigma_\chi \int_0^t e^{\kappa (s-t)} dZ_{\chi,s} \]  
\[ \xi_t = \xi_0 + \mu t + \sigma_\xi \int_0^t dZ_{\xi,s} \]

The expected values and covariance matrix of the short-term and long-term components are given by

\[ \mathbb{E}_0[\chi_t, \xi_t] = [\chi_0 e^{-\kappa t}, \xi_0 + \mu t] \]  
\[ \text{Cov}_0[\chi_t, \xi_t] = \begin{pmatrix} \frac{\sigma_\chi^2}{2\kappa} (1 - e^{-2\kappa t}) & (1 - e^{-\kappa t}) \rho_\chi \sigma_\xi \kappa \\ (1 - e^{-\kappa t}) \rho_\chi \sigma_\xi \kappa & \sigma_\xi^2 t \end{pmatrix} \]
Therefore the expected spot price and its variance are:

\[
E_0[S_t] = f(t) + \chi_0 e^{-\kappa t} + \xi_0 + \mu t \quad (1.38)
\]

\[
Var_0[S_t] = Var_0[f(t) + \chi_t + \xi_t] \quad (1.39)
\]

\[
= Var_0[f(t)] + Var_0[\chi_t] + Var_0[\xi_t] + 2cov_0(\chi_t, \xi_t) \quad (1.40)
\]

\[
= 0 + \frac{\sigma^2}{2\kappa} (1 - e^{-2\kappa t}) + \sigma^2 t + 2 \left( 1 - e^{-\kappa t} \right) \frac{\rho \sigma_\chi \sigma_\xi}{\kappa} \quad (1.41)
\]

\[
= \frac{\sigma^2}{2\kappa} (1 - e^{-2\kappa t}) + \sigma^2 t + 2 \left( 1 - e^{-\kappa t} \right) \frac{\rho \sigma_\chi \sigma_\xi}{\kappa} \quad (1.42)
\]

Now let’s evaluate these expressions in the risk-neutral framework so that we can later apply the fundamental theorem of derivatives pricing. The risk-adjusted version of the processes are

\[
d\chi_t = \kappa (\alpha - \chi_t) dt + \sigma_\chi d\tilde{Z}_\chi \quad (1.43)
\]

\[
d\xi_t = \tilde{\mu} dt + \sigma_\xi d\tilde{Z}_\xi \quad (1.44)
\]

\[
d\tilde{Z}_\chi d\tilde{Z}_\xi = \rho dt \quad (1.45)
\]

with \( \alpha = -\lambda_\chi \sigma_\chi / \kappa \) and \( \tilde{\mu} = \mu - \lambda_\xi \sigma_\xi \).

Under the risk-neutral measure, we verify that the expectations and variances of \( S_t \) are

\[
E_0^Q[S_t] = f(t) + \chi_0 e^{-\kappa t} + \alpha (1 - e^{-\kappa t}) + \chi_0 + \tilde{\mu} t \quad (1.47)
\]

\[
Var_0^Q[S_t] = Var_0[S_t] \quad (1.48)
\]

\[
= \frac{\sigma^2}{2\kappa} (1 - e^{-2\kappa t}) + \sigma^2 t + 2 \left( 1 - e^{-\kappa t} \right) \frac{\rho \sigma_\chi \sigma_\xi}{\kappa} \quad (1.49)
\]

Since \( Cov_0[\chi_t, \xi_t] = Cov_0^Q[\chi_t, \xi_t] \).

The application of the fundamental theorem of asset pricing to a forward contract yields:

\[
0 = E_0^Q\left[ (S_T - F_0(S_0, T)) e^{-rT} \right] \quad (1.50)
\]
if the riskless rate is constant and equal to $r$. The forward day-ahead price of electricity is

$$F_0(S_0, T) = E_0^Q[S_T] = f(T) + \chi_0e^{-\kappa T} + \alpha(1 - e^{-\kappa T}) + \xi_0 + \mu T \quad (1.51)$$

Or, taking the valuation at $t$ instead of 0:

$$F_t(S_t, T) = f(t + \tau) + \chi_t e^{-\kappa \tau} + \alpha(1 - e^{-\kappa \tau}) + \xi_t + \mu \tau \quad (1.52)$$

$$= \chi_t e^{-\kappa \tau} + \xi_t + G(t + \tau) \quad (1.53)$$

with $T = t + \tau$, and

$$G(t + \tau) = f(t + \tau) + \alpha(1 - e^{-\kappa \tau}) + \mu \tau. \quad (1.54)$$

**Seasonality** Electricity demand depends on weather conditions. Electricity can not be stored at large scale and therefore prices show strong seasonal variations (as exhibited by the forward curve Figure[1-3]). The deterministic component $f(t)$ of the electricity price $S_t$ is meant to capture the seasonality of electricity price and can be expressed in several forms. We choose to express it as the sum of two periodic functions:

$$f(t) = s_1 \cos(2\pi \frac{t}{\tau}) + s_2 \sin(2\pi \frac{t}{\tau}) + s_3 \cos(2\pi \frac{t}{2\tau}) + s_4 \sin(2\pi \frac{t}{2\tau}) \quad (1.55)$$

where $s_1, s_2, s_3$ and $s_4$ are constant parameters and $\tau$ is equal to one year. The above formulation of $f(t)$ captures the seasonal variations of the electricity price: a sum of sine functions of period 1-year and 6-month, which we assume to be the highest modes of the price series$^9$.

$^9$The highest modes can be identified rigorously by a spectral analysis (Fourier transform). 

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1.3.3 Calibration and estimation of parameters

One-factor model - least square method  The advantage of the one-factor models is that their parameters can be simply estimated by least-square methods. We calibrate the parameters on the monthly average historical day-ahead price data $s_t$ at the location of interest.

The stochastic differential equations are discretized in the form

$$S_t = f_t + X_t \quad (1.56)$$
$$f_t = f(t) \quad (1.57)$$
$$X_t = \phi X_{t-1} + \epsilon_t \quad (1.58)$$

with $\epsilon_t$ random variable of mean zero and variance $\sigma^2$. $\phi$ is given by the Itô process that defines $dX_t$. We have $\phi = (1 - \kappa)$.

We notice that

$$S_t - \phi S_{t-1} = f_t - \phi f_{t-1} + \epsilon_t \quad (1.59)$$
$$S_t = \phi (S_{t-1} - f_{t-1}) + f_t + \epsilon_t \quad (1.60)$$

The unknown parameters $\phi$ and $s_i$ are estimated simultaneously by a linear regression of $S_t$ versus $(S_{t-1} - f_{t-1})$ minimizing the sum of squared residuals (least square method). The standard error of the linear regression is a direct estimate of the standard deviation of $\epsilon_t$.

Two-factor model - Kalman filter  The calibration of the two-factor model (or risk-neutral, one-factor model) requires observation of both the spot price and the futures prices with several maturities. The difficulty lies in that the two state variables - $\chi_t$ and $\xi_t$ - are unobservable directly. Only their sum can be observed. An advanced estimation technique, the Kalman filter [106], is used to identify the two state variables and their variance for a given set of observation. An iteration procedure on the unknown parameters ($\kappa, \mu, \bar{\mu}$, etc.) is then used to minimize the discrepancy between
forecasts and observation. This last step comes down to maximizing a “likelihood”
function, i.e. the likelihood of the model fitting the data. Our estimation procedure
follows the steps of Schwartz [147] and Herce et al. [130].

The Kalman filtering technique starts with the definition of the measurement and
transition equations, respectively:

\[
x_t = A x_{t-1} + B u_t \tag{1.61}
\]
\[
y_t = C_t x_t + D \epsilon_t \tag{1.62}
\]

With

- \( x_t = \begin{pmatrix} \chi_t \\ \xi_t \\ d_t \end{pmatrix} \) vector of state variables. \( \chi_t \) and \( \xi_t \) are equal to their discrete values
  at time \( t \) and \( d_t \) is a dummy, constant state variable.

- \( y_t = \begin{pmatrix} F_t(S_t,0) = S_t \\ F_t(S_t, \tau_1) \\ \vdots \\ F_t(S_t, \tau_M) \end{pmatrix} \) is the vector of \( M + 1 \) observed prices at time \( t \). The
  first term is the spot price and the \( M \) following terms correspond to the price
  of the futures contracts at \( M \) different maturities ranging from \( \tau_1 \) to \( \tau_M \).

- \( u_t \) is a \( 3 \times 1 \) vector of uncorrelated, normally distributed, unit-variance state
  disturbances at time \( t \).

- \( \epsilon_t \) is a \( (M + 1) \times 1 \) vector of uncorrelated, normally distributed, unit-variance
  observation innovations at time \( t \).

- \( A \) is the state-transition matrix.

- \( B \) is the state-disturbance-loading matrix.

- \( C_t \) is the measurement-sensitivity matrix.
D is the observation-innovation matrix, or “measurement error” matrix.

In our formulation all matrices but $C_t$ are time-invariant because the time interval $\Delta t$ between our observation times $t_0, t_1, \ldots, t_N$ is constant. Note that in a more general Kalman filtering case, all matrices could be time-varying.

Our state-space model formulation is more compact than the formulation of Schwartz \cite{147} and Herce et al. \cite{130}, due to our introduction of the dummy state variable $d_t$. There are less terms in the measurement and transition equations because the constant terms $c$ and $d$ of Herce have been internalized in our matrices $A$ and $C_t$. Our solver - the Matlab ssm class - requires such a compact formulation.

The full expressions \cite{1.34} and \cite{1.35} of $\chi_t$ and $\xi_t$ help us identify matrix $A$ and $B$:

$$A = \begin{pmatrix} e^{-\kappa \Delta t} & 0 & 0 \\ 0 & 1 & \mu \Delta t \\ 0 & 0 & 1 \end{pmatrix} \quad (1.63)$$

$B$ is defined such that $BB^T$ is the state-disturbance covariance matrix for period $t$:

$$BB^T = \text{Cov}[\chi_{\Delta t}, \xi_{\Delta t}, d_{\Delta t}] = \begin{pmatrix} \frac{\sigma^2_{\chi}}{2\kappa} \left(1 - e^{-2\kappa \Delta t}\right) & (1 - e^{-\kappa \Delta t}) \frac{\rho \sigma_{\chi} \sigma_{\xi}}{\kappa} & 0 \\ (1 - e^{-\kappa \Delta t}) \frac{\rho \sigma_{\chi} \sigma_{\xi}}{\kappa} & \frac{\sigma^2_{\xi} \Delta t}{\kappa} & 0 \\ 0 & 0 & 0 \end{pmatrix} \quad (1.64)$$

In practice, we use the Matlab function chol (Cholesky factorization) to construct $B$ given $\text{Cov}[\chi_{\Delta t}, \xi_{\Delta t}]$ \footnote{$B_{2 \times 2} = \text{chol}(\text{Cov}_{2 \times 2})'$ where $2 \times 2$ denotes the upper left part of the matrices}.
The expression \[ F_t(S_t, \tau) \] defines matrix \( C_t \):  

\[
C_t = \begin{pmatrix}
1 & 1 & G(t) \\
e^{-\kappa \tau_1} & 1 & G(t + \tau_1) \\
\vdots \\
e^{-\kappa \tau_M} & 1 & G(t + \tau_M)
\end{pmatrix}
\]  

(1.65)

where \( G(t) \) is defined by equation 1.54.

The observation-innovation matrix \( D \) is meant to capture the discrepancies between the observations and the model estimations. These discrepancies can come from errors in the dataset (for instance asynchronous time series, reporting error, user error) or from the model’s fit to the data. In theory \( D \) has \((M + 1)(M + 2)/2\) free parameters that need to be estimated, but we restrict this number to \( M + 1 \) by assuming that the errors between expiration dates are uncorrelated, which makes \( D \) a diagonal matrix:

\[
D = \begin{pmatrix}
v_1^2 & 0 & \cdots & 0 \\
0 & v_2^2 & 0 & \vdots \\
\vdots & \ddots & \ddots \\
0 & \cdots & 0 & v_{M+1}^2
\end{pmatrix}
\]  

(1.66)

Note that some authors such as Burger et al. [123] simply omit this error matrix. Removing \( D \) from the measurement equation results in state variables that perfectly matches the data. The few tests we carried on removing \( D \) were not positive. The estimated parameters such as the drift rate were completely unrealistic.

To initiate the Kalman filter procedure, we can start with an initial set of state variable equal to their long-term mean \( x_0 = \begin{pmatrix} \text{mean}(S_t) \\ 0 \\ 1 \end{pmatrix} \). This is an approximation since \( \xi_t \) is a diffuse state and grows at a constant rate. In practice however, we leave
\textbf{Data series} To illustrate how we estimate the models parameters, we use a 5-year data set of electricity prices observed at the Western Hub in the PJM region (Mid-Atlantic). This hub is chosen because it is one of the most actively traded hubs, where the futures market is the most likely to be liquid. We choose to use the monthly-average day-ahead wholesale price at the hub as our spot price \( S_t \). Since nuclear power plant are base load plants with a long lifetime and limited flexibility, we expect that choosing a monthly average rather than an hourly or daily average for \( S_t \) has little impact on the final value of the asset. The advantage of choosing monthly values is that the time interval between observations matches the time interval between futures delivery. It makes the formulation of the numerical solving easier\textsuperscript{12}.

The futures contract we observe - labeled with Bloomberg tickers \( PJPA \) and

\textsuperscript{11}We generally use the Treasury bond yields as an estimate for \( r \)
\textsuperscript{12}It also smoothes the hourly, daily and weekly variations
$PJBA$ - expire on a monthly basis, and use the monthly-average day-ahead price of electricity at the Western Hub as the underlying commodity, which is exactly our $S_t$. More precisely, PJPA and PJBA correspond to the peak and off-peak monthly average of $S_t$ for the delivery month, and must therefore be transformed into the around-the-clock delivery contract $y_t$. Using the definition of the peak and off-peak hours in PJM, we define our observed variable $y_t$ as

$$y_t = (80 \times PJPA_t + 88 \times PJBA_t) / 168$$  \hspace{1cm} (1.67)$$

Figure 1-4: The 2014 polar vortex seems to have changed the pricing of the futures. The futures curves became more peaky for winter months after this event.

The observation are made every last trading day of the month, and span from February 2012 to March 2017 for a total of 62 observations times. Note that the time interval between observation varies and is not exactly 30 days, which can introduces small perturbations in the calibration of the seasonal function $f(t)$. 

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In general, futures prices are available for delivery up to 45 months forward. However, prior to 2013, expiration times were not going as far into the future, which makes our data set inconsistent. Fortunately, the Matlab function \texttt{ssm} accommodates missing data. Matlab’s Kalman filter algorithm automatically ignores the missing data in its filtered state estimation.

The term structure of the futures data is plotted in Figure 1-4. We notice a modification of the futures curve after the 2014 polar vortex. Market agents seems to have re-evaluated their pricing upward for winter months after this event. Still, our parameters reflect then best estimate of the parameters over the whole dataset.

**Estimation results** The one-factor model is first calibrated on the spot price observations only by least square method. The estimated parameters of the model are reported in Table 1.4. We notice a strong negative drift rate \( \mu \), which ultimately brings the long-term price to zero and later negative values. This is obviously an unrealistic behavior because electricity will never be free (at least not over long-period of times).

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Description</th>
<th>Estimate</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>( \kappa )</td>
<td>mean-reversion rate</td>
<td>0.64002</td>
<td>/month</td>
</tr>
<tr>
<td>( \mu )</td>
<td>drift rate</td>
<td>-0.25447</td>
<td>$/MWh-month</td>
</tr>
<tr>
<td>( \sigma )</td>
<td>volatility</td>
<td>13.0868</td>
<td>$/MWh</td>
</tr>
<tr>
<td>( s_1 )</td>
<td>seasonal factor 1</td>
<td>amplitude</td>
<td>4.82054</td>
</tr>
<tr>
<td>( s_2 )</td>
<td>seasonal factor 2</td>
<td>amplitude</td>
<td>-3.85095</td>
</tr>
<tr>
<td>( s_3 )</td>
<td>seasonal factor 3</td>
<td>amplitude</td>
<td>0.275271</td>
</tr>
<tr>
<td>( s_4 )</td>
<td>seasonal factor 4</td>
<td>amplitude</td>
<td>-5.44103</td>
</tr>
</tbody>
</table>

The one-factor model is then calibrated on the futures price observations, using
the Kalman filter and maximum likelihood technique. The estimated parameters of the model are reported in Table 1.5. The risk-neutral mean $\alpha$ can now be estimated, although the accuracy of its estimation ($-190.88$/MWh) can be questioned. The seasonal and long-term (constant) mean are however captured by the futures estimation, as can be seen in Figure 1-5. The estimation errors are greatest during the polar vortexes of 2014 and 2015 (1-6).

Table 1.5: Estimation of the parameters of the one-factor model on PJM Western hub monthly spot and futures price with maximum likelihood technique.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Description</th>
<th>Estimate</th>
<th>Standard Error</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>$\kappa$</td>
<td>mean-reversion rate</td>
<td>0.00017</td>
<td>0.00008</td>
<td>/month</td>
</tr>
<tr>
<td>$\mu$</td>
<td>drift rate</td>
<td>0 $/$MWh-month</td>
<td></td>
<td></td>
</tr>
<tr>
<td>$\alpha$</td>
<td>risk-neutral mean</td>
<td>$-190.83812$</td>
<td>18.77870</td>
<td>$/$MWh</td>
</tr>
<tr>
<td>$\sigma$</td>
<td>volatility</td>
<td>1.19881</td>
<td>0.33075</td>
<td>$/$MWh</td>
</tr>
<tr>
<td>$s_1$</td>
<td>seasonal factor 1 amplitude</td>
<td>3.03399</td>
<td>0.39856</td>
<td>$/$MWh</td>
</tr>
<tr>
<td>$s_2$</td>
<td>seasonal factor 2 amplitude</td>
<td>$-0.08182$</td>
<td>0.76587</td>
<td>$/$MWh</td>
</tr>
<tr>
<td>$s_3$</td>
<td>seasonal factor 3 amplitude</td>
<td>5.13908</td>
<td>0.88527</td>
<td>$/$MWh</td>
</tr>
<tr>
<td>$s_4$</td>
<td>seasonal factor 4 amplitude</td>
<td>$-3.34403$</td>
<td>0.83351</td>
<td>$/$MWh</td>
</tr>
</tbody>
</table>

The results of the estimation of the two-factor model parameters are shown in Table 1.6 and Figure 1-6. The standard errors on the parameters are significant, in the same order of magnitude or larger than the estimates themselves. This may be explained by the large number of observation (2617), made over a long period of time (Feb. 2012 to March 2017), with major price events. Two polar vortexes occur over the time period, which created big jumps in monthly spot prices and short-term futures. Also, the futures curve seems to have been modified significantly after 2013, which certainly adds difficulty to fit the forward curves over such a long period. Limiting the observations to post-polar vortex observations does not lead to a better estimation because the errors become larger (less data points).
Figure 1-5: The one-factor futures estimate replicates the long-term average and seasonal variations but fails at capturing the risk-neutral premium ($\alpha = -$190/MWh).

The magnitude of the different parameters are highlighted by the contributions of the futures estimate of electricity prices as of March 2017 (Figure 1-6). The direction of the futures curve is given by the risk-neutral drift $\bar{\mu}$. The seasonal oscillations are given by the seasonal component $f(t)$. The short-term state variable $\chi_t$ gives rise to two components: a short-term exponential decay $\chi_t e^{-\kappa \tau}$ of half-life $\ln(2)/\kappa \sim 1$ year and a short-term volatility contribution $\alpha (1 - e^{-\kappa(\tau)})$ approaching a constant value $\alpha$ for long contract maturities.

Figure 1-7 compares the forecast of the short-term and equilibrium state variable $\chi_t$ and $\xi_t$ with the observed spot price. We confirm visually that the long-term equilibrium component of price $\chi_t$ has a smaller volatility and a negative drift, whereas the short-term state variable $\xi_t$ displays larger volatility. The forecasted spot price
Table 1.6: Estimation of the parameters of the two-factor model on PJM Western hub monthly futures. The 2617 observations span over a long period (Feb. 2012 to March 2017), which may explain the large errors on the parameters estimate.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Description</th>
<th>Estimate</th>
<th>Standard Error</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>$\kappa$</td>
<td>short-term mean-reversion rate</td>
<td>0.05368</td>
<td>0.05241</td>
<td>/month</td>
</tr>
<tr>
<td>$\mu$</td>
<td>equilibrium drift rate</td>
<td>$-0.22324$</td>
<td>0.58546</td>
<td>$/MWh-month$</td>
</tr>
<tr>
<td>$\mu = \mu - \lambda \sigma_\xi$</td>
<td>equilibrium risk-neutral drift rate</td>
<td>0.02940</td>
<td>0.08944</td>
<td>$/MWh-month$</td>
</tr>
<tr>
<td>$\alpha = -\lambda \sigma_\chi / \kappa$</td>
<td>short-term risk-neutral average</td>
<td>$-1.45732$</td>
<td>13.61028</td>
<td>$/MW-month$</td>
</tr>
<tr>
<td>$\sigma_\chi$</td>
<td>short-term volatility</td>
<td>2.13479</td>
<td>2.01083</td>
<td>$/MWh$</td>
</tr>
<tr>
<td>$\sigma_\xi$</td>
<td>long-term volatility</td>
<td>0.91238</td>
<td>1.52811</td>
<td>$/MWh$</td>
</tr>
<tr>
<td>$\rho$</td>
<td>correlation in increments</td>
<td>0.00547</td>
<td>3.47241</td>
<td>$/MWh$</td>
</tr>
<tr>
<td>$s_1$</td>
<td>seasonal amplitude factor 1</td>
<td>3.06396</td>
<td>0.55363</td>
<td>$/MWh$</td>
</tr>
<tr>
<td>$s_2$</td>
<td>seasonal amplitude factor 2</td>
<td>$-0.07287$</td>
<td>0.99579</td>
<td>$/MWh$</td>
</tr>
<tr>
<td>$s_3$</td>
<td>seasonal amplitude factor 3</td>
<td>5.11575</td>
<td>0.67385</td>
<td>$/MWh$</td>
</tr>
<tr>
<td>$s_4$</td>
<td>seasonal amplitude factor 4</td>
<td>$-3.37157$</td>
<td>0.66223</td>
<td>$/MWh$</td>
</tr>
</tbody>
</table>

$(f(t) + \chi_t + \xi_t)$ still shows significant discrepancy with the observations. The difference peaks during the very cold winters of 2014-15 and 2015-16, suggesting that these climate events were unusual. The residuals are the highest for the spot price and near-term futures contracts, suggesting that the two-factor model is better at reproducing medium- and long-term futures (Figure 1-8) than spot prices. This is the most relevant feature we want for our valuation problem. The average error is 0.5% for the two-factor model, and 0.7% for the one-factor model (Table 1.7) on the latest futures contract observations (March 2017). The average error over all observations and all maturities for the two-factor model is $-1.8\%$. The average error over all spot price observations is 9.7%.
Figure 1-6: The futures estimate replicates fairly well the observed futures as of March 2017, notably the long-term drift and the seasonal variations.

Table 1.7: The two-factor model simulation is close to the observed futures curve for valuation purpose (price differs by less than 1% on average) for the Western Hub as of March 2017.

<table>
<thead>
<tr>
<th></th>
<th>Average price ($/MWh)</th>
<th>Mean error ($/MWh)</th>
<th>St. dev. of error ($/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Observed futures curve</td>
<td>30.888</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Simulation - one-factor model</td>
<td>30.671</td>
<td>-0.2279</td>
<td>3.086</td>
</tr>
<tr>
<td>Simulation - two-factor model</td>
<td>30.720</td>
<td>-0.1683</td>
<td>2.822</td>
</tr>
</tbody>
</table>

Figures 1-9 displays the expected long-term risk-free price paths calculated with Monte Carlo simulations. Figure 1-10 shows the same curve but deseasonalized. We can notice that the one-factor and the two-factor models are very close on the medium term but start to differ on the long-term (10 years and beyond). The slope of the two models are different, with the slope of the two-factor model being greater than the slope of the one-factor model. This is due to the large negative value of alpha in the
Figure 1-7: The forecasted state variables and observations exhibit significant discrepancy during the polar vortexes of 2014 and 2015.

Figure 1-8: The two-factor model is more accurate for long-term futures maturities than for the spot or short-term futures maturities. The average error is $-0.655/\text{MWh}$, that is $-1.8\%$ of the mean observation.
one-factor model, which creates a strong risk premium on the long-term and brings futures prices to very low values.

![Price paths](image)

Figure 1-9: The one- and two-factor model differ on their long-term expectations. Example for the Western Hub price simulation as of March 2017. The 95% confidence interval corresponds to the $1.96\sigma$ deviation from the mean.

Unfortunately the quality of our estimation cannot be validated with other data than the futures curve. It would have been ideal to have other traded derivatives based on underlying spot price, such as option contracts. Option contracts can indeed inform us about the implied volatility of the spot price. The Boomberg terminal we have access to does not trade such products. Interestingly a new exchange platform — Nodal Exchange — that could resolve this problem is developing. Nodal Exchange enables the trading of electricity futures at more than five hundreds nodes in the United States for delivery up to 11 year in the future. It also recently created option contracts on electricity prices. We requested access but had not received an answer at the time this thesis was written.

The models are considered satisfactory at this point and we now turn to the task of nuclear asset valuation.
1.3.4 Nuclear asset valuation

In this section we formulate the economic value of a nuclear power plant under uncertain price given by the previous stochastic process, and under flexible retirement decision. In the classical setting, the present value \( V_t \) of an asset at time \( t \) is the sum of its expected discounted future cash flows. The uncertainty and risk associated with future cash flow is accounted in the discount factor. Here, we explicitly price the risk associated with spot price variations with the help of our risk-neutral price process.

As in the classical formulation, the value of the plant is equal to its expected discounted cash flows. The discrete time formulation yields:

\[
V = \mathbb{E} \left[ \sum_{t=0}^{T} \pi_t e^{-\rho t} \right]
\]  
(1.68)
where $\rho$ is the discount rate.

The cash flow in the general case includes energy sales, capacity payments, subsidy payments and costs:

$$\pi_t = q_t (S_t + ZEC_t) + Cap_t - C_t$$  \hspace{1cm} (1.69)

where $Cap_s$ is the capacity payment, and $ZEC_s$ the subsidy payment per unit energy generated. We assume that the cost of generation is independent from the reactor output level (entirely fixed cost), which is consistent with the assumption that the short-run marginal cost of production of a nuclear plant is zero \[103\].

The valuation must either use a risk-adjusted discount factor and the true expectation of cash flows, or use the risk-free rate and the risk-neutral expectation. Having previously identified the risk-neutral expectation of spot price with our two-factor model of futures price, we want to take advantage of it. To do so, we need to simplify the term $\mathbb{E} \left[ \sum_{t=0}^{T} q_t S_t e^{-\rho t} \right]$. If we assume that the output level $q_s$ of the plant is 1) perfectly predictable, i.e. riskless and 2) uniformly distributed over each time period, i.e. constant on a given time period, then we can take $q_s$ out of the integral and make the risk-neutral expectation of spot prices (i.e. futures) appear:

$$\mathbb{E} \left[ \sum_{t=0}^{T} q_t S_t e^{-\rho t} \right] \simeq \mathbb{E}^Q \left[ \sum_{t=0}^{T} q_t S_t e^{-rt} \right]$$  \hspace{1cm} (1.72)

$$\simeq \sum_{t=0}^{T} q_t \mathbb{E}^Q [S_t] e^{-rt}$$  \hspace{1cm} (1.73)

$$\simeq \sum_{t=0}^{T} q_t F_0 (S_t, 0) e^{-rt}$$  \hspace{1cm} (1.74)

How reasonable is it to assume that the plant output is riskless and constant? Most commercial reactors operate reliably at maximum output. Their forced (unexpected)
outage rate is very low. For instance the average forced outage rate (EFORd) in PJM for the year 2016 was 1.86% \[15\]. Very few reactors in the U.S. do load following and therefore operate at maximum output when they can. As for the planned outages, we can consider that they occur at time of low electricity price and that they do not cause a large error in the expected energy sales for this future month (the monthly average output level $q_s$ is reduced to account for the outage).

The other terms of the valuation equation can be evaluated with their true probability distribution and a risk-adjusted discount factor $\rho$. We have in these conditions:

$$V = \mathbb{E} \left[ \sum_{t=0}^{T} q_t S_t e^{-\rho t} \right] + \mathbb{E} \left[ \sum_{t=0}^{T} (q_t ZEC_t + Cap_t - C_t) e^{-\rho t} \right] \quad (1.75)$$

$$= \sum_{t=0}^{T} q_t \mathbb{E} Q[S_t] e^{-rt} + \mathbb{E} \left[ \sum_{t=0}^{T} (q_t ZEC_t + Cap_t - C_t) e^{-\rho t} \right] \quad (1.76)$$

Although the calculation of the risk-adjusted discount factor $\rho$ still represents a difficulty, the above expression provides a better quantification of the value of the plant compared to the classical full DCF valuation method. The largest source of risk — spot price risk — is measured from the futures market and is believed to be more accurate than a default discount factor such as the WACC.

The nature of price risk — a hedgeable risk factor — as opposed to generation and cost risk — “idosyncratic” risk factors — leads to a different treatment in the valuation of the plant. The value of energy sales is evaluated with risk-neutral expectations and risk-free discount rate because they can be replicated with a financial portfolio (the market is complete). Hedged optimally, their expected return is the risk-free rate of return (equal to that of bond yield for instance). By contrast the idiosyncratic sources of risk are not tradable (incomplete market). There is no price for their risk and their value depends on the risk preference (utility function) of the firm. Some authors avoid this difficulty and compute their specific risk with a CAPM-like formula based on the correlation of the risky factor with a market index such as a stock market index \[86\]. But to be applied the CAPM assumes an equilibrium between the asset being priced and the market portfolio. This equilibrium is absent in the case of generation cost and power output. Therefore it is hard to define a risk
premium for generation and cost that is independent from the decision-maker’s risk preference. Each company uses a specific discount rate that reflects its level of risk aversion.

For simplicity, we perform the valuation assuming that capacity payments, costs and operation level are a small source of uncertainty for a nuclear plant, and apply a risk-free factor to their cash flow contribution.

Armed with this tractable valuation method that better quantifies price risk, we then introduce the option pricing framework in order to determine the optimal retirement strategy of a nuclear power plant in competitive market.

1.3.5 Optimal retirement strategy

In the real option framework, the asset owner can make operating decision during the lifetime of the asset. In our case, the plant owner can for instance retire the nuclear asset permanently, or make investments to extend the plant lifetime depending on the price trajectory of electricity price. The decision can also be deferred to gain more information on price.

These decisions offer flexibility and bring value to the plant. For instance, the option to shutdown early minimize the losses of the owner once exercised optimally. It is important to include these options to capture the full value of nuclear assets and make optimal decision.

We build our model upon a legacy of work on financial engineering, starting from the option pricing framework developed by Black, Scholes and Merton\cite{77, 128}. Financial option pricing was later applied to the “physical world” to determine the optimal policies for developing, managing and abandoning real assets \cite{126, 79, 87}. In the electricity sector, the real option theory proved useful to value flexibility in operation and projects \cite{89, 149}. It was applied to nuclear assets in several journal articles \cite{143, 142, 152, 159}.

Our approach is similar although we focus more on existing nuclear power plant rather than on new builds, with a valuation horizon of 10-20 years. Mid-term and long-term price paths are important, hence the introduction of our two-factor model
of electricity price. A simple mean-reverting process or geometric Brownian motion alone would not prove satisfactory as it would fail to capture the time value of uncertainty and would lead to potentially inaccurate valuation. The two-factor calibration on futures price also provides us with the risk premium associated with future electricity prices. We believe and demonstrate that this improvement makes the valuation more accurate and more applicable to real-world problems encountered in the industry.

We consider here several options when it comes to manage the nuclear asset: the premature retirement decision, the mothballing option, and the lifetime extension. These options can be considered in combination or separately.

**Premature retirement** The simplest case is a situation where the plant owner faces the option to retire permanently the power plant before the end of its operating license.

In this formulation, there are two states for the nuclear power plant. An operating mode, denoted by the subscript 1, and a retired mode, denoted by the subscript 0. The project can switch from operation to retirement, but can not switch back to operation once retired (irreversible shutdown). The value of the electricity price at which the retirement occurs is denoted by \( S_{\text{shut}} \). \( S_{\text{shut}} \) depends on time because the remaining lifetime of the plant impacts its value and the decision to retire.

The value of the plant \( V_1 \) (in \$/MW\( e \)) depends on time and on the current electricity price.

\[
V_1 = V_1(t, S(t)) \quad (\text{continuous time}) \tag{1.77}
\]
\[
= V_1(t, S_t) \quad (\text{discrete time}) \tag{1.78}
\]

By contrast, the value of a retired plant is constant and equal to zero.

\[
V_0 = 0 \tag{1.79}
\]

Retiring a plant has usually a cost, which we denote by \(-D\). \( D \) is positive if there
Figure 1-11: The option value of premature retirement as a function of the starting electricity price $S_0$. We recognize the characteristic shape of a financial put option. The calculation assumes $D = 0, C = $35/MWh and electricity price following the forecasted two-factor model at the Western Hub as of March 2017. The result was obtained by running 400,000 price path simulation (Monte Carlo).

is a net sunk cost in decommissioning.

The retirement decision is taken at time $t$ if the present value of the plant is less than the value of decommissioning. The present value is the sum of the cash flow at time $t$ plus the expected discounted future value in the next period. In mathematical terms:

$$V_1(t, S(t)) = \max \left[ \pi(t) + E_t^Q (V_1(t + \Delta t, S(t + \Delta t))) e^{-r \Delta t}, -D \right]$$  \hspace{1cm} (1.80)

This formulation can be used recursively in Monte Carlo simulations for assessing the value of $V_1$, as well as the value of $S_t = S_{\text{shut}}$ that triggers the retirement.

The termination value at the end of the operating license at time $T$ defines a
boundary condition

\[ V_1 (T, S_T) = -D + V_0 \]  \hspace{1cm} (1.81)

At time of early retirement, the following equation is verified:

\[ V_1 (t, S_{\text{shut}}) = -D + V_0 = -D \]  \hspace{1cm} (1.82)

The option value is equal to the difference between the value of the asset with option and the value of the asset without option. Figures 1-11 and 1-12 exhibit an example of option valuation using Monte Carlo simulations. The retirement option has greater value when prices are lower (Figure 1-11), and when we are far from the termination date (Figure 1-12). The shutdown price level can be seen as a metric of the likelihood of early retirement: the higher is the shutdown price, the closer is the plant to premature retirement.
**Lifetime extension** The option of extending the lifetime of the plant occurs at the end of the operation license, at \( t = T \). The owner can then decide to pay the investment cost \( I \) to extend the operating license of the asset by a period \( L \).

Figure 1-13: Once the operation license has been renewed, the value of the plant increases dramatically. The calculation assumes \( D = 0 \), \( C = $35/MWh \) and an electricity price trajectory following the forecasted two-factor model at the Western Hub as of March 2017. The result was obtained by running 50,000 price path simulation (Monte Carlo)

At time \( T \):

\[
V_1(T, S(T)) = \max \left[ -I + \mathbb{E}^Q_T (V_1(T+\Delta T, S(T+\Delta t))) e^{-r\Delta t}, -D \right] \quad (1.83)
\]

The new termination condition is then:

\[
V_1(T + L, S_{T+L}) = -D \text{ (termination)} \quad (1.84)
\]

(1.85)
Figure 1-14: When the operation license expires (April 2032), the plant has a high likelihood to retire, as illustrated by the relatively large spot electricity price requirement. The option value of license renewal accounts for most of the initial plant value (in 2017).

The option value of lifetime extension is plotted in Figure 1-14 for an example of a 20-year lifetime extension occurring 15 years from now. The fictitious plant has the option to retire at any month based on the current spot price of electricity. We see that when the first operation license expires (April 2032), the plant has a high likelihood to retire, as illustrated by the relatively large spot electricity price requirement to maintain operation (around 28$/MWh). Once the operation license has been renewed, the value of the plant increases dramatically as shown in Figure 1-13. In this example, the price is expected to increase in the long-run. Therefore, the option value of license renewal is very large: it accounts for most of the initial plant value (in 2017). In this case, neglecting the option to extend the operating license would lead to a major underestimation of the asset value.

Mothballing The mothballing status, denoted by the subscript $M$, is a state in which the plant is shutdown temporarily. The plant owner does not receive revenue
from the market but continues to face expenses to keep the plant in operable condition. The cash flow rate of a mothballed plant is

\[ \pi_t = -C_M \]  

(1.86)

where \( C_M \) is the cost of keeping the plant in the mothballed state. \( C_M \) is assumed constant. We also assume that there is no additional cost from switching from operating to mothballing mode.

Figure 1-15: The mothballing option is interesting when the electricity price is very low but expected to rebound. The calculation shown assumes \( R = 1000$/MWe, Cm = $3.5/MWh \) and an electricity price trajectory following the forecasted two-factor model at the Western Hub as of March 2017. The result was obtained by running 500000 price path simulation (Monte Carlo)

The plant switches from the operating mode to the mothballed mode if

\[
(S(t) - C) + \mathbb{E}_t^Q (V_1 (t + \Delta t, S(t + \Delta t))) e^{-r\Delta t} < -C_M + \mathbb{E}_t^Q (V_M (t + \Delta t, S(t + \Delta t))) e^{-r\Delta t}
\]

(1.87)
As opposed to the permanent shutdown decision, the mothballed status allows to return to the operating status. The plant switches from the mothballed mode to the active mode if

\[-C_M + \mathbb{E}_t (V_M(t + \Delta t, S(t + \Delta t))) e^{-r\Delta t} < (S(t) - C) + \mathbb{E}_t (V_1(t + \Delta t, S(t + \Delta t))) e^{-r\Delta t}\]  

(1.88)

\(R\) represents the cost of restarting the plant \((R > 0)\).

The boundary conditions in this case are:

\[V_1(T, S_T) = -D \text{ (termination)}\]  

(1.89)

\[V_M(T, S_T) = -D \text{ (termination)}\]  

(1.90)

\[V_1(t, S_M) = V_M(t, S_M) \text{ (mothballing)}\]  

(1.91)

\[V_M(t, S_R) = R + V_1(t, S_R) \text{ (restart)}\]  

(1.92)
The option value of lifetime extension is plotted in Figure 1-16. In our simulations we observe it is very sensitive to the mothballing cost and restart cost, as well as the cash flow trajectory. The mothballing option becomes worthless as the plant comes close to the end of its lifetime. The threshold boundaries are better estimated with a large number of Monte Carlo simulations so that sufficient price paths “hit” the exercise threshold and are recorded.

1.3.6 Numerical solving

This section present numerical approaches to assess the value of nuclear assets: Monte Carlo simulation and finite-difference. Both are applicable to continuous-time settings. The alternative “tree” approach is not reviewed here because it is not suitable for continuous time with infinite number of states (the price of electricity can take an infinite number of value).

Monte Carlo Monte Carlo simulations consist in simulating a large number of individual price paths using a random number generator. The law of large numbers states that if the number of simulated random variables \( Y_1, Y_2, \cdots \) is large, the sequence \( (Y_1 + \cdots + Y_n)/n \) converges toward \( \mathbb{E}[Y] \).

In our case, we want to estimate

\[
V = \mathbb{E} \left[ \sum_{t=0}^{T} \pi_t e^{-rt} \right] \quad (1.93)
\]

\[
V = \sum_{t=0}^{T} \mathbb{E} [\pi_t] e^{-rt} \quad (1.94)
\]

\( \mathbb{E} [\pi_t] = \mathbb{E} [\pi (S_t)] \) can be estimated by Monte Carlo simulations, starting from \( \mathbb{E} [\pi_0] = \pi_0 \) and with increments given by the discrete version of the Itô processes. For instance, in the case of the one-factor model:

\[
S_t^\omega_{t+1} = f_{t+1} + \chi_{t+1}^\omega + \xi_{t+1} = f_{t+1} + (1 - \kappa \Delta t) \chi_t^\omega + \kappa \alpha \Delta t + \sigma u_t^\omega + \xi_t + \mu \Delta t \quad (1.95)
\]

\[
(1.96)
\]
where \( \omega \) denotes the path number. \( u_t^\omega \) is generated numerically from a uniform distribution of variance 1. Matlab provides such random number generators. By simulating a large number of possible state variables \( S_{t+1}^\omega \) and averaging \( \pi \left( S_{t+1}^\omega \right) \) over the simulations, we approximate \( \mathbb{E} \left[ \pi \left( S_{t+1} \right) \right] \). The real standard deviation of \( S_{t+1} \) is approximated by the standard deviation of the simulated state variable \( S_{t+1}^\omega \).

In the case of several correlated random processes, say \( \chi_t \) and \( \xi_t \), the random number generator takes the form of

\[
B \begin{pmatrix} u_t \\ \epsilon_t \end{pmatrix}
\]

(1.97)

where \( u_t \) and \( \epsilon_t \) are independent, uniformly distributed random number of variance 1 and

\[
BB^T = \text{Cov} [\chi_t, \xi_t] = \begin{pmatrix} \sigma^2 \chi & \rho \sigma \chi \sigma \xi \\ \rho \sigma \chi \sigma \xi & \sigma^2 \xi \end{pmatrix}
\]

(1.99)

In our cases where the asset has a termination value, it is practical to use recursive algorithms and to perform the valuation of the plant starting from the termination date.

The calculation of the value of a nuclear asset based on the underlying electricity price involves three steps:

1. Simulate \( n \) electricity price paths over the lifetime of the asset. The discretized version of the Itô processes describe the evolution of the state variables between two timesteps. The starting price is the latest observation.

2. Calculate the discounted cash flows (payoff) for each price path \( \omega \). If a decision needs to be taken at each time step that impacts future cash flow, evaluate the decision criteria starting from the termination time back to the initial time step.
3. Calculate the present value of the asset (or derivative) over time by averaging the discounted cash flow over all \( n \) price paths.

How many simulations are needed to have an accurate approximation of the asset value? We know that the variance of \( Y_1 + \cdots + Y_n \) converges toward \( \sigma^2 \). The convergence speed is given by the central limit theorem. The 95\% confidence interval of approximating the true expected value is given by

\[
\left[ \hat{\mu}_N - 1.96 \frac{\hat{\sigma}_N}{\sqrt{N}}, \hat{\mu}_N + 1.96 \frac{\hat{\sigma}_N}{\sqrt{N}} \right]
\]

where \( \hat{\mu}_N \) and \( \hat{\sigma}_N \) are the average and standard deviation of the \( N \) simulations respectively. In practice 10 to 100 thousand price paths are a good compromise between accuracy and computation time.

**Finite-difference** The finite-difference method is commonly used for solving differential equations. It can be used to solve the stochastic differential equations that \( V \) verifies together with the boundary conditions \[88\]. This numerical approach is powerful but requires some preparatory work. It requires a discretization of the price and time domain, together with a differentiation scheme and initiation to be carried out. The solution can be unstable or the solver may not converge at all if the scheme is not adequate.

We tested the finite difference method on an univariate formulation of the Clinton nuclear power plant value in Illinois. We adopted an explicit differentiation scheme. The approach was much more work intensive than the Monte Carlo approach and was not converging inconditionnally. Figure 1-17 exhibits an example of a 3-D curve that we obtain with the method.

In general, we prefer the Monte Carlo approach to asset valuation, unless a 3-D curve needs to be plotted. Computational power today allows a large number of simulations in a reasonable amount of time, and the Monte Carlo method is less prone to user error.
Figure 1-17: Example of 3-D value curve that can be obtained with the finite difference method. The time and price domain needs to be discretized and the differentiation scheme carefully selected. The example assumes a simple mean-reverting process for price, without seasonal variation.
Chapter 2

Nuclear energy in deregulated electricity markets

2.1 U.S. Case

In 2015, nuclear represented 20% of the total U.S. electricity generation and 60% of the country’s carbon-free electricity [22]. With a total installed capacity of 104 GW, the reactor fleet reported a record high 92.5% capacity factor [13]. Almost all reactors have been granted a 20-year license extension from 40 to 60 years by the Nuclear Regulatory Commission [63].

Despite this consistently positive performance, in the past three years five nuclear power plants, totaling 4.7 GW of installed capacity, retired from the electrical grid before the end of their operating license. Eight additional ones have officially announced their retirement in the coming years (see Table 2.1), and many more are at risk of retiring prematurely according to studies by Steckler (2016) and Rorke (2016). Low historical and forward power and capacity prices, together with relatively large long-term operating costs, make nuclear plant operation unprofitable in many locations. Even plants owned by public power utilities or rate-of-return regulated utilities have started to shut down (case of Fort Calhoun in 2016).

In this section we first provide an updated assessment of the economic viability of the U.S. nuclear plants. We then study the levers of profitability to explain why re-
Table 2.1: Executed, contingent, or planned nuclear retirements in the United States as of January 2017.

<table>
<thead>
<tr>
<th>Plant name</th>
<th>Year</th>
<th>Retirement age (yr)</th>
<th>Capacity (MW)</th>
<th>Market</th>
</tr>
</thead>
<tbody>
<tr>
<td>Crystal River</td>
<td>2013</td>
<td>36</td>
<td>877</td>
<td>South East</td>
</tr>
<tr>
<td>San Onofre</td>
<td>2013</td>
<td>30</td>
<td>2,150</td>
<td>CAISO</td>
</tr>
<tr>
<td>Kewaunee</td>
<td>2013</td>
<td>39</td>
<td>574</td>
<td>MISO</td>
</tr>
<tr>
<td>Vermont Yankee</td>
<td>2014</td>
<td>42</td>
<td>619</td>
<td>New England</td>
</tr>
<tr>
<td>Fort Calhoun</td>
<td>2016</td>
<td>43</td>
<td>478</td>
<td>SPP</td>
</tr>
<tr>
<td>Clinton</td>
<td>2017</td>
<td>30</td>
<td>1,078</td>
<td>MISO</td>
</tr>
<tr>
<td>Quad Cities</td>
<td>2018</td>
<td>46</td>
<td>1,819</td>
<td>PJM</td>
</tr>
<tr>
<td>Fitzpatrick</td>
<td>2017</td>
<td>42</td>
<td>853</td>
<td>NYISO</td>
</tr>
<tr>
<td>Palisades</td>
<td>2018</td>
<td>47</td>
<td>820</td>
<td>MISO</td>
</tr>
<tr>
<td>Oyster Creek</td>
<td>2019</td>
<td>50</td>
<td>637</td>
<td>PJM</td>
</tr>
<tr>
<td>Pilgrim</td>
<td>2019</td>
<td>47</td>
<td>685</td>
<td>New England</td>
</tr>
<tr>
<td>Indian Point</td>
<td>2020-21</td>
<td>46-46</td>
<td>1,030</td>
<td>NYISO</td>
</tr>
<tr>
<td>Diablo Canyon</td>
<td>2024</td>
<td>39</td>
<td>2,240</td>
<td>CAISO</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td></td>
<td></td>
<td><strong>14,901</strong></td>
<td></td>
</tr>
</tbody>
</table>

The retirements occur using a wholesale electricity market model. In Section 3 the potential consequences of the closures are presented.

### 2.1.1 Profitability Outlook for U.S. Nuclear Plants

What is the extent of the financial troubles of the U.S. nuclear power plants? This section provides an estimate of the past, present and future profitability of every single plant in the country. The assessment is based on public data, i.e. published prices and costs. Bilateral power purchase agreements, which are usually confidential, and unforeseen expenditures are absent from the revenue estimate. Although bilateral purchase contracts can delay the retirements of assets, we can reasonably assume that in the long run the re-negotiated price of these contracts match the price listed on the exchange market.
Results

The profitability of the 60 U.S. nuclear plants is defined in this section as the net pre-tax earnings of the individual facilities. For any given year, the profitability is the sum of a) the energy sales, b) the capacity market revenue, c) the policy support (subsidies if applicable) minus d) the cost of generation. Both historical (from 2013 until 2016) and future (2017-2019) earnings are estimated. The spreadsheet for the calculation can be accessed online on the MIT CEEPR website[1].

The profitability of the U.S. nuclear plants is performed with the methodology described in Chapter 1.

Results were obtained for the 60 U.S. nuclear plants existing as of January 2017, regardless of whether they are located in regulated or deregulated market environments. The precision of the estimates varies. In particular the 15 plants located in the Southeast are subject to imprecision due to the coarse assessment of future bilateral contract prices of electricity.

The plant-by-plant analysis reveals profitability in the range of -$29 to +$15 /MWh generated over the 2017-2019 period (Figure 2-1). The number represents a crude average; no discount factor was applied. Prairie Island and Monticello in Minnesota appear to be the least profitable plants by far, due to low wholesale price in North-West MISO and low capacity factor (80-82%). Most of the Southeast plants show a negative outlook due to their larger cost of production.

Results show that 35 plants, totaling 59 GW of capacity, are out-of-the-money over the 2017-2019 period. When adding the 5 plants — 6 GW — that have announced their retirement, nearly two thirds of the U.S. nuclear fleet display negative outlooks (Figure 2-1).

The “merchant” plants — the plants that solely rely on competitive markets for their revenue — are of course more exposed and have a higher risk of shutting down prematurely than those owned by a regulated utility or a public power company. As a matter of fact regulated utilities are remunerated based on their cost-of-service and are largely protected from direct market forces. Public power companies (TVA,

---

[1] ceepr.mit.edu
Figure 2-1: The profitability of the 60 U.S. nuclear plants studied ranges from -$29 to +$15/MWh over the 2017-2019 time period. The subsidies (ZECs) are accounted; the lightly shaded bars represent the hypothetical profitability of the plants if ZECs were removed.
Energy Northwest, etc.) are also expected to respond with less pressure to short-term market signals [39]. We expect most of the plants owned by regulated or publicly-owned utilities to remain in operation. Figure 2-2 shows the profitability outlook by ownership structure. 12 GW of uncompetitive nuclear capacity is in the “merchant” category and is at high risk or retiring in the coming years.

![Profitability outlook over 2017-2019 period (MW of installed capacity)](image)

Figure 2-2: Market signals indicate that the majority of the 102 GW nuclear fleet is uncompetitive in the near future. 39% of the merchant capacity is on a path to retirement. The plants owned by regulated- or public power utilities are to a large extent protected from market forces. Note that recently-voted-on state subsidies are accounted.

We recognize that the final decision to retire an individual plant does not solely depend on its expected net pre-tax earnings over the next three years\(^2\). Nevertheless we consider the aggregate number to be a good indicator of the risk of premature nuclear capacity withdrawal under the current price trajectory. To determine the risk of retirement, the advanced method of valuation under uncertainty developed in Chapter 2 needs to be used. We apply it to an example - the Fitzpatrick plant, later in this Chapter.

The breakdown by region reveals strong differences (Figure 2-3). The Midwest, California and Texas regions are particularly unprofitable for merchant nuclear over

\(^2\text{Other factors need to be considered such as medium- to long-term market conditions, and the uncertainty related to all future cash flows.}\)
the four-year period. PJM displays a mixed outlook, whereas New York and New England are favorable. The next section analyzes why and how these differences arise.

![Chart showing profitability by region over 2017-2019 period ($/MWh)](chart)

Figure 2-3: The Northeast markets are more favorable environments for nuclear power plants due to higher wholesale electricity spot prices. By contrast, the Midwest, California and Texas markets are challenging.

Table 2.2 shows the revenue gap each year for the plants in distress out of the 60 plants studied (retired plants as of January 2017 are not accounted). The numbers for merchant plants are also shown separately. The total number of struggling plants varies from year to year and peaks at 52 in 2016, a particularly challenging year for nuclear. The future is uncertain but forward markets seem to indicate a price recovery. Still, about 35 plants – 55 GW – are durably uncompetitive. The average revenue shortfall for these plants is about $5.5-7 / MWh per year over 2017-2019. This number can be viewed as the minimum amount of policy support that would be needed to bring them breakeven financially.

### 2.1.2 Drivers of Un-Competitiveness

The economics of nuclear power in competitive environment have been deteriorating. As seen previously the revenues from the wholesale and capacity markets are often not sufficient to cover the cost of electricity generation. In this section, we analyze the fundamental sources of change that drive down the competitiveness of
nuclear. Electricity generation revenue comes from several sources, namely: supplying electricity (kWh); assuring electricity generating capacity on demand (kW); and providing grid ancillary services.

Wholesale Prices

As displayed in Figure 2-4, the wholesale price of electricity has been declining everywhere in the United States since the years 2007-08. This phenomena has directly impacted nuclear power plants, which supply base-load electricity and for which the wholesale market is the primary source of revenue. In fact, the sales of electricity represent 90% of the revenue of the U.S. nuclear plants. This ratio is larger than for coal and natural gas power plants, for which capacity markets and ancillary services represent a larger share of revenue.

To better understand the reasons for the price decline, we propose replicating the price formation of wholesale prices in two zones relevant for nuclear plants: the Midwest and the Mid-Atlantic region, which total 50 GW of nuclear capacity. We compare the years 2008 and 2015 and analyze the single structural changes affecting price and the magnitude of their impact.

<table>
<thead>
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</tr>
</thead>
<tbody>
<tr>
<td><strong>Total</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Unprofitable plants</td>
<td>29</td>
<td>9</td>
<td>37</td>
<td>52</td>
<td>36</td>
<td>38</td>
<td>43</td>
</tr>
<tr>
<td>Capacity (MW)</td>
<td>42,378</td>
<td>8,533</td>
<td>59,282</td>
<td>87,347</td>
<td>57,557</td>
<td>61,867</td>
<td>73,517</td>
</tr>
<tr>
<td>Total revenue gap (M$)</td>
<td>-1,466</td>
<td>-582</td>
<td>-2,943</td>
<td>-5,103</td>
<td>-2,604</td>
<td>3,173</td>
<td>-3,562</td>
</tr>
<tr>
<td>Average loss in $/MWh</td>
<td>-4.57</td>
<td>-9.29</td>
<td>-6.29</td>
<td>-7.53</td>
<td>-5.87</td>
<td>-6.66</td>
<td>-6.29</td>
</tr>
<tr>
<td><strong>Merchant</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Unprofitable plants</td>
<td>8</td>
<td>0</td>
<td>11</td>
<td>22</td>
<td>10</td>
<td>10</td>
<td>14</td>
</tr>
<tr>
<td>Capacity (MW)</td>
<td>11,702</td>
<td>622</td>
<td>15,152</td>
<td>34,755</td>
<td>15,044</td>
<td>13,338</td>
<td>23,116</td>
</tr>
<tr>
<td>Total revenue gap (M$)</td>
<td>-339</td>
<td>-72</td>
<td>-661</td>
<td>-1,346</td>
<td>-372</td>
<td>-536</td>
<td>-762</td>
</tr>
<tr>
<td>Average loss in $/MWh</td>
<td>-3.83</td>
<td>0</td>
<td>-5.83</td>
<td>-5.05</td>
<td>-3.24</td>
<td>-5.27</td>
<td>-4.37</td>
</tr>
</tbody>
</table>
Figure 2-4: Wholesale price of electricity have gone down everywhere in the United States in the past decade.

**Model of wholesale market** The wholesale price of electricity is simulated with a simple economic dispatch model of the generators in the zone spanning one year (8760 hours). The model takes the hourly demand for electricity, the generation profile of renewables (wind), the installed generation capacity, and its short-run marginal cost in order to dispatch the generation and meet the demand at minimal cost. The price of electricity for each hour is determined by the marginal unit that serves the load. The transmission line constraints inside the zone are ignored, as well as the transmission losses (single node approximation), and the power exchanged with the neighbouring regions is treated as an addition (export) or reduction (import) of the total demand for the zone. The constraints introduced in the optimization problem are: the load demand constraint, the constraints on the maximum output of each generator, and the flexibility constraint (ability to power up and down each generator). The cost of not meeting the demand is equal to the value of lost load, which is set at $500/MWh.

The formulation of the problem leads to the solving of a linear optimization problem, which is faster to compute than if binary constraints had been introduced. The generators of a given class are aggregated when their characteristics are similar. The model formulation as well as the cost and technical assumptions for the generators
are listed in Appendix.

Results: Midwest region (IA, IL, IN, MI, MN, MO, ND, WI)  The first region of interest is the Midwest, defined here as eight states together: Iowa, Illinois, Indiana, Michigan, Minnesota, Missouri, North Dakota and Wisconsin. Nuclear plants in this region are particularly affected by low wholesale prices. In Minnesota, average day-ahead hub prices were as low as $22.2 / MWh in 2015. Despite its simplicity, our model reproduces fairly well the observed wholesale prices as well as their relative drop between 2008 and 2015 (Table 2.3). To do so, it is essential to correctly model the coal-fired power plants in the region since they dominate the installed capacity (44-49% of all capacity). The model is very sensitive to their heat rate and availability. See the Appendix for more details.

Table 2.3: Actual vs. computed annual wholesale price in the Midwest region ($/MWh).

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Illinois hub</td>
<td>46.2</td>
<td>26.7</td>
<td>-42%</td>
</tr>
<tr>
<td>Michigan hub</td>
<td>52.1</td>
<td>28.6</td>
<td>-45%</td>
</tr>
<tr>
<td>Minnesota hub</td>
<td>47.7</td>
<td>22.2</td>
<td>-53%</td>
</tr>
<tr>
<td>Midwest model</td>
<td>42.4</td>
<td>26.9</td>
<td>-36%</td>
</tr>
</tbody>
</table>

The region has seen important structural changes from 2008 to 2015, specifically:

- Addition of 12.8 GW of wind power capacity, which added up to 9% of the total electricity supply in 2015.

- Decrease of natural gas price from $9.3 to $3.2 /MMBtu, and increase of coal price from $1.45 to $1.85 /MMBtu [23, 21].

- Reduction of total electricity demand by 3.8%. Most of this change (3.3% out of 3.8%) was caused by a reduction in electricity exports[^3].

[^3]: Net imports are calculated as the sum of the net interstate imports for each states reported by the EIA (2016a). The total demand is equal to the total supply in the zone. The “internal” demand is defined as the difference between the total demand and the net exports of electricity in the zone.
- Retirement of 4.5 GW of coal power plants.

To quantify the effects on price caused by each of these factors, we employed our wholesale electricity model. Starting from the 2008 conditions, we replaced the inputs once-at-a-time by their 2015 value, and then reported the effect on price. Note that due to the non-linear nature of the wholesale market model, the sum of the effects does not equal the effect of their combination. The separate and combined price effects are reported in Figure 2-5.

Figure 2-5: The primary drivers of the price collapse in the Midwest are the decline in load demand and the collapse of natural gas prices. The effect of increased wind capacity is offset by the retirement of coal power plants during the same period.

In the Midwest, despite natural gas price collapse, production costs from coal-fired generators have remained cheaper than from Combined-Cycle Gas Turbines (CCGTs). The merit order of generation resources has stayed mostly the same in the supply curve. However, the drop in marginal cost of production for gas-fired units
due to cheap natural gas has been the primary cause of wholesale price contraction. The diminution in total electricity demand – and in exports in particular – has been the second most significant contributor. More surprisingly, the large introduction of renewables (wind) had a relatively small effect on price (-$4.6/ MWh). It was completely offset by the retirement of coal-fired generators (+$6.0/MWh). The effect of wind capacity introduction might have been more severe at the nodal level, but our market model did not capture these local effects.

**Results: Mid-Atlantic region (DC, DE, KY, MD, NJ, OH, PA, VA, WV)**

The Mid-Atlantic region (D.C., Delaware, Kentucky, Maryland, New Jersey, Ohio, Pennsylvania, Virginia and West Virginia) is another relevant region due to its high concentration of nuclear power plants (23 GW of capacity installed, 23% of the U.S. fleet). It is also the region that hosts the Marcellus shale gas deposit, whose exploitation has led to the dramatic boost in domestic natural gas production and associated price disruption between 2008 and 2015.

Nevertheless, the abundance of cheap natural gas has not yet materialized in electricity cheaper than in the Midwest, as can be observed in Table 2.4. Electricity prices were still 3to16/ MWh more expensive than in the Midwest in 2015. Our model replicated these wholesale prices in a satisfactory manner again; they lie in the range of the historical hub prices. For this region, the model is very sensitive to both coal- and gas-fired generator assumptions. These assumptions are reported in Appendix.

**Table 2.4: Actual vs. computed annual wholesale price in the Mid-Atlantic region ($/MWh).**

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>PJM Western hub</td>
<td>69.8</td>
<td>35.8</td>
<td>-49%</td>
</tr>
<tr>
<td>AEP Dayton hub</td>
<td>53.2</td>
<td>31.5</td>
<td>-41%</td>
</tr>
<tr>
<td>Dominion hub</td>
<td>73.5</td>
<td>38.2</td>
<td>-48%</td>
</tr>
<tr>
<td><strong>Mid-Atlantic model</strong></td>
<td><strong>59.4</strong></td>
<td><strong>31.8</strong></td>
<td><strong>-46%</strong></td>
</tr>
</tbody>
</table>

The Mid-Atlantic zone saw the same list of structural changes as the Midwest, although their magnitude is different:
• Addition of 1.8 GW of wind power capacity, a very moderate amount compared to the Midwest.

• Decrease of natural gas price from $10.3 to $3.2 /MMBtu, and increase of coal price from $3.3 to $3.4 /MMBtu [23, 21]. These relative changes are explained by the fact that the region sits on the newly-exploited Marcellus gas deposit and is farther from the Powder River and Illinois coal deposits than the Midwest.

• Reduction of total electricity demand by 8.3%. The internal load demand dropped by 12.1% but the region imported less electricity, which alleviated the effect on price (when the local producers clear more generation, the locational marginal price of electricity increases).

• Retirement of 16 GW of coal power plants, and addition of 13.1 GW of new gas-fired power plants.

The price decomposition of these individual factors is shown in Figure 2-6. It follows the same methodology as for the Midwest price decomposition.

As expected, the change in load demand had a more moderate impact in the Mid-Atlantic than in the Midwest. Natural gas price collapse had the largest single effect (-$28.1/MWh). Not only did it decrease the cost of generating electricity, but it changed the merit order of the technologies in the supply stack. Figure 2-7 shows that CCGT units displaced coal as the source of base-load electricity, forcing a large number of them to retire. If natural gas prices were to increase, the situation could revert and price could spike to high levels again. The retirement of coal-fired units makes the Mid-Atlantic market more sensitive to natural gas prices than in 2008, as demonstrated by the +$17.6/ MWh effect on price which would occur if 2008 natural gas prices were to return.

**Perspectives on future wholesale prices** Since natural gas price is the major agent of change in the wholesale power market, it is legitimate to wonder if its current low price is expected to last or not. Unfortunately for nuclear generators, and fortunately for consumers, natural gas is expected to remain cheap. Figure 2-8 shows
Figure 2-6: The primary drivers of the price collapse in the Mid-Atlantic are the collapse of natural gas prices and, to lesser extents, the drop in load demand and the change in capacity mix. The replacement of base-load coal-fired plants by base-load CCGT units yields a greater exposure to natural gas price.

the current “market view”: albeit recovering slightly, natural gas prices do not reach their pre-2008 levels in the short- and medium term.

How do natural gas prices translate into wholesale electricity prices? In Figure 2-9, we run simulations and plot the average wholesale price as a function of natural gas price in the Mid-Atlantic and Midwest regions, keeping all the other parameters (load demand, installed capacity, coal prices, etc.) identical to their 2015 values. In the simulation, we assume that all the gas-fired plants see the same natural gas price uniformly. Natural gas price changes the cost of generation but also the dispatch of the generators. We observe that the coal-to-gas dispatch transition occurs between $3 and $6/ MMBtu for the Mid-Atlantic, and below $5/ MMBtu for the Midwest. The Mid-Atlantic region exhibits a stronger sensitivity to natural gas price due to its high concentration of gas-fired plants. The possible massive replacement of nuclear
Figure 2-7: In the supply stack of 2008 (top), CCGT units are more expensive to dispatch than coal-fired units. In 2015 (bottom), the situation has been reversed and coal is being displaced by CCGT.

plants by CCGT units would intensify this sensitivity even more.

With natural gas price not exceeding $4/MMBtu, wholesale electricity market spot prices will not go beyond $35 and $30/ MWh in the Mid-Atlantic and Midwest. The wholesale market will most likely continue to provide low revenue for nuclear plants in the medium term. Therefore, saving the nuclear fleet requires other levers.
Figure 2-8: Forecasts based on raw futures prices indicate that natural gas prices remain low in the near- and medium-term (plot as of mid-January 2017). The 95% confidence interval displays significant uncertainty. It is calculated according to the EIA methodology which is based on the implied volatility of financial options traded on the market (EIA, 2009).

Cost of nuclear power generation

The cost of electricity generation from existing nuclear plants averaged $35.5/ MWh in 2015. This includes annual capital expenditures (equipment replacement and upgrade), operation and maintenance (O&M), and fuel. Unlike generators running on fossil fuels, a large share of the expenses are “fixed” and do not depend on the electricity output. For instance, the number of security personnel (around 5% of the total cost) is set by the regulator and is incurred whatever the size or power output of the plant. This characteristic favors large plants: the average cost of generation was $32.9/ MWh for multi-unit plants and as high as $42.5/ MWh for single-unit plants. Single-units plants are the first plants to suffer from low wholesale prices and this is not a surprise that they form the majority of the plants that are expected to retire prematurely (Table 2.1). Although relatively high, average generation costs have been decreasing since 2012 (Figure 2-10). Capital expenditures have been reduced after the 2011-2012 peaks, which were due to post-Fukushima upgrades.
Figure 2-9: The simulations show that the Mid-Atlantic zone is more sensitive to the price of natural gas than the Midwest due to the former’s higher concentration of gas-fired power plants. The retirement of nuclear plants and their replacement by gas-fired units would intensify this dependence and sensitivity.

and license extension programs. More recently, fuel costs have gone down thanks to progress in technology. O&M, the major cost item, remains expensive nevertheless. The industry committed to reduce them by $3.5/ MWh from the 2012 level (UBS, 2016). The objective of this initiative called “Delivering the Nuclear Promise” is to achieve $28/ MWh in total generation cost by the end of the 2020’s. We quickly see that this initiative will not be sufficient for the single-unit plants, and / or the plants located in regions with wholesale electricity spot prices in the low $20/ MWh range such as in the Midwest.

Capacity markets

Capacity markets are a secondary but important source of revenue for nuclear plants in deregulated regions where capacity markets exist (Figure 2-11). They can add up $300/ MW-day ~ $14/ MWh to the revenue of the plants in the best case (Pilgrim, 2018). The fleet-average revenue was nevertheless more moderate, between
Figure 2-10: After a peak in 2012 due to large capital expenditures, nuclear power generation costs have been decreasing \[58\]. However, they are still greater than market revenues in many locations. The costs are converted into 2015 USD for comparison.

$60$ and $80$/ MW-day over the last years, i.e. around $3$/ MWh. When plants fail to clear the capacity market, they receive zero for an entire year which can precipitate their retirement.

Figure 2-11: Capacity price differ between regions but in general provide moderate revenue for nuclear plants when these prices exist. The fleet-average price was $60-80$/ MW-day over the last years, i.e. around $3$/ MWh. Texas does not have any capacity mechanism.

Capacity markets were implemented in the late 2000’s, i.e. quite recently in the history of electricity market deregulation. Capacity market design is still evolv-
ing. Important reforms were implemented in the Northeast after the polar vortex in 2013-2014 when numerous fossil power plants failed at providing the capacity they promised. More reforms could happen but they are not likely to change the revenue game for nuclear plants due to the relatively low levels of capacity payments.

Other drivers of retirement: safety and business divestment strategy

Although economics are the origin of most premature nuclear retirements, and the main area of focus of this paper, we should highlight that in some instances non-economic factors are more decisive. In at least two recent cases – Oyster Creek and Indian Point – safety concerns and the associated cost of compliance with regulation led to the decision to close the facilities. Economics were not the primary driver. Indian Point appears for instance very profitable in our analysis earlier. But political pressure pushed the owner of the plant, Entergy, to announce in January 2017 the closure of the plant, which sits 50 miles away from NYC. The same owner Entergy also announced the shutdown of Pilgrim in Massachusetts. Similarly to Indian Point, the economics would advocate for continued operation but in this case the business strategy of Entergy is responsible. Entergy decided to divest from merchant nuclear power and entered the process of either selling or closing all its nuclear assets located in deregulated markets [52].

2.1.3 Implications of Premature Nuclear Retirements

What are the consequences of a massive wave of nuclear retirements? This section analyzes the impact of the hypothetical retirement of 20 GW of nuclear capacity, which is about a fifth of the total U.S. nuclear capacity[4]. Running at 92% capacity factor, 20 GW of nuclear generation represent 161 TWh of zero-emission electricity. Such a large withdrawal impacts environmental policy, electricity price and the natural gas market.

---

[4] 20 GW roughly correspond to the retirement of the 12 GW merchant plants at risk identified in section previously, plus the 6.5 GW of already-announced capacity retirement in Table {listOfRetirements}
Four scenarios are considered when it comes to the replacement of this nuclear power supply:

**Scenario 1** The retired nuclear generation is replaced by generation from other sources in place. These existing sources, which run on fossil fuel, increase their production to make up for the withdrawal of nuclear capacity and satisfy demand.

**Scenario 2** The retired nuclear generation is replaced by new gas combined cycle plants (CCGT). These modern units have a heat rate of 6,600 Btu/kWh and an availability factor of 87%.

**Scenario 3** The retired nuclear generation is replaced by renewable generation coming from new wind turbines. In the Midwest, the average wind capacity factor was 39% in 2015.

Although these scenarios are extreme and ignore possible grid congestion constraints, they have the merit of drawing the boundaries of the possible outcomes resulting from the mix that replaces the retired nuclear assets. Renewables and CCGT are now – and certainly will be – the preferred generators installed in the coming years due to their good economics (Figure 3-20). The CCGT additions are based on pure market economics while the renewable growth is more dependent on public subsidies. How much of each will be built depends on the market conditions and the policy incentives.

**Impact on Carbon Emission and Climate Policy** Unless replaced by emission-free hydro or renewable energy, the retirement of nuclear generation from the grid results in a net increase in greenhouse gas emissions. The immediate impact of 20 GW nuclear retirement is a 5.8% increase in CO2 emissions for the U.S. power sector (carbon intensity of the dispatchable generators times 161 TWh). This would

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5 Our simulations account for plant flexibility limitations but not for the limitations in power transmission capacity.
represent a large setback in achieving the objective of 32% emission reduction from the 2005 level by 2030\(^6\).

Is it feasible to reach climate policy objectives without nuclear? Calculations shows that carbon emissions reduction goals could still achieved without nuclear if coal power plants retire massively and are replaced by natural gas and renewables. An example of such a scenario is exhibited in Figure 2-12. A transition away from coal and nuclear would be politically challenging but could be affordable if natural gas remains cheap and the cost of renewables and energy storage continues to decrease\[^{54}\].

Figure 2-12: 2030 climate policy objectives could be achieved without nuclear in a hypothetical scenario where half of the coal-fired capacity retires, demand is stable, renewables production expand by a factor 3 and natural gas accounts for the rest (58%) of the electricity generation. Still, nuclear would be essential to meet the 2050 policy objectives.

However, more aggressive goals such as an 80% emissions decrease by 2050 would require full utilization of emission-free resources to eliminate coal power generation and reduce natural gas utilization. Nuclear would prove essential to reach long-term climate objectives.

The cost of carbon damage avoided by 20 GW of nuclear capacity is evaluated to $4.6\text{ billion} / \text{yr}$ at the current social cost of carbon of $41.2 / \text{MT CO}_2 \[^{65}\]$ and the 2015 carbon intensity of 0.695 MT CO\(_2\) / MWh for the make-up generation (refer to Table 2.5 for scenario comparison).

\[^{6}\text{Goal of the Clean Power Plan for the power sector}\]
Short-term Impact on Electricity Price  The immediate retirement of a power plant creates a shift to the left of the supply curve, leading to an upward price shock. However such a case occurs rarely in practice. Instead, retirements are announced years in advance (see Table 2.1) and the market agents have time to react, for instance by planning the construction of new power plants, by refurbishing old ones, or by postponing the outage and retirements of existing generators. The price shock observed in the real world is therefore less severe than if the plants were to retire overnight, without notice.

For the purposes of estimating the upper limit of the price shock, we nevertheless simulated the brutal retirement of 20% of the nuclear capacity in the 2015 Midwest and Mid-Atlantic wholesale market models presented and in Appendix. To meet the electricity demand, the other generators augment their production; this is our scenario 1. The yearly-average price shock is +$0.6 and +$0.9/MWh in the Midwest and Mid-Atlantic respectively. These represent an increase in the cost for the consumers of $410M and $640M/ year in these two regions. This cost has the same order of magnitude as the revenue gap the nuclear plants need to stay open ($0.2–12.0 B/ year for 20 GW of nuclear capacity in the entire United States).

Long-term Impact on Electricity Price  The long-term impact on price resulting from an adaptation of the market agents to the nuclear retirements is more complex and uncertain to predict. Some types of electricity market models (Sepulveda, 2016) can infer what type of generators and how many of them will replace the retired generators. As we can expect, the type of generators being build depends heavily on fuel prices (for dispatchable generators) and policy support (for renewables). For the purpose of brevity in this paper a simpler approach is employed. The wholesale market model is conserved while modifying the assumption on the installed capacity mix. In scenario 2 and 3, 20% of the nuclear capacity is replaced by new combined cycle plants and wind turbines respectively. The amount of capacity addition is inversely proportional to the capacity factor of the technology considered (0.87 for CCGT and 0.39 for Midwest wind for instance). The effect on average wholesale electricity spot
As expected, in both cases the effect is much milder than the “short-term” effect where market agents do not have time to react. The price increase is about +$0.02/MWh in scenario 2 due to currently low gas prices (2015 gas prices are assumed: $3.2/ MMBtu average). In the Mid-Atlantic region, the effect would be negligible due to the fact that gas plants are infra-marginal and that coal plants still set the price of electricity (Figure 2-7). In scenario 3 where renewables replace nuclear, there is nearly zero price effect because wind replaces nuclear base-load generators. Based on our simulations, there is enough flexibility in the grid to accommodate wind production intermittency. Wind and nuclear are always infra-marginal in the supply curve and never set the spot price of electricity.

**Impact on Natural Gas Market** The retirement of base-load nuclear increases the production of electricity from fossil fuel, and from natural gas in particular. This additional demand has a significant impact on the natural gas market. In scenario 1 (nuclear replaced by existing generators), the increase in natural gas burn is 570 Bcf/year, i.e. 2.1% of the total U.S. consumption. In scenario 2 (nuclear replaced by modern CCGT), the increase is 1,020 Bcf/yr, 3.7% of the U.S. consumption. In scenario 3, there is no increase in gas consumption.

As seen previously in Figure 2-9, the replacement of nuclear plants by gas-fired plants would make electricity markets even more dependent on natural gas supply and therefore more sensitive to natural gas price variations. This high dependence could also jeopardize the security of electricity supply when natural gas is scarce (e.g. in case of polar vortex or pipeline failure).

**Impact on the Cost of Generation** The average cost of generation of the nuclear capacity at risk is $36-37/ MWh over 2017-2019, which amounts to $5.8-6.0 B / yr for 20 GW of capacity. By comparison, the equivalent generation from new CCGT would come at a levelized cost of $25-38.5/ MWh or $4.0-6.2 B / yr. The equivalent

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7The natural gas consumption in the U.S. in 2015 was 27,306 Bcf. The heat rate for existing natural gas power plant is assumed to be 7,476 Btu/ kWh.  
8Assumptions: 8% discount rate, CF= .4-.7, fuel price $2.4-5.2/ MMBtu. Cost range based on Lazard.
wind power generation would have a levelized cost of $34-47/ MWh or $5.4-7.6 B / yr.[9]

**Impact on the Cost of Subsidies**  Preserving 20 GW of nuclear at risk would come at a cost of $0.2 to 1.9 B / year, and $1.9 to 12.0/ MWh . This is well below the $3.9 B / yr cost of carbon damage – a price externality – caused by their retirement ($41.8/MT CO2 avoided according to the 2016 EPA cost of carbon damage and in scenario 2). Replacing nuclear by renewables would have a neutral impact on emissions, but doing so would be more costly than preserving the existing nuclear plants. As an illustration, the federal Production Tax Credit for wind power was $23/ MWh in 2016 (DOE). The most representative state subsidy, the Renewable Energy Certificates, traded at about $13/ MWh in 2015-2016 in PJM (more precisely, in PA/NJ/MA). Replacing 161 TWh/ yr of nuclear by wind electricity would therefore come at the “policy” cost of at least 161,000,000*36 = $5.8 billion/ yr, which is several times greater than the estimated policy cost of preserving all the nuclear plants of the country.

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[9] Assumptions: 8% discount rate, CF=0.3-0.55. Cost range based on Lazard [54].
<table>
<thead>
<tr>
<th>Scenario 0</th>
<th>Scenario 1</th>
<th>Scenario 2</th>
<th>Scenario 3</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nuclear fleet maintained</td>
<td>Nuclear replaced by existing sources</td>
<td>Nuclear replaced by CCGT</td>
<td>Nuclear replaced by renewables</td>
</tr>
<tr>
<td>CO2 emissions</td>
<td>1,919 MM MT /yr (power sect.)</td>
<td>+5.8%</td>
<td>+3.2%</td>
</tr>
<tr>
<td>Wholesale price of electricity</td>
<td>$26.9/MWh (Midwest)</td>
<td>+$0.59/MWh (Midwest)</td>
<td>+$0.02/MWh (Midwest)</td>
</tr>
<tr>
<td>Gas burn</td>
<td>9,671 Bcf/yr (power sect.)</td>
<td>+570 Bcf/yr</td>
<td>+1,020 Bcf/yr</td>
</tr>
<tr>
<td>Cost of generation</td>
<td>$36-37/ MWh</td>
<td>-</td>
<td>$25-38.5/ MWh</td>
</tr>
<tr>
<td>Cost of subsidies</td>
<td>$1.9-12.0/ MWh</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td></td>
<td>$0.2-1.9B/ year (revenue gap)</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>
2.1.4 Retirement under uncertainty

The decision to retire a nuclear plant hangs on its expected future cash flows. Uncertainty plays a key role over the long lifetime of nuclear assets, especially in competitive markets. The flexibility (option) to report the decision is also a fundamental instrument the owner of the plant can exert that impacts the timing of retirement. These observations motivated the development of a novel methodology to value nuclear assets in Chapter 2. We now propose to apply this methodology in a case study.

We chose to focus on the Fitzpatrick plant in upstate New York. In November 2015, Entergy, the owner, announced the closure of the single-unit Fitzpatrick BWR reactor at the end of its fuel cycle, i.e. in late 2016-early 2017 [43]. But in August 2016, Exelon announced the purchase of the plant from Entergy [57]. The sale was conditioned to the approval of the Zero-Emission Credits (subsidies) from the New York legislator, approval which was confirmed on the same month.

The case of Fitzpatrick is interesting because it offers an opportunity to test our methodology on a real case. We also know what price Fitzpatrick was handed over in March 2017: $110 million, plus $107 million for the fresh refueling and outage-related expenses. Many aspects of the deal are confidential but we hope that by running sensitivity studies we can identify the drivers of an actual nuclear asset retirement decision.

Assumptions

Fitzpatrick lies on the shore of Lake Ontario. The locational marginal price of electricity in this location has been low, with yearly averages at $27.0 and 20.2 /MWh in 2015 and 2016. With capacity prices below $5/MWh, the plant could not recover its annual cost of production evaluated at $33.5/MWh for the year 2015.

The asset valuation is based on expected future cash flows, which we express for a given time interval $n$ (one month) by:

$$\pi_n = (P_n + Cap_n + ZEC_n) q_n - C_n$$

(2.1)
where $P_i$ is the average electricity price (LMP), $Cap_n$ the average capacity price, $ZEC_n$ the average ZEC subsidy, all expressed in $/ \text{MWh}$. $q_n$ is the expected net electricity production (in MWh) for the time period. $C_n$ the total production cost in $.

The electricity price is assumed to be the main source of uncertainty and the methodology we developed enables us to provide a long-time estimate of the forward price. The forward price fits the actual futures curve and extrapolate it. It captures the main features of the price dynamics (seasonality, long-time drift, short-term mean reversion and long-term arithmetic brownian motion) and evaluates the market risk premium associated with price.

Unfortunately electricity futures are not traded for all nodes of the electrical network. Typically futures curves are only available for the main hubs of the U.S. Fortunately the closest hub - NY ISO Zone C (Central) - is not too far from Fitzpatrick. We therefore use the hub price $P_{hub,n}$ of NY ISO Zone C as a substitute for the price of Fitzpatrick and add a correction term $\Delta_n$:

$$P_n = P_{hub,n} + \Delta_n \quad (2.2)$$

The correction $\Delta_n$ represents the spread between Zone C and Fitzpatrick. The spread seems to be evolving with time but for simplicity we use the average of the previous 3 years as our correction term $\Delta_n$ for future projection (Figure 2-13). It amounts to -$0.74 and +0.96/ \text{MWh}$ in October 2015 and July 2016 respectively.

The capacity market price is difficult to forecast as it depends on the capacity installed and the expected peak demand in the future. We adopt a projection based on the average month of the previous 4 years for future monthly projection, as illustrated in Figure 2-14. For instance, for a valuation done on August 2016, the January 2017 capacity price is the average of the January 2016, 2015, 2014 and 2013 prices. We assume that Fitzpatrick will always receive capacity market payments until it retires.

Finally the zero-emission credits (ZEC) to whom Fitzpatrick is eligible are reported by the Public Service Commission [62]. ZECs increase over time to reflect an
Figure 2-13: We use the historical, rolling 3-yr average price spread between Fitzpatrick and NY Zone C for projections.

Figure 2-14: We use the average of the months of the previous 4-years for capacity revenue projections.

increase in the price of carbon. They represent a large source of revenue, equal to $1.76 billion nominal over 12 years.

The cost of generation for future years is taken as the average of the past 5 years (2012-2016), which results in $19.943 million per month ($239.313 million per year). The cost data come from SNL financial [16]. The cost is inflated at an annual rate of
Figure 2-15: ZECs increase over time to reflect an increase in the price of carbon.

2.3%, which is the rate used by SNL in its future cost estimates [16]. We breakdown this cost in fixed O&M, incurred every month, and refueling cost which includes fuel and outage operation, inspection and maintenance cost. The refueling cost is incurred only during refueling months - once every two years.

Table 2.6: The cost assumptions are an average over the past 5 years taken from SNL [16].

<table>
<thead>
<tr>
<th>Cost</th>
<th>Occurrence</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fixed operation and maintenance</td>
<td>$15.4 MM every month</td>
</tr>
<tr>
<td>Refueling</td>
<td>$108.8 MM every two years</td>
</tr>
</tbody>
</table>

The future electricity generation is also considered equal to the historical average over 2012-2016. The capacity factor was 85.7% over this period, which is much lower than the average performance of the Exelon plants - 94% across their fleet (regardless of the plant size). We can expect that with a change in ownership and operation from Entergy to Exelon, the capacity factor of the plant will increase. We therefore apply a bonus of \(0.94/0.857 - 1 = +9.68\%\) to the expected generation under Exelon command.

We also consider the variations in generation due to the fuel cycle. The assump-
tions are summarized in Table 2.7. The underlying assumption is that Entergy refueling outages take 31 days/ a full month whereas the Exelon refueling outages takes half of that. Overall the capacity factors stated above are conserved over the entire cycle.

Table 2.7: The valuation accounts for refueling outages. We assume that an Exelon ownership would boost the capacity factor of the plant to 94%, their fleet-average performance.

<table>
<thead>
<tr>
<th></th>
<th>Entergy</th>
<th></th>
<th>Exelon</th>
<th>CF</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Generation</td>
<td>CF</td>
<td>Generation</td>
<td>CF</td>
</tr>
<tr>
<td>Refueling month</td>
<td>0 MWh</td>
<td>0%</td>
<td>298,748 MWh</td>
<td>48.0%</td>
</tr>
<tr>
<td>Standard month</td>
<td>556,442 MWh</td>
<td>89.4%</td>
<td>597,496 MWh</td>
<td>96.0%</td>
</tr>
<tr>
<td>2-yr average</td>
<td>533,257 MWh</td>
<td>86.7%</td>
<td>585,049 MWh</td>
<td>94.0%</td>
</tr>
</tbody>
</table>

For the risk-free rate used in the valuation, we use the 20 year Treasury Bond Yield. It was equal to 2.50 and 1.82% per year in October 2015 and July 2016. We apply the same discount rate to all contributions of the cash flow. We will later discuss this assumption.

The decommissioning cost is set to zero, because we assume that the decommissioning fund would be sufficient to cover the decommissioning expense when necessary. This fund represented $785 million in interest in the decommissioning trust fund and $714 million in asset retirement obligation in early 2017 [48]. Those are transferred to Exelon in the sale. The scrapping value of the property, plant and equipments was valued at zero by Entergy (book value [48]).

Finally, we assume that Fitzpatrick is a price taker. In other words, retiring or maintaining the plant in operation does not change the electricity nor capacity price. This is of course inaccurate because the plant has a large nameplate capacity - 853 MW - translates the supply curve. Our electricity market model can quantify this impact but for the capacity revenue we would need a model of capacity market. We expect it to be small however, in the order of a few $ / MW maximum, and decide to neglect it for the sake of simplicity.

Note that in theory we could use our electricity market model to calculate the
price disruption caused by any future event and include this expected disruption in our valuation formulation.

**Results**

We perform the valuation as of two moments in time:

- as of October 2015, when Entergy decided to shut down the plant. The announcement was made in mid-November. We call this valuation the “Entergy valuation”.

- as of July 2016, when Exelon performed the valuation of the plant. The purchase decision was made in early August 2016. We call this valuation the “Exelon valuation”.

The observed spot curve and the futures curve at these two times is plotted in Figure 2-16. We run the estimation of the two-factor model of spot price on these two dates, as if done by Entergy and Exelon. In the two estimation cases the observations start on January 2011 and contract maturities go up to 37 months in the future. The “around-the-clock” price are reconstructed from the off-peak and on-peak prices. This amounts to 1549 and 1900 observations for the “Entergy” and “Exelon” valuation respectively. The results of the estimation are displayed in Table 2.9. The parameters are considered statistically significant and satisfactory even though the parameters that measure the market risk premium ($\alpha$ and $\tilde{\mu}$) are difficult to estimate as always and suffer from imprecision. We also notice that with a larger dataset (“Entergy” vs. “Exelon”) the errors decrease, as expected.

The two forecasted curves are plotted in Figure 2-17 up to the end of the operating license of the reactor - October 2034 [63]. The drift of the forecasted price is slightly more negative in the “Exelon case” due to a devaluation of the futures curve between November 2015 and July 2016. Over the 37 futures contract maturities, the deviation with respect to the actual futures curve is small: $0.06 and $0.26/ MWh for the Entergy and Exelon case respectively (0.2% and 0.9%). This gives us confidence that
Figure 2-16: The futures curve has evolved between October 2015 and July 2016 at Fitzpatrick’s nearest hub. Note the below-expectations winter 2015-16 price.

Table 2.8: The estimation of the parameters of the two-factor model for price on NY ISO Zone C monthly futures is considered satisfactory even though the risk-premium parameters $\alpha$ and $\tilde{\mu}$ suffer from imprecision.

<table>
<thead>
<tr>
<th></th>
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<th></th>
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</thead>
<tbody>
<tr>
<td></td>
<td>Estimate</td>
<td>St. Error</td>
<td>Estimate</td>
</tr>
<tr>
<td>$\kappa$</td>
<td>0.11680</td>
<td>0.14409</td>
<td>0.14869</td>
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<tr>
<td>$\mu$</td>
<td>-0.24791</td>
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<tr>
<td>$\tilde{\mu} = \mu - \lambda_\xi \sigma_\xi$</td>
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<td>0.52018</td>
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<tr>
<td>$\alpha = -\lambda_\chi \frac{\sigma_\chi}{\kappa}$</td>
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<td>$s_1$</td>
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<tr>
<td>$s_3$</td>
<td>5.96136</td>
<td>0.98918</td>
<td>5.92702</td>
</tr>
<tr>
<td>$s_4$</td>
<td>2.96698</td>
<td>1.97597</td>
<td>2.93888</td>
</tr>
</tbody>
</table>

the fit is acceptable. The confidence level on price decreases with the time horizon, as we would expect intuitively.

Finally, the plant valuation is performed. Stochastic cash flows are simulated with
Figure 2-17: The drift of the forecasted price is slightly more negative in the “Exelon case” due to a devaluation of the futures curve between November 2015 and July 2016.

Monte Carlo methods and assume that at every time step (every month), the plant owner can make the decision to retire the asset if its present value is less than the decommissioning value (zero). In our reference case, the cash flows are discounted using the risk-free discount rate\textsuperscript{10} without including the zero-emission credits and without considering the option to extend the operating license beyond 2034. The results are displayed in Table 2.9.

Table 2.9: The reference Fitzpatrick valuation assumes at risk-free rate and no ZEC.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Valuation</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Entergy</td>
<td>Exelon</td>
</tr>
<tr>
<td>Fitzpatrick value on April 2017</td>
<td>207 M</td>
<td>260 M</td>
</tr>
<tr>
<td>Expected retirement</td>
<td>Oct. 2034</td>
<td>Oct. 2034</td>
</tr>
<tr>
<td>M+1 expected price</td>
<td>27.8</td>
<td>28.6</td>
</tr>
<tr>
<td>M+1 “shutdown price”</td>
<td>20.6</td>
<td>18.1</td>
</tr>
<tr>
<td>M+1 observed price</td>
<td>16.3</td>
<td>30.4</td>
</tr>
</tbody>
</table>

\textsuperscript{10}Electricity prices are already adjusted for risk.
We first notice a value above $200 millions for the Entergy valuation, which seems in contradiction with the decision to retire the plant. Is our valuation inaccurate? In its 2015 Annual Report, Entergy mentions a “fair value” of Fitzpatrick in the order of $29 million. The fair value is classically equal to the mark-to-market value of the asset, that is the value of the asset under the current futures curve. For comparison purpose, we use the actual futures curve to price the plant over the next 37 future months as of October 2015 and at the risk-free rate. We obtain a “fair value” of Fitzpatrick equal to $5 million. In the absence of a transparent valuation of Fitzpatrick by Entergy, it is difficult to be assertive on the reasons of the discrepancy, but we can make hypothesis. Price volatility provides a significant option value to delay the retirement decision, and it is possible that Entergy did not account for this option value. Perhaps the reported fair value by Entergy does not include costs of production. Perhaps Entergy valuation does not go very far in the future, or similarly, perhaps their discount factor is more important.

![Fitzpatrick valuation ($)](image)

Figure 2-18: The expected value of the plant by Exelon is higher than the value by Entergy. Note the impact of the refueling expenses.

The observation of the “shutdown price” also provides a possible explanation. In October 2015, the expected price for November 2015 was $27.8/ MWh and the “shutdown” price was $20.6/ MWh, suggesting that despite its relatively high value,
the plant is on the edge of retirement due to the expected price dynamics. The Winter 2015-16 is essential for the plant revenue, meaning that if the price is below expectation, retirement should be exercised. What happened was a mild winter, and a realized November 2016 price of $16.3/ MWh, well below expectation. Entergy might have observed the absence of short-run price rebound and decided to precipitate the shut down of the plant.

The Exelon valuation, at $260 million without ZEC, is not too far from the $217 actual transaction price of Fitzpatrick. This suggests that neither Entergy nor Exelon accounted for the ZECs in their valuation process.

In order to gain additional insights, we then run the valuation using different assumptions (Table 2.10). First, we use higher discount rates. Although our valuation accounts for the price risk premium, we acknowledge that there are other risk factors that we ignored such as cost risk and generation risk. The access to capital of the two firms can also translate into higher discount rates in order to remunerate investors and banks appropriately. Finally, firms can also have their own view on the required return of nuclear projects which translates into a discount premium. We therefore change the discount factor to see its impact on the plant present value.

We choose to use the Weighted Average Cost of Capital (WACC) of the two firms instead of the risk-free rate [45]. The calculated WACC based on financial indicators [16] is equal to 5.12% / yr for the Entergy valuation (2015) and 4.66% / yr for the Exelon valuation (2016). In both cases, the use of the WACC instead of the risk-free rates results in lower values of the Fitzpatrick project, in the order of -15%.

Returning to the base case, we then include the option to extend the lifetime of the plant for an additional 20-year period in 2034. We assume that the cost of lifetime extension is $800,000/ MWe, or $682 millions total as in [45]. The option value of lifetime extension we calculate is in the order of $10-15 million, which is small compared to the base value of the plant (5%), and small compared to the other uncertainties we face in the valuation. Neglecting the option of lifetime extension is therefore understandable.
Table 2.10: Sensitivity analysis. The value is the projected value of the plant in April 2017, right after refueling is completed.

<table>
<thead>
<tr>
<th></th>
<th>Entergy</th>
<th>Variation</th>
<th>Exelon</th>
<th>Variation</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Base case</strong></td>
<td>$207 MM</td>
<td>-</td>
<td>$260 MM</td>
<td>-</td>
</tr>
<tr>
<td><strong>WACC discount rate</strong></td>
<td>$180 MM</td>
<td>-13%</td>
<td>$221 MM</td>
<td>-15%</td>
</tr>
<tr>
<td><strong>Lifetime extension option</strong></td>
<td>$217 MM</td>
<td>+5%</td>
<td>$274 MM</td>
<td>+5%</td>
</tr>
<tr>
<td><strong>ZEC</strong></td>
<td>$1,104 MM</td>
<td>+434%</td>
<td>$1,371 MM</td>
<td>+428%</td>
</tr>
<tr>
<td><strong>-50% price volatility</strong></td>
<td>$97 MM</td>
<td>-53%</td>
<td>$127 MM</td>
<td>-51%</td>
</tr>
<tr>
<td><strong>No price volatility</strong></td>
<td>$84 MM</td>
<td>-59%</td>
<td>$104 MM</td>
<td>-60%</td>
</tr>
</tbody>
</table>

The inclusion of the ZECs in the valuation however has a dramatic effect (Table 2.10). It boosts the net present value of the plant by about $1 billion (risk-free rate). ZECs are clearly a game changer when it comes to future prospects. Under this regime, Fitzpatrick becomes highly profitable and the retirement option vanishes. We also notice that the end of the ZECs payments will be a critical moment in the lifetime of the plant, as the plant value plummets suddenly.

Finally we run a sensitivity calculation on price volatility. Reducing the short-run and long-run volatility of the price process by 50 and 100% produces a drop in the plant value by 50 to 60%. It also advances the timing of optimal retirement, and advocates for an optimal shutdown at the next refueling phase (see Figure 2-19). This observation has several interpretations:

- Uncertainty on future price creates risks but also opportunities. In the case of an existing reactors, volatility enhances the option value of waiting and delaying the retirement in the hope of a future price rebound.

- A miscalculation of volatility and future cash flow probability density can strongly impact the decision to retire a nuclear plant. Option valuation is very sensitive to assumptions and should be used with caution.

Previous results of the real option literature have shown that price uncertainty and volatility delays the exercise of strategic decisions, and advocate for the statu quo.
The mark-to-market value or “fair value” of Fitzpatrick with no ZEC is very low and converges to zero in the short term. In other words, not accounting for price volatility and the option to delay retirement would lead to a premature shutdown of the plant before the next refueling.

Rothwell showed that volatility delays the decision to invest in a new nuclear power plant. We demonstrate here that it delays the decision to retire unprofitable nuclear assets. If uncertainty is a characteristic of deregulated market that precludes new nuclear investments, it nevertheless promotes the continued operation of reactors already in operation despite potential short-run losses. In this regard and counter-intuitively, liberalized electricity markets preserve unprofitable generation assets rather than it pushes them to retire quickly (leading to overcapacity potentially).

This finding would also explain why in a context of high regulatory uncertainty plant owners prefer to wait and delay their retirement decision.

In summary, we measured several key drivers of nuclear power plant retirement decision:

- Fuel cycles create large fluctuations in the present value of nuclear power plants. They play an important role in the timing of retirement, as it is optimal to wait for the end of present fuel cycle to retire the asset.

- An unexpectedly low winter price of electricity can potentially trigger a nuclear
retirement as it eliminates the prospects for a price rebound and positive cash flow.

- Discount rates and expected returns from investors have a significant impact (\(\sim 15\%\) in the Fitzpatrick case) on the value of long-life assets such as nuclear plants and can accelerate retirements.

- The option to extend the operation license has a relatively little role to play in the retirement decision when it occurs far in the future (10-15 years).

- Price volatility and uncertainty creates optionality and opportunities. All other things being constant, it delays nuclear retirements instead of accelerating them.
2.2 Japan case

2.2.1 The electric power sector of Japan

The 2014 Strategic Energy Plan [37] defines the energy policy of Japan. The plan provides a goal for the electric power sector, and in particular for the energy mix. This mix is defined in the “Long-Term Energy Supply and Demand Outlook” by the Ministry of Economy Trade and Industry (METI) of Japan [41].

Japan’s energy policy is based on four pillars:

**Energy security** Japan is an island with scarce natural resources. Its energy sector depends heavily on imports. Japan is the largest importer of natural gas in the world, the second largest importer of coal and the third largest importer of oil. The country aims at reducing its dependency and at increasing its security of supply in the future.

**Economic efficiency** The cost of energy in Japan is among the highest in the world due to the country’s isolation as an island, the lack of domestic natural resources, the high reliability and quality standards, the cost of natural disasters, and the large seasonal and daily variation in energy demand. Reducing the cost of energy would benefit the whole economy.

**Environmental conservation** Japan is committed to reduce its greenhouse gas (GHG) emission by 26% from its 2013 level by 2030. This commitment was made at the COP21 in Paris.

**Safety** The nuclear, but also fossil-fired plants will improve their resilience to natural disasters and meet the highest safety standard.

These ambitious targets for the energy sector translate into a balanced energy mix for the future electric power sector (see Figure 2-20). Nuclear is expected to restart and supply 20-22% of the electricity demand, compared to the 1% level of 2013 and to the 30% level before the 2011 Tsunami. The introduction of renewables
will be promoted in order to account for 22-24% of the total electricity supply\textsuperscript{11}. This represents nearly twice the 2013 level. Efforts will be made to reduce electricity demand through energy efficiency and conservation programs. The old oil-fired, coal and gas plants will retire and be replaced by state-of-the-art power stations.

Figure 2-20: The 2030 energy mix objective relies on nuclear restart, renewable introduction, energy efficiency and conservation and fossil-fuel efficiency improvement \textsuperscript{11}. In this regard the liberalization and restructuring of the power sector is both a chance and a challenge. It could attract private investments and help stabilize tariffs, but it will also give policy makers less central control over entry and exits of generators.

In order to attract the investments necessary for this transition while increasing economic efficiency, Japan undertook to deregulate its electric power sector \textsuperscript{12}. The liberalization of the electricity market is an opportunity but also a challenge for the policy makers, because they will have less control over investments and retirements of the generation units and consequently on the energy mix. A sound and well-designed market is therefore crucial to make the environmental goal compatible with

\textsuperscript{11}Hydro is included in this number.

\textsuperscript{12}The natural gas sector is also being reformed.
free competition, without compromising energy security.

More specifically, the electricity market liberalization (electricity reform) aims to improve the economic efficiency of the sector and decrease electricity tariff\textsuperscript{13}. Full retail competition was introduced in April 2016, and some competition was introduced in the wholesale sector. An independent transmission operator was created. However, the ten vertically-integrated electricity power companies (the so-called “Electric Power Companies”, or EPCOs — see Figure 2-21) still own and operate more than 90\% of the generation capacity and the distribution and transmission network. On the other hand, METI today acts as both the regulator, the political entity and the jurisdiction that resolves disputes. METI delivers the license to operate in the wholesale, transmission, distribution and retail activities and therefore controls the new entrants and the level of competition in the retail and wholesale market; it approves the tariffs and monitors market power.

\textsuperscript{13}The cost for industrial customers was 204 USD per MWh in 2012; residential customers paid 290 USD. In 2014, these tariffs decreased to 188 USD and 253 USD respectively. By comparison, in the United States, the average industrial customer paid 70 USD per MWh and the average household paid 125 USD in 2014.
Figure 2-21: The current electric power market is not yet fully deregulated in Japan. The reform is expected to be completed in 2020.
A feed-in-tariff (FIT) for renewables was introduced in Japan in 2012. It applies to solar PV, wind, geothermal, hydro below 30MW and biomass. The system is similar to the original German system of FIT. The utilities have obligation to purchase the electricity from these generators at the price set by METI. The price is adjusted every year by METI and is active for the first 15 to 20 years of the generator lifetime. Each technology receives a different FIT. For solar PV, unlike other technologies, the FIT amount can be adjusted from year to year for a given generator to reflect the rapid progress of the technology.

Very generous FIT for solar PV (initially ∼42 JPY/kWh [5], equivalent to around 400 $/MWh) boosted installation of solar PV, which represents most of the renewable capacity addition. Public utilities have been slow in some case to connect this distributed generation to the grid due to the fast pace of new capacity addition, which caused complains from the renewable generators. In some regions, the volume of small and medium solar PV installations now exceeds the minimum demand, which requires restrictions on new solar PV additions.

As the installation of renewables exceeds expectations, so does the cost of the subsidies for renewables. More than 22 GWe of new renewable generation was benefiting from FIT in late 2015 [132]. Electricity tariff in Japan is already one of the highest of the OECD countries, and adding the policy cost of these subsidies to the tariff further creates the incentives to opt for distributed generation off grid. The policy cost of supporting the existing renewable generation with the FIT system already leads to an extra 13 to 20% tariff increase [154]. The situation is therefore not sustainable and the FIT system will need to be reviewed to achieve the long-term policy goals of Japan [132].

Japan power system is poorly interconnected at the transmission level (Figure 2-22). This is explained by the slender shape of Japan, the existence of two frequencies (60 Hz in the West and 50 Hz in the East), the mountainous terrain and the fragmentation of the national territory in 10 regional utilities. The lack of interconnection became obvious in March 2011 when the sudden drop of supply capacity in the East – including Tokyo – could not be supplemented by the Western regions. The East-West
connection-frequency converter was indeed limited to 1,200 MW. In addition, wind resources lie in the North islands of Hokkaido and Tohoku, which is weakly connected with the main island and the consumption centers. Grid restrictions are now slowing down the expansion of gigawatts of new solar PV, which causes big criticism from renewables developers. A national grid does not really exist in Japan, in the sense that regions are isolated from each other. Inter-utility trade was less than 5% in 1996. Japan needs more interconnection for a power pool and a free market to develop. Efforts are under way to reinforce the grid but they are costly due to the difficult geography and high standards of construction. For instance the upgrade of the West-East DC frequency converter from 1,200 to 2,100 MW by 2020 will cost more than a billion dollar.

The electricity reform aims at creating the condition for an efficient wholesale market. One recent step was the creation of the Organization for Cross-regional Coordination of Transmission Operators (OCCTO). The OCCTO can be seen as the embryo of an ISO and an independent grid-expansion planner at the national level.

The wholesale market in Japan is still regulated as of today (see Figure 2-21). The wholesale tariff is based on a cost-of-service scheme. New entities besides the ten EPCos have been able to enter the generation business, but the price they get is regulated, which does not promote efficiency. Wholesale market agents make bids and contract trades with the EPCos for a duration of 10 to 15 years. Unexpectedly, the bidding process in the wholesale market is implemented by the utilities themselves, which poses a risk of uncompetitive practices. EPCos can refuse grid connection to generators when justified which happened in recent history with some solar PV generators.

The creation of the Japan Electric Power Exchange (JEPX) was an important step to develop a neutral platform for trading in the wholesale market. However the volume of exchange has so far been very low: only a few percent of the total electricity supply is traded via JEPX. The EPCos are participating very marginally and the

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14 To illustrate the magnitude of the interconnection: the peak power demand in 2012 was 156 GW.

15 These two islands represent more than 200 GW of onshore and offshore wind capacity resource.
transmission network does not support nation-wide trading. JEPX publishes a single price for the entire Japan whereas locational pricing would be needed to inform market participants about local congestions and business opportunities. Locational price signals are particularly important for optimal siting of renewables.

The rules of the newly deregulated markets are still under development.

2.2.2 Prospects for nuclear in competitive Japan market

Background

Due to the vulnerable energy situation of Japan – no natural resources – the security of supply has always been a big concern for policy makers. Prior to the Great East Japan Earthquake, Japan had a well-balanced energy mix, with no particular
electricity source (nuclear, LNG, coal, petroleum, renewables) counting for more than one third of the total generation. This has changed after Fukushima, and the country is now more than ever dependent on fossil fuel imports. Japan is now the first importer of LNG in the world, the second importer of coal and the third importer of oil.

The liberalization process of the wholesale sector brings additional concerns, since investments will be driven by short-term revenue prospects rather than geopolitical or long-term strategies. As an illustration, the plans for new capacity additions consist mainly of coal (20GW) and natural gas (30GW) power generators, which do not correspond to what the ideal mix would look like. Coal and LNG are the most economical technologies to build and operate at the moment together with nuclear (Figure 2-23).
Figure 2-23: Nuclear, coal and LNG are the most economical electricity generation sources at the moment in Japan [10].
Nuclear power has all the attributes of the ideal generation technology for Japan: carbon-free, reliable, and quasi-domestic. It was identified as the most cost effective source of power generation by the subcommittee in charge of the Analysis of Generation Cost for Long-Term Energy Supply (Figure 2-23 and 46). The total levelized cost even includes the cost of severe accidents and the cost of the safety upgrade of the fleet of reactors. Nuclear remains the safest source of power generation: it has the lowest casualty records of all the technologies including solar PV. No one died from radiation exposure in the Fukushima accidents. 50 of the 54 Japanese reactors withstood the most intense natural disaster ever recorded in centuries and were still operable afterwards (2011 earthquake of magnitude 9.0 Mw followed by largest tsunami wave ever observed in Japan). Despite the negative impact of the Fukushima meltdown on the public opinion, voters elected a pro-nuclear party at the Diet in 2012. The new government decided to re-evaluate the energy policy of Japan and ultimately to restart most of the nuclear fleet. The restart process, however, is lengthy and tedious as safety is upgraded and re-evaluated for every single reactor. As of June 2017, only 5 reactors had returned back to operation out of the 42 potentially operable reactors. Local opposition sometimes delays the approval for restart. These factors may prevent nuclear generation from reaching the 20-22% penetration goal by 2030. In the meantime, nuclear is being replaced by coal and LNG for base-load generation.

The replacement of nuclear by coal and natural gas are bad news for carbon emissions and energy security. And as long as fossil fuel are cheap and carbon is not priced, market forces will push these technologies forward. Furthermore low-carbon technologies (nuclear and renewables) are capital-intensive and more severely affected by uncertainty in future electricity price than thermal generators. Nuclear

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16. Uranium is supplied by stable countries such as Canada, Australia and Kazakhstan and can be stored in large amount for decades to provide strategic reserves.
17. Coal is the deadliest due to the air pollution and coal extraction. Solar PV causes accidents during rooftop installation.
18. Two plant workers died while being hit by the Tsunami wave. Others died during evacuation of hospitals and cities.
19. LNG and — to some extent — coal plants are naturally “hedged” against changes in electricity price because wholesale prices are correlated to natural gas prices and because fuel cost represent...
and renewables need a predictable, long-term source of revenue to compete in current market conditions. Another threat for nuclear is the depression of wholesale prices that occurs when subsidized renewables bid negative prices on the wholesale market.

There is currently no carbon price in Japan. Nevertheless, a “tax for climate change mitigation” was implemented in 2014 which taxes fossil fuels. The $2\text{ billion USD}$ revenue generated in this way is being used to finance renewables and energy conservation measures. The tax is more severe for oil and natural gas than it is for coal. This does not make sense from a climate change mitigation standpoint, as coal emits more GHG than the other two. In addition, some sectors are exempted from the tax, such as steel and cement makers (use coal) and petrochemical companies (use oil products) [120].

Nuclear profitability in a competitive environment

Unlike in regulated markets, energy resources compete in competitive markets on the basis of their short-run marginal costs of production rather than on their long-run cost of producing electricity. Although nuclear appears competitive on a levelized cost basis over the entire lifetime of generation assets, there is no guarantee that the existing reactors if they restart will face the electricity price that allows them to recover their investment.

Our electricity market model offers us the possibility to simulate the functioning of the Japanese market under competitive bidding rules. Starting from the existing installed capacity and costs of generation, we can draw scenarios for the future energy mix. In particular, we want to simulate the restart of nuclear reactors and observe the drivers of their hypothetical revenue in a competitive market environment.

Due to the lack of available power sector data in english, we can not describe the supply stack and geographical specificities of Japan as accurately as we did for the Midwest and Mid-Atlantic region of the U.S. in the previous section. We instead focus on the TEPCO area of service (Tokyo region) because it is the region that discloses a large share of their generation cost. For an excellent analysis on the impact of uncertainty on nuclear investment, see [?].
the most data regarding its generation mix in the English language [18].

Model assumptions The demand is assumed to be the demand in the TEPCO area of service in 2014. 2014 was a relatively mild year in terms of peak temperature and peak demand but it was the most recent database we found at the time of the study [19]. Demand is expected to decrease in future years due to declining demographics and energy use. The generation from solar PV is simulated based on sunlight exposure data from the meteorological agency of Japan and following the methodology of Esteban et al [93].

The installed capacity and marginal generation cost of the different technologies for the base case are reported in Table [2.11]. It accounts for TEPCO’s own capacity plus the capacity with whom TEPCO has purchase agreements.

Most of the generation cost assumption come from the 2015 Report on Analysis of Generation Costs from METI [46]. The fuel prices are the 2014 average price. The efficiency are the average of the latest units that came online: 48% for coal, 52% for CCGT and 39% for oil units. The METI report however did not differentiate variable vs. fixed operation & maintenance costs. We chose to apply the breakdown ratio from Lazard [54]. For coal, the ratio of variable to fixed O&M is assumed to be 5/95 and for CCGT 30/70. The “other” capacity category is assumed to be represented by peaking, open-cycle gas turbines. The availability of peaking units is assumed to be 100% to reflect the fact that they are available at time of scarcity. The availability of the hydro units is adjusted to match their historical generation. The ramping capabilities of the different resources are from Komiyama [119].
Table 2.11: Base case assumptions for the electricity market model of the TEPCO area of service in 2014. Note that nuclear plants had not yet restarted.

<table>
<thead>
<tr>
<th>Resource</th>
<th>Capacity (MW)</th>
<th>Availability (%/ hr)</th>
<th>Fuel price ($/MMBtu)</th>
<th>Heat rate (Btu/kWh)</th>
<th>Fuel cost ($/MWh)</th>
<th>Var. O&amp;M ($/MWh)</th>
<th>Supply bid ($/MWh)</th>
<th>Ramp. up/down (%/ hr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nuclear</td>
<td>0</td>
<td>70%</td>
<td>1.4</td>
<td>10339</td>
<td>14.2</td>
<td>0.5</td>
<td>0</td>
<td>0% / 0%</td>
</tr>
<tr>
<td>Coal</td>
<td>6620</td>
<td>83%</td>
<td>4.1</td>
<td>7108</td>
<td>28.5</td>
<td>0.8</td>
<td>29.3</td>
<td>31% / 58%</td>
</tr>
<tr>
<td>Oil</td>
<td>12890</td>
<td>100%</td>
<td>18.1</td>
<td>8749</td>
<td>158.6</td>
<td>15.0</td>
<td>173.6</td>
<td>82% / 75%</td>
</tr>
<tr>
<td>CCGT</td>
<td>26133</td>
<td>85%</td>
<td>16.3</td>
<td>6562</td>
<td>106.8</td>
<td>1.70</td>
<td>108.5</td>
<td>82% / 75%</td>
</tr>
<tr>
<td>Other</td>
<td>4307</td>
<td>100%</td>
<td>16.3</td>
<td>9500</td>
<td>154.7</td>
<td>6.10</td>
<td>160.8</td>
<td>82% / 75%</td>
</tr>
<tr>
<td>Hydro</td>
<td>15490</td>
<td>12%</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>5% / 5%</td>
</tr>
<tr>
<td>Solar PV</td>
<td>1850</td>
<td>CF = 17%</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0% / 0%</td>
</tr>
</tbody>
</table>
The value of lost load (VOLL) is fixed at $500/ \text{MWh}. The grid is considered as one single node; there is no electricity transmission constraints and no imports nor exports of electricity through the borders.

**Comparison to historical spot market price and energy mix**  The simulated energy mix matches fairly well the historical generation mix of the TEPCO area of service in 2014. The oil-fired generation is underestimated but overall the contribution from the peaking plants (oil+“other”) is similar (9% simulated vs. 13% actual). The average historical spot price from JEPX is higher than the simulated price but we should keep in mind that the two prices do not refer to the same geographical areas: JEPX computes a single price for the whole country \(^8\) whereas our simulation computes the TEPCO price. In addition, only a small fraction (<5%) of the total electricity supply was traded on the spot market in Japan in 2014. In the absence of better grid data, we consider that our model is satisfactory to run sensitivity studies.

![Simulation results vs. historical values for energy mix composition and wholesale price](image)

Figure 2-24: The simulated energy mix matches fairly well the historical generation mix of the TEPCO area of service in 2014. The average spot price from JEPX is higher than the simulated price but the two prices do not refer to the same geographical areas: JEPX computes a single price for the whole country \(^8\).
Hypothetical revenue  13,490 MW of nuclear capacity was operable in 2014 in the TEPCO area but none was running [19]. As we saw previously, the Strategic Energy Plan counts on the restart of most nuclear plants to provide 20-22% of the total electricity generation in 2030. For the TEPCO region, the restart of 8809 MW (65%) of the nuclear capacity is required to achieve this objective.

We simulated the restart of the nuclear capacity based on the 2014 model of the TEPCO grid. The results are shown in Table 2.15. As expected, the restart of nuclear causes a significant drop in the wholesale price (14% drop in the average wholesale spot price) due to the shift of the supply curve to the right. We observe that nuclear restart displaces generation from natural gas and oil.

Table 2.12: The restart of 65% of the nuclear power plant capacity would lead to a significant decrease of the average wholesale spot price in the TEPCO region. It would displace power generation from natural gas and oil. The simulation assumes all the other parameters are similar to the reference 2014 case.

<table>
<thead>
<tr>
<th>Energy mix</th>
<th>Zero nuclear</th>
<th>Nuclear restart</th>
</tr>
</thead>
<tbody>
<tr>
<td>Av. spot price</td>
<td>$133.6/ MWh</td>
<td>$115.4/ MWh</td>
</tr>
<tr>
<td>Nuclear</td>
<td>0%</td>
<td>21%</td>
</tr>
<tr>
<td>CCGT</td>
<td>67%</td>
<td>52%</td>
</tr>
<tr>
<td>Peakers (oil &amp; other)</td>
<td>7%</td>
<td>1%</td>
</tr>
</tbody>
</table>

By the time the electricity sector is reformed and the wholesale market becomes competitive, market conditions can change. Most likely, fossil fuel prices will evolve and the installed capacity will change. We therefore run sensitivity analysis with respect to the reference case (2014) with nuclear restart. The results are visually displayed in Figure 2-25.

We notice that natural gas price variations are the primary driver of electricity prices due to the fact that CCGT and some peaking units set the price of electricity during most hours of the year. If the 2014 low natural gas prices ($4/ MMBtu) were to return in Japan, electricity prices could reach bottom levels that are comparable to the ones we observe in the United States at the moment ($25-35/ MWh). Such low prices are a result of short-term market factors because the cost of liquefaction
of natural gas will result in LNG equilibrium prices being several dollars per million BTU more than pipeline natural gas in locations such as the United States; however, as prices of natural gas in the United States and elsewhere decrease due to fracking, LNG prices will follow.

Similarly, crude oil prices affect prices due to the relatively large installed capacity of oil-fired generators that are often setting the spot price. 2014 oil prices were at their historical high and have decreased since.

Renewable introduction to the level required by the Strategic Plan (22-24% of total generation) has a significant impact on the value of electricity as well, on the order of -$13/ MWh. If renewables are allowed to make negative bids on the market, electricity prices would be further lowered.

Coal plant installation has a relatively low impact surprisingly. 20GW are expected to be built nationwide because they are the cheapest source of electricity. However these new projects could be cancelled if nuclear plants restart as planned or if a carbon price is enacted.

Load changes have almost a negligible impact.

![Sensitivity of average spot price ($)MWh](image)

Figure 2-25: The simulated price of electricity after the restart of 65% of the nuclear capacity in the TEPCO region is $115.4 . It is very sensitive to the price of fossil fuels (LNG and crude oil). Solar PV introduction is the second driver. Coal capacity addition and demand have less impact.
**Long-term cost of nuclear generation**  The revenue of nuclear plants that would be restarted in the future deregulated electricity market needs to be put in perspective of their long-term cost of electricity generation. We consider here two options for nuclear power generation. An Advanced Boiling Water Reactor (ABWR) whose construction would be completed and an existing plant that would be restarted after a safety upgrade. The two cases are foreseeable across Japan (the Kashiwazaki Kariwa site in the TEPCO grid has the two options).

The 2015 OECD report about the cost of generating electricity [45] lists the expected economics of Advanced LWR in Japan. The corresponding assumptions are reported in Table 2.13. We assume that the construction is currently completed at 30% [133]. We assume that the construction can be completed without design modifications. If safety upgrades are necessary, the capital cost would be significantly higher (by up to ~30%).

Table 2.13: Assumption for ABWR completion decision. The long-term cost includes the cost of completing construction.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Overnight investment cost</td>
<td>$3883/ MWe minus 30% (pre-completed)</td>
</tr>
<tr>
<td>Lifetime</td>
<td>60 years</td>
</tr>
<tr>
<td>Construction time</td>
<td>4 years</td>
</tr>
<tr>
<td>Capacity factor</td>
<td>85%</td>
</tr>
<tr>
<td>Contingency during construction</td>
<td>15% of investment cost</td>
</tr>
<tr>
<td>Decommissioning fee</td>
<td>15% of investment cost</td>
</tr>
<tr>
<td>Fuel cost</td>
<td>$14.2/ MWh</td>
</tr>
<tr>
<td>O&amp;M cost</td>
<td>$27.4/ MWh</td>
</tr>
</tbody>
</table>

The calculated levelized cost of generation turns out to be quite high. At 3 and 7% discount rate (traditional range for regulated utilities [45]) it reaches $56.8 and 70.9/ MWh respectively. The cost of completing the plant alone account for $15.2 and 29.4/ MWh.

Restarting a shutdown plant also requires capital expenditures. The initial construction cost is sunk but investments are required to upgrade the safety, comply with the new regulation and ultimately restart the plants. The METI analysis committee
reports average costs of 100 billion JPY per reactor, equivalent to $1,000/ kWe. The average remaining lifetime of the reactors who shutdown in 2011 was 22 years. Table 2.14 reports the other assumptions.

Table 2.14: Assumption for existing reactor restart. The long-term cost includes the capital expenditures for safety upgrades.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Overnight investment cost</td>
<td>$1,000/ MWe</td>
</tr>
<tr>
<td>Remaining lifetime</td>
<td>22 years</td>
</tr>
<tr>
<td>Upgrading time</td>
<td>2 years</td>
</tr>
<tr>
<td>Capacity factor</td>
<td>70%</td>
</tr>
<tr>
<td>Decommissioning fee</td>
<td>15% of investment cost</td>
</tr>
<tr>
<td>Fuel cost</td>
<td>$14.2/ MWh</td>
</tr>
<tr>
<td>O&amp;M cost</td>
<td>$31.2/ MWh</td>
</tr>
</tbody>
</table>

Restarting an existing plant results in a levelized generation cost of $56.6 and $61.1/ MWh for 3 and 7% discount rate respectively. This is slightly higher than the cost of the METI committee ($51.0/ MWh for fuel, O&M and safety measures) due to the fact that we consider a short remaining lifetime of the plant instead of the standard 40 years.

Table 2.15: Long-term generation costs

<table>
<thead>
<tr>
<th></th>
<th>ABWR completion</th>
<th>Nuclear restart</th>
</tr>
</thead>
<tbody>
<tr>
<td>Discount rate</td>
<td></td>
<td></td>
</tr>
<tr>
<td>3%</td>
<td>$56.8/ MWh</td>
<td>$56.6/ MWh</td>
</tr>
<tr>
<td>7%</td>
<td>$70.9/ MWh</td>
<td>$61.1/ MWh</td>
</tr>
</tbody>
</table>

**Profitability** This comparison of market prices and cost of electricity generation suggests that nuclear reactors in Japan would recover their capital investments if fossil fuel prices remain high (>8-12/ MMBtu for gas and >50-100/ bbl for crude oil). They could cope with the aggressive introduction of solar PV generators with FIT in these conditions but keep being exposed to fossil fuel price fluctuations. Fossil fuel prices have bottomed down to $4/ MMBtu for gas in 2011 and $25/ bbl for crude oil.
in 2002. The restart of nuclear plants as well as the development of LNG export from the U.S. will probably affect these prices in the future. It is therefore hard to draw scenarios and the uncertainty is large for nuclear plant owners. In this situation, real option valuation can give us important insights about optimal restart strategy.
Chapter 3

Options for maintaining nuclear power

Nuclear power plants in Japan, the U.S. and Europe were built in period of high load growth, expensive fossil fuels and by regulated energy companies. They are now facing stalling electricity demand, cheap fossil fuels and competition from other power generators on the basis of short-run marginal cost of production. Are they doomed to retire? How can existing nuclear plants adapt to this new economic and regulatory environment and deliver the benefits of their attributes to society?

We propose and investigate in this chapter a range of solutions that could prevent the early and permanent closure of nuclear power plants. Most of these solutions involve enhancing the attractiveness of nuclear while maximizing its social benefits.

In the first part we focus on technological/technical innovations that could boost the revenue of nuclear plants in current, deregulated markets. These new features are: the capability to follow the hourly load demand (flexibility), the delivery of ancillary services, the coupling with energy storage technologies, and the sales of products beyond pure electricity.

In the second part we discuss changes to market rules and to the regulatory regime with whom nuclear plants comply. These policy and regulatory options are: carbon pricing, direct subsidies, low-carbon capacity mechanisms, renewable portfolio extension and the mothballing option.
We discuss their pros and cons, and try to evaluate the potential of each solution quantitatively when possible. We acknowledge that some options would require a full dissertation to be evaluated but we limit ourselves to the big picture in order to narrow down the most promising options for the reader.

3.1 Technological innovation

On the technological front engineers can propose solutions that address the market needs. On the liability side, nuclear economics could be improved by efforts on cost reduction. However we showed in Chapter 2 that the potential for changing the profitability game on this side was slim. A significant cost production reduction would require transformation of the technology that are not accessible to existing plants. We therefore did not focus our attention to this side of the equation. New nuclear power plants however hold the promise of major cost savings.

3.1.1 Load-follow capability

Nuclear power plant are traditionally operated in “base-load” mode. They run constantly at the maximum of their rated capacity unless they are forced to shut down for refueling, inspection, maintenance or for an unforeseen reason. This mode of operation is generally optimal from an economic point of view because fuel costs are relatively small and fixed costs large in nuclear operation.

However, there are peculiar situations where there is an incentive for nuclear plants to be flexible and change their power output. One of these situations is the situation of France where the nuclear capacity installed is significantly larger than the load demand during some hours of the day\footnote{The installed nuclear capacity in France is 63 GW and the yearly average power consumption was 52 GW in 2012 \cite{68}.} But another of these situations occur when the penetration of intermittent renewables is so large that energy prices are severely depressed during some hours of the day. Renewables like wind and solar have zero marginal cost of production, and they tend to produce with the same hourly
generation pattern over a given region (due to similar weather conditions spreading over large areas). When entitled to energy production subsidies (e.g. feed-in-tariffs, production tax credits) they bid negative prices to make sure to be dispatched in priority. When the penetration and production of these intermittent sources is large, they set the price of electricity, which comes down to zero or even negative values. Nuclear plants, if they can not adjust their power output, suffer financial losses during these hours. If the electricity price is negative, power plants even have to pay the grid to deliver their electricity.

Figure 3-1 illustrates the price depreciation that would result from wind capacity addition in the Midwest (the reference case is the 2015 Midwest electricity market model of Chapter 1). The price decrease is magnified if wind power producers make negative offer bids to ensure their dispatch and receive subsidies. In this case we assumed a conservative subsidy of $23/MWh, equal to the federal production tax credit for renewables. This subsidy is in effect for 10 years, although it will stop being applied for generators being installed after 2020 \[20\]. The simulated effect of renewables penetration on the revenue of the nuclear plants and wind turbines is depicted in figure 3-2. The effect is more severe in relative terms for wind producers than for nuclear, which means that ultimately it is not economical to install more wind farms. There is an economical limit to how much wind capacity can be installed which prevents the average spot price to become too low. Nevertheless the revenue cut for nuclear is significant when wind capacity installed is large. At 40% wind penetration into the Midwest grid, the revenue drop for nuclear is 30% and 45% without and with wind PTC respectively. Currently (in 2016) wind penetration is less than 10%.

Can load-follow capability minimize the effect of wind penetration on nuclear revenue? To answer this question, we simulated the annual dispatch of nuclear power plants in the Midwest with and without load-follow capability. By default, nuclear plants operate at 100% of their rated capacity with no flexibility in the model. The load-follow capability is assumed to give the plants the ability to adjust their output
Figure 3-1: The addition of wind capacity in the Midwest curbs the average electricity price. The effect is magnified by wind subsidies (PTC), which create negative prices when wind penetration is large (sensible above 30%). The figure simulates wind capacity addition starting from the 2015 Midwest reference case (with no grid congestion).

Figure 3-2: The revenue from energy sales of every generators decrease as more wind capacity is installed. The revenue cut is more severe in relative terms for wind producers than for nuclear. Wind subsidies aggravate the phenomena.
anywhere from 100% to 50% of the nameplate capacity and inversely in one hour (same ability to ramp up and down), in accordance with the European Utility Requirements for new nuclear power plants [34]. This flexibility assumption is a simplification since in reality fission product poisoning and reactivity reserves can limit the fast ramp-up of commercial nuclear reactors (xenon poisoning peaks at $\sim$11 hours after power down and reactivity is reduced at the end of a fuel cycle) [99]. The results in Figure 3-3 show that there is indeed an additional revenue per MWh generated when annual wind power generation is greater than 30% in the Midwest (equivalent to $\sim$ 60GW wind capacity installed) if nuclear operates flexibly (see Figures 3-3 and 3-4). This increase in revenue is caused by the fact that nuclear either set the price of electricity (to zero) or limits its losses when wind sets the price.

Nuclear load-follow modifies the capacity factor, therefore we plotted the value of load-follow both expressed in $/ MWh and in $/ MWe installed. If wind producers bid at zero and not negative, nuclear load-follow does not provide extra $ revenue per capacity installed because plants receive zero whether they produce or not during zero-price hours (nuclear also bids at zero). Due to the lower total generation however, there is a modest added value in the $/ MWh ratio ($\sim$ $+0.7/MWh at 40% wind penetration).

In the case where wind producers bid negative and cause negative price hours however, load-following prevents major losses during negative price hours. The value of load-following is significant. For instance, it results in $+18/kWe-yr $+3/MWh extra revenue at 40% wind penetration and $23/MWh wind PTC in the simulation.

U.S. nuclear power plants do not generally operate in load-follow mode, but they could. French nuclear power plants frequently adjust their production to match demand [3-5]. French Pressurized Water Reactor Technology is derived from U.S. PWR technology [2]. Load-following requires some refurbishment and training but is technologically doable with installed reactors [34]. Similarly, Boiling Water Reactors (BWRs)

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2PWR technology was originally developed for powering submarines, which require fast ramping capabilities.
Figure 3-3: Nuclear load-follow capability generates extra revenue when wind capacity installed is large (> 30% total supply). In the situation where wind producers create negative energy prices, the incentive for nuclear to follow load becomes important (> $3/MWh at 40% wind penetration and $23/MWh wind PTC).

Figure 3-4: There is no added value of load-following when wind producers bid at zero because producing during zero-price hours is worthless (both nuclear and wind bid at zero). However, there is an economic incentive in the presence of negative prices (the estimated cost of load follow is ∼ $7/kWe-yr).

could be refurbished and licensed to follow load. In the Northwest of the U.S., the Columbia Generating Station BWR already performs load-following or "load shaping" in response to the grid needs [102]. The Nuclear Regulatory Commission has approved such operation mode and therefore there should be no major regulatory obstacle for other reactors to do load following.
Figure 3-5: Example of power output of a French pressurized water reactor, in % of rated power [34]. The power history shows daily cycles that can shift from 100% to 30% rated capacity and inversely in less than one hour.

A publication from the Joint Research Centre of the European Commission [80] estimates the maximum cost of load following at maximum 2% of the theoretical availability of a nuclear plant. The loss in availability stems from added system repair due to the increased ageing of some components. This would result in an added cost per kilowatt-year that is approximatively $2/92$ times the base-load generation cost \(^3\) that is on average $35.5 \times 8760 \times \frac{2}{92} \approx \$7/kWe-yr$. After reporting this number on Figure 3-4, it seems that the benefits of load-following do not always exceed its cost. Nuclear load-follow profitability requires large amount of renewable penetration (>30%) and negative energy prices altogether. If wind producers do not cause negative prices, our case study shows that there is no economic incentive to do load-following in the Midwest of the U.S. (cost $7/kWe-yr > benefit 0/kWe-yr$).

We also observe that nuclear load-follow capability enables nuclear plants to set

\(^3\)We assume here that the reference capacity factor is 92% and the average cost of nuclear generation $35.5/MWh$
the price of electricity. An inflexible plant is a price taker and is never responsible for price formation as of today [66]. But a plant with flexible output can potentially set the system marginal cost - the wholesale electricity spot price - during some hours of the year [4]. This property does not impact prices if nuclear bids at zero (as we would expect). But it would if nuclear were to bid positive or negative on the supply curve. In other words, load-follow capability gives nuclear the power to govern prices during some hours of the day. For illustration purpose, we computed the added revenue of the nuclear plants in the Midwest due to a modification of their supply bids in Figure 3-6. We assume that nuclear plants bid electricity at $8.11/MWh (fuel cost + variable O&M in 2015) instead of at $0/MWh. We observe that modifying their bids create substantial added revenue - several $/MWh - to the nuclear power plant owners when wind penetration exceeds 30%. This added revenue peaks at $45% wind penetration, which corresponds to the point where nuclear maximizes the time it sets prices. It then decreases for very high level of wind penetration because the number of production hours decreases faster than the number of hours where nuclear is price maker. Again, this property of influencing price only appears if nuclear is able to adjust its power output in response to demand. This market power could manifest itself on the day-ahead market but also on the real-time market if nuclear starts bidding on both.

3.1.2 Grid ancillary services

The grid ancillary market - black start capability, voltage and frequency regulation, reserve - is traditionally served by fossil-fired and fast-ramping generators. Nonetheless, in some countries, nuclear energy resources also provide ancillary services. This is the case for instance in France, where the nuclear fleet has islanding and/or black-start capability [29], i.e. it can restart without offsite power and initiate the grid restoration after a grid blackout. The European Utility Requirements (EUR)

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4 The system marginal cost is the shadow price of the load demand constraint. It is equal to the supply bid of the last unit that can increase or decrease its output as a response to a load demand change. Base-load nuclear cannot modify its output in response to load demand but a flexible generator is able to.
Figure 3-6: Nuclear load-follow capability is a potential source of market power. Nuclear plant owner can influence market price with their bids. (The simulation case assumes negative bids from wind power producers.)

for new Light Water Reactors [35] also demand new reactors to be able to deliver ancillary services. The EPR and new VVER reactors are thus designed to provide grid restoration, voltage control and reserve (load-following) services. But in the U.S., to our knowledge, very few or zero reactors provide such services. What would be the economic benefits for existing nuclear reactors to provide ancillary services in competitive markets?

Black-start capability is a service that is commonly demanded to nuclear power plants in France. Operators are trained to set reactors in “islanding mode” in case of a sudden loss of offsite power. In this configuration, the steam supply largely bypasses the turbine toward the condenser, which generates a reactor transient. Reactor power is decreased to \(~30\)% of nominal capacity and the turbine-generator power to \(~2-5\)% that is exactly the power output needed to supply the auxiliaries [134]. The plant therefore generates its own power supply, disconnected and desynchronized from the electrical grid as an island. The success of the islanding operation is not 100% guaranteed but still sufficient to make sure that a large number of nuclear reactors in France keep operating in case of a major blackout. The reactors are then asked
to help restore the grid following the instructions of the grid operators [29]. It seems
that some nuclear power plants in France are also able to restart by using emergency
diesel generators (non-nuclear-safety class diesel generators) [5].

From a technical point of view, providing black start capability would require
training and regular testing (in France, one test every three to four years). The nuclear
units may need an additional back-up source of power supply (e.g. diesel generator) if
they want to restart without offsite power and without using their nuclear-safety-class
diesel generators.

The ability of nuclear plants to black-start the electrical grid is a potential source
of revenue. But is it substantial? In PJM, black-start services are procured out-of-the-market. In 2015 and 2016, the average rates for black-start services were $1.03
and $1.09 / MW-day respectively. This would represent a source of revenue of about
$0.04 /MWh for a reactor with 92% availability factor. Therefore it would be a rela-
tively minor extra revenue for reactors. In MISO, the service tariff is not disclosed.

The regulation market (short-term response to load for frequency regulation) is a
service market accessible to nuclear if one allows flexible nuclear operation [80]. It is
the largest ancillary service market in terms of revenue and capacity, and is growing
overall [64]. Currently nuclear reactors do not participate in PJM regulation market
[70], although this could provide them with additional revenue. In 2015 and 2016, the
regulation market cleared at $32.3 and $15.7/ MWh on average. In 2014, due to the
polar vortex, prices spiked to $3304/ MWh [64]. We see that some instances regula-
tion market prices are higher than energy prices, which offer arbitrage opportunities
to generating plants. Nuclear plants could offer 2% of their rated capacity on the
regulation market if they followed the prescription of the EUR [35], and benefit from
this arbitrage option. The regulation market may be worth considering if the cost of
offering regulation capacity is zero as expected (most modern design allow short-term
power variations of 2% power).

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5This information was obtained from a private discussion with a French power plant operator
but could not be confirmed by literature review.
Our electricity market model does not allow us to simulate the regulation market price unfortunately which makes our quantification of market benefits impossible. We invite however nuclear operator to evaluate this option, especially in regions with cold winters and/or a growing market share of intermittent renewables.

The other traditionally ancillary service market - spinning reserve and non-spinning reserve - are considered uneconomical for nuclear as they would have to maintain a lower or zero power output for extended periods of time and could be limited by xenon poisoning when reserves are needed.

3.1.3 Heat storage: FIRES

In a deregulated electricity market we saw that the large scale deployment of solar or wind will cause electricity price collapse at times of high solar or wind input as production approaches electricity demand (Figure 3-1). The collapsing revenue (1) limits the deployment of wind and solar unless subsidies increase and (2) hurts base-load nuclear power plant economics. One strategy to limit revenue collapse is to find a use for low-price electricity. One option to limit electricity price collapse is to transfer energy from the electrical grid to the industrial sector to use as heat whenever electricity prices are less than the costs of fossil fuels. This opens up a large secondary market for low-cost electricity and price floor for electricity.

Several heat storage technologies could possibly be coupled to light water reactors. Work is currently underway to identify and characterize the different technological options in this domain [67]. We focus here on one particular technology — Firebrick Resistance-Heated Energy Storage — but depending on the market needs and the speed of technology development others could emerge such as steam accumulators, sensible heat fluid systems, cryogenic air systems, packed-bed thermal energy storage, hot rock storage, geothermal heat storage [67].
Firebrick Resistance-Heated Energy Storage (FIRES)

The storage technology we consider here for boosting nuclear power plant revenue is Firebrick Resistance-Heated Energy Storage (FIRES) [97, 150, 84]. It is a large-scale storage technology that is well-suited to the markets with 1) increasing penetration of renewables, 2) a demand for heat and 3) nuclear plants, which makes it attractive for Japan and the Midwest of the United States in particular.

From the market point of view, FIRES is a system that stores “cheap” electricity in the form of high-temperature heat, and delivers it later as needed on the heat market (Figure 3-7). The potential users of FIRES heat are diverse. Industrial facilities may be the primary users because they consume heat all year but residential consumers may form a market as well in winter because the technology is easily scalable.

![Figure 3-7: FIRES concept: low-cost electricity is stored and transferred to the heat market.](image)

A schematic of FIRES is shown in Figure 3-8. At times of low electricity prices (less than the price of natural gas typically, in $/MWh), electricity is used to heat a set of firebricks to high temperatures via electrical heaters. The firebrick are thermally insulated and can conserve the heat for very long periods of time with very low losses. Heat is then provided to industrial users as needed by blowing cold air through the brick and sending the hot air to the industrial process such as a furnace or kiln. The temperature of the hot air output is controlled by adding cold air or burning natural
gas to raise exit temperatures. Firebrick can be heated to ~1800°C to meet high-temperature needs. Firebrick is used as the heat storage media because of its very low cost compared to other alternatives.

Figure 3-8: FIRES converts electricity into heat up to ~1800°C for later use (diagram from C. Forsberg).

Potential for FIRES in Japan

Large introduction of renewables in Japan (>20GWe for a 50 GWe peak demand in the Tokyo area) can lead to excess generation during some hours of the year, as shown by the calculated load duration curve of Figure 3-9. In Tokyo, the calculated capacity factor of solar PV was 17% in 2014. The maximum solar generation does not occur when the load (demand) is maximum. Instead, it is large when the load is moderate (in the 20-30 GWe demand range). This is why the introduction of solar power displaces first the gas and oil plants, and does not affect too strongly coal and nuclear plants. From that point of view solar PV and baseload generators are compatible up to fairly high level of solar PV penetration into the grid. This effect can be see on Figure 3-10. We see that the “solar PV price” itself collapses rapidly after 10-15% solar PV penetration; solar PV “cannibalizes” its own revenue if installed in excess. This phenomena is discussed in the MIT Future of Solar Energy study. 

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The large-scale penetration of solar PV in the Tokyo grid would generate excess renewables generation and zero-cost electricity. The original load demand is the one of the Topkyo (TEPCO) area in 2014.

The introduction of FIRES is interesting when excess cheap electricity is present, that is when renewables penetration is important. How cheap should electricity be purchased from the wholesale electricity market? Heat from FIRES competes with heat from fossil-fired plants on the heat market. The cost of burning fossil fuels is relatively high in Japan, as illustrated by Figure 3-11. For instance, if FIRES heat compete with natural gas heat, it must generate heat at a marginal cost lower than $39/ MWh to be competitive in the heat market (we neglect the operation and maintenance costs of NG burners for the sake of simplicity and conservatism).

In a first-order approximation, the marginal cost of FIRES heat generation is mostly the price of the absorbed electricity. The electricity-to-heat conversion efficiency is nearly 100% as electrical heaters are used and as thermal leakage is negligible [150]. Operation and maintenance cost is neglected for now but is expected to be low.

The price of electricity is given by the system marginal cost of supplying electricity at a given time of the day, e.g. it is equal to the most expensive generator’s marginal
Figure 3-10: The introduction of solar PV in Japan leaves base-load plants like nuclear relatively protected from the price collapse observed in the middle of the day as compared to other generators. The “solar PV price” itself collapses rapidly after 10-15% solar PV penetration; solar PV “cannibalizes” its own revenue if installed in excess. Solar subsidies ($50/ MWh here) magnify the revenue collapse.

Figure 3-11: The all-time average reported spot price of natural gas (LNG) in Japan at the time of the analysis (summer 2015) was $11.6 / MMBtu, or $39/ MWh [10]. Since then, prices have decreased.

electricity cost when there is no line congestion. In the Tokyo grid, solar is first in the supply curve, followed by hydro, nuclear, coal, CCGT, OCGT and finally oil (see
Table 2.11). FIRES is economical when it stores electricity below the price of fossil fuels, which is the case when solar PV, nuclear and hydro set the price of electricity. For this condition to occur, a significant amount of nuclear and solar PV capacity must be installed. With the current state of the TEPCO grid (zero nuclear and 1,850 MWe of solar PV) the cost of electricity never drops below $40/MWh and FIRES is not economical.

Looking at the load duration curve, one notices that a large amount of \{solar + nuclear + hydro\} instantaneous generation must take place to drive the cost of electricity below that from fossil plants during some hours of the day. Assuming the restart of \~65\% of nuclear capacity, more than 30 GWe of solar PV installed - equivalent to 17\% of total generation - is needed to drive the price low enough for FIRES to start using it.

The amount of energy available for FIRES storage is equal to the amount of energy that can be generated from low-carbon generators once the base electricity demand has been satisfied. These low-carbon generators - solar PV, hydro and nuclear - have a short-run marginal cost of production of zero. FIRES stores electricity from these resources because it is cheaper than that of fossil fuels on a $/MWh basis. The energy available for FIRES in the Tokyo area of Japan is plotted in Figure 3-12. Energy becomes available for FIRES when more than 20 GWe of solar PV is installed (\~15\% of total electricity supply). Electricity consumed by FIRES amounts to 16 TWh (representing 6\% of total electricity generation) when 50 GWe of solar panels are installed (equivalent to 27\% of solar penetration) and without considering the flexibility (ramping) constraints. Moneywise, it potentially represents up to 16 TWh \times (39.6-0) $/MWh = \~$634 million of savings every year in the system (difference in the marginal cost of heat from FIRES and from natural gas).

If one assumes that FIRES has infinite storage capacity, it can absorb all the excess low-cost electricity generated by solar, nuclear and hydro and prevent the curtailment of the electricity generation from these technologies. This effect is visible when comparing Figure 3-13 and Figure 3-14 below. FIRES allows to take full advantage of the cheap electricity available when large renewable capacity is installed.
Figure 3-12: Energy becomes available for FIRES when more than 30 GWe of solar PV is installed on the Tokyo region (17% of solar PV in the energy mix). It amounts to 16 TWh (representing 6% of total electricity demand) when 50 GWe of solar panels are installed (equivalent to 27% of solar penetration).

It also reduces significantly the carbon emission of the energy sector (power and heat market altogether). Note that at high solar output, there is a near constant energy output (MWh) from non-renewable energy sources: this corresponds to the electricity produced when there is no solar output.

Figure 3-13: Without FIRES, solar PV energy is curtailed when large amounts of renewables are present in the grid. Nuclear plants runs at full capacity because we assume their can not adjust their power output.
Figure 3-14: FIRES creates an additional electricity demand and enable the low-marginal-cost generators – solar, nuclear and hydro – to run at full capacity. Note that FIRES also reduces significantly the carbon footprint of the energy sector (power and heat market altogether).

FIRES creates additional demand. The impact of FIRES on the electricity price depends on the demand bids that FIRES will make. If they purchase electricity at 0 $/MWh (monopsony) the price does not increase for a given capacity installed. However, if we assume that FIRES makes a demand bid that is non-zero, FIRES would set a floor to the electricity price equal to this demand bid. In the case of competition on the energy storage market, FIRES would make a demand bid up to the marginal cost of producing heat, that is the cost of burning natural gas.

That being said, FIRES allows a virtually limitless penetration of renewables in the energy mix because there is no more curtailment. Without FIRES, the penetration of solar PV is limited to ~30-35% because solar PV does not produce during nighttimes and there is more than enough production in the middle of the day (2014 solar irradiance is assumed in the simulations). However if FIRES is present the excess electricity during day time can be absorbed and the penetration of solar PV is not bounded anymore.

If we plot the revenue of generators versus solar PV penetration instead of solar PV capacity installed (Figure 3-15), we observe that FIRES increases the revenue of generators for a given level of solar PV penetration. This is due to both an increase in
price an an increase in solar PV dispatch for a given solar PV capacity installed. By this mechanism, FIRES prevents to some extent the major price collapse that occurs when high levels of solar PV penetration are present.

Figure 3-15: FIRES prevents to some extent the major price collapse that occurs when high levels of solar PV penetration are present. It boosts the revenue of nuclear and renewables.

Overall the \{electricity + heat\} market benefits from FIRES as it displaces a large amount of expensive gas burners by low-carbon energy resources in the heat market (FIRES electricity-to-heat efficiency is nearly 100%). There are major savings in the short-run marginal cost of heat production. This makes the FIRES technology particularly attractive for Japan where the cost of fossil fuels for heat are among the highest in the world. Ultimately, the amount FIRES and solar capacity installed will depend on capital costs.

FIRES is particularly interesting for solar PV owners, as it prevents the curtailment of their production and enables their large-scale deployment. We see that there are synergies between low-cost energy producers, FIRES owners and heat consumers. Capital investments could be secured for instance by long-term purchase agreement
between nuclear and PV owners on one side, and industrial heat consumers on the other.

Note that FIRES does not prevent the fossil fuel power plants and heat producers from losing revenue in this market transformation. FIRES displaces fossil fuel technologies. In this regard it is beneficial to Japan’s energy policy because it limits carbon emissions and fossil fuel import dependency.

**Potential for FIRES in the American Midwest**

The Midwest of the United States is a region where renewable penetration is large and increasing. Wholesale electricity prices are low as shown in Chapter 2, which puts nuclear reactor under financial pressure. It is also a region with a significant heat demand (households in winter, industrial processes such as ammonia production plants and refineries). It is therefore a market where FIRES could bring substantial economical benefits, as well as prevent nuclear economic retirements by opening up a new application for near-zero-marginal-cost electricity.

We simulated the introduction of FIRES in the 2015 Midwest electricity market using the modelling approach described in Chapter 2. FIRES is considered as an additional source of load demand. The objective function is slightly modified with the addition of the production cost of heat. In this formulation there is no spillage in the electrical grid even at very high levels of wind penetration. Like in the Japan case, we assume that FIRES capacity is unrestricted in order to estimate the upper limit of FIRES impact on the grid. The amount of electricity available for FIRES is depicted in Figure 3-16.

As in Japan with solar PV, FIRES provides benefits to existing nuclear only if wind is deployed at a large scale in the Midwest. Figure 3-17 shows that at least 30-40% of wind penetration is required to have a revenue impact. At 40% wind penetration, FIRES provides $\sim$10-20/ MWe-yr of additional revenue to nuclear plants, that is a 8-16% increase in revenue.\(^6\) It provides a 15-25% boost in wind power plant revenue

\(^6\) Depending on the level of the demand bid of FIRES on the electricity market
Figure 3-16: FIRES would harness the “excess” electricity generated from the full-capacity output of wind, hydro and nuclear. The current level of wind penetration is 9% in the Midwest but is growing fast.

at the same level of penetration\textsuperscript{7}

It is very likely that FIRES would have an impact at the local/ nodal level, although the simulations above can not exhibit this effect due to the fact that the transmission network is not modeled (single node approximation). We expect the “pockets” affected by low or negative wholesale prices to already see equivalent levels of wind penetration above 40%. This means that FIRES could already have a significant influence in these areas if it was deployed today. Future work should focus on a more precise modeling of the transmission network to exhibit the full potential of FIRES in today’s grid.

\subsection*{3.1.4 Output diversification}

With persistently low electricity prices, nuclear power plants seem condemned to low revenue. But what if plants were able to offer other valuable products beyond electricity and diversify their sales? Commercial nuclear reactor are designed to generate electricity, but they could be modified to produce other types of outputs \textsuperscript{69}. We assess here three promising outputs that could provide substantial revenue

\textsuperscript{7}Note that the capacity factor of generators of wind power plants is modified by FIRES introduction. 50% of wind penetration requires 110 GW of wind capacity installed if FIRES is present and 120 GW otherwise
Figure 3-17: FIRES storage technology boosts the revenue of nuclear power if wind is deployed at a large scale. We assume that wind offers zero and not negative bids, and that from existing nuclear power plants in the near future: hydrogen, heat for industrial processes, and radioactive isotopes.

**Hydrogen**

Industrial hydrogen can be produced from nuclear energy through different processes: low-temperature electrolysis, high-temperature electrolysis, and thermo-chemical cycles [69] [73]. The hydrogen demand is relatively important, with multiple industrial processes relying on it such as refineries, steel factories and chemical plants. If adopted, “nuclear hydrogen” would substitute hydrogen produced from the carbon-intensive Steam Methane Reforming (SMR) process: \( CH_4 + O_2 \rightarrow CO_2 + 2H_2 \). Cheap natural gas makes the SMR process very cost-competitive. In 2012, the cost estimate of hydrogen production from SMR was $1.21, $1.39 and $1.57/ kg for natural gas.
prices of $2, $3 and $4/ MMBtu respectively, according to DOE [3]. Steam methane reforming represents the overwhelming production source of hydrogen today.

Low-temperature, alkaline electrolysis is the most mature technology to compete with SMR. It uses electricity to split water molecules into hydrogen and oxygen. Low-temperature electrolysis is a mature process that could be implemented today, but the downside is that nuclear does not benefit from a peculiar competitive advantage by delivering its electricity to the process. Nuclear would compete with the same generators it competes with on the electricity market. In addition, hydrogen produced this way is more expensive than hydrogen produced by steam methane reforming, which explains why electrolysis has not yet replaced SMR for large-scale hydrogen production. Figure 3-18 with data from [47, 158] reports costs much higher for electrolysis than for SMR, at the current natural gas and electricity prices.

High-Temperature Electrolysis (HTE), also called “steam electrolysis”, is a potential future contender. The technology is still under development but has made significant progress in the past decades. It is an electrolysis process that uses heat to lower the electrical power requirement to split the water molecules. The higher the temperature, the better for the process efficiency. The technology could be directly coupled to a pressurized water reactor by diverting steam from the steam generators (P = 70 bars, T = 278 celsius) toward the electrolysis cells of a hydrogen plant and instead of feeding the turbine. Haratyk [105] designed a system that couples an existing PWR to a new HTE plant, and estimates its hypothetical techno-economic performance. Assuming a cost of electricity of $40 / MWh, 2% degradation rate of the HTE cells and $400/ kWe cell capital cost, hydrogen could be produced at $3.1/ kg (levelized cost over 30 years of operation, in 2010 US dollars). With $20 / MWh electricity (purchased from the wholesale electricity market), the hydrogen cost goes down to around $2/ kg. Producing hydrogen from a hydrogen facility next to an existing nuclear power plant is therefore still expensive with respect to steam methane reforming, but could become cost-effective one day if the technology continues to improve. Nuclear-HTE coupling would also require the construction of a new hydrogen facility next to the nuclear site which would be a major project. Some NRC approval
Figure 3-18: The cost of hydrogen produced by proton membrane electrolyzer (PEM EL) is more expensive than by steam methane reforming (NG) in the U.S. and Japan. 85% load factor is assumed. “Low” assumes $5.9/ MMBtu natural gas, no transport cost, “medium” $11.7/ MMBtu and moderate transport cost, “high” $17.6/ MMBtu and high transport cost. The dashed lines refer to 30% variation in cost and 10% in efficiency. Figure taken from [47].

Thermo-chemical cycles such as the iodine-sulfur process are potentially even more efficient than electrolysis and are often mentioned as a promising application of nuclear heat [73]. They could produce hydrogen at $1.5-2 / kg but they require high temperatures, in the range of 800-1000 celsius. They are therefore not accessible to existing light-water reactor technology, whose outlet temperature is limited to ~330-340 celsius.
Heat

Heat from nuclear reactors can be used in a variety of industrial processes (Figure 3-19 and [69]). Due to differences in thermal efficiencies, it turns out that nuclear heat is competitive with heat from CCGT plants, even with the low natural gas prices we encounter today in the United States (see Table 3.1). Nuclear heat is also competitive with coal in some areas (i.e. in areas remote from the Midwest of Appalachians, such as the Mid-Atlantic or California). Temperature at the outlet of a nuclear reactor is of course lower than in a fossil-fuelled plant furnace, which means that nuclear heat is restricted to “low” temperature industrial applications. More specifically, existing light-water reactors are readily suitable to two main heat applications: desalination and district heating (Figure 3-19). If a demand for biofuels develop, biofuel production (fuel ethanol) could also be a short-term market.

Table 3.1: Despite low natural prices, (low-temperature) nuclear heat is still competitive in the U.S. and Japan. The reported costs are the short-run marginal cost of production, i.e. initial capex is considered a sunk cost. The numbers assume the latest reported fuel costs (2015 for the US and 2014 for Japan), which are: $2.42/MMBtu for OH natural gas, $68-34/t for VA-IL coal, $16.3/MMBtu for Japan natural gas and $97/t for Japan coal.

<table>
<thead>
<tr>
<th>Market</th>
<th>Source</th>
<th>Heat cost ($/ MWh)</th>
<th>Electricity cost ($/ MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>U.S.A</td>
<td>Nuclear</td>
<td>2.6</td>
<td>8.11</td>
</tr>
<tr>
<td></td>
<td>CCGT (OH)</td>
<td>9.4</td>
<td>21.2</td>
</tr>
<tr>
<td></td>
<td>Coal (VA)</td>
<td>14.7</td>
<td>45.2</td>
</tr>
<tr>
<td></td>
<td>Coal (IL)</td>
<td>6.4</td>
<td>19.7</td>
</tr>
<tr>
<td>Japan</td>
<td>Nuclear</td>
<td>4.9</td>
<td>14.7</td>
</tr>
<tr>
<td></td>
<td>CCGT</td>
<td>67.7</td>
<td>108.5</td>
</tr>
<tr>
<td></td>
<td>Coal</td>
<td>14.1</td>
<td>29.3</td>
</tr>
</tbody>
</table>

Coupling nuclear and desalination aggregates to 250 reactor-years of experience, mostly in Kazakhstan, India and Japan [56]. In the U.S., the Diablo Canyon nuclear plant already utilizes Reverse Osmosis (RO) to produce its own fresh water. In Japan,

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8 Cargill investigated such market in the case of Fort Calhoun in the Midwest.
Figure 3-19: Nuclear heat is readily suitable to desalination and district heating. Other heat applications require temperatures that are not accessible to light water reactors. Figure from [69]

10 reactors produce their own water using Multi-Stage Flash (MSF) desalination technology.

Desalination technologies compatible with nuclear include thermal desalination processes - multi-stage flash distillation, multieffect (MED) distillation - and membrane desalination processes - reverse osmosis and electro dialysis. Thermal processes require relatively low heat (50-70 celsius for MED and 110-120 celsius for MSF) which
can come from from the secondary of tertiary loop of a nuclear plant\textsuperscript{9}. Membrane processes use pure electricity (see Table \ref{tab:3.2} which can come from a combination of nuclear and other sources. The competitiveness of nuclear heat (Table \ref{tab:3.1}) implies that the thermal processes (MSF and MED) could make nuclear desalination competitive with desalination from fossil-fired plant. Other recent studies confirm the competitiveness of thermal desalination from nuclear energy \cite{69,72}.

Table \ref{tab:3.2}: Multi-stage flash mainly requires heat, whereas reverse osmosis requires electricity only \cite{56,30}. Note that the energy efficiency of desalination processes could decrease significantly with technological progress.

<table>
<thead>
<tr>
<th>Process</th>
<th>Heat consumption</th>
<th>Electric consumption</th>
</tr>
</thead>
<tbody>
<tr>
<td>Multi-stage flash</td>
<td>100 kWh/L</td>
<td>3.5 kw/L</td>
</tr>
<tr>
<td>Multi-effect distillation</td>
<td>50 kWh/L</td>
<td>2.5 kw/L</td>
</tr>
<tr>
<td>Reverse osmosis</td>
<td>0 kWh/L</td>
<td>4.5 kw/L</td>
</tr>
</tbody>
</table>

Ultimately the competitiveness of nuclear desalination depends on the need for and the cost of fresh water. Ziolkowska \cite{160} estimates that the cost of desalinated water varies widely around the world, between $0.45 and 2.51 \text{m}^3$ (2014 numbers). The major water cost drivers are the seawater salinity, the cost of energy (heat and electricity), the capital cost, the production capacity and the capacity factor of the facility. In parallel, it is relatively difficult to estimate the price of water in each country, because the tariff structure is often regulated. The price is not always transparent across and within countries \cite{40}. The tariff often includes services like sewage and wastewater in addition to the cost of drinking water production and distribution. That being said, the total cost of water was lower in Japan and the US than in Europe in 2013 ($1.5-2.8/ \text{m}^3$ for Japan and $1-4/ \text{m}^3$ in the U.S.). Finally, in addition to the uncertainty related to future revenues, installing a desalination plant next to a nuclear site could be a challenge. Land availability, permitting, financing and regulations are major sources of risk for such a project \cite{160}. It is therefore not clear whether desalination would be an attractive option in regions where existing nuclear plants threaten to close. The desalination option should be examined on a

\textsuperscript{9}Some standard engineering work would be required for the desalination feature addition
case-by-case basis, and would require long-term supply agreements for nuclear desalination to be conducted due to the water market regulation.

Nuclear district heating also cumulates an long experience, with over 500 reactor years [69]. District heating does not require very elevated temperatures (less than 150 celsius). Nuclear would substitute natural gas as a source of heat in the communities that adopt district heating. The need for heat is huge in northern U.S. and Japan, but for an already-built nuclear plant to provide heated water to communities, a substantial investment in piping and centralized heating system would be needed. In the U.S. central water heating is not common unfortunately, and nuclear plants are relatively remote from urban areas. The effort and cost to convert an existing nuclear power plant to a cogeneration plant with distribution network for district heating therefore does not look appealing.

Radioisotopes

Finally, existing nuclear power reactors could diversify their output by producing and selling radioisotopes for medicine application. The global supply of medical isotopes is regularly facing shortages due to the limited number of research reactors that generate them [41]. All the more, these facilities are ageing and plan to retire in the next decades. Power reactors could be modified to allow for radioisotope side production and reach a new market beyond electricity.

The list of useful radioisotopes that could potentially be produced by nuclear reactors is long [28]. These isotopes differ by irradiation requirements and by their half life, which condition their production method and processing. The most demanded isotope is Technetium-99m, which represents about 90% of the isotopes used in today’s nuclear medicine [74]. Tc-99m is the daughter product of Molybdenum 99, an isotope with a decay half-life of 66 hours. Mo-99 is produced by irradiating neutron targets. Typically highly-enriched uranium (HEU) targets are used but other targets such as Mo-98 can be employed [36]. Research reactors dominate the supply of radioisotopes, but power reactors could be an alternative source of supply if they make the necessary
upgrade effort. The Clinton plant in the U.S., and other non-LWRs around the world are already equipped to produce radioisotopes [26]. In 2015 NorthStar Medical Radioisotopes partnered with Westinghouse to investigate the production of Mo-99 in BWR instrumentation guide tubes. Exelon filed a pre-application with the NRC to start the production of Mo-99 at the Byron site (two BWRs) [74]. The patent and NRC documents describe the irradiation of Mo-98 targets for 7 days using the movable incore detector system, which would be modified to enable Mo-99 production. Exelon does not anticipate any major perturbation of the core neutronics [94]. The targets would be processed offsite by NorthStar. The quantity potentially produced by the two reactors is not clearly stated, but the patent US 20150348663 A1 from GE [25] explains that “a core loaded with no more than about 8 to 16 BIG bundles (out of a total of several hundred fuel bundles) could potentially produce sufficient isotope product to satisfy the current world demand for those applications that require medical and/or industrial isotopes.”

Even if the Byron plants were only able to supply a share of the U.S market, the potential revenue would be considerable. If we assume that the Mo-99 market in the US represents $1.8 billion/year, a 50% supply share would still represent hundreds of million of dollars a year of revenue for the plant [10]. This product diversification would be sufficient to bridge the revenue gap the Byron plant is facing over the 2017-2019 period (loss of ~ $150 million/year). It could not be a major source of revenue for the entire fleet however; only 1 or 2 power reactors would provide enough isotopes to satisfy the demand and saturate the market.

### 3.2 Regulatory options

We have seen in Chapter 2 that existing nuclear power plants often serve policy objectives that are sought by states or legislators such as greenhouse gas emission... 

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10 The global radiopharmaceutical market was assessed at about $4.7 billion in 2016 [6]. If we consider that Mo-99 accounts for 80% of the market of medical radioisotopes and that the U.S represents half of the global demand, the Mo-99 market of the U.S represents about $1.9 billion/year. If Mo-99 reactor owners capture 25% of the final product value, it opens up a source of revenue equivalent to $450 million/year to them.
reduction and security of supply. They are nevertheless at risk of shutting down for economic reasons. On what basis should the regulator and policy-maker take action on the market?

In the absence of a price of carbon, zero-emission attributes are not valued by deregulated electricity markets. The cost of carbon emissions damage is a price externality. Deregulated markets favor the cheapest generation technologies, regardless of their carbon intensity. To meet environmental objectives, subsidies have been set up to promote the installation of clean energy resources in most countries (mostly wind and solar PV). These policy support mechanisms have taken multiple forms (Feed-in-Tariffs, Investment Tax Credit, etc.) but are similar in that they take place “out-of-the-market”. Some could argue that these ”out-of-the-market” payments are a market fix but they are not equivalent to a carbon price: they are not given equally to all low-carbon technologies nor penalize carbon-intensive generators. In particular, nuclear and large-scale hydro do not benefit from these payments even though they are the largest contributors to carbon-free electricity in the United States and in Japan. As a result, nuclear reactors have been competing directly with fossil-fuel technologies on one hand and subsidized renewables on the other hand (see Figure 3-20 below and prophetic article by Rothwell [141]). A large share of the already-built, existing fleet is struggling financially, as discussed in chapter 2. It is needless to say that in these conditions capital investments in new nuclear are even less attractive, even in regulated markets. Figure 3-20 exhibits the competitiveness gap for new nuclear at the moment in the United States, on the basis of levelized cost of electricity (LCOE). LCOE has limitations - notably when it comes to compare the system cost of intermittent generators versus dispatchable generators - but it is a simple way to compare the competitiveness of technologies taken in isolation.

As seen in Chapter 2, the threat to nuclear capacity is immediate and invites to a rapid response, which can effectively, timely and decisively come from the policy-makers and regulators. This section discusses possible options that could relieve the financial pressure on nuclear. The discussion can also more broadly apply to any
Figure 3-20: Under current costs, retired U.S. nuclear reactors are being replaced by CCGT units and subsidized renewables. The capital cost assumptions are from Lazard [54].

capital-intensive low-carbon energy resources.

### 3.2.1 Putting a Price on Carbon

Putting a price on carbon would capture the externality of environmental and societal damage caused by carbon emissions [136]. Two systems are generally proposed for carbon price: a carbon tax or a cap & trade system. The carbon tax lets the regulator control the price level, with the risk of over- or under-shooting the emission targets. The cap & trade system relies on markets. The emission targets are set by the regulator who grants credits, which are then traded between generators. In the second system, the difficulty lies in the initial allocation of the credits.

Carbon pricing is a very efficient measure to achieve carbon emission reduction at a minimal cost. It is technology-neutral. It favors low-carbon generators at the expense of the carbon-intensive ones, such that the current “out-of-the-market” payments are no longer justified. It modifies the dispatch of the generators on the short-term and provides a long-term price signal that incentivizes innovative clean technologies to enter the market and displace the polluting and less efficient generators.

However, putting a price of carbon is a challenge. One of the major obstacles
is the increase in the energy price resulting from the addition of the cost of carbon, especially if it applies to all sectors of the economy including transportation. The price of goods would increase, which would hurt the economy in the short and medium term, even though the long-term damages are minimized on the long run. The lowest-income population would suffer more than the richest in relative terms. If carbon pricing is implemented unevenly on a given territory, the markets that adopt it face a competitive disadvantage with respect to the other markets because their operating costs and products become pricier [127].

Some attempt have been made to price carbon in deregulated markets. In the US, the Regional Greenhouse Gases Initiative (RGGI) is a voluntary program to price carbon emissions from the power sector at the state level. Nine states in three ISOs (the New England states, NY, MD, DE) currently participate. The carbon price is determined by a cap&trade mechanism, where the emission allowances are allocated through periodic auctions. Allowances are given to fossil-fuel plants and are then traded on the market. The large amount of allowance currently yields a very small spot price of carbon in this market, below $4/MTCO₂. In California, a cap-and-trade program for carbon emission is also in place [49]. The price of the carbon allowances was higher in the latest auction, in the order of $14/MTCO₂. In both California and RGGI programs however, carbon pricing is unevenly applied; emissions from the transportation sector are excluded, whereas they represented 29% emissions of the country in 2015 [53].

An intermediate approach for pricing carbon was proposed by NEPOOL, the association of the market participants of ISO-NE [95]. It consists in adding the cost of carbon to the bids of the market participants, for calculation in the resource dispatch algorithm. Low carbon technologies like nuclear would benefit from a higher price of electricity, and low-carbon subsidies could be eliminated. An important element of the mechanism is the re-allocation of the carbon cost: carbon-emitting generators that are called and dispatched would compensate the ISO for their emissions. The proceedings would then be allocated to the load serving entities (i.e. the consumers) to lower their energy bill. This mechanism enables to partially alleviate the burden
of carbon pricing to the consumer. This carbon price could be added rapidly to an already-existing ISO that controls the dispatch algorithm. The carbon price could be small at the beginning and progressively increase. The low-carbon subsidies would be progressively reduced to ensure a smooth transition and give market agents time to adapt.
Table 3.3: Putting a price on carbon lowers CO$_2$ emissions and increases the wholesale price of electricity, which would benefit nuclear plants. The price increase for consumers could be partly alleviated by charging the polluters for the carbon damage (simulation results obtained with 2015 cost assumptions).

<table>
<thead>
<tr>
<th>Carbon price ($/MT CO2)</th>
<th>0</th>
<th>10</th>
<th>20</th>
<th>30</th>
<th>41.2 $^{[1]}$</th>
</tr>
</thead>
<tbody>
<tr>
<td>Emissions (MM MT CO2)</td>
<td>431</td>
<td>361</td>
<td>272</td>
<td>259</td>
<td>259</td>
</tr>
<tr>
<td>Midwest</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Wholesale electricity price ($/MWh)</td>
<td>26.9</td>
<td>+7.2</td>
<td>+14.4</td>
<td>+23.1</td>
<td>+33.2</td>
</tr>
<tr>
<td>Consumer price w/ rebate ($/MWh)</td>
<td>26.9</td>
<td>+2.0</td>
<td>+6.6</td>
<td>+12.0</td>
<td>+17.9</td>
</tr>
<tr>
<td>Emissions (MM MT CO2)</td>
<td>272</td>
<td>263</td>
<td>263</td>
<td>263</td>
<td>263</td>
</tr>
<tr>
<td>Mid-Atlantic</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Wholesale electricity price ($/MWh)</td>
<td>31.8</td>
<td>+8.4</td>
<td>+16.9</td>
<td>+25.3</td>
<td>+34.8</td>
</tr>
<tr>
<td>Consumer price w/ rebate ($/MWh)</td>
<td>31.8</td>
<td>+4.6</td>
<td>+9.2</td>
<td>+13.8</td>
<td>+18.9</td>
</tr>
</tbody>
</table>
Table 3.3 illustrates the hypothetical outcome of a carbon price that would be applied to the Midwest and Mid-Atlantic regions. The simulations use the 2015 wholesale market model presented in Chapter 2. A moderate carbon price as low as $10 / MT CO2 would provide extra revenues to the nuclear plants equal to $7.2 and $8.4/ MWh for the Midwest and Mid-Atlantic respectively. This measure would potentially suffice to prevent most nuclear retirements (according to Table 1.1 and Figure 2-1). By allocating the cost of carbon to coal-, gas- and oil-fired generators, the price increase for the consumers would be limited to $2.0 and $4.6/ MWh respectively.

In the U.S, individual states and stakeholders often display very different degrees of commitment toward climate policy and carbon pricing. It is therefore difficult or impossible within a given area such as ISO-NE or PJM to agree on a common market-based approach to carbon pricing. Some states would be willing to adopt an aggressive carbon price whereas others are firmly opposed. To accommodate the different carbon policies of the states with markets, borders adjustments to carbon pricing have been proposed, for instance by PJM [138] or Bloomberg New Energy Finance [82]. Carbon price border adjustment would ensure that imports and exports of electricity between subregions correctly account for carbon emissions. If there was no adjustment for electricity crossing the borders, carbon prices and carbon emissions could “leak” from one sub-region to another, and price leakage would unfairly affect a non-carbon price subregion (see Figure 3-21). Due to the nature of power flows, it is impossible to track the origin and destination of every single electron in the system and to deliver “certificates of origin”. Yet net, average financial adjustments for electricity crossing adjacent states should be doable. California for instance adopted a border adjustment mechanism for the electric power sector in its Cape-and-Trade program [12].

12 If the adjustment were applies to all industries the task would be more tedious [32]. In this case a so-called “output-based” approach is recommended instead of border adjustment. See for instance [127] for California.
3.2.2 Crediting Zero-Emission Attributes (direct subsidy)

Subsidies are the most direct way to value a specific attribute and maintain or expand a given generation resource. They are the most popular form of policy support, together with tax credits. Subsidies can take different names depending on the mechanism – Feed-in-Tariffs (FIT), Feed-in-Premiums (FIP), Contract-for-Differences (CfD), Zero-Emission Credits (ZEC), etc. – but in the end they all result in an additional revenue for the targeted generator. They generally take the form of payment for the electricity supplied to the grid from a given technology or plant, and are expressed in $/MWh.

FITs have been a common method of policy support for wind and solar PV technologies at the beginning, but were later replaced in Europe by FIPs with competitive auctions. Premiums are a payment that is added to the wholesale electricity sale revenue rather than a substitutive fixed tariff. Note that subsidies through competitive bidding requires multiple independent agents to be effective. A CfD can be seen as a long-term power purchase agreement for the electricity generated from a particular source. The U.K. implemented a CfD program for new nuclear which led investors to the decision to build two large EPR reactors [39].
New York and Illinois States recently voted for another form of direct subsidy for nuclear, in the form of “Zero Emission Credits” (ZECs). Both New York and Illinois subsidies are based on the social cost of carbon, which is adjusted by an electricity price index (energy + capacity) in order to limit the cost to the consumers. The NY subsidy is revised every other year based on the EPA cost of carbon and a forward power market index. The formula is as follows:

\[
ZEC(\$/MWh) = CarbonCost - RGGI - \max(PriceIndex - 39, 0)
\]

with RGGI the Regional Greenhouse Gas Initiative payments ($10.4/short ton), and the carbon cost fixed at $42.9/short ton. The market price index is equal to the sum of the a) the day-ahead fixed price future and b) the capacity price, both averaged over two years in the zone (NY Public Service Commission, 2016). The initial ZEC calculation results in a subsidy of $17.5/MWh. If implemented, the subsidy will secure the continued operation of three nuclear plants (3.4 GW total capacity) in upstate New York for the next 14 years.

The Illinois program has a similar structure, with more provisions on the maximum payment that the plant owners can receive. Nuclear capacity is large in Illinois, and the regulator cannot afford to subsidize all of it. The subsidy is limited to 16% of electricity supplied to consumers, or 1.65% equivalent retail price increase on the bills of the consumers - whichever is larger. The subsidy is updated every year based on market price indexes. The formula is the following:

\[
ZEC(\$/MWh) = CarbonCost - \max(PriceIndex - BaselinePrice, 0)
\]

The carbon cost is originally taken at $16.5/ MWh and the baseline price at $31.4/MWh for the first calculation in 2017. The carbon cost is corrected for inflation in subsequent years. The price index is similar to the NY price index: it is a sum of a) the forward wholesale price at the Northern Illinois hub and b) the capacity price in Illinois, which is a 50/50 price blend of MISO zone 4 and PJM ComEd region (Illinois General Assembly, 2016). At current future prices, the subsidy amounts to
$14.7/MWh for the first year for Quad Cities and Clinton (2.9 GW total capacity).

From a design perspective, ZECs or other direct subsidies have the advantage of being closely controlled by the regulator or policy maker. The final dollar amount is set by the formulas above. Therefore, it can be tailored to the exact “competitiveness gap” that the technologies deserve and include provisions to prevent deviations. For instance the NY and Illinois subsidies target the specific plants at risk of shutdown and leave the profitable ones unsubsidized. To further guarantee the legitimacy of the subsidy, Illinois demands the plant owner to (privately) disclose its cost of generation.

History shows that in general it is difficult to determine the cost-effective level of direct subsidy that the generators deserve [111]. Direct support programs have commonly been more costly than anticipated, and past experience shows that designers of FITs have often revised their tariff several times for the same country over a short period of time (for example in Spain). Frequent regulatory changes can send confusing signals to investors, whereas long-term vision and regulatory stability are essential for clean technologies to develop. To support large-scale investments in new nuclear, subsidies must be guaranteed for tens of years (35 years in the U.K.) and cannot be left at the mercy of changing political agendas.

Direct subsidies are effective but on the other hand they can have adverse effects. They distort the functioning of electricity markets, and in particular the price signal for capacity entry and exit. They alter the “natural” generation mix and the bids of the generators, which are in some instance willing to bid negative prices to ensure their dispatch and receive policy payments. Negative prices have for instance appeared in several wholesale markets at times when energy demand is low and renewable generation large. The collapse of energy prices during some hours of the day negatively impacts the revenue of the technologies that do not benefit from the same treatment. The investment and retirement decision are modified because the price signal does not reflect the payments the market agents receive. Lastly, they create a source of uncertainty in competitive markets, since the legislator has the discretionary power to support a given set of resources with short notice. This phenomena can deter future investments because investors require long-term, transparent price signals to make
decisions.

In some instances (such as the “Hughes vs. Talen Energy Marketing” case), the regulator (FERC in this case) rejected the instrument because it interfered too much with markets. When designing the mechanism for nuclear, it is therefore essential to stress the value of the zero-carbon attribute as well as avoiding the direct interference with day-ahead and real-time wholesale markets. The New York Clean Energy Standard was designed according to this principle.

In the case of early nuclear shutdown, the best merits of ZECs are their effectiveness, easiness and rapidity of implementation. If approved by the Federal Energy Regulatory Commission (FERC), the NY and Illinois subsidies will have taken less than a year to be designed, voted and implemented. More states could follow and adopt a similar ZEC to preserve their nuclear capacity.

3.2.3 Creating a Low-Carbon Capacity Mechanism

Capacity mechanisms are designed to ensure adequate generating capacity is installed in the grid to meet the peak load demand and thus ensure security of supply. They provide a substantial source of revenue to generators, especially to those who run for a limited number of hours per year (the ”peakers”). They solve the so-called ”missing money” problem that occurs when energy prices are capped and they ensure the generators are properly remunerated for the reliability they offer [114]. Capacity mechanisms are therefore unnecessary when energy prices are not capped (such as in Texas and Australia). They are present in most deregulated markets of the United States (PJM, New England, New York, MISO, California) and in Europe. They enable the regulator to better control security of supply by running capacity auctions up to several years before delivery. Early auctions also lower the risk for investors because stakeholders know what capacity price and generation mix to expect before investing in new assets.

Capacity mechanisms can take several forms: capacity payments, capacity markets, or reliability options. They are a relatively recent addition to energy markets; their design is still on-going and reforms take place regularly. A recent change oc-
curred in the PJM and New England capacity markets, following the 2014 polar vortex. The regulator now imposes heavy penalties the generators that clear the capacity market but are not available when needed (i.e. during scarcity periods). Bids and prices have consequently increased. The reform helps the most reliable generators such as nuclear and hydro be more profitable and competitive in the capacity market.

The advantage of capacity mechanisms is that they are already in place in many regions. They are a market-based approach to value reliability: the capacity needed is forecasted by the regulator and the price is given by market. It also means that the capacity price may be zero if there is over-capacity in the grid. From a design perspective, the rules of the capacity auction (time-to-delivery) are crucial for determining which new technologies can bid. If the costs of new generation change, the technology being built may be different than the one the policy-maker expected in the first place.

A more oriented and innovative approach to value reliable, low-carbon generation capacity could be to add an environmental dimension to capacity mechanisms. It would give an instrument for policy makers to ensure that a ”cleaner” capacity and energy mix is achieved. The concept would be to give a premium to zero-carbon technologies and/or a penalty to carbon-emissive technologies. The environmental dimension could be directly included in the market clearing algorithm (case of a penalty), or occur after market clearing (case of a premium/credit). The capacity auction could alternatively be set in a separate capacity market dedicated to low-carbon resource. The tender for low-carbon capacity would be run 5 to 10 years before the date of capacity delivery, such as large infrastructure projects such as nuclear and hydro - with or without new transmission lines - could compete. The demand-side of the capacity market would be composed of aggregators, large consumers and retailers. The auction would be run by the regulator or grid operator. The ”clean” capacity mechanism would allow the regulator to better control the capacity mix. As a downside, load-follow and peak generators (coal, gas-fired and oil-fired) could accelerate their retirement if their capacity payments drop too quickly. It may have detrimental consequences on grid reliability and the cost of energy (currently, there is no cheap
zero-emission substitute to “dirty” generators for peak generation). Therefore, the transition from classical to clean capacity mechanism should be progressive to prevent the disruption of peak power supply.

The European Commission recently proposed to include the environmental dimension to capacity market by excluding generators emitting more than 550g CO2/kWh [60]. This could be a first step to cleaner capacity mechanisms in Europe.

3.2.4 Expanding Low-Carbon Portfolio Standards

A portfolio standard is a system where electricity providers are mandated to buy a certain target of clean electricity, i.e. generated from clean energy sources. Certificates are granted to clean energy generators for the electricity they produce. They are then traded on an exchange platform, which provides extra revenue to the clean generators. In the U.S., portfolio standards usually comprise renewables but not nuclear nor large hydro. A more consistent approach would be to include all low-carbon generators in these portfolios. The nuclear fleet, with its large electricity output, would benefit considerably from this measure. The advantage of a portfolio standard as opposed to a direct subsidy (FIT, ZEC, CfD, etc.) is that the price is set by the market instead of being dictated by the regulator of policy maker. Only the target will need to be decided in advance. Renewable portfolio standards already exist in many states of the U.S., and adding other technologies would be a minimal modification to the rules – albeit it would change the price equilibrium of the certificates. The regulator would have to adjust the mandates to prevent too much disruption. As a disadvantage, the regulator does not directly control the level of investment in clean technologies. The price is given by the market and can be too low if excess clean generation is present. If certificates are inexpensive, new investment in low-carbon technologies will stall. If there is a single portfolio standard, all clean generation technologies are remunerated at the same price ($/ MWh). Renewables would compete with nuclear on an equal field. Alternatively, the regulator can create several portfolio standards to differentiate different technologies. For instance in Massachusetts, solar PV has its own standard and does not directly compete with wind. The certificates
from solar PV do not trade at the same price as the certificates from wind.

### 3.2.5 Cost-Effective Mothballing of Nuclear Assets

As seen previously, current market conditions displace nuclear power plants in the United States. They retire and enter the decommissioning process a few months later, preventing their restart forever [51]. What if we could instead restart them at a minimal cost when the market conditions improve? This is the mothballing option. It consists of temporarily stopping the generation of electricity for a few years in the hope that the market conditions become more favorable. The idea of mothballing a non-profitable nuclear asset is not new, and is technically feasible. It was for instance proposed in the 1970 for the Zion plant, or more recently by E. Kee [104]. In Ontario, the four reactors of Bruce A were shut down in the mid-1990 due to overcapacity [110]. They remained idle for 6 to 17 years before returning to service [13].

For the mothballing option to be applied, it is necessary for the cost of mothballing to be lower than the expected loss of continued operation. The expected losses in operation ranged in 2016 from $0 to 32/MWh throughout the fleet, with an average at $7.5/MWh. Can the cost of mothballing be lower than this?

Unlike fossil-fuel generators, the cost of nuclear generation has a very large fixed component due to security and operation personnel (labour), routine inspection, and maintenance. These fixed costs average to $18-19/MWh. Variable costs (fuel and variable O&M) represent the rest: 40 to 60% of the annual cost of generation. We see that stopping the plant and saving the variable cost is not sufficient for preventing plants to lose money. This is why premature retirements have so far been the only option for uneconomic plants to limit their losses. The temporary shutdown of a plant for several years has not been considered due to high fixed cost required for security, safety and equipment care.

The mothballing option would become interesting for nuclear operators only if the fixed cost requirements were lowered. After all, once the reactor has shut down and the

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[13] The mothballing cost was low because four other units on site remained in operation and covered the security and other fixed costs of the mothballed units.
core has cooled down, the risk of an accident or malevolent act is considerably reduced. This would justify to lower the safety and security requirements, two major cost items. Unfortunately, there is no special regulatory status for a mothballed plant in the United States currently. The Nuclear Regulatory Commission (NRC) recognizes only two types of regulatory status: a nuclear plant is either under an operation license or under a decommissioning license. It would be desirable to create a mothballing license for uneconomic plants. This new licensing status would define a set of reduced requirements to lower the cost of mothballing down to $7.5 \times 8760 \times 0.92 = \sim \$60$ million /

\text{GW-yr.} \quad \text{Society would then preserve the option to restart these zero-emission generation assets in the future when appropriate. Note that the mothballing option would also preserve the option to extend the lifetime of the plants.}

Mothballing should be a preferable alternative to irreversible retirement.

3.2.6 In- or out-of-the-market? Looking ahead on the future of low-carbon grids.

The nuclear subsidies voted in New York and Illinois, together with other low-carbon resource procurements, have generated a debate in the United States about the interference of state policies with competitive (ISO) markets. The debate culminated with a technical conference at FERC where stakeholders exposed their point of view. Proponents claim for the legitimacy of states to enforce their policy and environmental agenda, whereas opponents stress the unfair competition these subsidies create in markets. The solutions we and other propose can be classified in two categories: in- or out-of the market.

The “in-the-market” approach is a reconciliation of markets with state objective, and consists in accommodating the attributes sought by policy makers into the market. Carbon pricing, clean capacity markets belong to this category because they value the low-carbon and reliability attributes of resources in the existing markets. They are also technology neutral. By contrast, out-of-the-market solutions such as subsidies, long-term purchase & procurements agreements are meant to support spe-
cific resources regardless of the traditional markets operated by the ISO, which are: the markets for energy, capacity and ancillary services \[14\]

The risk of a failure to reconcile state agendas with competitive markets is a re-regulation of the power sector, where states procure long-term resources based on criteria they select and where RTOs are only responsible for daily dispatch. This re-regulated regime resembles today’s California power sector \[15\]. Stakeholders in Ohio, seeking to protect their coal- and nuclear units, already pushed Ohio to leave competitive markets if FERC ruled again against its envisioned support mechanism \[157\].

On the longer term, the large-scale deployment of renewables raises the question of the cost recovery of capital in a grid running on low marginal cost. If prices during peak hours do not spike \[16\] they will fail to compensate generators for low-price hours. Technologies with high fixed costs like nuclear will suffer financially and will continue to ask for alternative sources of revenue (in the form of capacity or out-of-the-market payments) or retire. For instance if the bids of renewables continue to spread negative prices, electricity price will continue to drop which will signal the other generators that they are not needed anymore whereas in fact they are needed for reliability purpose (to meet peak load demand).

It is therefore crucial for the sustainability of competitive markets to protect the formation of a price signal that reflects scarcity in order to achieve an economically efficient market - a market where supply and demand drive entry and exit of generators while ensuring reliability. Out-the-market payments may be effective on the short run but in the medium- to long term market-based mechanisms are expected to be more economically efficient.

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\[14\]Current RPS are a market-based mechanism but is discriminatory and therefore can be classified as an out-of-the-market solution.

\[15\]California (CAISO) electricity market used to be fully deregulated until repeated blackouts and market abuse led to re-regulation.

\[16\]due to price caps for instance
Conclusion

Summary

Existing nuclear reactors are in economic difficulty in competitive electricity markets. Nuclear plants in the United States have started to shut down due to deteriorating economics and at an unprecedented scale, which may jeopardize long-term policy objectives. This situation invites an assessment of the causes and possible consequences of this phenomena in order to inform future decisions and actions. Academic literature has so far mostly focused on new reactors economics but few authors have worked on the economics and prospects of existing commercial reactors in competitive electricity markets.

Liberalized electricity markets are characterized by competition at different time scales for electricity generation. The market outcome is complex and uncertain, which requires advanced tools to analyze and measure it. We developed and employed in this thesis a set of tools relevant for assessing the economic retirement of existing nuclear reactors in these markets. The classical tool evaluates plant retirement based on their net present value and a risk-adjusted discount factor applied to an expected cash flow. We use this method as a reference. The second tool is a regional electricity market model, which mimics supply and demand with the physical constraints of the generators and their marginal cost of production. The model is built upon market fundamentals such as fuel prices and computes the hourly dispatch of the generators and the spot electricity price. It is optimized for simulating the revenue of nuclear power plants. The third tool is a valuation methodology for nuclear plants under price uncertainty. Price is modeled as a two-factor stochastic process whose parameters
are calibrated on historical and forward price curves. The “risk-neutral” expectation of future spot price is then discounted at the risk-free rate in the asset valuation formula. Strategic options of the plant owners such as early retirement, mothballing and lifetime extension are integrated into the value of the plant. This approach offers a robust framework to integrate price risk as well as option value over the long life of nuclear assets. It informs us about when it is optimal to close a nuclear asset permanently.

These tools are applied to gain insights about the situation of existing nuclear in two countries of interest: the United States and Japan. The United States has mature deregulated electricity markets whereas Japan is in the process of restructuring its power sector for a completion in 2020. We evaluate that cheap natural gas and stagnant electricity demand have been responsible for the drop in nuclear plant revenue in the U.S. We estimate that two-thirds of the nuclear capacity are uncompetitive and that 20% are retiring or are at risk of retiring in the short-term. In Japan, market data are more scarce and less reliable but we nevertheless attempted in drawing projections. We estimate that most nuclear plants should be competitive when they restart in the newly deregulated market at the condition that fossil fuel prices remain high, such as in the $8-12/ MMBtu range for LNG. In both countries current levels of renewable penetration have a small effect on nuclear plant revenue compared to other factors. We measure that they notably impact nuclear plant operation when their share of total generation exceeds 15% for solar PV in Japan and 30% for wind in the U.S. Midwest. Their effect can be very much aggravated if their subsidies are carried through their supply bids and create negative spot prices.

We find that price uncertainty and volatility, which characterizes competitive markets, delays strategic decisions such as plant retirement instead of accelerating them. A case study - the Fitzpatrick plant in New York - also shows a strong cyclical pattern in nuclear asset value, making it most vulnerable at the end of its fuel cycles. Discount rates are important but are a second-order effect. The option to extend the operation license for an additional 20 years has little impact in the Fitzpatrick retirement decision.
The change in the fundamentals of deregulated markets, namely cheap fossil fuels, zero demand growth and increased renewables penetration, is an incentive for nuclear plants to adapt. On the technological side, load-follow capability proves beneficial when renewables are deployed at large scale to avoid possible losses caused by negative prices. In these conditions nuclear becomes a price maker, which could enhance the recovery of its operating expenses. In addition, flexible nuclear generation offers arbitrage opportunities in the real-time and grid ancillary service markets, which can in some cases provide additional revenue. In the medium-term, the development of heat storage technologies such as FIRES can help high penetrations of renewables while preserving nuclear plant profitability. In this sense, they are an instrument of deep decarbonization of the energy sector. Finally, beyond electricity, nuclear could produce heat for desalination purposes, and radioisotopes for medicine. However we consider these two applications as niche markets; they could not sustain a large nuclear fleet.

We recognize that the carbon-free attributes of nuclear generation are not valued by competitive markets. Yet a carbon price could maintain nuclear assets by itself. We calculate that even a moderate carbon price, say $10/ MWh could save most nuclear power plants in difficulty in the Midwest and Mid-Atlantic region of the U.S. It would preserve the soundness of the market price signal and help achieve climate objectives at the same time. If not possible, States and countries may want to subsidize nuclear in order to avoid the irreversible retirement of these low-carbon assets. As a last resort, a mothballing license should be created for reactors to stop and restart production at minimal cost years later. This would give society the insurance of their operability in case they are needed in the future.

**Future work**

The methods and tools we developed are a solid base upon which developments can be brought and with which more cases can be studied.

The electricity market model is powerful, relatively simple and computationally
efficient. It could be made more accurate, although it would be at the expense of complexity. The priority should probably be to add the representation of the transmission networks in order to exhibit and measure grid congestion effects. This feature would prove useful to study the local effects of renewables concentration such as in Iowa. It could also help design a carbon pricing mechanism with state border adjustment, a promising path to foster adoption. The model could also be applied as is to other regions such as Texas, the North-East and to European countries to simulate their fundamental market drivers and their impact on nuclear revenue.

In parallel or coupled with the electricity market model, we could develop a framework for simulating capacity markets. Capacity markets are more difficult to model because they are relatively recent and unsettled, and because they require projections of supply and demand over multiple years. Having a model of capacity market would inform the design of market reforms.

Our stochastic process of electricity price captures the most important features of observed monthly-average spot prices: seasonal variations, short-term mean reversion and long-term variations. A possible improvement would be to add a price jump process for winter months. This addition would improve accuracy and capture price spike opportunity. It would also be relevant if the price process was used to value peak power plants. The two-factor process could also be optimized to precisely predict futures curves and develop financial hedging strategies.

Our long-term asset valuation methodology captures and quantifies spot price risk, but falls short at evaluating generation and cost risk. This is an understandable caveat as there no actively traded product based on these underlyings. To price these risk factors, one could perhaps explore statistical data, alternative methods, and/or establish benchmark based on the spread options (heat rate options) that are traded for fossil power plants.

We applied our retirement decision model to a limited number of case study. As we saw, short-run unprofitability does not necessarily imply immediate retirement as prescribed by the traditional net present value rule. In order to have a full picture of vulnerability of the fleet to short-term retirement, we should apply our valuation
methodology to every nuclear power plant of the country. In this regard, the growing volume of trade on Nodal Exchange could help characterize price dynamics at each nuclear plant location with improved accuracy. It is a new exchange platform that enables the trading of electricity futures for more than five hundreds nodes in the United States for delivery up to 11 year in the future [11]. It also recently created option contracts on electricity prices.

Finally, our valuation model could be expanded for assessing business decisions affecting other generators who face different types of risk: renewables (subsidy and generation risk), fossil power plants (fossil fuel price risk and dispatch risk), and hydro (water risk).
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Appendix A

Derivative security pricing theory

Complete market A complete market is a market in which assets have a price, i.e. are traded. For instance electricity, bond, and stock markets are complete. By contrast, an incomplete market is illiquid and its assets are not traded on a regular basis.

Arbitrage An arbitrage is a situation where there exists a riskless trading strategy.

Arbitrage, equivalent martingale and market completeness Under technical conditions described in Duffie §8 §8 that we omit here, it is possible to demonstrate that the following assertions are essentially equivalent:

• The market is complete.

• There is no arbitrage.

• There is a unique equivalent martingale measure.

• There is a state-price vector.

Risk-neutral pricing Under the risk-neutral (probability) measure and in the absence of arbitrage an asset has the same expected return as a risk-free asset.

As a consequence valuation under the risk-neutral measure uses the risk-free rate.
**Fundamental theorem of asset pricing**  In a complete market the price $P_t$ of a derivative at time $t$ is the discounted expected value of the future payoffs under the unique risk-neutral measure $Q$.

$$
P_t = E^Q_t \left[ \int_t^T H_s e^{-rs} ds \right]$$

$r$ is the risk-free discount rate (Treasury Bond yield typically) assumed constant and $H$ the future payoff rate.
Appendix B

Electricity market model assumptions

The generators’ parameters for the year 2015 and 2008 in the Midwest and Mid-Atlantic are listed in Figures B.1, B.2, B.3 and B.4.
Table B.1: Cost and technical assumptions for generators in the Midwest region in 2015.

<table>
<thead>
<tr>
<th>Resource</th>
<th>Capacity (MW)</th>
<th>Availability ($/MMBtu)</th>
<th>Fuel price (Btu/kWh)</th>
<th>Heat rate ($/MWh)</th>
<th>Fuel cost ($/MWh)</th>
<th>Var. O&amp;M ($/MWh)</th>
<th>Supply bid ($/MWh)</th>
<th>Ramp. up/down (%/hr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nuclear</td>
<td>20,200.5</td>
<td>92%</td>
<td>0.72</td>
<td>10,458</td>
<td>7.5</td>
<td>0.63</td>
<td>0</td>
<td>0% / 0%</td>
</tr>
<tr>
<td>Coal IA</td>
<td>5,638.1</td>
<td>83%</td>
<td>1.47</td>
<td>10,495</td>
<td>15.4</td>
<td>5.50</td>
<td>20.9</td>
<td>31% / 58%</td>
</tr>
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<td>Coal IL</td>
<td>14,658</td>
<td>83%</td>
<td>1.75</td>
<td>10,495</td>
<td>18.4</td>
<td>4.27</td>
<td>22.6</td>
<td>31% / 58%</td>
</tr>
<tr>
<td>Coal IN</td>
<td>16,611.5</td>
<td>83%</td>
<td>2.65</td>
<td>10,495</td>
<td>27.8</td>
<td>5.36</td>
<td>33.2</td>
<td>31% / 58%</td>
</tr>
<tr>
<td>Coal MI</td>
<td>10,743.7</td>
<td>83%</td>
<td>2.33</td>
<td>10,495</td>
<td>24.5</td>
<td>5.62</td>
<td>30.1</td>
<td>31% / 58%</td>
</tr>
<tr>
<td>Coal MN</td>
<td>4,169.9</td>
<td>83%</td>
<td>1.74</td>
<td>10,495</td>
<td>18.3</td>
<td>7.31</td>
<td>25.6</td>
<td>31% / 58%</td>
</tr>
<tr>
<td>Coal MO</td>
<td>12,101</td>
<td>83%</td>
<td>1.73</td>
<td>10,495</td>
<td>18.1</td>
<td>4.43</td>
<td>22.6</td>
<td>31% / 58%</td>
</tr>
<tr>
<td>Coal ND</td>
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<td>10,495</td>
<td>11.3</td>
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<td>Coal WI</td>
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<td>83%</td>
<td>2.09</td>
<td>10,495</td>
<td>21.9</td>
<td>8.94</td>
<td>30.8</td>
<td>31% / 58%</td>
</tr>
<tr>
<td>CCGT IA</td>
<td>2,630.5</td>
<td>85%</td>
<td>3.23</td>
<td>7878</td>
<td>25.4</td>
<td>6.07</td>
<td>31.5</td>
<td>82% / 75%</td>
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<td>CCGT IL</td>
<td>13,507.7</td>
<td>85%</td>
<td>3.23</td>
<td>7878</td>
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<td>5.08</td>
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<td>82% / 75%</td>
</tr>
<tr>
<td>CCGT IN</td>
<td>5,069.9</td>
<td>85%</td>
<td>3.23</td>
<td>7878</td>
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<td>2.15</td>
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<td>3.21</td>
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<td>3.23</td>
<td>7878</td>
<td>25.4</td>
<td>8.01</td>
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<td>82% / 75%</td>
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<td>85%</td>
<td>2.89</td>
<td>7878</td>
<td>22.8</td>
<td>2.01</td>
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<td>82% / 75%</td>
</tr>
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<td>85%</td>
<td>3.23</td>
<td>7878</td>
<td>25.4</td>
<td>4.19</td>
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<td>82% / 75%</td>
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<tr>
<td>CCGT new</td>
<td>0</td>
<td>87%</td>
<td>3.23</td>
<td>6600</td>
<td>21.3</td>
<td>2.75</td>
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<tr>
<td>GT</td>
<td>9,120.1</td>
<td>100%</td>
<td>6.74</td>
<td>10,987</td>
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<td>51%</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>5% / 5%</td>
</tr>
<tr>
<td>Wind</td>
<td>19,271.1</td>
<td>CF = 39%</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td></td>
</tr>
<tr>
<td>Total</td>
<td>171,323.7</td>
<td>CF = 39%</td>
<td></td>
<td></td>
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</table>
Table B.2: Cost and technical assumptions for generators in the Midwest region in 2008.

<table>
<thead>
<tr>
<th>Resource</th>
<th>Capacity (MW)</th>
<th>Availability (%)</th>
<th>Fuel price ($/MMBtu)</th>
<th>Heat rate (Btu/ kWh)</th>
<th>Fuel cost ($/MWh)</th>
<th>Var. O&amp;M ($/MWh)</th>
<th>Supply bid ($/MWh)</th>
<th>Ramp. up/down (%/ hr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nuclear</td>
<td>20,368</td>
<td>91%</td>
<td>0.51</td>
<td>10,452</td>
<td>5.29</td>
<td>0.56</td>
<td>0</td>
<td>0% / 0%</td>
</tr>
<tr>
<td>Coal IA</td>
<td>6,528</td>
<td>84%</td>
<td>1.01</td>
<td>10,378</td>
<td>10.53</td>
<td>5.62</td>
<td>16.14</td>
<td>31% / 58%</td>
</tr>
<tr>
<td>Coal IL</td>
<td>14,658</td>
<td>84%</td>
<td>1.75</td>
<td>10,378</td>
<td>14.50</td>
<td>3.53</td>
<td>18.03</td>
<td>31% / 58%</td>
</tr>
<tr>
<td>Coal IN</td>
<td>15,117</td>
<td>84%</td>
<td>1.40</td>
<td>10,378</td>
<td>21.10</td>
<td>4.35</td>
<td>25.45</td>
<td>31% / 58%</td>
</tr>
<tr>
<td>Coal MI</td>
<td>11,597</td>
<td>84%</td>
<td>2.03</td>
<td>10,378</td>
<td>19.90</td>
<td>4.43</td>
<td>24.33</td>
<td>31% / 58%</td>
</tr>
<tr>
<td>Coal MN</td>
<td>5,077</td>
<td>84%</td>
<td>1.48</td>
<td>10,378</td>
<td>15.40</td>
<td>6.28</td>
<td>21.68</td>
<td>31% / 58%</td>
</tr>
<tr>
<td>Coal MO</td>
<td>11,146</td>
<td>84%</td>
<td>1.33</td>
<td>10,378</td>
<td>13.79</td>
<td>4.28</td>
<td>18.07</td>
<td>31% / 58%</td>
</tr>
<tr>
<td>Coal ND</td>
<td>4,098</td>
<td>84%</td>
<td>0.72</td>
<td>10,378</td>
<td>7.50</td>
<td>4.07</td>
<td>11.57</td>
<td>31% / 58%</td>
</tr>
<tr>
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<td>84%</td>
<td>1.74</td>
<td>10,378</td>
<td>18.04</td>
<td>5.19</td>
<td>23.23</td>
<td>31% / 58%</td>
</tr>
<tr>
<td>CCGT IA</td>
<td>2,395</td>
<td>88%</td>
<td>9.02</td>
<td>8305</td>
<td>74.91</td>
<td>4.17</td>
<td>79.08</td>
<td>82% / 75%</td>
</tr>
<tr>
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<td>13,462</td>
<td>88%</td>
<td>10.10</td>
<td>8305</td>
<td>83.88</td>
<td>13.42</td>
<td>97.30</td>
<td>82% / 75%</td>
</tr>
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<td>CCGT IN</td>
<td>5,360</td>
<td>88%</td>
<td>9.61</td>
<td>8305</td>
<td>79.81</td>
<td>6.04</td>
<td>85.85</td>
<td>82% / 75%</td>
</tr>
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<td>8.75</td>
<td>8305</td>
<td>72.67</td>
<td>9.27</td>
<td>81.93</td>
<td>82% / 75%</td>
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</tr>
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<td>9.02</td>
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<td>5.11</td>
<td>80.02</td>
<td>82% / 75%</td>
</tr>
<tr>
<td>CCGT ND</td>
<td>10</td>
<td>88%</td>
<td>9.02</td>
<td>8305</td>
<td>74.91</td>
<td>3.89</td>
<td>78.81</td>
<td>82% / 75%</td>
</tr>
<tr>
<td>CCGT WI</td>
<td>6,165</td>
<td>88%</td>
<td>9.24</td>
<td>8305</td>
<td>76.74</td>
<td>7.03</td>
<td>83.77</td>
<td>82% / 75%</td>
</tr>
<tr>
<td>GT</td>
<td>9,557</td>
<td>100%</td>
<td>10.87</td>
<td>11015</td>
<td>119.73</td>
<td>19.39</td>
<td>139.12</td>
<td>82% / 75%</td>
</tr>
<tr>
<td>Hydro</td>
<td>2,136</td>
<td>43%</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>5% / 5%</td>
</tr>
<tr>
<td>Wind</td>
<td>6,482</td>
<td>CF = 31%</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
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</tr>
<tr>
<td>Total</td>
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</table>
Table B.3: Cost and technical assumptions for generators in the Mid-Atlantic region in 2015.

<table>
<thead>
<tr>
<th>Resource</th>
<th>Capacity (MW)</th>
<th>Availability (%/MMBtu)</th>
<th>Fuel price ($/MMBtu)</th>
<th>Heat rate (Btu/kWh)</th>
<th>Fuel cost ($/MWh)</th>
<th>Var. O&amp;M ($/MWh)</th>
<th>Supply bid ($/MWh)</th>
<th>Ramp. up/down (%/hr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nuclear</td>
<td>21,237</td>
<td>92%</td>
<td>0.72</td>
<td>10,458</td>
<td>7.5</td>
<td>0.63</td>
<td>0</td>
<td>0% / 0%</td>
</tr>
<tr>
<td>Coal DE</td>
<td>410</td>
<td>83%</td>
<td>4.29</td>
<td>10,495</td>
<td>45.05</td>
<td>8.99</td>
<td>54.05</td>
<td>31% / 58%</td>
</tr>
<tr>
<td>Coal KY</td>
<td>13,437</td>
<td>83%</td>
<td>2.54</td>
<td>10,495</td>
<td>26.64</td>
<td>3.74</td>
<td>30.39</td>
<td>31% / 58%</td>
</tr>
<tr>
<td>Coal MD</td>
<td>4,472</td>
<td>83%</td>
<td>3.74</td>
<td>10,495</td>
<td>39.28</td>
<td>6.49</td>
<td>45.77</td>
<td>31% / 58%</td>
</tr>
<tr>
<td>Coal NJ</td>
<td>782</td>
<td>83%</td>
<td>5.10</td>
<td>10,495</td>
<td>53.49</td>
<td>6.70</td>
<td>60.19</td>
<td>31% / 58%</td>
</tr>
<tr>
<td>Coal OH</td>
<td>15,231</td>
<td>83%</td>
<td>2.77</td>
<td>10,495</td>
<td>29.10</td>
<td>5.70</td>
<td>34.80</td>
<td>31% / 58%</td>
</tr>
<tr>
<td>Coal PA</td>
<td>12,989</td>
<td>83%</td>
<td>2.63</td>
<td>10,495</td>
<td>27.59</td>
<td>4.33</td>
<td>31.93</td>
<td>31% / 58%</td>
</tr>
<tr>
<td>Coal VA</td>
<td>4,029</td>
<td>83%</td>
<td>3.52</td>
<td>10,495</td>
<td>36.92</td>
<td>8.25</td>
<td>45.17</td>
<td>31% / 58%</td>
</tr>
<tr>
<td>Coal WV</td>
<td>12,908</td>
<td>83%</td>
<td>2.92</td>
<td>10,495</td>
<td>30.67</td>
<td>3.01</td>
<td>33.68</td>
<td>31% / 58%</td>
</tr>
<tr>
<td>CCGT DE</td>
<td>2,465</td>
<td>85%</td>
<td>3.23</td>
<td>7878</td>
<td>25.45</td>
<td>1.77</td>
<td>27.22</td>
<td>82% / 75%</td>
</tr>
<tr>
<td>CCGT KY</td>
<td>5,617</td>
<td>85%</td>
<td>3.23</td>
<td>7878</td>
<td>25.4</td>
<td>1.19</td>
<td>26.63</td>
<td>82% / 75%</td>
</tr>
<tr>
<td>CCGT MD</td>
<td>2,900</td>
<td>85%</td>
<td>4.06</td>
<td>7878</td>
<td>31.98</td>
<td>1.87</td>
<td>33.86</td>
<td>82% / 75%</td>
</tr>
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<td>10,758</td>
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<td>2.96</td>
<td>7878</td>
<td>23.32</td>
<td>4.05</td>
<td>27.37</td>
<td>82% / 75%</td>
</tr>
<tr>
<td>CCGT OH</td>
<td>9,513</td>
<td>85%</td>
<td>2.42</td>
<td>7878</td>
<td>19.06</td>
<td>2.73</td>
<td>21.80</td>
<td>82% / 75%</td>
</tr>
<tr>
<td>CCGT PA</td>
<td>11,516</td>
<td>85%</td>
<td>2.52</td>
<td>7878</td>
<td>19.85</td>
<td>2.17</td>
<td>22.02</td>
<td>82% / 75%</td>
</tr>
<tr>
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<td>85%</td>
<td>3.55</td>
<td>7878</td>
<td>27.97</td>
<td>1.67</td>
<td>29.64</td>
<td>82% / 75%</td>
</tr>
<tr>
<td>CCGT WV</td>
<td>1,071</td>
<td>85%</td>
<td>3.23</td>
<td>7878</td>
<td>25.45</td>
<td>4.19</td>
<td>29.64</td>
<td>82% / 75%</td>
</tr>
<tr>
<td>CCGT new</td>
<td>0</td>
<td>87%</td>
<td>3.23</td>
<td>6600</td>
<td>21.3</td>
<td>2.75</td>
<td>24.1</td>
<td>82% / 75%</td>
</tr>
<tr>
<td>GT</td>
<td>14,001</td>
<td>100%</td>
<td>6.74</td>
<td>10,987</td>
<td>74.1</td>
<td>15</td>
<td>89.1</td>
<td>82% / 75%</td>
</tr>
<tr>
<td>Hydro</td>
<td>3,502</td>
<td>33%</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>5% / 5%</td>
</tr>
<tr>
<td>Wind</td>
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<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0% / 0%</td>
</tr>
<tr>
<td>Total</td>
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<td></td>
<td></td>
<td></td>
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</table>
Table B.4: Cost and technical assumptions for generators in the Mid-Atlantic region in 2008.

<table>
<thead>
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<th>Resource</th>
<th>Capacity (MW)</th>
<th>Availability (%/hr)</th>
<th>Fuel price ($/MMBtu)</th>
<th>Heat rate (Btu/kWh)</th>
<th>Fuel cost ($/MWh)</th>
<th>Var. O&amp;M ($/MWh)</th>
<th>Supply bid ($/MWh)</th>
<th>Ramp. up/down (%/hr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nuclear</td>
<td>21,708</td>
<td>91%</td>
<td>0.51</td>
<td>10,378</td>
<td>5.29</td>
<td>0.56</td>
<td>0</td>
<td>0% / 0%</td>
</tr>
<tr>
<td>Coal DE</td>
<td>780</td>
<td>84%</td>
<td>4.46</td>
<td>10,378</td>
<td>46.31</td>
<td>3.96</td>
<td>50.28</td>
<td>31% / 58%</td>
</tr>
<tr>
<td>Coal KY</td>
<td>14,302</td>
<td>84%</td>
<td>2.48</td>
<td>10,378</td>
<td>25.74</td>
<td>2.95</td>
<td>28.70</td>
<td>31% / 58%</td>
</tr>
<tr>
<td>Coal MD</td>
<td>4,704</td>
<td>84%</td>
<td>4.63</td>
<td>10,378</td>
<td>48.08</td>
<td>3.66</td>
<td>51.74</td>
<td>31% / 58%</td>
</tr>
<tr>
<td>Coal NJ</td>
<td>1,573</td>
<td>84%</td>
<td>4.04</td>
<td>10,378</td>
<td>41.96</td>
<td>4.59</td>
<td>46.56</td>
<td>31% / 58%</td>
</tr>
<tr>
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<td>21,742</td>
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<td>2.36</td>
<td>10,378</td>
<td>24.49</td>
<td>4.92</td>
<td>29.41</td>
<td>31% / 58%</td>
</tr>
<tr>
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<td>84%</td>
<td>2.33</td>
<td>10,378</td>
<td>24.22</td>
<td>3.55</td>
<td>27.77</td>
<td>31% / 58%</td>
</tr>
<tr>
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<td>3.41</td>
<td>10,378</td>
<td>35.41</td>
<td>6.41</td>
<td>41.82</td>
<td>31% / 58%</td>
</tr>
<tr>
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<td>2.64</td>
<td>10,378</td>
<td>27.38</td>
<td>2.75</td>
<td>30.13</td>
<td>31% / 58%</td>
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<tr>
<td>CCGT DE</td>
<td>1,313</td>
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<td>9.02</td>
<td>8305</td>
<td>74.91</td>
<td>3.31</td>
<td>78.22</td>
<td>82% / 75%</td>
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<td>9.02</td>
<td>8305</td>
<td>74.91</td>
<td>3.19</td>
<td>78.10</td>
<td>82% / 75%</td>
</tr>
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<td>11.06</td>
<td>8305</td>
<td>92.68</td>
<td>2.05</td>
<td>94.73</td>
<td>82% / 75%</td>
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<td>10.78</td>
<td>8305</td>
<td>89.53</td>
<td>4.44</td>
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<td>82% / 75%</td>
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<td>89.61</td>
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<td>82% / 75%</td>
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<td>86.87</td>
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<td>89.11</td>
<td>82% / 75%</td>
</tr>
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<td>10.87</td>
<td>8305</td>
<td>90.28</td>
<td>2.76</td>
<td>93.04</td>
<td>82% / 75%</td>
</tr>
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<td>10.08</td>
<td>8305</td>
<td>83.71</td>
<td>7.03</td>
<td>90.74</td>
<td>82% / 75%</td>
</tr>
<tr>
<td>GT</td>
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<td>100%</td>
<td>10.87</td>
<td>11015</td>
<td>119.73</td>
<td>19.39</td>
<td>139.12</td>
<td>82% / 75%</td>
</tr>
<tr>
<td>Hydro</td>
<td>3,107</td>
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<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>5% / 5%</td>
</tr>
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<td>Wind</td>
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<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
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</tr>
<tr>
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</table>
Appendix C

Exchange rate and consumer price index

The following tables display the exchange rates used for currency conversion, and the consumer price index used to calculate inflation (time value of money). The data comes from the OECD [3] [2].

Table C.1: Exchange rates used for currency conversion [4].

<table>
<thead>
<tr>
<th>Year</th>
<th>US dollar ($ or USD)</th>
<th>Japan Yen (JPY)</th>
<th>Euro (EUR)</th>
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<td>2000</td>
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<td>107.765498</td>
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</tr>
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<td>2001</td>
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<td>121.528948</td>
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</tr>
<tr>
<td>2002</td>
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</tr>
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</tr>
<tr>
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</tr>
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<td>2005</td>
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<td>110.218212</td>
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</tr>
<tr>
<td>2006</td>
<td>1</td>
<td>116.299312</td>
<td>0.797141</td>
</tr>
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Table C.2: Consumer prices used for computing the time value of money [2].

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