Long-Term Capacity Planning and Feasibility of Nuclear Power in Estonia Under Uncertain Conditions

MART LANDSBERG

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MART LANDSBERG

TALLINN UNIVERSITY OF TECHNOLOGY
Faculty of Power Engineering
Department of Electrical Power Engineering

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Supervisors: Professor Olev Liik, Department of Electrical Power Engineering, Tallinn University of Technology
Professor Heiki Tammoja, Department of Electrical Power Engineering, Tallinn University of Technology

Opponents: Ahti Salo, Professor, Helsinki University of Technology, Visiting Professor at London Business School
Raine Pajo, PhD, Eesti Energia AS, Member of the Board, Technical Director
Rimantas Deksnys, Professor, Kaunas University of Technology

Defence of the thesis: December 10, 2008 at Tallinn University of Technology, Ehitajate tee 5, Tallinn, Estonia

Declaration:
Hereby I declare that this doctoral thesis, my original investigation and achievement, submitted for a doctoral degree at Tallinn University of Technology, has not been submitted for any academic degree.

Mart Landsberg ……………….

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ENERGEETIKA, ELEKTROENERGEETIKA, MÄEDUS D33

Pikaajaline elektritootmisvõimsuste planeerimine ja tuumaelektrijaama tasuvus Eestis määramatuse tingimustes

MART LANDSBERG

ABBREVIATIONS AND UNITS

AC	alternating current
BALTSO	Organization of Baltic Transmission System Operators
BRELL	Organization of Belarusian, Russian, Estonian, Latvian, Lithuanian Transmission System Operators
CANDU	The acronym "CANDU", a registered trademark of Atomic Energy of Canada Limited, stands for "CANada Deuterium Uranium"
CCGT	combined cycle gas turbine
CCS	carbon capture and storage
CFB	circulating fluidized bed
CFBC	circulating fluidized bed combustion
CHP	combined heat and power
CIS	Commonwealth of Independent States
CO	carbon oxide
CO_2	carbon dioxide
DC	direct current
deNOx	NO_X cleaning of flue gases
deSOx	desulphurisation of flue gases
EEK	Estonian crown
EPC	engineer-procure-construct
ETL	endogenous technology learning
ETSAP	Energy Technology System Analysis Programme
EU	European Union
EUR	European momentary unit euro
FOAKE	first-of-a-kind engineering
GDP	gross domestic product
GJ	gigajoule
Gt	gigatonnes
GW	gigawatt
GWh	gigawatt hour
HPP	hydro power plant
HRSG	heat recovery steam generator
HVDC	high voltage direct current
IAEA	International Atomic Energy Agency
IEA	International Energy Agency
IGCC	integrated gasification combined-cycle
invfuel	investment and fuel
IRIS	International Reactor Innovative and Secure
kV	kilovolt
kW	kilowatt
LP	linear programming
LWR	light water reactor

MARKAL	long-term energy-environment planning model, abbreviation of “Market Allocation”
max	maximum
min	minimum
MW	megawatt
N-1	security criteria of the power system, described in Estonian Grid Code
NEA	Nuclear Energy Agency
NO_X	nitrogen oxides
NPP	nuclear power plant
NPV	net present value
“NUC” or “nuc”	nuclear
O&M	operation and maintenance
OECD	Organisation for Economic Cooperation and Development
PFBC	pressurized fluidized bed combustion
PHARE	Abbreviation of “Poland and Hungary: Assistance for Restructuring their Economies”. Programme, financed by the EU
PJ	petajoule
PP	power plant
PSS/E	Power System Simulator for Engineering
PWR	pressurized water reactor
RES	renewable energy source
SO_2	sulphur dioxide
TJ	terajoule
TPP	thermal power plant
toe	ton of oil equivalent
TSO	transmission system operator
TUT	Tallinn University of Technology
TWh	terawatt hour
UNFCCC	United Nations Framework Convention on Climate Change

Conversion factors

1 GWh	3600 GJ
1 toe	41,86 GJ

Unit prefixes

k	kilo, 10^3
M	Mega, 10^6
G	Giga, 10^9
T	Tera, 10^{12}
P	Peta, 10^{15}
E	Exa, 10^{18}

LIST OF ORIGINAL PAPERS

The present doctoral thesis is partly based on the following papers, which are referred to in the text by their Roman numerals I-V:

I **M. Landsberg**, H. Tammoja, J. Kilter. Optimal Introduction of a Nuclear Power Plant in Estonia Under Uncertain Conditions. 2008 Power Quality and Supply Reliability Conference, Pärnu, 27 Aug - 29 Aug 2008. 2008 Power Quality And Supply Reliability Conference Proceedings ISBN: 978-1-4244-2501-3. Copyright IEEE.

II H. Agabus, **M. Landsberg**, H. Tammoja. Reduction of CO_2 Emissions in Estonia During 2000-2030. Oil Shale, Vol. 24 No. 2 pp. 209-224. 2007 Estonian Academy Publishers ISSN 0208-189X

III Liik, O., Oidram, R., Keel, M., Ojangu, J., **Landsberg, M**., Dorovatovski, N. Co-operation of Estonia’s oil shale-based power system with wind turbines // Oil Shale. 22 (2005) 2S, p. 127–142

IV Liik O., **Landsberg M**., Oidram R. About Possibilities to Integrate Wind Farms into Estonian Power System. Fourth International Workshop on Large-Scale Integration of Wind Power and Transmission Networks for Offshore Wind Farms, 20-21 October 2003, in Billund, Denmark Session 6a, paper 3. 20–21 October 2003. Billund [Denmark], 2003. p. 1–10.

In appendix A, copies of these papers have been included

Author's own contribution

The contribution by the author to the papers included in the thesis is as follows:

I Mart Landsberg wrote the paper and is the corresponding author. He performed the modelling and analysis of the Estonian power system and studied the possible introduction of nuclear power plant into the power system.

II Mart Landsberg participated in writing the paper. He performed the modelling and analysis of the Estonian power system and studied different reduction options of CO_2 and interpreted the results.

III Mart Landsberg participated in writing the paper. He performed the modelling and analysis of the Estonian power system and studied the possibility of integrating wind power into the Estonian power grid.

IV Mart Landsberg participated in writing the paper. He performed the modelling and analysis of the Estonian power grid and studied the possibility of integrating wind power into the Estonian power grid and interpreted the results of power grid simulations.

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CONTENTS

INTRODUCTION

The energy sector is a basis for the rest of economy and cannot be separated from environmental and social issues. Considering also its operation costs and investment needs, one can easily conclude that energy system operation and development have to be optimal.

The rapidly growing environmental concerns during recent decades have been playing an important role in decisions in the official energy policy in most European countries. The main reason is that priority is given to environmental protection, and from the environmental viewpoint, the energy system contains a number of sources which emit harmful pollutants, produce waste or are otherwise operated in such way that they might constitute a risk to the environment. Thus, environmental aspects should be integrated in all energy planning phases from the formulation of energy policies to the approval of implementation programmes.

Investments in the energy system made today have long-term implications for the future, thus the creation of an efficient and effective energy policy is one of the key issues for the national economy. The goal of that policy is to ensure cost-effective and sustainable development of the energy system.

It is a fact that there are at the moment environmental problems in Estonia. The background of these problems is the centrally planned economy period, when all attention was directed to fulfilling energy demand without taking environmental effects into consideration. A lot of damage to the Estonian ecology is already evident. The main source of air pollution is from oil shale power engineering. At present, a big reduction in the impact on the environment is required in Estonia.

To find a cost-effective solution to this problem it is necessary to look at the situation in its entirety:

- Development of the energy system
- Control of emissions

Estonia has a special difference from other countries in the world - oil shale, which is the most important fuel for power stations in Estonia.

Indigenous fuels (oil shale, wood and peat) form approximately 2/3 of the primary energy supply of Estonia. The share of renewable energy sources (mainly wood) is about 10%. Estonian oil shale is unique; its reserves are the largest commercially exploited deposit in the world. Oil shale is characterised as a low-grade fuel with a low heating value (average 8, 6 MJ/kg) [30].

As from 2008, our power plants have to comply with the EU directive on the limitation of emissions into the air from large combustion plants. During the accession negotiations with the EU, Estonia got some transition periods but the existing oil shale pulverized combustion units cannot work after the year 2015 without additional investments in flue gas cleaning devices. As a result, only 18% of the capacity of power plants (burning oil shale) operating in 2006 (about 2400 MW) can continue operating after 2015 [2]. Another reason is that existing power plants are close to their technical lifetime. Previous assumptions give estimations to extend the lifetime of existing units until 2020-2025. After that period it has not been decided what power plant will replace current ones.

One possibility is to construct new domestic oil-shale based modern circulating fluidized bed combustion units with subcritical or supercritical parameters. The second possibility is to use imported resources-based power production technologies, such as gas or coal. During recent decades technologies such as combined cycle generation have shown high characteristics of efficiency both for natural gas and with gasification cycle of coal.

During the last decade great attention has been paid to climate change. CO_2 emissions from fossil-fuel based power generation are one of the major contributors to the climate change. For that reason, CO_2 quotas and emission trading has been introduced in the European Union. In coming years it is forecast that the price of CO_2 will be higher than 25 EUR/tonne, but in the longer term future there is great uncertainty about price and EU policy on CO_2. It is assumed [32] that the price of CO_2 could be 50 EUR/tonne by 2025.

In the European Union great attention is paid to the introduction of a larger share of CO_2-free renewable electricity generation. During negotiations with the EU, Estonia was set an indicative target for production of electricity from renewable energy sources (RES). The electricity produced from RES must cover at least 5.1% (ca 400 GW/h) of the gross inland electricity consumption in 2010. The long-term policy of the EU envisages a share of RES 20% in 2020, but it is a fact that RES-based power generation sources are not competitive without additional subsidies.

Another possibility is to introduce nuclear generation into the Estonian power system. Nuclear generation is widely used in neighbouring countries such as Finland, Sweden, Russia and Lithuania. The development of nuclear-based generation has halted during recent decades due to public resistance since the Chernobyl catastrophe, but it is a CO_2-free, cost-effective base-load power generation alternative. Recently development of nuclear generation has experienced a renaissance all over the world.

At the moment there are several nuclear reactors under construction and several countries are planning nuclear power stations. It has also led to an increase in the capital cost of nuclear power and a rise in the nuclear fuel price is also expected, [32], [34] especially in conjunction with rapid growth of the economies of China and India.

During the last year there has also been discussion in Estonia, in government and amongst the public, about the introduction of nuclear power into the Estonian power system [7]. There are several factors that promote the introduction of nuclear and several factors that might constrain the introduction of nuclear power. Factors that may promote the introduction of nuclear power are, for example, the forecasted high price of CO_2 and fossil fuels. Factors that may constrain the introduction of nuclear power are, for example, the high capital cost and availability of nuclear fuel, the big unit size of nuclear generating units and a high interest rate. There are also some consequences in the large-scale introduction of intermittent, renewable generation such as wind. All of these factors are related to the high level of uncertainty and the introduction of nuclear power could not be handled in long term planning by conventional methods and approaches. All of these questions provided the motivation to study the complex problem of finding cost-efficient ways under uncertain conditions to introduce and integrate nuclear power in the Estonian power system.

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During the research I have received constant support from my colleagues from OÜ Põhivõrk Planning and Engineering Division and colleagues from Latvia and Lithuania, participating in the BALTSO Development Working Group. I wish to express my special thanks to Dr. Tomas Larsson, for guidance with the first steps of the Estonian MARKAL model and for support at the time of the preparation of my diploma thesis at Chalmers University of Technology.

CONTRIBUTION

The purpose of the thesis is to elaborate theoretical approaches, methodological and practical recommendations considering uncertanties in future developments and in the generation planning process. As a test case, the adoption of the nuclear power plant option by the Estonian power system was studied. The originality of the thesis consists of the theoretical and practical results.

Theoretical originality includes the determination of uncertainty factors and the minimum-maximum intervals of these factors. The influence of uncertainty factors in decisions for future investments in new power plants, and a theoretical approach considering uncertainty factors in the decision making process for long-term investments in generating capacity was elaborated. As a result, a three-step methodology using uncertainty data, decision making strategies to deal with interval-uncertain information and a long-term energy-plannning model is proposed.

The practical originality includes a comprehensive study, the first of its kind, comprising an evaluation of the introduction of nuclear power into the Estonian power system. The results of the thesis involve assessment of the most important uncertainty factors, evaluation of economic profitability of the investment under uncertain conditions and assessment of the reserves needed to operate in conjunction with a nuclear power plant in Estonia. Also incuded is an evaluation of the different plant locations from the viewpoint of the accommodation of the power plant in the future power grid in Estonia.

The current relevance of the thesis is based on the fact that the existing oil-shale power plants are at the end of their lifetime, and decisions regarding future generating options are under discussion at state and public level. At the same time, recent liberalisation of the power and fuel markets, economic uncertainties and environmental constraints create complex problems with uncertain future implications. Thus, decision-making about future generation is complicated without novel generation planning methodologies.

1 LITERATURE SURVEY

Long-term energy development planning approaches can be classified from different viewpoints. From the viewpoint of uncertainties, long-term energy planning approaches can be classified in:

- deterministic, and
- non-deterministic approaches.

In deterministic approaches the development plan is designed for the most probable forecasts of the system without considering theit probability of occurrence (degree of occurrence). Usually the most probable forecast (from the planner's viewpoint) is used to draw conclusions.

In non-deterministic approaches the development plan is designed for all possible cases which may occur in the future whilst also considering their occurrence probability. Hence, non-deterministic approaches are able to take into account past experience and future expectations. Cases, unlike forecasts, do not presuppose knowledge of the main drivers of the energy system. Instead, a case consists of a set of coherent assumptions about the future trajectories of these drivers, leading to a coherent organization of the system under study. Non-deterministic approaches are explained in subsection 1.1 in more detail. Deterministic approaches are described in brief in subsection 1.4.

From the viewpoint of energy system-horizons, development planning approaches can be classified in:

- static, and
- dynamic approaches.

In static planning the planner seeks the optimal plan for a single year on the planning horizon, that is, the planner answers only questions relating to "what" facilities must be added to the energy system. In dynamic planning several years must be considered, and planners seek the optimal strategy for the whole planning period. In other words, in dynamic planning, in addition to "what", planners answer the question "when" the facilities must be installed in the planning horizon. For long term energy planning models the latter approach is usually used. The models used for long term energy planning are described in section 1.3.

Here the publications on long-term energy planning approaches for uncertain environments are reviewed in section 1.1. The publications of the planning approaches in neighbouring countries are presented in section 1.2

The publications on the theory of taking into account future uncertainty factors is reviewed in section 1.1

1.1 Energy sector planning under uncertainty

Decision-making theory

Energy systems analysis can be used at several levels in the decision-making process, from the formulation of the political agenda to the day-to-day operation of production units. Investments in energy technology usually have long lead times and long life times. The consequences of different developments of the energy system must be evaluated over a long time period (25-40 years). Within this time horizon, uncertainties about the developments in the system environment greatly influence the cost-efficiency of different technological options. The treatment of these uncertainties is one of the key issues in the energy planning process.

The decision-theoretic approach to statistics and econometrics specifies a set of models under consideration, a set of actions available to the analyst, and a loss function (or equivalently, a utility function) that quantifies the value to the decision-maker of applying a particular action when a particular model holds. Decision rules, or procedures, map data into actions, and can be evaluated on the basis of their expected loss. Abraham Wald, in a series of papers beginning with [18] and culminating in the monograph [19], developed statistical decision theory as an extension of the Neyman-Pearson theory of testing. It has since played a major role in statistical theory for point estimation, hypothesis testing, and forecasting, especially in the construction of “optimal” procedures. The decision theory framework is sufficiently flexible that it can be used for many empirical applications that do not fit neatly into the usual statistical setups. There does not always exist a single rule that dominates all others uniformly over the parameter space, just as there does not always exist a uniformly most powerful test in the special case of hypothesis testing. Wald, who also made contributions to game theory, proposed evaluating a procedure by its minmax risk, the worst-case expected loss over the parameter space. Savage [16] discusses the minmax principle and suggests an alternative, the minmax-regret principle. He argued that in cases where the minmax criterion is unduly conservative, minmax regret rules can be reasonable. Savage [17] showed that a decision-maker who satisfied certain axioms of coherent behaviour would act as if she placed a priority on the parameter space and minimized posterior expected loss. Alternatively, one can place a probability measure on the parameter space, and evaluate rules by their weighted average (Bayes) risk.

The design of the method also depends on the nature of the uncertainties involved. Strangert [20] uses time-dependence to classify uncertainties as described below:

- Static uncertainty, when, in planning, several alternatives are recognized as possible and when there is no indication that the uncertainty may change over time or that it can be affected (diminished).'
- Quasi-static uncertainty, the form of uncertainty that can be reduced in a negligible period of time relative to the decision alternatives.
- Dynamic uncertainty, when the uncertainty is expected to resolve over time.
- Unspecified uncertainty, when the potential outcome of an external input is not (completely) specified

Variations in load factors, in spot prices of energy carriers, and in the availability of energy production units play an important role in the daily and seasonal planning for the operation of an energy system. These variations are examples of static uncertainty, and can be handled by, for instance, stochastic or dynamic programming approaches [21].

Factors in the system environment are characterized by either static or dynamic uncertainty if there remains significant uncertainty about their development within the planning horizon at the time when the initial decision has to be made. Unlike a static uncertainty, however, a dynamic uncertainty resolves itself over time.

Modelling of Uncertainty in Standard MARKAL [46]

The long term analysis of an energy system is fraught with uncertainties, be it the specification of demands and prices, or the availability and characteristics of future technologies, or the emission targets that should be adopted. Older versions of MARKAL, along with most least-cost, bottom-up models assume perfect foresight, and thus a deterministic environment. This is also the case for traditional general equilibrium models, although there are important exceptions. In the absence of explicit modelling of uncertainties, model users resort to scenario analysis, i.e. accounting for multiple possible futures via contrasted scenarios of demands, technological development, and emission constraints.

An alternate approach to running multiple deterministic scenarios consists in building a single scenario, but one where the future event bifurcation is embedded. The resulting stochastic model will be quite different in nature from the initial model. The Stochastic Programming paradigm consists of representing multiple scenarios (usually called states-of-the-world, or sow), each having a possibility of occurring, within a single coherent formulation.

Stochastic programming is easily generalized to any number of events, each with many possible outcomes. The resulting stochastic scenario is best represented by an event tree, such as the one depicted in Figure 1-1, showing 4 states-of-the-world.

In the context of energy-environment systems, stochastic modelling has been extensively used to study restricted energy systems such as optimizing the electricity generation process [25]. Studies of socio-economic impacts of the uncertain outcomes of global warming have also used stochastic models [27]. In the case of integrated energy systems, a two-step model for robustness analysis in energy planning was implemented in Larsson and Wene [24] and Larsson [66]. The method provided for assessing the efficiency and robustness of exogenously determined alternative strategies.

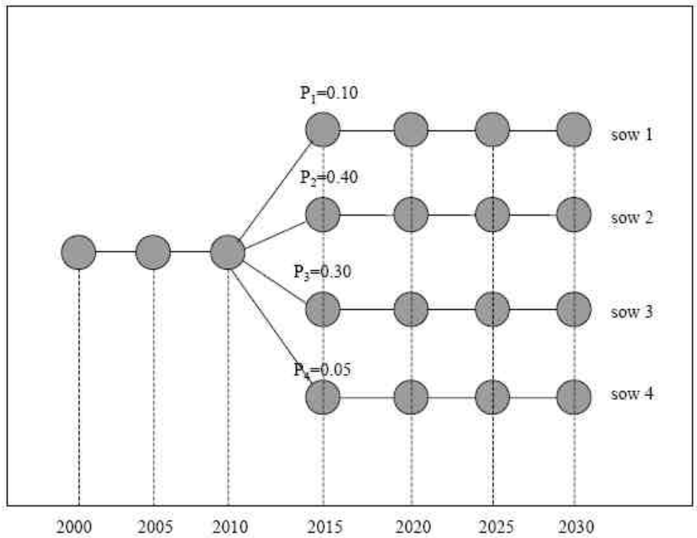

Figure 1-1 Event tree with four states-of-the-world and resolution time at period 2015 [46]

Loulou R. and Kanudia A; "Minimax regret strategies for Greenhouse Gas Abatement: methodology and application"

Loulou and Kanudia have experimentally verified that the solution of this minimax regret criterion only depends on the two extreme scenarios. They also made a comparison between deterministic, stochastic and minimax strategy for the optimisation of investment strategies under uncertainty for the energy system of the province of Québec (Canada). In their comparison, five possible limits on the maximum amount of CO_2 emissions during the period 1990-2030 were considered. The stochastic strategy assumed until 2012 that each of the 5 outcomes has a probability of 0,20 of taking place.

The minimax regret strategy considers that until 2012 each of the 5 outcomes can take place. After 2012 the best strategy is followed taking into account the true outcome and the past actions. The authors calculated the total discounted costs for the whole period for each of the strategies. In this example the solutions of the stochastic and the minimax regret strategy are very close. The expected cost of the minimax regret strategy is only 0,002% larger than the expected cost of the stochastic strategy, while the maximum regret of the stochastic strategy is 0,017% larger than the expected cost of the stochastic strategy.

From the data in Kanudia and Loulou, it is evident that none of the deterministic strategies performs nearly as well as the stochastic or the minimax regret strategy, the expected cost of their solutions is much larger, as well as the maximum regret that can be incurred

1.2 Development plans of energy sector in neighbouring countries

Finland, Outline of the Energy and Climate Policy for the Near Future - National Strategy to Implement the Kyoto Protocol

Developments and future scenarios in the Finnish power sector are described in "Outline of the Energy and Climate Policy for the Near Future - National Strategy to Implement the Kyoto Protocol Government Report to Parliament 24 November 2005" [10].

In the paper it is stated that the consumption of power is estimated to grow so that the capacity requirement will increase by some 200 MW annually until 2015, and thereafter by about 100 MW. This increase, combined with the de-commissioning of the existing capacity, will be covered by the construction of new domestic capacity and by electricity imports. As regards the security of the energy supply, the domestic capacity should, however, be sufficient also in situations in which imports are not be possible due to exceptional weather or other conditions. Cogeneration of power and heat, as well as the nuclear power unit under construction, will cover most of the additional need for domestic capacity, at least until the mid-2010s. It was mentioned in the policy that the decisions on nuclear power have a major influence on power procurement and CO_2 emissions.

At the moment there is under construction a fifth nuclear reactor, situated in Olkiluoto, and there is an ongoing process of Environmental impact assessment of 3 additional nuclear reactors in Finland.

Latvia, Guidelines for Energy Sector Development 2007 – 2016

The Latvian power system is a system with power capacity deficit, especially in the base load segment. During the last decade the share of imports in the electricity balance was in the range of 30%...40%. The problem of security of electricity supply becomes even more urgent with the dynamic growth of electric loads and the retirement of generation capacities in neighbouring markets. Most electricity is produced in hydro power plants which are "run of river" type and dependent on hydrological conditions.

Developments and future scenarios in the Latvian power sector are described in "Guidelines for Energy Sector Development 2007 – 2016" [13].

The main target for the electricity sector is to reach the self-sufficiency of the Latvian power system of 80% by 2012 and 100% by 2016, as well as a share of renewable energy sources (RES) of 49.3% by 2010.

The Government's most important policy objective is to achieve a balance between electricity demand and the supply potential of power plants by 2011 – 2012. To achieve this objective, the Government will focus on the maximum promotion of energy-efficiency measures and supplies from power plants using local fuel and renewable resources in high-efficiency cogeneration. The remaining supply capacities required will be diversified to other types of fossil fuel to prevent excessive domination of natural gas

The development plan foresees an increase of cogeneration plants from 310 MW to 650 MW in 2015, and the construction of a new solid fuel (coal) power plant by 2015. The share of RES generated electricity will grow from 63 MW in 2005 to 350 MW in 2025.

At the moment there is under construction a new combined cycle cogeneration plant with capacity 400 MW in Riga. It will replace one existing 110 MW unit of Riga CHP-2. There is also a political desire to participate in the construction of the new Ignalina nuclear power plant. It is assumed that the Latvian share in the project will be 300 MW.

Lithuania, National Energy Strategy

Developments and future scenarios in the Lithuanian power sector are described in the "National Energy Strategy" [14]. It defines the main targets set by the State and directions for their implementation until 2025. Lithuania's most important driving forces in the energy sector are growth in the economy, growing dependence on imports of primary energy from a single country (Russia) and the envisaged decommissioning of the Ignalina Nuclear Power Plant in 2009.

During the forecasting period, final energy demand would increase 1.4 to 2.1 times depending on the chosen economic growth scenario. Electricity consumption over the last five years showed in Lithuania the most rapid increase as compared to the consumption of other energy forms. According to forecasts, growth in the economy could stimulate a rapid growth in electricity demand. During the period until 2025, the basic scenario forecasts an annual average increase in electricity demand in some branches of the economy of 3.7%. According to this scenario, electricity consumption at the end of the forecasting period would be about twice as high as in 2004.

The total installed electricity-generating capacity (nuclear and non-nuclear) amounts to nearly 5000 MW and exceeds the present domestic needs of Lithuania by more than two times. After closure of Ignalina NPP, most power is to be supplied by gas-fired power plants. Due to the prospect of ever-rising CO_2 prices, the closure of Ignalina NPP will lead to increasing electricity prices in the whole Baltic region. To compensate for the lost capacity after the closure of Ignalina NPP and to increase the competitive potential of electricity production, the construction of two new combined cycle gas turbine units in Lietuvos Power Plant are planned. The capacity of one unit would be about 400 MW.

The most important targets in the power sector are described as follows: the construction of a new nuclear power plant in Lithuania to satisfy the needs of the Baltic countries and the region, and its inclusion in the electricity market of the region not later than 2015; the interconnection of Baltic electricity transmission networks with the networks of Western European and Scandinavian countries by 2012, and more efficient use of generating capacities and the Kruonis HPSP for the needs of the wider EU region. The capacity of new nuclear power plant could be up to 3400 MW.

1.3 Energy System planning using Models

This thesis presents a planning process that links long-range strategic goals to detailed long-term energy development needs and opportunities. The method begins with an articulation of long-term energy development goals, accounting for the difficulty of predicting the distant future. It then covers evaluation of the potential of a technology to meet these long-term energy planning goals, determines the fundamental technical problems that underlie development risks and uncertainties, and identifies alternative development approaches that are directly related to long-term planning goals.

An effective assessment of energy-related policy instruments requires the use of models capable of simulating the technological change necessary to induce long-term economic shifts towards a sustainable energy system, while simultaneously representing in adequate detail key energy-economy-environment interactions. The analysis has been carried out using the Estonian MARKAL model [3], [65], PAPER 2, [62], [63], [64].

Since its initial development started in the late 1970s, the MARKAL model has become a widely applied tool for evaluating the impacts of policies imposed on the energy system. As for any other MARKAL (Market Allocation)-type modelling exercises, the analyses and results reported herein should also be considered prospective, with emphasis placed on the trends and insights resulting from driving forces determined by implementing the respective policy options [18].

The MARKAL models allow a wide flexibility in representation of energy supply and demand technologies, and are typically used to examine the role of energy technologies under specific policy constraints, e.g. CO_2 mitigation, local air pollution reduction, etc.

Energy planning consists of energy system development, systematic analysis, estimation and formation. It includes establishment of objectives, strategy determination and the achievement of objectives. Energy planning objectives are energy supply adequacy, security, economic efficiency and environmental-social acceptability.

Accordingly, it is necessary, that energy system planning must be optimal. Therefore, both in the short and in the long perspective, we must ensure that security of supply, reliability, use of resources, environment indexes, consumption etc are all optimal.

Important planning task input data are:

- Existing energy system description (RES - Reference Energy System);
- Base year energy balance;
- Planning period and base rate;
- Beneficial energy demand forecast according to economic progress scenario;
- Technology lifetime, technical shape and spending prognosis;
- New possible technologies and existing reconstruction;
- Primaries-energy resources and limitations;

- Fuel prices forecast;
- Environmental limits – taxes;
- Socio-economic limits.

As the planning task is very complex, if possible, certain calculation models are used. The great bulk of models proceed from the etalon energy system conception. Reference Energy System describes itself as a scheme where, in the buses, there are included all substantively existing and future system energy resources, processes, transformation technologies, electricity networks, cleaning procedures, consumer durables, economy measures, beneficial energy consumption etc. and this is all consolidated by a corresponding power flow. Reference Energy System shows us all possible primary energy flows through different transformation processes up to all energy customer-services. This etalon energy system scheme also expresses emissions caused by energy transformation and transmission. According to the task, Reference Energy System displays very different aggregative steps. A very simple reference energy system example is shown in Figure 1-3.

1.4 Energy system planning models

There are many different energy system-planning models used today (integrated resource planning models, integrated energy-economy-environment optimization models etc.).

Integrated resource planning models for the energy system are:
MARKAL – an abbreviation of the phrase *Market Allocation* – linear planning models family (MARKAL (common balance model), RMARKAL (considers several regions), MARKAL – MICRO (partly balance model), MARKAL – MATTER (counts energy and material flows), Stochastic MARKAL (Expected outcome is generated as a result of assumed states of nature)). All these models are developed under the aegis of the IEA (International Energy Agency) with the collaboration of scientists from 17 countries, and over 90 research institutions in over 50 countries around the world use it. Currently the model is developed under IEA programme ETSAP [48] (*Energy Technology Systems Analysis Programme*).

As regards the content of MARKAL, it is a long-term, technology-rich energy system optimization model and provides a flexible framework for evaluating alternative technology and policy options. It is primarily used to look at the role of technology in sustainable economic development in the context of energy and environmental issues.

EFOM-ENV [49] (*Energy Flow Optimization Model*). It is practically a model with the same characteristics as MARKAL. Elaborated under EU Committee order. It is used in EU member countries, in some East European countries (Lithuania etc.) and in Latin-American countries.

MESAP – *Modular Energy Systems Analysis and Planning*. Planning software with modular structure, which is based on huge database. Contains several modules, like INCA - investments planning, PlaNET - energy system description, E3-NET – energy system optimization etc. MESAP has flexible user interface and therefore it is widely used.

TIMES – new model developed under IEA aegis. The main purpose is to combine the best properties of MARKAL, EFORM and MESAP.

MESSAGE [50] III – bottom-up technical systems linear planning software, which is used for energy systems development optimization. This model is developed by IIASA (International Institute for Applied Systems Analysis) with WEC (World Energy Council) collaboration. Model is used for energy development and emission research (time horizon up to 100 years).

ENPEPEP – modules package for the energy complex development (time horizon 1-50 years). Model estimates electroenergetic system influence on the rest of the energy system and on the economy as a whole. This model is developed at the request of IAEA (International Atomic Energy Agency). Very widely used.

IKARUS – modules constitutive package, which is based on linear planning model, where minimum costs are sought. Developed by German think tank KFA Jürlich.

Integrated energy-economy-environment optimization models (E3 optimization models) are:

MARKAL-MACRO – MARKAL models family member. Here, the standard MARKAL is linked to a macroeconomic growth model with demands determined endogenously. If MARKAL represents a technical approach, then MAKRO represents an economic approach. The MACRO-MARCAL advantage over MARKAL is that a price-variation influence interacts with energy consumption.

GEM-E3 (General Equilibrium Model for Energy – Economics – Environment. Relatively new model. Macroeconomics and its interaction with environment and energy system are analyzed. Developed under JOULE (EU Committee) programme.

MEGEVE-E3ME. It is similar to the GEM-E3 model. Also developed under the EU Committee budget.

There are many other E3 optimization models used, such as PRIMES and MELODIE (macro-economic model).

Similarly, there are many different Energy system development models (does not contain optimization) like LEAP (Long-range energy Alternatives Planning), POLES; MIDAS; SEAM, MEDEE. Local energy system planning models, like EnergyPro and MIMES/WASTE.

In Estonia, MARKAL; MARKAL-MACRO; MEDEE-N and EnergyPro models are in use at Tallinn University of Technology, Department of Electrical Power Engineering.

1.5 MARKAL model

MARKAL is energy-system optimization models that represent current and potential future technology alternatives through the so-called Reference Energy System. The MARKAL model is a generic technology-oriented model tailored by the input data to obtain the least-cost energy system configuration for a given time horizon under a set of assumptions about end-use demands, technologies and resource potentials. It represents the time evolution of a specific Reference Energy System at the local, national, regional, or global level [48]. The MARKAL models allow a wide flexibility in the representation of energy supply and demand technologies and are typically used to examine the role of energy-technologies under specific policy constraints, e.g. CO_2 mitigation, local air pollution reduction, etc.

MARKAL, an acronym for *MARK*et *AL*location, is a large scale Linear Programming (LP) optimisation model which captures the complex interrelationships of energy systems across the spectrum from primary energy supply to energy service demands [44], [45]. It belongs to the family of energy systems models, which were developed during the 70's to support the analysis of energy policy options for numerous countries. The first examples of these models were developed in the middle of the 70's after the first oil crisis. During the following years several international organisations developed their own dynamic Linear- Programming (LP) models [45]: International Energy Agency, MARKAL [44], [48] European Community, EFOM [49], and International Institute for Applied Systems Analysis MESSAGE [50]. In energy modelling during the '50s and '60s all energy commodities were treated in isolation, while substitution among energy carriers was almost negligible. The new models of the '70s were primarily designed to find efficient energy paths in a changing word where energy substitution became increasingly important, and to investigate the market potential for new energy technologies [44], [48].

MARKAL (MARKet ALlocation) was developed between 1976 and 1981 as a multinational collaborative effort within the framework of the IEA. MARKAL's historical antecedents are another Brookhaven National Laboratory (BNL), and another Kernforschungsanlage-Jülich (KFA) model. MARKAL is a technologically-oriented LP model. The system boundaries are defined by the user. The model has been used for studies of the national energy systems for most countries within the IEA. Two preliminary versions were combined in one overall model in the 80's, and it has been continuously improved.

In 1993 a macro-economic planning model MACRO was linked with MARKAL [46]. As a result of that hybrid model, MARKAL - MACRO was created [47]. The models mentioned above proved to be useful tools for finding efficient strategies to reduce emissions. Due to increasing environmental concerns during the recent decades, the model assumed great importance as a means of finding methods for cost-efficient reduction of pollutants.

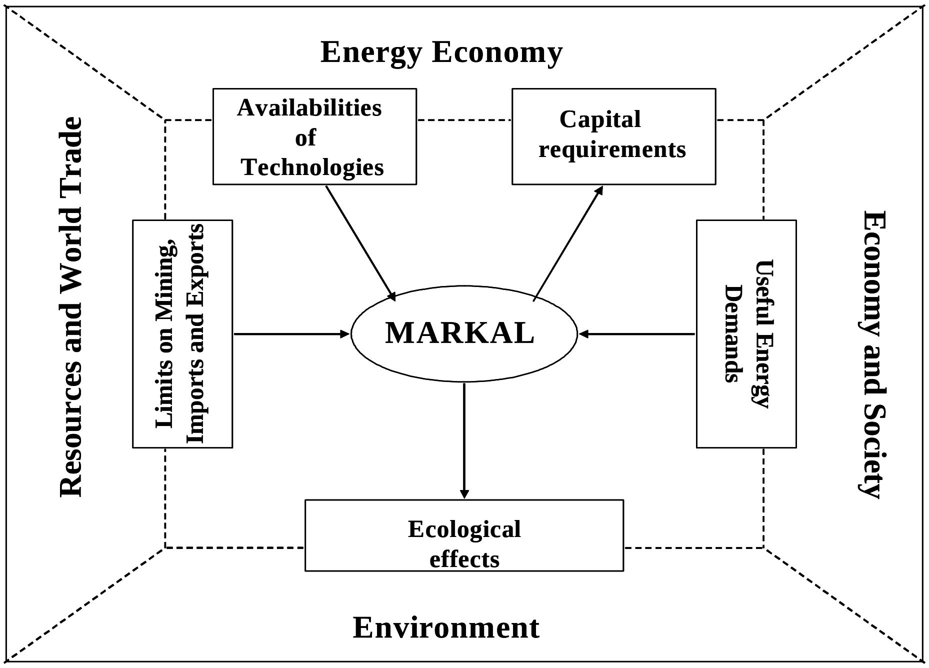

Figure 1-2 MARKAL model

1.6 Nature of MARKAL.

MARKAL is a demand-driven, multiperiod, LP model of energy supply and demands [44], [48].
A linear programming model has the following structure:
Minimise the objective function

$$z = \sum_{j=1}^{n} c_i \bullet x_j \qquad \textbf{(1)}$$

subject to:

$$\sum_{j=1} a_{ij} \quad x_i \leq b_i \quad , \quad \textbf{and} \quad x_j \geq 0 \quad , \qquad \textbf{(2)}$$

The coefficients c_i for the objective function and a_{ji} and b_j for the constraints are the known parameters; the vectors X_i are the unknown quantities to be found, e.g. the solution of the problem. Here $i = [1,...,T]$ denotes the index of a time period in the total planning time horizon T and j denotes the index of a constraint.

The system objective is generally expressed as minimum total system cost with a real rate of discount r%. Other objectives are possible, e.g. weighted sum of this cost, minimised emissions of a specific compound, maximised use of renewables, security of energy supply, etc. The most important system constraints are:

- energy balance (annual),
- electricity balance (seasonal),
- load management,
- satisfaction of demands;
- fuel balances,
- low-temperature heat balance,
- peak-load and base-load relations,
- limit on operations,
- period-to-period capacity transfer relation,
- cumulative and growth constraints,
- exogenous limits such as those on market penetration of individual types of technology,
- other constraints such as maximum allowable emissions from the energy system.

It is a systems engineering (physical process) analysis built on the concept of a Reference Energy System [46]. MARKAL allows a detailed description of existing and alternative energy technologies and existing and alternative paths of energy carriers from their source - through different conversion technologies until the point of final use. The MARKAL structure makes it possible to build in supply curves of technical conservation. In most applications, the end use demands are fixed, and a cost-efficient solution is obtained by minimising the energy system's costs over the whole studied period. Basically, MARKAL takes exogenously supplied energy demand figures and determines the optimal energy supply and end-use-device network which can meet the demand. For a feasible solution, the demand must be met in each period. The exact nature of an optimal solution depends both on the criterion of optimality and the ensemble of technological and economic data supplied by the user to characterise a country's energy technologies. The existing energy system is described in detail, together with alternative technologies and flow paths.

A "menu" consisting of data on the existing energy system, possible alternative technologies and energy carriers is provided to the model. The expected future energy demands are specified by quality, duration and consumer-category. To each consumer-category there are several alternative end-use technologies for conversion of final energy. Each technology is described with its technical, economic and environmental properties. Centralised energy conversion is described in a similar way, but with the difference that production from those technologies can be distributed to any consumer-category. Where applicable, optional abatement technologies are specified for each type of conversion technology.

From the menu, the model chooses the combination of energy technologies and energy flow paths that best satisfies the objective over the studied period (usually 25- 40 years). The system objective is generally expressed as minimum total system cost with a real rate of discount. Other objectives are possible, e.g., minimised emissions of a specific compound, maximised use of renewables, etc.

The focus of the MARKAL is development of the technical energy system. This makes the model suited to exploring how investment patterns change under different developments of the environment. The physical environment consists of two parts [66]:

- Physical Constraints on the use of technologies,
- Environmental Control.

Constraints, costs or benefits are included to internalise the external damage of the technical energy system. Emissions Control is part of environmental control.

Figure 1-3. shows the energy flows modelled by MARKAL [46]. This nomenclature represents generic classes of energy technologies or resources, of which the most important in MARKAL are these [45]:

- origin of energy resources, such as mining, importation/exportation.
- energy carriers, such as primary and secondary fuels.
- processes, which transform energy carriers into one another.
- conversion systems, which convert energy carriers into electricity district heat.

A user can supply as many members of such classes as his data allows. These data are of a technological, economic, or policy nature. Basically, for each energy carrier, a user must supply the following information for each applicable period: resource cost, period of first availability. For each process, conversion system, and demand device, the requisite data are a subset of the lifetime, period of first availability, availability factors, energy conversion efficiencies, and costs for investment and variable operation and maintenance [43]. For energy carriers, minimum and maximum bounds on use are optional. So also are minimum and maximum bounds on capacity or utilisation for processes, conversion systems, and demand devices.

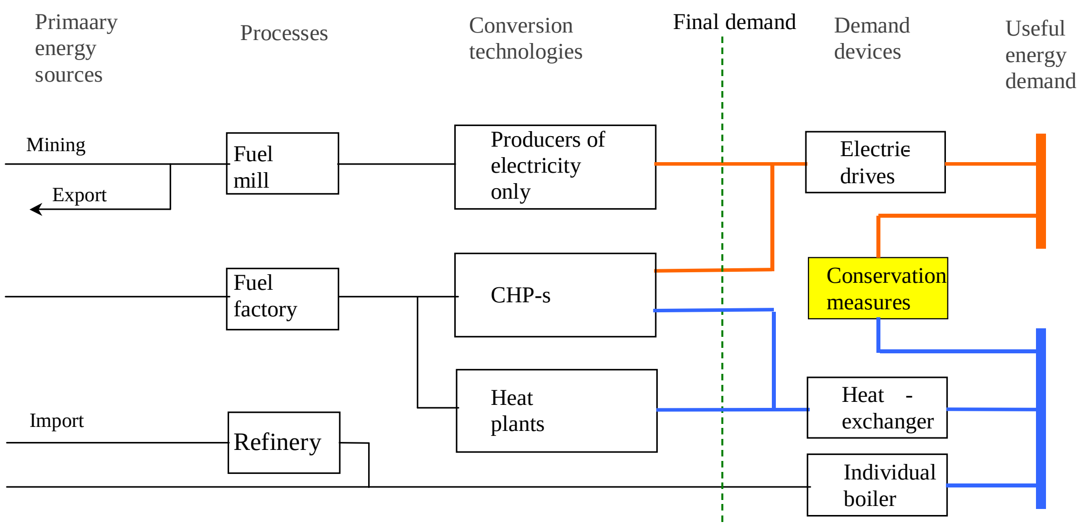

Figure 1-3 Simple Reference Energy System [46]

MARKAL family models are

- Standard MARKAL: Linear program with demands defined exogenously.
- MARKAL-MACRO: Standard MARKAL linked to a macroeconomic growth model with demands determined endogenously.
- MARKAL Elastic Demand (MED): Demand is price-responsive and determined endogenously.
- Endogenous Technology Learning (ETL): Technology costs change with cumulative experience.
- Stochastic MARKAL: Expected outcome is generated as a result of assumed states of nature.
- MARKAL-EV: Environmental damage estimates included in the MARKAL cost considerations.
- SAGE: Multi-region time-stepped, period-by-period solving of MARKAL (myopic solution algorithm.)
- MARKAL-GP: Goal-programming formulation used to examine the effects of weighting environmental vs. economic goals.

1.7 A simplified description of the MARKAL Optimization Program

The computation of the MARKAL partial equilibrium is equivalent to the optimization of a suitably constructed mathematical program. A mathematical optimization program is defined as the minimization (or maximization) of an objective function, subject to constraints. If all the mathematical expressions representing the objective function and the constraints are linear, the problem becomes a Linear Program (LP), which may be solved via standard Linear Programming optimizers.

MARKAL objective function: total system cost

The MARKAL objective is to minimize the total cost of the system, adequately discounted over the planning horizon. Each year, the total cost includes the following elements:

- Annualized investments in technologies (see below);
- Fixed and variable annual Operation and Maintenance (O&M) costs of technologies;
- Cost of exogenous energy and material imports and domestic resource production (e.g., mining);
- Revenue from exogenous energy and material exports;
- Fuel and material delivery costs;
- Welfare loss resulting from reduced end-use demands.
- Taxes and subsidies associated with energy sources, technologies, and emissions.

In each period, the investment costs are first annualized, before being added to the other costs (which are all annual costs) to obtain the annual cost in each period. MARKAL then computes a total net present value of all annual costs, discounted to a user-selected reference year. This quantity is the one that is minimized by the model to compute the equilibrium.

While minimizing total discounted cost, the MARKAL model must obey a large number of constraints (the so-called equations of the model) which express the physical and logical relationships that must be satisfied in order to properly depict the associated energy system. MARKAL constraints are of several kinds. If any constraint is not satisfied, the model is said to be unfeasible, a condition caused by a data error or an over-specification of some requirement.

The most important constraints are:

- Satisfaction of Energy Service Demands,
- Capacity Transfer (conservation of investments),
- Use of capacity,
- Balance for Commodities (except electricity and low temperature heat),
- Electricity & Heat Balance,
- Peaking Reserve Constraint (electricity and heat sectors only),
- Base Load (electricity generation only),

- Seasonal availability factors (electricity and heat sectors only),
- Emission constraint(s).

A simplified Mathematical Formulation of the MARKAL Linear Program

An optimization problem formulation consists of three types of entities:

- decision variables: i.e. the unknowns, to be determined by the optimization,
- objective function: expressing the criterion to minimize or maximize, and
- constraints: equations, or in equations involving the decision variables, that must be satisfied by the optimal solution.

The model variables and equations use the following indexes:

r,r': indicates the region (omitted when a single region is modelled);
t: time period;
k: technology;
s: time-slice;
c: commodity (energy or material);
l: price level (used only for multiple sources of the same commodity distinguished only by their unit cost)

Objective function

The objective function is the sum over all regions of the discounted present value of the stream of annual costs incurred in each year of the horizon. Therefore:

$$NPV = \sum_{r=1}^{R} \sum_{t=1}^{t=NPER} (1+d)^{NYRS \bullet (1-t)} \bullet ANNCOST(r,t) \bullet \left(1 + (1+d)^{-1} + (1+d)^{-2} + \cdots + (1+d)^{1-NYRS}\right) \quad \textbf{(3)}$$

where:
NPV is the net present value of the total cost for all regions (the MARKAL objective function)
ANNCOST(r, t) is the annual cost in region *r* for period t, discussed below
d is the general discount rate
NPER is the number of periods in the planning horizon
NYRS is the number of years in each period *t*
R is the number or regions

The total annual cost ***ANNCOST(r, t)*** is the sum over all technologies k, all demand segments d, all pollutants, and all input fuels ***f,*** of the various costs incurred, namely: annualized investments, annual operating costs (including fixed and variable technology costs, fuel delivery costs, costs of extracting and importing energy carriers), minus revenue from exported energy carriers, plus taxes on emissions, plus cost of demand losses.

Mathematically, ***ANNCOST(r,t)*** is expressed as follows:

$$
\begin{aligned}
ANNCOST(r,t) = \Sigma k\, \{ & Annualized\_Invcost(r,t,k) * INV(r,t,k) \\
& + Fixom(r,t,k) * CAP(r,t,k) \\
& + Varom(r,t,k) * \Sigma_{s,s}\, ACT(r,t,k,s) \\
& + \Sigma_{c}\, [Delivcost(r,t,k,c) * Input(r,t,k,c) * \Sigma_{s}\, ACT(r,t,k,s)]\}\, () \\
& + \Sigma_{c,s}\, \{ Miningcost(r,t,c,l) * Mining(r,t,c,t) \\
& \quad + Tradecost(r,t,c) * TRADE(r,t,c,s,i/e) \\
& \quad + Importprice(r,t,c,l) * Import(r,t,c,l) \\
& \quad - Exportprice(r,t,c,l) * Export(r,t,c,l)\, \} \\
& + \Sigma c\, \{Tax\,(r,t,p) * ENV(r,t,p)\} \\
& + \Sigma_{d}\, \{\mathrm{DemandLoss}(r,t,d)\, \}
\end{aligned} \qquad \textbf{(4)}
$$

where:

Annualized_Invcost(r,t,k) is the annual equivalent of the lump sum unit investment cost, obtained by replacing this lump sum by a stream of equal annual payments over the life of the equipment, in such a way that the present value of the stream is exactly equal to the lump sum unit investment cost, for technology ***k***, in period ***t.***

$$ANNUALIZED\_INVCOST = INVCOST / \sum_{j=1}^{LIFE} (1+h)^{-j} \qquad \textbf{(5)}$$

where:
INVCOST is the lump sum unit investment cost of a technology
ANNUALIZED_INVCOST is the annualized equivalent of *INVCOST*
LIFE is the physical life of the technology

h is the discount rate used for that technology, also called the hurdle rate. If the technology specific discount rate is not defined, the general discount rate d is used instead.

Fixom(k,t,r), Varom(r,t,k), are unit costs of fixed and operational maintenance of technology ***k,*** in region ***r*** and period **t;**
Delivcost(r,t,k,c) is the delivery cost per unit of commodity ***c*** to technology ***k,*** in region ***r*** and period ***t;***
Input(r,t,k,c) is the amount of commodity ***c*** required to operate one unit of technology ***k,*** in region ***r*** and period ***t;***
Miningcost(r,t,c,l) is the cost of mining commodity ***c*** at price level ***l,*** in region ***r*** and period ***t;***

Tradecost(r,t,c) is the unit transport or transaction cost for commodity ***c*** exported or imported by region ***r*** in period ***t;***
Importprice(r,t,c,l) is the (exogenous) import price of commodity ***c,*** in region ***r*** and period ***t;*** this price is used only for exogenous trade,
Exportprice(r,t,c,l) is the (exogenous) export price of commodity ***c,*** in region ***r*** and period ***t;*** this price is used only for exogenous trade,
Tax(r,t,p) is the tax on emission ***p,*** in region ***r*** and period ***t;*** and
DemandLoss(r,t,d) represents the welfare loss (in non reference scenarios) incurred by consumers when a service demand ***d,*** in region ***r*** and period ***t,*** is less than its value in the reference case.

2 IMPROVEMENT OF OPTIMIZATION METHODOLOGY FOR LONG-TERM ENERGY PLANNING.

As initial information for deterministic models of optimal production units is inaccurate, then problems of optimal production units had to be solved under incomplete information. Therefore deterministic models of optimization must be replaced by models that can optimize production units under uncertainty and fuzzy conditions.

Classifying decision-making criteria follows [17]:

- Decision making under certainty. The future state-of-nature is assumed to be known.
- Decision making under risk. There is some knowledge of the probability of the prevailing states of nature.
- Decision making under uncertainty. There is no knowledge about the probability of the prevalent states of nature.

In decision making under uncertainty, the decision criteria are based on the decision maker's attitude toward life. The criteria include the:

- maximin criterion - pessimistic or conservative approach,
- minimax regret criterion - pessimistic or conservative approach,
- equally likely, also called LaPlace criterion - assumes that all probabilities of occurrence for states of nature are equal
- maximax criterion - optimistic or aggressive approach,
- principle of insufficient reasoning – no information about the likelihood of the various states of nature.

This thesis will give only a general description of energy planning under conditions of uncertainty by using the nonlinear programming methods. Several publications such as [53, 54, 55, 56, 69] show the wide interest in this topic in recent years.

The development of the concepts of linear and nonlinear optimization models presumes that all of the data for the optimization model are known with certainty. However, uncertainty and inexactness of data and outcomes pervade many aspects of most optimization problems. As it turns out, when the uncertainty in the problem is of a particular (and fairly general) form, it is relatively easy to incorporate the uncertainty into the optimization model [23].

2.1 Maxmin Criterion

For each action, the worst outcome (smallest reward) is determined. The maximin criterion chooses the action with the "best" worst outcome. The method assumes that the worst payoff can occur for each alternative. Maxmin, or the pessimist criterion was established by Abraham Wald, who considers that the best option is the one that presents maximum advantages when the objective conditions

are unfavourable. Optimizing decisions with the help of this technique can be done through the following relation:
where:

$$V_{optimum} = \max_i \min_j (V_i, C_j) \quad \textbf{(6)}$$

V_i – the decisional variant;
C_j – the objective state.

2.2 Equally Likely (LaPlace) Criterion

The equally likely, also called LaPlace, criterion finds the decision alternative with the highest average payoff (profits) and the lowest average payoff (costs). The LaPlace criterion assumes that all probabilities of occurrence for states of nature are equal.

The Laplace criterion is based upon Bernoulli's postulate, and it says that if we have a certain sequence of events, we cannot state that one of them is more likely to occur than the others, therefore they are all equally probable. It is founded on the premise that all the objective conditions have the same probability of occurrence, according to the relation below.

For each variant the mathematical expectation of the variants must be determined; the optimum variant which results from this is the one that satisfies the condition presented in the following calculations:

$$E_i = \frac{1}{n} \sum_j a_{ij} \quad \textbf{(7)}$$

E_i – the mathematical expectation for variant *i*

$$V_{optimum} = \max\{E_i\} = \max_i \left\{ \frac{1}{n} \sum_i a_{ij} \right\} \quad \textbf{(8)}$$

2.3 Minimax Regret Criterion

The minmax criterion fits both a pessimistic and a conservative decision-maker approach, and Savage [17] advocated it in 1954. The payoff table can be based on lost opportunity, or regret. The rows correspond to the possible decision alternatives, the columns correspond to the possible future events. Events (states of nature) are mutually exclusive and collectively exhaustive and the table entries are the payoffs. The decision-maker incurs regret by failing to choose the best decision. To find an optimal decision, for each state of nature the best payoff over all decisions is determined.

Regret is calculated for each decision-alternative as the difference between its actual payoff value and this best payoff value.

$$R_{ij} = a_{ij} - \max_{i}\left(a_{ij}\right) \qquad \textbf{(9)}$$

R_{ij} - the regret of alternative *i* in the state of nature *j*;
a_{ij} - variant *i* in the condition of the state of nature *j*.
Here for each investment decision the maximum regret over all states of nature is calculated. The optimum is the investment decision alternative that has the minimum of these maximum regrets.

The minmax regret criterion uses the concept of opportunity cost to arrive at a decision. For each possible event (state of nature) $\mathbf{s_j}$, find an action **i*(j)** that maximizes $\mathbf{r_{ij}}$. **i*(j)** is the best possible action to choose if the event (state of nature) is actually $\mathbf{s_j}$. For any action $\mathbf{a_i}$ and state $\mathbf{s_j}$, the opportunity loss or regret for $\mathbf{a_i}$ in $\mathbf{s_j}$ is $\mathbf{r_{i*(j),j} - r_{ij}}$.

The decision-maker incurs regret by failing to make the best decision. To find an optimal decision, for each event (state of nature) the best payoff over all decisions is calculated.

A major advantage of the minmax regret criterion is that one can work with smaller models inasmuch as only the extreme values are needed. Lolou and Kanudia [22] experimentally verified that the minmax regret strategy depends only on the extreme targets and not on intermediate ones. The principal advantage of the minmax regret strategy is that no assumption needs to be made about the likely severity of future emission reduction requirements. The only additional assumption required is the date at which the uncertainty in the requirements is resolved [22].

2.3.1 Minmax model

The best criterion for electricity production capacity optimization is the minmax regret criterion [53], [54]. The minmax regret criterion is named the criterion of minmax regret or risk caused by uncertainty of information. The minmax criterion fits both a pessimistic and a conservative decision-maker approach. The payoff can be based on lost opportunity, or regret.

$$\min_{\overline{P}(t)} \max_{Z(t)} \int_0^T R(\overline{P}(t), \tilde{Z}(t))dt \qquad \textbf{(10)}$$

where *R* – function of risk or regret caused by uncertainty factors:

$$R(\overline{P}(t), \tilde{Z}(t)) = C_\Sigma(\overline{P}(t), \tilde{Z}(t)) - \min C_\Sigma(P(t), \tilde{Z}(t)) \qquad \textbf{(11)}$$

$\overline{P}(t)$ - vector of planned load duration curves of units,

$\tilde{Z}(t)$ - vector of uncertain factors,

C_Σ - actual total costs of power units,

$\min C_{\Sigma}$ - minimum of total costs if we could have the exact deterministic information about uncertainty factors.
Operator minmax *R* means the minimization of maximum regret or risk caused by uncertainty factors

Optimality conditions

The optimality conditions of a minmax problem arise from the main theorem of game theory and can be expressed as follows [59]:
If the $\left(\overline{P}^{0}(t)\right)$ is the optimal plan for min max *R* criterion, then:

$$R\left(\overline{P}^{0}(t), Z^{-}(t)\right) = R\left(\overline{P}^{0}(t), Z^{+}(t)\right) \qquad \textbf{(12)}$$

In a general case, it is necessary to solve the problem

$$\min_{\overline{P}(t)} \max_{\Omega} \int_{0}^{T} E\ R(\overline{P}(t)\ , \widetilde{Z}(t))dt \qquad \textbf{(13)}$$

Where:
E – expected value of risk or loss of opportunity,
Ω – a set of mixed strategy of uncertain factors

It is possible to compose the deterministic equivalent of a minmax problem on the basis of the conditions given above. It requires finding the minmax load demand curves and cost functions of technologies and environmental constraints and taxes. If we replace the deterministic data by the minmax input data, we can use the initial deterministic model for calculating the minmax optimal results.

2.3.2 Risk (regret)

At first, we have to define the risk or regret function caused by uncertainty of information:

$$R(\overline{Y}, Z) = F(\overline{Y}, Z) - \min F(Y, Z) \qquad \textbf{(14)}$$

where $\min F(Y,Z)$ - minimum total costs if optimization has taken place under conditions of complete information; Y - vector of controllable variables; Z - vector of non-controllable variables.
Now, for optimization under uncertainty the following problem of the minmax risk (regret) must be solved:

$$\min_{\overline{Y}} \max_{Z} R(\overline{Y}, Z) \qquad \textbf{(15)}$$

The major uncertainty factors for the optimization of electricity production capacity under uncertainty are $P_{l)}(t)$ - the net energy system active power demand in the time period *T*, the input and output characteristics of production units and other related costs and taxes.

2.4 Optimization of generating power under uncertain conditions

Generation expansion planning is an important planning problem for power systems. In the models of integrated energy-economy-environment planning like MARKAL [43] which is used in Estonia [3], [62], [63], [1], the long-term planning of electricity generation capacity is based on the requirement to fulfil the electricity consumption forecast. The seasonal and diurnal variations of the power system load are described quite simply, and they are derived from the annual consumption. MARKAL uses 3 seasons (winter, intermediate, summer) and differentiates day and night in each season, thus splitting a year into 6 time divisions. The user of the model can determine the lengths of seasons and day/night in each season. After that the user can define for each energy consumer the distribution of its total annual energy consumption between those 6 time divisions. The load in each time division is calculated by dividing the energy consumption in that interval by the length of the interval (number of hours in it).

As a result, 6 average load levels will represent the annual load curve. To take into account the peaks of electric load, a special coefficient is used. It shows the amount by which installed capacity exceeds the average load in the time division of maximum demand. Reserve capacity requirements are specified by determining the coefficients for scheduled and forced outages of power plants. The user can also define those power plants that are not able to follow the load (base load plants), but he cannot define the plants that are envisaged as covering only the peak load.

Practice has shown that in some cases this relatively simple description of electric load curve can lead to unrealistic results in generating capacity planning. For example, the model can "build" power plants that will never operate, but serve as reserve only. Balancing of wind power fluctuations by fast peak load power plants (gas turbines etc.) cannot be taken into account either. In addition, the random nature of the power plant characteristics and load are usually neglected in the long-term energy planning models.

The limitations of linear programming (LP) planning tools gave the motivation to start elaborating improved optimal power generation planning methodology.

The objective of long-term optimization of electricity generation capacity is the minimization of the total costs (expected investment and operational costs) in relation to the reliability constraints.

The task of optimal long-term planning of electricity production capacity considering uncertainty intervals of the base, peak and intermediate loads, and multistage nature of the planning process will be tackled. A theoretical minmax approach to the problem will be given.

Minmax optimization models enable us to take into account the uncertainty of uncontrollable factors and to minimize the maximum possible economic loss (regret) caused by uncertainty.

Therefore, the objective of long-term optimization of electricity production capacity is the minimization of the total costs (expected investment and operational costs) considering the reliability and environmental constraints.

2.5 The sources of uncertainty

The main uncertainty factors in the model are:

- load demand duration curve $P_D\ (t)$,
- functions of total costs for every generating unit *Ci(Pi)*

These uncontrollable factors are considered below in detail. Two kinds of uncertainty can obtain [55], [56]:

- Deterministic-uncertain information - uncertainty zones of factual values of functions or parameters are known.
- Probabilistic-uncertain information - probabilistic characteristics of object are not known exactly, but in the form of uncertainty zones.

In this thesis only deterministic-uncertain information will be considered. Let the load duration curve $P_D\ (t)$ be given in the form of intervals in Figure 2-1.

$$P_D^{\min}(t) \leq P_D(t) \leq P_D^{\max}(t) \qquad \textbf{(16)}$$

where the functions $P_D^{\min}(t)$

and $P_D^{\max}(t)$

are given.

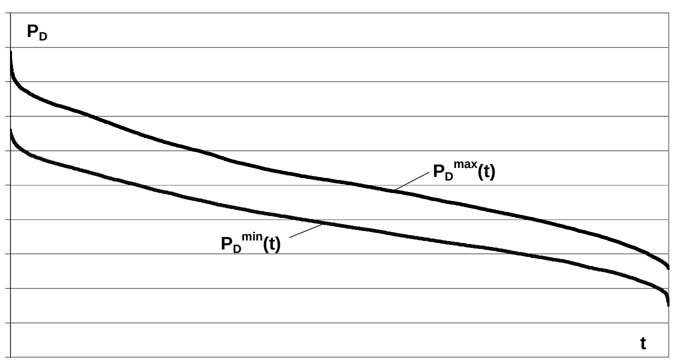

Figure 2-1 Load demand duration curve in the uncertainty form

The cost functions of generating units are given in the form of intervals too:
$C_i^{\min}(P_i) \le C_i(P_i) \le C_i^{\max}(P_i)$

$C_i^{\min}\left(P_i\right)$ and $C_i^{\max}\left(P_i\right)$ are given (Figure 2-2)

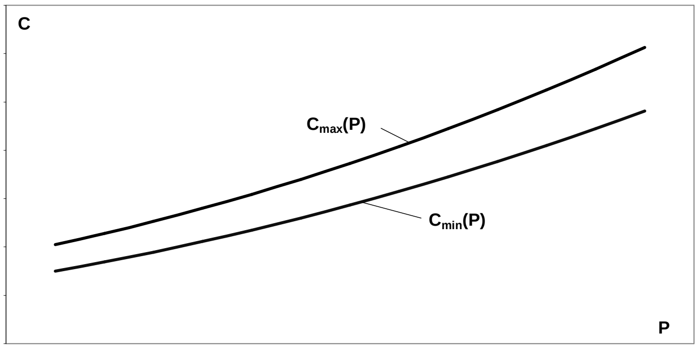

Figure 2-2 Unit cost function in the uncertainty form

2.5.1 Uncertainty of energy demand

Usually demand forecasts are represented as deterministic scenarios for predetermined macroeconomic scenarios. For linear models demand is represented as time-series of final energy demand. Different load growth scenarios are used – normally the most probable scenario is chosen as a basis, but other (min and max scenarios) are also used. Instead of calculating different scenarios the minmax optimization model allows us to use a single case. The minimal and maximal demand growth scenarios are taken as boundary limits, with uncertainty obtaining between these extremes.

Also it must be taken into account that load demand is continually changing. The most important factor is the issue of electricity demand. The changes of electrical load may be described by load curves or by load duration curves. Load curves are used for the operational and short-term (days, weeks and month) scheduling, and load duration curves for long-term (years) planning. Examples of the long-term load curve and load curve for one year are shown in -Figure 2-3 Long-term power consumption forecast example and Figure 2-4 One year load curve example.

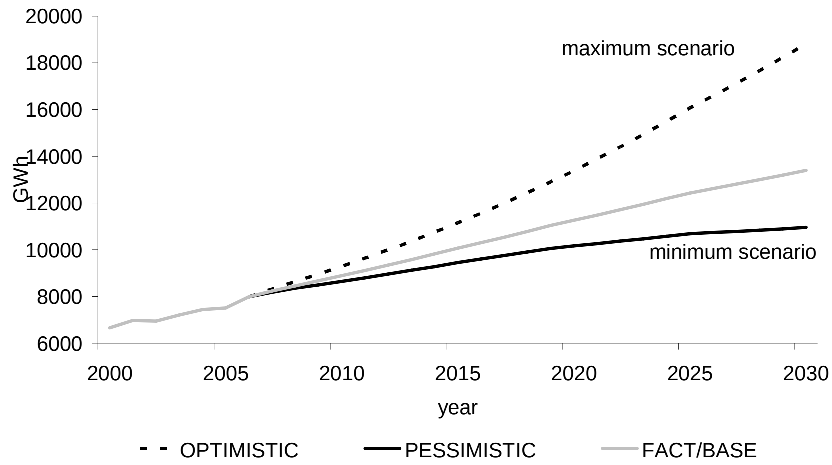

Figure 2-3 Long-term power consumption forecast example

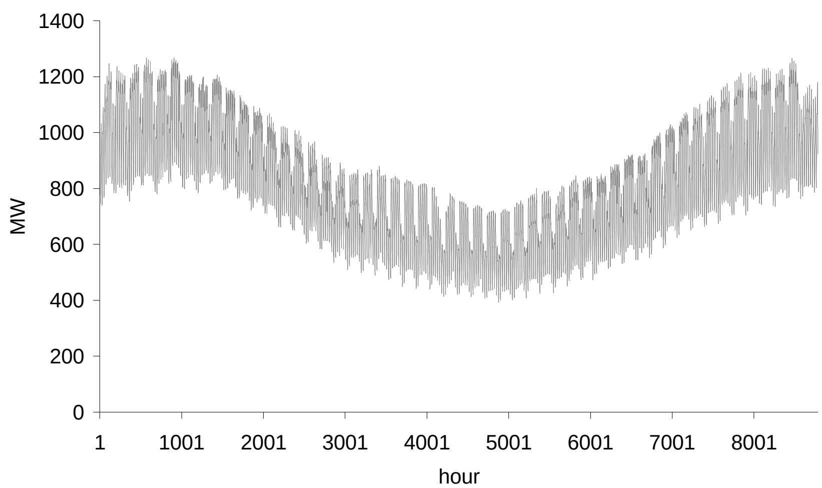

Figure 2-4 One year load curve example

The power system load is usually divided into 3 categories:

1. Base-load (duration time 8760 hours)
2. Intermediate load (duration time from 2000 to 8760 hours)
3. Peak-load (duration time up to 2000 hours).

In the Estonian power system, the base-load forms about 35%, intermediate load about 40% and peak-load about 25% of the maximum load. The power system must have sufficient active and reactive power generating capacity to cover the load changes, since the electricity cannot be conveniently stored in sufficient quantities.

2.5.2 Uncertainty of technology data

The required data can be categorized as technical data and economic data. Technical data includes all information relating to specific technologies' operation and life. The most critical technical information includes but is not restricted to: availability factors, fuel conversion efficiency rates, fuel types, emission factors, technology life and retirement rates, construction delays, load duration and engineering ratios. The characteristics of similar technology types can vary greatly; therefore all technical data inherent in the model typically represents the average values of technical information (for example simple cycle gas turbines' conversion efficiency averages 33% over all variants).

Economic data relates to information on specific financial cost of technologies, such as capital costs (per installed kW), and operating and maintenance (O & M) costs (per kWh). Other economic data includes fuel prices and taxes.

As deployment levels of new technologies rise the investment cost of said technologies drops. Endogenous technology learning (ETL) permits modelling of this phenomenon in MARKAL to help identify the best strategies for promoting the development and deployment of key technologies.

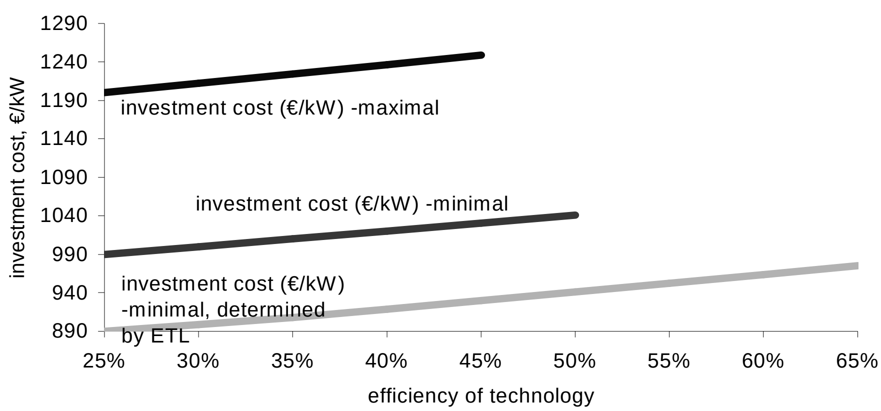

Figure 2-5 Marginal values of investment cost with ETL

2.5.3 Uncertainty of environmental constraints and taxes

MARKAL has the capacity to track the production or consumption of environmentally relevant quantities according to the activity, installed capacity or new investment in a resource or technology. This capacity has most often been used to track emissions of traditional pollutants such as CO_2, NO_X, SO_X, CO, and particulates. However, it could also be used to track consumption of land or other resources, or the removal of pollutants from the system. Key environmental variable related data (expressed in terms of pollutant emissions) includes:

- emissions per unit of technology activity, installed capacity, or new investment;
- emission constraints, which can take the form of a cap on total emissions in a year, or a cumulative cap on emissions over the entire modelling horizon, if desired.
- emission taxes and costs.

Usually decisions concerning environmental restrictions and taxes are political. Thus, numerous deterministic scenarios for different environmental constraints and taxes must be created. After all, the result may be not very realistic because of the human tendency to correct targets after getting the first results. Thus, it is important to use, instead of deterministic targets, a range of targets.

The basic question is: how can we determine an interim energy-sector strategy, i.e., before the level and timing of abatement of pollutants are known with certainty? The endeavour is to determine a strategy which hedges against all possible requirements to reduce the emissions of various pollutants. A similar approach would be equally relevant for an environmental tax situation.

3 THE ESTONIAN ENERGY SYSTEM AND MARKET

3.1 Basic energy data

Estonian power engineering has a long history and tradition. Electric lighting was first used in factories in 1882. The first industrial power plant was built at the Kunda cement factory in 1893 and the first public power plant in Pärnu in 1907. 1918 is regarded as the year of the establishment of the Estonian power system. The first national electrification programme was developed in 1930. Until World War 2 the sources of electricity were thermal power plants that used local peat and oil shale, and numerous small hydro plants. The era of oil shale–based power production began in the 1950s and two of Estonia's oil shale power plants are still the world's largest.

The regaining of political and economic independence in 1991 brought about drastic changes in Estonia’s economy. For the energy sector, these changes meant a dramatic rise of fuel and raw material prices, a decrease in energy consumption and electricity exports, but also problems with imports of oil products from Russia. A decisive factor that helped the energy system survive through the difficult first years was the fact that all necessary electricity was produced locally and 99% of it from oil shale.

Developments of primary energy supply and final energy consumption as well as electricity and heat production and consumption are shown in Figure 3-1 and Figure 3-2. The source of all statistical data in this report is the Statistical Office of Estonia [30], [31], etc.

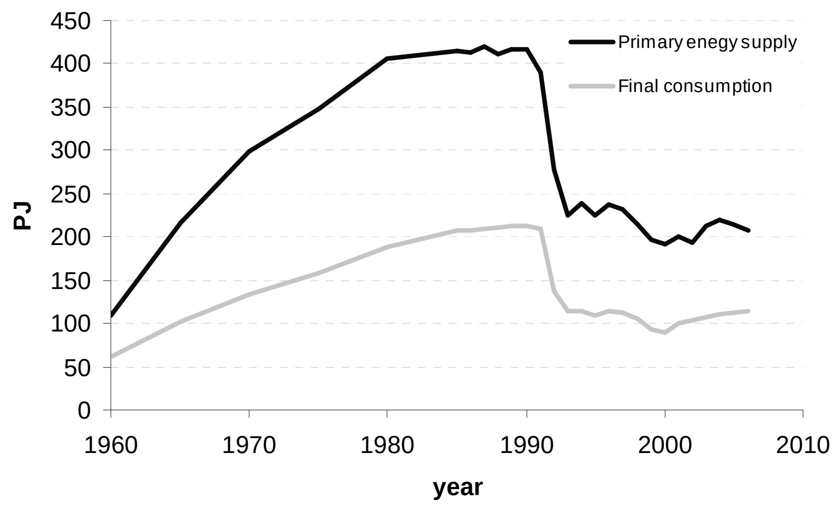

Figure 3-1 Primary energy supply and final consumption 1960-2006

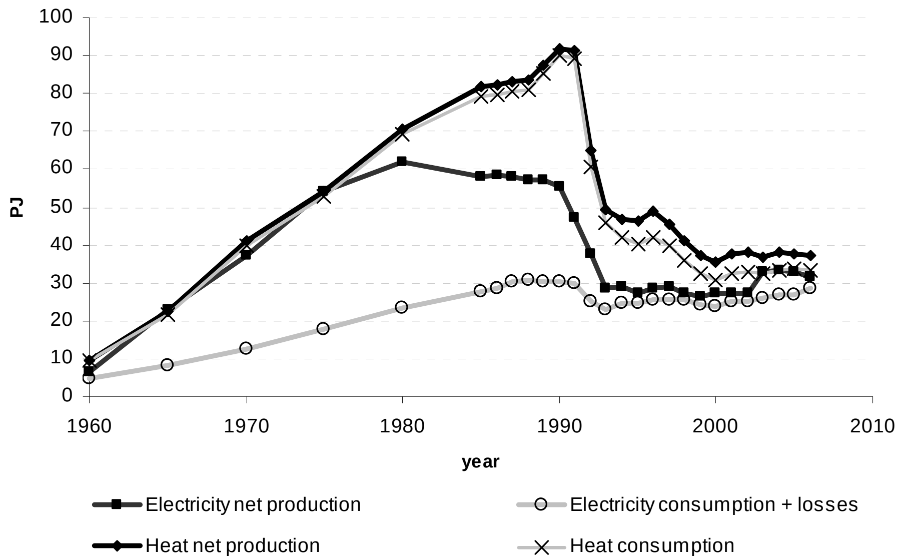

Figure 3-2 Electricity and heat production and consumption during 1960-2006

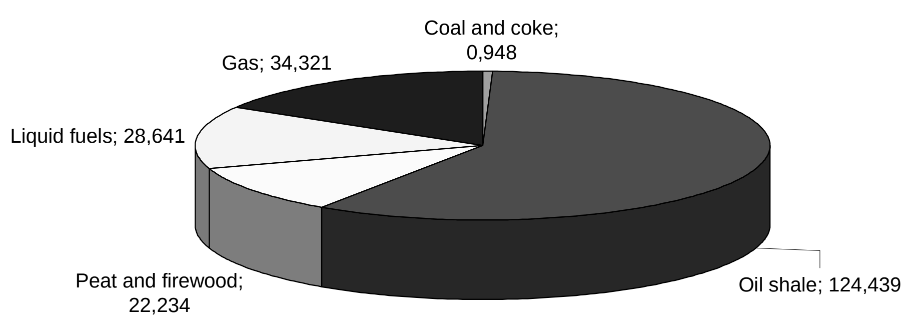

Figure 3-3 Primary energy supply, 2006

Indigenous fuels (oil shale, wood and peat) form approximately 2/3 of the primary energy supply of Estonia. The share of renewable energy sources (mainly wood) was 11% in 2006 (Figure 3-3). Estonian oil shale is virtually unique; its reserves are the largest commercially-exploited deposit in the world. Oil shale is characterised as a low-grade fuel with a low heating value (average 8,6 MJ/kg). Oil shale is a sedimentary formation which consists of organic matter or kerogen; carbonate matter and sandy-clay minerals (18–42%). Oil shale contains 1.2–1.7% sulphur, mostly organic and pyretic [63].

Estonia imports gas, coal, motor fuels and fuel oils, and exports electricity and some of its secondary fuels – oil and coke from oil shale, peat briquettes and wood pellets. In 2006, the primary fuels (234 PJ) were consumed as follows:

- 38% for electricity production,
- 19% for heat production,
- 15% for production of secondary fuels,
- 3% for non-energy purposes,
- 25% for direct final consumption (industrial processes, household use, transport, etc.).

A decrease in the share of oil shale in electricity production began in 1996 when the use of natural gas began to rise. In 2006 about 93% of electricity was produced from oil shale and ca 3% from gas. The other resources (hydro, wind, peat, fuel oils etc.) covered a total of 4%.

In heat production, switching from imported fuel oils to natural gas and woodchips should be mentioned. In 2000 heat production in boiler houses was

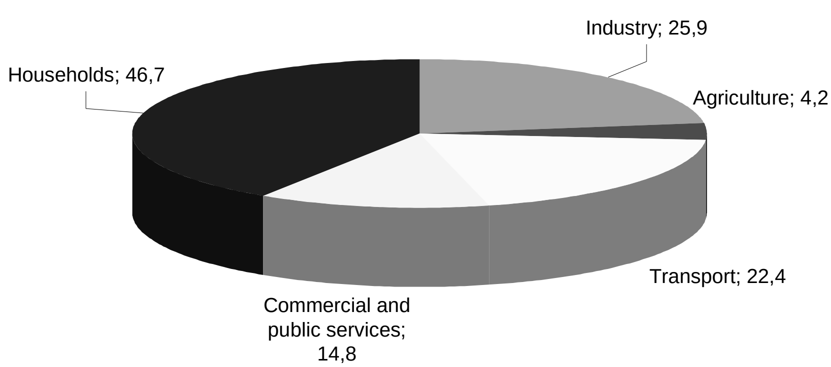

Figure 3-4 Final consumption of energy, 2006, PJ

based mainly on natural gas and local fuels - oil shale, wood, peat and shale oil (over 40%). About 12-14% of electricity and one third of heat is produced in the combined heat and power plants (CHP). The share of district heating in heat consumption is approximately 70%.After economic restructuring energy consumption in industries, transport and in particular in agriculture has decreased, and households are now the largest energy consumer group (Figure 3-4). Household consumption also includes private cars.

By the early 1990s, Estonia's power system had maintained substantial electricity and heat production capacities. However, the keywords were still: low efficiency, great age, high pollution and inconsistency in relation to the restructured economy. Although marked changes have taken place in the energy sector, bigger challenges are yet to come.

3.2 Power consumption in Estonia

3.2.1 Present Situation

Consumption in Estonia decreased at the beginning of the 1990-s after a steady increase for decades. In the period 1996-2000 consumption stabilized and started to increase considerably. Already by 2001 electricity consumption was 3% higher than in 2000 and growth has continued until now. Consumption by business did not change as compared with 2000. However, residential consumption increased by over 8%. Total final consumption in Estonia in 2006 was 7,288 TWh. The dynamics of consumption by each branch of the economy reflects quite precisely changes in these economic tendencies. While in industry, construction and transportat consumption stabilized in the middle of the 1990-s, in agriculture the decrease lasted for the whole decade. Thus, the most spectacular decrease has been in agriculture. After 1995 consumption increased greatly in the household sector. The increase in business and public services shows the importantce of these fields in the national economy. After 1995, household consumption increased. In 2001 residents consumed 1585 GWh energy, which was 28 % of total domestic consumption. The increase in household consumption in Estonia is typical for the EU countries.

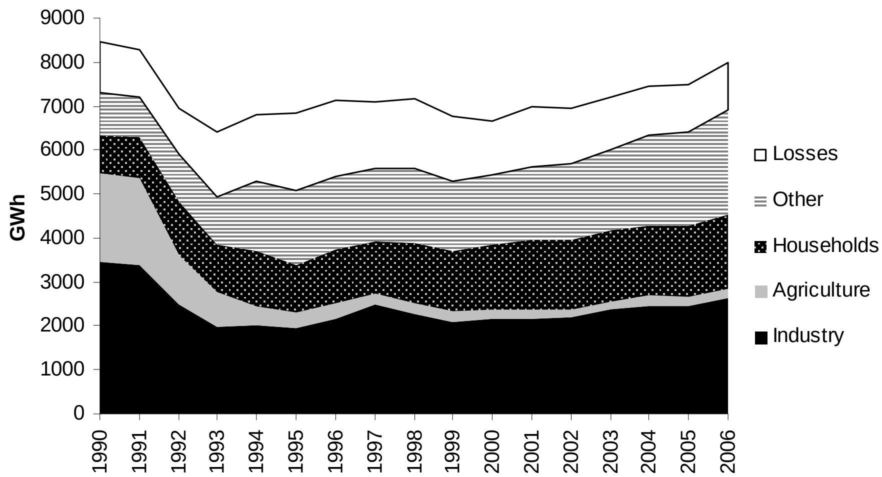

Figure 3-5 Structure of Estonian electricity consumption 1990-2006

In recent years from the beginning of the 90s until now, there have been big changes in losses, there is a stabilizing trend and losses are maintaining a slow decline. The biggest influence on the changes to losses have been decreasing commercial losses that involve non-measured energy and faulty measurement equipment. Commercial losses were enormously high at the beginning of the 90s, after the independence of the Estonian republic because of big changes in the economy and politics of Estonia.

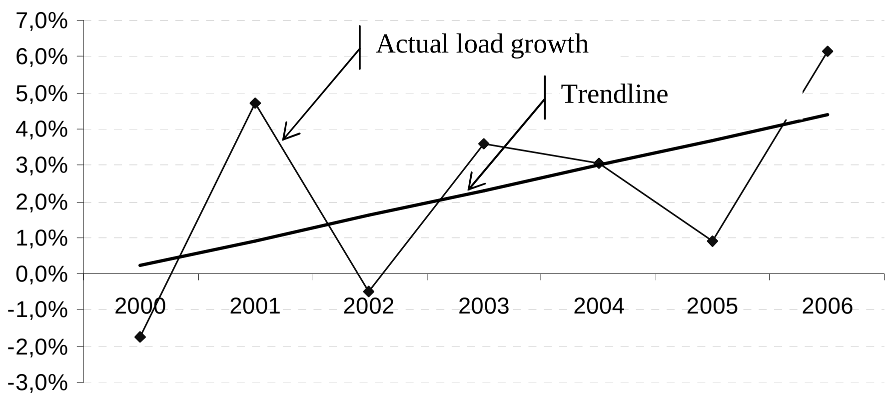

Figure 3-6 Actual demand growth, 2000-2006

3.3 Power generation in Estonia

It was 20 years ago that the last sizeable power plant (Iru CHP) was built. Units of oil shale plants are at least 40 years old; of which several have been closed during the last years. The structure of the electric grid with the available net capacities of power plants (as of year 2008) is depicted in Figure 3-7. Today domestic consumption and modest exports of electricity are adequately covered, but severe restrictions are expected in 2010 and 2015. The Estonian Environmental Strategy and agreements with Finland state that sulphur dioxide (SO_2) emissions in 2005 should not exceed 20% of the 1990 level, emission of solid particles must be reduced by 25% as compared to 1995, and NO_X emissions should not exceed the 1987 level. Until now the SO_2 emission constraints have been fulfilled, mainly thanks to decreased consumption and electricity export. No problems exist with regard to fulfilling the UNFCCC Kyoto Protocol commitment on CO_2 reduction (8% decrease in 2008 as compared to 1990) since over 50% of emissions have been cut.

Starting from 2008 our power plants have to comply with the EU directive on the limitation of emissions into the air from large combustion plants. During the accession negotiations with the EU Estonia got some transition periods, but existing oil shale pulverized combustion units cannot operate after 2015.

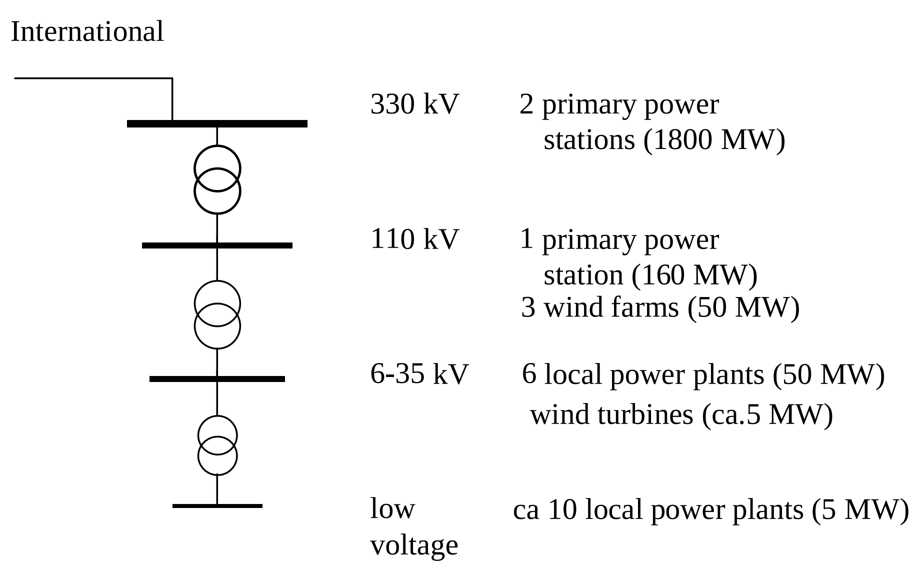

Figure 3-7 Structure of the electric network of Estonia in 2008

After 2015 only 6% of the capacity of power plants that existed in the 1990s (over 3000 MW) can continue operating. This means that billions of Estonian kroons (EEK) have to be invested in a short time interval in new generating equipment. It has been suggested that the total installed capacity should never fall below 2000 MW. Considering the economic growth targets, a reduction of electricity demand cannot be envisaged. In addition to investments in power plants, substantial funds are required to develop and modernize the electrical networks and to implement environmental projects as well.

To fulfil the environmental requirements, reconstruction of two production units of the oil shale power plants with the total net capacity of 390 MW and renewal of the ash filters of all units were be completed in 2004 and 2005. The new units use circulating fluidized bed combustion technology which raises conversion efficiency from 29% to 34% and minimizes sulphur emissions.

Strong competitors of the new oil shale plants will be natural gas power plants and plants that use renewable resources and therefore have economic support mechanisms, described below in 3.3.3. Coal, peat and co-combustion of different fuels are also important options. It is important to continue research in advanced combustion technologies, such as pressurized fluidized bed combustion of oil shale or boilers with supercritical parameters. Only those technologies could provide oil shale plants with the necessary conversion efficiency (ca 44%) and emissions reduction in the long-term. The ash removal systems of oil shale power plants have to be renewed before July 2009

3.3.1 Present Situation

At the moment the installed net production capacity in the energy system of Estonia is 2322,6 MW (Table 3-1). The actual possible net generation in 2006/2007 winter peak demand was 1711 MW. Consequently the maintenance and forced outages of generation equipment and opportunities of generation by means of wind- and hydro resources reduce significantly the generating capacity available in real-time operation. In September 2007 the installed net capacity in Narva Power Plants is circa 2000 MW, installed net capacity in Iru PP is 165 MW, in Kohtla-Järve and Ahtme – 54,4 MW. In the latter the available capacity is 10-22 MW.

Installed wind parks 52,3 MW, from which the available capacity in peak demand is 0 MW. Installed capacity of all other power plants (hydro plants included) (according to 2005. data) – 40,2 MW, from which the available capacity is 36 MW. Total amount of installed net generation capacity is 2322,6 MW

Table 3-1 Installed net generation capacities in Estonia (01.09.2007)

Power plant	Generation, condensed, MW	Generation from CHP, MW	Total
Balti PP	462	192	654
Eesti PP	1346		1346
Iru CHP		165	165
Ahtme CHP		24,4	24,4
Kohtla-Järve CHP		30	30
Industrial CHPs		30	30
Small CHPs		16	16
Hydro plants	4,9		4,9
Wind parks	52,3		52,3
Total	1865,2	457,4	2322,6

3.3.2 New power plants under construction

In Estonia there are two CHP-s (2x25 MW) under construction, one in Iru (near Tallinn) and the second in Tartu. These two CHP-s are planned to come into commission in year 2008/2009. At the moment final decisions have not been made regarding the purchase of new generation equipment to power plants in the Narva region (Eesti and Balti PP).

Additionally to CHP-s, there are planned and under construction a number of new windparks (Table 3-2). In Table 3-2 the column of conservative prognosis is compiled on the assumption of clients who have signed contracts with the Estonian transmission system operator, taking into account the capped subsidy to wind-generated electricity (previously 400 GWh annually). Best estimate prognosis is compiled on the assumption of clients who have signed contracts with the Estonian transmission system operator. The maximum prognosis consists of of emitted connection offers.

Table 3-2 Predictable connection of windparks to Transmission Grid (MW)

Year	Maximum prognosis	Best estimate prognosis	Conservative prognosis
2007	52,3	52,3	52,3
2008	57,4	57,4	57,4
2009	90,4	90,4	90,4
2010	236,2	215	150
2011	422,4	260	200
2012	970,4	450	200

Wind parks under construction are as follows: 14 MW in western Estonia, in Hanila parish (Virtsu), 48,6 MW wind park in western Estonia, in Noarootsi parish (Aulepa), 150 MW wind park in eastern Estonia (Ida-Virumaa, Lüganuse parish

(Püssi), a 24 MW wind park will be connected to Aseri, a 76 MW wind park will be connected with the Balti power plant substation and a 6 MW wind park in Võiküla.

From 2012 the annual limitations of sulphur emissions come into effect. Annual production of existing units is limited to about 5,8 TWh.
From the standpoint of the economics of Estonian energy, of critical importance is the year 2016, when all energy generation must be harmonized with EU requirements concerning large combustion units' SO_2 and NO_x emissions. In year 2016, from existing available electrical generation it is possible to keep in operation two new fluidized bed boilers in the Narva Power plants, the second generation unit in Iru Power plant and small power plants. Therefore it is necessary to refurbish existing units (DeSOX, DeNOX) or to build additional generation capacities instead of closing generation equipment for the year 2016.

According to the agreement with the EU, altogether 1614 MW in Narva power plants and 54,4 MW of the generation equipment in Kohtla-Järve and Ahtme power plants will be unavailable. When considering the year 2015 net available capacity at the peak demand in winter, 1624 MW or 74% of available installed net generation capacity will be closed down. Altogether, from existent available power for peak demand, 572 MW is used.

3.3.3 Renewables

Target for renewables

During negotiations with the EU, Estonia was set an indicative target for production of electricity from renewable energy sources (RES). The electricity produced from RES must cover at least 5.1% (ca 400 GW/h) of the gross inland electricity consumption by 2010. This is a heavy task as the share was 1,7 % in 2007. The options are: the use of biomass, wind generators and restoration of former small hydro plants. However, the hydro option is very limited because the real potential is only ca 30 MW. Hydro could contribute to a large extent if an agreement with Russia on joint operation of the 123 MW plant on the border river Narva is reached.

Present situation

In 2002, the first wind farm of 3x600 kW capacity was erected in Virtsu and restoration of the present biggest hydro plant (1.1 MW) was completed in Linnamäe. One 250 kW wind turbine was connected to the grid in 2003.

The current situation in Estonia is as follows: 58.5 MW of wind capacity is already in operation. The largest wind farms are Paldiski 18.4 MW, Viru-Nigula 24 MW, and Rõuste 8 MW.

Support schemes for RES-electricity

Support schemes for RES-electricity are available for RES-electricity production with the capacity of production machine below 100 MW and with open supply when the capacity of production machine is below 1 MW.
A producer who uses wind as the source of energy and who commenced work with the generating installation before 31 December 2007 may sell the electricity produced with such generating installation as open supply to a seller designated by the transmission network operator at a price which is 115 EEK cents for a kilowatt-hour until 31 December 2008. Up to now there is no balance responsibility for wind energy, but starting from 2009 wind is treated on equal terms with other balance-responsible parties. The support price for produced and sold electricity is 115 EEK cents per kilowatt-hour up to production capacity 200 GWh/y, afterwards the price will be 84 EEK cents per kilowatt-hour until the wind energy annual limit for support 400 GWh/y is reached (Table 3-3). The producer has the right to get a support price for 12 years from the start of production. Start of production means that at least 80% of nominal power is supplied to the network. Producers shall not subsidise generation from renewable energy sources at the expense of generation from other sources and vice versa. At the request of the Energy Market Inspectorate, a producer shall submit information on the allocation of revenue and expenses separately for generation from renewable energy sources and for generation from other sources

Table 3-3 Support schemes for RES-electricity in Estonia

<table>
<tr><th>Purchase obligation</th><th>Support, when electricity is sold in the market</th><td rowspan="4">Electricity sold in the market according to the guarantee of origin.
Status product</td></tr>
<tr><td>1.15 EEK/kWh</td><td>0.84 EEK/kWh</td></tr>
<tr><td colspan="2">1 EUR = 15.4644 EEK</td></tr>
<tr><td>For wind energy until production capacity of 200 GWh/y</td><td>For wind energy until production capacity of 400 GWh/y</td></tr>
</table>

3.3.4 Investment plans in power generation

In Narva power plant two new generation units are planned to be built, both with capacity up to 400 MW (in years 2015 and 2016.). Also, in the four existing generation units flue gas cleaning devices (deSOx and deNOx) will be installed, which allows the use of these units to be extended beyond 2015. In the case of this scenario in the Narva power plants, it will be possible to use, after 2015, circa 1800 MW of generation capacity. At the moment in the Narva power plants, the Environmental Impact Assessment of the planned units is being compiled. Transmission System Operator OÜ Põhivõrk is also considering the building of an additional gas turbine plant (capacity circa 100 MW) for year 2011, to use for covering the emergency reserves in possible emergency cases. The final investment decision to build this plant has not been made yet.

Renewables

Connection agreements for wind farms are agreed at 665.7 MW; connection applications for 2695 MW are being processed (including 2 offshore wind parks 900 MW and 990 MW).

Points of connection for wind parks, altogether for 345.9 MW, are under construction at the moment: Virtsu 14 MW, Aseri 24 MW, Püssi 150 MW, Balti 76 MW, and Aulepa 48 MW. Several points (153.4 MW) of connection are already completed, but are on hold, due to problems concerning land usage.

3.3.5 Future scenarios of power generation

From the point of view of the economics of Estonian energy the critically important year is 2016, when the whole of energy generation must be harmonized with EU requirements. In the National Long Term Development Plan for Fuel and Energy Sector the following future scenarios are decribed. The alternative possibilities for Estonia in the development of power engineering are the following [3]:

1. To continue the renovation of Narva power stations on the basis of the circulating fluidised bed combustion technology.
2. To apply, in oil shale power industry, other technological solutions, such as combustion under pressure, mixing of oil shale with other (e.g. also renewable) fuels, large-scale production of shale oil and application thereof on the basis of the principle of distributed energy production etc.
3. To change the structure of the whole Estonian energy sector fundamentally, abandon oil shale power industry and concentrate on other, mainly imported energy carriers. The most likely alternatives for this solution are natural gas and coal.
4. To cooperate with other states – e.g. participate in a possible project for the construction of a new nuclear power station in Lithuania which already has the trained personnel and infrastructure necessary for operation.

It was envisaged in the plan that renovation of the oil shale blocks continues on the basis of the following schedule [3]:

- by the end of 2010, two blocks in the Narva power stations and Ahtme power station are completed (altogether 535 MWe).
- by the end of 2015, three blocks in the Narva power stations and Kohtla-Järve power station are completed (altogether 665 MWe).

Today, it is clear that it is not possible to implement the plans decribed above due to the construction time of new units. It was stated in the plan that natural gas is the first alternative for oil shale power industry as it is the cleanest fossil fuel. At the same time, if the consumption of natural gas increases to a great extent, the security of the energy supply is critical both from the point of view of gas transmission network transmission capability and political risks. The price of natural gas in Estonia depends on the price of the alternative energy carriers. It is possible to use coal for the production of electric energy. Coal supply is the largest supply of fossil fuels in the world, and there are several sources of supply. At the same time, the environmental impact of coal energy is comparable to that of oil shale power industry, to which the social policy expenditure arising from the replacement of oil shale energy and the effect on the foreign trade balance are added. The long-term competitiveness of electrical production capacities also depends directly on the development of EU environmental restrictions; the Plan did not take into account current trends in the price of carbon dioxide. Under current assumptions oil-shale or coal generation is not considered a viable option without additional subsidies.

3.4 Energy and Environment Related Legislation in Estonia

Until July 2003 the most important law in the energy field was the Energy Act adopted by the Parliament in 1997. The Electric Safety Act, the Act on Energy Efficiency of Appliances, the Law on Minimum Reserves of Liquid Fuels, etc. regulate narrower areas. In 1992, the Government adopted its Energy Conservation Programme and in 2000 it was updated as the Target Programme of Energy Conservation. The independent Energy Market Inspectorate, the main regulator in the energy field, was established in 1998.

To harmonize Estonian legislation with EU directives and to improve the regulation of dynamic energy markets, the Energy Act was replaced by four separate laws: the Electricity Market Act, the Natural Gas Act, the District Heating Act, and the Liquid Fuels Act. They were adopted by the Parliament on February 11, 2003 and they came into force on July 1, 2003. Also, the Electric Grid Code was elaborated as a supplement to the Electricity Market Act.

The Energy sector is also strongly influenced by environmental legislation, such as the Sustainable Development Act, the Atmosphere Protection Act, the Pollution Fees Act, the Environmental Strategy, etc.

Estonia has ratified several international agreements, such as the European Energy Charter Treaty, the United Nations Framework Convention on Climate Change (UNFCCC) and its Kyoto Protocol, the Convention on Long-range Transboundary Air Pollution and its protocols, and the Vienna Convention for the Protection of the Ozone Layer.

Elaboration of a comprehensive and optimal system of energy and environmental taxes and subsidies is an important task for the near future.

3.4.1 Energy sector planning

The energy sector is the basis of the rest of the economy and cannot be separated from environmental and social issues. Considering also its operation costs and investment needs, one can easily conclude that energy system operation and development have to be optimal.

The first long–term national energy programme after World War II was drawn up in 1989. Since then numerous plans at different levels have been developed. Of the most important ones, the following could be listed: “General Principles of the Development of Estonian Power Engineering until 2030” (1990), “Energy Master Plan for Estonia” (1992-93, international project), “Energy Strategy for Estonia” (1996-97, EU PHARE project), “Long-Term Development Plan for the Estonian Fuel and Energy Sector” adopted in the Parliament in 1998, EU PHARE-financed programme “Energy Planning for Municipalities” (1998-2000) which consisted of 20 different planning projects and “Action Plan for the Restructuring of Estonian Oil Shale Power Engineering 2001-2006” (2001). Several international projects on environmental emissions have also been drafted, where the energy system development projections have been of key importance.

In 2003 the main energy policy document - “National Long Term Development Plan for Fuel and Energy Sector until 2015 (with a vision until 2030)” was adopted by the Parliament. The national strategy “Sustainable Estonia 21” was completed in 2003 as well.

Development in the electricity sector is adumbrated in “Electricity sector development plan until 2005-2015”. The most important goals are:

- to guarantee local generating capacity for peak-load cover;
- to develop efficient energy-conversion technologies, including co-generation of electricity and heat;
- to support increased efficiency of local, oil-shale based electricity generation as a strategic resource in an open electricity market;
- to stimulate saving of electricity;
- to create new interconnections with neighbouring EU members to increase security of supply and promote development of the electricity market.

3.4.2 Liberalization of the electricity market

Liberalization of the electricity market means the opening of electricity production and sales to competition when the transmission and distribution remain natural monopolies. Since 1999 the Estonian electricity market has been open for eligible customers whose annual consumption exceeds 40 GWh. These consumers have a right to purchase electricity from any producer or seller in the market and an obligation to pay for network services. The consumption by eligible customers presently forms ca 10% of the total consumption. During the accession negotiations, Estonia and the EU reached a compromise solution for further step-by-step opening of the electricity market. At least 35% must be opened before December 31, 2008 and for all non-household consumers (ca 77%) before December 31, 2012. The market will operate according to the rules of the Electricity Market Act and the Grid Code.

There is a widespread belief that liberalization will enchance the system’s efficiency and the quality of services. Reductions in consumer prices are probably only short-term. An open market also creates new problems. In Estonia's case, the main risks are:

- the market will not be open in practice if there are insufficient independent producers and sellers (no competition with Eesti Energia AS)
- shortage of generation capacity can occur and prices rise if the market participants want just to sell and buy, but not to invest
- Estonia is so small that large-scale cheap imports can destroy local production and investments, and make us dependent on neighbouring countries
- new power plant investments can increase the share of imported fuels (natural gas technologies are cheaper, more efficient and environment-friendly than other fossil technologies) and cause supply security and price risks, and worsen foreign the trade balance
- the pressure to increase the electricity prices of the closed part of the market (especially households) will increase.
- considering the small size of the Estonian electricity market, the complication of power system control, the costs of operating the market, volatile prices and the possible lowering of supply security and reliability due to insufficient investments in the whole region could easily outweigh the expected positive effect of liberalization.

The opening of the electricity market also causes institutional changes in the energy companies: production, network and sales activities have to be separated from each other.

3.5 Long-Term Forecast of the Estonian Economy's Main Indicators

The energy demand forecast is based on a long-term economic evolution prognosis which has been made by the Ministry of Finance of the Republic of Estonia. There are three scenarios:

- Optimistic scenario
- Base scenario
- Pessimistic scenario

Each scenario has taken account of the influence of global politics and the economic tendency of the economy as a whole, not just of the energy sector. Various interpretations have been explored, which mainly relate to the long-term perspective. Scenarios describe long-term trends. At the same time, actual progress depends on specific political and economic factors, which may in the short-term cause measurable deviations from overall trends.

Optimistic scenario presumes tight integration with EU economic and political structures. At the same time, Estonia retains quite strong connections with Russia and other CIS countries. Estonia joins the European Monetary Union in 2007-2008, which means increasingly closer connections with European markets and companies' extensive collaboration with, and access to, international corporations. The second premise is the continued development of private enterprise involvement in Russia, which enables Estonia to become a transit country between East and West.

Base scenario presumes tight integration with Western economic and political structures, especially the EU. At the same time, connections with Russia and other CIS countries decrease, essentially because economic development in Russia involves a de-emphasis of economic relations with so-called local foreign states. Such evolution may be dominant in a rather shorter time period. When economic problems lead to political instability, these negative tendencies may have a prolonged and deeper influence.

Pessimistic scenario presumes that integration with Western economic and political structures, especially the EU, stalls and at the same time relations with Russia and other CIS counties are unsettled. Estonia partly retains the role of a transit country but besides oil, smuggled commodities take a significant part of the GDP. Estonia becomes a corporate state where the illegal world has close relations with the political and business community. The Estonian economy settles at Eastern European standards.

The value of Estonian GDP was 5.584 billion EUR (4076 EUR per capita) in 2000 [12]. The annual growth forecast for the current project was taken from [1] (average forecast) and is depicted in Figure 3-8.

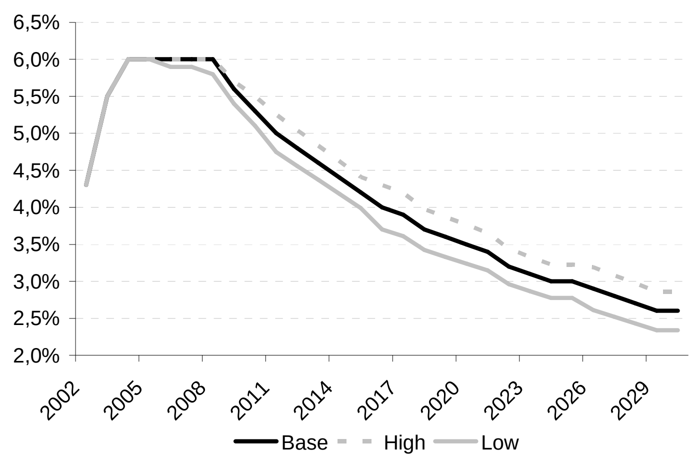

Figure 3-8 Annual GDP growth forecast [1]

The forecasts of population and GDP used in the modelling are presented in PAPER 2 [60], [62], [63], [64]

3.6 Basic modelling assumptions

The basic assumptions considered in all the investigated scenarios are presented in PAPER II. As there are some changes foreseen from the premises used previously, the following assumptions were modified:

1. Estonia will not use old pulverized combustion oil shale power plants after 2015 without additional flue gas cleansing devices, in accordance with the schedule agreed with the EU. As a result, only 2 refurbished fluidized-bed combustion units can operate after 2015, and other units must be equipped with flue gas cleansing devices or closed.
2. Imported fuel prices are according to estimates of IEA World Energy Outlook 2007 [32]. The forecasts of tax-free production and import prices (without inflation and transport costs) of the main fuels for MARKAL modelling are presented in Table 3-4.
3. Planning period is 2005-2035 and discount factor is 0,05.

Table 3-4 Fossil-fuel price assumptions [32]

		2006	2010	2015	2030
oil	$/barrel	62	65	71	108
coal	$/ton	63	62	70	106
gas	$/Mbtu	7,3	7,3	8,2	12,7
oil	EUR/GJ	9,3	11,2	12,2	18,6
coal	EUR/GJ	2,3	2,5	2,8	4,2
gas	EUR/GJ	6,1	7,0	7,8	12,1
oil-shale	EUR/GJ	1,38	1,38	2,37	2,37

The primary energy resources of Estonia are estimated as follows [3]:

Oil shale – active resources of the deposit are ca 1,2 Gt and passive resources 4 Gt. Latest research results of the Mining Department of TUT estimate that the resources will last 60 years under current level of exploitation.

Table 3-5 Estonian oil-shale resources 01.01.2005 (gigatonnes) [4]

Type of stock	**Fields G t**	**Free G t**
Active consumption in stock	1,15	0,61
Active reserve in stock	0,27	0,23
Passive consumption in stock	1,59	1.48
Passive reserve in stock	1,75	1,58
Total	**4,76**	**3,90**

Wind – theoretically a very large resource, but its use is limited by several restrictions [57], [58]. Considering the possibilities of the Estonian power system and its neighbours to integrate windmills, the capacity limit is currently ca. 700 MW, which corresponds to an annual production of ca. 1,6 TWh/a = 6 PJ/a. Maximum long-term annual utilization of wind energy is estimated at 15 PJ/a (requires 2000 MW of installed capacity of windmills).
Forecasts of final energy consumption are presented in PAPER II.

4 ELECTRIC GENERATION TECHNOLOGIES AND FUTURE DEVELOPMENT OUTLOOK

4.1 Thermal Generation Technologies

Fossil power plants

Fossil power plants include coal-fired, oil-fired, and natural gas-fuelled power plants.

The combustion of pulverised or powdered coal to raise steam in boilers has been the main fossil-based power generation worldwide for almost a hundred years. The efficiency of the current generation of pulverised coal units has steadily improved and today ranges between 30% and 45% (on a lower heating-value basis) depending on the quality of coal used, ambient conditions and the back-end cooling employed. A number of advanced power-generation technologies have been or are being developed to improve thermal efficiency and to reduce other emissions, notably nitrogen oxides (NO_x) and sulphur dioxide (SO_2). These technologies hold out the prospect of significantly raising the efficiency of the new coal-fired plants that will be built in the coming decades and reducing their emissions. The most important of current technologies and others in development are

Supercritical and ultra-supercritical pulverised combustion

The efficiency of a steam cycle is largely a function of steam pressure and temperature. Typical subcritical steam cycles, as in the vast majority of today's power plants, operate at 163 bar pressure and 538°C With supercritical designs, pressure is typically 245 bar and temperature in excess of 550°C, i.e. above the critical point at which water turns to steam without boiling. In ultra-supercritical designs, even higher temperatures are used, sometimes exceeding 600°C. More expensive materials are required, but the impact of this higher capital cost on the overall economics of the plant is, to some extent, balanced by the increased efficiency, which brings fuel and fuel-handling cost savings. Supercritical technology has become the norm for new plants in the OECD. Commercial ultra-supercritical plants are in operation in Japan, Germany and Denmark. Research into materials taking place today aims to push efficiencies to over 50%.

Circulating fluidized bed combustion (CFBC)

CFBC plants can be designed for a wide variety of fuels and particle sizes. Because fuel is burned at low temperatures and in a staged manner, they produce low NO_x compared with conventional pulverised coal (PC) boilers. In addition, operating temperatures are ideally suited for in-situ capture of SO_2. The efficiency of CFBC plants is similar to PC units. At present, the largest operating CFBC unit is 320 MW. CFBC-s is now available commercially at a scale that allows them to be used in supercritical mode. The first supercritical CFBC unit (460 MW) is currently undergoing construction in Poland, and is scheduled to operate in the first half of 2009. However, relatively low operating temperatures mean CFBCs may not be practicable for ultra-steam supercritical plants, which operate at much higher than 550 °C temperatures.

Combined Cycle Plants

Combined cycle plants have become a popular generation scheme in recent years. A combined cycle unit uses a gas turbine (Brayton) top cycle with the excess heat going to a steam turbine (Rankin) bottom cycle, compressed before injecting fuel for ignition in the gas turbine. The resulting combustion gases are first used to drive the gas turbine, then the hot exhaust gases are sent to a heat recovery steam generator (HRSG), before release through the slack. The heat transferred to the HRSG produces steam, which is used to drive a steam turbine-generator set.
The overall thermal efficiency of combined cycle plants built today is remarkable (electrical – over 50%). Combined cycle plants are designed for intermediate load due to their relatively quick start-up time. Additional advantages of these plants are that they can be constructed in a relatively short period (about 2 years), and that they use natural gas, which is an environmentally good choice.

Integrated gasification combined-cycle (IGCC)

IGCC combines coal gasification with a combined-cycle power plant. Coal is gasified under pressure with air or oxygen to produce fuel gas which, after cleaning, is burned in a gas turbine to produce power. Exhaust gas from the gas turbine passes through a heat-recovery steam generator or boiler to raise steam for a steam turbine which generates extra power. Only four successful IGCC plants have so far been built: two in Europe and two in the United States. At high temperatures, efficiency can be as high as 41%, or even higher with the latest gas-turbine models. A number of plants are being built in China and Japan, and several others are being considered elsewhere. IGCC has inherent advantages for emission control, as gas clean-up takes place before combustion of the fuel gas, using relatively little equipment, and solid waste is in the form of a vitrified slag. If CCS becomes an established mitigation measure, then CO_2 capture from an IGCC plant is technically easier than post-combustion capture from a conventional steam plant.

Table 4-1 OECD Coal-Fired Power Plant Investment Costs ($/kW) [26]

	without carbon capture		with carbon capture	
	min	max	min	max
IGCC	1600	2000	2100	2800
Oxy-Firing in PC	-	-	2100	2950
CFBC	1500	2000	2500	3500
Ultra-Supercritical PC	1500	2100	2300	3250
Supercritical PC	1500	2000	2400	3200
Subcritical PC	1400	1700	2500	3250

4.1.1 CO_2 Capture and Storage

CO_2 capture and storage (CCS) is one of the most promising options for mitigating emissions from coal-fired power plants and other industrial facilities. It plays a major role in stabilising CO_2 concentrations. CCS is a three-step process involving the capture of CO_2 emitted by large-scale stationary sources and the compression of the gas and its transportation (usually via pipelines) to a storage site, such as a deep saline formation, depleted oil/gas field or unmineable coal seam. The CO_2 may also be used for enhanced oil or gas recovery. CCS processes can currently capture more than 85% of the CO_2 that would otherwise be emitted by a power plant, but they reduce the plant's thermal efficiency by about 8 to 12 percentage points and thus increase fossil-fuel inputs, because of the additional energy consumed in capturing the gas. Initially, CCS is expected to be deployed primarily in coal-fired power stations, because the CO_2 emissions to be captured are proportionately larger than in oil- or natural-gas-fired plants, reducing the per-tonne cost.

The process of capturing CO_2 generally represents the largest component of CCS costs. There are three main processes currently available:

- Pre-combustion capture
- Post-combustion capture
- The oxy-combustion process

CO_2 capture from combustion processes is highly energy-intensive and expensive. CCS in power generation is cheapest for large, highly efficient coal-fired plants

The expected cost of CCS corresponds to the CO_2 cost of 40-70 EUR/tonne, but costs can be much higher depending on technology, CO_2 purity and site. It also means that installation of CCS is economically feasible if CO_2 cost is higher than values mentioned before, but on the other hand the cost of CO_2 cannot be higher than the marginal cost of CCS.

4.2 Nuclear power

Nuclear reactors for civilian electricity production have been in use in the OECD since 1956, when the 50 MWe Unit 1 of the Calder Hall Station began operation in the United Kingdom. The programme with the most profound effect on the development of civilian reactor technology was the development of the nuclear submarine programme in the United States. Its goal was to design and produce compact nuclear reactors allowing extended autonomy for submarines. The results were pressurised water and boiling water reactor designs which now account for most of OECD nuclear plant capacity [36]. The Soviet Union developed two types of nuclear plants for civilian electricity generation, beginning in 1954. The first was a unique design of the type used at the Chernobyl plant ("RBMK") and the second was basically similar to the pressurised water design of the United States. The initial reactor of this latter type was put into operation in Russia in 1964 [36]. All credible scenarios of future energy demand and supply show that the more nuclear is used, the more GHG emissions are avoided. Countries with high nuclear shares have the lowest per capita GHG emissions. The main advantages of nuclear power are:

- cheap to operate,
- stable and predictable generating costs,
- long life time,
- supply security.

Disadvantages:

- high upfront capital costs can be difficult to finance,
- sensitive to interest rates,
- long lead times (planning, construction, etc),
- long payback periods,
- regulatory/policy risks.

4.2.1 The cost of nuclear power

Capital costs

Capital costs are incurred while the generating plant is under construction and include expenditure on the necessary equipment, engineering and labour. These are often quoted as "overnight" costs which are exclusive of interest accruing during the construction period. They include engineer-procure-construct (EPC) costs, owners' costs and various contingencies. Once the plant is completed and electricity sales begin, the plant owner begins to repay the sum of the overnight and accrued interest charges. The price charged must cover not only these costs, but also annual fuel costs and expenditure on the operation and maintenance (O&M) of the plant. In the case of nuclear plants, fuel costs will include an allowance for the management and disposal of the spent fuel. A periodic charge for the decommissioning of the plant should also be made, provided over the economic life of the plant, to pay for the eventual cost. This is likely to be some 40 to 60 years in the future.

Most studies of the competitiveness of nuclear power base their estimates of capital costs on data of construction costs for recent reactors in Asian countries, and use overnight costs (i.e. without interest charges and financing costs) at and above $2000 per kW of capacity. For example, [33] used a starting point of $2083 per kW for its estimates in its 2004 Annual Energy Outlook, while [37] used $2000 per kW. In both cases, lower costs were also considered, based on the learning benefits of later units and the innovative designs of the latest reactors.

Estimates have been produced by vendors and their partners and scrutinized by outside reviewers as far as is possible without building a test plant. For designs such as the Westinghouse AP1000, the GE12 ESBWR and the AECL13 ACR-1000, the overnight capital costs of building twin units on one site are in the range $1000-1500 per kW including all costs from first to second unit. This would include all the first-time costs for completing design, engineering and licensing of an initial project. The industry feels strongly that the $1000-1500 per kW level is achievable now and reflects a rigorous design, engineering and construction assessment. Achieving costs at this level will make a major contribution to the competitiveness of new reactors against alternative technologies.

Variation of capital costs

Alternative reactor technologies can generate different cost estimates while reactor components can be quoted at higher or lower levels at various times. Allowances for contingencies are necessary when vendors make firm fixed price offers, while some estimates may include first-of-a-kind engineering (FOAKE) costs and others may not. Some estimates include reductions for nth-of-a-kind reactors, through learning-by-doing, or for building two or more reactors simultaneously on one site.

About 80% of overnight costs are engineer-procure-construct (EPC) costs, with about 70% of these direct (physical plant equipment with labour and materials to assemble them) and 30% indirect (supervisory engineering and support labour costs with some materials). The remaining 20% of overnight costs are contingencies and owners' costs (essentially the cost of testing systems and training of staff). In addition, FOAKE costs are a fixed cost of a particular reactor and can amount to $300-600 million. How these are added to overnight capital costs depends on how the vendor wishes to allocate these across various reactors. If he wishes to recover them all on the first reactor, this could easily add 35% to an overnight cost of $ 1000 per kW.

The example of France (58 reactors) shows that the industrial organization and standardization of a series of reactors allowed construction costs, construction time and operating and maintenance costs to be brought under control. The total overnight investment cost of the French PWR programme amounted to less than 75 billion EUR at 2004 prices. When divided by the total installed capacity (63 GW), the average overnight cost is less than 1300 Euros 2004/kW. This is much in line with the costs that were then provided by the manufacturers.

OECD-NEA [38], a comprehensive report on the subject, highlights several areas where vendors have identified specific steps to reduce capital costs to a range they regard as feasible: $1000-1400 per kW of installed gross capacity. Key areas of cost reduction include the following:

- Larger unit capacities provide substantial economies of scale, suggesting that nuclear plants should, for economic reasons, use higher-capacity reactors.
- Replicating several reactors of one design on one site or country can bring major unit cost reductions.
- Standardization of reactors and construction in series will yield substantial savings over the series.
- Learning-by-doing can save substantial capital costs, both through replication at the factory for components and at the construction site for installation.
- Simpler designs, some incorporating passive safety systems, can yield sizeable savings, as can improved construction methods.
- A predictable licensing process can avoid unexpected costs and facilitate getting the new plant up to safety and design requirements at an early date in order to to start electricity - and revenue - generation.

4.3 Renewables

Wind

Wind energy is assuming importance throughout the world. This rapid development of wind energy technology and of the market has serious implications for power systems. Wind is clearly one of the CO_2-free technologies closest to being cost-effective without subsidies. The utilization of this renewable source of power is spreading fast to other areas of the world.

During the last decades of the twentieth century, worldwide wind capacity doubled approximately every three years. The cost of electricity from wind power has fallen to about one sixth of the cost in the early 1980s. And the trend seems set to continue.

Over the years, the typical wind turbine size increased to about 200 kW at the end of the 1980s. By the end of the twentieth century, 20 years after the unsuccessful worldwide testing of megawatt wind turbines, the 2 to 5 MW wind turbines had become the technical state of the art.

Wind energy was the fastest growing energy technology in the 1990s, in terms of percentage of yearly growth of installed capacity per technology source.
Over the past 10 years, the cost of manufacturing wind turbines has declined by about 20 % each time the number of manufactured wind turbines has doubled. In particular, the impact of wind speed on the economics of wind power must be stressed: a 10 % increase in wind speed, achieved at a better location for example, will in principle result in 30 % higher energy-production at a wind farm.

The horizontal axis, or propeller-type approach currently dominates wind turbine applications.

4.4 Options for power generation in Estonia until 2035

The scenario for new power conversion technologies is conservative as regards the technological development of oil shale combustion. It includes only the circulating fluidized bed combustion (CFBC) technology and does not take into account the more advanced and efficient, but premature pressurized fluidized bed combustion (PFBC) option. Also CFBC with supercritical parameters is included as a future option.

New power plant options are based mainly on the investments and assumptions made in Chapter 3.3. This envisages the partial reconstruction of oil shale power plants to meet requirements concerning SO_2 and NO_X reduction , but also investments in wind turbines and gas turbines. Biomass CHP-s already planned are also included. The major investments in electricity production will be:

- Peat and biomass CHP-s with gross capacity of 100 MW in 2010-2015
- Wind turbines with gross capacity of 200 MW by the year 2015.
- 1st oil shale CFBC unit with gross capacity of 270 MW in 2015,
- 2nd oil shale CFBC unit with gross capacity of 270 MW in 2016,

Table 4-2 Options for non-nuclear power generation until 2035, MW.

	2005	2010	2015	2020	2025	2030	2035
Eesti PP, old boilers	1120	1120	1120	800	0	0	0
Balti PP, old boilers	450	450	450	450	0	0	0
Eesti PP CFBC unit	190	190	190	190	190	190	190
Coal condensing				500	1000	1000	1000
Oil-shale supercritical CFBC, new					600	1200	1200
Oil-shale CFBC, new			300	600	600	1200	1200
Pulp and Paper			74	74	74	74	74
Hydro	15	15	15	15	15	15	30
Gas, combined cycle			200	400	400	400	400
Gas, gas turbine		100	200	1000	1500	2000	2000
Iru CHP, existing unit 2	90	90	90	90	90	90	90
Iru CHP, existing unit 1	60	60	60	60	60	60	60
Kohtla Järve CHP, existing	19	19	0	0	0	0	0
Ahtme CHP, existing	20	0	0	0	0	0	0
Balti PP CFBC unit	180	180	180	180	180	180	180
Peat and biomass CHP	0	50	200	200	200	200	300
Wind, onshore	30	120	700	700	700	700	700
Wind, offshore			500	1000	2000	2000	2000
Possible maximum	**2144**	**2294**	**2779**	**3959**	**4909**	**6009**	**6724**

5 ADDITIONAL MODELLING ISSUES.

5.1 Introduction

Additionally, nuclear power plant with capacities of 300, 600 and 1000 MW is included starting from the year 2020. Also all scenarios described in Chapter 6 are modelled. It should be mentioned here that the MARKAL model cannot describe the electricity sector in the required detail, thus additional analysis is needed for balancing issues and for accommodation in the power grid (incl. disturbance reserve). These matters are discussed in detail in Chapter 5.2 and 5.5. The results of analysis with the MARKAL model are described below in Chapter 5.5.

5.1.1 Representation of load in MARKAL

Energy service demands in MARKAL are represented in six annual time slices with two diurnal (day: 6:30 am- 23:30 pm and night: 23:30pm- 6:30am) and three seasons (winter, summer & intermediate) If any demand technologies choose to use electricity, then the model algorithm calculates the electric demand capacity for each of these six time periods by aggregating the various demands in each period. This means that total day and night period electricity demands (GWh) are averaged to calculate the capacity demand (GW) of day and night respectively. Thus the model has only two diurnal demands. However, electricity demand varies seasonally and diurnally with the daily variation being quite significant. Typically, peak demand occurs in the evening and lasts for less than two hours depending on the time in the week, whether a weekday or weekend. The shoulder load occurs in the morning and lasts for five to six hours. Thus a simplified diurnal representation in MARKAL typically underestimates and sometimes overestimates (during low-load) the actual load demands. Figure 5-1 shows the actual electric demand on a typical summer and winter day with their corresponding representation in MARKAL. It can be seen that MARKAL only approximates the demand profile, although it provides a closer fit for total electricity demand i.e. the area under the two lines is similar. This is one of the limitations in the current MARKAL structure.

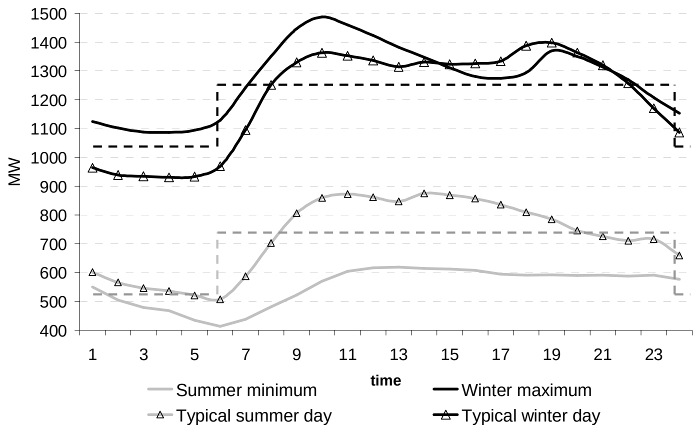

Figure 5-1 Typical seasonal load profiles in Estonia, year 2007. The dotted line shows the load presentation in MARKAL.

However, to address this issue of underestimating the peak demands, non-traditional reserve capacity is included and discussed in Chapter 5.2.

5.2 Balancing of the Estonian system with baseload nuclear power

It is clear from the above that electricity demand fluctuates throughout every 24-hour period as well as through the week and also seasonally. It also varies from place to place depending on the mix of demand, the climate, and other factors. A load duration curve and load curve over one year of the Estonian electricity system is shown in Figure 5-2 and Figure 5-3. The base load power is determined by the load duration curve of the system. For a typical power system, the rule of thumb is that the base load power is usually 35-40% of the maximum load during the year. For the Estonian power system, it can be seen that there is a base load of about 30% of the maximum load for a year previously and it rises to 38% in the year 2035. As well as the daily and weekly variations in demand, there are gradual changes occurring in the pattern of electricity demand from year to year.

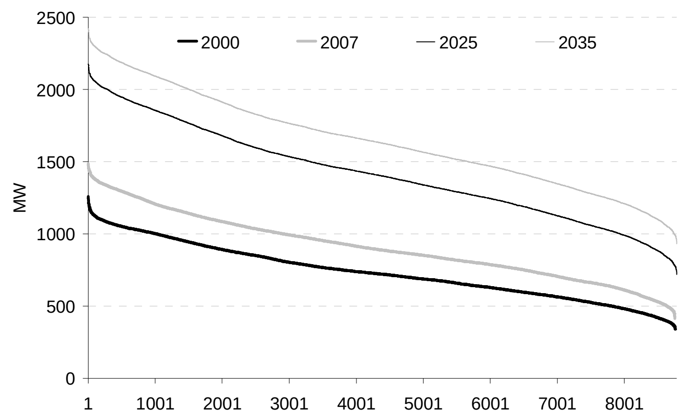

Figure 5-2 Duration curve of demand over one year. Years 2000 and 2007 factual, years 2025 and 2035 forecast.

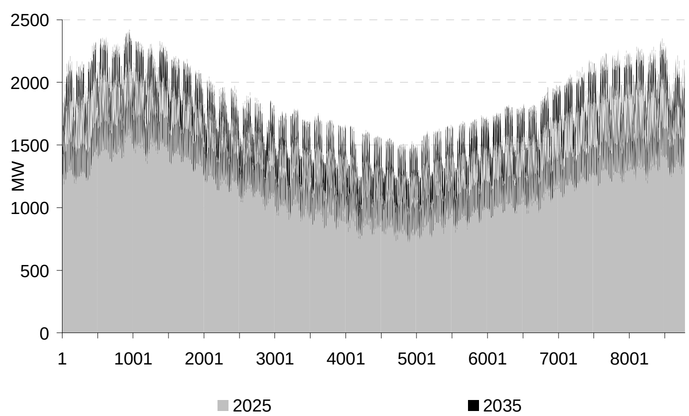

Figure 5-3 Load curve of one year. Forecast of years 2025 and 2035

Because of the large fluctuations in demand over the course of the day, it is normal to have several types of power stations, broadly categorised as base-load, intermediate-load and peak-load stations. The base-load stations are usually steam-driven power stations and run more or less continuously at near-rated power output. Oilshale, coal and nuclear power stations are the main alternative energy sources to cover base-load in Estonia. Intermediate-load and peak-load stations must be capable of being brought on line and shut down quickly once or twice daily. A variety of power station types are used for intermediate and peak-load generation, including gas turbines, gas- and oil-fired steam boilers and hydro-electric generation. As hydro resources are limited in Estonia, pumped water storage, using available base-load capacity overnight and on weekends, may be developed as an alternative to peak-load power stations.

Any practical system has to allow for some of the plant being unserviceable or under maintenance for part of the time. Installed capacity should therefore be about 20% more than maximum load in a system. If new nuclear power plant is introduced in the Estonian power system, it is clear that it will cover all the baseload of the system. If the capacity of the power plant is over 600 MW, part of the generated electricity should be exported or stored during the low-load period in summer. In Figure 5-4 and Figure 5-5 there is shown the additional requirement for balancing the system load if nuclear power plant with capacity of 1000 MW is introduced. It is clear that for about 3000 hours in the year a surplus of generated electricity can occur, even if it comprises only a small part of produced energy, as is shown in Figure 5-5. Typically, such periods are during weekend nights in the low-load period.

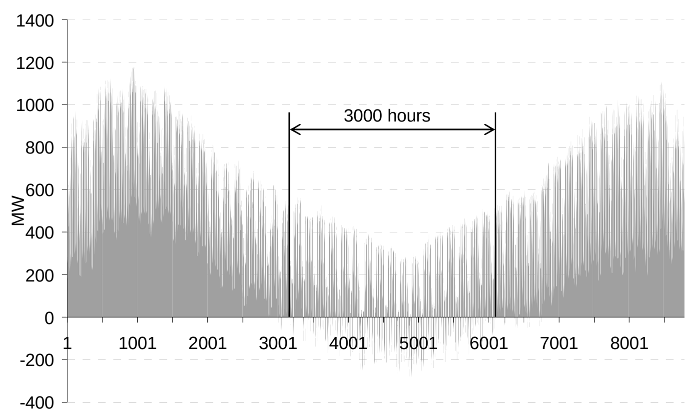

Figure 5-4 Need for additional capacity to cover domestic demand in 2025. Nuclear power plant 1000 MW

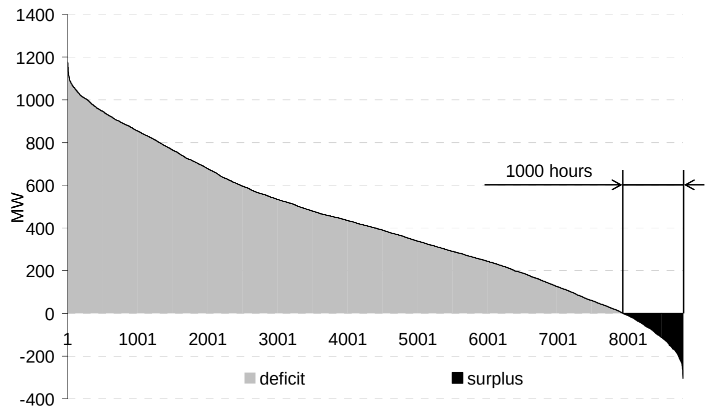

Figure 5-5 Duration curve of additional capacity utilisation to cover domestic demand in 2025. Nuclear power plant 1000 MW

As is seen from Figure 5-6, as load growth is forecast there is no need for export or energy storage during the low-load period even if nuclear power plant with capacity 1000 MW is installed.

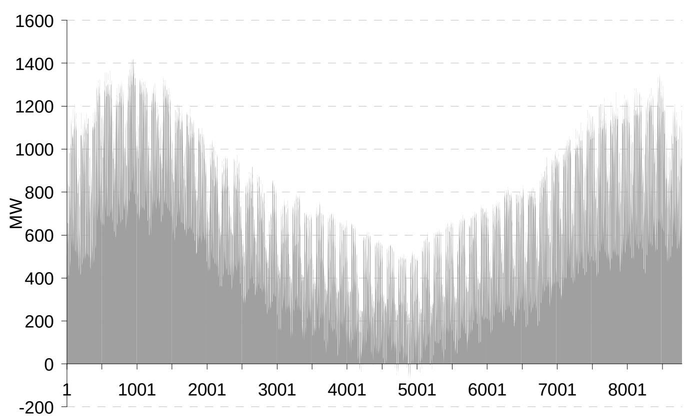

Figure 5-6 Need for additional capacity to cover domestic demand in 2035. Nuclear power plant 1000 MW

It is clear that there will also be other sources of generation in the power system, such as combined heat and power and wind power sources. The must-run co-generation operates typically during winter and intermediate period, during summer load is small or district heat is produced in heat only boilers. Wind generation can occur at any time period in the year, thus total generating capacity can exceed the load of the system. This means that generation should be curtailed or exported. As wind-generated electricity may constitute the largest proportion of must-run generating sources, the next chapter deals with the influence of wind in combination with nuclear power in power-generation balancing.

5.2.1 Additional balancing issues in combination with wind power

The problems related to the integration of wind power are described in PAPER IV. Problems with cooperation of wind power with thermal power plants are described in PAPER III.

The lowest overall power costs to the consumer are usually obtained when the peak-load increment is very small and a steady base-load utilises all of the available generating capacity fairly constantly. Therefore, additional fluctuating capacity (mainly wind power) creates an additional need for peak power and creates problems with system-balancing. Figure 5-7 shows the situation with 1000 MW baseload nuclear power and 1500 MW wind power. The main difference without wind power is that additional capacity must serve only as peak power. It also creates the need to export power during surplus hours or curtailment of wind power. In the case under consideration, without curtailment of wind power, export capability must be over 1500 MW.

Wind power behaviour is modelled by extrapolating the current wind farm hourly production in Estonia. Here it is also assumed that, due to geographical distribution, a significant smoothing effect will take place in the future.

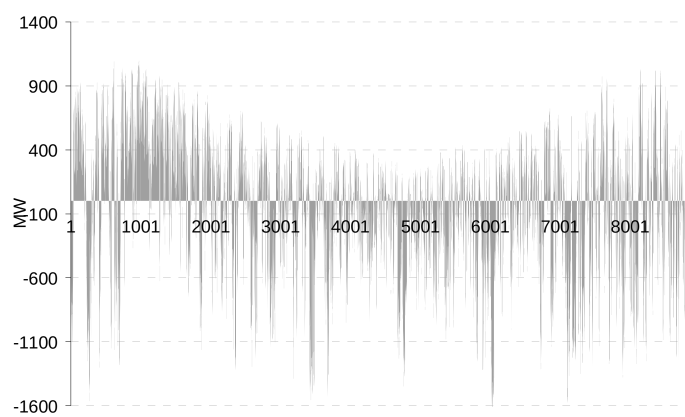

Figure 5-7 Need for additional capacity to cover domestic demand in 2025. Nuclear power plant 1000 MW and renewable (wind) power sources 1500 MW

As shown in Figure 5-7, there will be in combination with wind short-duration peaks where balancing (reserve) power is needed. It is clear that it can be covered only by using fast-start generating units, such as gas turbines or hydro power. As seen in Figure 5-8, the total amount of reserve capacity must be, with wind power of 1500 MW, almost 2000 MW. The total amount of other kinds of generation in the scenario with no substantial amount of wind power is ca. 900 MW.

The difference between these cases is that with wind power all reserve must have quick- start capability, but in a case without wind there could be different types of generation, such as seasonal base, intermediate and peaking generation. Chapter 5.3 consentrates on a scenario without a substantial amount of wind-power generation.

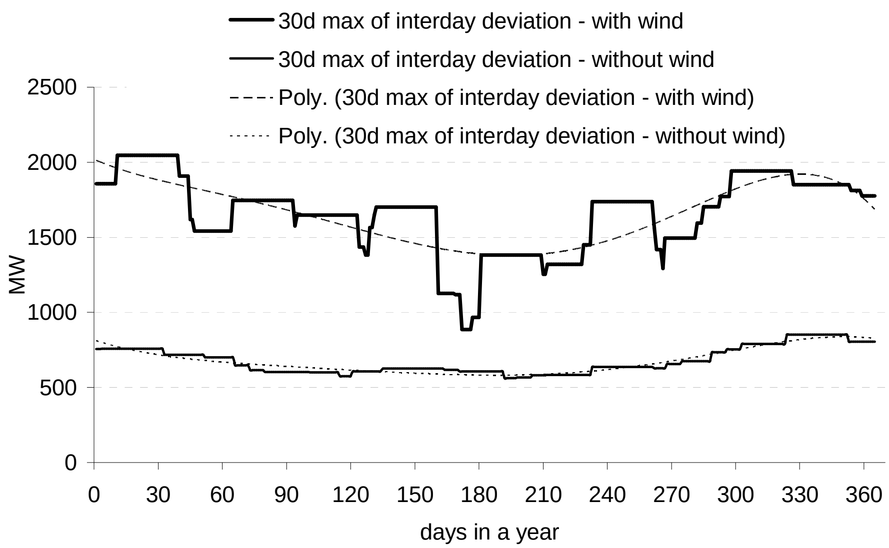

Figure 5-8 Interday deviation of load needed for system balancing, 2025

5.3 Regulating Reserve Capacity

Due to this simplified representation of diurnal demand, a specified share of the installed capacity of each plant is assumed to contribute to the peaking requirements. The minimum installed capacity is calculated by adding a capacity reserve to the total electricity demands. This reserve capacity is typically much larger than prevailing rule-of-thumb values used by the electric utilities. The reason for this is that the reserve margin in MARKAL also encompasses the difference between the average daytime demand (in winter or summer) and the instantaneous peak in that same period when the demand is actually the highest.

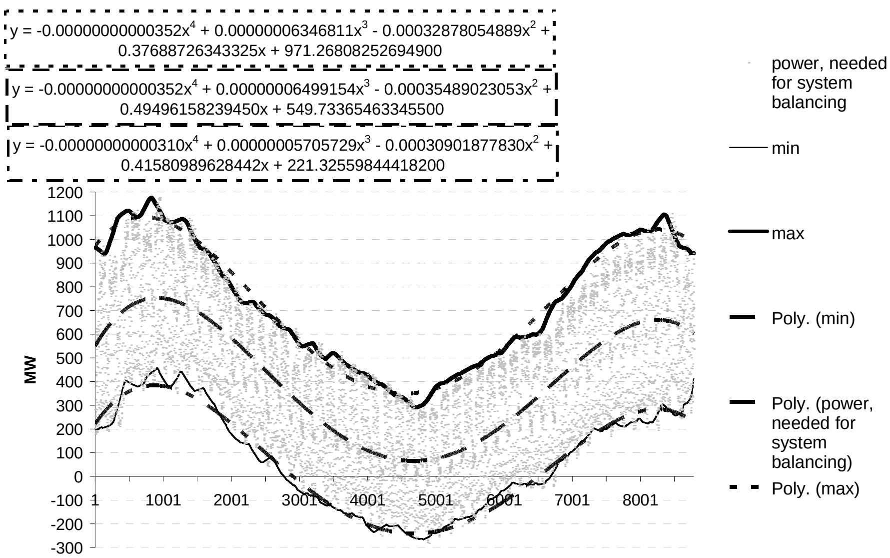

Figure 5-9 Need for additional capacity to cover domestic demand in 2025, Nuclear power plant 1000 MW.

The second limitation is the representation of the load during the low-load period. Due to this simplified representation of the load, it is clear, that MARKAL overestimates the minimum load in the low-load period. All units have minimum and maximum levels of the load. If demand is lower than the minimum permitted load of the generator, the load-following of the unit should be used at least weekly or, in the worst case, the unit should be switched off. In the case of nuclear generation, units are usually large and the units (reactors) in the nuclear power plant could not switch off and on several times in a week. This means that generated electricity should be exported or, if there are limitations on export capability the unit should be used with limitations or switched off during the low-load period. In the Estonian case, with nuclear power plant with a capacity of 1000 MW, limitations may occur during 3000 hours in the year 2025, decreasing gradually to zero hours in 2035 as consumption grows. With smaller nuclear power units, e.g. 300 or 600 MW, such limitations will not occur (Figure 5-4 - Figure 5-10).

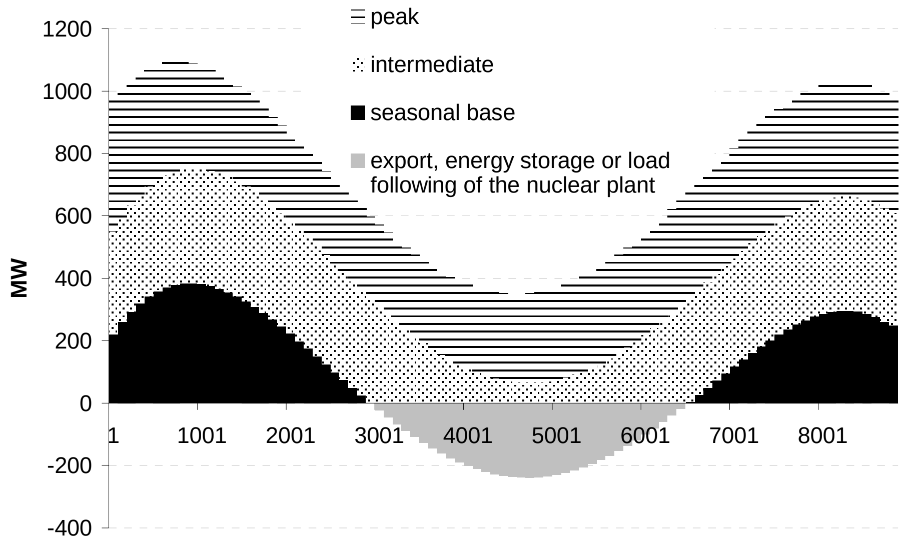

Figure 5-10 Need for additional capacity (weekly maximum) to balance system in addition to 1000 MW of nuclear power

Figure 5-10 shows that, in addition to nuclear power plant, different types of generating units must exist. Typically, a variation of the load does not grow at the same rate as load growth and we can assume that intermediate and peaking generation capacities shown in Figure 5-10 will remain the same for the longer period. The amounts of different capacity types, in addition to 1000 MW nuclear power, are:

- Seasonal base – means capacity constantly operating over the period with capacity shown in Figure 5-10. In 2025 ca. 400 MW must be available. If load grows the fraction of seasonal base must also grow.
- Intermediate – means capacity to cover half-peak load during the day. In 2025 ca. 400 MW must be available.
- Peak – means capacity used to cover peaks of the load. In 2025 ca. 400 MW must be available.

5.3.1 Disturbance reserve for nuclear power

There must be sufficient generating capacity in the system to cover initial power imbalance, secondary (fast start-up or running) and tertiary (start-up after 15 minutes or running) reserves after tripping of the nuclear unit. The reliability criterion is based on the n-1 criterion according to the Estonian Grid Code. This means that reserves must be available in the same amount as provided by the biggest unit in the system. If the nuclear power plant has a capacity of 1000 MW, in addition 1000 MW of reserves must also be available in the system at every moment. Typically, part of the reserves could be imported from the neighbouring power systems, but the amount of the imported reserves depends on the export-import capability of the system.

In Estonia the export import capability from the synchronous area varies from 0 to 1200 MW, depending on the transit through the Estonian power grid [8]. Typically, export-import capability is +/- 600 MW. Reserve import restrictions also depend on the adequacy of the Baltic transmission grid, generation capacity, existing and possible links with neighbouring systems, conditions for using links for reservation purposes and the power flow situation at the time. The balancing of the system after tripping of the nuclear unit is described in Figure 5-11.

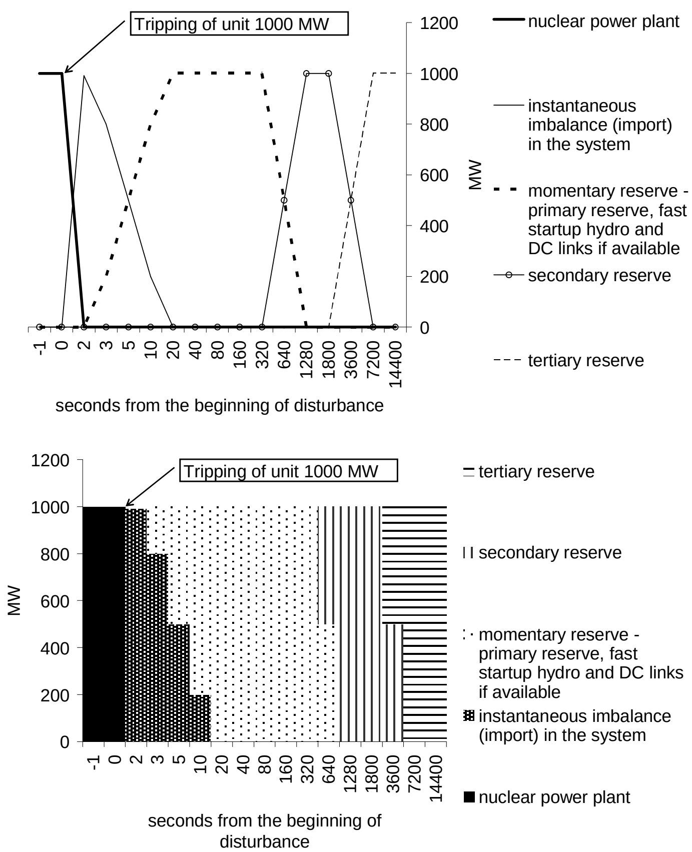

Figure 5-11 Balancing of system after disturbance (tripping) of nuclear unit

The limitations by initial power imbalance

A power reserve to cover initial imbalance has to be received from adjacent, synchronous, systems after tripping the nuclear reactor while secondary (fast) reserves of are deployed. This means that from a synchronous system only 600 MW nuclear power plant's initial imbalance after tripping could be covered in the case of a balanced system before tripping of the nuclear power plant.

In the event of of using the existing Russian and Latvian tie lines, generation capacity and load increase in the considered period, the allowed power capacity imbalance is approximately 800 MW [9]. The amount of 800 MW is assumed to be an average figure for two scenarios as follows: primary reserve that can be received from Russia and Belarus or maximum allowed size of a generating unit to trip in isolated operation mode of the Baltic Power Systems in order to avoid load shedding. According to the Baltic Grid 2025 [9], there is under discussion a third interconnection line between Latvia and Estonia. If the line is constructed, the import capability will be sufficient to cover initial imbalance for most times in the year.

The second possibility is to use DC links and system protection to cover initial imbalance. At the moment a DC link to Finland with capacity of 350 MW is in operation and a second link to Finland with a capacity up to 750 MW is planned by the year 2013. This means that the interconnection capacity to Finland will be ca. 1000 MW in the year 2015. The total capacity of interconnections is assumed to be in the range of 2000 MW (AC and DC).

If a nuclear power plant has a capacity of 1000 MW, these links are considered to be sufficient to cover initial imbalance after unplanned outage of the nuclear power plant if adequate contracts with adjacent systems are available.

If the new nuclear power plant in Ignalina is built, these reserves could be managed in cooperation and costs can be shared.

The limitations by the secondary and tertiary reserves

Secondary and tertiary reserves balance the power system after initial imported power imbalance. Usually hydro power plants (incl. pumped hydro), gas turbines and spinning reserve of thermal power plants can be used for the secondary reserve. Tertiary disturbance reserve usually includes start-up of gas turbines and thermal power units. Tertiary reserves are used to release secondary reserves for covering possible imbalance after second N-1. Here it is assumed that all secondary reserve must be available locally. This means that there must be available ca 1000 MW gas turbines if the capacity of the nuclear plant is 1000 MW. It is rather a conservative approach if we takie into account the present approach of covering the disturbance reserve where reserves are shared between participants in the synchronous area (Byelorussia, Russia, Estonia, Latvia, Lithuania).

The present mechanism of covering the disturbance reserve is based on the proportionality of the disturbance reserve to the biggest unit in each system in the Baltic area, and part of the reserve (currently 300 MW) is covered by Russia and Byelorussia. The biggest unit at the moment is Ignalina unit with a capacity of 1300 MW. And Estonia's share is currently ca 100 MW. If we take into account future developments and the possible construction of the new Ignalina power plant with a unit size ca 1000 MW, the sharing of the disturbance reserve in reality could be as follows:

- Latvia ca. 200 MW (biggest unit 400 MW)
- Lithuania ca. 400 MW (biggest unit 1000 MW)
- Estonia ca. 400 MW (biggest unit 1000 MW)

Here it is assumed that there is no disturbance reserve provided by Russia as a synchronous connection will be possible by the time the nuclear power plant is constructed.

The tertiary reserves could be thermal units or imports from neighbouring (DC) power systems. It is assumed that most of the time local thermal units are available to take over secondary reserves. If sufficient hydropower is available, it can be also used as tertiary reserve. The tertiary reserve for the Estonian power system could include existing or new oil-shale (Narva) or gas (Iru) units. The reserve could include also utilization of CHP units in the condensing mode or imports from neighbouring systems. If importing from neighbouring system, the amount of imported tertiary reserve power could be limited also by the transfer capacities of interconnections. The biggest unit in the system is assumed to be ESTLINK 2 with capacity ca. 650 MW. This means that import capability to cover initial imbalance after tripping 650 MW must be available when importing tertiary reserve power. It is assumed that local tertiary reserve includes at least 2 oil-shale units in Narva (ca. 400 MW) and one unit in Iru (ca 70 MW). This means that ca 180 MW of tertiary reserves must be imported in the worst case. As interconnection capacity with the synchronous area is over 800 MW in 2025, the tertiary reserve could be imported all the year round without any restrictions.

5.4 Reserves needed in the system; modelling of the reserves and utilisation of nuclear power plant in MARKAL

It is assumed that instantaneous imbalance after tripping the largest generating unit can be covered by using interconnections to other power systems if the largest unit does not exceed 1000 MW. Without a substantial amount of wind power a reserve capacity of 30% is used in MARKAL. It is an approximation derived by taking into account the difference between the actual winter peak demand and the average daytime demands, and it corresponds to about 20% of the actual reserve margin in the system. This reserve enables the capture of peak demand caused by the simplified two-step diurnal periods. Additionally, the most expensive case concerning reserves is chosen and it is forced to use MARKAL to use fast-start gas-turbines with the same amount that the biggest generating unit (nuclear power plant) is. If a substantial amount of wind power is introduced, it is assumed that it does not contribute to the peaking relations in MARKAL. It causes the model to install peaking power equal to the wind power. If a substantial amount of wind power is installed, it is assumed that reserves for wind power can also be utilized for nuclear power plant reserves.

It is also assumed that during the low-load period (during 3000 hours), there could occur restrictions in the use of baseload generating unit larger than the yearly baseload in the system. It is modelled in MARKAL via a reduced availability factor during the low-load period. In the year 2020 the largest uni, with capacity up to 600 MW, will be able to operate all year without constraints. For a nuclear power plant with a capacity of 1000 MW during the low-load period (3000 hours during summer days and summer nights) an availability factor of 0,5 (utilization ca. 1500 h during the period) is proposed. The real restrictions may occur during 1000 hours in 2025 (Figure 5-5), but it is clear that switching off and start-up of nuclear power plant is not allowed every week. For this reason, it is proposed that only 50% of possible energy production is produced in this season. It is also assumed that by 2035 the availability factor will increase gradually to 0,8 during low-load period (ca. 2400 hours during the period) depending on growth in the base-load.

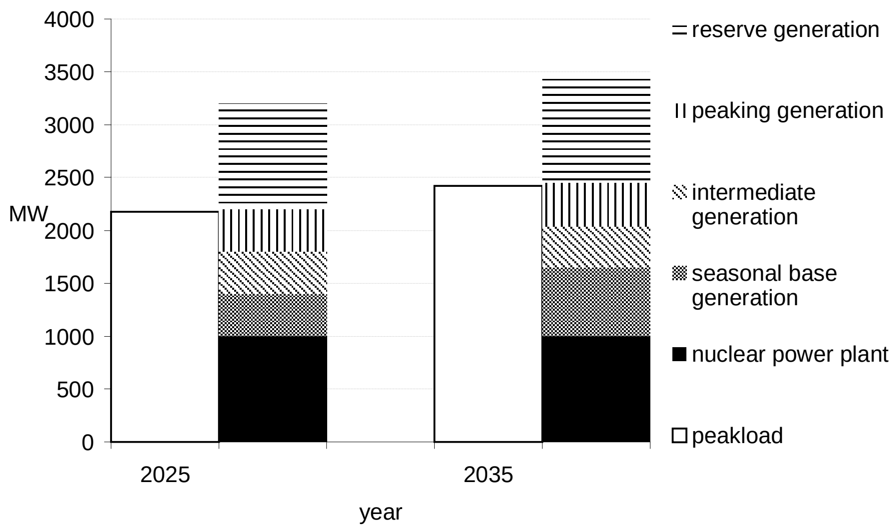

Figure 5-12 Types of generating capacity needed in the Estonian power system, nuclear power plant 1000 MW

5.5 Accommodation of nuclear power in the power grid

The Estonian 330 kV network is relatively powerful and allows the country to import or export 400 ... 1400 MW power. The Estonian energy system is connected to neighbouring countries via five 330 kV transmission lines. With Latvia, Estonia has two 330 kV lines – one from Tartu, another from the Tsirguliina substation. With Russia, Estonia has three 330 kV interconnection lines – one from Balti PP, the second from Eesti PP and the third from Tartu SS. From the year 2006 the Estonian network has been connected to the Finland network via 350 MW DC submarine cable (Estlink).

In the Baltic countries it is planned to strengthen the interconnecting networks, but not in the next ten years. The main goal in this strengthening is to reduce the Baltic countries' networks' dependence on the Russian system. As regards interstate connections, it is planned to create a third connection between Estonia and Latvia. The final investment decision for this connection has not yet been made. At the moment the cost-benefit analysis and line course selection is in progress. The earliest possible completion date is in 2017; allowing time for analysis, line right-of-way coordination and building. For the year 2013 the second connection between Estonia and Finland, Estlink-2, is planned. According to the Estonian grid development plan, it is efficient to establish 330 kV connections between Tartu-Viljandi-Sindi-Harku (Figure 5-13). The new 330 kV transmission lines in Tartu-Viljandi-Sindi-Harku will enhance the connections between the north and south 330 kV networks and provide greater reliability in the Tallinn and Pärnu regions. Additionally, the new transmission lines provide better opportunities for connecting new power plants to the transmission grid.

To provide connections with the new power plants in the Tallinn region and to ease import restrictions from Finland through the Estlink 1, an additional 330 kV connection between Kiisa and Aruküla will be established. According to development plans for the year 2025, the majority of existing 330 kV lines must, after depletion of technical resources, be upgraded to a bigger cross-section (3 x 400 mm^2), which guarantees considerably higher transmission capacity.

When considering construction of a nuclear power plant there must be cooling water available. Therefore, three coastal sites are briefly studied from the viewpoint of grid connection. The grid simulations have been carried out using Power System Simulation for Engineering (PSS/E) software [52]. Preliminary contingency analyses show that it is possible to connect a generating unit with a capacity of up to 1000 MW into the Estonian power grid, but substantial reinforcements in the internal grid are required. One of the most important preconditions is reconstruction of existing power lines to a higher thermal capability, and a bigger cross-section of conductors (3 x 400 mm^2).

Additionally, there must also exist a second interconnection between Finland and Estonia and associated system protection for cases where the import capability from synchronous area is limited. Three possible sites to connect nuclear power plants with a capacity 1000 MW are briefly discussed.

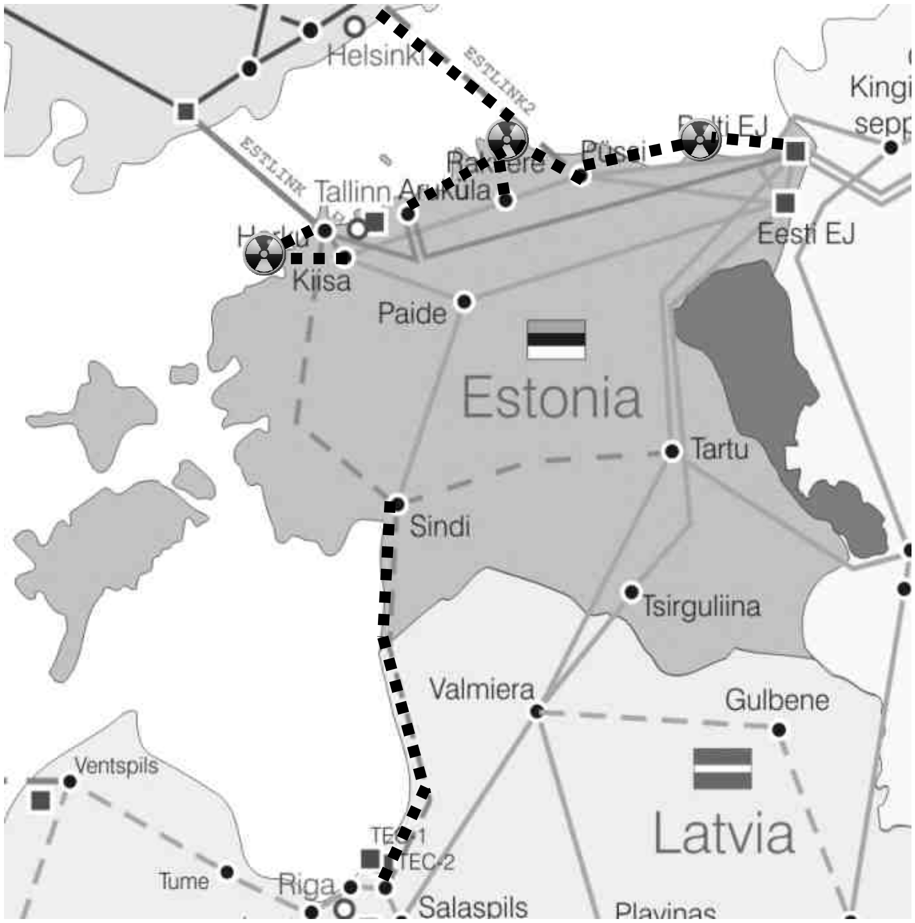

Figure 5-13 The Estonian transmission system in 2020. Grey dotted lines are planned, black bold dotted lines are needed in conjunction with nuclear power plant.

Eastern part of the northern coastline (Sillamäe)

For connection of the power plant, new 330 kV lines Sillamäe-Püssi and Sillamäe-Balti must be built. The line between Püssi and Kiisa must be upgraded or a new line between Püssi and Aruküla should be built.
The third interconnecting line between Estonia and Latvia is optional, but it reduces the risks associated with transit flows affecting the import and export capability of the Estonian power system.

Central part of the northern coastline (Kunda)

For connection of the power plant, new 330 kV lines Kunda-Rakvere and Kunda-Püssi must be built. The line between Rakvere and Aruküla must be upgraded. An alternative is the construction of lines Kunda-Aruküla and Kunda-Püssi. In that case line Rakvere- Aruküla does not need to be upgraded

The third interconnecting line between Estonia and Latvia is optional, but it reduces risks associated with transit flows affecting the import and export capability of the Estonian power system.

Western part of the northern coastline (Paldiski)

For connection of the power plant, a new 330 kV double circuit line to Harku or new 330 kV lines to Harku and Kiisa substations must be built. The line between Püssi and Rakvere must be upgraded.

The third interconnecting line between Estonia and Latvia must be built together with the Sindi-Harku power line.

For all sites sufficient export capability, over 1500 MW, exists. As regards import-capability, initial reserve imports must be reserved for the nuclear power plant.. If there is import capability without nuclear power plant up to 2000 MW [9], it means that an import capability of 1000 MW must be reserved for the nuclear power plant. This means that import capability could be limited to zero if there is large transit flow through the Estonian power system.

6 SCENARIOS

Scenarios are developed here according to the possible capacities of a nuclear power plant, possible developments of CO_2 price and possible development of renewable intermittent generation.

The main uncertainties relating to nuclear power plant technology are related to the capacity of the power plant, input characteristics such as capital cost, and the fuel costs of the nuclear power plant. On the other hand, results can show what plant size is feasible.

The main uncertainties in connection with CO_2 are related to the price of CO_2 in emission trading.

The main uncertainties with development of renewable intermittent generation are related to the large-scale development of wind-power in Estonia.

These scenarios assume that other parameters such as load growth and fuel prices are known, although these parameters have a certain influence on results. In test cases it was evident that other parameters didn't have a major influence on the final results.

6.1 Scenarios of nuclear power plant

In scenarios different nuclear technologies, with their technical properties and different safety issues, are not looked at closely. Here, the nuclear power plant is regarded as a "black box" with different installed capacities and input costs of fuel and input capital cost. Other costs, such as operating and maintenance costs, and parameters like thermal efficiency are given as average values of the capacity of the plant. It is assumed here that the first year of availability (operation) of the power plant is 2020. This year is chosen in accordance with the possible planning and construction schedule of the power plant described in [34] and [32].

6.1.1 Capacity of the power plant

As Estonia is a small power system, the size of the installed capacity has important implications for the real-time operation of the system. Here it is assumed that maximum capacity could be technically 1000 MW. This means that the plant will contribute about 50% to the maximum in the year 2020. Limits are set mainly due to the transfer capacity of the power network to cover initial imbalance after possible forced outage of the power plant. It also means that fast reserves should be available to cover this imbalance after the first few moments. These reserves must be either local generating units or imported. In the latter case the transmission system operator should reserve transmission capacity to import reserve power from neighbouring power systems, which set limits to the possible import-export capability. From the standpoint of the power system, smaller units are preferable, but on the other hand smaller units have higher per unit capital costs. This means that a reasonable trade-off between unit size and the network ability to accommodate that unit must be found. In some cases, from the economic point of view, network reinforcements might be advisable in order to accommodate a larger unit. Here three sizes of nuclear power plant are assumed:

- nuclear power plant with capacity of 300 MW
- nuclear power plant with capacity of 600 MW
- nuclear power plant with capacity of 1000 MW

Nuclear power plant with capacity of 300 MW could possibly be the IRIS (International Reactor Innovative and Secure) reactor type. This is a smaller-scale advanced light water reactor (LWR), designed for smaller power systems. For future installations the capacity of the IRIS reactor is assumed to be ca 500 MW.

Nuclear power plant with capacity of 600 MW could possibly be CANDU 6 (Atomic Energy of Canada Limited) or two IRIS reactors.

Nuclear power plant with capacity of 1000 MW could possibly be AP-1000 (Westinghouse), ACR-1000 (Advanced CANDU Reactor) or V-392 PWR (Gidropress & Atomenergoproject / Atomstroyexport).

6.1.2 Costs, related to nuclear power plant

Nuclear power plants have a "front-loaded" cost structure, i.e. they are relatively expensive to build but relatively inexpensive to operate. Thus the initial capital cost and interest rate have a major impact on the competitiveness of nuclear power.

Investment costs

The most useful point of reference for investment cost is the Olkiluoto nuclear power plant investment cost. The power plant is constructed as a turn-key project. Initial forecasts assumed that the cost per kilowatt would be in the range 1200-1500 EUR/kW [39]. The construction cost was reported to be at least 2000 EUR/kW. This is higher than nearly all forecasts. Several reports [34[, [36], [37], [38], [39] have forecast that gigawatt-range nuclear power plant capital costs will be in the range 1200-1900 EUR/kW. The latest prognoses have forecast Olkiluoto + 20% for the cost of generation III reactors. Some conservative forecasts assumed that, due to a nuclear boom in the coming decades, capital costs could even be in the range of 3000-4000 EUR/kW. Investment cost forecasts for smaller scale reactors (200-400 MW) are in the range of 2000-4500 EUR/kW.

It is assumed here that minimum construction costs will not be lower than those for current real contracts. For the maximum prognosis, it is here assumed that large-scale construction will lead to higher costs, but at the same time enchanced technology learning and standardisation will take place. It is assumed here that the maximum cost per kilowatt will be about 20% lower than most pessimistic prognoses. Investment costs in maximum and minimum cases as a function of installed capacity are presented in Table 6-1 and in Figure 6-1.

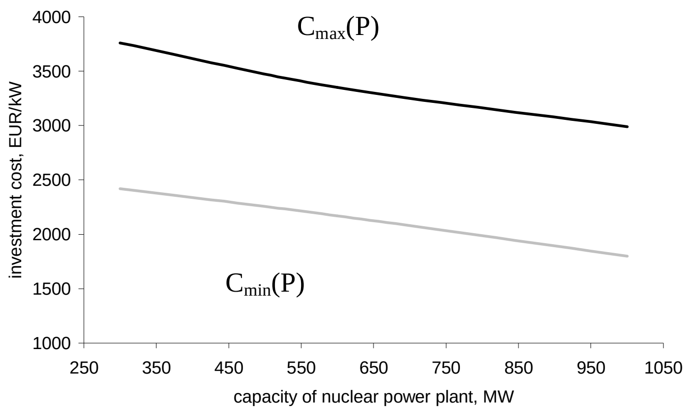

Figure 6-1 Investment cost (C), interval of nuclear power plant with capacity range 300-1000 MW, EUR/kW

Fuel costs

Uranium resources are abundant and widely distributed. Uranium resources are not expected to constrain development of new nuclear power capacity. Proven resources are sufficient to meet world requirements well beyond 2030. This makes nuclear power a valuable option for enhancing the security of electricity supply [32], [33]. The cost of nuclear fuel is small compared with the capital cost of a nuclear power plant, but the disposal of waste from nuclear power plants is related to their fuel, and both costs should be treated as fuel costs. Nuclear fuel purchase is a small part of the generation cost. Spent fuel disposal costs are expected to be relatively small, but are very uncertain. Nuclear fuel cost consists typically of 25% uranium; 30% enrichment; 20% manufacturing 25% waste disposal costs.

Driven partly by the renewal of interest in nuclear power, uranium spot prices continued to rise in 2006, reaching \$72/lb U_3O_8 by the end of the year - more than ten times higher than their historic low in December 2000. Exploration and mine development have begun to follow suit, with exploration expenditures increasing more than three-fold between 2001 and 2005.

The latest estimate of global uranium resources published by the OECD Nuclear Energy Agency [42], shows that, while substantial uranium resources are likely to be available, it is estimated that significant investment in uranium mining capacity and nuclear fuel manufacture production capacity will be needed to meet projected needs.

The present average cost of nuclear fuel in Europe is ca. 200 EUR/kg (0,05 EUR/GJ). It is assumed that together with enrichment, manufacturing and waste disposal, the minimum price in 2020, if we take into account the high demand, will be about 1,92 EUR/GJ. The maximum is expected to be about 3 times higher than the minimum cost – 5,75 EUR/GJ.

6.2 Scenarios of CO_2 costs

Previously new nuclear power plants have not been an attractive investment, given plentiful low-cost coal and natural gas, no CO_2 emission limits, and the investment risks associated with official policy and public acceptance. In recent years great attention has been paid to reducing emissions of CO_2, especially from power generation.

To reduce emissions of CO_2, emission trading as an economic mechanism has been implemented in the European Union. It is applied to the all the largest emitters of CO_2. Other regions in the world have not engaged in emission trading at company level. Starting from 2008, the Kyoto protocol's second stage in emissions trading will begin, with emissions trading at state level to achieve reduction of emissions at the required level. The price level in the European Union region is expected to be ca 25 EUR/ton. The penalty for emissions exceeding the quota for CO_2 is, in the period between 2008-2012, 100 EUR/ton. Possibly, after 2013, no quotas will be shared free of charge or will be shared only in smaller amounts than at present. The biggest share will possibly be sold at auctions arranged by the European Union Commission or by member state governments or in the free market of emissions. Today it is clear that the objective of the EU is to keep the price of CO_2 at a level that motivates producers of electricity to choose less CO_2 intensive production of electricity or to invest in CO_2 capture and storage. To encourage such motivation, the price of CO_2 must be at least at the level of 50 EUR/ton for new power stations using coal. For retrofitting existing power stations it must be at least at the level of 75 EUR/ton. As most existing power stations will still be in operation beyond 2020, the level of costs involved in retrofitting existing power stations will also tend to maximize the market price of CO_2.

The minimum price for CO_2 could be taken as the price in the absence of restrictions on emissions. As the biggest emitters of CO_2, such as the United States and China, do not charge and limit emissions of CO_2, this could be considered as one scenario for the EU region.

6.3 Scenarios in brief

Investment scenarios of nuclear power plant are presented in Table 6-1. Table 6-2 presents scenarios of CO_2 and nuclear fuel costs.

Table 6-1 Investment cost scenarios of a nuclear power plant, EEK/kW (1 EUR =15,6466 EEK)

	300 MW	600 MW	1000 MW	
Maximum expected capital cost	58831	52416	46783	EEK/kW
Minimum expected capital cost	37865	33953	28164	EEK/kW

Table 6-2 CO_2 cost and nuclear fuel cost (sum of uranium, enrichment, manufacturing, waste disposal costs) scenarios, EEK/kW (1 EUR =15,6466 EEK)

Maximum expected CO_2 cost	1173	EEK/ton
Minimum expected CO_2 cost	0	EEK/ton
Maximum expected nuclear fuel cost	30	EEK/GJ
Minimum expected nuclear fuel cost	90	EEK/GJ

Table 6-3 presents combinations of scenarios and decision alternatives for a nuclear power plant. As was discussed in section 6.1.1 decision alternatives for a nuclear power plant are chosen with a capacity of 300, 600 and 1000 MW. Baseline alternative is without nuclear power plant in a particular time horizon.

Table 6-3 Combination of scenarios and decision alternatives

DECISION ALTERNATIVES	CO_2 - low		CO_2 - high	
	low investment low fuel cost	high investment high fuel cost	low investment low fuel cost	high investment high fuel cost
no nuclear, baseline	CASE 13	CASE 13	CASE 14	CASE 14
nuclear 300 MW	CASE 9	CASE 10	CASE 11	CASE 12
nuclear 600 MW	CASE 5	CASE 6	CASE 7	CASE 8
nuclear 1000 MW	CASE 1	CASE 2	CASE 3	CASE 4

7 RESULTS OF MODELLING OF SCENARIOS WITH MARKAL

7.1 Introduction and general remarks

The most important MARKAL modelling results of scenarios are presented in the Figures in Appendix B.

Besides oil-shale, Estonia has two main domestic energy sources – the renewables biomass and wind. Hydro potential is only ca 30 MW. Wind power is limited by the balancing capability of the existing power system and the balancing capability of neighbouring power systems, and is also determined by the transfer capabilities of interconnections. Use of these domestic resources is in large part derived from the future price of CO_2 and the possible introduction of nuclear power. In different cases the model uses these resources up to their limits, or use of the resource is bounded by their economic competitiveness.

Future solutions in the Estonian energy system are also very sensitive to the price of natural gas. Security of the Russian gas supply is an extremely important factor as well. Here the high gas price scenario was used. The share of natural gas and nuclear largely determine the CO_2 reduction. If the gas price forecast is lower, the MARKAL would build condensing power plants mainly using natural gas instead of oil shale. Comparing the carbon emission factors (tons of carbon per 1 TJ of fuel) of oil shale (29,1 tC/TJ for pulverized or CFB combustion under atmospheric conditions) and natural gas (15,6 tC/TJ), and comparing the efficiency coefficients of condensing oil shale power plants (29% for pulverized combustion, 34% for CFBC, 44% for supercritical CFB) and combined cycle natural gas plants (56%), and considering the lower specific investment and O&M costs and other advantages of natural gas plants, the preference for natural gas is not surprising if nuclear power is unavailable. Nuclear plant appears in the optimal solution of energy modelling when it is allowed, emission taxes are high and CO_2 targets are strict. Introduction of nuclear plant changes all the scenario results significantly.

The co-combustion of different fuels with oil shale in the fluidized bed boilers of large power plants is theoretically discussed in Estonia [57], but has not been tested or implemented. The options are coal, peat and woodchips. It is calculated that the co-combustion of wood in the oil shale power plants would require imports of wood.

This study did not use the electricity and biomass net import options as possible ways to cover domestic demand.

All energy networks are modelled as dummy technologies in the Estonian MARKAL model. These technologies are described with their residual capacity, investment costs and O&M costs, and they use a dummy energy carrier without cost. Demand technologies are linked to the networks using ADRATIO equations. This means that network investments are accounted for in the optimization process.

The Estonian model has 3 levels of electric network depending on grid voltage, 1 high pressure and 3 different distribution networks of natural gas and 2 different district heat grids depending on the density of consumers. The MARKAL model is based on the concept of a Reference Energy System and therefore the representation of energy flows differs slightly from the official energy balance statistics.

In low CO_2 scenarios, power plants continue to use oil shale as the main fuel. New CFBC condensing capacity will be built using CFBC and supercritical CFBC technology during 2015-2030. They will replace more than half of initial installed capacity of the old pulverized combustion plants. This will increase the average conversion efficiency from 28% to 34%, will eliminate sulphur emissions and solve problems of fly ashes. At the end of the planning period, a coal power plant will be built.

Total capacity of CHP plants will increase quite rapidly, thus providing the main future solution for heat production as well. This tendency is universal in all scenarios. The CHP potential will be used fully at the end of the planning period in all scenarios; only the market shares of different fuels differ by scenario.

Wind power increases rapidly in high CO_2 scenarios and does not depend much on the scenario of nuclear power. Total wind capacity limit will be reached at the end of the planning period in all scenarios with a high CO_2 cost.

Natural gas and LFO power plants (mainly peaking gas turbines and combined cycle) will be built starting from 2010. Their capacity will be substantial, but their utilization factor will be very low. They will be used for covering sharp peak loads, for the balancing of wind power and for reserve capacity. One reason for the low utilization factor is the limited ability of the MARKAL model to describe the load curve in detail.

The main driving factors towards efficient power generation are the use of nuclear power, improvement of the conversion efficiency of fossil technologies, and the increase in the share of CHP and renewables. The targets of SO_2 and NO_X will be met by installing flue gas cleaning devices in existing oil-shale units and changes in generating technology after 2020. In spite of decreasing specific emissions, the total CO_2 emissions will increase after 2010 due to increasing energy consumption. This increase will not be rapid and the emissions will not reach the 1995 level, or that of 1990.

If nuclear power is unavailable in high CO_2 cost scenarios, additional carbon costs will be avoided mainly by greater use of renewables and natural gas in high efficiency combined cycle power plants. Use of oil shale in electricity generation will decrease, and supercritical CFBC technology is an important option as from 2025. The higher the target for CO_2 reduction, the higher will be the share of imported energy carriers (mainly natural gas, in addition to motor fuels, coal and fuel oils).

The baseline scenario deals with cases where nuclear power is unavailable for the energy supply of Estonia. Nuclear scenarios were formed for nuclear power plant with capacity 300, 600 and 1000 MW. All scenarios were analysed with high and low nuclear fuel and investment cost scenarios, as was described in Chapter 6. Also, two CO_2 cases, with cost 0 EUR/ton and 75 EUR/ton, were analysed. The main results of the decision of the MARKAL model concerning nuclear power plant feasibility are presented in Table 7-1.

Table 7-1 Actual decision of the model

INVESTMENT ALTERNATIVES	CO_2 - low		CO_2 - high	
	low investment low fuel cost	high investment high fuel cost	low investment low fuel cost	high investment high fuel cost
no nuclear	no nuclear	no nuclear	no nuclear	no nuclear
nuclear 300 MW	by year 2020	no nuclear	by year 2020	by year 2020
nuclear 600 MW	by year 2020	no nuclear	by year 2020	by year 2020
nuclear 1000 MW	by year 2020	no nuclear	by year 2020	by year 2025

The objective function of the optimisation was determined to be the minimisation of total discounted system cost. The total discounted system cost consists of capital costs (investments), operating and maintenance costs and costs for fuel. It is the most important indicator of the energy system, and the value of total discounted system cost in different scenarios can be taken as the cost of different scenarios.

Table 7-2 and Figure 7-1 show the cost of the Estonian energy system under different nuclear scenarios and CO_2 costs. The cost differences between the constrained nuclear case and cases with nuclear power available vary by a maximum of 3-4%. This is achieved in cases with low nuclear investment and fuel costs. Those cases with high CO_2 costs manifest the greatest cost differences.

Table 7-2 Total discounted system cost, 10^9 EEK = GigaEEK (further, GEEK)

INVESTMENT ALTERNATIVES	CO_2 - low		CO_2 - high	
	low investment low fuel cost	high investment high fuel cost	low investment low fuel cost	high investment high fuel cost
no nuclear	264 542	264 542	281 919	281 919
nuclear 300 MW	261 914	264 542	277 319	281 088
nuclear 600 MW	259 121	264 542	273 585	280 743
nuclear 1000 MW	256 117	264 542	270 429	281 967

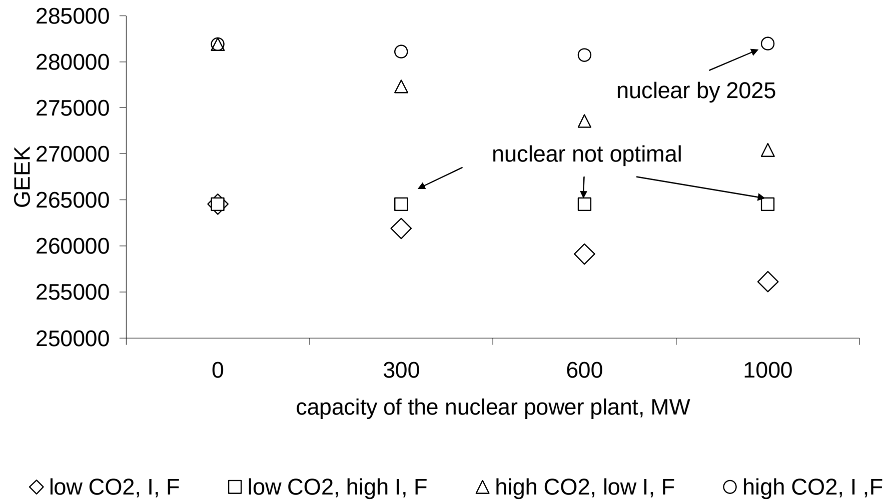

Figure 7-1 Total discounted system cost, GEEK (CO2=CO_2; I=investment; F=fuel)

According to the optimal decision of the model, it can be seen that under low CO_2 costs and high nuclear cost scenarios, nuclear power plant is not feasible. Under high CO_2 cost and high nuclear cost scenarios, nuclear power plants with capacity 300 and 600 MW are introduced in 2020 and nuclear power plant with capacity 1000 MW in 2025. The later introduction of nuclear power is due to possible limitations of production during the low-load period.

7.2 Cases with constrained nuclear power

To get a clear view of the initial situation it is necessary to give some outlines of the starting point – the constrained nuclear scenario. Since the two CO_2 cost cases were calculated by the MARKAL model, it is also important to observe the development of power generation in the case of constrained nuclear power. The main results in all cases, including cases with nuclear generation available, of installed generating capacities and production of different types of generation are presented in Appendix B.

The most important questions were the MARKAL decisions for the domestic fuel of Estonia - oil shale. At the moment most electricity is generated in two power plants, both fired by oil shale. The two power plants produce over 95 % of the electricity consumed in Estonia. In addition, these power plants are the main “producers” of CO_2, SO_2 and NO_X emissions. Due to the advanced age of these power plants, they are both close to their operation limit time. Starting from 2012 there will also be limitations on production due to the high emission level of SO_2 and NO_X. So the question was whether plants will continue to use oil shale power engineering and which new energy carriers will be introduced for electrical power generation.

7.2.1 Results with low CO_2 price

Installed capacity of power generation technologies is presented in Figure 7-2. Results show that in both cases abatement technologies to reduce emissions of SO_2 and NO_X from existing oil-shale power plants will be installed, although the plants will be closed down by 2025 at the end of their technical lifetime. In the low CO_2 scenario, new oil-shale units using fluidized bed boilers will be installed. Also, oil-shale units with supercritical parameters are introduced in 2025 and 2030. In 2020 a coal condensed unit will be introduced with a capacity of 500 MW. For peak-load and disturbance reserve coverage gas turbines using natural gas and light fuel-oil will be introduced. The total installed capacity of oil and gas-fired generating technologies will reach 660 MW by the year 2035.

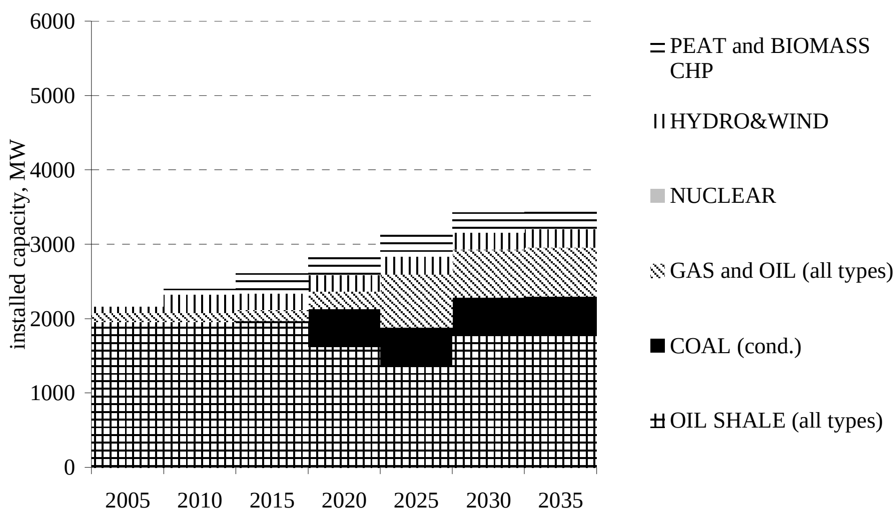

Figure 7-2 Installed capacities of power generation technologies in scenario of nuclear unavailable and low CO_2 cost (case 13)

7.2.2 Results with high CO_2 price

In the case of a high CO_2 price a large amount of wind turbines will be installed. The model chooses almost all possible values for wind generation. The installed capacity of wind turbines reaches 2230 MW in the year 2030. For reserve purposes, gas turbines will also be introduced almost to the same extent as wind power. The installed capacity of gas turbines reaches 1990 MW in the year 2035. In addition, oil-shale generating capacity will remain with a capacity of 700 MW.

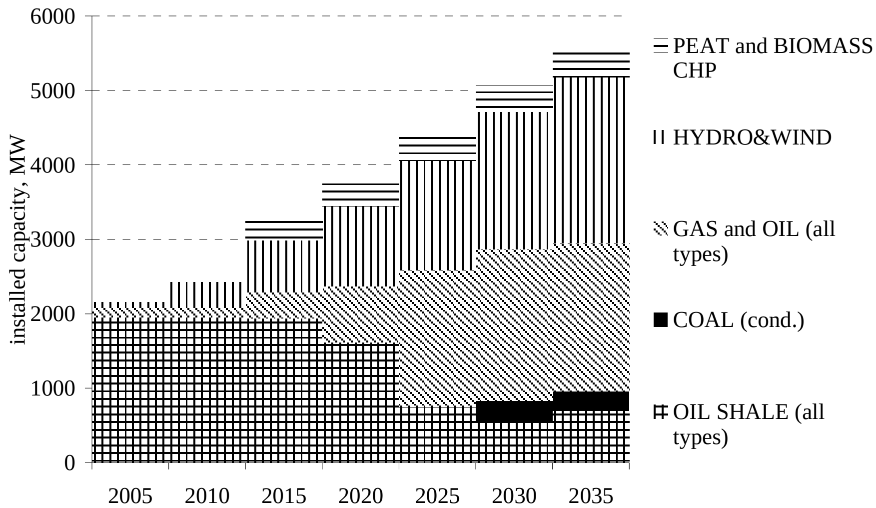

Figure 7-3 Installed capacities of power generation technologies in scenario of nuclear unavailable and high CO_2 cost (case 14)

7.3 Cases with nuclear power available

Here are analysed mainly cases with nuclear power plant 1000 MW, as the differences from nuclear unavailable cases are the greatest. The results of all cases with all capacities of nuclear generation are presented in appendix B.

7.3.1 Results with low CO_2 price

In the low CO_2 case, nuclear power is not feasible when nuclear fuel and investment costs are high. In low fuel and investment cost cases, nuclear power plant is introduced in 2020 in all capacity variants. The other main generating sources are oil-shale fired generation and gas turbines for nuclear backup purposes. Most electricity is generated by a nuclear power station and oil-shale based generation. If the capacity of the nuclear power plant is less than 1000 MW, a coal condensed power plant is introduced to cover demand.

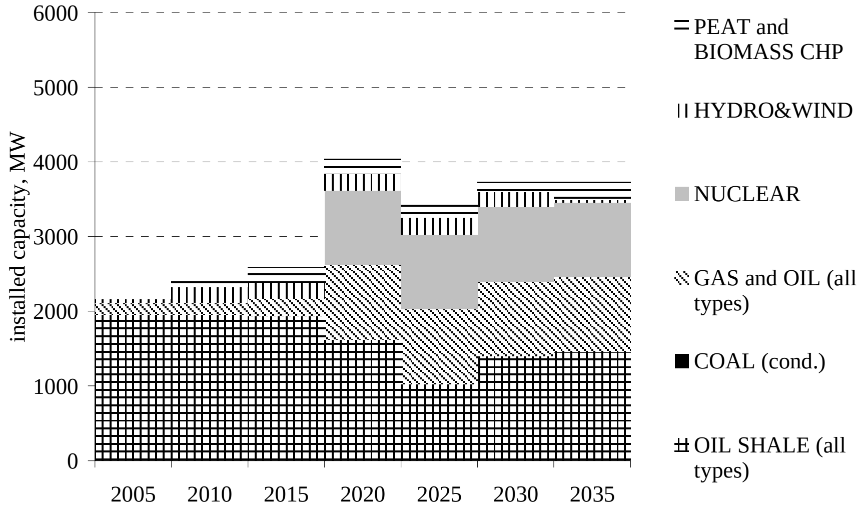

Figure 7-4 Installed capacities of power generation technologies in scenario of nuclear available, low nuclear fuel and investment cost and low CO_2 cost (case 1)

7.3.2 Results with high CO_2 price

In the high CO_2 case, nuclear power is feasible in all cases. In high fuel and investment cost cases nuclear power plant with a capacity of 1000 MW is introduced in 2025 (case 4), in other cases in 2020. The other main generating sources are wind generation and gas turbines for wind and nuclear backup purposes. Oil-shale is retained in the case of a 1000 MW nuclear power but to the amount of 190 MW only. If the nuclear power plant has a capacity of 300 MW, the capacity of oil-shale based generation is ca 700 MW. Most electricity is generated by the nuclear power station and wind generation. If the capacity of the nuclear power plant is less than 1000 MW, a considerable amount of electricity is also produced by oil-shale generating technologies.

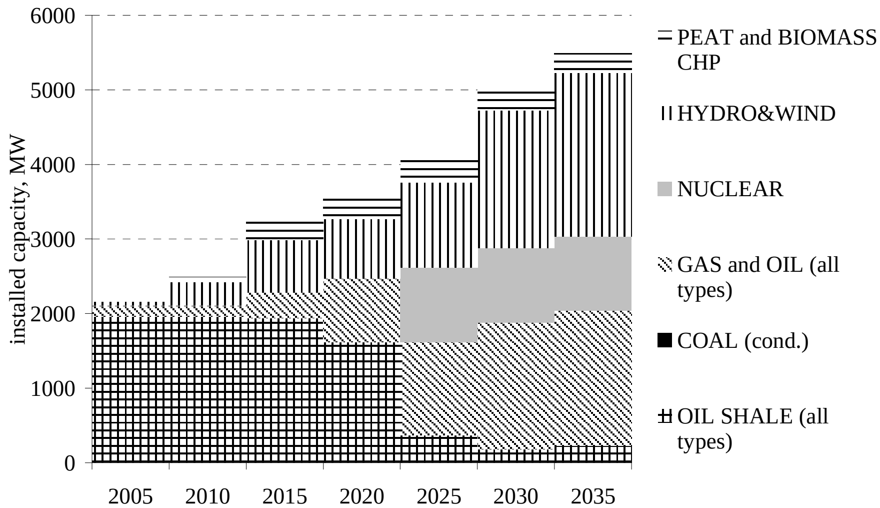

Figure 7-5 Installed capacities of power generation technologies in scenario of nuclear available, low nuclear fuel and investment cost and low CO_2 cost (case 4)

7.4 Summary of the section

Results show clearly that the results completely depend on the CO_2 price. If the price is low, and the nuclear power plant is not available, most capacity is oil-shale based. In the year 2035 about 2/3 of generated electricity and the major part of capacity is oil-shale based. If CO_2 prices are high only a small share of installed capacity will be oil-shale based. In cases of high CO_2 price about half the electricity is generated by carbon-free wind power, and for backup gas turbines are used. The capacity of gas generated technologies will depend on the introduction of wind power, although the amount of energy produced is considerable only in high CO_2 cases. It can be seen from the results that in both cases Peat and biomass CHP-s with a capacity of 300 MW are installed. Today the share of domestic fuels in the primary energy supply has reached 70%, while in high CO_2 cases the share will be about 50%.

The results show that nuclear power plant is feasible in all cases except in the combination of a low CO_2 price and high nuclear fuel and investment cost (Table 7-1). When feasible, nuclear power is introduced by the year 2020, except in the case of nuclear power plant 1000 MW and the scenario involving a combination of high CO_2 price and high nuclear fuel and investment cost. The capacities of other generation sources depend mainly on the price of carbon. If the price is low, fossil-based generating technologies such as coal and oil-shale are used. If the price is high, fossil-free technology, such as wind, is mainly used. For peaking and reserve purposes gas turbines, both gas and light fuel oil fired, are also used. The capacity of gas turbines depends mainly on the capacity of wind and nuclear power installed. In the case of a high CO_2 price, natural gas fired gas turbines and combined cycle power plants are used for production of electricity. This is due to the high cost of oil-shale based generation and the lack of available capacity due to the closure of existing oil-shale pulverised combustion units.

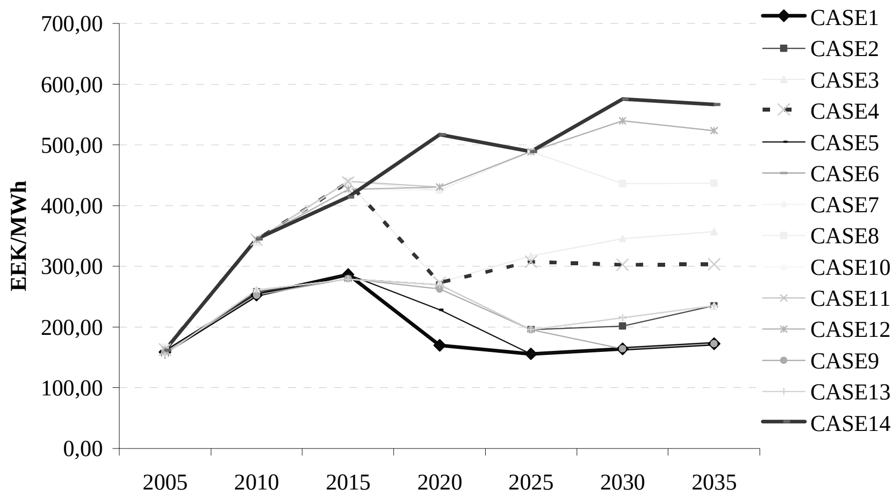

Figure 7-6 Final price (shadow price) of electricity in all cases (intermediate day, EEK/MWh)

Figure 7-6 shows the development of the shadow price of electricity in all cases. It can be seen that the price depends principally on the CO_2 price. In the worst case it climbs to 600 EEK/MWh (nuclear not allowed and high CO_2 price – case 14). In the best case, it stays at today's level (nuclear power plant 1000 MW, low CO_2 price – case 1). Introduction of new conversion technologies, investments and a rise in prices cause the shadow prices to rise. The biggest rise in the shadow prices will take place in the period 2005 to 2020

8 NUCLEAR INVESTMENT DECISION MAKING UNDER UNCERTAINTY

8.1 Introduction

For evaluating and choosing among alternatives, all the possible alternatives and possible outcomes are listed. With MARKAL all possible outcomes for each alternative were calculated.

Maxmin, LaPlace and Minmax decision modelling techniques are applied to choose an alternative. First, results with total discounted system cost are presented. In chapter 8.3.4 an analysis based on yearly costs is presented.

8.2 Methodology

Figure 8-1 shows the process of decision-making for new investment under uncertainty using different decision-making techniques and modelling in MARKAL. As is shown, the results of scenarios are used to choose the optimal strategy for nuclear power.

The decision-making process started with the creation of a database, as described in Chapters 3-5. The next step was the identification and modelling of scenarios. The scenarios are described in Chapter 6 and the results of scenarios are presented in Chapter 7.

Figure 8-2 shows the decision tree of the problem under scrutiny and in Table 8-1 and Figure 8-2 the payoffs (regrets against worst scenario) of different scenarios are presented. The payoffs are calculated on the basis of total discounted system cost, which was chosen as an objective function for optimization using the MARKAL model.

The next step is analysis of scenarios using Maxmin, LaPlace and Minmax decision criteria based on the payoffs of different scenarios. Here different analyses are presented. In Section 8.3 analysis is done using the total discounted system cost, and in Section 8.3.4 analysis is based on annual system costs. The optimum is usually selected when the saddle point is achieved. In Section 8.3 it is seen that the results are different, hence in this case it is clear that the final decisions cannot be made using the results based on total system costs. In Section 8.3.4 analysis for each year is performed and the results are used for the creation of the optimal scenario.

After that, the optimal scenario is selected and final calculations with MARKAL are done using results of the introduction of nuclear power.

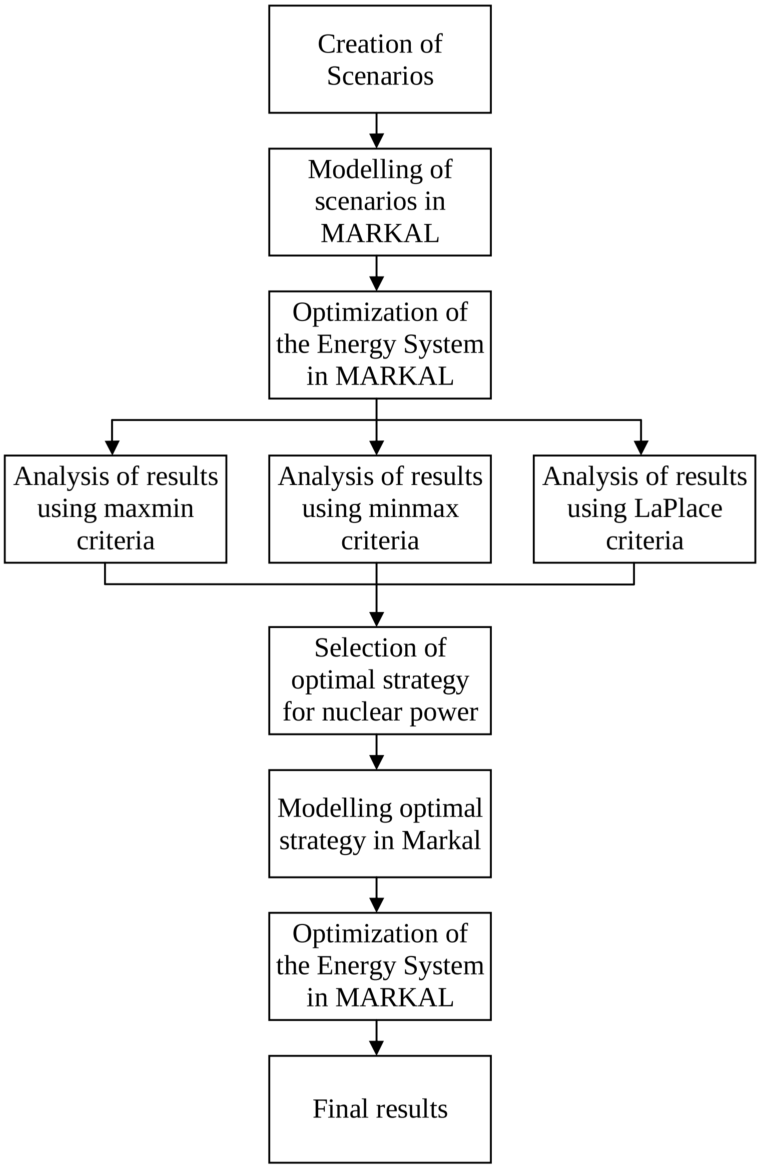

Figure 8-1 Decision –making process for nuclear power

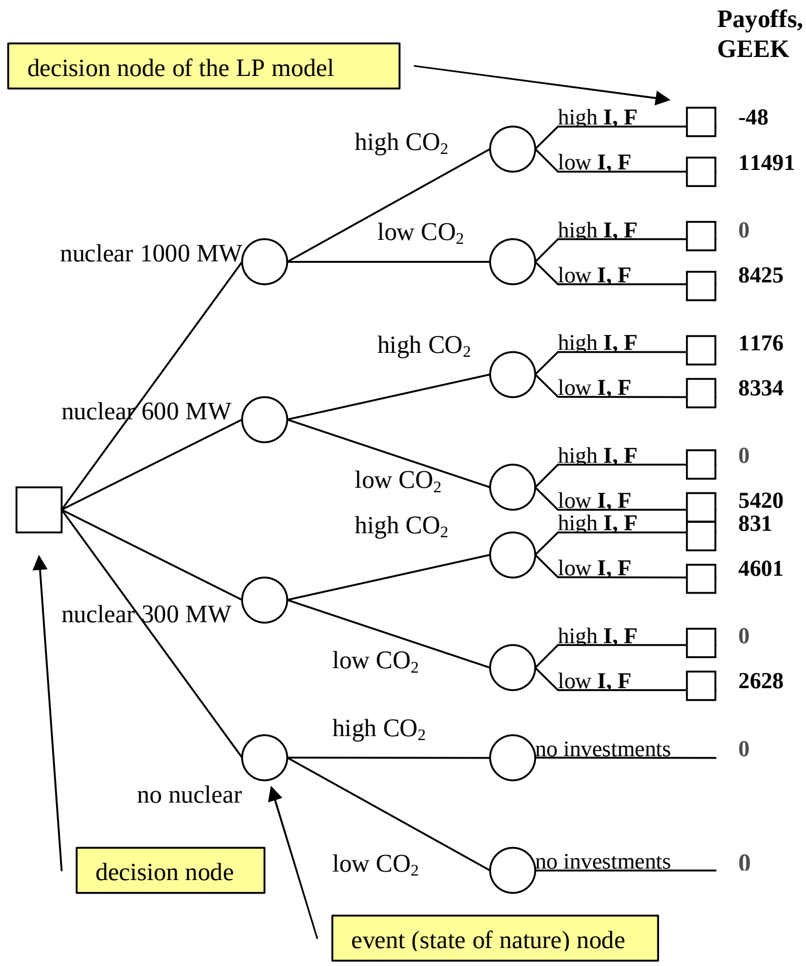

Figure 8-2 Decision tree (I=investment, F=fuel cost)

Table 8-1 Payoff table, GEEK

INVESTMENT ALTERNATIVES	CO_2 - low		CO_2 - high	
	low investment low fuel cost	high investment high fuel cost	low investment low fuel cost	high investment high fuel cost
no nuclear	0	0	0	0
nuclear 300 MW	2 628	0	4 601	831
nuclear 600 MW	5 420	0	8 334	1 176
nuclear 1000 MW	8 425	0	11 491	-48

8.3 Decision making using total system cost

8.3.1 An Example of the Maxmin Criterion

For each action, the worst outcome (smallest reward) is determined. The maximin criterion chooses the action with the "best" worst outcome.
Thus, the minimax regret criterion tends towards the adoption of the variant with nuclear power plant 600 MW.

Table 8-2 Payoff, maxmin criterion, GEEK

INVESTMENT ALTERNATIVES	CO_2 - low		CO_2 - high		Maxmin criterion
	low investment low fuel cost	high investment high fuel cost	low investment low fuel cost	high investment high fuel cost	minimum
no nuclear	0	0	0	0	0,00
nuclear 300 MW	2 628	0	4 601	831	830,80
nuclear 600 MW	5 420	0	8 334	1 176	1176,25
nuclear 1000 MW	8 425	0	11 491	-48	-47,83

maxmin payoff	1176,25
maxmin decision	nuclear 600 MW

8.3.2 An example of the Equally Likely (LaPlace) Criterion

The Equally Likely, also called LaPlace, Criterion finds the decision alternative with the highest average payoff (profits); lowest average payoff (costs). The average payoff for every alternative is calculated in Table 8-3. The optimum is the alternative with the maximum average payoff.

Thus, the LaPlace criterion tends towards the adoption of the variant with nuclear power plant 1000 MW.

Table 8-3 Payoff, Equally Likely (LaPlace) Criterion, GEEK

INVESTMENT ALTERNATIVES	CO_2 – low: low investment low fuel cost	CO_2 – low: high investment high fuel cost	CO_2 - high: low investment low fuel cost	CO_2 - high: high investment high fuel cost	Equally Likely (LaPlace) Criterion: average
no nuclear	0	0	0	0	0,00
nuclear 300 MW	2 628	0	4 601	831	2014,77
nuclear 600 MW	5 420	0	8 334	1 176	3732,75
nuclear 1000 MW	8 425	0	11 491	-48	4966,94

Equally Likely (LaPlace) Criterion	4966,94
LaPlace decision	nuclear 1000 MW

8.3.3 An Example of Minimax Regret Criterion

The minmax criterion fits both a pessimistic and a conservative decision maker approach. The payoff table can be based on lost opportunity, or regret. The rows correspond to the possible decision alternatives, the columns correspond to possible future events. To find an optimal decision, for each state of nature the best payoff over all decisions is determined. Regret is calculated for each decision alternative as the difference between its payoff value and this best payoff value.

The regret matrix obtained with the help of the data from Table 8-1 applying the condition $\min_i \max_j \left(R_{ij}\right)$ to the matrix, is presented in Table 8-4.

Thus, the minimax regret criterion tends towards the adoption of the variant with nuclear power plant 1000 MW.

Table 8-4 Regret, Minmax Regret Criterion, GEEK

INVESTMENT ALTERNATIVES	CO_2 – low: low investment low fuel cost	CO_2 – low: high investment high fuel cost	CO_2 - high: low investment low fuel cost	CO_2 - high: high investment high fuel cost	maximum
no nuclear	8 425	0	11 491	1 176	11491
nuclear 300 MW	5 797	0	6 890	345	6890
nuclear 600 MW	3 005	0	3 156	0	3156
nuclear 1000 MW	0	0	0	1 224	1224

minmax regret	1224
minmax decision	nuclear 1000 MW

8.3.4 Interpretation of results

The results with total discounted system cost show that:

- using maxmin criterion nuclear power plant with capacity of 600 MW is optimal
- using LaPlace criterion nuclear power plant with capacity of 1000 MW is optimal
- using minmax criterion nuclear power plant with capacity of 1000 MW is optimal

It can be seen that power plant with low capacity is not optimal due to the high per unit cost of the nuclear power plant. It can be concluded here that a nuclear power plant with a capacity of 600 or 1000 MW is optimal. From the "pessimists" point of view plant with capacity of 600 MW is a good choice, i.e. the best of worst outcomes is found. In such a case the risks are usually lowest.

Using the LaPlace and minmax criterion possible regrets have the lowest value. Thus it can be concluded that the risks are higher but possible outcome is better. The final decision will be based on the choice between two alternatives, to reduce risks or minimize maximum or average regrets.

8.4 Optimal introduction of nuclear power plant under uncertainty

The choice of introduction of nuclear technology differs significantly between an analysis based on total system costs and one based on yearly costs. The input data for analysis is presented in Table 8-5. The annual payoff against the worst case is presented in Table 8-6. The minimum payoffs are shown in Table 8-7, average payoff Table 8-8 and maximum payoffs in Table 8-9. Table 8-10 presents minmax regret and maxmin, LaPlace and minmax decision results derived using previous tables. It can be seen that using the maxmin criterion nuclear power plant is not optimal from 2020-2025. Nuclear power with a capacity of 1000 MW is introduced in 2025. This means that in order to reduce risks, the later introduction of nuclear power can be proposed. This is is mainly due to higher loads in the later period due to economic growth.

LaPlace decision criteria lead to the decision to introduce a power plant with a capacity of 600 MW in 2020 with an extension to 1000 MW in 2027.

The minmax regret criterion tends towards the adoption of the variant with nuclear power plant 600 MW in 2020 with an extension to 1000 MW in 2030.

While a nuclear power plant with a capacity of 1000 MW is optimal starting from 2030 in all decision criteria, and nuclear power plant with a capacity of 600 or 1000 MW starting from 2025, it can be concluded that the best option is the introduction of a nuclear power plant with 1000 MW in 2030.

Between 2025 and 2030 the power plant with capacity 600 or 1000 MW is optimal, the final decision depending on the decision-makers viewpoint. The power plant with a capacity of 600 MW can be regarded as a risk-free option, but the larger capacity can reduce possible regrets. Between 2020 and 2025 no nuclear option or power plant with a capacity of 600 MW are regarded as the best options.

Table 8-5 Annual system cost under different scenarios, GEEK

				2005	2010	2015	2020	2025	2030	2035
min CO2	min invfuel	no NUC	CASE13	11393	9797	8687	7367	6598	5045	4021
min CO2	min invfuel	nuc 300	CASE14	11391	9802	8687	7302	6429	4872	3900
min CO2	min invfuel	nuc 600	CASE5	11384	9808	8650	7284	6179	4736	3784
min CO2	min invfuel	nuc 1000	CASE1	11368	9777	8665	7764	6007	4575	3587
min CO2	max invfuel	no NUC	CASE13	11393	9797	8687	7367	6598	5045	4021
min CO2	max invfuel	nuc 300	CASE10	11393	9797	8687	7367	6598	5045	4021
min CO2	max invfuel	nuc 600	CASE6	11393	9797	8687	7367	6598	5045	4021
min CO2	max invfuel	nuc 1000	CASE2	11393	9797	8687	7760	6826	4999	3980
max CO2	min invfuel	no NUC	CASE14	11283	10265	10195	8316	7047	5307	3970
max CO2	min invfuel	nuc 300	CASE11	11283	10265	10195	8345	6612	4974	3790
max CO2	min invfuel	nuc 600	CASE7	11179	10209	10089	8260	6344	4920	3717
max CO2	min invfuel	nuc 1000	CASE3	11283	10265	10193	8140	6248	4941	3535
max CO2	max invfuel	no NUC	CASE14	11283	10265	10195	8316	7047	5307	3970
max CO2	max invfuel	nuc 300	CASE12	11283	10265	10195	8815	6731	5066	3863
max CO2	max invfuel	nuc 600	CASE8	11179	10209	10089	9124	6581	5105	3862
max CO2	max invfuel	nuc 1000	CASE4	11283	10265	10195	9506	6648	5252	3765

Table 8-6 Annual payoff table, GEEK

				2005	2010	2015	2020	2025	2030	2035
min CO2	min invfuel	no NUC	CASE13	0	0	0	0	0	0	0
min CO2	min invfuel	nuc 300	CASE14	3	-5	0	65	168	173	120
min CO2	min invfuel	nuc 600	CASE5	10	-11	37	83	418	309	237
min CO2	min invfuel	nuc 1000	CASE1	26	20	22	-396	591	470	433
min CO2	max invfuel	no NUC	CASE13	0	0	0	0	0	0	0
min CO2	max invfuel	nuc 300	CASE10	0	0	0	0	0	0	0
min CO2	max invfuel	nuc 600	CASE6	0	0	0	0	0	0	0
min CO2	max invfuel	nuc 1000	CASE2	0	0	0	-392	-228	46	40
max CO2	min invfuel	no NUC	CASE14	0	0	0	0	0	0	0
max CO2	min invfuel	nuc 300	CASE11	0	0	0	-29	435	334	180
max CO2	min invfuel	nuc 600	CASE7	105	56	106	56	703	387	253
max CO2	min invfuel	nuc 1000	CASE3	0	0	2	176	799	366	435
max CO2	max invfuel	no NUC	CASE14	0	0	0	0	0	0	0
max CO2	max invfuel	nuc 300	CASE12	0	0	0	-499	317	241	107
max CO2	max invfuel	nuc 600	CASE8	105	56	106	-808	467	202	108
max CO2	max invfuel	nuc 1000	CASE4	0	0	0	-1 190	399	56	205

Table 8-7 Minimum payoff, GEEK

	2 020	2 021	2 022	2 023	2 024	2 025	2 026	2 027	2 028	2 029	2 030	2 031	2 032	2 033	2 034	2 035
no NUC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
nuc 300	-499	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
nuc 600	-808	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
nuc 1000	-1 190	-228	-228	-228	-228	-228	16	16	46	46	46	40	40	40	40	40

Table 8-8 Average payoff, GEEK

	2 020	2 021	2 022	2 023	2 024	2 025	2 026	2 027	2 028	2 029	2 030	2 031	2 032	2 033	2 034	2 035
no NUC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
nuc 300	-116	230	230	230	230	230	187	187	187	187	187	102	102	102	102	102
nuc 600	-167	397	397	397	397	397	225	225	225	225	225	150	150	150	150	150
nuc 1000	-451	390	390	390	390	390	204	204	234	234	234	278	278	278	278	278

Table 8-9 Maximum payoff, GEEK

	2 020	2 021	2 022	2 023	2 024	2 025	2 026	2 027	2 028	2 029	2 030	2 031	2 032	2 033	2 034	2 035
no NUC	176	799	799	799	799	799	440	440	470	470	470	435	435	435	435	435
nuc 300	499	422	422	422	422	422	267	267	297	297	297	313	313	313	313	313
nuc 600	808	172	172	172	172	172	131	131	161	161	161	196	196	196	196	196
nuc 1000	1 190	228	228	228	228	228	215	215	185	185	185	0	0	0	0	0

Table 8-10 Minmax regret, GEEK and decisions of nuclear power plant under different criteria

	2 020	2 021	2 022	2 023	2 024	2 025	2 026	2 027	2 028	2 029	2 030	2 031	2 032	2 033	2 034	2 035
minmax regret	176	172	172	172	172	172	131	131	161	161	161	0	0	0	0	0
minmax decision	no NUC	nuc 600	nuc 600	nuc 600	nuc 600	nuc 600	nuc 600	nuc 600	nuc 600	nuc 600	nuc 600	nuc 1000	nuc 1000	nuc 1000	nuc 1000	nuc 1000
maxmin decision	no NUC	no NUC	no NUC	no NUC	no NUC	no NUC	nuc 1000	nuc 1000	nuc 1000	nuc 1000	nuc 1000	nuc 1000	nuc 1000	nuc 1000	nuc 1000	nuc 1000
LaPlace decision	no NUC	nuc 600	nuc 600	nuc 600	nuc 600	nuc 600	nuc 600	nuc 600	nuc 1000	nuc 1000	nuc 1000	nuc 1000	nuc 1000	nuc 1000	nuc 1000	nuc 1000

8.5 Scenario for optimal introduction of nuclear power

The results of different scenarios of power plant capacity are presented in Figure 8-3. As we can conclude from the results of Section 8.4, the following decision can be proposed:

- introduction of a nuclear power plant with capacity of 600 MW in 2025,
- increase in nuclear power plant capacity to 1000 MW by 2030.

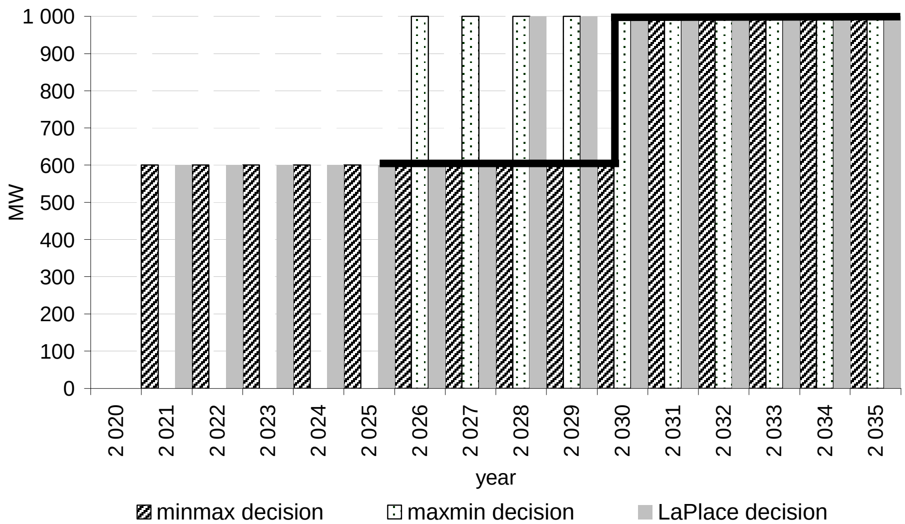

Figure 8-3 Optimal introduction of nuclear power under different decision criteria and scenario of optimal introduction of nuclear power (red line)

The scenario described above is modelled in MARKAL as a forced option concerning the introduction of nuclear power plant capacities. No freedom is given for the model to optimize the capacity. The first year of availability is 2025 with nuclear power 600 MW, and 1000 MW will be introduced in 2030. As the main costs of a nuclear power plant inhere in initial capital costs they cannot influence the optimal choice of the model, as the introduction of nuclear power is a forced solution. The decision of the model regarding other generating sources can be influenced only by the CO_2 cost. Thus, the two scenarios described before are modelled: high CO_2 cost scenario and a low CO_2 cost scenario.

8.6 Final results of modelling

Oil – shale, natural gas and coal fired technologies are cost-effective in low CO_2 cost. Coal is phased out when a high price of CO_2 emissions is introduced. Natural gas can to some extent be used, but it continues to play a minor role in production for all scenarios studied, but the share of natural gas and oil-based generation is high for both cases. This is mainly due to the nature of power plants, which are mainly designed for reserve and peaking purposes. Increased use of biomass and peat is cost-effective in both scenarios, especially in the high CO_2 cost cases, where all available energy sources are exploited, but it assumes that existing subsidies will remain ath the same level. Wind power is crucial if high CO_2 prices are included. When CO_2 prices are low and there are no subsidies for RES, wind is not competitive against other kinds of generating sources. Wind is reserved mainly by using gas turbines. CHP production is the most cost-effective alternative for electricity generation, followed by nuclear power and natural gas. However, the differences between the latter technologies are small. Changes in fuel and CO_2 prices could therefore alter their ranking.

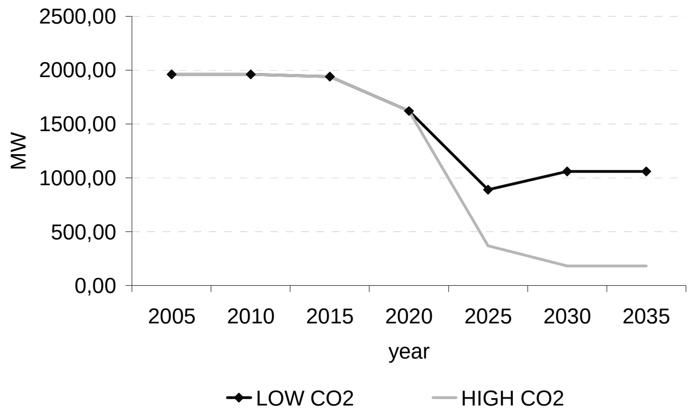

Figure 8-4 Installed capacity of oil-shale based generation

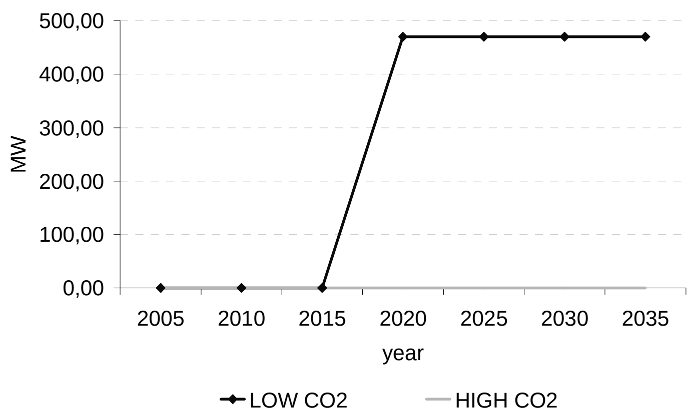

Figure 8-5 Installed capacity of coal-based generation

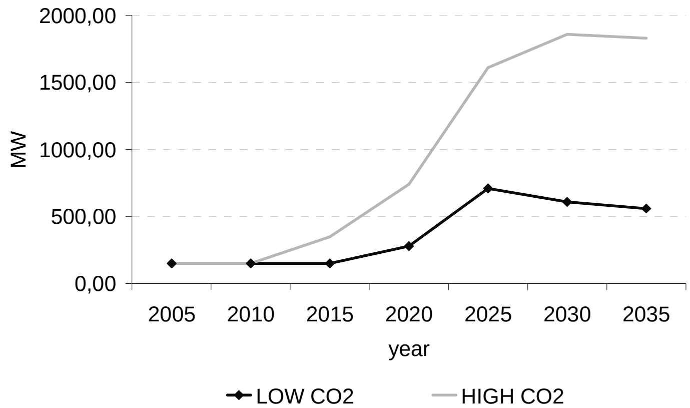

Figure 8-6 Installed capacity of oil and gas based generation

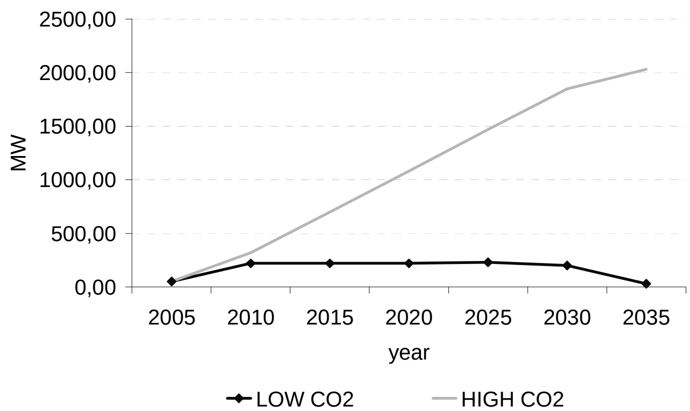

Figure 8-7 Installed capacity of hydro and wind based generation

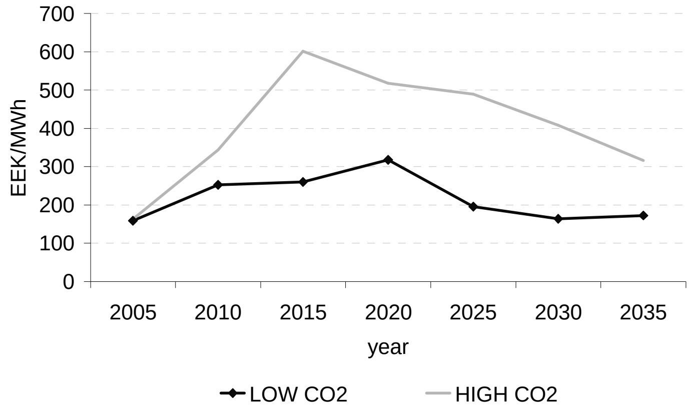

Figure 8-8 Final price (shadow price of domestic generation) of electricity in low and high CO_2 cases (intermediate day, EEK/MWh)

The shadow price of electricity increases rapidly when the price of CO_2 is high. The price could decrease after nuclear power is introduced. The other reasons for the increase of price are an increase in fuel prices such as gas and oil, and huge investments in generating capacities after old oil-shale generation is phased out.

8.7 Final considerations concerning future decisions about generating capacity

Nuclear power is considered to be the lowest-risk option for future power generation. The impacts of fossil fuel and CO_2 prices are insignificant. The biggest risks are associated with public acceptance and a possible rise in investment and fuel costs. As rises in raw material and construction price also influence other kinds of generation, it can be assumed that investment costs would also be higher for other kinds of generation. The recommendation from the results of the study is to start with a medium-sized nuclear power plant with a capacity of 600 MW. As the baseload of the Estonian power system grows, a larger amount of nuclear power should be introduced. The introduction of a larger unit could also be considered starting from 2025, but it is associated with risks of overcapacity in the system which can be eliminated by means of a larger market area and sufficient interconnection capacities with neighbouring power systems. Another possibility is to introduce energy storing power plants such as pumped hydro or compressed air power stations. Lower investment costs can also significantly reduce future risks, i.e. the decision concerning capacity should be taken into account when construction prices are known and a final decision has to be made.

Gas and oil-fired power plants (mainly gas turbines) can also be considered a low-risk investment. They are needed in both CO_2 cost cases. When prices are low, such generation is needed for reserving nuclear power plant during outages. When prices are high and large-scale wind production is introduced, such generation is needed for the balancing of wind power.

Future decisions concerning **oil-shale and coal** depend completely on the future of the CO_2 price. If the price is high, it is not practical to install a large amount of carbon intensive technologies. New oil-shale CFBC units will be installed between 2015 and 2025 as during that time most of the existing generation will be phased out due to old age, but in the later period the use of these units is minimal if the price of CO_2 is high. Thus an alternative to the introduction of new units is the use of imports if sufficient generating capacities exist and the interconnection capability is sufficient. The introduction of CFBC units with supercritical parameters is optimal only in the low CO_2 case.

The future of **wind power** depends completely on future CO_2 prices. If the price is low the technology is not competitive without subsidies. The second threat is the competitiveness of wind power in an open electricity market. When there are high winds and a large amount of wind power in the market, market prices are expected to be low and consequently economic profitability will suffer. The future competitiveness of wind power can be improved considerably if efficient energy storage is implemented.

The **peat and biomass** CHP-s are used almost to the furthest possible extent, but it is assumed here that subsidies equal to today’s amount will remain. Total capacity of peat and biomass based generation will reach 300 MW in the high CO_2 case and 250 MW in the low CO_2 case. The difference arises from the use of biomass in the high CO_2 case.

9 CONCLUSIONS

The results of the study can be summarized as follows:

1. General considerations

In the future, along with the decommissioning of the existing old oil-shale plants and increasing electricity consumption, other generation types and fuels will be used. Restricted availability of imported fuels, large-scale introduction of nuclear power or enabling large scale electricity import can significantly change the existing Estonian power system and future choices.

The aim of this thesis is to present a generation expansion planning approach for environments with an uncertain future. The approach is tested on the Estonian case for introduction of nuclear power. The minmax approach shows that results differ significantly from the deterministic approach. The approach and methodology described in this thesis are validated through a real case scenario. This methodology can be used for evaluating different types of technologies and it can also be used in other power systems. Moreover, through the methodology proposed here, the interval uncertainty data can be considered. The data can be related to the costs associated with the technology under study.

2. Evaluations of nuclear competitiveness

As nuclear plants have relatively high capital costs but low marginal operating costs, they run most economically at very high load factors, meeting the demand for base-load electricity. Lower capital costs per/kW can be expected for larger units. On the other hand, considering the relatively low demand in Estonia, large nuclear unit size can create additional problems with balancing during low-load period and losses in profitability due to lower market prices during that period. Higher growth rate of the load and later introduction (after 2030) of larger units can considerably reducethe risks and improve the economics of larger units.

Although there is a range of assumptions used in the study, it is possible to draw some general conclusions. Nuclear energy competitiveness mainly depends on the capital cost per/kW of the plant, together with the costs avoided for CO_2. An important factor is also the useability of the nuclear power plant during the low-load period, but this can be reduced through load-following of the units or using two generators per one reactor. Another possibility to improve competitiveness is using nuclear power plant for district heat production, but this can be taken into account after a site suitable for this purpose is selected.

As fossil fuel begins to incur costs associated with its impact on the climate through carbon taxes or emissions trading regimes, the competitiveness of new nuclear plants clearly improves. The comparison is being made with oil-shale fired plants but it also applies, to a lesser extent, to coal or gas-fired plants. On the other hand, implementation of carbon taxes and costs improves competitiveness of intermittent electricity generated by renewable sources. This can create additional uncertainties for nuclear competitiveness in the future. The above mentioned factors can be considered for long-term planning by the minmax decision-making approach, as described in this thesis.

3. Recommendations for future generating capacity in Estonia

Real actions towards implementation of nuclear power in the future will also be affected by the social costs and political influences that are not concidered in the optimization process. Nevertheless, it is clear that the new nuclear plant is competitive against the alternative future scenarios and generation technologies. Nuclear plant in Estonian power system should be regarded as the only good long-term investment against future uncertainties. The approach described in the thesis leads to implementation of nuclear power in the Estonian power system with capacity of 600-1000 MW by the year 2025. For balancing and reserve purposes gas turbines, fired by natural gas and/or light fuel oil, are widely used.

Investments in carbon extensive oil-shale and coal-based technologies are considered to be high risk because of future uncertainties regarding carbon costs. This can also be widened to renewable generation or peat-fired technologies, which cannot be competitive without subsidies or high carbon costs.

4. Further areas to be studied

Input data in an interval uncertainty mode can be used for a wide range of information. The present research concentrates only on the most important uncertainties relating to the introduction of nuclear power in Estonia. Further work must therefore include all uncertain factors that may affect future decisions.

The current energy system model, used in the study, has several disadvantages which can be improved in future studies through more precise modelling of system load and the future electricity market area. Representation of hourly-interval load and generation patterns would give more exact results, especially when considering reserves and intermittent generation. On the other hand, balancing and reserves for the base-load nuclear generation and intermittent wind generation can be reduced significantly when looking at the problem holistically.

The nonlinear optimization methods can also be applied in long-term energy planning. Several models are in the development stage, but no widely acknowledged nonlinear energy planning model is in use. Future research into and implementation of nonlinear optimization methods can significantly improve optimisation results when the input data is given in uncertainty form.

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ABSTRACT

Long-Term Capacity Planning and Feasibility of Nuclear Power in Estonia Under Uncertain Conditions

The thesis aims to introduce an efficient energy system development strategy in electric utility long-term planning under conditions of uncertainty. The main focus is on the introduction of nuclear power in the Estonian power system under conditions of uncertainty relating to the long-term CO_2 price and the capital costs of possible a nuclear power plant.

In recent years, electric utilities have recognized that the concepts of robustness, flexibility and risk-exposure have to be considered in their resource-development strategy. Therefore, system-optimization under the rubric of these concepts can be a very onerous task. Energy systems operation-planning is in general a rich area for the application of optimization methodology. In addition, the recent deregulation of the power markets has led to a new situation for the power producers. On a wide time-scale, the uncertainty about problematic data such as environmental constraints, capital costs, prices of fuels and demand must be incorporated into the model to make the solutions robust against risk. As these parameters are influenced by many uncertain conditions associated with the changes in public perceptions, government regulations, energy policies, economic situations and competitive markets, it is difficult to provide definite data. There are several approaches to optimizing electricity production under uncertainty conditions. Different approaches will arise depending on what criterion of optimality is used (Laplace and maxmin criterion, minmax cost and minmax regret criterion). The criterion chosen here for electricity-production, capacity-optimization is minmax regret. Minmax optimization models enable us to take into account the uncertainty of uncontrollable factors and to minimize the maximum possible economic loss caused by uncertainty. Therefore, the objective of the long-term optimization of electricity production capacity is the minimization of the total costs (expected investment and operational costs) considering the reliability and environmental constraints criterion. The technical energy system of Estonia is modelled with MARKAL. MARKAL is a dynamic linear programming model of the technical energy system, used to explore different energy-environmental policy scenarios.

A data base including energy demand categories, different power generation technology options and emissions of SO_2, NO_X and CO_2 from the Estonian energy system has been set up. The database also includes optional abatement technologies. The MARKAL model has been used to find cost-effective solutions to both reduce emissions and develop the energy system under different scenario assumptions. The results of the MARKAL model are used to develop a robust scenario against uncertainties in future developments. As a result, an optimal scenario for the introduction of nuclear power under uncertainty is developed.

KOKKUVÕTE

Pikaajaline elektritootmisvõimsuste planeerimine ja tuumaelektrijaama tasuvus Eestis määramatuse tingimustes

Antud töö eesmärgiks oli välja töötada meetod energiasüsteemi arengu planeerimiseks määramatuse tingimuses. Töö oli peamiselt suunatud tuumaenergia võimalikule arendamisele Eesti energiasüsteemis määramatuse tingimustes tulenevalt määramatusest mis tulenevad pikaajalisest CO_2,- tuumaelektrijaama kapitali- ja kütusekulude määramatusest.

Viimastel aastatel on energiafirmadele tähtsaks muutunud majanduslikud kontsepsionid resursside arengu planeerimisel, mis on seotud robustsete strateegiatega, universaalsuse ja riski arvestamisega. Seetõttu võib öelda et vastavate strateregiate arvessevõtmine on kujunenud väga mahukaks ülesandeks arvestades optimeerimese metoodikatega määramatuse tingimustes. Lisaks on viimastel kümnenditel toimunud energiaturgude avanemine toonud uue dimensiooni energiaettevõtete arengu planeerimisse, kus erinevad mõjufaktorid nagu keskkonnapiirangud, investeeringukulud, kütusekulud ja tarbimine tuleb arvestada koos nendega seotud määramatusega energiasüsteemi arengu planeerimisse muutes lahendused universaalseks erinevate arenguvariantide korral. Kuna eeltoodud parameetrid on mõjutatud oluliselt avalikust arvamusest, seadusandlusest, energiapoliitikast, majanduslikust olukorrast ja turusituatsioonist on võimatu leida selliseid algandmeid mis oleksid lõplikud. On välja töötatud mitmeid meetodeid määramatuse arvestamiseks energiasüsteemide arengu planeerimisel. Erinevad lähenemisviisid tulenevad sellest millist optimeerimiskriteeriumit kasutatakse. Käesolevas töös on vaadeldud minmax kriteeriumit ning võrreldud seda maxmin ja LaPlace kriteeriumiga. Minmax optimeerimismudel võimaldab arvesse võtta erinevate faktorite määramatust ja minimeerida maksimaalset majanduslikku kahjumit, mis tuleneb tuleviku määramatusest.

Eesti energiasektor on modeleeritud kasutades MARKAL mudelit. MARKAL on dünaamiline, lineaarset optimeerimist kasutav tehnilise energiasüsteemi mudel, mida kasutatakse erinevate Energia ning keskkonnastsenaariumide modelleerimiseks. Sihifunktsiooniks energiasüsteemi arengu planeerimisel kasutatakse kogukulude minimeerimist (investeeringu-, muutuv- ja püsikulud) arvestades erinevate piirangutega.

MARKAL- mudeli arvutustulemusi on kasutatud määramatuse analüüsiks kasutades minmax, maxmin ja LaPlace kriteeriumit ning leitud on universaalne lahend tuumaenergia sissetoomiseks Eesti energiasüsteemi, mis on robustne erinevate tulevikustsenaariumide suhtes.

APPENDIX A

Paper I

M. Landsberg, H. Tammoja, J. Kilter. Optimal Introduction of a Nuclear Power Plant in Estonia Under Uncertain Conditions. 2008 Power Quality and Supply Reliability Conference, Pärnu, 27 Aug - 29 Aug 2008. 2008 Power Quality And Supply Reliability Conference Proceedings ISBN: 978-1-4244-2501-3. Copyright IEEE

Paper II

H. Agabus, **M. Landsberg**, H. Tammoja. Reduction of CO_2 Emissions in Estonia During 2000-2030. Oil Shale, Vol. 24 No. 2 pp. 209-224. 2007 Estonian Academy Publishers ISSN 0208-189X

Paper III

Liik, O., Oidram, R., Keel, M., Ojangu, J., **Landsberg, M**., Dorovatovski, N. Co-operation of Estonia's oil shale-based power system with wind turbines // Oil Shale. 22 (2005) 2S, p. 127–142

Paper IV

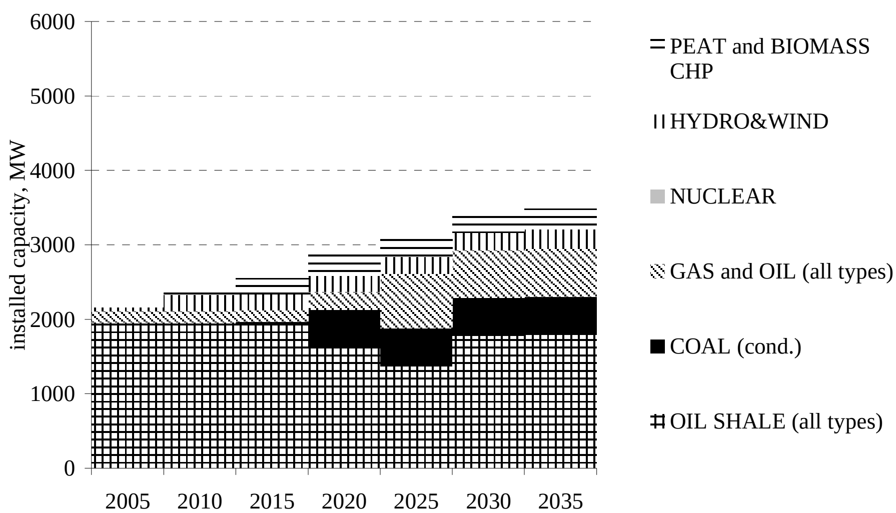
Liik O., **Landsberg M**., Oidram R. About Possibilities to Integrate Wind Farms into Estonian Power System. Fourth International Workshop on Large-Scale Integration of Wind Power and Transmission Networks for Offshore Wind Farms, 20-21 October 2003, in Billund, Denmark Session 6a, paper 3. 2021 October 2003. Billund [Denmark], 2003. p. 110.

APPENDIX B

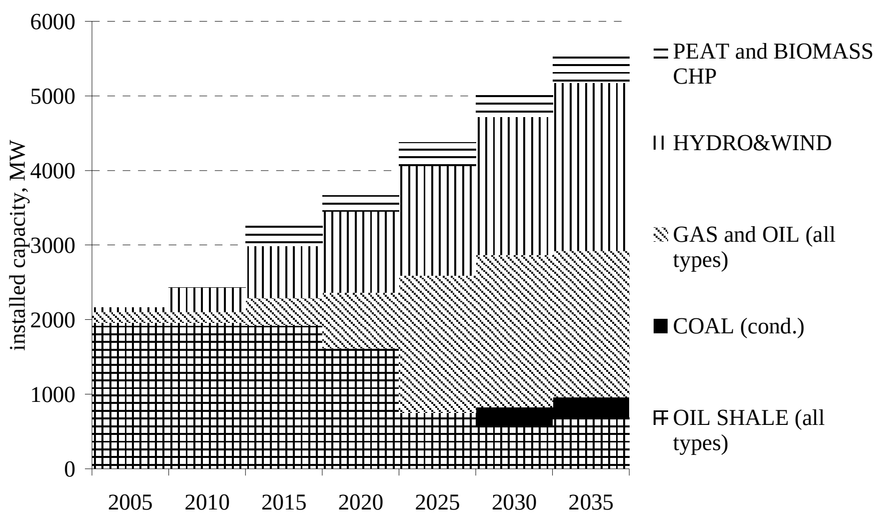
Cases with nuclear power plant being unavailable

Installed Capacity of different generating types 2005-2035

Case13: MINCO2

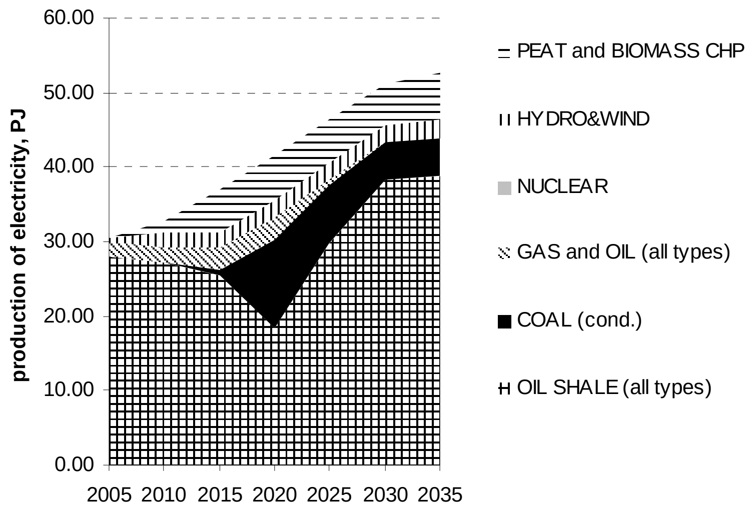


Case14: MAXCO2

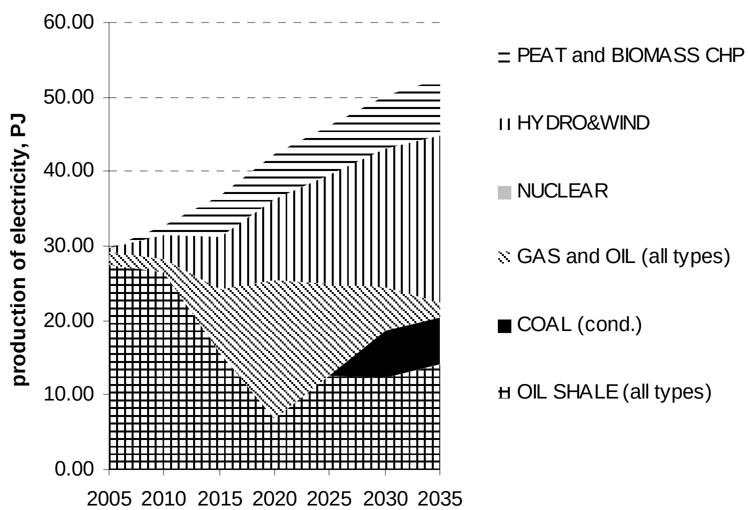


Production of electricity by fuel

Case13: MINCO2



Case14: MAXCO2

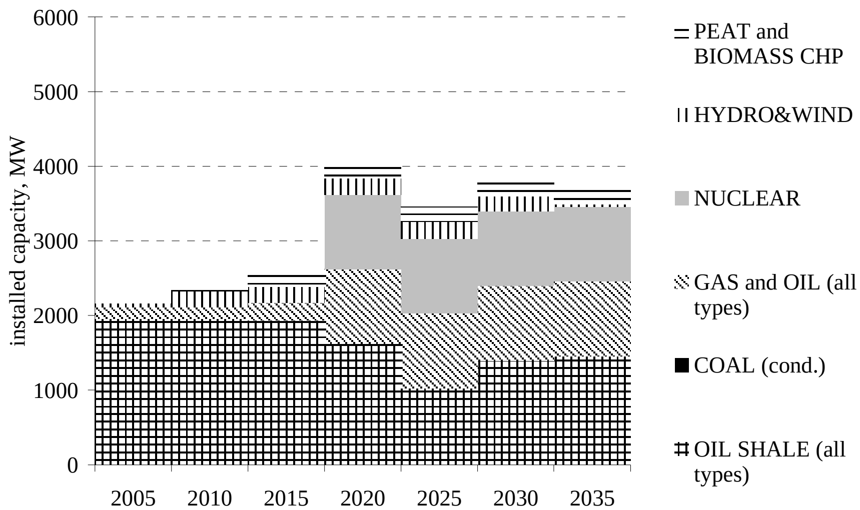


Cases with nuclear power plant being available

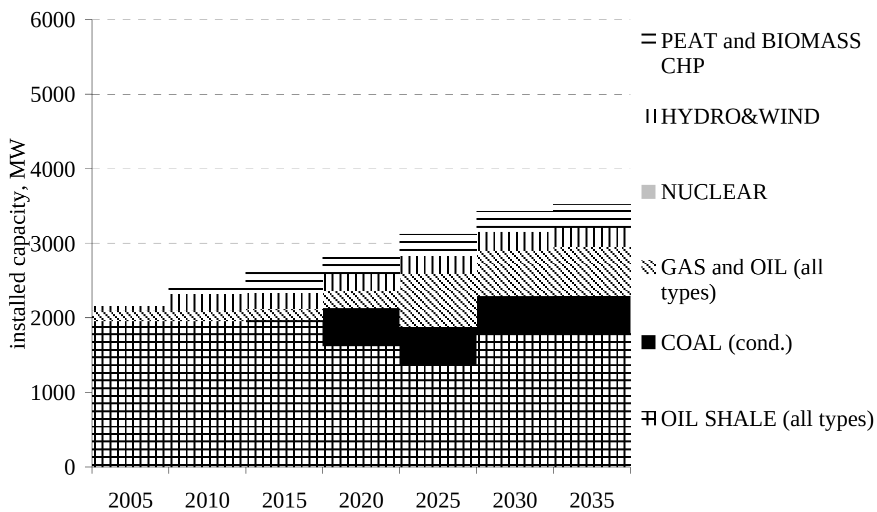
Installed Capacity of different generating types 2005-2035

Nuclear 1000 MW

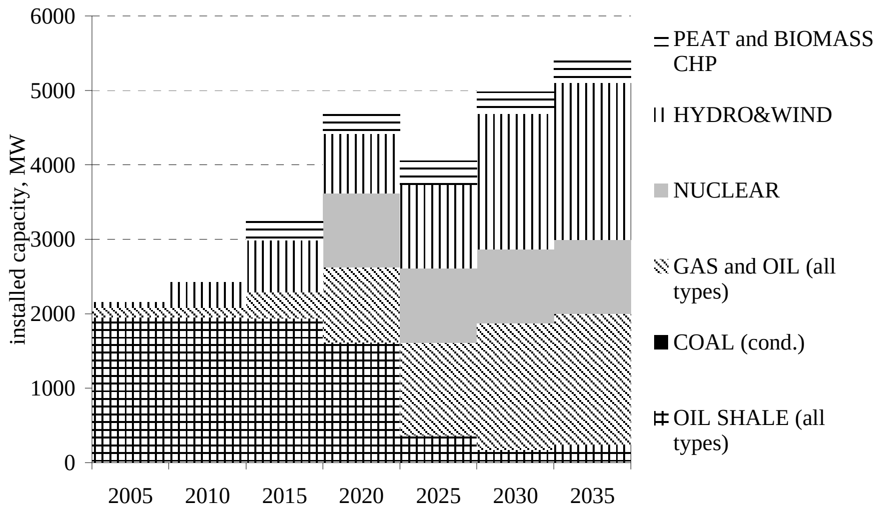
Case1: MINCO2 /MIN inv/MIN fuel



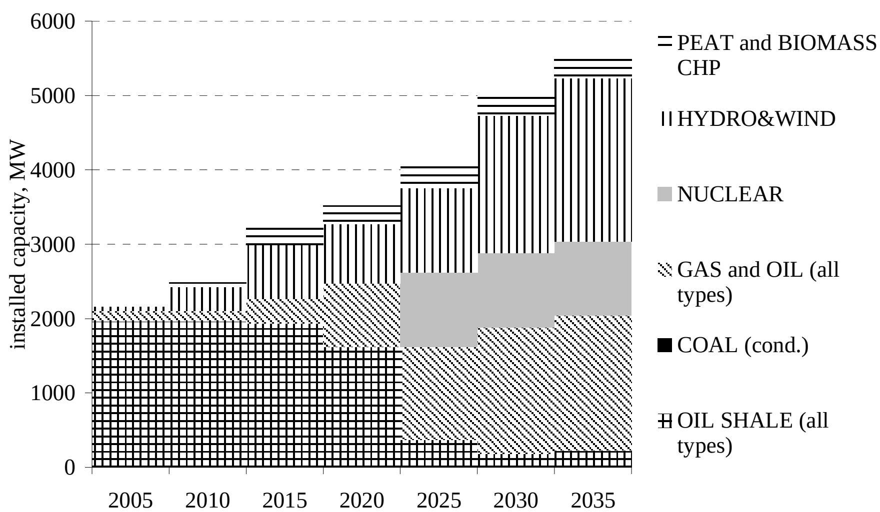
Case2: MINCO2 /MAX inv/MAX fuel



Case3: MAXCO2 /MIN inv/MIN fuel

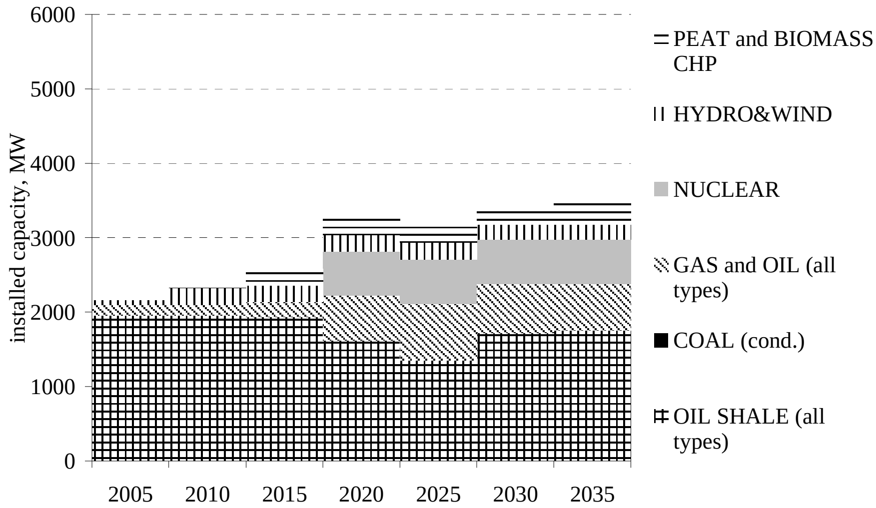


Case4: MAXCO2 /MAX inv/MAX fuel

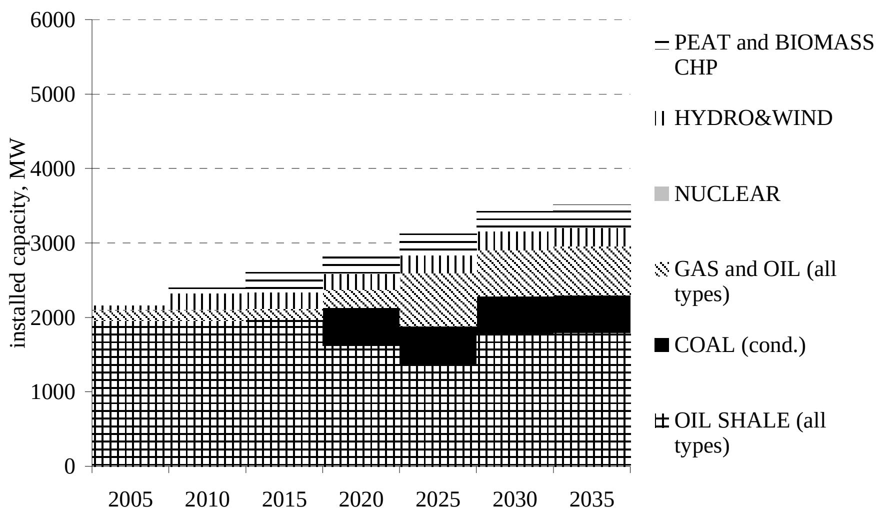


Nuclear 600 MW

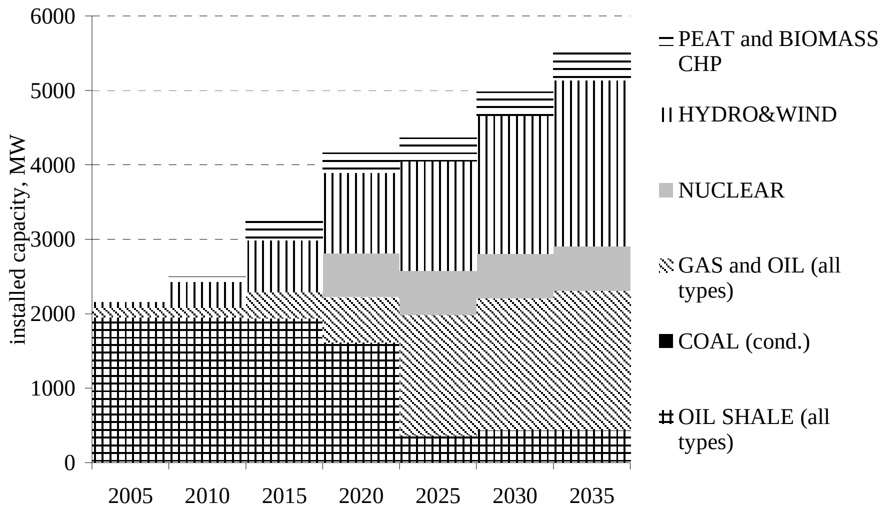
Case5: MINCO2 /MIN inv/MIN fuel



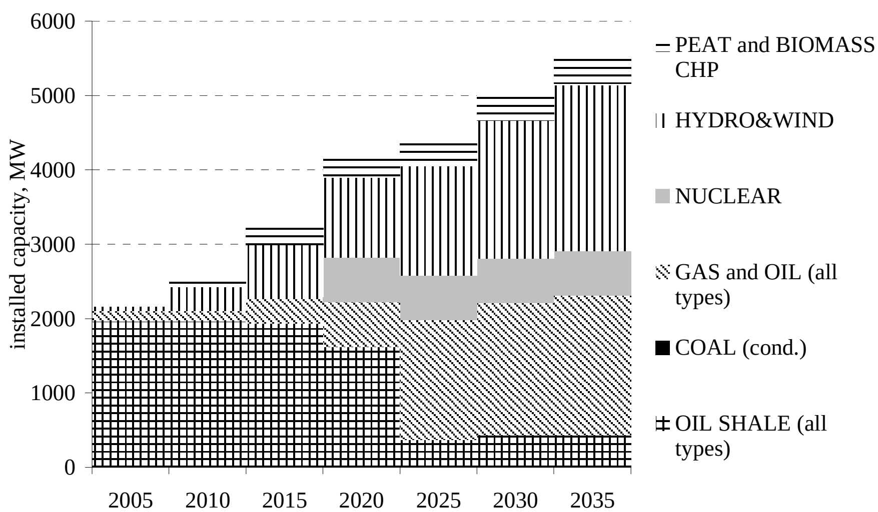
Case6: MINCO2 /MAX inv/MAX fuel



Case7: MAXCO2 /MIN inv/MIN fuel

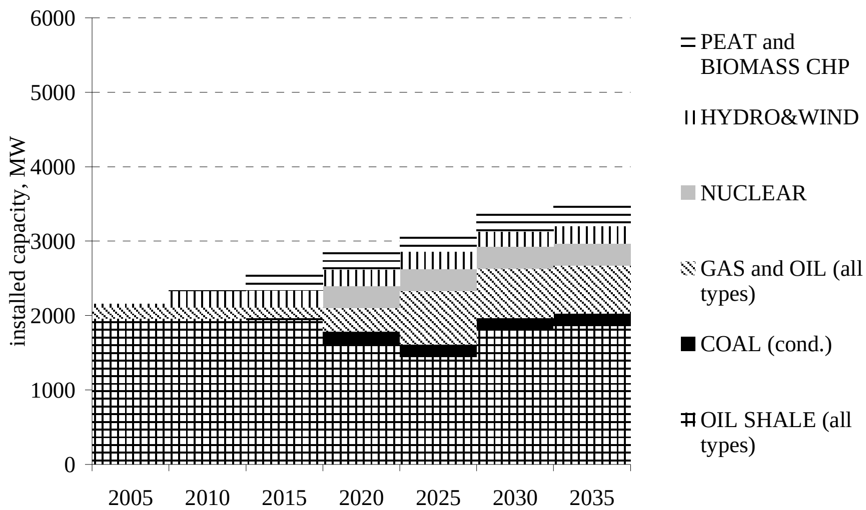


Case8: MAXCO2 /MAX inv/MAX fuel

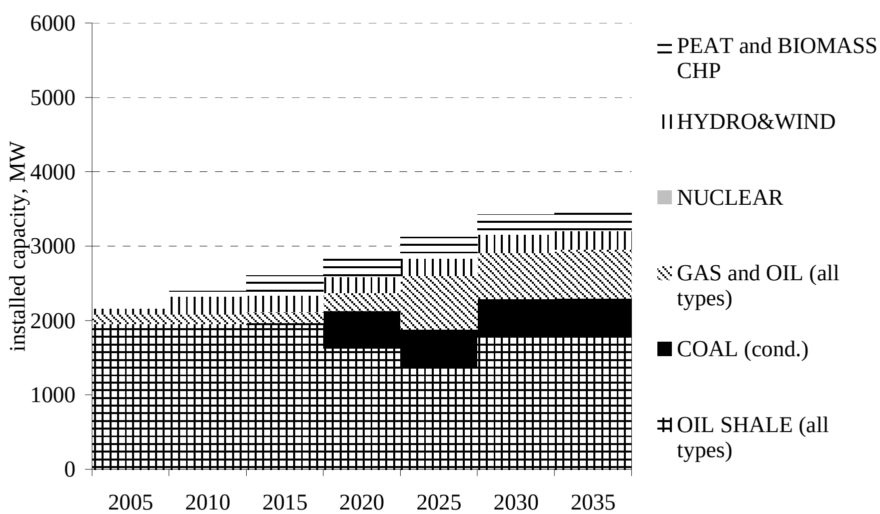


Nuclear 300 MW

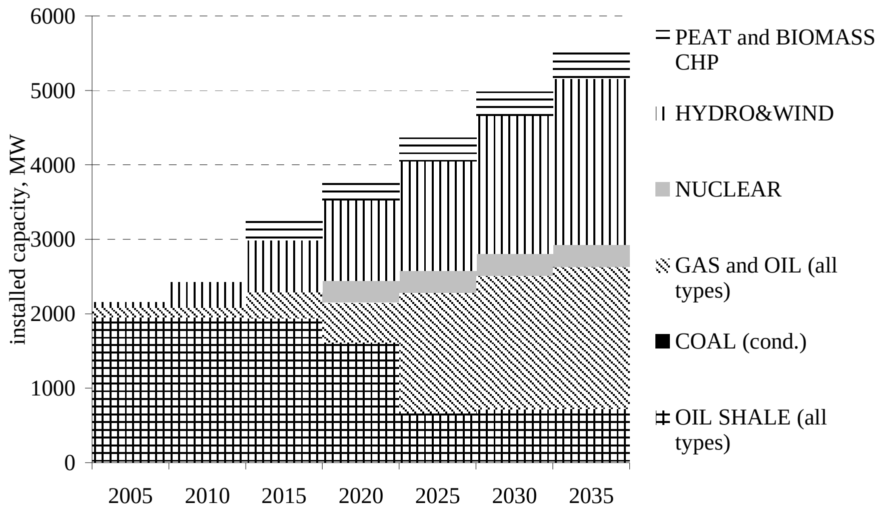
Case9: MINCO2 /MIN inv/MIN fuel



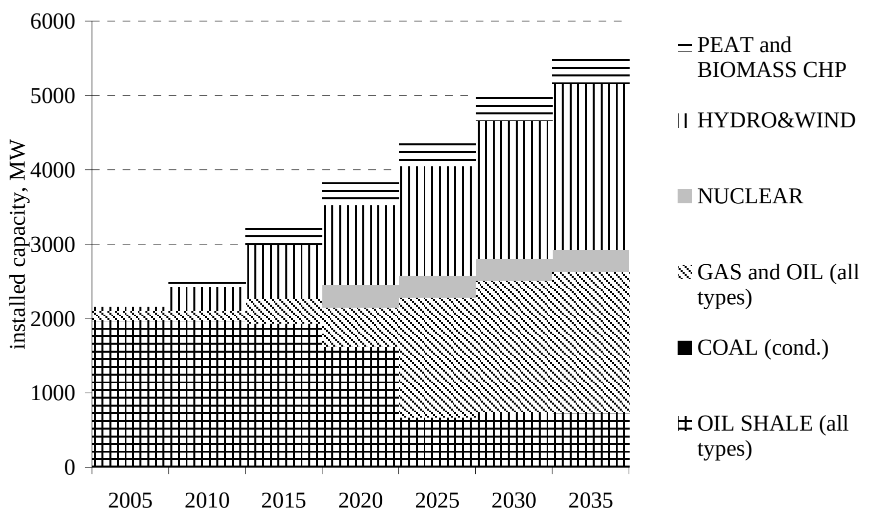
Case10: MINCO2 /MAX inv/MAX fuel



Case11: MAXCO2 /MIN inv/MIN fuel



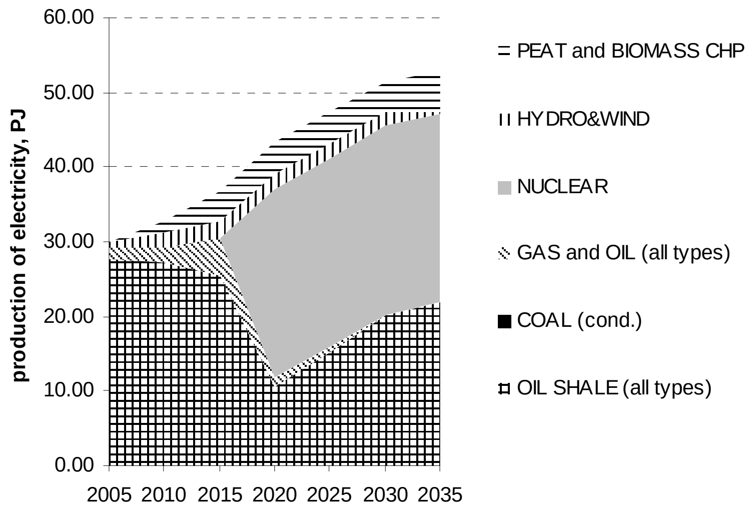
Case12: MAXCO2 /MAX inv/MAX fuel



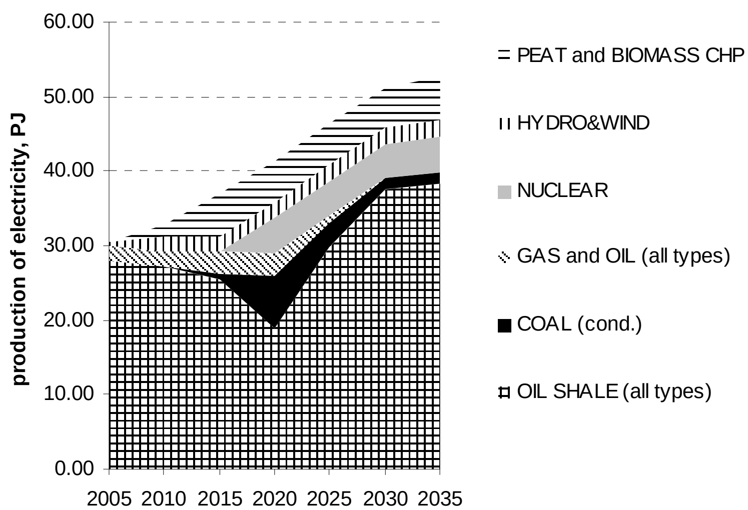
Production of electricity by fuel 2005-2035

Nuclear 1000 MW

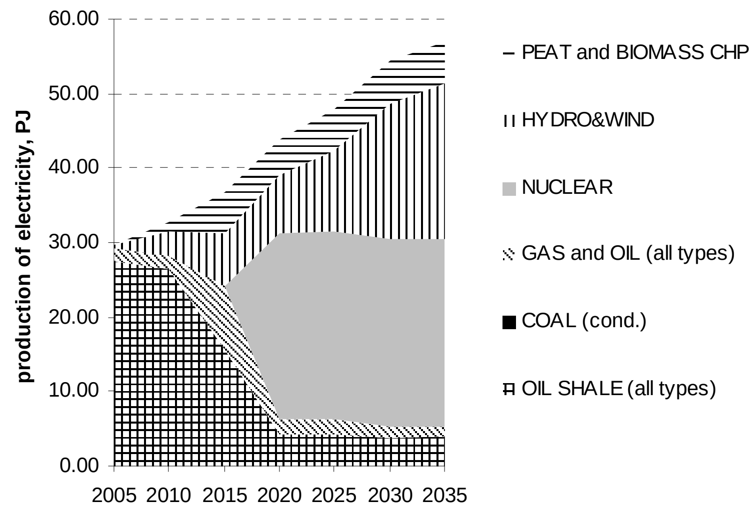
Case1: MINCO2 /MIN inv/MIN fuel



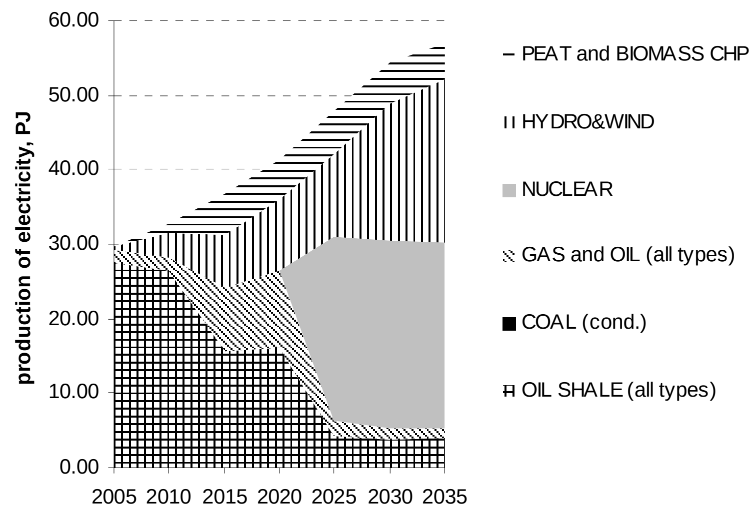
Case2: MINCO2 /MAX inv/MAX fuel



Case3: MAXCO2 /MIN inv/MIN fuel

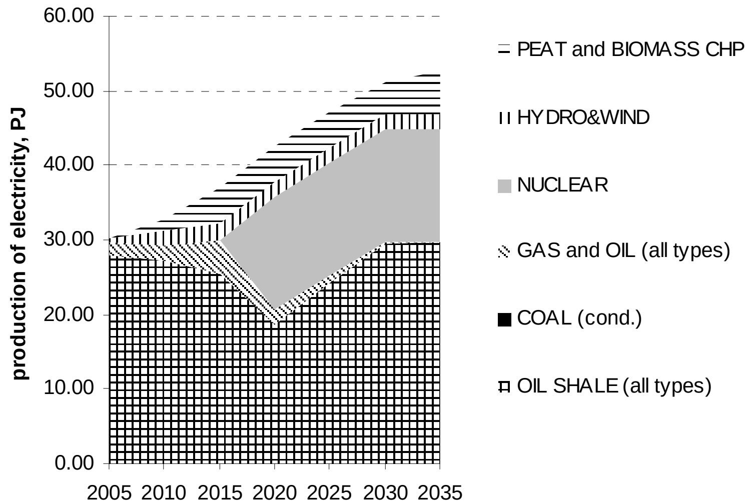


Case4: MAXCO2 /MAX inv/MAX fuel

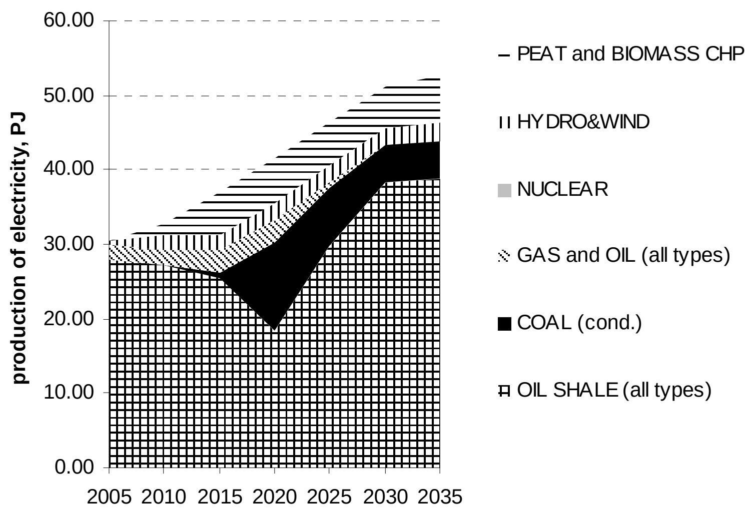


Nuclear 600 MW

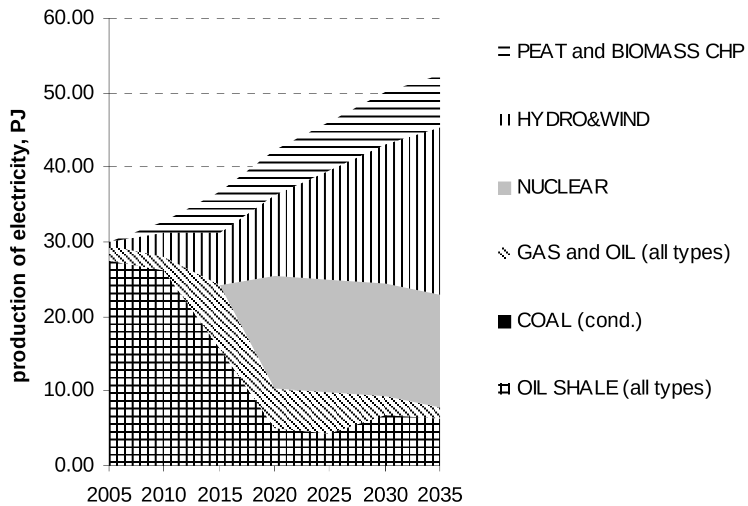
Case5: MINCO2 /MIN inv/MIN fuel



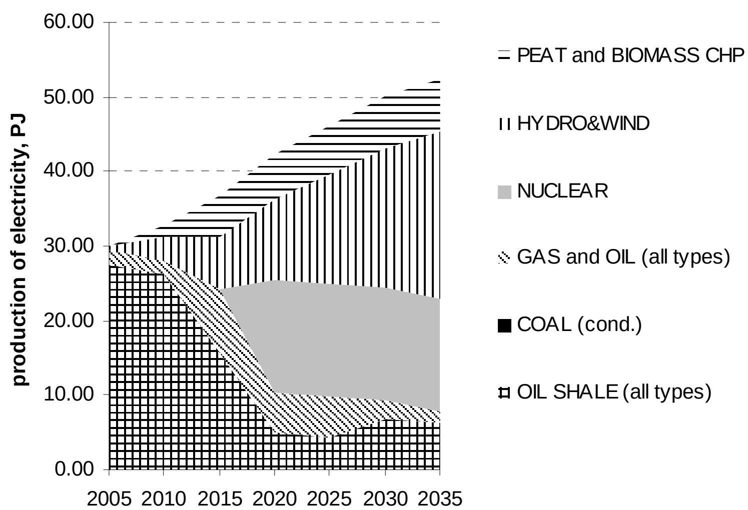
Case6: MINCO2 /MAX inv/MAX fuel



Case7: MAXCO2 /MIN inv/MIN fuel

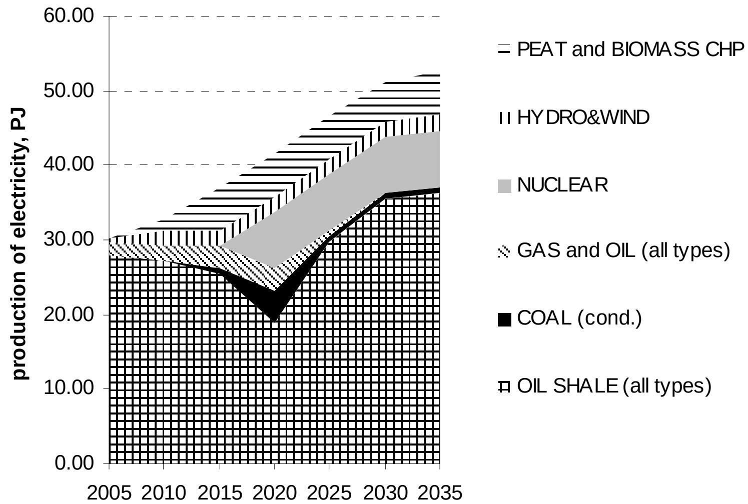


Case8: MAXCO2 /MAX inv/MAX fuel

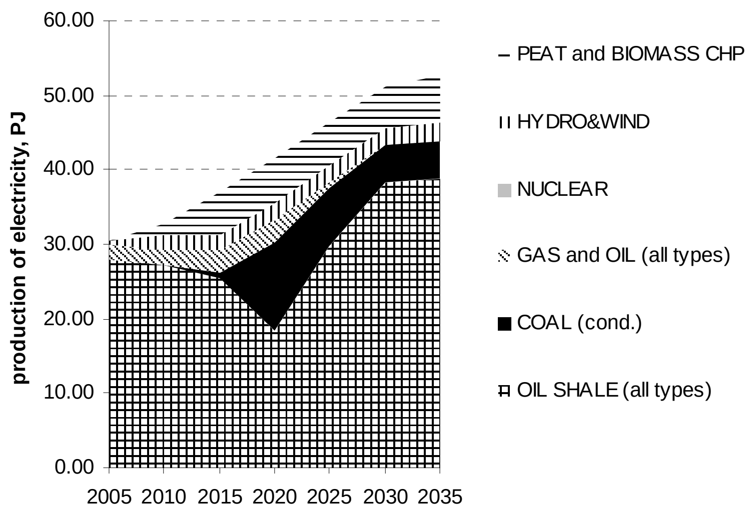


Nuclear 300 MW

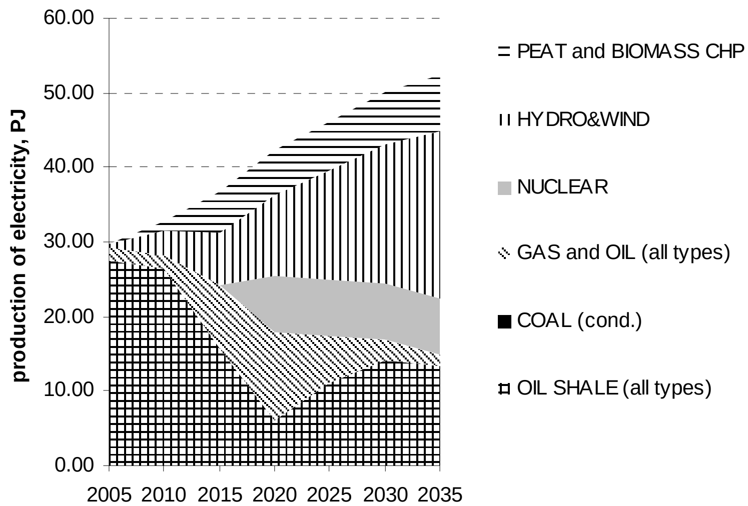
Case9: MINCO2 /MIN inv/MIN fuel



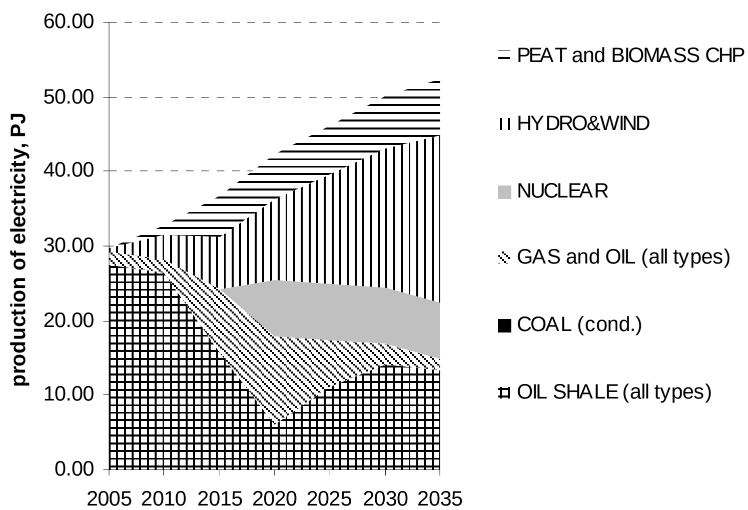
Case10: MINCO2 /MAX inv/MAX fuel



Case11: MAXCO2 /MIN inv/MIN fuel



Case12: MAXCO2 /MAX inv/MAX fuel



ELULOOKIRJELDUS

1. Isikuandmed
   Ees- ja perekonnanimi: Mart Landsberg
   Sünniaeg ja –koht: 07.01.1971, Tallinn
   Kodakondsus: Eesti

2. Kontaktandmed
   Aadress: Kajaka 37A/2 Tallinn, Eesti
   Telefon: 51 74 405
   E-posti aadress: mart.landsberg@mail.ee

3. Hariduskäik

Õppeasutus (nimetus lõpetamise ajal)	Lõpetamise aeg	Haridus (eriala/kraad)
Tallinna Tehnikaülikool	2002	elektroenergeetika eriala, tehnikateaduste magister.
Tallinna Tehnikaülikool	1995	elektroenergeetika eriala,, dipl. insener
Tallinna Polütehnikum, Tööstusettevõtete elektriseadmete eriala	1990	tööstusettevõtete elektriseadmed
Tallinna I Keskkool	1986	põhiharidus

4. Keelteoskus (alg-, kesk- või kõrgtase)

Keel	Tase
eesti	emakeel
inglise	kõrgtase
vene	kesktase
soome	kesktase

5. Täiendusõpe

Õppimise aeg	Täiendusõppe läbiviija nimetus
2002	Fingrid Oy, Soome
1999-2000	Mercury International, Eesti
1997	DC Baltija, Läti
1996	Power Technologies Int. , USA
1995	Chalmersi Tehnikaülikool (Göteborg).
1995	Rahvaülikool, Rootsi
1994	Tampere Tehnikaülikool

6. Teenistuskäik

Töötamise aeg	Tööandja nimetus	Ametikoht
1994-1998	Eesti Energia AS	planeerimisinsener
1998-2001	Eesti Energia AS Põhivõrk	reziimisektori juhataja
2001-jätkub	OÜ Põhivõrk	elektrivõrgu planeerimise sektori juhataja

7. Teadustegevus

Eesti Teadusfondi grant G4276 Võimalused elektituulikute kasutamiseks Eestis

Modelleerimisprojekt: "A quantitative analysis of the effects of market-based mechanisms addressing energy efficiency in Estonia" Leping Lundi ülikooliga.

Teadustöö leping nr. l 697 / 666, "Energiatoodete maksustamise uuring", Rahandusministeerium.

8. Kaitstud lõputööd

- Magistritöö: "Keskkonnamaksude mõju Eesti energeetika arengule", 2002, Juhendaja prof. Olev Liik
- Diplomitöö: "Impact of Environmental Restrictions on the Development of the Estonian Energy System" ("Keskkonnapiirangute mõju Eesti energiasüsteemi arengule"), 1995. Auhinnatud Eesti Teaduste Akadeemia poolt parimaks üliõpilatööks 1995 aastal.

Diplomitöö koostati Chalmersi Tehnikaülikooli (CTH) Energiasüsteemide Tehnoloogia kateedris (Energy Systems Technology Division). Diplomitöö juhendajateks olid Dr. Tomas Larsson (CTH) ja Olev Liik (Tallinna Tehnikaülikool).

9. Teadustöö põhisuunad

Elektritootmise optimaalne struktuur ja paigutus, erinevate elektritootmisviiside analüüs lähtuvalt tulevikustsenaariumidest, erinevate elektritootmisviiside mõju hindamine keskkonnale.

CURRICULUM VITAE

1. Personal data

   Name: Mart Landsberg
   Date and place of birth: 07.01.1971, Tallinn

2. Contact information
   Address: Kajaka 37A/2 Tallinn, Eesti
   Phone: 51 74 405
   E-mail: mart.landsberg@mail.ee

3. Education

Educational institution	Graduation year	Education (field of study/degree)
Tallinn Technical University	2002	electrical power engineering master of technical sciences.
Tallinn Technical University	1995	electrical power engineering, dipl. engineer.
Tallinn Polytechnical School	1990	power installations in industrial enterprises, secondary education
Tallinn I Secondary School	1986	basic education

4. Language competence/skills (fluent; average, basic skills)

Language	Level
Estonian	mother tongue
English	fluent
Russian	average
Finnish	average

5. Special Courses

Period	Educational or other organisation
2002	Fingrid Oy, Finland
1999-2000	Mercury International, Estonia
1997	DC Baltija, Latvia
1996	Power Technologies Int. , USA
1995	Chalmers University of Technology, Göteborg, Sweden
1995	Folkuniversitet, Sweden
1994	Tampere University of Technology

6. Professional Employment

Period	Organisation	Position
1994-1998	Eesti Energia AS	planning engineer
1998-2001	Eesti Energia AS Põhivõrk	Head of Division Operational Planning
2001-continuing	OÜ Põhivõrk	Head of Division Planning and Engineering

7. Scientific work

Estonian Science Foundation grant project G4276 Possibilities and efficiency of the use of wind generators in Estonia.

Modelling project: A quantitative analysis of the effects of market-based mechanisms addressing energy efficiency in Estonia

8. Defended theses

- Master thesis: "Impact of Emission Charges on the Development of the Power Production", 2002, Supervsor: prof. Olev Liik
- Diploma thesis: "Impact of Environmental Restrictions on the Development of the Estonian Energy System", 1995. Supervisors:

dr. Tomas Larsson from Chalmers Technical University and dr. Olev Liik from Tallinn Technical University. Selected by the Estonian Academy of Sciences as the best student research paper of 1995.

9. Main areas of scientific work/Current research topics

Area of research is optimal structure and allocation of power production, elaboration of different power conversion technologies for the future, impact of different energy conversion technologies on the environment

PUBLICATIONS RELATED TO THE TOPIC

1. Liik, O., Landsberg M. Some scenarios of CO2 emissions from the energy system // Punning J.-M. (ed.). Estonia in the System of Global Climate Change. Institute of Ecology, Tallinn, 1996. Pp. 190 -206. ISBN 9985-9035-5-2.
2. Martins A., Roos I., Pesur A., Karindi A., Punning J.-M., Landsberg M., Liik O., Purju A., Roostalu H., Tamm T., Tullus H. Mitigation Analysis for Estonia: Research report under US Country Studies Program: Support for Climate Change Studies. Tallinn, 1996. P. 67.
3. A. Martins, I. Roos, A. Pesur, A. Karindi, J.M. Punning, M. Landsberg, O. Liik, H. Roostalu, T. Tamm. Mitigation Analysis for Estonia. // Meyers S., Goldberg B., Sathaye J., Simeonova K. (editors). Global Climate Change Mitigation Assessment: Results for 14 Transitioning and Developing Countries. Washington, USA, August 1997, pp. 59-73.
4. Kallaste, T., Pallo, T, Esop, M.-R., Liik, O., Valdma, M., Landsberg, M., Martins, A. Roos, I. The interim report to the UNEP/GEF project GF/2200-96-15. Tallinn : Stockholm Environment Institute : Tallinn Office, 1997. 102 p.
5. Kallaste, T., Pallo, T, Esop, M.-R., Liik, O., Valdma, M., Landsberg, M., Martins, A. Roos, I. The interim report to the UNEP/GEF project GF/2200-96-15. Tallinn : Stockholm Environment Institute : Tallinn Office, 1997. 102 p.
6. Valdma, M. (töö juht), Keel, M., Liik, O., Tammoja, H., Esop M.-R, Landsberg, M., Kodumets, M. Energiasüsteemide talitluse koordineerimise meetodid normaalse turumajanduse tingimustes ja sellele üleminekul : Eesti teadusfondi granti nr. 440 lõpparuanne. Tallinn : TTÜ elektroenergeetika instituut, 1997. 41 lk.
7. Economics of greenhouse gases limitations : country study series : Estonia / Edited by T. Kallaste, O. Liik, A. Ots, autors ... M.-R. Esop, M. Landsberg, O. Liik, M. Valdma et al. Denmark : UNEP Collaborating Centre on Energy and Environment : Risø National Laboratory, 1999. 205 p.
8. Liik, O., Landsberg, M., Esop, M.-R. / Analysis of Estonian Power System Development Using MARKAL Model/ Proceedings of the International Energy Agency’s Energy Technology Systems Analysis Programme / Annex VII 8th Workshop, Torino, Italy, 28-31 October 2002. http://www.etsap.org/worksh7-8/LiikMARKAL-Estonia.pdf
9. Landsberg M.. Master thesis: “Impact of Emission Charges on the Development of the Estonian Power Production” , Tallinn Technical University, 2002
10. Liik O., Landsberg M., Oidram R. About Possibilities to Integrate Wind Farms into Estonian Power System. Fourth International Workshop on Large-Scale Integration of Wind Power and Transmission Networks for

Offshore Wind Farms, 20-21 October 2003, in Billund, Denmark Session 6a, paper 3. 2021 October 2003. Billund [Denmark], 2003. p. 110.
11. Liik O., Oidram R., Raesaar P., Keel M., Esop M-R, Landsberg M., Tiigimägi E., Möller K. Possibilities and efficiency of the use of wind generators in Estonia. Final report of Estonian Science Foundation grant project G4276; Tallinn: Tallinn Technical University; 2003; 100 pp.; in Estonian.
12. Liik, O., Landsberg, M., Oidram, R. Analysis of possibilities to integrate wind turbines into Estonian power system // Scientific proceedings of Riga Technical University. 4. [series], Power and electrical engineering. 9 (2003) p. 196-203.
13. "Terms of connection to the National Grid" – Ettekanne seminaril "DISTRIBUTED GENERATION" November 9, 2004, Tallinn,
14. Liik, O., Landsberg, M. Modelling project: A quantitative analysis of the effects of market-based mechanisms addressing energy efficiency in Estonia : Report to IIIEE at Lund University. Tallinn : TUT Press, 2004. 86 p.
15. Liik O., Oidram R., Keel M., Landsberg M. A New Method for Estimation of Fuel Savings by Wind Energy and its Impact on Power System Planning. Power-Gen Europe 2004 25-27 May 2004, Barcelona, Spain. paper 357, [18] p.
16. Liik, O., Oidram, R., Keel, M., Landsberg, M. Co-operation of Wind generators with fossil power plants : problems and gains // Proc. of Nord Wind Power Conference : Gothenburg, 2004. Cothenburg [Göteborg, Rootsi] : Chalmers University of Technology, 2004. [6] p. 2004
17. O. Liik, R. Oidram, M. Keel, J. Ojangu M. Landsberg, N. Dorovatovski "Integration of Wind Farms Into Estonian Oil Shale-Based Power System" , Oil Shale, 2005, Vol. 22, No. 2 pp. 21-24, Tallinn
18. Landsberg, M., Agabus, H., Liik, O. Possibilities to develop the use of renewable energy and co-generation in Saaremaa // 2nd International Symposium „Topical Problems of Education in the Field of Electrical and Power Engineering" : Kuressaare, Estonia, January 1722, Kuressaare, 2005. p. 113 118.
19. Liik, O., Landsberg, M., Ojangu, J., Kilk, K., Agabus, H. Possibilities to develop the use of wind energy in Saaremaa island // Scientific proceedings of Riga Technical University. Serija 4, Power and electrical engineering. 14 (2005) Riga : RTU, 2005.. p. 8693.
20. Liik, O., Oidram, R., Keel, M., Ojangu, J., Landsberg, M., Dorovatovski, N. Co-operation of Estonia's oil shale-based power system with wind turbines // Oil Shale. 22 (2005) 2S, p. 127142
21. Landsberg M., Liik O. Estonia's Fourth National Communication. Under the UN Framework Convention on Climate Change. pp. Estonian Ministry of Environment, 2005, ISSN 1736-36832005

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23. Agabus H., Landsberg M., Liik O. Optimal Investment Strategies for Energy Sector Under Uncertainty. 2nd International Symposium „Topical Problems of Education in the Field of Electrical and Power Engineering". Tallinn Technical University, January, 17 – 22, 2005 in Kuressaare pp 120-127, Estonia Tallinn 2006. ISBN 9985-69-036-2
24. Landsberg M., Agabus H., CO_2 Emission Reduction Options for Estonia. Proceedings of International Conference "Electrical and Control Technologies". Kaunas 2006. ISSN 1822-5934
25. Landsberg, M., Agabus, H. CO_2 emission reduction options for Estonia // Proceedings of International Conference Electrical and Control Technologies – 2006 p. 405–410. ISBN 9955-25-054-2 2006
26. Landsberg, M., Agabus, H., Liik, O. CO_2 emission reduction options for Estonia. 3rd International // Symposium "Topical Problems of Education in the Field of Electrical and Power Engineering". Doctoral School of Energy and Geotechnology: Kuressaare, Estonia, January 16̃21, 2006. Tallinn: Tallinn University of Technology, Department of Electrical Drives and Power Electronics. 2006. p. 112̃119.
27. H. Agabus, M. Landsberg, H. Tammoja. Reduction of CO_2 Emissions in Estonia During 2000-2030. Oil Shale, Vol. 24 No. 2 pp. 209-224. 2007 Estonian Academy Publishers ISSN 0208-189X
28. M. Landsberg, H. Tammoja, J. Kilter. Optimal Introduction of a Nuclear Power Plant in Estonia Under Uncertain Conditions. Quality and Supply Reliability Conference, Pärnu, 27 Aug - 29 Aug 2008. ISBN: 978-1-4244-2501-3