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Generation Capacity Expansion Under Long-term Uncertainties in the US Electric Market

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Generation capacity expansion under long-term uncertainties in the US electric market

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Abstract

In this paper, we deal with generation capacity expansion under long-term uncertainties regarding fuel prices and CO_2 emissions regulation. We present a model based on stochastic dynamic programming which gives optimal generation investment planning for perfectly competitive power markets. It is applied to the US continuous electricity market with DOE's fuel price scenarios. We show that taking into account uncertainties on fuel costs and on CO_2 emissions regulation can change the optimal investment decisions. Moreover, we show that, for generators, the level of risk-aversion is a major factor influencing the investment decisions.

1 Introduction

The recent high volatility in fuel markets, combined with environmental regulation policies, has introduced major uncertainties into the planning of generation capacity expansion. These uncertainties make generators' decisions to invest in new capacities more difficult. The literature has focused mainly on long-term demand uncertainties, but little has been done regarding fuel price and environmental policy uncertainties. This article discusses the optimal generation investment choices made in an electricity market with fuel price and regulatory uncertainties over the period 2010-2030. It focuses particularly on long-term uncertainties surrounding coal and gas prices, and on CO_2 emissions reduction policy. We have developed an optimization model for electric generation investments based on stochastic dynamic programming to tackle this issue.
To illustrate our discussion, we consider the case of the US long-term electricity market seen as perfectly competitive. The electricity market data and the fuel price scenarios are taken from the Annual Energy Outlook 2008 of the US Department of Energy (DOE).

The paper is organized as follows: in the next section, is summarized the related literature. Then, in section 3 is presented the generation investment model. Section 4 describes the general data and assumptions made regarding the long-term US electricity market and section 5 presents the results obtained for this market. Finally, section 6 concludes.

2 Related literature

As far as electric generation capacity expansion is concerned, many articles in recent years have dealt with the deregulation of the electricity market in comparison with the former public monopoly (Murphy and Smeers [1] for example). But application of real option theory to

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electricity markets gave rise to a large literature on the impact of long-term uncertainties on generation investment decisions. Most of these papers consider a perfectly competitive market where investors are price-takers and face an uncertain future. For example, Deng et al. [2] value an investment in thermal power plant in a market where electricity and gas prices are seen as stochastic future contracts (geometric Brownian motion or mean-reverting process). However, the price-taker assumption is questionable in electricity markets because generation investments will modify electricity prices in the long-term since costs and technological mix are changed.

In order to take into account the effect of new generation investments on electricity market price, some papers consider models where electricity prices are endogenous. Pineau and Murto [3] developed a dynamic stochastic oligopoly model applied to the Finnish electricity market. An uncertain demand is introduced and is modeled as a markovian event tree. Although based on an open loop information structure, the model helps to understand dynamics of production, investment and market power in a medium time horizon. One of their results shows that the uncertain demand can lead players to delay their investments in order to gain some information on the future demand. Botterud et al. [4] use a similar representation of an uncertain demand in their capacity expansion model. They focus mainly on the impact of the market design (energy-only market, capacity payments) on the generation investment decisions both on a centralized and a decentralized electricity market (represented with a single profit-maximization player). Then a large part of this literature considers only uncertainty on the demand (the main challenge is to guarantee load supply). But little has been done regarding the impact of uncertainties on fuel prices and on CO_2 regulation on generation capacity expansion.

3 The generation investment model

Assuming that the long-term electricity market is perfectly competitive, the model determines the optimal investment decisions in order to maximize the social welfare over a time period. A backwards stochastic dynamic programming (SDP) algorithm is used to solve the investment problem. The model uses an annual time step. At each time step, a set of new investments can be decided which takes place at the beginning of each time step. No construction delay is modeled here. Two types of technologies are considered:

- *the initial technologies*: they can be decommissioned over the period. No new investment in these technologies will be made
- *the new technologies*: generators can invest in a set of new technologies. The quantity a generator can invest in is not a continuous variable but a discrete capacity step. Once some generators have decided to invest in a new technology, it will not be decommissioned over the period

From Soyster and Murphy [5], we know that a capacity expansion model designed for an efficient public monopoly converts directly into one applicable to a perfectly competitive market. Then, the overall problem is stated as the following optimization problem:

$$\min_{(i_t)_{t\in T}} \mathbb{E}_S \sum_{t=1}^{T-1} \left[g_t(l_t, i_t, x_t)(1+r)^{-t} + g_T(l_T, i_T, x_T)(1+r)^{-T} \right]$$
$$\text{s.t} \quad x_{t+1} = x_t + i_t - d_t$$

where:
T planning horizon (years)
t time step (year)
S the set of long-term scenarios
i_t vector of invested capacities (MW) - *command variable*
d_t vector of decommissioned capacities (MW)
x_t vector of existing capacities (MW) - *state variable*
l_t load duration curve (MW, hourly block)
r risk-adjusted real discount rate
g_t objective function-total cost function ($)
g_T terminal cost function($), year T

The total cost function at time t is $g_t(l_t, i_t, x_t) = C_t^{Gen}(l_t, x_t) + C_t^{O\&M}(x_t) + C_t^{Inv}(i_t)$ where:

- $C_t^{Gen}(l_t, x_t)$ is *the generation cost.* For each technology, we can convert the fuel price associated and the CO_2 price into a generation variable cost ($/MWhr). Then, the model computes a merit order stack on the generation variable cost in order to minimize generation costs. If the demand load is curtailed, then the electricity market must pay the value of lost load (VOLL) proportionally to the curtailed energy

- $C_t^{O\&M}(x_t)$ is *the Operation and Maintenance costs.* For each technology O&M costs are defined. They correspond to fixed yearly costs ($/MW.year). The model calculates the total O&M costs for the electric system

- $C_t^{Inv}(i_t)$ is *the investment cost.* We associate to each new technology a fixed investment cost ($/kW) and a lifetime (years). Then, the model calculates constant annuities for new investments

Generally, SDP assumes the terminal values being the final values of the objective function associated to the state variables. Addressing terminal values can be intricate since they correspond to the end of the period whereas there is no information on the future. In our modeling, we have not such a problem since the investment cost is annualized. Then, the terminal cost function $g_T(l_T, i_T, x_T)$ can therefore simply be set equal to the cost function in the last period.

We consider a possible uncertain future on fuel prices, CO_2 taxation and demand growth. These uncertainties are modeled as a discrete markovian event tree denoted S. At each time step, the system can be in different states and transitions from one state to another occur with given probabilities (see Figure 1).

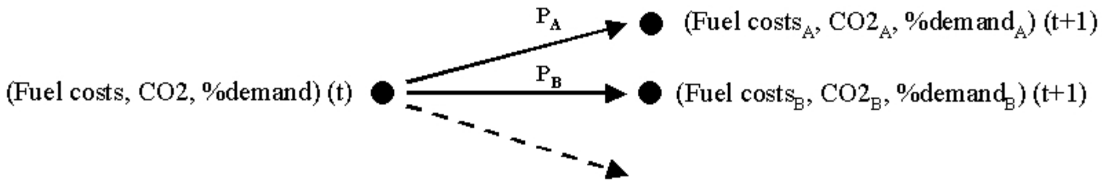

Figure 1: Event tree detail

Finally, the backward problem is solved using the Bellman algorithm. It consists in calculating backwardly the investment decisions that minimize the objective function (here the total cost function). For each node n of the event tree, for each possible vector of the state variable (here the existing capacities) x_t, the algorithm calculates a Bellman value $Vb_n(x_t)$ which corresponds to the minimum of the expected future objective function at node n:

$$Vb_n(x_t) = \min^{n}_{(i_t)_{t\in T}} \left(g_t(l_t, i_t, x_t)(1+r)^{-t} + \sum_{n'\in F(n)} proba_{n'/n} Vb_{n'}(x_t + i_t) \right)$$

where n' is a node son of n, $F(n)$ is the set of all the nodes son of n and $proba_{n'/n}$ is the probability to switch from node n to node n'.

4 Case study from the US electricity market

4.1 The general problem

We analyse potential investments in new generation capacities on the US electricity market over the period 2010-2030. Investments are decided every five years and plants start producing immediately. We make strong assumptions on decommissioned capacities since we are more interested in determining the long-term optimal generation fleet rather than forecasting the future real investments. The US electricity market is seen as a perfectly competitive market. We use the three fuel price scenarios from the Annual Energy Outlook 2008 [6] : the Reference, the High price and the Low price cases. First, we describe the optimal investment decisions if the Reference case occurs. The impact of different CO_2 prices on the generation mix will be studied. Then, we combine the three scenarios in an event tree centered around the Reference Price scenario with constant probabilities to switch definitely to the Low or to the High price scenarios. Assuming generators are risk-neutral, we test the robustness of the Reference case investment decisions to these uncertainties. Finally, we assume that generators are no longer risk-neutral but are risk-averse. We compare the investment decisions with the previous risk-neutral case.

4.2 General data on the US electricity market

The following data are taken from the Annual Energy Outlook 2008 [6] and from the FERC [7]. The generators can invest either in new coal plants, in new combined-cycle gas power plants (CCGTs) or in new oil peak plants. Investments in new nuclear plants will be analysed in a specific section. Table 1 presents the technical specifications of the new power plants.

	Coal plant	CCGT	Nuclear plant	Peak unit
Heat rate $BTU/kWhr$	9200	7196	10400	10833
Investment cost $\$/kW$	1534	717	2475	500
Fixed O&M $\$/kW.year$	26.8	12.1	66.1	11.8
Variable O&M $\$/MWhr$	4.5	2	0.5	3.5
CO_2 emissions $ton/MWhr$	0.74	0.35	0	0.83
Lifetime $years$	35	25	40	25
Size MW	600	250	1350	160

Table 1: Technical specifications

The initial generation fleet capacity in 2005 equals 905 GW. Details on the initial capacities are given in Table 2.

Coal plants	305 GW
Gas plants/CCGTs	258 GW
Peak units	127 GW
Nuclear plants	100 GW
Renewable energies	15 GW
Pumped storage	22 GW
Conventional Hydro power	77 GW
Total	**905 GW**

Table 2: 2005 US generation fleet

We make the following assumption regarding the power plant decommissionings: 20% of all initial technologies are phased-out every five years (except for renewable energies and hydro-units which are not phased-out or replaced identically). In order to consider only economic trade-offs between the technologies, we set the load factor to 90% for all the thermal technologies and to 25% for the renewable energies.

The fuel price scenarios for coal (Average delivered price), gas (Henry Hub price) and oil (Distillate fuel oil) are presented in Figure 4 (at the end of the paper). These scenarios are taken from the Annual Energy Outlook 2008 [6]. Then, using the technical specifications of the technologies, these fuel prices are converted into variable generation costs for each technology. In addition to fuel variables, we add a CO_2 emission price. Like on the EU CO_2 market, it represents the emission cost for producing 1 MWhr of electricity.
We combine these three scenarios as an event tree centered around the Reference scenario with constant probabilities P_{Low} and P_{High} to switch definitively to the Low or High price scenarios. The switch can occur every five years. This event tree is presented in Figure 2.

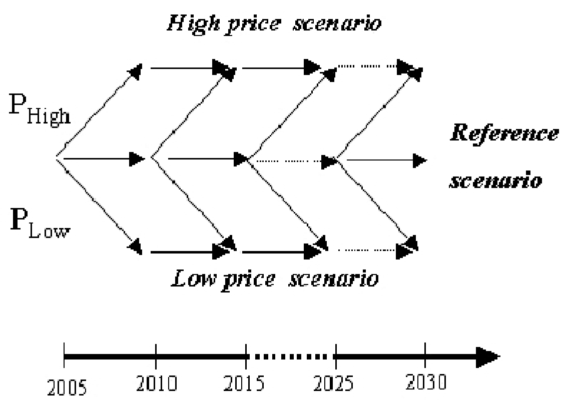

Figure 2: Event tree from the AEO 2008 scenarios

We assume that the US electric grid is perfectly interconnected. The US continuous load duration curve was made using FERC data [7] by aggregating the regional electric grids load duration curves in 2005 (Figure 3). We assume that the electricity demand growth will be supplied by investments in renewable energies, so we do not consider any demand growth over the period.

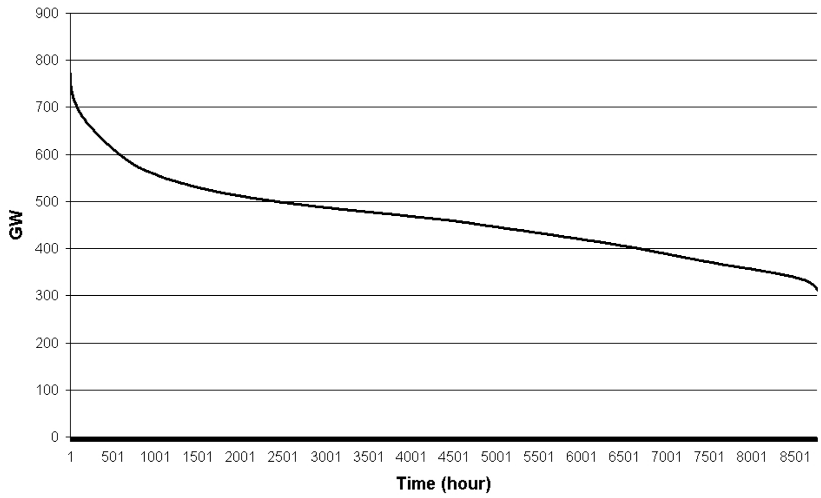

Figure 3: 2005 Continuous US Load duration curve

Finally, we choose a discount rate equal to 8% and we set the VOLL to 20 000 \$/MWh.

5 Results

5.1 Result 1: Optimal investment planning for the Reference scenario - no nuclear technology

In the Reference scenario, with no CO_2 price, we observe that the optimal investment decision is a mix between coal units, CCGTs and peak units. Finally, a total of 750 GW are installed over the period, mainly in coal units (510 MW). The coal plants are the most competitive to supply base load while CCGTs are more efficient to supply semi-base load. Finally, 80 GW are installed to supply peak-load.

GW	2010	2015	2020	2025	2030
Coal units	0	30	160	160	160
CCGTs	40	120	0	0	0
Peak units	80	0	0	0	0

Table 3: Reference scenario investment decisions - no nuclear and CO_2 price=0 \$/ton

Then, we test the sensitivity of investment decisions to different CO_2 prices (each price is supposed constant over the period). For a CO_2 price inferior to 40 \$/ton, the technology mix is still made of coal units to supply base-load and of CCGTs to supply semi-base load. Above 40 \$/ton, CCGT becomes the most competitive technology both for base and semi-base load.

In the following (results 2 and 3), we will use a CO_2 price equal to 30 \$/ton. Therefore, we present in table 5 the optimal investment planning for further comparisons.

GW	CO_2 price ($/ton)				
	10	20	30	40	50
Coal units	480	450	400	160	0
CCGTs	190	220	270	510	670

Table 4: Sensitivity to CO_2 price

GW	2010	2015	2020	2025	2030
Coal units	0	0	80	160	160
CCGTs	40	150	80	0	0
Peak units	80	0	0	0	0

Table 5: Reference scenario investment decisions - no nuclear and CO_2 price=30 $/ton

5.2 Result 2a: Impact of fuel price uncertainties on the investment decisions - no nuclear technology

We set CO_2 price to 30 $/ton over the period. Uncertainties are modeled as the event tree presented in Figure 2. We consider successively the possibility to switch to the Low and to the High scenario with different probabilities P_{Low} and P_{High} (if $P_{Low} > 0$ then $P_{High} = 0$ and inversely). We focus on the investment decisions if the Reference scenario occurs.

GW	Low	P_{Low}				Reference	P_{High}				High
		40%	30%	20%	10%	(CO_2 30$/ton)	10%	20%	30%	40%	
Coal units	0	160	320	370	380	**400**	410	440	450	450	480
CCGTs	670	510	350	300	290	**270**	260	230	220	220	190

Table 6: Impact of fuel price uncertainties - no nuclear technology

The results show that the optimal investment mixes in the Reference and High price scenarios are fairly similar (coal units predominant). However, if the Reference scenario occurs, we observe that the higher P_{High} is, the higher the investments in coal units are. A high probability to switch to the High scenario leads generators to increase their investments in coal units in order to hedge against the risk of high gas prices. But, since the overall fractions in the different technologies are not changed, we can conclude that the investment decisions obtained in the Reference scenario are robust to uncertainty to switch to the High price scenario.

Conversely, we cannot conclude on the robustness of the investment decisions for the Reference scenario as far as uncertainties to switch to the Low scenario are concerned. Indeed, the decisions if the Low scenario occurs lead to invest only in CCGTs. Then, for high probability to switch to the Low scenario, we show that CCGTs become predominant (especially if P_{Low} is greater than 30%).

Moreover, investments in peak units are constant for all the cases and are equal to 80 GW over the period.

5.3 Result 2b: Impact of fuel price uncertainties on the investment decisions - with nuclear technology

We consider the possibility for the generators to invest in nuclear plants in addition to CCGTs, coal and peak units. We test if the investment decisions for the Reference scenario are identically modified by fuel price uncertainties as previously in Results 2a.

GW	Low	P_{Low}				Reference	P_{High}				High
		40%	30%	20%	10%	(CO_2 30$/ton)	10%	20%	30%	40%	
Coal units	0	0	0	0	0	**0**	0	0	0	0	0
CCGTs	200	200	170	170	170	**170**	170	170	170	170	170
Nuclear units	470	470	500	500	500	**500**	500	500	500	500	500

Table 7: Impact of fuel price uncertainties - with nuclear technology

We show that, whatever scenario we consider, generators no longer invest in coal units but in nuclear units in order to supply base-load demand. CCGTs are the most competitive to serve semi-base load. As previously, peak unit investments are constant and equal to 80 GW.
The most striking point is that, if nuclear investments are allowed, the investment decisions in the Reference scenario are robust to the risk to switch to another scenario. Therefore, we can conclude that considering possible nuclear investments make the decisions not impacted by uncertainties regarding fuel prices.

5.4 Result 3: Impact of risk-aversion on the investment decisions - no nuclear technology

Previously, generators took their investment decisions considering that each scenario had a probability to occur and solved the problem using mathematical expectation. In this section, we assume that the generators are risk-averse: they take their investment decisions in order to minimize the maximum cost over the period. This criterion is known as the 'MinMax Regret' criterion. Then, the optimization program the generators have to solve turns into :

$$\min_{(i_t)_{t\in T}} \left(\max_S \sum_{t=1}^{T-1} g_t(l_t, i_t, x_t)(1+r)^{-t} + g_T(l_T, i_T, x_T)(1+r)^{-T} \right)$$

$$\text{s.t} \quad x_{t+1} = x_t + i_t - d_t$$

The objective of this section is to see what is the worst fuel and CO_2 price trajectory that risk-averse generators will focus on in their decisions in the uncertain future modeled as previously (Figure 2). Then, if we focus on the Reference scenario, generators will take their investment decisions considering the possibility to switch either to the high price or to the low price scenario.

We show that the investments are similar to the ones made in the deterministic High price scenario. The worst case for generators corresponds to the scenario with relative high gas prices. Then, their best strategy in order to minimize the maximum total generation cost is to focus only on the High price scenario.

GW	2010	2015	2020	2025	2030
Coal units	0	0	160	160	160
CCGTs	40	150	0	0	0
Peak units	80	0	0	0	0

Table 8: investment decisions for risk-averse generators - CO_2 price = 30 $/ton

6 Conclusions

We show that generation capacity expansion planning in the continuous US is sensitive to uncertainties regarding fuel and CO_2 costs as far as nuclear unit investments are not considered. Indeed, if only fossil thermal units are allowed, the DOE Reference scenario is not robust to these uncertainties. Conversely, allowing nuclear investments make the generation investment decisions robust. Finally, we show that generators react differently to uncertainties on fuel and CO_2 costs depending on risk-aversion.

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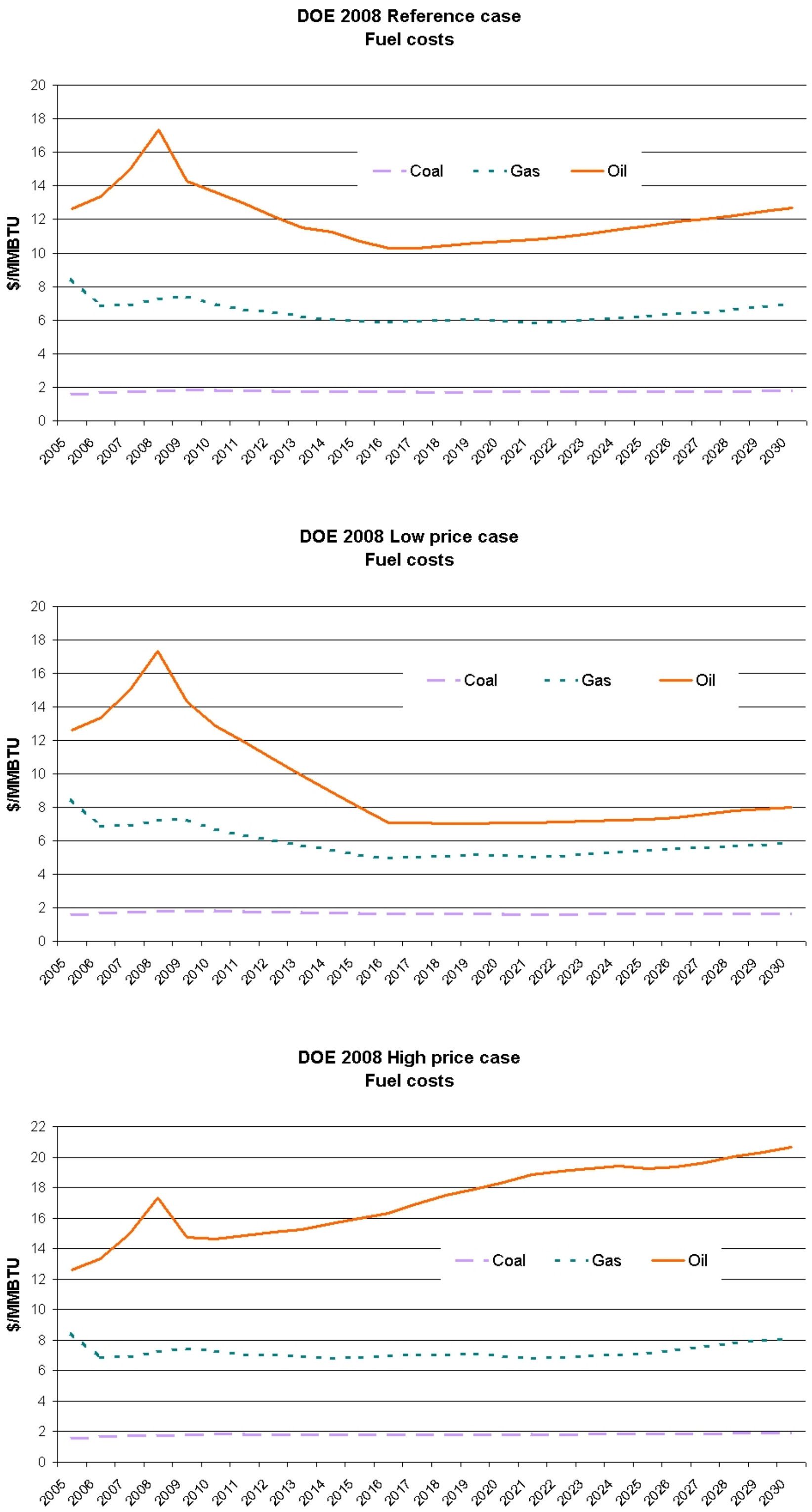

Figure 4: Annual Energy Outlook 2008's fuel price scenarios

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