2

Publication 2

Reprinted from *Energy Policy*, Articles In Press, Laurikka, H., Koljonen, T., Emissions trading and investment decisions in the power sector – a case study in Finland, 12 p., Copyright (2005) with permission from Elsevier

ARTICLE IN PRESS

ELSEVIER

Energy Policy ▮ (▮▮▮▮) ▮▮▮–▮▮▮

ENERGY POLICY

www.elsevier.com/locate/enpol

Emissions trading and investment decisions in the power sector—a case study in Finland

Harri Laurikka[a,*], Tiina Koljonen[b]

[a]Laboratory for Energy Economics and Power Plant Engineering, Helsinki University of Technology, P.O. Box 4100, 02015 TKK Espoo, Finland
[b]VTT Processes, Energy Economics, P.O. Box 1606, 02044 VTT, Finland

Abstract

Organizations, which consider investment in or divestment of power production licences/capacity within the European Community, are exposed to the impacts of the European Union Emission allowance Trading Scheme (EU ETS). In this paper, the consequences of the EU ETS on investment decisions are explored in a country-specific setting in Finland. First, we review the general mechanisms through which the EU ETS influences size, timing and cashflows of an investment. Next, we discuss the projected changes in Finnish power producers' investment environment and examine the financial impacts due to the EU ETS on a case investment decision, a hypothetical condensing power plant (250 MW_e). The standard discounted cash flow (DCF) analysis is extended to take into account the value of two real options: the option to wait and the option to alter operating scale. In a quantitative investment appraisal, the impact of emissions trading not only depends on the expected level of allowance prices, but also on their volatility and correlation with electricity and fuel prices. The case study shows that the uncertainty regarding the allocation of emission allowances is critical in a quantitative investment appraisal of fossil fuel-fired power plants.

Keywords: Emissions trading; Investment; Power generation

1. Introduction

On 13 October 2003, the Directive 2003/87/EC of the European Parliament and of the Council establishing a carbon dioxide (CO_2) emission allowance trading scheme (EU ETS) within the Community entered into force. The directive creates a framework for emissions trading and gives guidance on the details of the trading scheme, such as the allocation method and penalties, until 2012.

The European Union is expected to need some 650 GW of new power capacity and to replace some 330 GW of existing power stations over the next 30 years (IEA, 2003a). The economic lifetime of an investment in power capacity typically ranges from 20–40 years (OECD NEA/IEA, 1998). Within the EU ETS, the value of emission allowances can affect the cashflows of a power plant during its entire lifetime. In particular, there is a considerable and fundamental price risk ("what is the value of an allowance? will trading continue?") (see e.g. Springer and Varilek, 2004). The character of the price risk is somewhat different from that of fuels or electricity, which can be considered "genuine necessities" and are already traded in large volumes. IEA (2003b, p. 31) characterizes the price risk as "potentially critical". Any investor within the Community considering investment or divestment of power production licences or capacity, be it a green-field plant, a retrofit of an existing plant or an acquisition, should therefore be interested in the impacts of the allowance trading scheme.

Implications of the EU ETS for investment decisions in the power sector have been discussed on a European

*Corresponding author. Tel.: +358 40 7620 979; fax: +358 9 451 3674.
E-mail addresses: harri.laurikka@hut.fi (H. Laurikka), tiina.koljonen@vtt.fi (T. Koljonen).

0301-4215/$ - see front matter
doi:10.1016/j.enpol.2004.09.004

scale e.g. by Reinaud (2003) and de Leyva and Lekander (2003). In this paper, the impacts of the EU ETS on investment decisions are explored in a more detailed regional setting in Finland. We consider a single-firm optimization problem using an exogenous, stochastic price model,[1] and back the modelling results with an analysis of the investment environment. Section 2 provides a brief review on the general mechanisms through which emissions trading affects size, timing and cashflows of an investment decision. Section 3 explores the projected changes in the Finnish power producers' investment environment. Section 4 examines the financial impacts due to the EU ETS on a case investment decision, a hypothetical 250 MW_e condensing power plant. We extend the broadly used discounted cash flow (DCF) analysis to better reflect the value of two real options:[2] the option to wait and the option to alter operating scale. Finally, some conclusions are drawn.

2. Emissions trading in power investment decisions

Size and timing of the initial investment together with the subsequent annual cashflows mainly determine the financial performance of a power investment. Flexibility in timing gives the investor a valuable *option to wait* for new information. The standard models of irreversible investment under uncertainty show that the value of this option increases with a higher degree of uncertainty in the operating environment (McDonald and Siegel, 1986). As the EU ETS introduces new price risks for capacity investments, it should thus contribute to this direction. On the other hand, it has been argued that emissions trading as such does not reduce a firm's incentive to invest in abatement capital, such as renewable technologies, relative to e.g. emission taxes, since the most important uncertainty factor—the abatement cost uncertainty—is there irrespective of the regulatory instrument (Zhao, 2003).

In addition to the option to wait, investors may also have an *option to stage the investment*: instead of committing to a "lump" project, the investor may implement several smaller projects sequentially. However, this typically results in higher unit costs. It has been argued that a higher uncertainty, e.g. due to emissions trading, may nevertheless cause the investor to prefer the smaller project(s) to the lump project (e.g. Dixit and Pindyck, 1994, pp. 51–54). Kort et al. (2004) have recently called this intuitively appealing result into question. They argue that a higher uncertainty makes the lump investment more attractive relative to the sequential investment.

The cumulative cashflow, CF, for a thermal power plant in any selected period can be calculated from:

$$CF = \int P(t)S(t)\,dt - C_f, \tag{1}$$

where $P(t)$ is the output capacity (in MW) of the plant at time t, $S(t)$ is the spark spread (in €/MWh) of the plant at time t, and C_f is the fixed cost. The spark spread comprises thus both variable revenues and costs per unit of output. It is a widely used variable for option-based power plant valuations (Deng et al., 2001; Deng and Oren, 2003; Hsu, 1998; Näsäkkälä and Fleten, 2004; Tseng and Barz, 2002).

If Eq. (1) is simplified so that the plant produces electricity only, when $S(t)$ is positive, and always with its maximum capacity P_{max}, we obtain

$$CF = P_{max} \int max\,[S(t), 0]\,dt - C_f. \tag{2}$$

Eq. (2) somewhat overestimates revenues due to the technical constraints omitted (Deng and Oren, 2003; Tseng and Barz, 2002).

Emissions trading is likely to impact CF through four mechanisms:

- emissions trading will have an impact on *existing cost categories*, such as fuel costs and thus affect the spark spread, $S(t)$. It has been estimated that producer price of coal and oil would decrease compared to a baseline scenario (Holtsmark, 2003; Holtsmark and Mæstad, 2002). Expectations on the impacts on gas producer prices in Europe due to the EU ETS are diverse: while e.g. Holtsmark (2003) projects a decrease in prices, e.g. de Leyva and Lekander (2003) and Reinaud (2003) expect an opposite market reaction. A detailed regional bottom-up analysis in Finland clearly shows that under a free allocation of allowances the demand on gas on the market will increase, which should thus result in a corresponding price increase (Electrowatt-Ekono, 2003). Similarly, the improved competitiveness of biomass is likely to increase its market price. In addition to fuel costs, it has also been identified that emissions trading can cause a pressure to modify the existing energy taxes (see Section 3.2.2).
- emissions trading introduces new costs hence reducing S and increasing C_f. The most important is likely to be the value of surrendered emission allowances. For example, the spark spread for a condensing power plant within the EU ETS can be presented as follows:

$$S = p_e - \frac{p_f}{\eta} - \frac{e_f}{\eta} p_{CO_2} - \psi, \tag{3}$$

where p_e is the market price of electricity, p_f is the market price of fuel, p_{CO_2} is the market price of emission allowances, η is the thermal efficiency of the plant, and e_f is the emission factor of the fuel.

[1]See Ventosa et al. (2004) for a taxonomy on electricity market models.

[2]For an overview on real options, see Trigeorgis (1995).

Constant parameter ψ consists, for example, of plant-specific operation and maintenance costs.
In addition to the surrendered emission allowances, emissions trading will introduce new transaction costs.

- emissions trading will increase the *market price of energy outputs* (*power and heat*) and thus affects the spark spread, S, positively. It has been projected that the EU ETS can raise wholesale power prices from 20% to 60% (de Leyva and Lekander, 2003; Reinaud, 2003). See Section 3 or Ilex Energy Consulting (2004) for examples on more detailed region-specific studies.
- emissions trading will provide *additional revenues* through the free emission allowances. Within the EU trading scheme, utilities obtain at least 95% of the allocated amount of emission allowances for the period 2005–2007 and at least 90% for the period 2008–2012 free of charge. The value of the free allowances obtained annually consists of the number of allowances (N) and their unit value (p_{CO_2}). Free emission allowances are, however, linked to a simultaneous *obligation* to surrender emission allowances during the same period. From (2) and (3) we therefore obtain for a condensing power plant:

$$CF = P_{max} \int max\left[\left(p_e - \frac{p_f}{\eta} - \frac{e_f}{\eta} p_{CO_2} - \psi\right), 0\right] dt + Np_{CO_2} - C_f. \quad (4)$$

The component Np_{CO_2} can be regarded as fixed but uncertain. Free allowances are obtained in the EU ETS regardless of whether the plant is used during the period or not. Instead, the fixed revenue for *subsequent* periods *may* change due to the selected operating strategy in the current period. The EU ETS does not, however contain provisions that this would *need to be* the case, since several methods may be applied in allowance allocation.

Many power generation technologies possess flexibility that can reduce the negative impacts of emissions trading on CF.[3] Firstly, emission free and less emission intensive technologies (i.e. with a low e_f/η) are *robust* to negative impacts of emissions trading. Secondly, all plants have a valuable *option to alter their operating scale*, if the market conditions get worse. The option is of significant value for technologies with high variable costs, such as condensing power. Thirdly, multi-fired power plants have another valuable *option to switch between fuels*, if their relative competitiveness changes. Finally, CHP extraction plants may have an *option to switch between products*, if they are connected with adequate heat only capacity.

[3] See Laurikka (2004) for a more detailed discussion.

3. Investment environment of power producers in Finland

3.1. Current investment environment

3.1.1. The Nordic electricity system

Denmark, Finland, Norway and Sweden form a common electricity market area with the Nord Pool power exchange. The Nord Pool has six spot price areas that take into account constraints in transmission capacity: Finland, Sweden, Southern Norway, Middle/Northern Norway, Western Denmark and Eastern Denmark. Together, the price areas create one system price.

A large share of hydropower characterizes the Nordic electricity system (Table 1). During dry periods the shortage of hydropower has been covered by production of condensing coal power, which is mostly produced in Finland and Denmark. This is directly reflected in CO_2 emission inventories of these countries. In Finland, the yearly average specific CO_2 emissions have varied from 182 g CO_2/kWh (year 2000) to 225 g CO_2/kWh (year 1996) during the period of 1996–2001. Condensing coal power tends to dominate the production margin of the power system most of the year in any hydrological year thus principally defining the price of electricity (Finergy, 2003). During rainy years, electricity has been exported from Norway and Sweden to Finland and Denmark, and the yearly operating hours of condensing power plants together with the spot price of electricity have been at a low level. The year 2002 (Table 1) was an average hydrological year and the year 2003 exceptionally dry (Table 2).

The available peak capacity is usually lower than the installed capacities because of reserve capacities, variation of hydrological conditions, variation of heat production in CHP plants, variation of wind power production, and in some cases also due to the bottlenecks of electricity transmission capacities.

Demand on electricity in the Nordic countries mainly depends on economic growth and the yearly average outdoor temperatures. Since 1990, the total electricity consumption in the Nordic countries has risen by an average of 1.2% annually (Swedish Energy Agency, 2003). In 2003, electricity demand in the Nord Pool area was 380 TWh (Nordel, 2004).

In Finland, the total consumption in 2003 was 84.7 TWh and the corresponding yearly growth of electricity demand in Finland was 1.4% (1.2 TWh) (Statistics Finland, 2004). The demand of electricity is projected to grow to 96 TWh by 2010 (Finergy, 2004). The additional demand would be mostly covered by the fifth nuclear reactor, which is planned to start operation in 2009. After 2010, the increasing demand and shutdowns of old generating capacity are expected to create a gap between demand and supply without investments in new generation capacity. New transmission capacity

Table 1
Electricity production in the Nord Pool area in 2003 (2002), TWh (Nordel, 2004)

Area	Hydro power	Nuclear power	Thermal power		Wind power etc.	Total
			Condensing	CHP		
Denmark	—	—	NA[a]	38.2 (32.3)[b]	5.6 (4.9)	43.8 (37.3)
Finland	9.3 (10.6)	21.8 (21.4)	20.0 (12.9)	28.7 (26.9)	0.1 (0.1)	79.9 (71.9)
Norway	106.0 (129.7)	—	0.6[c] (0.6)	0.4 (1.0)	0.2 (0.1)	107.1 (130.6)
Sweden	53.0 (66.0)	65.5 (65.6)	1.8[c] (1.0)	11.7 (10.1)	0.6 (0.6)	132.5 (143.4)
Nordpool area	168.3 (206.4)	87.3 (87.0)	22.3[c] (14.3)	101.2 (69.7)	6.5 (5.6)	363.3 (386.8)

[a]Not available.
[b]Condensing power included.
[c]Gas turbines included.

Table 2
Installed electricity production capacities in 1996 and on 31 December 2002, the maximum system load on 3 January 2003, and the maximum system loads in each country (Nordel, 2004; Finergy, 2003)

Area	Capacity 1996 (MW)	Capacity 2002 (MW)	Change (MW)	Maximum system load in 2003 (MWh/h)	Maximum load in 2003 (MWh/h)
Denmark	10937	12632	1695	6047	3788/2665[a]
Finland	14963	16866	1903	12325	14040
Norway	27631	27960	329	16130	19984
Sweden	34158	32223	−1935	22228	26400
Nordpool area	87689	89681	1992	57734	

[a]Denmark—West/Denmark—East.

is needed, if electricity imports are to be increased considerably. On the other hand, the deficiency of generating capacity holds also—especially during dry hydrological years—in the other Nordic countries, which would make imported electricity from this region uncompetitive.

3.1.2. The electricity markets

Since the market deregulation in 1996 the average electricity market prices have experienced a downward trend until 2001 as old generating capacities have been closed down. As about 55% of the electricity in the Nordic area was hydropower, the low price level also reflected good hydrological years.

Due to the low electricity prices, the largest generating capacity investments in Finland have been upgrades and modernizations of nuclear power plants and renovations of power plants at pulp and paper mills. At the same time the absolute consumption of electricity has been growing steadily. Therefore, substantial investments are needed to cover the increasing demand in the future.

Since the end of the year 2002, the water reservoirs have been at an exceptionally low level and, as a consequence, the monthly average market prices have risen by about 100% (Figs. 1 and 2). In 2003, the monthly average spot electricity prices were at the highest level since the market deregulation. It is, however, unlikely that the price would remain high during normal hydrological years without considerable increases in fuel prices or electricity demand, or new environmental constraints. The Nordic countries also have power grid interconnections to Russia and Central Europe. Therefore, the price level of electricity in Central Europe and Russia could also affect the Nordic spot prices in the future.

3.1.3. National energy and climate policy in Finland

The Kyoto target for Finland is to hold GHG emissions at the 1990 level. In 1990, the total GHG emissions in Finland were 76.8 Mt CO_2 eq. and in 2002 they were 5.2 Mt CO_2 above this level (MoE, 2004). In 2003, there was a drastic increase in CO_2 emissions (ca. 5 Mt) mainly due to increased electricity exports and the resulting additional coal use in condensing power plants (Statistics Finland, 2004).

The Kyoto target is projected hard to achieve. According to the new emission scenario, with measures (WM), and the strategic emission path of the government, the total reduction need will be on the average 7.6 Mt CO_2 eq per year during the Kyoto Period (MTI, 2004a). In the WM scenario, the measures already decided and the measures in the preparation phase (such as the 1600 MW_e nuclear reactor) are taken into account. The planned start-up of the new nuclear

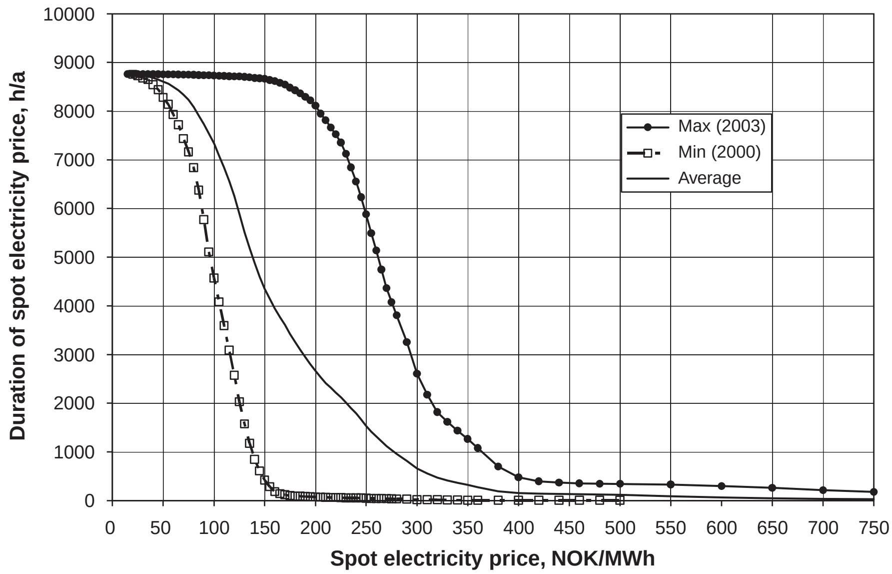

Fig. 1. Duration curves of the Nord Pool spot electricity prices (Nord Pool, 2004). The average duration curve corresponds to the period of 1996–2003. The highest market prices of electricity were recorded in 2003 and the lowest in 2000.

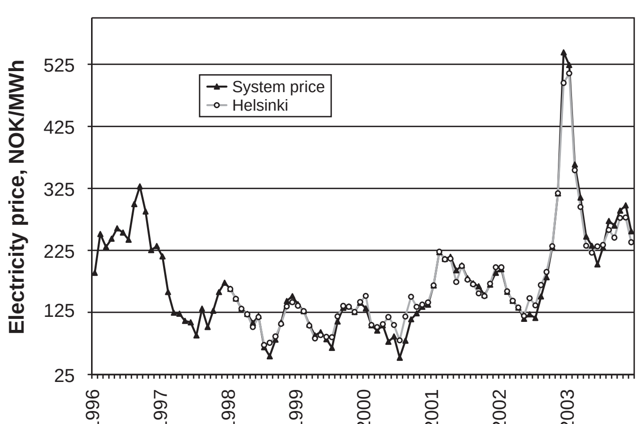

Fig. 2. The Nord Pool monthly average spot market (system) price and regional prices in Helsinki (Nord Pool, 2004).

reactor is in 2009. Energy efficiency in energy production and industrial processes and the share of renewable energy sources in electricity production (25% in 2002) are already high (VTT, 1997).

Excise taxes are levied on electricity, fossil fuels, peat and tall oil. From the beginning of 2004 all these, expect peat, are included in the harmonized EU energy taxation. Biomass-based fuels are excluded from both national and EU harmonized energy taxation systems. The existing system already follows the EU harmonized taxation and the current tax levels are higher than the minimum levels in the EU directive.

The excise taxes for electricity are levied only on electricity consumption, which means that the production technology or fuel do not affect the amount of the tax. In CHP production, excise tax is only for heat production. Subsidy for electricity generation is 6.9 €/MWh$_e$ for wind power and cutting residues, 4.2 €/MWh$_e$ for by-product wood, biogas, with a rated power under 1 mega voltage ampere (MVA) hydropower, under 40 MVA peat-fired boiler plants and waste heat from chemical and metallurgical processes, as well as 2.5 €/kWh$_e$ for recycled fuel. Part of the excise taxes for energy intensive industrial companies is returned.

3.2. Changes in the investment environment due to emissions trading

3.2.1. Changes in costs and prices

Emissions trading will change the competitiveness of fuels and electricity market prices as discussed in Section 2. It has been estimated that the Nordic spot market price would be in the order of 4–16 €/MWh higher when the allowance price level is 5–20 €/t CO_2, respectively (Electrowatt-Ekono, 2003; VTT, 2004). However, the error margin of these calculations is quite wide, e.g. due to the assumptions of new electricity generating capacities and electricity demand. Both studies assumed also moderate fuel prices compared to the 2003 market price level in Finland, especially for natural gas. Uncertainty regarding in particular the market prices of natural gas (see Section 2) and biomass can be considered high.

3.2.2. National allocation plan and taxation

The EU ETS will cover approximately 55% of the average CO_2 emissions in Finland, which is one of the highest percentages among the EU countries. As described in Section 3.1.1, the yearly variation of CO_2 emissions may be large due to climatic conditions.

According to the National Allocation Plan (MTI, 2004a), the total amount of free emission allowances in 2005–2007 will be 136.5 Mt of which 2.5 Mt is reserved for new installations. The total amount is 2.3% less than the projected emissions. The National Allocation Plan for the first trading period 2005–2007 gives no guidance to the allocation during the Kyoto period or beyond. The allocation criteria for 2008–2012 will be finalized during 2005.

Finland has decided to use the opt-in for boilers with a capacity of less than 20 $MW_{th,}$ if they are connected to a district heating network with boilers greater than 20 MW_{th}. Without the opt-in, CHP producers would have had the possibility to produce heat with small boilers, and increase their annual CO_2 emissions without utilizing their free CO_2 allowances.

The Ministry of Trade and Industry has reported that only minor changes to the current energy taxation may be expected during the first EU ETS period (MTI, 2004a). A recent working group report suggested a reduction in the excise tax of peat and removal of electricity subsidy from by-product wood and waste heat from chemical and metallurgical processes (MTI, 2004b).

3.2.3. Investment alternatives for electricity generation

Partial equilibrium energy system models have been used to explore the investment alternatives at macro level with a presence of an emissions trading system (VTT, 2003, 2004). Recently, the new generation energy system model TIMES has been taken into regular use for scenario calculations in Finland. The model seeks for the solution that offers the least cost to fulfil demand requirements and other constraints such as given emission limits. The model includes emissions of all Kyoto Protocol greenhouse gases and the whole Finnish energy production and the consumption system. Both investment and operating costs are included. The TIMES model also includes price elasticities of demand.

The scenario calculations (VTT, 2004) that take into account the national allocation plan for 2005–2007 and Kyoto commitment for 2008–2012 indicated that at the low allowance price level, the new capacity alternatives for Finland would be wind power and additional CHP. Condensing natural gas power became important only in the scenario with the allowance price level of 30 €/t CO_2. The consumption of electricity slightly decreases at the all allowance price levels from 5 €/t CO_2 due to energy saving investments. Natural gas and biomass consumption increase while coal and peat consumption decrease especially in the scenarios with a high CO_2 allowance price. The slow increase in capacities of CHP and wind power implies that condensing coal power still has an important role in the Finnish energy system until the new nuclear power plant starts operation in 2009.

4. Case study: a condensing power plant in Finland

In this section, we illustrate the impacts identified in Section 2 on a hypothetical investment decision in a regional setting discussed in Section 3. We extend a standard DCF analysis to better reflect the value of two real options involved: the option to wait and the option to alter operating scale. The value of an investment opportunity NPV_{opp} thus becomes:[4]

$$NPV_{opp} = NPV_{now} + O_{scale} + O_{wait} \tag{5}$$

with NPV_{now} being the simple Net Present Value of the immediate investment based on the expected cashflows, O_{scale} the value of the option to alter operating scale and O_{wait} the value of an option to wait. Here, O_{wait} includes both the value of the option *not having to invest* (if the outlook is poor) and the option to *wait for even better conditions* (if the outlook seems fine). If $O_{wait} > 0$ then the optimal decision is hence not to invest. If $O_{scale} \geqslant 0$ then the simple NPV analysis fails to evaluate the investment correctly.

In the case study, a price-taking[5] investor considers a condensing power plant in Finland. There are two options: a coal-fired plant and a gas-fired plant. The investor has basically three alternatives until the investment decision has been made:

- invest in a coal plant: pay the investment cost I, and commit to the fixed costs caused by the plant (C_f).[6] In response, the investor obtains risky revenues from the free emission allowances and an option to generate electricity, when prices are favourable.
- invest in a gas plant: similarly as above; and
- wait: obtain return for the capital and keep the *option to invest* i.e. opportunity to invest later on, when the market is more favourable.

The value of real options is ideally estimated in a risk-neutral valuation framework (see e.g. Dixit and Pindyck, 1994, pp. 120–121). In the context of this paper, this is difficult, since the behaviour of allowance prices is unknown. Therefore, we approach the value of the options through a *dynamic DCF analysis*[7] in a normal risk-adjusted valuation framework. It must be emphasized that the results are for this reason not fully

[4]For more on "extended NPV", see Trigeorgis (1995).

[5]In oligopolistic settings, investors are not necessarily price-takers. Such a setting requires explicit inclusion of game theory. Murto (2003) gives a good overview.

[6]For simplicity, we allow only a single level of fixed costs and thus ignore the option of the investor to mothball the plant (see e.g. Reinaud, 2003, or Näsäkkälä and Fleten, 2004).

[7]See Teisberg (1995).

consistent with asset pricing theory. Rather, the starting point is a manager, who applies a *subjective* experience-based discount rate or the weighted average cost of capital (WACC) for the valuation problem irrespective of the "*objective*" riskiness of the cashflows (such as e.g. in Cox et al., 1985).

4.1. Model

We consider the following simplified model:

1. The investment decision needs to be made within the time frame 2005–2007.
2. There are two stochastic variables (the price of electricity, p_e, and the price of emission allowance, p_{CO_2}) and two deterministic variables (fuel price, p_f, and the number of free allowances, N) in Eq. (4). N is modelled as independent on the operation of the power plant in previous periods.
3. The stochastic variables, p_e and p_{CO_2} follow discrete-time continuous-state processes. The time period in the model is a year.
4. The price of an emission allowance, p_{CO_2}, is constant within a year.
5. There are no switching costs (start-up or shut-down costs)[8]

Assumption 5 will somewhat favour the coal plant, as gas turbines are typically easier to adjust for changing market conditions than coal plants.

Based on Sections 2 and 3 it can be further assumed that:

6. The price of electricity directly depends on the allowance price.

For simplicity, we ignore a similar potential relationship between the allowance price and the market prices of fuels.

We can now separate the market price of electricity, p_e, to two parts, the "baseline" (business-as-usual) part ($p_{e,base}$) and the "CO_2-driven" part ($\gamma \cdot p_{CO_2}$):

$$p_e = p_{e,base} + \gamma \cdot p_{CO_2} \tag{6}$$

where γ is the estimated transformation factor. This is equal to the emission factor of the marginal plant, which results from the merit order in the power system (e.g. Reinaud, 2003). The transformation factor γ thus depends on fluctuation in electricity supply and demand.

Eq. (6) allows us to explicitly model γ. A further advantage is that there is historical data on $p_{e,base}$, whereas we know little about p_e. As discussed in 3.1.1, the electricity supply in the Nordic countries—and thereby the price of electricity—significantly varies with hydrological conditions. However, the *form* of the price duration curve varies much less (Fig. 1). Therefore, we will add two more simplifying assumptions:

7. The marginal plant (type) in the power system and thus the transformation factor γ is a function of $p_{e,base}$.
8. The *form* of the duration curve of $p_{e,base}$ within any single year is constant i.e. the proportions of peak and bottom prices vs. the average level are constant.

From Eq. (3) we thus obtain for the spark spread:

$$S = p_{e,base} - \frac{p_f}{\eta} + \left(\gamma(p_{e,base}) - \frac{e_f}{\eta}\right) p_{CO_2} - \psi. \tag{7}$$

Deriving from Deng and Oren (2003), we use a Monte Carlo simulation with mean reverting stochastic processes for $p_{e,base}$ and p_{CO_2} (see Appendix 1 for details) to explore the expected value of different investment alternatives. Many authors argue that stochastic processes dealing with commodity prices need to be mean reverting as opposite to the commonly used Geometric Brownian motion, in which the variance grows infinitely (e.g. Deng et al., 2001; Laughton and Jacoby, 1995; Schwartz, 1997). Mean reversion reflects the long-term equilibrium of production and demand. Geometric Brownian motion models have been used mainly due to tractable solutions and close-form expressions that can be readily analysed. Hasset and Metcalf (1995) argue that geometric Brownian motion could be used to approximate mean reversion, but Sarkar (2003) opposes this argument.

Cash flows created in the simulation are discounted with a risk-adjusted rate. The expected values are based on 400 runs, which gives a standard error of the mean of ca. 1–5% for the discounted cashflows.

In order to identify the impact of emissions trading on the investment, we consider different outcomes for the price of the allowance, its volatility, and the correlation to the baseline price of electricity ($p_{e,base}$). We also simulate the development without emissions trading (business-as-usual). To demonstrate the effect of the free allocation of allowances, the following two case are explored: (1) "free allocation": companies obtain allowances free of charge from the regulator infinitely; and (2) "scarce allocation": companies obtain less allowances free of charge and only until 2012 (when the allocation method is switched to auction).

4.2. Data

The development, engineering and construction time of both plants is assumed to be 3 years. We use the following values (Table 3).

In the case of emissions trading, we assume that the price of allowances will start at 7 €/t CO_2 in 2005 based on forward trades in the EU market (PointCarbon, 2004). A (low) mean-reversion (k_Y) of 0.2 is assumed for the allowance price process. Two scenarios for the long-run mean (reached in 2013) of allowance prices are tested:

[8] See Tseng and Barz (2002) and Deng and Oren (2003) for studies on the importance of switching costs.

Table 3
Plant-specific parameter values (based on Reinaud, 2003; Ryden, 2003)

Parameter	Symbol	Unit	Coal plant	Gas plant
Output capacity	P_{max}	MW_e	250	250
Operating lifetime	T_p	a	30	25
Thermal efficiency	η	%	40	55
Investment cost	I	€/kW_e	1050	570
Fixed cost	C_f	€/MW_e	18700	11000
O&M costs and fees[a]	ψ	€/MWh_e	4.0	1.7
CO_2 emission factor	e_f	g CO_2/kWh	334	201

[a]Includes a precautionary stock fee.

Table 4
Assumed price paths for fuels (in €/MWh)

Fuel	2005	2010	2020	2030
Coal (on the coast)	5.5	5.8	6.1	6.5
Natural gas[a]	13.3	13.3	13.3	13.3

[a]Tariff for a customer with a consumption of 1000 GWh/a, 6000 h/a (Energy Market Authority, 2004).

- high scenario: the long-run average price is 20 €/t CO_2,
- low scenario: the long-run average price is 1 €/t CO_2.

Regarding the allocation method, we test two hypothetical scenarios. In both scenarios, we assume a free of charge allocation until 2012. The free of charge allocation is supposed to follow the principles defined in MTI (2004a):

$$N_t = x_{ref}\frac{P_{max}}{\eta}e_{ref}, \tag{8}$$

where x_{ref} is the reference operating time of the plant, and e_{ref} is the emission factor of the reference fuel. In 2005–2007, x_{ref} is 6000 h, e_{ref} for coal is 0.27 t CO_2/MWh,[9] and e_{ref} for gas 0.20 t CO_2/MWh (MTI, 2004a). For later periods, we assume equal reference fuels. In the "free allocation" scenario, x_{ref} is 5000 h for the period 2008–2012 and 4000 h after 2012. In the "scarce allocation" scenario, x_{ref} is 4000 h between 2008–2012 and x_{ref} is 0 h after 2012 (due to the presumed auction).

In a normal hydrological year, coal-condensing power is assumed to determine the emission factor on the margin (γ), and γ is estimated at 0.77 t CO_2/MWh (see e.g. Electrowatt-Ekono, 2003). When the hydrological conditions are good, CHP plants are estimated to be in the marginal position (Electrowatt-Ekono, 2003). We therefore apply the following function for γ (in t CO_2/MWh_e) in order to mimic this effect in the model:The function $\gamma(p_{e,base})$ applied here is very simplified, but can be more accurately estimated with sophisticated electricity market models.

$$\gamma(p_{e,base}) = \begin{cases} 0.77, & \text{when } p_{e,base} \geqslant 22.0\ €/\text{MWh} \\ 0.065 \cdot p_{e,base} - 0.67, & \text{when } 13.7 \leqslant p_{e,base} \leqslant 22.0\ €/\text{MWh} \\ 0.22, & \text{when } p_{e,base} \leqslant 13.7\ €/\text{MWh} \end{cases} \tag{9}$$

The long-run mean for the baseline price of electricity ($p_{e,base}$*), 22 €/MWh, is obtained from the mean of the annual average prices at Helsinki area in the period 1996–2003. Similarly, we obtain a standard deviation (σ_X) of 37%. A mean reversion factor (k_X) of 0.4 is obtained through a regression of the annual average prices during 1996–2003.

The starting price for electricity ($p_{e,base}$) in 2005 is assumed equal to its long-run mean value. We do not use the forward prices (for p_e) to estimate $p_{e,base}$ as it is unclear how consistent the assumptions of the market regarding p_{CO_2} and γ are with those used here.

For coal and gas we assume the following deterministic producer price paths, which are simplified as being independent on the allowance price (Table 4). The price for coal is based on data from Finland and global projections (MTI, 2003; IEA, 2002). Between the years given, the prices are assumed linear. The producer price for gas is assumed to stay at its initial level (April 2004). Prices contain the costs of transport and handling.

Yield of a 10-year Finnish government bond is used a basis for the risk-free discount rate (4.2% in the end of April 2004). Assuming an inflation of 2%, we obtain a real risk-free discount rate of 2.1%. The real risk-adjusted discount rate for p_e and electricity production is approximated at 6% based on the nominal rate of 8% in Reinaud (2003).

4.3. Results

In the starting position (without emissions trading) neither the coal nor the gas plant seems viable (Tables 5 and 6). The expected values of the investment opportunities, $E(NPV_{opp})$, are zero. The optimal decision seems to be to wait with the investment ($E(O_{wait}) \geqslant 0$).

Emissions trading in a "low allowance price" scenario does not significantly improve viability of the power plants. However, emissions trading in a "high allowance price + free allocation" scenario changes the picture for the gas plant (Table 6), while viability of the coal plant

[9]The reference fuel is assumed to be 70% peat and 30% biomass.

Table 5
Expected values from the simulation (400 runs) for a coal plant in different scenarios for emissions trading (in M€)

Scenarios		"Free allocation" 2005-			"Scarce allocation" 2005–2012, (Auction 2013-)
Correlation (ρ) of allowance and baseline electricity price		0	0	0.5	0
Volatility of allowance price (σ_Y)		10%	40%	10%	10%
High allowance price (p_{CO_2})	$+NPV_{now}$[a]	−169	−169	−169	−206
	$+E(O_{scale})$[b]	+52	+52	+52	+49
	$+E(O_{wait})$[c]	+116	+117	+116	+157
	$=E(NPV_{opp})$[d]	=0	=0	=0	=0
Low allowance price (p_{CO_2})	$+NPV_{now}$[a]	−195	−195	−195	−198
	$+E(O_{scale})$[b]	+46	+49	+55	+53
	$+E(O_{wait})$[c]	+148	+146	+140	+145
	$=E(NPV_{opp})$[d]	=0	=0	=0	=0
No emissions trading	$+NPV_{now}$[a]	−198	−198	−198	−198
	$+E(O_{scale})$[b]	+42	+42	+42	+42
	$+E(O_{wait})$[c]	+155	+155	+155	+155
	$=E(NPV_{opp})$[d]	=0	=0	=0	=0

[a] NPV_{now} = Net present value.
[b] (O_{scale}) = Expected value of the option to alter operating scale.
[c] $E(O_{wait})$ = Expected value of the option to wait.
[d] $E(NPV_{opp})$ = Expected value of the investment opportunity.

Table 6
Expected values from the simulation (400 runs) for a gas plant in different scenarios for emissions trading (in M€)

Scenarios		"Free allocation" 2005-			"Scarce allocation" 2005–2012, (Auction 2013-)
Correlation (ρ) of allowance and baseline electricity price		0	0	0.5	0
Volatility of allowance price (σ_Y)		10%	40%	10%	10%
High allowance price (p_{CO_2})	$+NPV_{now}$[a]	−15	−15	−15	−49
	$+E(O_{scale})$[b]	+34	+46	+46	+42
	$+E(O_{wait})$[c]	+1	+0	+0	+7
	$=E(NPV_{opp})$[d]	=20	=30	=30	=0
Low allowance price (p_{CO_2})	$+NPV_{now}$[a]	−127	−127	−127	−129
	$+E(O_{scale})$[b]	+49	+54	+52	+51
	$+E(O_{wait})$[c]	+78	+73	+75	+79
	$=E(NPV_{opp})$[d]	=0	=0	=0	=0
No emissions trading	$+NPV_{now}$[a]	−135	−135	−135	−135
	$+E(O_{scale})$[b]	+36	+36	+36	+36
	$+E(O_{wait})$[c]	+99	+99	+99	+99
	$=E(NPV_{opp})$[d]	=0	=0	=0	=0

[a] NPV_{now} = Net present value.
[b] $E(O_{scale})$ = Expected value of the option to alter operating scale.
[c] $E(O_{wait})$ = Expected value of the option to wait.
[d] $E(NPV_{opp})$ = Expected value of the investment opportunity.

remains to a large extent unaffected (Table 5). The expected value of the opportunity to invest in the gas plant in these scenarios, $E(NPV_{opp})$, can rise up to €30 million. A high volatility for the allowance price (p_{CO_2}) and a positive correlation (ρ) of the baseline electricity price ($p_{e,base}$) and p_{CO_2} have a positive effect on NPV_{opp}: the expected return increases from 14% to 21%. It is optimal to wait with the investment ($O_{wait} > 0$), if the

Table 7
Sensitivity of the gas plant viability (in M€)

Scenarios		"Free allocation" 2005-	
		Average baseline electricity price ($p_{e,base}$*) + 10%	Gas price (p_f) + 10%
Correlation (ρ) of allowance and baseline electricity price		0	0
Volatility of allowance price (σ_Y)		40%	40%
High allowance price (p_{CO_2})	$+NPV_{now}$[a]	+28	−46
	$+E(O_{scale})$[b]	+42	+49
	$+E(O_{wait})$[c]	+0	+0
	$=E(NPV_{opp})$[d]	=70	=2

[a] NPV_{now} = Net present value.
[b] $E(O_{scale})$ = Expected value of the option to alter operating scale.
[c] $E(O_{wait})$ = Expected value of the option to wait.
[d] $E(NPV_{opp})$ = Expected value of the investment opportunity.

correlation, ρ, is low and the volatility of p_{CO_2} low. If the allowance price volatility is high, or there is a positive correlation, ρ, the optimal decision seems to be to invest in the gas plant.

There are however additional uncertainties and constraints, which affect the decision. In the "scarce allocation" scenario, the option value to invest in a gas plant would remain zero, even if the allowance price level were high (Table 6). The viability of the gas plant is also very sensitive to the assumed average electricity and gas prices (Table 7). In the context of our case study, natural gas is currently supplied through a single pipeline to the Finnish market, which raises concerns about market power exertion. Further, the expected value is based on an idealized power plant without operational or technical constraints.

It should be noted that the expected value of the option to alter operating scale, $E(O_{scale})$, of the plants explored ranges from €34 to €55 million in different scenarios. This option value is ignored in a simple NPV analysis. A higher volatility for allowance prices increases the option value somewhat, but the impact is not drastic. Allowance price scenarios and the allowance allocation after 2007 have more significant impacts.

5. Discussion and conclusions

Emissions trading has significant impacts on the results of a quantitative investment appraisal through *several variables*: through the output prices, through the value of the surrendered allowances, through the operating hours and through the value of free allowances allocated for installations. This makes it challenging to weigh up the impacts.

Since the investment costs are known with a reasonable certainty, financial performance of power projects depends in particular on the concurrent level and projected development of the stochastic market prices of electricity, fuels and (potential) emission allowances. In addition, there is a stepwise uncertainty regarding the number of free allowances.

Stochastic process assumed for each market price, the parameters of the stochastic process and the mutual correlations of the market prices determine the total impact. In our case study, two stochastic market prices were considered: the price of an emission allowance and the baseline electricity price (price without emissions trading). Fuel prices were treated as deterministic and independent on the allowance price for simplicity.

The case study shows that the result of a quantitative investment appraisal for a gas-fired power plant highly depends on the assumptions made on emissions trading in a power market similar to that of Finland. The impact mainly depends on the assumed price level of emission allowances and the (potential) allocation of free allowances. However, *behaviour of the allowance market* (e.g. volatility, correlation to electricity and fuel prices) can have a significant impact on the *expected return* of gas-fired power plants. In the "high allowance price" scenario of our case study, the value of an option to invest in a gas-fired plant became positive, whereas the value of an option to invest in a coal-fired plant remained unaffected. Uncertainty regarding the impact of the EU ETS on fuel prices may decrease the attractiveness of gas plants from that seen here.

The case study also shows that a simple NPV approach ignores the *value of the option to alter operating scale*, which can be important for technologies with high variable costs.

Power companies and investors should *move from deterministic to stochastic valuation* and *consider the impacts of emissions trading schemes comprehensively* in markets similar to Europe. The high uncertainty regarding the allocation of free allowances is *critical to decisions to switch to natural gas*. It should also be noted that *renewable energy and nuclear power remain unaffected by this uncertainty*.

We approached valuation of real options in a real risk-adjusted framework, which is not the optimal way to value options theoretically. Our analysis provides a new perspective to the decision-making of managers, who are not necessarily fully consistent in their treatment of risk and apply a subjective discount rate in valuation. Emissions trading will change the risk of free cash flows (and thus returns on assets). A rational investor would aim at taking this into account in the selection of the discount rate, which was not considered here.

The analysis carried out here is sensitive to the stochastic processes assumed and their parameters. We used mean-reverting price processes, which can be regarded as a "conservative approach" to power plant valuation: a mean-reverting price process implies that potential market outcomes tomorrow differ less from today than in the commonly used geometric Brownian motion (i.e. the variance is smaller).

Acknowledgements

We would like to thank Pekka Pirilä, Ilkka Keppo, Erkka Näsäkkälä, Pekka Vile and Pauli Murto for valuable comments. All remaining errors are those of the authors. The financial support of National Technology Agency of Finland, the Environment Pool of the Finnish Energy Industries Federation and the Foundation for Economic Education is gratefully acknowledged. The views expressed in this paper are those of the authors and do not necessarily reflect the opinions of the financiers.

Appendix 1—simulation of the stochastic processes

The value of the underlying asset (the power plant) at any level of baseline electricity price ($p_{e,base}$) and emission allowance price (p_{CO_2}) is estimated through a Monte Carlo simulation. The simulation takes into account the owner's option to alter operating scale (O_{scale}) during the project lifetime (i.e. production only if $S_t \geqslant 0$).

Deriving from Deng and Oren (2003), we model two stochastic processes in discrete time using a quadrinomial tree

$$(X_{t+1}, Y_{t+1}) = \begin{cases} (X^1_{t+1}, Y^1_{t+1}) = (X_t + \Delta X_t, Y_t + \Delta Y_t) \\ (X^2_{t+1}, Y^2_{t+1}) = (X_t + \Delta X_t, Y_t - \Delta Y_t) \\ (X^3_{t+1}, Y^3_{t+1}) = (X_t - \Delta X_t, Y_t - \Delta Y_t) \\ (X^4_{t+1}, Y^4_{t+1}) = (X_t - \Delta X_t, Y_t + \Delta Y_t) \end{cases} \tag{A.1}$$

with X and Y being the state variables for the natural logarithms of $p_{e,base}$ and p_{CO_2}. We consider a simple mean-reverting Ito process, the Ornstein–Uhlenbeck process

$$\mathrm{d}X = k_x(X^* - X)\,\mathrm{d}t + \sigma_x\,\mathrm{d}z_x \tag{A.2}$$

with X being the natural logarithm of $p_{e,base}$. X^* is the natural logarithm of the long-term mean level of baseline electricity price, $p_{e,base}*$, k_x the speed of mean reversion, $\mathrm{d}z_x$ the increment of a Wiener process, and σ_x the variance parameter. Y is modelled similarly.

As opposite to Deng and Oren (2003), ΔX_t and ΔY_t are random so that

$$\begin{cases} \Delta X_t = |\sigma_X\,\mathrm{d}z_X|, \\ \Delta Y_t = |\sigma_Y\,\mathrm{d}z_Y|. \end{cases} \tag{A.3}$$

We further derive from Deng and Oren (2003) the transition probabilities p^N for any (X^N, Y^N):

$$\begin{cases} B = k_X(X^* - X_t) \\ C = k_Y(Y^* - Y_t) \\ p^1_t = \frac{1+\rho}{4} + \frac{B}{4\Delta X_t} + \frac{C}{4\Delta Y_t} + \frac{BC}{4\Delta X_t \Delta Y_t} \\ p^2_t = \frac{1-\rho}{4} + \frac{B}{4\Delta X_t} - \frac{C}{4\Delta Y_t} - \frac{BC}{4\Delta X_t \Delta Y_t} \\ p^3_t = \frac{1+\rho}{4} - \frac{B}{4\Delta X_t} + \frac{C}{4\Delta Y_t} + \frac{BC}{4\Delta X_t \Delta Y_t} \\ p^4_t = \frac{1-\rho}{4} - \frac{B}{4\Delta X_t} - \frac{C}{4\Delta Y_t} - \frac{BC}{4\Delta X_t \Delta Y_t} \end{cases} \tag{A.4}$$

where ρ is the correlation coefficient between $\mathrm{d}z_X$ and $\mathrm{d}z_Y$. Deng and Oren (2003) analyse the state–space (X_t, Y_t) through the subset $\{(X_0+m\sigma_X,\ Y_0+n\sigma_Y)$: $m, n=-t,\ -t+2, -t+4, \ldots, t-4,\ t-2,\ t\}$ and note that Eq. (4) gives probabilities between [0,1] for all components only if:

$$|m| = \frac{1-\sqrt{|\rho|}}{k_X} \quad \text{and} \quad |n| = \frac{1-\sqrt{|\rho|}}{k_Y}. \tag{A.5}$$

If this is not the case for m, we use accordingly the following equation:

$$X_{t+1} = X^* + \sigma_x\,\mathrm{d}z_X. \tag{A.6}$$

The state variable is thus forced to a new level that is likely to be close to the long-run mean.

After a new value X_{t+1} and hence $p_{e,base}$ has been found for period t+1, we multiply it with a factor A in order to adjust the expected value of the time series:

$$A = \frac{p_{e,base} + k_x(p^*_{e,base} - p_{e,base})}{0.5 p_{e,base} e^{k_x(X^*-X)}(\mathrm{e}^{\Delta X_t} + \mathrm{e}^{-\Delta X_t})}, \tag{A.7}$$

repectively similar approaches are used for Y.

References

Cox, J.C., Ingersoll, J., Ross, S.A., 1985. An intertemporal general equilibrium model of asset prices. Econometrica 53 (2), 363–384.

de Leyva, E., Lekander, P.A., 2003. Climate change for Europe's utilities. The McKinsey Quarterly 1, 120–131.

Deng, S., Oren, S.S., 2003. Incorporating operational characteristics and startup costs in option-based valuation of power generation capacity. Probability in the Engineering and Informational Sciences 17 (2), 155–181.

Deng, S., Johnson, B., Sogomonian, A., 2001. Exotic electricity options and the valuation of electricity generation and transmission assets. Decision Support Systems 30, 383–392.

Dixit, A.K., Pindyck, R.S., 1994. Investment Under Uncertainty. Princeton University Press, Princeton, NJ.

Electrowatt-Ekono, 2003. Emissions trading and the Nordic electricity market. Report for the Ministry of Trade and Industry of Finland. Espoo.

Energy Market Authority (of Finland), 2004. www.energiamarkkina-virasto.fi.

Finergy (Finnish Energy Industries Federation), 2003. Electricity markets during the winter 2002–2003 [Talven 2002–2003 sähkö-markkinat. Finergyn selvitys.] Research Report No. 12, Helsinki (in Finnish).

Finergy, 2004. Finergy's electricity need estimate until 2020 [Arvio Suomen sähkön tarpeesta vuoteen 2020]. 29.1.2004. http://www.fi-nergy.fi (in Finnish).

Hassett, K.A., Metcalf, G.E., 1995. Investment under alternative return assumptions: comparing random walks and mean reversion. Journal of Economic Dynamics and Control 19, 1471–1488.

Holtsmark, B., 2003. Russian behaviour in the market for permits under the Kyoto Protocol. Climate Policy 3, 399–415.

Holtsmark, B., Mæstad, O., 2002. Emission trading under the Kyoto Protocol—effects on fossil fuel markets under alternative regimes. Energy Policy 30, 207–218.

Hsu, M., 1998. Spark Spread Options Are Hot! The Electricity Journal March, 28–39.

IEA (International Energy Agency), 2002. World Energy Outlook. Paris.

IEA, 2003a. World Energy Investment Outlook. Paris.

IEA, 2003b. Power Generation Investment in Electricity Markets. OECD/IEA, Paris.

Ilex Energy Consulting, 2004. The Impact of the EU ETS on European Electricity Prices. A Report to DTI, July.

Kort, P.M., Murto, P., Pawlina, G., 2004. The value of flexibility in sequencing growth investment. Paper presented at the 8th annual Real Option Conference, June 17–19, Montréal.

Laughton, D.G., Jacoby, H.D., 1995. The effects of reversion on commodity projects of different length. In: Trigeorgis, L. (Ed.), Real Options in Capital Investment—Models, Strategies and Applications. Praeger, Westport, CT.

Laurikka, H., 2004. The impact of climate policy on heat and power capacity investment decisions. In: Hansjürgens, B. (Ed.), Proceedings of the Workshop "Business and Emissions Trading" held in Wittenberg, Germany, November 11–14, forthcoming.

McDonald, R., Siegel, D., 1986. The value of waiting to invest. Quarterly Journal of Economics 101, 707–727.

MoE, 2004. Greenhouse gas emissions in Finland 1990–2002—National Inventory Report to the UNFCCC Secreteriat.

MTI, 2003. Energy Review. www.ktm.fi.

MTI, 2004a. Government Decision on the Proposal for a National Allocation Plan, 19.8.2004. http://www.ktm.fi.

MTI, 2004b. EU:n päästökaupan, energiaverotuksen ja energiantuotannon tukien yhteensovittaminen—työryhmän mietintö 10.8.2004 (in Finnish).

Murto, P., 2003. On investment, uncertainty, and strategic interaction with applications in energy markets. Systems Analysis Laboratory Research Reports A 84. Helsinki University of Technology.

Nordel, 2004. www.nordel.org.

Nord Pool, 2004. Nord Pool Statistics.

Näsäkkälä, E., Fleten, S.E., 2004. Flexibility and Technology Choice in Gas Fired Power Plant Investments. Helsinki University of Technology.

OECD NEA/IEA (Nuclear Energy Agency/International Energy Agency), 1998. Projected Costs of Generating Electricity—Update 1998, Paris.

PointCarbon, 2004. Carbon Market Indicator 30.4.2004.

Reinaud, J., 2003. Emissions trading and its possible impacts on investment decisions in the power sector. IEA Information Paper, Paris.

Ryden, B (Ed.), 2003. Nordleden—Slutrapport för Etapp 2. Gothenburg (in Swedish).

Sarkar, S., 2003. The effect of mean reversion on investment under uncertainty. Journal of Economic Dynamics and Control 28, 377–396.

Schwartz, E.S., 1997. The stochastic behaviour of commodity prices: implications for valuation and hedging. The Journal of Finance LII (3), 923–973.

Springer, U., Varilek, M., 2004. Estimating the price of tradable permits for greenhouse gas emissions in 2008–2012. Energy Policy 32, 611–621.

Statistics Finland, 2004. Preliminary Energy Statistics. Helsinki.

Swedish Energy Agency, 2003. The Electricity market2003. http://www.stem.se.

Teisberg, E.O., 1995. Methods for evaluating capital investment decisions under uncertainty. In: Trigeorgis, L. (Ed.), Real Options in Capital Investment—Models, Strategies and Applications. Praeger, Westport, CT.

Trigeorgis, L., 1995. Real options: an overview. In: Trigeorgis, L. (Ed.) Real Options in Capital Investment—Models, Strategies and Applications. Praeger, Westport, CT.

Tseng, C., Barz, G., 2002. Short-term generation asset valuation: a real options approach. Operations Research 50 (2), 297–310.

Ventosa, M., Baíllo, Á., Ramos, A., Rivier, M., 2004. Electricity market modeling trends. Energy Policy, forthcoming.

VTT (Lehtilä, A., Savolainen, I., Tuhkanen, S.), 1997. Indicators of CO_2 emissions and energy efficiency. Comparison of Finland with other countries. VTT Publications 328, Espoo.

VTT (Lehtilä, A., Syri, S.), 2003. Scenarios for the Finnish energy system and emissions. Study made for the Climtech Programme [Suomen energiajärjestelmän ja päästöjen kehitysarvioita. Climtech-ohjelman skenaariotarkastelu]. Research Notes 2196, Espoo, Finland (in Finnish).

VTT (Koljonen, T., Kekkonen, V., Lehtilä, A., Hongisto, M., Savolainen, I.), 2004. The impacts of emissions trading in Finnish energy and metal industries. VTT Research Notes 2259 (in Finnish).

Zhao, J., 2003. Irreversible abatement investment under cost uncertainties: tradable emission permits and emissions charges. Journal of Public Economics 87, 2765–2789.