4

Publication 4

Reprinted from *Energy Policy*, Articles In Press, Laurikka, H., Option value of gasification technology within an emissions trading scheme, 13 p., Copyright (2005), with permission from Elsevier

ELSEVIER

Energy Policy ∎ (∎∎∎∎) ∎∎∎–∎∎∎

ENERGY POLICY

www.elsevier.com/locate/enpol

Option value of gasification technology within an emissions trading scheme

Harri Laurikka*

Laboratory of Energy Economics and Power Plant Engineering, Helsinki University of Technology, P.O. Box 4100, 02015 TKK, Finland

Abstract

Investment analysis is mostly implemented with Discounted Cash Flow (DCF) methods, such as the Net Present Value (NPV). The problem in a typical application of these methods is the limited ability to value real options, management's ability to adapt to changing market conditions or to revise decisions. This paper presents a simulation model, in which the investment is regarded as a single-firm problem in an operating environment with multiple exogenous and stochastic prices. The simulation model is used to explore the impact of emissions trading, and in particular the European Union Emissions Trading Scheme (EU ETS), on investments in Integrated Gasification Combined Cycle (IGCC) plants. Two real case studies are presented: modifications of an existing condensing power plant and a new combined heat and power plant. The benefit of the selected approach is that it can take into account the value of multiple simultaneous real options better than a standard DCF analysis. The results show that a straightforward application of DCF analysis can lead to biased results in competitive energy markets within an emissions trading scheme, where a number of uncertainties potentially combined with several real options can make quantitative investment appraisals very complex.

Keywords: Emissions trading; Gasification; Investment

1. Introduction

Investment analysis is mostly implemented with Discounted Cash Flow (DCF) methods, such as the Net Present Value (NPV). A DCF analysis essentially involves discounting the expected net cash flows from an investment at a discount rate that reflects the risk of those cash flows. Typically the analysis is based on scenarios, which presume management's passive commitment to certain operating strategies, and is accompanied with a sensitivity analysis to the components of the cash flow. The problem in the approach is its limited ability to value active flexibility or *real options*.[1] A real option is a right, but not an obligation, to take action concerning an investment project: for example, to alter operating scale or to switch inputs, such as fuels. It thus refers to management's ability to adapt to changing market conditions or to revise decisions.

This paper presents a simulation model, in which the investment is regarded as a single-firm problem in an operating environment with multiple exogenous and stochastic prices.[2] The simulation model is used to explore the impact of emissions trading, and in particular the European Union Emissions Trading Scheme (EU ETS),[3] on investments in a specific energy production technology. Two real case studies are studied. The benefit of the selected approach is that it can take into account the value of multiple simultaneous real options better than a standard DCF analysis.

Valuation of real options requires an expansion of the standard analysis. As a simple equation: the Extended Net Present Value (NPV_{ext}) is equal to the standard Net Present Value (NPV) plus the value of the real options (O)

*Tel.: +358 40 762 0979; fax: +358 9 451 3674.
E-mail address: harri.laurikka@greenstream.net.

[1]For an overview on real options, see e.g. Dixit and Pindyck (1994), Trigeorgis (1995) or Schwartz and Trigeorgis (2001).

[2]For a taxonomy on energy system models, see Ventosa et al. (2005). As the prices are exogenous, it is implicitly assumed that the investment is small compared to the market size and cannot hence significantly affect any of the market prices. "Stochastic" refers to the fact that the prices at least partly depend on random events.

[3]For more on the EU ETS, see http://europa.eu.int/comm/environment/climat/emission.htm.

0301-4215/$ - see front matter © 2005 Elsevier Ltd. All rights reserved.
doi:10.1016/j.enpol.2005.09.002

(Trigeorgis, 1995). Literature provides different methods to the estimation of NPV_{ext} ranging from contingent claims analysis to dynamic programming and to simulation (e.g. Dixit and Pindyck, 1994; Amram and Kulatilaka, 1999). All the methods have strengths and weaknesses, and set different requirements for the problem formulation and availability of data. For example, contingent claims analysis is based on the idea that determination of the risk-adjusted discount rate is avoided through market-traded assets, such as futures for commodities. The method works, if the project cash flows can be completely replicated with market-traded assets, which is not currently the case, e.g. in heat and power projects within the EU ETS. In such cases, the determination of the risk-adjusted discount rate is necessary.

Laurikka and Koljonen (2005) applied Monte Carlo simulation for valuation of a power generation investment within the EU ETS using two stochastic variables (price of electricity and emission allowance price) in a risk-adjusted framework. The simulation model presented here is also based on a risk-adjusted framework, but can simultaneously deal with multiple stochastic variables, such as prices of electricity, emission allowance, and fuels, to estimate the value of flexibility.

The object of the case studies of this paper is the Integrated Gasification Combined Cycle (IGCC) technology. Solid fuel gasification technologies, such as IGCC, are promising alternatives for future heat and power generation due to the high generating efficiency and favourable characteristics regarding potential carbon dioxide capture (e.g. Harmoinen et al., 2002; Lako, 2004). The IGCC technology is expected to find first commercial applications in oil refineries and coal power condensed power plants (Harmoinen et al., 2002).

Section 2 describes the basic structure of the model and the common data applied in the case studies. Specifications in the model, the case-specific data, and the model outcomes are presented in Sections 3 (gasification of biomass in an existing condensing power plant) and 4 (gasification of coal in a residential CHP plant). Section 5 concludes.

2. Model

The model in this paper estimates the expected change in the Extended Net Present Value ($E(\Delta NPV_{ext})$) through the investment:

$$\Delta NPV_{ext} = NPV_{ext,2} - NPV_{ext,1} = \Delta NPV + \Delta O, \tag{1}$$

where $NPV_{ext,2}$ and $NPV_{ext,1}$ is the Extended Net Present Value after and before the investment, respectively, ΔNPV is the change in the NPV and ΔO the change in the option value.

A simple Monte Carlo simulation, in which multiple futures are generated in terms of a set of state variables, such as market prices of electricity, emission allowance and fuels, is used to evaluate ΔNPV_{ext}. In both case studies (Sections 3 and 4), there are 4–5 relevant state variables, which depend on random events in discrete time. The time period in the model is a year. As the value of the state variables fluctuates in the simulation, the reactions of the plant management are modelled so that they aim at cash flow maximization.

The stochastic processes used in the simulation mimic one-factor mean-reverting Ito processes, the Ornstein–Uhlenbeck processes (Dixit and Pindyck, 1994, pp. 74, 75). Mean-reverting processes in economic applications are based on the idea that in the long-term high prices for a commodity will increase its production capacity and hence cause the price to "revert to the long-term mean" and vice versa. In valuation of a real option, such a process gives a more conservative value than an equivalent process, where probability distributions are wider.

The state variables x_i for each period t ($x_{i,t}$) are modelled so that

$$E(X_{i,t}) = X_i^* + (X_{i,start} - X_i^*)\mathrm{e}^{-\kappa t} \tag{2}$$

with X_i being the natural logarithm[4] of the stochastic variable (x_i), $E(X)$ its expected value, $X_{i,start}$ the selected initial value, X_i* the natural logarithm of the mean value and κ the speed of mean reversion. Further, the volatility of X_i is given as

$$\sigma(X_{i,t}) = \frac{\sigma^2}{2\kappa}(1 - \mathrm{e}^{-2\kappa t}). \tag{3}$$

Stochastic state variables used in this paper are presented in Tables 1 and 2 with their key parameters: long-run average values, volatilities, speeds of mean reversion, and correlations to the other state variables. These parameters are considered static, and they are based on historical data and the market data at the time of writing. It is important to note that this approach presumes a certain continuum in the energy market. For example, price volatilities are assumed fairly low and biomass is assumed to be less integrated to the global energy market (low correlations to the prices of coal, oil and gas) also in the future. It is worth noting that the long-run average prices (x*) are *not necessarily equal to an expected value*.

Not much is known about the long-term behaviour of emission allowance prices at the time of writing. For this reason, *scenarios* are made on the price and volatility of allowances (Table 3).

All the state variables, except the annual average price of electricity (p_e) are assumed constant within a year for simplicity. The seasonal fluctuation of the electricity price is modelled endogenously. Similarly to Laurikka and Koljonen (2005) it is assumed that the annual average price of electricity (p_e) directly depends on the allowance price (see, e.g., Koljonen et al., 2004; Electrowatt-Ekono, 2003a), so that

$$p_e = p_{e,base} + \gamma \cdot p_{CO_2}, \tag{4}$$

[4]The logarithm is used, since it is assumed that state variables cannot be negative.

Table 1
Parameters of the stochastic processes applied in the model

Stochastic variable (x_i)	Symbol	Unit	Stochastic process	Long-run average (x^*)	Start value (x_0)	Volatility in % (σ)	Mean reversion (κ)
Annual average price of electricity (without emissions trading)	$p_{e,base}$	€/MWh	Lognormally distributed	24.1[a]	24.1	33[a]	0.5[a]
Allowance price	p_{CO_2}	€/tCO$_2$	Lognormally distributed	See Table 3	See Table 3	See Table 3	See Table 3
Price of natural gas	p_g	€/MWh	Lognormally distributed	2010: 14.0[b] 2020: 16.1[b] 2030: 18.2[b]	14.0[c]	13[a]	0.3[a]
Price of coal (on the coast of Finland)	p_c	€/MWh	Lognormally distributed	2010: 5.8[b] 2020: 6.1[b] 2030: 6.4[b]	7.6[c]	11[d]	0.8[d]
Price of biomass	p_b	€/MWh	Lognormally distributed	10.5[c]	10.5[c]	10[a]	0.4[a]
Price of Heavy Fuel Oil (HFO)	p_o	€/MWh	Lognormally distributed	2010: 13.4[b] 2020: 15.9[b] 2030: 17.7[c]	17.3[c]	19[d]	0.4[d]

[a]Based on real annual average prices from 1996 to Sep/Oct 2004 (Nordpool, 2004 Electrowatt-Ekono, 2004).
[b]Based on data from IEA(2004) vs. 2003 prices.
[c]Latest market price available.
[d]Based on real annual average prices from 1990 to Sep/Oct 2004 (Electrowatt-Ekono, 2004).

Table 2
User's input correlation matrix (C_u) for the model

Stochastic variable	$p_{e,base}$	p_g	p_c	p_o	p_b
Price of electricity without emissions trading ($p_{e,base}$)	1	0,5	0,3	0,2	0,6
Price of natural gas (p_g)	0,5	1	0,7	0,7	−0,1
Price of coal (p_c)	0,3	0,7	1	0,4[a]	−0,4
Price of oil (p_o)	0,2	0,7	0,4	1	0,0
Price of biomass (p_b)	0,6	−0,1	−0,4	0,0	1

Correlations based on annual average data 1996–2004 (fuels: on a monthly basis, electricity: on a weekly basis).
[a]Data basis different: 1991–2004.

Table 3
Scenarios for the price and volatility of allowances

Scenario	Symbol	Unit	Stochastic process	Long-run average (x^*)	Start value (x_0)	Volatility (%) (σ)	Mean reversion (κ)
"Low, well-predictable allowance price"	p_{CO_2}	€/tCO$_2$	Lognormally distributed	10	8	20	0,2
"High, volatile allowance price"	p_{CO_2}	€/tCO$_2$	Lognormally distributed	10 (−2007) 15 (2008–2012) 20 (2013–)	8	30	0,2
"Very high, well-predictable allowance price"	p_{CO_2}	€/tCO$_2$	Lognormally distributed	10 (–2007) 25 (2008–)	8	20	0,2

where $p_{e,base}$ is the annual average price of electricity without emissions trading, p_{CO_2} is the emission allowance price, and γ is the estimated transformation factor. The transformation factor γ is equal to the emission factor of the marginal plant in the power system, which results from the merit order, and thus depends on fluctuation in electricity supply and demand.

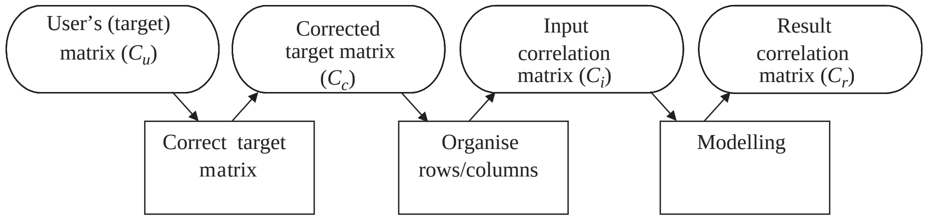

Fig. 1. Processing of the correlation matrix.

Eq. (4) allows explicit modelling of the transformation factor (γ). A further advantage is that there is historical data on $p_{e,base}$, whereas a little is known about the behaviour of p_e. The electricity supply in the Nordic countries—and thereby the price of electricity—significantly varies with hydrological conditions. Therefore, there are two more simplifying assumptions: (1) based on the results of ECON (2004), the marginal plant (type) in the power system and thus the transformation factor γ is a function of $p_{e,base}$ and the expected value for the emission allowance price, $E(p_{CO_2})$; (see Appendix A for details) and (2) 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.

The model applies an *optimal input correlation matrix, C_i,* for the state variables in time series generation (Fig. 1). In order to secure that the matrix does not have internal inconsistencies, i.e. it is positively semi-definite, the matrix given by the user, C_u (Table 2), is checked and then corrected with the spectral decomposition procedure proposed by Rebonato and Jäckel (1999). The model is sensitive to the *generation order* of the state variables, i.e. the time series are generated sequentially (as opposite to simultaneous generation), which implies that σ_{ij} with large i or j tend to be more inaccurate than those with small i or j. To improve this feature before modelling, the corrected target matrix (C_c) is experimentally organized so that the error in the expected result correlation matrix, $E(C_i - C_r)$, is minimized.

For correlations with the emission allowance price, the first scenario is that the emission allowance price is relatively independent on other market prices, i.e. all the correlations are set to zero (Table 4). In the second "correlations" scenario, there are strong positive correlations with p_g and p_b, since competitiveness of gas and biomass improves with a higher allowance price. In addition, there is a weaker correlation with $p_{e,base}$, as the shortage of rainfall in Scandinavia (and consequently high electricity prices) could somewhat increase the allowance market price.

In addition, a number of variables are assumed deterministic, for example, the investment costs. Different scenarios with varying probabilities can be applied to the deterministic variables.

Throughout the paper, different concepts for the NPV are used (Table 5).

In the case of a simple NPV, all decisions related to the management (e.g. production, fuel selection and expansion) of the project are assumed rigid and are made at t_0, the time of analysis. Two versions of the NPV_{ext} are estimated. In the first one, short-term electricity prices are assumed to be volatile, but long-term prices deterministic. Real options related to production decisions (e.g. option to alter operating scale, option to switch fuel, option to switch product) are therefore already incorporated. In the second one, long-term electricity prices are stochastic, and, e.g. real options related to sequential investment (option to expand) can be considered.

Table 4
Scenarios for correlations of emission allowance price and other market prices

Scenario	$p_{e,base}$	p_g	p_c	p_o	p_b
No correlations	0	0	0	0	0
Correlations	0.3	0.7	0	0	0.7

3. Case study 1: An existing condensing power plant

3.1. Objective

The objective of case study 1 is to explore the value of an option to invest in biomass gasification technology in an existing coal-fired condensing power plant in the Nordic electricity market. Through the gasification technology part of the fuel input can be replaced by biomass. This is however made only if the price of biomass vs. coal is favourable. An investment in the IGCC technology can thus give the owner a valuable *option to switch fuel* (e.g. Kulatilaka, 1993). In addition, both before and after the investment there is an *option to alter operating scale* (e.g. McDonald and Siegel, 1985), i.e. not to produce unless the *spark spread*, the market price of electricity minus the cost of its production, in the plant is positive.

The investment decision could be made at earliest in 2005 and the plant could in this case start operation in 2007. The lifetime of the existing power plant is assumed to be fixed. For this reason, the value of an *option to wait* is probably limited. The case study is thus focused on the evaluation of real options related to operation.

Table 5
Contents of the applied Net Present Value concepts

Feature of modelling	*NPV*	NPV_{ext} (deterministic)	NPV_{ext} (stochastic)
Modelling of short-term electricity prices and heat demand	Volatility included	Volatility included	Volatility included
Modelling of long-term prices	Deterministic	Deterministic	Stochastic
Modelling of project management	Rigid	Optimized	Optimized

3.2. Model specifications

The ΔNPV ignoring options would give the cash flow from the IGCC investment (CF_{NET}) for any period as

$$CF_{NET} = CF_{IGCC} - CF_{coal} + \Delta N p_{\mathrm{CO_2}} - \Delta Cf, \tag{5}$$

where CF_{IGCC} is the variable cash flow (in €) in the gasification-mode; CF_{coal} is the variable cash flow in the coal-only mode before the IGCC investment; ΔN is the change in the initial allocation of emission allowances; $p_{\mathrm{CO_2}}$ is the value of an emission allowance; and ΔC_f is the expected change in the fixed cost.

In each period t, the owner can however choose from three operating modes: (1) to run the plant with gasification; (2) to run the plant without gasification in a coal-fired mode; and (3) not to run the plant. The problem is simplified assuming that the switching costs are negligible in the long run.[5] To estimate ΔNPV_{ext}, the cash flow from the IGCC investment (CF_{NET}) for any period can thus be expressed as

$$\begin{aligned} CF_{NET} = {} & \mathrm{Max}[CF_{IGCC}, CF_{coal}, 0] - \mathrm{Max}[CF_{coal}, 0] \\ & + \Delta N p_{\mathrm{CO_2}} - \Delta Cf, \end{aligned} \tag{6}$$

where the variable cash flow in the coal-only mode *before* and *after* the IGCC investment are assumed equal. Eq. (4) thus implies that after the investment the plant is run whenever CF_{IGCC} or CF_{coal} are positive, and that the cash flow generated is compared with the optimal cash flow before the investment.

I assume that $\Delta N = 0$ implying that the construction of the gasification plant would *not* affect the initial allocation in the first or subsequent trading periods. This is, however, a regulatory risk for the project, which cannot be completely ruled out by the time of writing. It is further defined as

$$\begin{aligned} CF_{coal} = P_{coal}(t) \int \Bigg(& p_{e,base} - \frac{p_{coal}}{\eta_{coal}} + \bigg(\gamma(p_{e,base}, E(p_{\mathrm{CO_2}})) \\ & - \frac{e_{coal}}{\eta_{coal}} \bigg) p_{\mathrm{CO_2}} - \psi \Bigg) \, \mathrm{d}t, \end{aligned} \tag{7}$$

$$\begin{aligned} CF_{IGCC} = P_{IGCC}(t) \int & (p_{e,base} - B + (\gamma(p_{e,base}, E(p_{\mathrm{CO_2}})) \\ & - C) p_{\mathrm{CO_2}} + x_{bio}\phi_{bio} - \psi) \, \mathrm{d}t, \end{aligned}$$

$$\begin{aligned} & B = (x_{bio} p_{bio} + (1 - x_{bio}) p_{coal}) / \eta_{IGCC}, \\ & C = (1 - x_{bio}) e_{coal} / \eta_{IGCC}, \end{aligned} \tag{8}$$

where P_{coal} is the electric output of the coal mode; P_{IGCC} the electric output in the IGCC mode; x_{bio} is the share of biomass in the fuel mix, p_{coal} and p_{bio} are the prices of coal and biomass, respectively; e_{coal} is the emission factor of coal; ϕ_{bio} the tax subsidy paid for electricity produced with biomass; η_{coal} and η_{IGCC} are the thermal efficiencies of the plant before and after the investment; and ψ is the operation and maintenance cost. In the model, $\mathrm{d}t$ is assumed equal to one day, and P_{IGCC}, P_{coal} and the related thermal efficiencies are simplified as constants.

3.3. Constant parameters

The remaining lifetime of the plant (T_p) is estimated at 15 years. It is assumed that the thermal power of the plant is 560 MW_{th} and the output in the coal-only mode (P_{coal}) is 225MW_e. Two design alternatives are tested for the IGCC plant: a small and a large plant (Table 6). It is assumed that the IGCC plant somewhat decreases the thermal efficiency of the plant. The operation and maintenance cost (ψ) is assumed to be 2.0 €/MWh_e (Smekens et al., 2003) and unaffected by the IGCC plant. The maximum full-load hours per year are assumed to be 7500 h for the total plant, and the cash flows are multiplied by a factor of 0.9 in order to reflect part loads and potential risks in availability.

In ΔNPV, it is assumed that the plant will be run according to the maximum availability of the biomass fuel, i.e. in both cases 6000 h per year with full-load.

Electricity produced with biomass currently receives a production subsidy of 6.9 €/MWh_e. A governmental working group has made a proposal to remove this subsidy from concentrated liquors used by the pulp and paper industry as well as from industrial wood residues and by-products (MTI, 2004). In this analysis it is assumed that the subsidy is given until the end of the plant lifetime and that the biomass used is forest chip or a similar fuel, which obtains the highest subsidy.

Four stochastic variables are run 500 times for the remaining lifetime of the plant:

- price of electricity ($p_{e,base}$),
- allowance price ($p_{\mathrm{CO_2}}$),
- biomass price (p_{bio}),
- coal price (p_{coal}).

The real discount factor (R) is set at 1.06.

[5] See Tseng and Barz (2002) for significance of switching costs in a short-term asset valuation problem.

3.4. Results

The investment in a small or a large IGCC plant is clearly nonviable in all scenarios, and the result is non-sensitive to the assumed coal price (Tables 7 and 8). The Extended Net Present Values (ΔNPV_{ext}) do not significantly differ, but the difference to the ΔNPV ignoring options to switch or alter operating scale can be substantial: ΔO is at maximum −€13 million for the small plant and –€65 million for the large plant. ΔNPV tends to overestimate the loss with a low allowance price, and underestimate it with a high allowance price. The optimal investment decision would change in the best scenario for the large plant, where ΔNPV erroneously gives a positive outcome for the IGCC investment.

The results imply that the price of the option to switch fuel in this existing plant is too high. Two major factors explain the result. First, the initial investment and the increase in fixed costs are fairly high compared to the incoming revenue. Second, optimal operating hours of the plant seem to remain at a very low level, in particular in the case of the small plant (Fig. 2).

The full-load hours assumed for the ΔNPV seem far too high in a simulation. The reason for the low operating hours is the necessary cogeneration of electricity with biomass *and* coal simultaneously: a high value for emission allowances makes biomass more competitive, but it also increases the cost of production and reduces the competitiveness of the *total* plant. It is the variable cost of the total plant that determines the operating hours, not the variable cost of the IGCC plant.

The results are not sensitive to the assumed function for the marginal emission factor, γ (Table 9). As the price of electricity is higher the operating hours increase, but the loss in power due to the IGCC investment also gains in importance.

The results are fairly indifferent to the correlation scenario assumed, or the volatilities assumed for coal or biomass prices.

Table 6
Parameter scenarios for the IGCC plant

Parameter	Symbol	Unit	Scenario "small IGCC"	Scenario "large IGCC"
Biomass fuel share with gasification	x_{bio}	%	8.9	50
Thermal efficiency with gasification	η_{IGCC}	%	40.1	39.6
Investment cost	I	M€	19	61
Additional fixed cost due to IGCC	ΔC_f	M€/a	0.7	2.3

Table 7
Results for the small plant (in M€)

Scenario		E(ΔNPV)	E(ΔNPV_{ext}) deterministic	$E(\Delta NPV_{ext})$ stochastic
(1) No Emissions trading	+ Revenue[a]	−5.5	+ 0.0	+ 0.0
	−Investment[b]	−23.6	−23.6	−23.6
	= Net value	= −29.1	= −23.6	= −23.6
(2) "Low, well-predictable allowance price" and "No correlations"	+ Revenue[a]	+ 2.7	+ 2.4	+ 1.7
	−Investment[b]	−23.6	−23.6	−23.6
	= Net value	= −20.9	= −21.2	= −21.9
(3) "High, volatile allowance price" and "No correlations"	+ Revenue[a]	+ 7.7	+ 4.0	+ 2.8
	−Investmentb[b]	−23.6	−23.6	−23.6
	= Net value	= −15.9	= −19.6	= −20.8
(4) "Very high, well-predictable allowance price" and "No correlations"	+ Revenue[a]	+ 11.9	+ 3.9	+ 3.1
	−Investment[b]	−23.6	−23.6	−23.6
	= Net value	= −11.7	= −19.7	= −20.5
(5) "Very high, well-predictable allowance price" and "No correlations" and coal price 7,6 €/MWh 2005–2021	+ Revenue[a]	+ 16.3	+ 3.4	+ 3.2
	−Investment[b]	−23.6	−23.6	−23.6
	= Net value	= −7.3	= −20.2	= −20.4

[a]Expected present value of the revenue due to the investment.
[b]Expected present value of the investment and the fixed costs.

Table 8
Results for the large plant (in M€)

Scenario		E(Δ*NPV*)	E(ΔNPV_{ext}) deterministic	E(ΔNPV_{ext}) stochastic
(1) No Emissions trading	+ Revenue[a]	−31.1	+ 0.0	+ 0.3
	− Investment[b]	−76.4	−76.4	−76.4
	= Net value	= −107.5	= −76.4	= −76.1
(2) "Low, well-predictable allowance price" and "No correlations"	+ Revenue[a]	+15.1	+ 13.4	+ 10.8
	− Investment[b]	−76.4	−76.4	−76.4
	= Net value	= −61.3	= −63.0	= −65.6
(3) "High, volatile allowance price" and "No correlations"	+ Revenue[a]	+43.1	+ 28.0	+ 20.3
	− Investment[b]	−76.4	−76.4	−76.4
	= Net value	= −33.3	= −48.4	= −56.1
(4) "Very high, well-predictable allowance price" and "No correlations"	+ Revenue[a]	+66.5	+ 30.4	+23.6
	− Investment[b]	−76.4	−76.4	−76.4
	= Net value	= −9.9	= −46.0	= −52.8
(5) "Very high, well-predictable allowance price" and "No correlations" and coal price 7,6 €/MWh 2005–2021	+ Revenue[a]	+91.1	+30.3	+26.4
	− Investment[b]	−76.4	−76.4	−76.4
	= Net value	= +14.8	= −46.1	= -50.0

[a]Expected present value of the revenue due to the investment.
[b]Expected present value of the investment and the fixed costs.

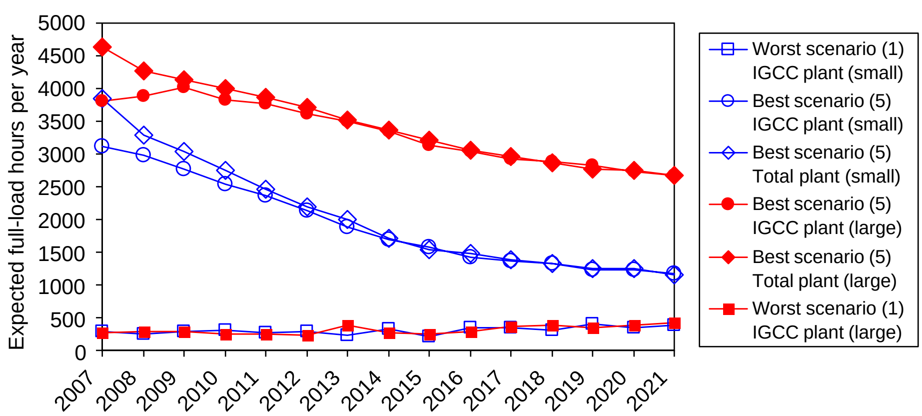

Fig. 2. Expected (500 runs) full-load hours of the IGCC and the total (IGCC + coal-only) plant.

Table 9
Sensitivity analysis for NPV_{ext} (stochastic) in the best scenario (5) (in M€)

Scenario	"Small IGCC"	"Large IGCC"
Base-case: γ as in Appendix A	−20.4	−50.0
$\gamma = 0$	−21.9	−62.3
γ as in Laurikka and Koljonen (2005)	−16.6	−29.2

4. Case study 2: A residential CHP plant

4.1. Objective and background

The objective of the second case study is to explore the value of an option to use gasification of coal in a residential CHP plant based on a Combined Cycle Gas Turbine (CCGT) in Helsinki, Finland. The investment in the CCGT plant is made in 2010 based on the estimated lack of cost competitive heat capacity. At a later time point, t_G, the investor may have an opportunity to upgrade the plant to use IGCC technology, if an upfront payment to prepare for a possible later use, I_0, is made in 2010.

The IGCC plant is considered to be an *additional component* to the energy system in place, i.e. after the investment, the company may choose whether it uses the CCGT as before or switches to coal use. The IGCC plant in this case produces gas to run the gas turbine of the CCGT plant. The remaining energy is led to the steam process, which is based on the existing heat recovery boiler and either on the existing or a new steam turbine.

The initial investment, I_0, thus provides a *compound* option[6] at time point t_0 to acquire a European option (with

[6]i.e. an option to an option. See e.g. Geske (1977).

maturity t_G) to switch fuel repeatedly depending on the market situation in periods beyond t_G. In addition, there are options to alter operating scale and an *option to switch product* (e.g. Trigeorgis, 1995) between heat and electricity in the CHP plant, since there is excess capacity (see below) in the heat production system.

4.2. Model specifications

Several technologies are important in valuation of the compound option of the case study: the new CCGT plant, the gasification technology, and the existing infrastructure to produce heat. The payoff of the IGCC technology for each period, t ($CF_{NET,\ t}$) is determined as

$$CF_{NET,t} = \text{Max}[CF_{IGCC,t}, CF_{CCGT,t}] - CF_{CCGT,t} - \Delta C_f \quad (9)$$

with $CF_{IGCC,\ t}$ being the variable cash flow if the gasification plant is run; $CF_{CCGT,t}$ being the variable cash flow of the CCGT plant; and ΔC_f is the expected change in the fixed cost. The problem is again simplified by assuming that costs for switching the production mode are negligible. Also, potential impacts on CF_{NET} due to changes in initial allocation of allowances are ignored. The future of the free allocation as a whole—not to mention the detailed rules for plant retrofits—is unclear beyond 2012.

The simulation is implemented so that in the CCGT design the plant may be run in three different *production modes*. In the *hold* mode, the plant owner does not produce energy (with *this* plant) and the variable cash flow, $CF_{CCGT}(M_0)$ is zero. In the *power only* mode, the variable cash flow is given by

$$CF(M_1) = P_{tot}(t) \int (\eta_e p_{e,base} - p_f + (\eta_e \gamma(p_{e,base}, E(p_{CO2})) - e_f) p_{CO2} - \eta_e \psi)\, dt \quad (10)$$

with P_{tot} being the thermal output of the plant; p_f the market price of the fuel; and η_e the thermal efficiency in the power only mode. In the *cogeneration* mode the cash flow is given by

$$CF(M_2) = P_{tot}(t) \int (\alpha A(p_{e,base} - \psi) + A p_h - p_f + (\alpha A \gamma(p_{e,base}, E(p_{CO_2})) - e_f) p_{CO_2} - \omega)\, dt,$$
$$A = \eta_{CHP}/(\alpha + 1), \quad (11)$$

where α is the power-to-heat ratio; η_{CHP} the thermal efficiency in the cogeneration mode; p_h the value of heat produced; and ω the tax on the fuel used in heat production.

In each period dt, there are thus three operating modes relying on the use of natural gas in the CCGT design. If the IGCC plant is built, the owner obtains two *additional* operating modes due to the opportunity to use coal as fuel, i.e. to run $CF(M_1)$ or $CF(M_2)$ with coal. CF_{CCGT} is defined as the maximum of the three alternative operating modes in the CCGT design, and CF_{IGCC} as the maximum of the CF_{CCGT} and the two additional operating modes.

The stochastic parameters ($x_1 \ldots x_5$) in the case study are:

- price of electricity without emissions trading;
- emission allowance price;
- coal price;
- natural gas price; and
- oil price.

In order to estimate CF_{IGCC} and CF_{CCGT}, the value of heat produced, p_H in (€/MWh), needs to be estimated and the seasonal fluctuation in the market price of electricity taken into account. This has been made with a rough *weekly level* modelling of the heat production system in place, in which the weekly electricity price and the weekly heat load are fixed functions of the respective annual average prices. The existing infrastructure is simplified as four capacity blocks: gas-fired CHP plants, coal-fired CHP plants, coal-fired heat only plants and oil-fired heat only plants. The model determines the merit order of the capacity blocks, i.e. which capacity blocks are optimally selected to produce heat taking into account the weekly heat load, the weekly market price of electricity and the stochastic market prices of fuels and emission allowance. A weekly level model may somewhat underestimate the value of an option to switch fuel in ideal conditions, but in shorter timescales the technical constraints of the plant, such as up- and downtimes, also become more important and may have an opposite effect (Tseng and Barz, 2002).

In order to estimate the value of the investment (ΔNPV_{ext}-stochastic) in the gasification plant a probability distribution for the cash flow (CF_{NET}) at time t_G is first created using N_1 model runs (Fig. 3). Second, k (where $k << N_1$) reference points with the corresponding state variables are selected evenly from the cash flow distribution. Third, from each reference point, the expected value of future cash flows until the end of the project lifetime, $E(DCF_{NET})$, is estimated using N_2 model runs. If $E(DCF_{NET})$ exceeds the remaining investment (after the initial investment I_0) to the IGCC technology (I_{tG}), then the model assumes that the investment is really implemented. If this is not the case, the owner only suffers a loss equal to the initial investment, I_0.

Finally, ΔNPV_{ext} is obtained as an average of the results from the individual reference points:

$$\Delta NPV_{ext} = \frac{1}{k} \sum_{i=1}^{k} \text{Max}\left[E_i(DCF_{NET}) - \frac{I_{tG}}{R^{tG}}, 0\right] - I_0,$$

where

$$DCF_{NET} = \sum_{j=tG+1}^{tG+T_p} \frac{CF^i_{NET,j}}{R^j}, \quad (12)$$

where R is the discount factor, and T_p the project lifetime. This method is easy to apply, but only a proxy to select the reference points, since a high/low cash flow for a specific reference point i does not perfectly predict a high/low $E_i(DCF_{NET})$.

The expected values of the state variables are determined in two phases. First, the start value for simulation is equal to the value at the time of the analysis, t_0. Second, in order to estimate the expected value for the period $t \in [t_G + 1, t_{G+} T_p]$, the start value is set to the expected value of the simulation for $t \in [t_0, t_G]$. In addition to the expected value, the standard error of the mean is estimated based on the assumption that deviations from $E_i(DCF_{NET})$ are perfectly correlated for varying i, and the standard deviation of ΔNPV_{ext} is equal to the average standard deviation of $E_i(DCF_{NET})$. The standard deviation of $E_i(DCF_{NET})$ is set to zero, if

$$E_i(DCF_{NET}) - \frac{I_{tG}}{R^{tG}} \leqslant 0, \tag{13}$$

i.e. when the follow-up investment seems unprofitable.

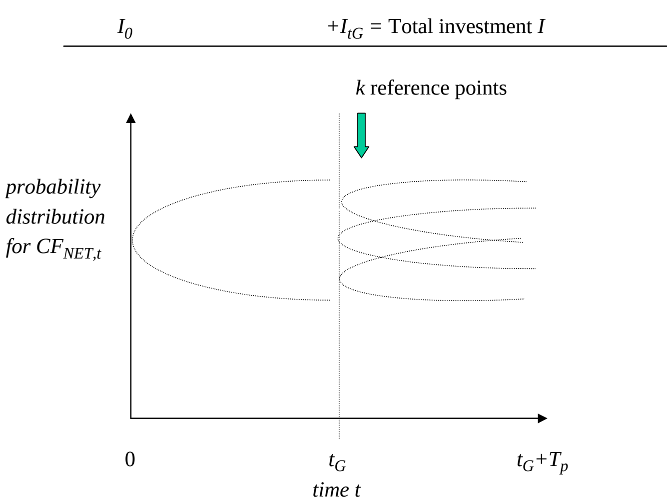

Fig. 3. Estimation of NPV_{ext} in case study 2.

4.3. Constant parameters

Table 10 shows the parameters applied in modelling. The parameters of the new CCGT plant are used also for the existing plants.

The total additional investment in the IGCC plant, I, is assumed to be the difference of a new IGCC CHP plant and a new CCGT for cogeneration ($I = 1425–550$ €/$kW_e = 875$ €/kW). This is a simplification, which is likely to underestimate the total investment, I, since any necessary retrofitting work is ignored. It is assumed that the initial payment I_0 is 2% (or 2.5 M€) of the total investment.

For demonstration of the model, N_1 is set to 500, $N_2 = 500$, and $k = 20$. The weekly price of electricity, $p_{e,week\_j}$, is based on the average weekly data from 1996 to 2004. Similarly to the first case study, the maximum full-load operating time of the plant is 7500 h annually; the cash flows are further multiplied by a factor of 0.9 in order to reflect part loads and potential risks in availability; and the real discount factor is 1.06. The annual maintenance breaks are expected to take place in the summer season. The construction time, during which the power plant is not in use at all, is assumed to be 1 year.

Table 10
Constant parameters applied

Parameter	Symbol	Unit	CCGT (CHP)	IGCC CHP (coal)	CHP coal	Heat only (coal)	Heat only (oil)
Output capacity	P_{tot}	MW_{th}	500	614	1190	189	n.a.
Operating lifetime	T_p	a	25[a]	25[b]	n.a.	n.a.	n.a.
Power-to-heat ratio	α	—	1.2[a]	1.143[b]	0.51	0	0
Thermal efficiency in CHP-mode	η_{CHP}	%	90[a]	75[b]	90	90	90
Thermal efficiency in power-only mode[c]	η_e	%	52	2010[d]:52 2020[d]:56 2030[e]:57	n.a.	—	—
Power output	P_e	MW_e	245	245	max. 360	—	—
Heat output	P_{th}	MW_h	205	215	max. 710	max. 170	large
Investment cost	I	€/kW_e	550	1425[b]	n.a.	n.a.	n.a.
Fixed cost	C_f	€/kW_e	11[a]	30[b]	n.a.	n.a.	n.a.
O&M costs and fees	ψ	€/MWh	1.75[a] (€/MWh_e)	9[b] (€/MWh_e)	1.0[b] (€/MWh_{th})	1.4[f] (€/MWh_{th})	0.6[f] (€/MWh_{th})
CO_2 emission factor	e_f	gCO_2/kWh_{th}	202	334	334	334	276
Tax for heat	ω	€/MWh_{th}	0.5	1.7	2.9	6.3	5.3

[a] Ryden, 2003, 1 EUR = 9.1 SEK
[b] Smekens et al. 2003, 1 EUR = 1.2 USD.
[c] The efficiency of the IGCC plant in the power only mode is assumed linear between the given years.
[d] Lako 2004.
[e] Harmoinen et al. 2002.
[f] Electrowatt-Ekono (2003b).

Table 11
Sensitivity analysis for the option value with $t_G = 2019$ and $I_0 = 2\%$ (in M€)

Scenario	"High, volatile allowance price "+" No correlations"				
	$E(\Delta NPV)$	$E(\Delta NPV_{ext})$ deterministic	$E(\Delta NPV_{ext})$ stochastic	(ΔO)	Standard error of the mean
Base-case: γ as in Appendix A	−3.2	−3.2	−3.2	0	0
γ as in Laurikka and Koljonen (2005)	−3.2	59	31	34	2

4.4. Results

The results (for $t_G = 2019$) suggest that the value of the compound option related to the IGCC technology is zero in all scenarios independent on how large the initial investment (I_0) is, if the total investment, I, is 875 €/kW$_e$. The result is however sensitive to the function assumed for the marginal emission factor γ (Table 11). If it is expected that a very large increase in the market price of electricity is possible due to emissions trading (see, e.g. Laurikka and Koljonen, 2005), then the option value can be considerable.

If the total investment can be significantly reduced then the option becomes valuable in particularly with the "low, well-predictable allowance price" scenario (Fig. 4, Table 12), and can change the investment decision according to a strict NPV rule.[7] The impact of a higher allowance price on the option value is dependent on the correlation scenario.

A higher volatility for fuel prices tends to increase the value of an investment in I_0. On the other hand, an earlier exercise year, t_G, decreases the value of an investment in I_0 and reduces the value of the compound option (Table 13). However, if a company pays the initial investment, I_0, it in reality has leeway concerning timing: instead of a European option, the company has an American option. It is therefore essential to note that if the company can invest either with $t_G = 2014$ or 2019, the value of the option must be at least equal to a sole investment option with $t_G = 2019$. It is also implicitly assumed that the IGCC investment extends the lifetime of the total plant with 25 years independent on t_G, which may exaggerate the effect.

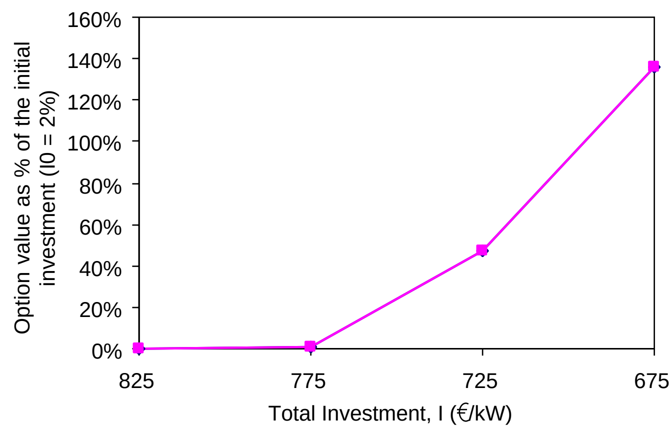

Fig. 4. Dependence of the option value (ΔO) on the investment cost, I, in the "low, well-predictable allowance price "+" No correlations" scenario.

5. Conclusions

The present paper explored the impacts of emissions trading on valuation of IGCC investments. A stochastic price model, which is able to quantify the value of multiple simultaneous real options involved in the investment decision, was applied in the analysis. The outcome was compared to the results from a simple DCF analysis ignoring all real options.

The results suggest that a straightforward application of DCF analysis can cause biased results in current competitive energy markets within an emissions trading scheme, where a number of uncertainties potentially combined with several real options can make quantitative investment appraisals very complex. The IGCC technology does not yet seem competitive in power plant retrofits within the EU ETS. The current investment cost of IGCC technology is too high for viable retrofit investments.

The first case study analysed the value of the IGCC technology as an additional component to an existing power plant with a limited lifetime and found no significant differences in deterministic vs. stochastic valuation. The price of the option to switch fuel provided by the IGCC technology was too high. However, there was a remarkable difference to the straightforward NPV estimate totally ignoring real options.

The second case study explored the value of a preparation investment to the potential later use of the IGCC technology. The price of such a compound option to switch fuel was too high with the current investment cost estimate. If the total investment were lower, the stochastic approach would give significantly different results from a deterministic approach and could even change the investment decision (according to a strict NPV rule).

The additional benefit from a stochastic approach for investment appraisals depends on the individual parameters of the appraisal, such as the investment cost. A stochastic approach to valuation requires more input

[7] Investment implemented if $NPV > 0$.

Table 12
NPVs, option value and the standard error of the mean (SEM) for $t_G = 2019$, $I = 675$ €/kW_e and $I_0 = 2\%$ (in M€)

Scenario	$E(\Delta NPV)$	$E(\Delta NPV_{ext})$ deterministic	$E(\Delta NPV_{ext})$ stochastic	(ΔO)	Standard error of the mean
No emissions trading	−2.5	−2.5	−2.5	0	0
"Low, well-predictable allowance price" and "No correlations"	−2.5	−2.5	0.9	3.4	1.2
"Low, well-predictable allowance price" and "Correlations"	−2.5	−2.5	1.1	3.6	1.4
"High, volatile allowance price" and "No correlations"	−2.5	−0.4	1.0	3.5	1.1
"High, volatile allowance price" and "Correlations"	−2.5	−0.4	−0.6	1.9	0.9

Table 13
Net Present Value (NPV_{ext}) with varying t_G, $I = 675$ €/kW$_e$ and $I_0 = 2\%$ (in M€)

Scenario	t_G	$E(\Delta NPV)$	$E(\Delta NPV_{ext})$ deterministic	$E(\Delta NPV_{ext})$ stochastic	(ΔO)	Standard error of the mean
"Low, well-predictable allowance price" and "No correlations"	2014	−2.5	−2.5	−2.5	0	0
	2019	−2.5	−2.5	0.9	3.4	1.2
	2024	−2.5	1.4	8.5	11	1.2
"High, volatile allowance price" and "No correlations"	2014	−2.5	−2.5	−2.5	0	0
	2019	−2.5	−0.4	1.0	3.5	1.1
	2024	−2.5	6.0	8.4	11	1.0

parameters and is more laborious than conventional methods. The additional work is probably negligible compared to the potential benefits in most—but not all—cases. An adequate pre-screening is therefore recommendable.

Acknowledgements

I would like to thank Pekka Pirilä, Ilkka Keppo, Lars Horn, Timo Arponen, Jussi Hintikka and Axel Michaelowa for help and/or valuable comments. All remaining errors are those of the author. The financial support of National Technology Agency of Finland, the Environment Pool of the Association of the Finnish Energy Industries, and the Foundation for Economic Education is gratefully acknowledged. The views expressed in this paper are those of the author and do not necessarily reflect the opinions of the financiers.

Appendix A. Modelling the marginal emission factor

(At least) Three studies have estimated the medium- to long-term impact of the EU ETS on the electricity price in the Nordic electricity market. From these studies, the average marginal emission factor can be derived (Table A1).

The studies find three major determinants for the marginal emission factor:

Time horizon: the price impact (and the marginal emission factor) are smaller in the long-term than short-term due to the expansion of gas-fired power plants (ECON, 2004, p. 35).

Hydrological year: Electrowatt-Ekono (2003a) projects that in a wet year with a low allowance value (5 €/t CO_2), CHP production mainly forms the Nordic marginal price (Finnish coal-fired condensing power is on the margin only 5% of the time). This should significantly reduce the marginal emission factor. However, ECON (2004) estimates only a slight difference. In dry years, the emission factor is estimated a lot larger than in a normal year with an allowance price of 10 €/t CO_2 (ECON, 2004), though Electrowatt-Ekono (2003a) projects that the number of hours, in which oil-fired CHP forms the margin, would increase in dry years (thus reducing the average marginal emission factor). With a high allowance price of 20–30 €/t CO_2, ECON (2004) and Koljonen et al. (2004) project opposite results (see above).

Allowance prices: the studies estimate the price impact nearly constant in normal and wet years. ECON

Table A1
The average marginal emission factor in Finland (in t CO_2/MWh)

Year	Hydrological year	Electrowatt-Ekono (2003a)	Koljonen et al. (2004)	ECON (2004)
2010	Normal	5 €/t CO_2: 0.78	5 €/t CO_2: 0.72	
	Normal	10 €/t CO_2: 0.76	15 €/t CO_2: 0.65	
	Normal	20 €/t CO_2: 0.765	30 €/t CO_2: 0.56	
	Dry	—	30 €/t CO_2: 0.6	
2012	Normal	—	—	10 €/t CO_2: 0.44
	Normal			20 €/t CO_2: 0.39
	Dry	—	—	10 €/t CO_2: 0.76
	Dry			20 €/t CO_2: 0.20
	Wet	—	—	10 €/t CO_2: 0.42
	Wet			20 €/t CO_2: 0.33

(2004, p. 63) projects that the impact in a dry year may be less with high allowance prices, since ‘‘higher CO_2 price stimulates the expansion of gas power in Norway, which, during normal years, is used for export to the Continent’’.

Generally, ECON (2004) projects a lower impact than Koljonen et al. (2004) or Electrowatt-Ekono (2003a). In the latter studies modelling of investments is based on deterministic[8] investment scenarios. Koljonen et al. (2004) note this as ‘‘the main error component in the market price projections’’. In ECON’s model, part of the capacity modelling is endogenous, since it is important to take the importance of market supply and demand changes into account when analysing the effects of emissions trading on the power price (ECON 2004, p. 37). They assume that gas-fuelled power stations are invested (mainly in Norway) as soon as the ‘‘average price is high enough to cover the total costs’’ (ECON 2004, p. 47).

In this paper, I model the marginal emission factor γ as a function of the baseline electricity price, $p_{e,base}$, reflecting the stochastic hydrological year,[9] *and* $E(p_{CO_2})$ reflecting the *expected* allowance price and thus electricity supply and demand for the year in question. I apply a simple regression to the results of ECON (2004) for the year 2012 to form the following rough function for the marginal emission factor:

$$\gamma(E(p_{CO_2}), p_{e,base}) = \mathrm{Max}[0,\ \mathrm{Min}\{0.77,\ Ap_{e,base}^2 + Bp_{e,base} + C\}],$$

so that

$$A = -0.00012302 \cdot E(p_{CO_2}) + 0.00223075,$$
$$B = 0.00205598 \cdot E(p_{CO_2}) - 0.04110245,$$
$$C = 0.44116282. \tag{A.1}$$

[8]Electrowatt-Ekono (2003a) varies the amount of wind power (2.1–8 TWh) and gas-fired capacity in Norway (400 or 800 MW) as a function of the allowance price. Koljonen et al. (2004) apply a single capacity scenario.

[9]This part of the function is similar to the one used in Laurikka and Koljonen (2005).

Eq. (A.1) is thus constrained so that the marginal emission factor $\gamma \in [0, 0.77]$.

It is further assumed that (A.1) can be applied to the time period beyond 2012. This kind of function for γ is simplified and time-sensitive, but can be improved with sophisticated energy system models.

References

Amram, M., Kulatilaka, N., 1999. Real Options—Managing Strategic Investment in an Uncertain World. Harvard Business School Press, Boston, MA.

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

ECON, 2004. Emissions trading and power prices. ECON Report 2004-020, Project No. 42100.

Electrowatt-Ekono, 2003a. Emissions trading and the Nordic electricity market. Report 60K04063-Q070-004.

Electrowatt-Ekono, 2003b. Selvitys päästökaupan ja energiaverotuksen vaikutuksesta sähkön ja lämmön yhteistuotannon asemaan ja lämmitysmarkkinoihin (in Finnish).

Electrowatt-Ekono, 2004. Polttoaineiden hintatietoja (in Finnish).

Geske, 1977. The valuation of corporate liabilities as compound options. Journal of Financial and Quantitative Analysis 12 (4), 541–552.

Harmoinen A., Heikkilä, J., Nyberg, K., Raiko, M., Hepola, J., Kurkela, E., 2002. Development scenarios of high-efficiency power plant technologies in centralised electricity and heat production and their impacts on Greenhouse gas emissions. In: Soimakallio, S., Savolainen, I. (Eds.), 2002: Technology and Climate Change—CLIMTECH 1999–2002. Tekes, National Technology Agency (of Finland). Technology Programme Report 14/2002, Helsinki, pp. 77–89.

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).

Kulatilaka, N., 1993. The value of flexibility: the case of a dual-fired industrial steam boiler. Financial Management 22 (3), 271–281.

Lako, P., 2004. Coal-fired power technologies – coal-fired power options on the brink of climate policies. ECN-C-04-076, Netherlands.

Laurikka, H., Koljonen, T., 2005. Emissions trading and investment decisions in the power sector—a case study in Finland. Energy Policy, in press.

McDonald, R.L., Siegel, D.R., 1985. Investment and the valuation of firms when there is an option to shut down. International Economic Review 26 (2), 331–349.

MTI (Ministry of Trade and Industry, Finland), 2004. EU:n päästökaupan, energiaverotuksen ja energiantuotannon tukien yhteensovittaminen. KTM julkaisuja 35/2004 (in Finnish).

Rebonato, R., Jäckel, P., 1999. The most general methodology to create a valid correlation matrix for risk management and option pricing purposes. Natwest group.

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

Schwartz, E., Trigeorgis, L. (Eds.), 2001. Real options and investment under uncertainty: classical readings and recent contributions. MIT Press, Cambridge, MA.

Smekens, K.E.L., Lako, P., Seebregts, A.J., 2003. Technologies and technology learning, contributions to IEA's Energy Technology Perspectives. ECN-C-03-046.

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., 2005. Electricity market modeling trends. Energy Policy 33 (7), 897–913.