Netherlands Bureau for Economic Policy Analysis

Energy Policies and Risks on Energy Markets

A cost-benefit analysis

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Abstract

The key question dealt with in this report is whether and how governments should be involved in taking measures regarding security of energy supply. In order to answer this question, we developed a framework for cost-benefit analysis and applied this framework to a number of policy options. The options chosen vary from government investments in strategic oil stocks to financial incentives for consumers to reduce their consumption of electricity. The set of options comprises several types of governmental action, including subsidies, regulation and government investments. Moreover, the selection includes measures meant to address risks on all three major energy markets: oil, natural gas, and electricity. The general picture following from the cases studied is that security of supply measures are hardly ever beneficial to welfare: benefits of policy measures do generally not outweigh costs. From an economic point of view, therefore, it would be often wiser to accept consequences of supply disruptions than to pursue security of supply at any cost. This implies that governments should exercise caution in imposing measures regarding security of supply. If serious market failure is detected, careful attention should be paid to the design of the corrective measure. Establishing and maintaining well-functioning markets appears to be an efficient approach in realising a secure supply of energy. That approach would include removal of entry barriers, securing equal access to essential facilities and increasing transparency of markets.

Korte samenvatting (in Dutch)

De vraag die in dit rapport centraal staat is op welke wijze de overheid betrokken zou moeten zijn bij het verzekeren van de energievoorziening. Om deze vraag te beantwoorden hebben we een raamwerk voor kosten-batenanalyses ontwikkeld en toegepast op een aantal beleidsopties. Deze opties variëren van investeringen in strategische olievoorraden tot het geven van financiële prikkels aan consumenten om het elektriciteitsverbruik te verminderen. De onderzochte beleidsopties omvatten subsidies, vormen van regelgeving, en investeringen. Risico’s op de drie grootste energiemarkten – olie, gas en elektriciteit – zijn in de analyse betrokken. Het algemene beeld dat naar voren komt is dat overheidsbeleid specifiek gericht op voorzieningszekerheid veelal niet kosteneffectief is: de baten van de beleidsmaatregelen wegen vaak niet op tegen de kosten. Economisch gezien is het dus veelal verstandiger kosten van storingen te accepteren in plaats van tegen elke prijs te proberen storingen te voorkomen. Dit betekent dat overheden terughoudend zouden moeten zijn bij het nemen van maatregelen die gericht zijn op voorzieningszekerheid. Als markten er niet in slagen om de energievoorziening goed te regelen, dan zou overheidsbeleid op zijn plaats kunnen zijn mits zorgvuldig aandacht wordt gegeven aan het ontwerp van de maatregelen. Bovenal geldt dat het realiseren van goed werkende energiemarkten ook bijdraagt aan het verzorgen van de energievoorziening. Kernelementen daarbij zijn: verminderen van toetredingsbelemmeringen, scheppen van gelijke toegang tot essentiële faciliteiten, en vergroten van transparantie van vraag, aanbod en prijzen.

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Preface

Sufficient supply of energy at all times is generally highly valued. Disruptions in supply can cause high costs to society. Since securing the supply of energy also incurs costs, the major question in this field refers to the optimum level of security. A related question is whether markets succeed or fail in realising that level. In the latter case, government involvement could be welfare improving.

In order to answer these questions, cost-benefit analyses are required. In contrast with other domains of governmental policies, only a few examples exist of studies analysing costs and benefits of security of energy supply measures. The Netherlands' Ministry of Economic Affairs requested the CPB to develop a framework for cost-benefit analysis directed at this domain of policy. In addition, the Ministry asked the CPB to apply that framework to a number of policy measures.

Because of the complexity and size of this project, we in turn asked several researchers from different institutes to contribute. Aad Correlje of the Technical University Delft made an overview of disturbances on energy markets in the past, and contributed, with the help of his students Philip Cocken and Jord Engel, to the analysis of risks on the natural gas market. Robert Mabro and Robert Arnott of the Oxford Institute for Energy Studies explored risks on the oil, coal and uranium markets. Christian Bos and Jaap Breunese of the Netherlands Institute of Applied Geoscience TNO increased our knowledge of technical aspects of the gas market. Rob Aalbers of the Erasmus University Rotterdam contributed to the analysis of the electricity market. Finally, Sander de Bruyn and Ron Wit of CE, a Dutch environmental research institute, explored policy options and calculated the direct effects of a number of these options.

During the project, we were advised by a steering committee from the Ministry, composed of Jeroen Brinkhoff, Hans Cahen, Tom Kolkena, Klaas-Jan Koops, Bert Roukens (chairman) and Jaco Stremler. In addition to this, we received highly useful comments on draft versions from energy market specialists from several organisations. In particular, we want to mention the contributions made by Manfred Decker (European Commission), Erik van Ewijk (EBN), Per Godfroij (VROM), Wim Groenendaal (NAM), Misja Mikkers (Dte), Michiel de Nooy (SEO), Laetitia Ouillet and colleagues (NUON), Martin Scheepers and Michiel van Werven (ECN), Martien Visser (Gasunie) and Laurens de Vries (TU Delft). Finally, we benefited from discussions with and among experts from research, industry and government at the workshop where we presented tentative results of this research.

We thank them all for their highly useful contributions. The responsibility for this report is, of course, entirely ours. Feedback on a regular basis from within the CPB was given by Paul

Besseling, Carel Eijgenraam, Taco van Hoek, Ruud Okker and Bert Smid. Besides this, several other colleagues put forward useful comments on the final draft version of this report.

Within the project team, a clear division of tasks was made. Jeroen de Joode went deeply into the 'Groningen' case, Douwe Kingma investigated policy options directed at the oil market, Mark Lijesen analysed all cases related to the electricity sector and made, in addition, a significant contribution to the framework of analysis, and Victoria Shestalova wrote the network chapter. Machiel Mulder managed the project, wrote the introductory and concluding chapters and did the final editing of this report. Besides the authors, Martin Vromans was very valuable to the project as he conducted the macroeconomic analysis of several policy options. Finally, Jeannette Verbruggen contributed by correcting the report according to CPB layout and style standards.

Henk Don
Director

Summary

Scope of the research

The key question dealt with in this report is whether and how governments should be involved in taking measures regarding the security of energy supply. In the past, the level of security in most energy markets was extremely high as governments were strongly involved in the energy sector. In liberalised markets, private firms will probably not ensure that high level of security, as private costs incurred could be higher than private benefits. The California electricity crisis in 2000 and 2001, and the liberalisation of the European energy markets have fuelled doubts about the willingness of private firms to invest in the maintenance and expansion of production and transport capacity. Moreover, the growing dependence on oil and natural gas from politically unstable countries has increased worries about the security of the supply of those energy carriers. The recent blackouts in North America and various European countries emphasize the importance to society of a secure supply of energy.

In order to assess the role for governments in energy markets from the perspective of energy security, we developed a framework of cost-benefit analysis and applied this framework to a number of policy options.

Interventionist approaches are not efficient

The general picture following from the cases studied is that security of supply measures are hardly ever beneficial to welfare. From an economic point of view, it would be often wiser to accept consequences of supply disruptions than to pursue security of supply at any cost. This implies that governments should proceed carefully in imposing measures regarding security of supply. If serious market failure is detected, careful attention should be paid to the design of the corrective measure.

The results of our analysis show that in some cases markets fail to deal with all costs and benefits of security of supply measures. The oil market is an obvious example. Benefits of investments in strategic oil stocks do not fully accrue to the investors, but also to other parts of the economy. As a result, private firms will invest less in these stocks than governments. In most other cases, however, markets seem to succeed in realising a sufficient level of security of supply. Moreover, in several cases where market failure is detected, costs of government action could easily be higher than the benefits generated.

Effective competition policy contributes to a secure supply of energy

If markets function well, prices will give producers incentives to invest if supply becomes scarce, while at the same time consumers are encouraged to reduce demand. So, this price mechanism enables markets to match supply and demand. Well-functioning markets may be prone to price spikes, as our studies of both the gas and electricity markets suggest. However, the welfare costs of price spikes in these cases are small in comparison to the costs of policies directed at preventing these spikes.

If prices do not reflect real scarcity or producers or consumers are not able to respond to changes in prices, security of supply problems could appear. Therefore, establishing and maintaining well-functioning markets appears to be an efficient approach in realising a secure supply of energy. Market design plays a crucial role here and includes removal of entry barriers, securing equal access to essential facilities, such as networks and storage, giving network owners incentives for investments, and increasing transparency of markets. The example of the crisis in California shows how serious the consequences of flaws in 'market architecture' can be.

Usefulness of the framework

The key element in the framework developed is the break-even frequency. The break-even frequency is defined as 'the frequency of occurrence of a predefined crisis at which the present value of the costs of the policy option exactly equals the present value of its benefits'. In our view, calculating the break-even frequency is a fruitful approach in dealing with risks. Consequently, the cost-benefit framework enables researchers and politicians to think systematically about consequences of security of supply measures. This does not imply that any new application of the framework is as easy as a routine job. In every cost and benefit analysis, researchers have to analyse specific characteristics of risks and policy measure(s) at stake.

Oil market: expanding strategic oil stocks and subsidising biomass

On the oil market, the crises analysed are a temporary disruption of supply, resulting in a short lasting surge in the crude oil price, and an effective cartel of oil producers, leading to a longer lasting but smaller price increase.

Investment in strategic oil stocks is an international policy measure focusing at the former risk. We conclude that extending strategic oil stocks internationally, as is proposed by the European Commission recently, is not an efficient policy measure, unless one views the risk of a long-lasting disruption of supply as a relatively high one.

Encouraging the use of biomass in the transport and chemical sectors is a measure aimed at decreasing vulnerability of an economy to oil price movements. This measure would be highly inefficient: even if the crude oil price would permanently be on a 20% higher level, this option entails high losses of welfare. The analysis of this measure includes assessment of environmental effects.

Natural gas market: capping production of 'Groningen' and diversifying the power sector

Risks on the natural gas market are primarily related to the flexibility of the gas system and the growing dependence on non-European suppliers.

Capping production from the Groningen gas would be a policy measure to increase the lifetime of the capability of this field to serve demand in a severely cold winter. This option is a highly expensive measure. Despite this conclusion, the question remains whether capping production from the Groningen field would be efficient if this issue is analysed from a broader perspective than that of meeting extremely high demand. In order to answer this question, additional research should be conducted.

The growing vulnerability to supply decisions made outside the European Union could be reduced by stimulating substitution within the power sector towards other fuels, such as coal, and other generation techniques, such as wind turbines and nuclear power. The break-even frequencies for all policy options investigated are high, implying that the disruption should occur very frequently in order to make these policy options viable. Sensitivity analysis shows that this conclusion is fairly robust for wind and coal-fired power. For nuclear power, however, changing some of the assumptions would alter the conclusion. Investments in nuclear power plants could be efficient if the latest techniques would be used, in combination with an exceptionally high load factor.

Electricity market: regulating reserve capacity and raising levies on use of electricity

The major risks on the electricity market consist of insufficient investments in peak production capacity and high power prices due to imperfect competition.

Introduction of measures giving private parties incentives to invest in peak capacity is an option to cope with the former risk. We assessed the costs and benefits of three options aimed at increasing the reliability of electricity production: capacity markets, reserve contracts and capacity payments. We found that each of these options induces high costs, capacity markets and reserve contracts because capacity is left idle and capacity payments because of large welfare costs induced by price increases. The policy options are not efficient in preventing price spikes, as the welfare costs of price spikes are lower than the costs of the policy options, unless price spikes occur at an implausibly high frequency.

Encouraging saving on the use of electricity, for instance by raising the rates of the energy tax, is an option to reduce the vulnerability of the economy to abuse of market power by producers. Our analysis shows that a price increase of 50% during one year should happen at least once every 4.2 years to make this policy option efficient. The result is fairly robust to changes in assumptions; it suggests that the policy is not viable from a supply security point of view.

Electricity network: restructuring of industry and regulating reliability

The power grid faces the risk of decreasing reliability. Furthermore, lack of independence of networks may cause execution of market power by regional generators.

We stress the importance of independent functioning of networks. We discuss two policy options that focus on increasing independence of regional transmission networks: creating a number of independent regional transmission companies and merging regional transmission with the Dutch Transmission System Operator (TenneT). Both options would involve a restructuring of the industry. Qualitatively, we highlight the trade offs that arise with respect to these two options. A deeper analysis and consultations regarding all options, including the option not to split regional transmission from distribution, would be needed to assess their overall effect on social welfare.

We discuss three policy options with respect to regulation of reliability of regional networks: the current policy consisting of minimum standards and compensations for violations, the new proposal of the Dutch regulator (DTe), and the option of maintaining the pre-liberalisation level of reliability. On theoretical basis, we can say that the base policy option (currently in place) does not safeguard reliability and may eventually lead to reliability decreasing below the optimal level. The new DTe proposal is more effective. The alternative policy option of maintaining the current reliability level is also less attractive than the DTe proposal.

A few caveats

Despite the fairly extensive research we conducted, we have to mention a few caveats. First of all, the set of policy options analysed does not cover all options and all designs of those options. In order to fully assess the role of governments in the field of security of supply, several other options would have to be analysed as well. Moreover, we analysed costs and benefits of each option given a defined design instead of searching for the optimal design. Theoretically, the latter is more appealing. In practice, defining the optimal design of a policy option requires a far more profound analysis than has been conducted in this report. As a result, this project cannot give the final answer regarding the role of governments.

Another caveat results from the characteristics of cost-benefit analyses. The results of any cost-benefit analysis offer only part of the information needed for decision making. Some effects are not measurable and, hence, are accounted for as a *pro memoria* item. Moreover, the distribution of costs and benefits within society generally plays an important role in the decision-making process. In our analysis, we analysed the distribution effects at a fairly aggregate level only. If a cost-benefit analysis is applied to risks, an additional caveat should be mentioned, being the risk attitude of decision makers. If governments are risk averse, for instance because of a suspected effect of a crisis on the reputation of politicians, or if societies as a whole are risk averse, the interpretation of the break-even frequency shifts in favour of the policy measures

1 Introduction

1.1 Background and scope of the research

The California electricity crisis in 2000 and 2001 and the liberalisation of the European energy markets have fuelled doubts about the willingness of private firms to invest in the maintenance and expansion of production and transport capacity. Moreover, the growing dependence on oil and natural gas from politically less stable countries has increased worries about the security of the supply of those energy carriers. The recent blackouts in North America and various European countries emphasize the importance to society of a secure supply of energy.

Policy makers and others involved in the energy sector, therefore, give a great deal of attention to the security of energy supply. In 2000, the European Commission presented its Green Paper (COM, 2000), and in 2001, the government of the United States published the 'US Energy Plan'. Small countries have also become increasingly aware of the uncertainties associated with energy markets. In the Netherlands, for instance, the government recently initiated a research programme focusing on policy options to cope with the risks related to the supply of energy.

The key research question within the debate of security of supply, from an economic point of view, is whether a particular type of government intervention improves or worsens welfare. Do markets fail in efficiently realising a secure supply of energy, or do regulatory failures exceed market failures? The Netherlands' Ministry of Economic Affairs asked CPB, firstly, to develop a framework of cost-benefit analysis in the field of security of supply and, secondly, to apply that framework with regard to a number of measures directed at security of energy supply which could be taken by the government of the Netherlands.

This introductory chapter explores the field of research. Section 1.2 analyses the sources of disturbances on energy markets. The next section focuses on the role of governments in securing the supply of energy. These two sections deliver the two key elements for the analytical framework, which is introduced in section 1.4. Those key elements are uncertainty and market failure. After having discussed the main components of the framework, the chapter proceeds with an application of the framework. Section 1.5 depicts the policy options which are chosen as subjects of the cost-benefit analysis. The chapter ends with an overview of the structure of the report.

1.2 Sources of disturbances on energy markets

Disturbances of energy markets could originate from different sources, such as technical failures, political restrictions on the supply side, and sharp increases in demand as a result of unexpected high economic growth or extreme weather conditions (see Appendix 1).

Risks on the oil market are strongly related to the supply side. In the short term, geo-political events and the behaviour of members of the OPEC cartel determine the price of oil. In the last few years, mainly due to these factors, the spot price of the Brent has shown great volatility, with a monthly average price ranging between 10 and 33 dollars per barrel. The major uncertainty in the medium term concerns the internal political situation in Saudi Arabia and other major Gulf countries (OIES, 2003; see Appendix 2). Social upheaval in these countries could lead to a dramatic reduction in oil production, resulting in a strong and relatively long-lasting rise in the price of oil. In the long-term, depletion of oil fields will affect the oil market and, hence, the price of oil.

The major risk on the natural gas market in the short term is related to weather conditions (IEA, 1995). In the past, very cold winter days caused several disturbances. In the winter of 1992/93, for instance, Canada experienced severe problems with the supply of natural gas. More recently in the Netherlands, the pipeline system was unable to deliver the gas demanded by end-users as a result of exceptionally low temperatures. The use of gas from storage facilities, however, prevented the occurrence of disruptions. In the long-term, disturbances on the natural gas market could stem from increasing market power of a few producers. After all, supply from the United Kingdom and the Netherlands will probably cease within the next few decades, making the European Union more dependent on gas from Russia, the Middle East and Northern Africa.

It appears that the coal market does not face significant risks, mainly due to an even distribution of abundant reserves over the world (OIES, 2003). The coal market is a highly competitive market, with prices strongly related to marginal costs of supply. The uranium market shows more uncertainties, especially in the medium term, when secondary resources will be depleted (OIES, 2003). The economic effects of these risks will be rather modest due to the small contribution of uranium to the generation of electricity in the Netherlands, although the Netherlands import some electricity produced by nuclear units. Risks and policies towards the coal market and the uranium market are, therefore, not within the venue of this analysis.

As electricity is a secondary energy carrier, risks on this market are, by definition, related not to depletion but to production. The most significant risk on this market concerns the level of investments in production and transportation capacity (Green, 2003). Due to the impossibility of storage of electricity, demand for this product should always be equal to production at any time. The demand for electricity shows, however, a large volatility from hour to hour, from day to day and from season to season. The capacity of production and transportation must, therefore, be sufficient to satisfy the largest peak in demand. The profitability of capacity that is hardly used is, usually, too low for private firms. Consequently, the margin between production capacity and peak demand has decreased in countries with liberalised markets, raising the probability of price hikes and physical shortages in cases of extremely high demand or disruptions on the supply side.

Within networks, risks are related to the functioning of the grid. Disturbances within the grid could follow from technical incidents (in the short term) or from insufficient investments in maintenance and extension of the grid.

The degree of flexibility of agents to react to shocks within demand or supply determines the economic consequences of the latter. In the short term, both supply and demand are rather inflexible to adapt to renewed market circumstances. At the supply side, investments in capacity for production, storage and transportation have a lead-time varying from one year (e.g. small gas-fired power plants) to more than a decade (e.g. international natural gas pipelines). Consumption of energy in the residential sector shows the greatest inflexibility in the short term, while several types of power plants, for instance, have relatively cost-effective opportunities to switch among fuels. The longer the time frame is, the greater the possibilities of both energy producers and consumers to implement adaptations.

1.3 Security of energy supply and role of governments

What is meant by 'securing the supply of energy'? According to politicians, it is guaranteeing a stable supply of energy at an 'affordable' price, no matter what the circumstances are (see e.g. COM, 2000). From an economic point of view, however, the concept of security of supply is less clear. In general economic terms, energy security refers to "the loss of welfare that may occur as the result of a change in price or availability of energy" (Bohi et al., 1996). However, markets will always show variations in supply and demand, and, hence, in prices. A reduction in supply allows prices to rise and demand to fall, while an upward shift in demand raises prices and, hence, supply. Economists who adhere to the value of free markets would argue "queues and visible physical shortage only appear when governments attempt to intervene with the market by fixing prices below the market clearing level or by introducing quantitative rationing" (OIES, 2003). However, shortages could also result from market failures.

The issue of security of supply can, therefore, be viewed as a problem of externalities: costs or benefits that are ignored by markets in the determination of prices. If private costs are smaller than social costs, consumption or production will be higher than the social optimum. Bohi et al. (1996) view the relationship between oil consumption and imports, on the one hand, and the market power of oil-producing countries, on the other, as a clear example of such a negative externality. A positive externality arises if social benefits exceed private benefits, resulting in a level of production below the socially optimum level. A clear example of such a positive externality is that profit-maximising firms probably do not invest in excess production capacity, which will rarely be used (Helm, et al., 1988).

As a general economic principle, governments should intervene with security of supply only if energy markets fail to realise efficient solutions (Bohi et al., 1996). Market failures exist if economic agents do not take into account all costs of price shocks and physical shortages to society. As a consequence, individual agents invest less in flexibility or consume more than would be optimal from a societal point of view. In order to require sufficient flexibility, governments could give private firms additional incentives or could themselves invest in, for instance, spare production capacity. Introduction of capacity markets is one option to encourage investments by private firms in peak capacity. In such a market, private firms receive a reward for investments in capacity, as well as a reward for the delivery of energy (see e.g. Barrera, et al., 2003). Another option is the introduction of capacity subscriptions, by which consumers can buy capacity and, hence, security of supply (see e.g. Doorman, 2003).

On the other hand, if regulatory failure exists, intervention by governments decreases welfare. In general, regulatory failures result from insufficient information within the government, diverging objectives between government and private firms, and non-welfare-maximising objectives of the government (Helm et al., 1988). Robinson (1993) emphasises the third source of regulatory failures by stating that those failures arise “from pursuit of short-term political interests, supported by the producer pressure groups which thrive and lobby government”.

Concluding, governmental intervention is justified, from an economic perspective, only if market failures are large, and if they are larger than the regulatory failures. The role of governments in securing supply of energy, therefore, demands a careful analysis.

1.4 Framework of analysis

From the above sections, it follows that *uncertainty* and *market failure* are the two key components in appraising governmental actions in the field of security of energy supply. The first component (uncertainty) tells us that the (expected) efficiency of measures in this field depends on the (expected) occurrence of disturbance. A security of supply measure is only profitable if a disturbance happens occasionally. This fact has two implications. The first one is that measures which are profitable without the occurrence of a disturbance do not belong to the category of security of supply measures. To illustrate this: an investment in strategic oil stocks is only efficient if the oil price rises sometimes, while the encouragement of energy-saving could be efficient without any change in energy prices, albeit a rising price would enhance the efficiency of that measure. The second implication is that measures which do belong to the above category should always be assessed against the background of disruptions on the energy market at stake.

The second component (market failure) says that governments should only take security of supply measures if market parties do not take into account all costs and benefits of that measure. This implies that in the cost-benefit analysis explicit attention should be given to private cost and benefits, on the one hand, and social costs and benefits on the other. Besides the welfare effects, distribution effects should also be made explicit in the analysis.

In order to cope with the uncertainty element, we construct risk scenarios based on a profound analysis of risks on energy markets. Risk scenarios are scenarios in which certain disturbances occur on one or more energy markets. Afterwards, we assess costs and benefits of policy options against such a scenario. In order to cope with the market failure element, we analyse not only the direct effects of a measure, but also the indirect effects and external effects.

Once we have determined the costs and benefits of the project alternative, we compute the break-even frequency of the risk scenario and the policy option. The break-even frequency is defined as the minimal frequency at which the defined disturbance should occur in order to make the net benefits of the policy option exactly zero. Finally, we compare the break-even frequency of the disturbance with the expected probability of occurrence following from the above-mentioned thorough analysis of energy markets.

The results of the analysis indicate which policy options contribute to welfare and which do not. Whether the government should implement options in the first category remains a political decision that involves taking into account other aspects, including distribution effects.

1.5 Selection of policy options

The framework developed in this report is applied to a number of policy options which could be taken by the government of the Netherlands. In general, governments have several options to cope with security of energy supply. These options can be distinguished in three major groups of points of application: a) prevention of disturbances, b) reduction of vulnerability, and c) mitigation of adverse effects of disturbances.

The first group consists of all those measures directed at preventing shocks in demand or supply. National governments have limited opportunities to prevent crises on the international energy markets. Therefore, most of the current policy measures focus on the reduction of the vulnerability of the economy to crises on energy markets. Generally, this vulnerability depends on 1) the energy-intensity of the economy (i.e. the use of energy per unit produced), 2) the relative importance of a certain energy carrier in the total use of energy (e.g. the share of oil in a nation’s total energy consumption) and 3) the ability to adapt the level and the structure of energy consumption (e.g. by means of energy-saving and fuel flexibility).

Table 1.1 Risks on energy markets and policy options subject of analysis

Risks on energy markets	Policy option *(point of application)*
Oil market:	
Temporary disruption of supply	Extending the oil emergency stocks *(= prevention of disturbance)*
Effective cartel behaviour of oil producers	Subsidisation of biofuels in the transport and chemical sector *(= reduction of vulnerability)*
Natural gas market:	
Insufficient flexibility of the gas system to meet shocks in demand and supply	Extending the lifetime of Groningen as a swing supplier *(= prevention of disturbance)*
Effective cartel behaviour of gas producers	Reducing dependency on gas by encouraging substitution within the power sector towards coal, nuclear or wind *(= reduction of vulnerability)*
Electricity market:	
Insufficient production capacity to meet peak demand	Introducing a capacity market giving private firms incentives to invest in peak capacity *(= prevention of disturbance)*
Imperfect competition resulting in high prices for power	Encouraging saving of electricity by raising tariffs of the energy tax *(= reduction of vulnerability)*
Electricity network:	
Abuse of local or regional market power due to lack of independence of networks	Completely unbundling networks from supply and generation or merging of transmission networks with TenneT *(= prevention of disturbance)*
Technical failures of networks	Including reliability indicators in tariff regulation*(= prevention of disturbance)*

The third and final group consists of measures mitigating adverse effects of disturbances. This type of policy is, by definition, highly reactive in nature and may consist of rationing and various types of socio-economic measures, such as offering financial support to sectors facing strong increases in their energy costs. A few years ago, several European countries decreased the levies on petrol in order to compensate the cargo transport sector for the, then, high oil prices.

As the number of conceivable policy options is large, a selection had to be made. In close co-operation with the Ministry of Economic Affairs and the research institute CE, we defined a shopping list of options that could be useful (see appendix 3). We selected a set of options covering a broad range of opportunities to deal with the security of energy supply (see table 1.1). The key criterion for the selection is methodological: in order to develop and demonstrate a framework of cost-benefit analysis we need to have different types of policy measures directed at different kinds of risks on energy markets. A caveat of this research is, therefore, that it does not answer the question which policy option is the most efficient. In order to answer that question, far more research should be conducted. Moreover, we only look into the effects of a policy option given a defined design. This implies that we do not search for the optimal design of a policy option, although we do compare the consequences of some alternative designs.

The options chosen vary from government investments in strategic oil stocks to financial incentives for consumers to reduce their consumption of electricity. For each market, we analyse a policy measure directed at preventing a disturbance and a measure directed at reducing the vulnerability of the economy. In addition, the set of options comprises several types of governmental action, including subsidies, taxation, government investments, regulation and voluntary agreements with other parties involved. Moreover, the selection includes measures meant to address risks on all three major energy markets – oil, natural gas, and electricity. As a consequence, the cost-benefit analysis of this set of policy options will give a great deal of insight into the costs and benefits of policies to cope with security of supply. In addition, the broad scope of the options to be analysed enables us to assess the capabilities of our framework as a tool for cost-benefit analysis.

It will be clear that some policy measures may actually be primarily aimed at other goals, in particular environmental goals, but can also be beneficial to security of supply. Policies aimed at reducing the demand for energy, for instance, are often initiated as climate policy measures, but they also reduce the dependence on fossil fuels. Policy options to be analysed here are obviously treated as policies aimed at security of supply. Therefore, effects on goals of other policies are treated as side-effects of the policy options. In the case of environmental effects, which will often be the type of side-effects we encounter, we will treat them as (avoided) external costs.

1.6 Structure of the report

Chapter 2 describes the theoretical framework of the cost benefit analysis. The cost-benefit analysis is conducted at the level of separate markets, namely the oil market (chapter 3), the natural gas market (chapter 4), the electricity market (chapter 5), and the electricity networks (chapter 6). Each chapter follows the same structure of analysis.

According to that structure, the analysis begins by exploring current and future risks. Which disturbances on the various markets can be expected, what could be the magnitude of those disturbances and which probability should be attributed to those risks? This part in each chapter ends by defining specific crises on the separate markets.

The next step consists of analysing the opportunities for government intervention. National and supra-national governments have formulated policies to cope with these risks. After giving a concise overview of the whole range of measures, this section ends by defining specific policy measures which could be directed towards the crises defined earlier.

The final step is the determination of the costs and benefits of the defined policy measures. What would be the economic consequences of the defined crises if no additional policy measures were taken? And: what would be the consequences if these policy measures were taken?

Chapter 7 summarises the main results, mentions a few caveats of the research and describes the key conclusions.

2 Framework of cost-benefit analysis

2.1 Introduction

This chapter describes the framework for a cost-benefit analysis of security of energy supply. This framework is primarily based on the general framework for executing a cost benefit analysis of infrastructure projects (section 2.2). Since policies directed at security of energy supply differ in several aspects from infrastructure projects, we adjusted that general framework. A major difference is that policies directed at supply security refer to uncertain future events. As a consequence, expected efficiency of policies depends on the expected probability of those events. As probabilities of future shocks within energy markets are nearly impossible to determine, we choose to compute break-even frequencies (section 2.3).

We use long-term scenarios as background for the analysis (section 2.4). Those scenarios refer to both the international and the national economy, and to the international energy markets. The probability of certain disturbances and specific policy measures depend on developments in other parts of the economy. Therefore, the policy options mentioned in chapter 1 will be analysed against different scenarios.

In order to quantify the effects of the measures and disturbances, we use several models (section 2.5). The direct effects are mainly assessed by various models of energy markets. A macroeconomic model is used to assess indirect effects, while external effects are quantified by using shadow prices of non-market effects such as changes in emissions to the environment.

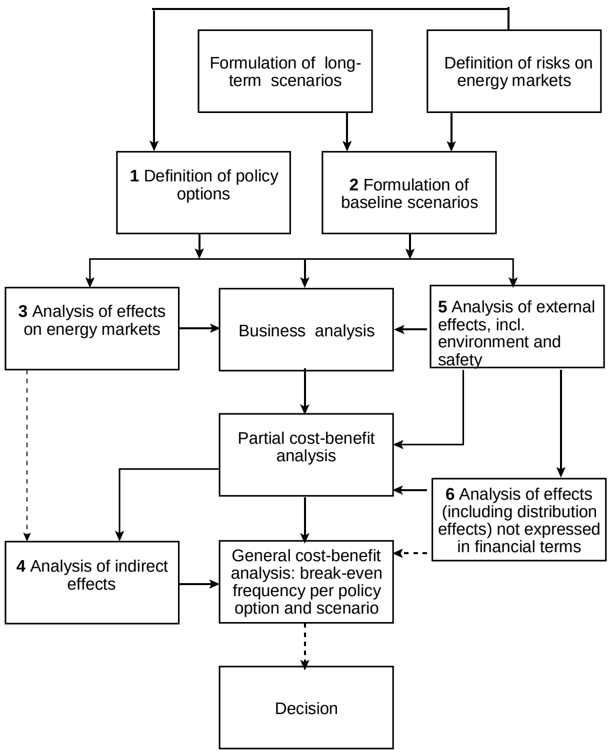
This chapter ends with section 2.6 offering an overview of the steps by which the framework can be applied in specific cases. These steps form the structure of the following chapters in which the cost and benefits of the above-mentioned policy options will be presented.

2.2 General framework: uncertainty and market failure

Eijgenraam et al. (2000) developed a framework for cost benefit analysis of infrastructure projects. We use this framework, adjusting it to the purpose of our analysis. The framework is well suited for the analysis of market failure, as it offers the calculation of direct effects, indirect effects, external effects, and distribution effect. The framework needs, however, an adaptation to cope with uncertainty, the other key element mentioned in chapter 1. Suppose we were to assess the viability of a policy option that would lower the economic damage of an (long-lasting) oil crisis, e.g. the formation of strategic oil stocks. How would we evaluate such a measure?

Costs and benefits of a project (or policy) are generally assessed by comparing a world with the project (or policy) to a world without it (the no-project alternative). The difference between these alternatives is analysed against the background of one or several economic scenarios or base-lines. In the case of supply security, this would not be a useful approach, since most types of supply interruptions have a low probability.[1] Consider again the example of oil stock formation. Such a policy option would be very viable if an oil crisis occurred, and totally unviable if it did not. A single base-line for our analysis would focus on a situation where no interruptions occur and policy would almost by definition be uneconomic. Therefore, we use several scenarios as a set of base-lines. Figure 2.1 graphically depicts the adjusted framework.

Figure 2.1 Framework of a cost-benefit analysis of policy measures aiming at security of energy supply



The first step is the definition of project alternatives and the no-project alternative (box 1). Before analysing these alternatives, base-line scenarios, based on long-term economic scenarios and predefined risk, are established (box 2). Afterwards, the cost benefit analysis can begin. In theory, it consist of an analysis of energy market effects (box 3), calculation of indirect effects using a macroeconomic analysis (box 4), calculation of external effects (box 5), and the determination of distribution effects (box 6). Those effects together constitute the entire costs and benefits of the project alternative compared to the no-project alternative. These results can form an input in the decision-making process.

[1] Small scale electricity outages are an exception here.

The distinction between direct and indirect effects requires some attention. Direct effects are defined as those effects following directly from the policy measure. More specifically, we define direct effects as the effects of a policy measure in the specific energy market it is directed towards. These effects may expand to other markets. Consider a price increase in the electricity market. The increase affects the relative price of production factors, changing the cost price of all products for which electricity is used in the production process, as well as the use of other production factors. This may in turn affect relative prices of both consumer goods and the other production factors and so on. Some of the indirect effects are merely redistributions of welfare, or transferred direct effects.

Indirect effects may be actual welfare effects as well, for two reasons (Eijgenraam et al., 2000). First, distribution effects may cross borders, causing national welfare effects. Second, distribution effects may stimulate (or hinder) economic activity in markets that are subject to market failure. Let us again consider the case of electricity prices to illustrate the second point. If all markets were perfect markets, the demand elasticity would reflect all the continued effects of a price increase, so that the direct effect would exactly equal the effect on the economy as a whole, i.e. the indirect effect would be zero. This implies that if we observe a non-zero indirect effect, we may assume the presence of a market failure.[2]

Definition of direct and indirect effects:

Direct effects are the effects of a policy measure in the specific energy market it is directed at.
Indirect effects are effects that do not relate directly to a policy measure, but follow from its direct effects.

We calculate indirect effects in this report using CPB's general equilibrium model Athena. Athena predicts the effect of a policy measure or a security of supply crisis for the national economy as a whole. The difference between the total effect and the direct effect then constitutes the indirect effect, which may be either positive or negative.

Disruptions of energy supply come at low frequencies and high costs. This implies that, in order to assess the effects of policies aimed at different types of energy crises, we need to build scenarios around a fairly large number of possible crises, each of which has a small but unknown probability. The uncertainty obstructs the possibility of computing probabilistic outcomes.

[2] The entire line of reason holds for government failure as well.

As an alternative, we compute 'if-then' outcomes. These outcomes are then used to compute 'break-even frequencies', the (decrease in a) expected frequency of a certain scenario at which net benefits are exactly zero. In the example of strategic oils stocks: the break-even frequency is the frequency of an oil market crisis at which the costs of maintaining stocks equal the costs of the damage prevented in case of such a crisis. Section 2.3 deals with the mathematics of calculating this frequency.

Another adaptation of the general framework that has to be implemented refers to the definition of the no-project-alternative. This term seems to imply that the government does not act at all. In a cost benefit analysis, an implicit other action exists, being that the money is spent on some other project (or goods, or transfer). This aspect is brought into the cost benefit analysis through the real interest rate, reflecting a time preference. In the special case we are dealing with here, this may not be sufficient. The 'no-project-alternative' does imply a passive government in terms of structural policies aimed at preventing crises or trying to diminish the economy's vulnerability to them. Let us return to the example mentioned before. If an oil crisis occurs and no strategic stocks are available (the no-project-alternative), government will still have the option to reduce the damage on an ad-hoc basis, for instance through issuing petrol coupons or by granting tax cuts to the transport sector. We could take reactive policies into account if it is reasonably possible to define them and quantify their effects. They would then be attached to those base-line scenarios that include a crisis in energy supply. In the analyses conducted in this report, we ignore reactive policies, focusing on costs and benefits of specific policy measures.

2.3 Computation of break-even frequencies

As mentioned above, the outcomes of our analysis will take the form of break-even frequencies: an expected frequency of a crisis at which a policy option breaks even. Reactive policies are considered as the 'no-policy-option', so we do not need to compute a break-even frequency. After all, reactive policies are only deployed after a crisis occurs, so that the frequency is no longer uncertain.

Definition of break-even frequency:

The break-even frequency is defined as the frequency of occurrence of a predefined crisis at which the present value of the costs of the policy option exactly equal the present value of its benefits.

Consider a policy option with cost c_t at time period t, so that, with a discount rate r, the present value of policy costs over time span T are defined as below:

$$C_{PV} = \sum_{t=1}^{T} \frac{c_t}{(1+r)^t} \tag{2.1}$$

Benefits may be measured as a fractional decrease ($b_{i,t}$) in damage caused by crisis i, occurring at time period t ($d_{i,t}$), occurring with an expected frequency of $P_{i,t}$:

$$B_{i,t} = \sum_{t=1}^{T} P_{i,t} \frac{b_{i,t} d_{i,t}}{(1+r)^t} \tag{2.2}$$

Parameter $b_{i,t}$ reflects whether the policy option prevents the crisis altogether ($b_{i,t}$ =1), or only mollifies its effects ($0<b_{i,t}<1$). The expected frequency of a crisis reveals no information on the timing of its occurrence. As we have no information on timing, our best guess would be that the occurrence in any year is as likely as in any other year. This is equivalent to a crisis in the median year of the period under consideration (i.e. $t=T/2$). An earlier (later) crisis increases (decreases) the benefits of the policy option, rendering the policy option more (less) attractive. We simplify equation (2.2) to:

$$B_i = TP_i \frac{b_i d_i}{(1+r)^{T/2}} \tag{2.3}$$

Implicitly assuming that occurrence of crises is distributed uniformly over the period of analysis. To compute the break-even frequency of a policy aimed at crisis i, we equate costs and benefits and reshuffle to find a frequency:

$$P_i = \sum_{t=1}^{T} \frac{c_t}{(1+r)^t} \Bigg/ T \frac{b_i d_i}{(1+r)^{T/2}} \tag{2.4}$$

Let us return again to the example of strategic oil stocks presented earlier. Suppose that our analysis reveals that the present value of the benefits of such a policy would be 50 billion euro if such a crisis were to occur and zero otherwise. Furthermore, suppose we find that the present value of the average annual costs of the policy option amount to 500 million euro, irrespective of the occurrence of an oil crisis. These outcomes imply that the policy option is economically viable if the expected frequency of a long-lasting oil crisis exceeds once every 100 years. In other words, the break-even frequency for this hypothetical policy option with respect to a long-lasting oil crisis is once every century.

In some cases, the time span in which a policy option will generate benefits is clearly defined. Consider for instance the case of a cap on the Groningen field, postponing the end of the lifetime of the swing function of the field from 2019 to 2023. Such a policy will only have an effect if a crisis occurs between 2019 and 2023. A crisis occurring before 2019 will be absorbed anyway, whereas the policy option will not help against a crisis occurring after 2023. For a case such as this, we may adjust the break-even frequency by multiplying both sides of the equation (2.3) by *T'*, the number of years that the policy will have effect:

$$P_i \, T' = \frac{T'}{T} \sum_{t=1}^{T} \frac{c_t}{(1+r)^t} \Bigg/ \frac{b_i d_i}{(1+r)^{T/2}} \tag{2.5}$$

The equation now reflects the adjusted break-even frequency, expressing how often in the pre-defined time period a crisis will have to occur to equal costs and benefits of the policy option.

Definition of adjusted break-even frequency:

The adjusted break-even frequency is defined as the number of occurrences of a pre-defined crisis within a pre-defined time period at which the present value of the costs of the policy option exactly equal its benefits.

Both the break-even frequency and its adjusted counterpart will *ceteris paribus* be higher if the costs of the project are higher. This implies that a policy with high cost 'needs' a higher expected frequency to be viable. If on the other hand the damage of a crisis ($d_{i,t}$) is larger, a lower break-even frequency suffices to make the project viable. Likewise, if a policy foregoes a larger fraction of the damage caused by a crisis i.e. ($b_{i,t}$ is large), a smaller expected frequency is sufficient for the policy to be economically viable.

Obviously, break-even frequencies will have to be confronted with expectations on the frequencies of possible crises. Although a solid numerical outcome is beyond reasonable expectations, the assessment of risks within each market will give some insight into the probability of incidence. One should keep in mind here that non-linearity's may exist. The effect of an event of twice the extent of another event may be more than twice as severe and, therefore, justify more than twice as much costs to prevent it.

2.4 Linking long-term scenarios, risks on energy markets and policy options

The definition of the base-line scenarios (box 2 in Figure 2.1) is based on the long-term scenarios and the assessment of risks. The long-term scenarios consist of conceivable time-paths of energy markets and the macro-economy in the long-term without paying attention to shocks in demand or supply.

Long-term scenarios of energy markets

Which factors will determine the future development of energy consumption, production and prices? In order to answer questions as these, CPB and RIVM developed four long-term scenarios for the international energy markets (Bollen et al. 2004). Three leading issues determine our thinking about energy in the future: a) economic growth, b) environmental policies and c) security of supply. The scenarios explore the possible developments in these key driving forces behind energy markets.

The scenarios are called 'Strong Europe', 'Transatlantic Market', 'Regional Communities' and 'Global Economy'. The first and the last one show a globalised world while regional fragmentation is characteristic of the other two scenarios. Environment and equity are major issues in 'Strong Europe' and 'Regional Communities' while in 'Transatlantic Market' and 'Global Economy' government policies are primarily directed at improving economic efficiency.

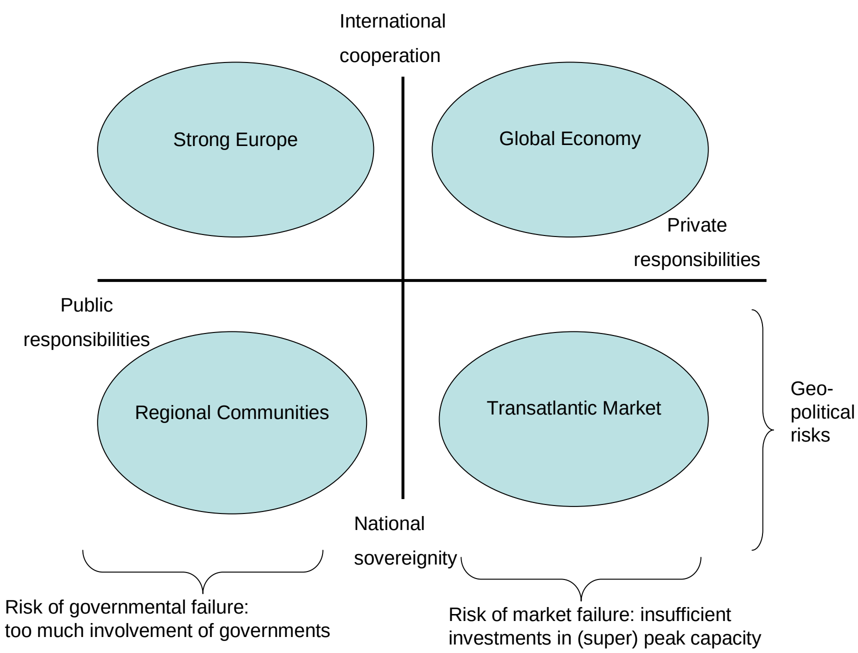
The scenarios can be linked to long-term scenarios developed by IPCC SRES. Strong Europe fits in the B1-scenario of IPCC, Regional Communities in the B2-scenario and 'Global Economy' in the A1-scenario. Close relationships also exist with scenarios developed by other international institutions. The scenarios differ, however, in regional detail and time horizon. We focus on Europe and end in 2040.

One of the key conclusions of this scenario study is that, in the long term, resource scarcity will probably not have a major influence on energy markets. Although reserves of conventional oil in all regions, including the Middle East could near their depletion before 2040, in particular in a scenario with a high economic growth, the global supply of oil will likely be secured by non-conventional sources. In addition, a structural increase of the price of oil is not highly probable due to demand responses which would be induced by such an increase. As a consequence, we expect that the price of oil (in real terms) will remain fairly flat. This conclusion holds to a greater extent for the natural gas market, as global resources are abundant here.
Therefore, we believe that the security of energy supply will hardly be threatened by the risk of depletion of fossil energy carriers in the next decades.

A major source of risk to European energy markets could be the growing dependency on non-European suppliers. Europe will become more and more dependent on foreign (in particular Russian and Middle Eastern) sources of natural gas. In all scenarios, the dependency on imports grows to at least 70%. Consequently, the natural gas market could become more vulnerable to geo-political developments.

The box 'Long-term scenarios of energy markets' summarises the major characteristics of these scenarios. By adding shocks to these scenarios, crisis scenarios emerge. Crises on energy markets result from accumulations of events. The probability of a particular event depends on developments within other aspects of society. In other words, the probability of a future event and, hence, a future crisis depends on the characteristics of a scenario. As a consequence, in each scenario a specific crisis is more conceivable than other crises. The same holds true for a specific policy measure.

Figure 2.2 Scenarios and risks



In Strong Europe and Regional Communities, governments are inclined to be heavily involved in markets. As a consequence, risks in these scenarios are mainly unrelated to market disturbances, but to too much government involvement (see figure 2.2). In the other two scenarios, investments in (super) peak capacity could be less than the socially optimal level. The scenarios in which international co-operation is not well developed (Regional Communities and Transatlantic Market), energy markets have a relatively high chance of disturbances due to geo-political events.

Table 2.1 gives an overview of the relationship between scenarios and risks on the one hand, and policy measures on the other. In Transatlantic Market, collusion among producers of natural gas and oil is a serious threat to the Western economies. In Global Economy, where decisions by market parties are dominant, market failures regarding investments in peak capacity (electricity) and flexibility (gas) are very conceivable. In Regional Communities, the internal electricity market bears a high risk of imperfect competition. In order to cope with that risk, the national governments would prefer raising energy taxes as that measure also generates environmental benefits. Raising taxes on energy would be aimed at decreasing the vulnerability to shocks rather than preventing those shocks.

Table 2.1 Linking risks on energy markets, scenarios and policy options

Links on energy markets	Strong Europe	Transatlantic Market	Regional Communities	Global Economy
Oil market:				
Temporary disruption within supply	Investing by governments in strategic oil stocks			
Effective cartel behaviour of oil producers		Subsidising use of biofuels in the transport and chemical sectors		
Natural gas market:				
Insufficient flexibility of the gas system to meet extreme shocks in demand				Extending the lifetime of the Groningen-field as a swing supplier
Effective cartel behaviour of gas producers		Reducing dependency on gas by encouraging substitution within power sector		
Electricity market:				
Insufficient production capacity to meet super peak demand				Introducing a capacity market giving private firms incentives to invest in super peak capacity
Imperfect competition resulting in high prices of electricity			Encouraging electricity saving by raising tariffs of the energy tax	
Electricity network:				
Abuse of local or regional market power due to lack of independence of networks	Completely unbundling networks from supply and generation or merging with TenneT *(= prevention of disturbance)*			
Technical failures of networks		Including reliability indicators in tariff regulation		

A temporary disruption within production or transport of oil could happen in any scenario, but only in Strong Europe an internationally coordinated policy regarding strategic oil stocks is highly probable. Technical failures within the power network could occur in any scenario, but the scenarios differ in the kind of policy measures which are most probable. In a scenario such as Regional Communities, governments would prefer government regulation, for instance, by imposing reliability standards, while in a scenario such as Transatlantic Market, market-based solutions, such as a price quality regulation system, would be chosen. The danger of execution of market power due to independence of networks is largest in a scenario with relatively weak competition policies, such as Strong Europe.

2.5 Quantification of direct, indirect, external and distribution effects

All the numbered items in figure 2.2 depict quantitative inputs for the cost-benefit analysis. Our next question is how these inputs can be achieved?

The direct energy effects (box 3 in figure 2.1), as well as the external effects (box 5), follow from the models of the various energy markets. The box ‘Models’ offers a concise overview of these models. The outcomes of these models are defined in terms of energy prices and volumes.

Figure 2.2 suggests two possibilities for final outcomes: break-even frequencies may either be computed from the partial or the general cost benefit analysis. Behind these two possibilities lies a split in approaches, based on the economic impact of the type of crisis a policy is aimed at.

Models used in the cost-benefit analysis

The models which are used in the project consist of two groups, energy market models and macroeconomic models.

Energy market models are used to assess direct effect of disturbances within energy supply on energy demand and prices. We use separate models for analysing the global oil market, the European natural gas market, and the European electricity market. The third is described briefly in Appendix 4. Each of these models is a partial-equilibrium oligopoly model of the market at stake.

The indirect, macroeconomic consequences of these changes in prices are analysed using Athena, a dynamic multi-sector model for the Dutch economy. The model describes, besides the important institutional sectors, 20 branches of industry. The production structure of the branches is characterised by nested CES functions which allows for price substitution between different material and primary production factors. Firms maximise profits and charge a mark-up over marginal costs and the model allows for entry and exit of firms. The model explicitly distinguishes between the short-term cost function and the long-term cost function by using shadow costs for the fixed factors. Athena assumes monopolistic competition on all product markets and contrasts, in this respect, with other related models.

Many energy delivery interruptions, mainly those with a technical cause, happen on a fairly small regional scale and last a short time. A 30-minute blackout in a city of 300.000 people obviously requires a different approach than a doubling of the oil price for a full year. The effects of small interruptions (and, therefore, the effects of policies aimed at preventing them or mitigating their impact) may be quantified directly through case studies of similar events, whereas larger crises require a more structural approach. In other words, the indirect effects of these small interruptions can be ignored. The same holds for large physical disruptions (such as the power shortages in North America and in Italy in the summer of 2003) as such events usually take very short periods (such as one or two days).

If the economic effects are likely to be larger, for instance, because feedback mechanisms in the economy play a role, we use ATHENA, a general equilibrium model of the Dutch economy, to compute indirect effects on the economy (box 4 in figure 2.1). We measure the total effect on the economy by Net National Income as this quantity comprises effects on domestic value added as well as balance of trade effects. Athena is also helpful in assessing distribution effects, for instance, between companies and households, as well as between economic sectors (see box 6 in figure 2.1). The possible existence of distribution effects may imply that some benefit more from supply security policy than others.

2.6 Discounting and the appraisal of risk

Comparing costs and benefits at different points in time requires discounting. Given that money has a time value as well, we need to correct for the discrepancy in timing of costs and benefits, using a discount rate. The discount rate reflects both the time value of money and the valuation of risks.

A key element in any cost benefit analysis project is the appraisal of uncertainty related to future costs and benefits of a policy measure. As this uncertainty differs among various measures, every project analysis should involve a risk assessment. The result of that assessment can be used to define the so called ‘risk premium’ in discounting future costs and benefits.

In the Netherlands, but also in many other countries, the official risk-free rate is determined at 4% (Ministry of Finance, 2003). This rate is the average rate of return to government bonds over the past 200 years (Newell et al., 2004). The governmental commission on risk appraisal (‘Commissie Risicowaardering’, Ministry of Finance, 2003) recommends the use of the following rules of thumb:

- Compare the project to a similar project in the private sector. If available, use the discount rate of that project.
- If no such project is available, check whether any systematic risk is involved in the project. A systematic risk is the risk which is systematically correlated to the level of national income and, therefore, not can be eliminated by spreading this risk across the economy. If no systematic risks are attached to the project, use the risk-free discount rate.
- If the project involves systematic risks, (i.e. future cash flows associated to the project depend on uncertain factors, such as economic growth), try to establish what risk premium is associated with the risk and add it to the risk-free discount rate.
- If it is impossible to establish a risk premium associated with the particular risk, use the central value of 3% as risk premium. As a result, the discount rate amounts to 7%. This percentage is approximately equal to the real rate of return to investments in large companies over the period 1926-1990, and is also advised by the US Office of Management and Budget for standard cost-benefit analysis (Newell et al., 2004).

In all projects considered in our analysis, except one, we use 7% as the discount rate in the base case. In order to assess the impact of the discount rate, all these projects are also analysed using 5% and 10%. The exception is the case of substitution of gas-fired plants. This policy option is comparable to a private project of investment in generation capacity. In this project, we use the usual discount rate of private investments in electricity generating capacity (10%). In all the other projects, similar private projects do not exist. For instance, private oil companies do not stock oil in other to influence market outcomes (although they do in order to have working stocks), and private gas firms do not voluntarily limit current production in order to receive highly uncertain benefits in the very long run. In each of these projects, systematic risks exist. After all, the benefits of the policies depend not only on the occurrence of crises, but also on the magnitude of damage prevented. The larger an economy, the larger the damage a disruption on an energy market could cause, and, hence, the larger the potential benefit of a policy option aiming at preventing that damage.

2.7 Summary: the framework in six steps

Summarising the above framework, six steps emerge:

1. Definition of a crisis on a energy market
   The first step consists of defining conceivable and probable disruptions on the energy market. As probability distributions are not available in most cases, these disruptions should be defined in terms of crisis scenarios. The major attributes of the definition are magnitude and duration of the disruption.

2. Definition of a policy measure

   In the next step, the appropriate policy measure has to be defined. The design of the measure is its major characteristic.

3. Calculation of costs of the measure in a disturbance-free scenario

   By definition, security of supply measures incur costs no matter whether a disturbance occurs or not. These costs, therefore, can be assessed against the baseline scenario, which is a disturbance-free scenario. The costs have to be distinguished in direct costs, indirect costs, and external costs. Besides this, the distribution of the costs has to be assessed.

4. Calculation of benefits of the measure in a crisis scenario

   The benefits of a security of supply measure depend on the occurrence of a disturbance on an energy market. Therefore, these benefits can only be appraised against the occurrence of such disruption. The benefits of a measure follow from a reduction of the costs incurred by the disruption. Just as the costs, the benefits have to be distinguished in direct benefits, indirect benefits and external benefits. In addition, distribution effects should be determined.

5. Calculation of the break-even-frequency and comparing it with evidence on risks

   Both costs and benefits should be discounted, using the appropriate rate of discount, and expressed in average annual values. If the discounted benefit of a crisis is divided by the discounted average annual costs, the break-even frequency appears. This frequency says in how many years the defined disturbance should occur at least once to make the policy measure economically viable.

6. Sensitivity analysis

   In order to assess the vulnerability of the results of step 5 to assumptions made, a sensitivity analysis has to be conducted. In this final step, costs and benefits should be calculated using different values for key assumptions or a different long-term scenario as a background for the analysis.

3 Oil market

3.1 Introduction

Oil is still the most important primary energy source on a global scale, although its share in total consumption has declined. Transport and chemical processes are activities that are highly dependent on availability and price of crude oil. It is not surprising then that the several supply disruptions and the accompanying price increases during the last five decades received due attention. Governments implemented several kinds of security of supply measures, both on national and on international level.

This chapter assesses the welfare effects of two types of policy measures directed at risks on the oil market. This assessment commences with a concise analysis of disruptive events that occurred in the past and that could occur on the oil market in the future. Next, policy options of governments to cope with these risks are explored. Then we arrive at the core of this chapter: the cost-benefit analysis of two policy options, notably the expansion of strategic oil stocks and the subsidisation of the use of biomass in transport and chemical sector. The chapter ends with a sensitivity analysis and the formulation of the conclusions.

3.2 Analysis of risks

3.2.1 Historical evidence on risks

During the second half of the last century, the world oil market showed several supply disruptions. The various disruptions, together with their duration and extent of the loss, are represented in table 3.1. “Gross loss” is the volume of oil that was being produced in the disrupted countries and that was no longer available.[3]

In the last half of the former century, more than 10 serious disruptions on the oil market occurred (see table 3.1). These disruptions were primarily caused by political events in the Middle East. The duration of the disruptions varied between 2 months (the Six-day War between Israel and the Arabic countries in 1967) and the OPEC Action Ryadh Pact which reduced the supply of oil for approximately one year. The magnitude of the disruptions varied between 0.6 million barrels a day (Nationalisation of oil firms in Algeria in 1971) and 4.6 million barrels a day (the first Gulf crisis in 1990).

[3] To improve the estimation of impacts of an oil supply disruption, one should take account of additional production by countries not affected by the disruption. In these countries, production would increase because of a higher oil price. This effect appears, however, only in the long-term, as the short-term price elasticity of oil production is very small.

Table 3.1 Crises in the oil market since 1950

Event	Period	Duration in months	Gross loss of supply (million barrels a day)	Total gross loss of supply (million barrels)
Nationalisation of oil industry in Iran (1)	1951-1954	44	0.7	940
Suez crises (2)	1956-1957	4	2.0	245
Syrian Transit Dispute (3)	1966-1967	3	0.7	65
Six Day War between Israel and Arabic countries (4)	1967	2	2.0	120
Libyan price dispute; Tapline damage (5)	1970-1971	9	1,3	360
Nationalisation of oil industry in Algeria (6)	1971	5	0.6	90
OPEC oil embargo on USA and the Netherlands (7)	1973-1974	6	6.0	475 (756)
Iranian Revolution (8)	1978-1979	6	6.0	640 (1008)
Iran-Iraq war (9)	1980	3	3.0	300 (360)
Gulf war (10)	1990	3	3.0	420 (378)
OPEC action Ryadh Pact (11)	1999-2000	12	12.0	>1000

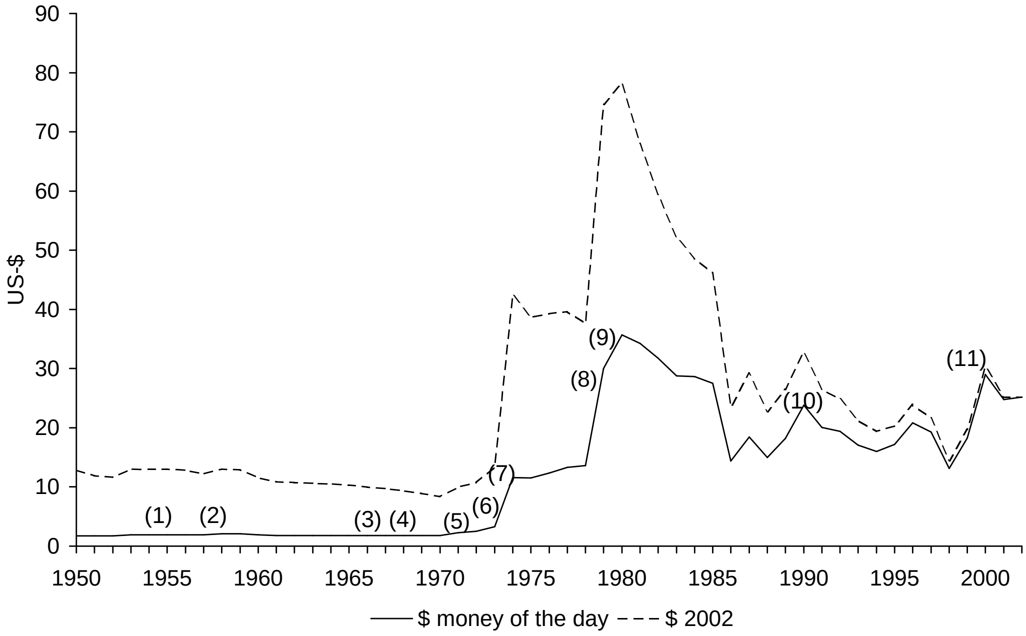
Source: Horsnell (2000) (IEA figures between brackets).

The price impact varied significantly from one disruption to the other (see figure 3.1). During the 50's and 60's of the last century the impact was negligible, due to the organisational structure of the oil market. "Before 1973, the large integrated oil companies (and a few smaller ones) took care of the supply of oil and allocated supplies with their own systems, redirecting tankers and balancing each other's shortages and excesses in crude and fuels. Prices were given, by and large." (Correlje, 2003).

Between 1973 and the mid-80's, the influence of disturbances on the oil price increased considerably. In the first oil crisis, in 1973-1974, the price of oil surged by approximately 400%. Since then, the oil price has never returned to the pre-1973 level. On the contrary, the price stayed at the new level during that whole decade although the event (the OPEC embargo on the USA and the Netherlands) that initially raised the price disappeared. The characteristics of the oil market had altered deeply, with the birth of a powerful oil cartel as the key component.

The second oil crisis, in 1978-1979, raised the oil price even further, by approximately 250%. Although the oil price stayed at that high level for several years, it was not sustainable, because it stimulated production by non-OPEC producers, on the one hand, and energy saving by oil consumers on the other. Consequently, the cooperation among OPEC members was challenged, ultimately leading to a collapse of both the efficacy of the cartel and the price of oil. In 1985, the oil price reached a level which would become the average level for the next years.

Figure 3.1 Oil prices, 1950 - 1999 (Brent, average annual values in US-dollars per barrel)



Note: the numbers refer to the crises mentioned in table 3.1; source: BP, Statistical Review of World Energy, 2003.

Since that time, the effect of disturbances on the price of oil has been less strong. This is partly due to the reduced oil-intensity of the industrialised economies. The high oil prices during the 70's and the first part of the 80's induced many investments in energy saving; moreover, the economies moved away from energy-intensive to energy-extensive activities. As a result, the current use of oil per unit of product in the industrialised countries is approximately no more than 60% of its level in the 70's (OECD, 1999). Besides these changes within the economy, the development of spot and future markets have enhanced the flexibility of market players to respond to (expected) disturbances and, hence, have reduced the vulnerability of economies to oil price peaks.

Albeit disturbances in supply affect prices less than before, volatility of the price of oil is still large and even growing (see figure 3.2). This volatility is partly due to the relatively high utilisation of production capacity, the relatively low sizes of storages, and the increased cohesion within OPEC.[4] As a result, growth in demand is hardly met by supply responses. The price fall in 1998, though, was caused by production levels far above demand due to an unexpected and strong decline in the world economy.

[4] See e.g. Pindyck (2001), who analyses relationships among volatility of commodity prices, levels of production and levels of inventories.

Figure 3.2 Price of crude (Brent) oil, 1993-2003 (daily data)

3.2.2 Assessment of future risks

The experiences up to now show that the oil market is highly vulnerable to disruptions. The factors causing these disturbances could be distinguished in (geo) political events, institutional developments within the oil market, economic factors, and technical characteristics.

To start with the last factor, some authors expect that the danger of depletion of oil fields is looming. Campbell (2000), Laherrere (2003) and Ivanhoe (1995) for instance, expect oil output to peak during the first decade of the 21st century with a rapid decline thereafter. However, this view is hotly debated. “The fact (…) that predictions for the peak of world oil production have always been some 10 years (on average) ahead of the current year gives ground for optimism that depletion issue is not a problem on the supply side in the near term and medium term. Oil supply constraints are more likely to arise from lack of investments than a lack of opportunities.” (OIES, 2003).

Over the past twenty years, proven reserves of conventional oil have increased globally. Current world-wide conventional reserves would last for more than 34 years if production remains at present levels. Besides these reserves, geologists believe that the earth’s crust contains large quantities of undiscovered resources. Moreover, in particular in Canada and Venezuela, there are large amounts of non-conventional oil: the volume of oil sands in Canada amounts to almost 310 billion barrels, the volume of heavy-oil and bitumen in Venezuela amounts to 270 billion barrels (IEA, 2002b).

We conclude, therefore, that the technical characteristics of the oil fields bear no serious risk to the oil market in the short and medium term (see also the box 'Long-term scenarios of energy markets' in section 2.4).

Economic factors, however, generate significant risks to the oil market as the production of oil is a function of investments made in the past. Insufficient investments in production or refinery capacity raise the risk of higher prices in the future. "A careful analysis of the market conditions that prevailed in the few years preceding the 1973 shock shows that the rate of investment in capacity in the late 1960s, early 1970s, although very high, was nevertheless insufficient relatively to the growth in world oil demand." (OIES, 2003)

The spare production capacity is just one of the critical factors that determine prices in the world oil market. Higher capacity utilisation indicates a tighter balance between supply and demand and exerts an upward pressure on oil prices. This holds not only for the crude oil market, but also for the market of refined products. World refinery utilisation rates increased significantly after 1980 from a little more than 70% in 1980 to more than 85% in 2001. In the United States and Europe, utilisation rates increased to 90% in that period. The current high utilisation rates can lead to supply problems in case of an unintended shutdown of some of the refining capacity or tighter product quality specifications.[5]

In the future, the supply of oil could be constrained due to restrictions on investments. These restrictions would primarily follow from political events. Currently, investments within the oil sector are hindered in several South American, African and Middle Eastern countries.[6] In the medium term, this could lead to a production capacity which is unable to meet growth in demand.

The institutional structure of the oil market has been extremely important for the development of the oil price in the last decades. During the last thirty years, the oil-producing countries organised in OPEC have tried to influence prices by withholding oil from the market. The track record of OPEC shows some successes, albeit that this cartel has been less successful than is often thought. "The two major successes attributed to OPEC – the price rises in 1973 and 1979

[5] For example in 2001, environmental requirements in the US caused an increase in the demand for 'clean' gasoline. Local refiners could not deal with this demand so this gasoline had to be imported from Europe. As Europe itself had capacity problems, this extra demand led to an increase in product prices in Europe.

[6] The National Oil Company's (NOCs) in the Middle East region for instance, created after nationalisation of the oil sector in the early-1970s, need strategic consolidation (Van de Linde, 2000). In order to attract foreign capital, a part of the privileges that are now in the hands of the NOCs should be shared with the international oil companies. The relation between the institutional and political setting on the one hand and investments in the oil sector on the other can be illustrated by the case of British Petroleum (BP). In 1997, BP lost the money it had put in a 10% stake in Sidanco, a Siberian oil company, in an allegedly rigged bankruptcy procedure. However, recently BP returned to Russia and decided to invest again in the Russian oil sector. With political and institutional reforms in the countries involved, those restrictions will probably be lifted in the future and the effect in the longer term is negligible.

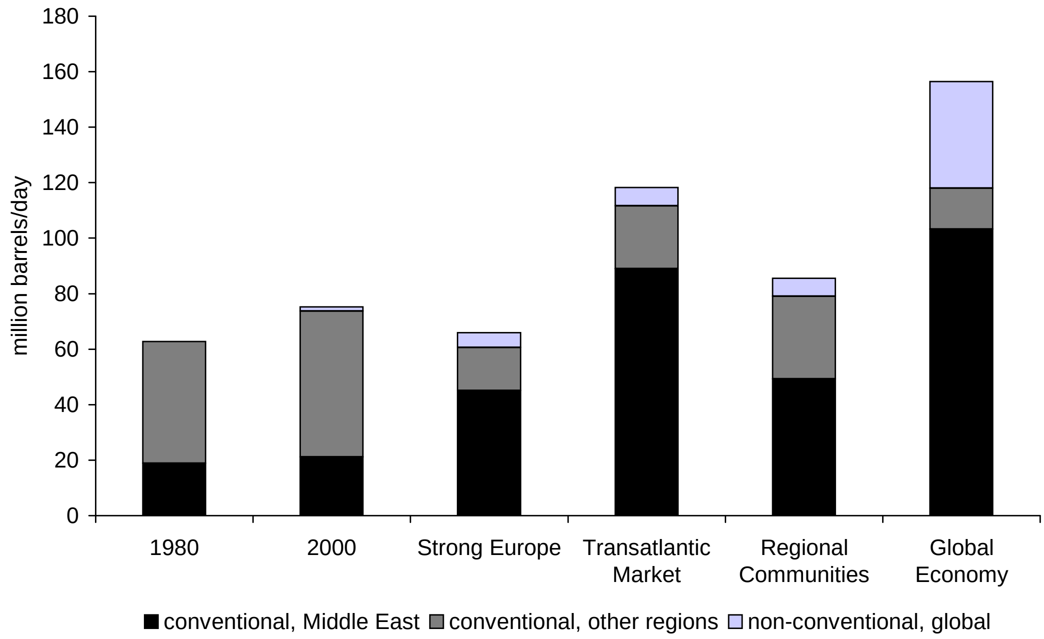
– had more to do with the market conditions prevailing at these precise moments than to an OPEC show of strength. (…) The truth, however, is that no merits are attached to a cartel when a price rise is the outcome of excess demand. (…) The OPEC golden age was neither in 1973 nor in 1979 but in 1974-8 when the oil price was held almost constant at a time of emerging surplus supplies; and in 1982-5 when a catastrophic fall in prices due to a huge supply surplus was moderated into a slow, gradual decline. (…) For long periods of its chequered history, OPEC failed to prevent falls in the real price of oil, most notably between 1960 and 1967, and between 1987 and 1997. Yet, it managed recently to shift the market subjective view of the ‘comfortable’ price level from 18 dollar per barrel to 25 dollar per barrel.” (OIES, 2003).

Looking into the near future, we can expect that OPEC will continue to strive to control the market. The capabilities of OPEC to do so depend primarily on its market share. This share will rise due to depletion of the fields in other regions. In our long-term scenario *GLOBAL ECONOMY*, reserves in the Middle East will reach their bottom, however, at the end of the period due to the high production in the years before. As a result, the market share of the Middle East region in *GLOBAL ECONOMY* in 2040 will be lower than in *Transatlantic Market* (see Figure 3.3). In the second part of the scenario period in *Global Economy*, non-conventional fields will become a major source of oil in this scenario, as investments will be more and more directed at the development of production from tar sand fields and other non-conventional fields in Canada, Venezuela and Russia. This development is enhanced by technological improvements decreasing the costs of production at these fields significantly. In 2040, production of this kind of oil will reach a level of 35 million barrels per day in *Global Economy*. In the other scenarios, production of non-conventional oil will increase as well, but at a much lower pace.

The efficacy of OPEC policy depends, as history has also shown, on market circumstances. If the market is tight, OPEC could ‘sail with the wind’ and steer prices onto a higher path. If, on the contrary, total supply is abundant, OPEC would try to prevent a falling oil price or to reverse a fall as soon as possible. Therefore, we can conclude that the institutional organisation of the oil market still bears a risk in regard to the price of oil.

Geo-political factors, finally, could result in sudden and strong disruptions in the supply of oil in the short and medium term. In his analysis of risks to the oil market, the Oxford Institute for Energy Studies (OIES, 2003) states that we must consider three major geo-political causes of oil supply disruptions: the Arab-Israel conflict, the US-Iraq conflict and the threats to the stability of political regimes in countries as Saudi-Arabia, Kuwait and Iran.

Figure 3.3 Production of oil, historically (1980 and 2000) and in four scenarios (2040)



Source: Bollen et al. (2004)

On the basis of that analysis, this institute foresees three types of politically induced disturbances on the oil market:

- Terrorist attack on oil installations (oil fields, pipelines, processing plants, terminals, or refinery) or to oil shipping. Oil tankers generally follow fixed maritime routes passing through narrow channels, e.g. the Strait of Hormuz (the passage between Iran and Oman connecting the Persian Gulf and the Indian Ocean) and the Bosporus, which theoretically could be blocked temporarily by terrorist attacks or by political measures from the adjacent countries. Pipelines often pass through more than one country. Likewise this transport by pipeline could be hindered by political measures.
- A significant increase in the Islamist and national political influence in an oil-exporting country, leading to growing militancy in oil policy and deterioration of circumstances (Western) oil firms have to operate in, and, hence, to a sudden single drop in production or in a decline over a period of time.
- A change of the political regime through a military coup or a popular revolution that brings Islamists or radical nationalists to power. Such change could be the result of the currently social divide and lack of democratic representation in the Gulf countries. With populations and unemployment increasing and with incomes falling many want social reform[7]. This call to reform will even be stronger in situations with low oil prices.

[7] The Economist, Time travellers: A survey of the Gulf, March 23rd 2002.

3.2.3 Definition of potential crisis

The previous section gave a concise listing of conceivable disruptions in the oil market. The major risks refer to geo-political events in the Middle East region and to market behaviour of the oil-producing countries. Besides these risks, insufficient investment in production, transportation and refinery capacity could also lead to shortages on the market. Depletion of oil fields, however, is not a serious risk in the short and medium term.

In our cost-benefit analysis of the Dutch policy options, the possible consequences of two specific types of supply disruptions will be investigated. These potential crises are defined as follows:

- a short-lived but large increase in oil prices because of a significant supply disruption which is the result of political unrest in the Middle East region.
- cartel behaviour of a group of major oil producers resulting in a long-lasting restraint of production and, hence, higher world oil prices.

3.3 Cost-benefit analysis of expanding emergency oil-stocks

3.3.1 Definition of a crisis

Political unrest could result in, for instance, a blockade of the Strait of Hormuz. As a consequence, a small part of the oil that is daily transported through the Straight would be transported by alternative routes. Besides this, producer countries not affected by the disturbance in the Strait produce some more oil in order to help offset the loss of oil to the market. However, as it takes some time to start up the existing spare capacity, the additional production of these countries is rather limited in the short term. The political unrest could also result in reduced production in the Middle East region. Producers in other regions would strive for enlarging their production, but that would hardly affect global production in the short term. Concluding, the crisis on the oil market we focus on is a disruption in the supply of 10 million barrels a day over a period of 6 months. This disruption is caused by political unrest in the Middle East region.

Comparable cost-benefit studies

Although cost-benefit studies in the field of security of supply are hardly conducted, welfare effects of investing in strategic oil stocks have been investigated before, in particular by Leiby et al. (2000a, 2000b, 2002). On request of the Strategic Petroleum Reserve Office of the U.S. Department of Energy, they assessed the costs and benefits of expanding the strategic stocks of the United States and in the Asian Pacific region. In addition, they contributed to the analysis made by the Asia Pacific Energy Research Centre of the costs and benefits of emergency oil stocks in the APEC region (APERC, 2000).

Costs of stockpiling are based on costs of facilities and oil stored. The former include capital costs to build storage facilities, operation and management costs and costs of (re)filling and drawing down. Costs of the oil are based on the difference between the costs of oil purchases and the oil sale revenues over the lifetime of the reserves.

Benefits of stockholding are measured by avoided costs of damage to the economy. These benefits consist of two components: avoided loss of GDP as the oil price rise less than would have been the case without the release of oil, and avoided loss of import expenditures due to the lower price of oil.

In our analysis, these costs and benefits are also taken into account. A major difference between the studies of Leiby et al. (op. cit.) and ours is the way uncertainty is dealt with. These authors use a Monte-Carlo simulation model of the world oil market including a disruption probability distribution function. As a consequence, they are able to calculate expected benefits of investing in strategic oil stocks.

The conclusion of Leiby et al. (op. cit.) regarding the United States is that an expansion in the stocks by 120 million barrels would be beneficial to the economy of the United States. Regarding the Asian Pacific region and the IEA-European region, they conclude that these regions would receive net profits from a coordinated expansion, but that individual member countries would bear a loss if they act separately.

3.3.2 Definition of the policy option

A wide range of policy options directed at security of supply exists (Correlje, 2003). Several of those measures have to be implemented at international level, such as proactive political initiatives, investments in strategic oil stocks, establishing international oil trade relations and measures focussing on production of oil in other regions.

While politically-proactive actions, as the dialogue between consumer and producer countries, could prevent a disturbance completely, the other measures could prevent price effects of a disturbance. For instance, oil released from strategic oil stocks could completely compensate for the effect of a shock. Even in cases where the stock is not large enough to make up for the whole disturbance, the price effects of the shock will, at least, be smaller than they would have been without the presence of an emergency stock. Stimulation of supply from other regions would augment the number of suppliers to the market and, hence, decrease the vulnerability of the oil market to disruptions somewhere on the supply side. International oil trade relations could be used to enhance flexibility of responding to supply side disruptions.

The instrument of strategic oil stocks seems to be an adequate measure to cope with short-lived disruptions within the supply of oil. As the amount of oil in stock is limited, a stock-draw policy is only valid in situations where the supply disruption and the accompanying price peak are short-lived (Green et al., 1988). But even in this case, the OECD countries might run out of stock before the situation is back to normal again. Running out of stock does not mean that the supply of oil from stocks will have no benefits. During the period that the stock is sold, oil prices and the accompanying “disruption costs” will probably be lower than in a situation without stocks.

The past shows only one example of an internationally coordinated release of oil from the emergency stocks. In January 1991 just before the first Gulf war took off, the oil price surged to a historically very high level. In order to restore the stability in the oil market, the IEA Governing Board decided to release approximately 2 million barrels a day. Besides this decision, IEA countries agreed to take demand-reducing measures and to stimulate indigenous production. Shortly after these internationally coordinated responses to the crisis on the oil market, the war against Iraq was launched. Although the price of oil declined sharply, this is not attributable to the response measures but to the quick and effective development of the war.

The instrument of strategic oil stocks is well conceivable in our long-term scenario Strong Europe. In that scenario, international co-operation is successful and governments are inclined to take on public responsibilities. On the other hand, the risk of political unrest in the Middle East fits well in this scenario because of the strong decline in the oil consumption which is induced by a fierce (internationally implemented) climate policy. That decline would have major consequences for the oil-producing countries and, hence, generate a substrate for political unrest.

Policies regarding the implementation of oil emergency stocks are, in essence, not “domestic” policies as they are based on international legislation. National policies regarding those stocks are based on two sets of legislation, EU legislation and IEA legislation.

The Governing Board of the IEA, which is made up of senior energy officials from member countries, directs the activities and makes the major policy decisions of the IEA. In the event of an actual or potential oil supply disruption, the Governing Board would meet promptly to consider what action should be taken. In case of a serious disruption, the Board could decide to make an amount of oil available to the market by means of a stock draw. This additional supply will help to balance demand and supply and thereby mitigate the price increase. On 1 January 2002, IEA countries held some 3.7 billion barrels of oil stocks[8] (crude oil and oil products). Of this stock 1.28 billion barrels were public stocks and 2.46 billion barrels were industry stocks.

[8] Results of the questionnaire on IEA oil stock drawdown capacity, IEA/SEQ(2002)22.

In the Netherlands, the emergency stockpile consists of both commercial and public parts managed by the Dutch stockholding agency: COVA. Table 3.2 gives an overview of the development in the Dutch emergency stocks during the last decade. In 2003, the total Dutch obligation amounted to 37.1 million barrels.

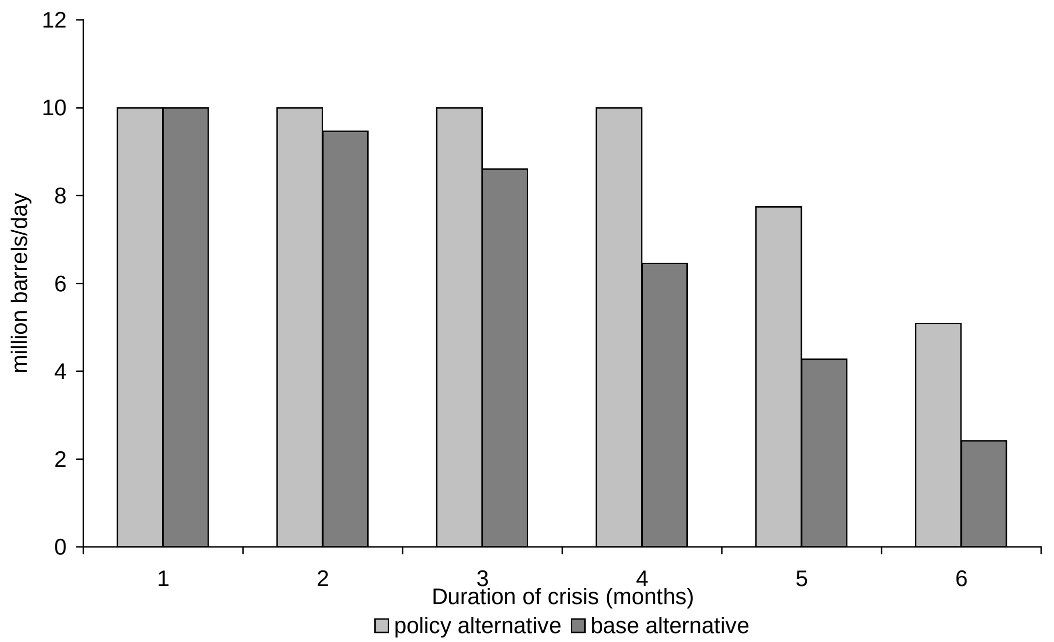
Table 3.2 Emergency stock obligation for the Netherlands as of April 1, 1994 – 2003

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
	million tons of raw oil equivalent									
Industry	1.068	1.099	1.188	1.246	1.269	1.468	1.451	0.677	0.666	0.669
COVA	2.536	2.446	2.606	2.553	3.015	3.002	3.427	4.103	4.232	4.415
Total	3.604	3.545	3.794	3.799	4.284	4.470	4.878	4.780	4.898	5.084

Note: On April 1, 2001, the WVA2001 came into force;
Source: Ministry of Economic Affairs, personal communication; COVA

The base alternative is the situation where the Dutch government and the other IEA-countries have the current emergency stocks at their disposal. The policy option is the extension of these strategic stocks by 33% following the proposal put forward recently by the Commission of the European Union (COM, 2002).

Figure 3.4 Release of oil during the crisis in the base alternative and the policy alternative, in million barrels a day



During the crisis defined above, oil from the strategic stocks is released. Figure 3.4 shows that in the base alternative, the strategic reserves fail to compensate fully for the disruption as from the second month. The extension of the stocks raises the drawdown capability. The difference in response capabilities between the policy alternative and the base alternative constitutes the benefits of the measure (see further section 3.4.3).

3.3.3 The costs of the policy option

Extending the magnitude of the strategic oil stocks incurs several costs. The direct costs comprise the effect of the additional oil demand on the oil price, the costs of holding of the stock, and the costs of an eventual stock release.

Direct costs

Building a public stockpile incurs additional oil demand. During the build-up of the stock, this could lead to higher prices than without stock building. As the build-up of the additional stock will usually take place in a period with normal (low) prices (due to ample oil supply) the absolute effect of this stock building on oil prices is probably limited. According to Considine (2002), the rebuilding of an emergency stock has minimal impacts on market prices, especially when purchases are phased over several months[9].

The costs of stockholding depend strongly on the characteristics of the storage facility, in particular, the geological characteristics and the drawdown capabilities of the facility. According to APERC (2000), salt caverns incur much lower capital costs than hard rock mines and in-ground trenches. The costs of bringing stocks to the market are negligible in all cases. According to APERC (2000) the costs of drawdown and refill are less than 0.10 dollar per barrel, no matter which type of storage facility is used. The sum of capital costs, operation & management costs, and costs of drawing down and refilling are approximately 6 dollars per barrel in the case of salt caverns, while the other two types of storage incur costs of more than 15 dollars per barrel. Besides these costs, storage implies that interest costs are incurred.

In the Netherlands, public oil stocks are mainly stored in salt caverns. The total annual costs of storage, including the interest foregone, are estimated at 17.7 euro per ton raw oil equivalent.[10] With a current total stock of 5.084 million tons of raw oil equivalents, an expansion of these stocks by 33% implies an additional stock of 1.678 million ton oil. The total annual cost of that increase is equal to approximately 30 million euro. The discounted average annual value of this cost amounts to 11 million euro.

[9] Recently, the manager of the SPR in the US was asked to stop increasing the SPR volume as this would increase the price of oil in the current situation.

[10] Based on Ministry of Economics Affairs, Wet voorraadvorming aardolieproducten, Memorie van Toelichting, 1999.

Determining the optimal size of the strategic oil stocks

Investments in oil emergency stocks are investments under uncertainty which could be dealt with as stochastic optimal control problem. From that perspective, several questions should be answered. First of all the investor (in this case: the government) has to decide whether investing in an emergency stock is profitable, taking into account all costs and benefits related to the investment. If the decision to invest is positive, one has to decide at what pace the stock should be built: all at once, over a small period of time, or over a longer period of time? Next, the optimal volume has to be determined.

The costs of investing consist of the purchasing price and the costs of stockholding. To the latter costs belong the storage costs and the interest foregone. The purchase of oil by the government might have a price-increasing effect. The negative effect on GDP of the higher oil price is an additional cost. The proceeds of the stock consist of the selling price of the oil and the avoided costs to the macro-economy because of the lower oil price. This lower price is the result of the additional oil supply out of stock.

A key element in the determination of the investment is, of course, the uncertainty regarding the future price of oil. The future path of the oil price depends on many factors, among which the (mean-reverting?) characteristics of the oil price under normal circumstances, the influence of stock-building and selling out of stock, the frequency of disruptions, the magnitude of the disruptions that occur and the duration of the disruptions. Some of the influences on the oil price can be taken care of by describing the oil price as a “geometric mean-reverting process with jumps” (Kamien et al., 1981) The parameters of all the processes discerned in this way have to be quantified. This activity is, however, extremely difficult because of the lack of adequate information. Another factor complicating the analysis is the fact that not the oil price but its effect on the economy constitutes the benefits of the stockpile. The link between the oil price and the aggregate economy is troublesome, albeit sensible assumptions could be made on the oil price elasticity of GDP.

This leads to the conclusion that only under strong simplifying assumptions analytical solutions might be found. Most analytical models only describe the critical threshold required to trigger investment (see Dixit et al., 1994). This is the reason that we have chosen to simulate the investment problem. A sensitivity analysis is conducted in order to explore the sensitivity of the results to numerical assumptions made.

Indirect and external costs

As stock piling has hardly any effect on the oil price, indirect and external effects are negligible. After all, both effects would only result if the oil price changes or if significant distribution effects would exist.

3.3.4 The benefits of the policy option

The benefits of expanding the oil emergency stocks depend, firstly, on the effects of the release of stock on the price of oil (the direct benefits) and, secondly, on the impact of the lower oil price on economic activity (the indirect benefits). Besides these benefits, we distinguish external benefits.

Direct benefits

The release of oil from emergency stocks diminishes the impact of a disruption in the total supply of oil. If a decline in production is totally compensated for by a release from these stocks, the price of oil would hardly be affected. The efficacy of this policy measure depends, therefore, on the extent it compensates for a disruption. If we have defined how large the remaining disruption in supply is (see section 3.4.2), the key question left to answer is the relationship between the decline in supply and the oil price.

Strategic oil stocks as a tool in a strategic game

The holding of strategic oil stocks affects the oil market even without the release of oil. Oil-exporting countries as well as large oil users respond to the mere existence of these stocks. The latter could, therefore, be seen as a tool for the oil-importing countries in a strategic game with other parties involved in the oil market.
The responses of oil-exporting countries could be categorised in two types. The first one raises the efficacy of the strategic oil stocks, while the other neutralises it. On the one hand, the existence of the stocks could deter oil-exporting countries from reducing the level of their production too much. If a decline in the production were followed by a release of oil by the oil-importing countries, the oil price would be unaffected, but the proceeds of the oil-exporting countries would be decreased. Of course, this deterrence holds only for short-lived reductions in supply. On the other hand, however, the oil-producing countries could be able to offset the effect of a release of oil from the strategic stocks. It is hardly possible to assess which of these conceivable responses dominates the effect of the stocks on the behaviour of the oil-exporting countries.
Large oil-consuming firms, holding their own stocks of oil, will also respond to the existence of strategic oil stocks held by governments. If these firms expect that the strategic oil stocks stabilise the oil price, they will reduce their own stocks. In this view, governmentally hold strategic oil stocks has a crowding out effect on privately hold stocks

The Energy Information Administration (EIA) of the US Department of Energy[11] uses the following rule-of-thumb: “for every one million barrels per day of oil supply disrupted and not made good by other supplies (i.e. the net disruption size), world oil prices could increase by $3-$5 per barrel.” In case of a tight market situation at the outset (a high oil price) the impact will probably be the biggest, whereas in an easy market the impact will be towards the lower end of the range mentioned.

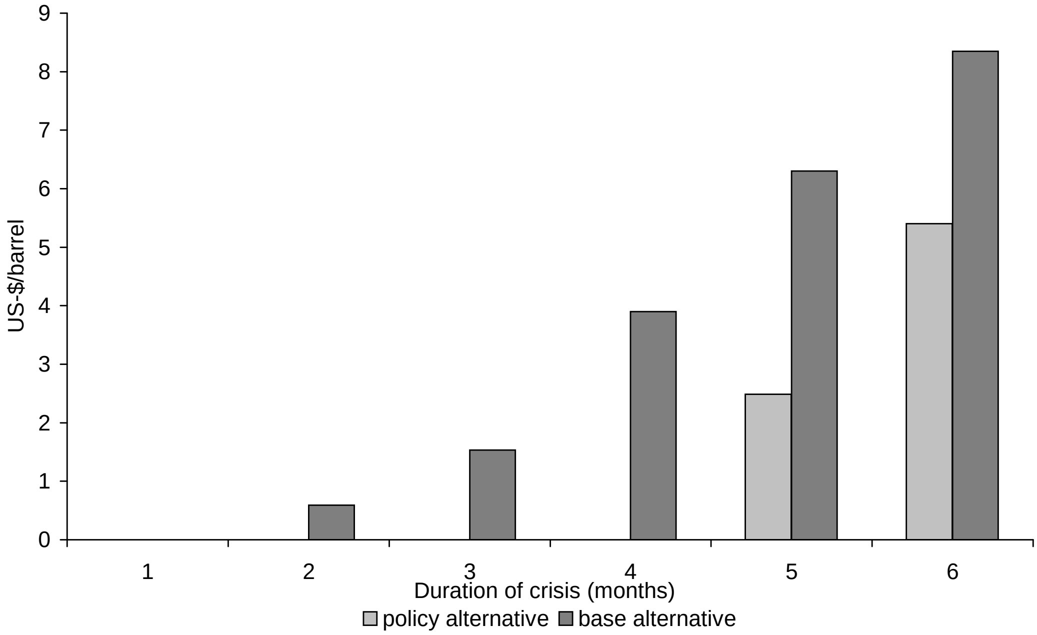
Considine (2001) provides estimates of the price effects of supply disruptions. According to his competitive model of the world oil market, a 1 million barrel daily shortfall in supply induces a significant price increase. The magnitude of this increase depends on the initial price (the higher this price the larger the price increase) and on whether the market is in backwardation or in contango. In case of a market contango, futures prices are higher than the spot price. As a result, market participants buy and hold inventories to sell in the future when prices are higher. This additional demand drives equilibrium prices even higher. In a backwardation situation, when spot prices exceed futures prices, a shortfall of 1 million barrel a day leads to a price increase between 4 and 6 dollars. In a contango situation the price rise is in the interval of 7 to 13 dollars per barrel.

In a more elaborate model with an imperfectly competitive market structure, Considine (2002) finds much smaller price effects than in the above simple competitive model. A disruption of 1 million barrels a day has a modest impact on prices: the equilibrium price only rises by a little

[11] Published at website: http://www.eia.doe.gov/security/rule.html (8/27/03).

more than 1 dollar. As this model seems to describe the market situation better than the above competitive model, we use the latter relationship between disruptions and oil price. The rule-of-thumb of the EIA lacks, in our view, proper foundations.

Figure 3.5 Changes in the price of oil during the crisis in the base alternative and in the policy alternative



The results of the analysis are presented in figure 3.5. In the base case, the monthly average price of oil increases in the second, third and fourth month, while in the policy alternative no price increase occurs due to the capabilities of the emergency stocks to compensate for the disruption within supply (see Figure 3.4). In the last two months of the crisis, the policy alternative also shows a shortage in stocks and, hence, rising prices. The benefit of the policy to expand the oil stocks is constituted by the difference in price development between the base and the policy alternative. On an annual basis, the oil price rises 4.5% less in the policy alternative compared to the base alternative.

Indirect benefits

There has been much debate about the relationship between oil prices and the performance of the economy (see the box ‘Why does a rising price of oil affect the economy?’). In general a negative correlation is found between GDP and oil prices. The quantitative strength of the relationship between price and GDP is summarised in the oil price elasticity of GDP. For the United States, Mory (1993) found a value of -0.055 which is in close agreement with the value of -0.054 that was found by Mork et al (1994). However, since 1985 this relationship seems much weaker than during the preceding period.

Elasticities based on simulations with macroeconomic models such as Interlink and Multimod are significantly smaller.[12] The aggregate level of these models precludes these models from obtaining the inter-sectoral resource allocation costs caused by an oil price shock.

Why does a rising price of oil affect the economy?

Several explanations have been put forward for the inverse relationship between oil price and aggregate economic activity. In their article giving an overview of evidence on this relationship, Brown et al. (2002) categorise the explanations into four groups.

The 'classic supply side shock' explanation mentions the rising price of a key production factor as the trigger. Increasing costs of production results in a lower growth of output and, hence, of productivity. Consequently, the growth of real wages declines and consumers reduce their savings or increase their debt as to smooth out their consumption. As a result, the real interest rate rises which boosts inflation if the supply of money is not adapted to the change in money demand. If nominal wages are sticky downward, unemployment will grow reducing production further.

A totally different explanation is given by the 'income transfer' explanation. This approach stresses the fact that rising oil prices transfer income from oil-importing countries to oil-exporting countries. As the latter have a lower propensity to consume, aggregate spending declines and, hence, aggregate production, particularly in the oil-importing countries. This effect is partly offset by the accompanying growth in aggregate savings which reduces the real rate of interest and, hence, stimulates investments and production.

The other approaches focus on the role of the supply of money. The 'real balance effect' explanation states that a rising oil price raises the demand for money while the supply of money grows insufficiently as to meet the higher demand. Consequently, interest rates rise and economic growth decreases.

The final approach sees 'the failure of monetary policy' as the major explanation. According to the adherents of this approach (as Bohi (1989) and Bernanke et al (1997)), inadequate policies of monetary authorities were the major cause for the relationship between the oil price and the aggregate economy. In the past, these authorities tightened the supply of money in order to beat inflatory tendencies. As a result of that contractionary monetary policy, economic activities would have declined. This view is, however, highly questioned by others (as Hamilton and Herrera (2001) and Hooker (2001).

According to Brown et al. (2002), the 'classic supply side shock' offers the best explanation for the inverse relationship between oil price and aggregate economic activity.

[12] The Interlink model is the macro-econometric model used by the OECD Economic Department for analysing effects and international spill-overs of macroeconomic policy and for assessing risks to the global outlook (OECD, 2001). Multimod.is IMF's multi-region macro-econometric model (IMF, 1998 and 2000). This model has been designed to analyse the macro economic effects of industrial country policies on the world economy.

In both models the impact of higher oil prices works its way through the economy along comparable lines. In the Interlink model the higher price of oil changes the terms of trade between oil-exporting and oil-importing countries. As the prices of oil and oil-related goods and services increase real disposable income of net oil-importing countries declines. This leads to lower output and higher inflation. The degree of the downturn depends on the way consumption reacts to lower disposable income and higher inflation and investment to lower output. In addition net exports might change because of slowing market growth and competitiveness changes. Higher consumer prices could lead to compensation in wages. If this occurs an inflationary spiral could start which induces (still) higher inflation and lower growth. The magnitude of the loss in output varies between countries. It depends on, among other things, the amount of domestic oil production and the oil intensity of GDP. We calculated the effects of the oil prices changes on the Dutch economy by using the Athena model (see chapter 2). The results are depicted in the tables 3.3 and 3.4.[13]

A temporary increase in the oil price raises inflation and reduces the purchasing power of households which generates negative effects on private consumption. On a world level, purchasing power decreases resulting in a lower growth rate of world trade. This reinforces, by diminishing exports (of energy and other goods), the negative influence on the national economy. As a consequence employment decreases which puts the economy under further pressure. In the energy sector, investments are higher through substitution of energy by capital, but outside the energy sector, investments decline because of rising costs and thus diminishing profitability.

As to be expected, the economic effects of a temporary oil price rise tend to zero after a few years. In the transition phase, a negative price-wage spiral occurs under the influence of a delayed adjustment of wages to the difference between the production and the consumption price. Consequently the terms of trade deteriorate resulting in a decline of real national income in year 2.

The economic benefits are measured in terms of net national income (NNI). The NNI[14] (instead of GDP) is used as there is a close relationship between the NNI and consumption. This later variable is the most important variable in welfare analysis (see chapter 2).

[13] The results in the tables 3.3 and 3.4 reflect the effects of the oil price rise only. But the size of the negative effects may depend on the circumstances in which the price increase takes place. Often, a fall in confidence, manifesting itself in a restraint of the willingness to consume of households and the propensity to invest of firms, will accompany a sudden sharp rise in the energy price. This fall in confidence will be larger in case of, for instance, a threat of war than if OPEC should restrict its production. In assessing the benefits of the prevention of a price rise by holding oil emergency stocks, the consideration of only a price rise seems justified.

[14] NNI is the sum of domestic product (GDP excluding depreciation) and the balance of income, interest and dividends from abroad.

The direct (discounted average annual) benefits are estimated at approximately 61 million euro (see table 3.4). Besides this direct benefit, a lower oil price generates also an indirect benefit, which is estimated at about 16 million euro.

Table 3.3 Macroeconomic effects of avoiding a temporary rise in the oil price by 4.5% (2003, cumulated % deviations of the baseline)

Item	Value
Net national income	0.0180
Private consumption	0.0225
Production of manufacturing excluding the energy sector	0.0270
Production of the energy sector	0.0990
Production of service sector	0.0135

Source: Athena

As one could expect, the positive impact of avoiding an oil price increase is largest for the energy production sector (see table 3.3). As the Dutch manufacturing sector is relatively energy intensive, the impact on this sector is also relatively large. Households benefit too from this measure due to the lower price of oil-base energy products such as gasoline. The increase in production by services, being the least energy intensive sector, lags behind.

External benefits

A negative external benefit arises due to the increased consumption of oil which raises emissions to the environment. These benefits are assesses at approximately 2¼ million euro (using a shadow price of 16 euro per ton carbon dioxide).

3.3.5 The break-even frequency

From the figures in the previous section, we can easily compute the break-even frequency (see table 3.4). This figure expresses at what frequency a pre-defined crisis will have to occur to equal costs and benefits of the policy options (see chapter 2 for more details)[15] The total (discounted average annual) costs of expanding the strategic oil stocks by 33% amount to 11 million euro. The total benefits of the measure are 76 million euro. This implies that the break-even frequency is once in every 6.9 year.

Comparing this result with the frequency and magnitude of past disruptions (see table 3.1), this necessary frequency to break-even is rather high. Not taking into account the last disruption mentioned in table 3.1, which was caused by execution of market power, there have been 10 disruptions with a mean gross disruption of 365 barrels over a period of approximately fifty

[15] Over the period between two disruptions, the emergency stocks should be replenished. It could reasonably be assumed that these periods are long enough for the actions of the stock manager not to have any effects on the price of oil.

years. So the actual frequency of disturbances on the oil market is higher than our break-even frequency but the magnitude of these disruptions has been smaller than in our crisis scenario.

Table 3.4 Cost and benefits of expanding the emergency stocks with 33% (discounted value in million euro)

Average annual costs	
Direct	11
Indirect	-
External	-
Total benefits	11
Total benefits in case of one crisis	
Direct	61
Indirect	16
Subtotal	78
External	– 2
Total benefits	76
Break-even frequency	
Once every … years	6.9

3.3.6 Sensitivity analysis

Table 3.5 depicts the sensitivity of the above outcome to the assumptions made. It appears that the result of the analysis is fairly robust. Changing the discount rate, the costs of storage or the shadow price of carbon dioxide does not have large effects on the break-even frequency.

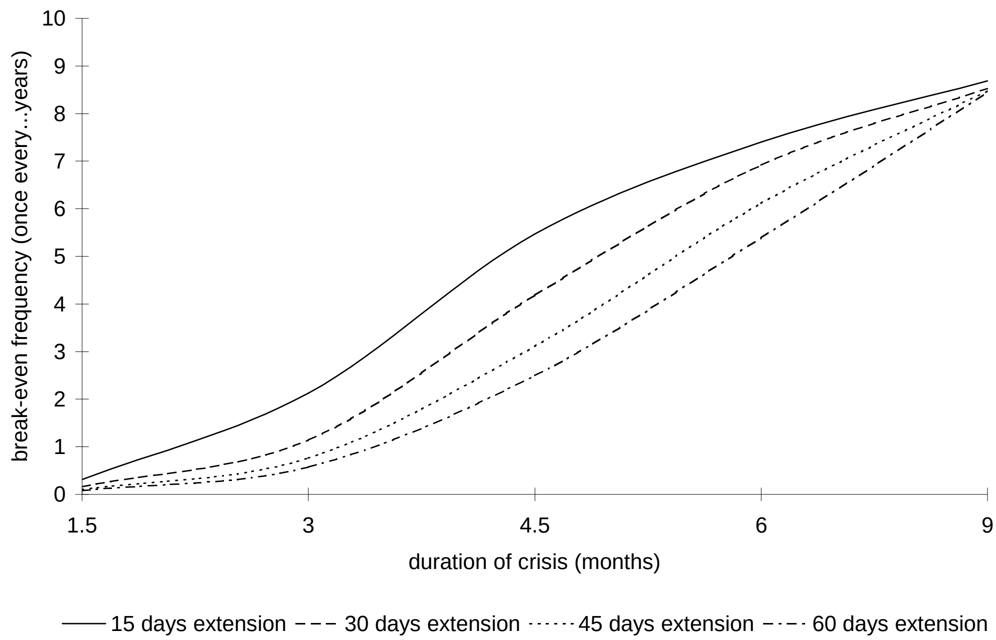
Table 3.5 Sensitivity of break-even frequency to assumptions

Variant	Break-even frequency
Base case	6.92
Discount rate is 5% instead of 7%	7.22
Discount rate is 10% instead of 7%	6.47
Cost of storage is 20 euro/ton raw oil equivalents instead of 17.65	6.11
Cost of storage is 15 euro/ton raw oil equivalents instead of 17.65	8.14
Shadow price of CO_2-emissions is 10 instead of 16 euro per ton	7.00
Shadow price of CO_2-emissions is 50 instead of 16 euro per ton	6.47

The results are, however, far more sensitive for the magnitude of the disruption and the size of the policy measure (see figure 3.6). The efficiency of the policy measure in the base case (33% expansion of the strategic stocks) increases as the duration of the disruption rises and vice versa. If a disruption (of 10 million barrels a day) takes no more than 1.5 month, the break-even frequency would be smaller than one, implying that that disruption should occur at least every year as to make the expansion efficient. On the other hand, if the duration would take 9 months, a break-even frequency of once in every 8 years results.

The sensitivity analysis shows also that smaller investments in strategic stocks have a higher chance of being profitable than larger ones. This difference disappears, however, if the duration of the crisis grows: a 9-month lasting crisis would utilise the oil stocks completely no matter what the extension would have been.

Figure 3.6 **Sensitivity of the break-even frequency to length of the disruptions and size of stock expansion**



3.3.7 Conclusion

The efficiency of additional investments in strategic oil stocks depends heavily on frequency, duration and magnitude of disruptions in the supply of oil. An expansion of the stocks by 33% would need a disruption of 10 million barrels a day at least once in every 7 years. Although the frequency of disruptions on the oil market was higher than 7 in the past decades, the magnitude of the disruptions was much smaller (see table 3.1). The analysis of future risks, described at the beginning of this chapter, gives some reasons for expecting larger disruptions in the future. In particular political unrest in major Middle East countries could result in a large and sudden decline in oil production. Our conclusion is, therefore, that additional investments in strategic oil stocks are not efficient unless one views the risk of a long lasting and severe disruption as a relatively large one.

We need, however, to mention a caveat. As described above, the impact of a shortfall in production on the world price of oil is uncertain. If the impact on the oil price would be bigger than we have assumed in this analysis, the benefits relating to an expansion of the emergency stocks would be higher. Accordingly, the necessary break-even frequency would be lower.

The results of our analysis also show that markets fail to deal with all costs incurred by disturbances on the oil market. Governmental investments in strategic stocks generate positive indirect benefits. At the same time, negative external benefits are realised, as the lower oil price (due to the policy action) increases consumption of oil and, hence, emissions.

The analysis in this section was based on the assumption that the expansion of the strategic oil stocks and the release of oil from these stocks are internationally coordinated. To which extent would our conclusions alter if national governments would act separately? The outcome for individual countries as the Netherlands could be more as well as less profitable. The former result could arise if a country decides not to expand his oil stocks while other countries do invest in expansion. As a result, the country acts as a free-rider as it would benefit from the release of oil from the other countries without making any costs. If, on the other hand, a small country as the Netherlands would expand its emergency stocks while other countries would not, the benefits of that investment in case of a crisis would be negligible.[16]

3.4 Cost-benefit analysis of subsidising biofuels and bio-feedstocks

3.4.1 Definition of a crisis

While strategic oil stocks measure could only be useful in dealing with short-lived disruptions within supply, the biomass measure makes sense in both short and long-lasting crises. In this analysis, we focus on a long-lasting crisis occurring as a result of effective cartel behaviour of oil-producing countries. The crisis is defined as a reduction in global supply of oil by 4 million barrels a day over a period of one year. Like in the case of strategic oil stocks, we use Considine (2002) to determine the relationship between the magnitude of a disruption and the price of oil. Consequently, the crisis defined results in a price rise of 5 dollars per barrel.

3.4.2 Definition of the policy option

Reducing the dependency of an economy on oil decreases its vulnerability to disturbances on the oil market. The dependency on oil could be lessened by energy saving as well as altering the fuel mix towards other fuels than oil. In this report, we focus on the latter option. An alternative to the use of oil is the use of biomass. Sectors where oil might be substituted for biomass are the power sector, the transport sector and the chemical sector. In the Netherlands, hardly any oil products are used in the power sector. Here, biomass replaces coal in order to reduce emissions. From the perspective of security of oil supply, therefore, it makes sense to focus on the

16 This conclusion also holds for certain groups of countries, as is shown by APERC (2000). In its cost-benefit analysis of investments in emergency stocks by Asian countries, they conclude among others that cooperative stock release by all Asian countries except Japan is not profitable. If, however, Japan would join the other Asian countries, stock holding generates positive net economic benefits.

transport sector and the chemical industry. The demand for biomass from the power sector, however, should be taken into account because of its effects on the market for and, hence, the price of biomass.

A recently published directive of the European Union offers a framework for encouraging the use of biofuels in the transport sector. This directive aims at “contributing to objectives such as meeting climate change commitments, environmentally friendly security of supply and promoting renewable energy sources” (European Union, 2003). According to this framework, the minimum proportion of biofuels and other renewable fuels in car fuels, measured by energy content, should be 2% in 2005 and 5.75% in 2010. Although these targets are not mandatory[17], we will use them as reference values in our analysis.

As biofuels are more expensive than their fossil counterparts, the realisation of these targets would need financial support of governments. The compensation could be given by reducing the excise duty on the blended fuel. As a consequence, fuel prices at the pump do not increase but government revenues decline. To balance the government budget, taxes have to be increased accordingly.

In the chemical industry, a part of the fossil fuel inputs can be replaced by biomass. Technically spoken, no problems arise if biomass is used as input in chemical processes. Availability and composition of the bio-feedstock could, however, be a bottleneck. Moreover, the conversion to a biomass-based industry would induce significant transition costs, as the whole infrastructure of the chemical industry has been oriented on naphtha as input for many years.

In contrast to biofuels, the European Union has not implemented policies regarding the use of bio-feedstocks in the chemical sector. Governments of several countries, inside and outside the European Union, have stressed the importance of substituting fossil-based chemical products by biomass-based products. Up to now, most of the existing policy initiatives refer to the stage of research and development of biomass (ECN, 2003). If specific targets are mentioned, these targets refer to long-term developments. An exception to this is the United States: this country has defined specific targets on bio-feedstocks both for the short and the medium term.

In this report, we analyse the consequences of substituting 10% of the naphtha consumption in the Dutch chemical industry. The accompanying policy measure consists of financially compensating the industry for the extra costs of biomass compared to naphtha by subsidies or tax reductions. As is the case with biofuels, we assume that the additional outlay of the government is compensated for by an increase in labour taxes.

[17] Article 4 of Directive 2003/30/EC states that national targets can differentiate if governments have good reasons to do so. The Commission will assess those reasons on their validity.

3.4.3 The costs of the policy option

Following our framework, we distinguish direct costs, indirect costs and external costs of a policy option.

Direct costs

Using biofuels is more expensive than using fossil fuels. As the Netherlands have very limited opportunities to produce biomass, we have to assume that all biomass needed for this policy measure will be imported. The direct costs of blending fossil-based fuels with biofuels depend primarily on the difference between the savings on oil imports, on the one hand, and the expenditures on imports of biomass on the other. Besides this, differences in processing costs contribute to the direct costs of this policy measure.

Much uncertainty exists regarding the extent of the direct costs of biomass usage. In determining the direct costs at macroeconomic level, attention should be given to five items:

- current additional costs per unit of product;
- developments on the market of biomass affecting the price of biomass,
- technological progress decreasing the production costs;
- the total demand for fuels in the future;
- other costs related to the use of biomass-based products.

Appendix 4 offers an assessment of estimations regarding the thirst three mentioned items; the fourth item is discussed in the box ‘Challenges for the biomass market’.

Blending fossil fuels with biofuels leads to an increase in costs, as the costs to produce biofuels are higher than the production costs of fossil fuels. NOVEM (2003) provides an overview of the costs studies that have appeared to date. Depending on the way fuel consumers are compensated for the increase in costs, the necessary excise duty reduction is somewhere between 0.8 euro cent per litre for the 2% bioethanol/gasoline blend in 2005 and 4.7 euro cent per litre for the 5.75% bioethanol/gasoline blend in 2010 (see appendix 4).

In our calculations, we use a constant price for biomass during the scenario period, as an increase in demand for biomass will have an upwards effect on biomass prices, whereas an increase in the scale of production will have an opposite effect. However, because of improvements in techniques in the refining stage, we assume an overall yearly cost reduction of 2%.

Although starting from the same cost increases per litre as NOVEM (2003), our costs differ from those in the NOVEM study because the development of fuel demand is different. In our Transatlantic Market scenario, the demand for fuels shows an annual increase of 1.5%, whereas in the scenario used by NOVEM (op. cit.) the yearly increase in demand amounts to 2.2%. Up tot 2040, fuel demand increases by 50% in our Transatlantic Market scenario.

Additional costs could arise from adapting combustion engines to the specific requirements of using blended fuels. In our case however, the share of biofuels in the blend is so small that adaptations seem unnecessary.

Production of bio-based chemical products, generally, is more expensive than production of their fossil-based counterparts. The extra direct costs for the Dutch industry of the policy measure defined above vary between 50 and 220 million euro (CE, 2003). CE computed this cost increase as an average over five bio-based products. As the eventual product mix is unknown, these five products have an equal weight in the determination of the average additional costs.

As is the case with biofuels, we assume a constant price for biomass. Learning effects and technical improvements in the refining stage will also lead to an overall cost decrease of 2%.

Challenges for the biomass market

Following the Directive of the European Union, many countries are going to stimulate the use of biomass. As a result, the use of biomass could double in the near future. Currently, supply of biomass consists mainly of municipal waste and residues from food industry. To enhance the future volume of biomass, supply will gradually move from wastes and residues to products from specific energy plantations. Future supply depends, therefore, on the ability of biomass production to compete for acreage with food production and nature conservation. Consequently, agricultural policies of the European Union, therefore, play a key role in the volume of biomass that will be produced within the European Union and elsewhere.

According to the European Commission, replacing 8% of the current use of fossil fuels would require 10% of the area currently used for agriculture (RIVM, 2003). If the European Union would be unable to produce the required amount of biomass, part of the demand has to be served by imports. Possible conflicts between biomass production and food production in exporting countries could arise. This holds, in particular, for developing countries if biomass production would lead to higher food prices. Anyway, an increasing demand and necessary transition from wastes and residues to specific energy crops will have an upward effect on prices of biomass. On the contrary, an increase in the scale of production and technological developments could have an opposite effect on the price (see Appendix 1). As a result, it is pretty conceivable that the future price of biomass remains fairly flat (see also Novem, 2003).

In our Transatlantic Market scenario, the input demand of the chemical industry increases by more than 50% up to 2040. We assume that the replaced volume of naphtha increases at the same rate.

Additional costs to the industry could arise because of the ‘lock-in effect’ of the current situation. The chemical infrastructure is completely based on naphtha as its basic feedstock. A forced transition to a bio-based industry in a relatively short period would lead to capital destruction. However, we assume that such costs will be avoided because of a gradual introduction of bio-based feedstock.

Indirect costs

The extent to which direct costs generate indirect costs depends fully on how the policy measure is financed. After all, as additional costs are fully compensated for by tax reductions, this policy options does not affect prices of energy. Indirect economic consequences, therefore, could only follow from the way these tax reductions will be financed. If the government raises taxes on labour to compensate for the reduced excise receipts, the labour market could be distorted, incurring negative macroeconomic effects. We used the Athena model to assess the extent of this component.

External costs

The external costs incurred by subsidising the use of biomass follow from the reduction in fossil oil consumption and, hence, in emissions. Table 3.6 shows the effect of the policy option on the emissions of carbon dioxide. The latter depends on the way biofuels would be produced. According to Novem, 2003, a reduction of 50 to 75% in CO_2-equivalents seems reasonable. These figures take account of all emissions from “well-to-wheel”. In our calculations, we assume a reduction in emissions of 60%. The value of these negative costs can be assessed by using a shadow price of the emission.

Table 3.6 Negative external costs of blending (reduction in emissions of CO_2)

		Shadow price of emissions (euro/ton)	
		16	50
	million ton/year	million euro/year	
2% blending (2005)	0.4	7	25
5.75% blending (2010)	1.3	22	70

In the chemical industry, the replacement of a part of naphtha by biomass also leads to lower CO_2-emissions. This effect is, however, very small: the replacement of 10% naphtha by biomass reduces the total emissions by no more than 1 ton.[18] Consequently, these external effects can be ignored in the remaining part of the analysis.

[18] According to VROM (1997), only part of the carbon contained in fossil fuels used as feedstock enters the atmosphere. From the potential emissions from naphtha 82% is stored in products. In a steady-state (long run) situation, however, almost 100% of the potential emission enters the atmosphere (Marland, E. and G. Marland, 2003).

3.4.4 The benefits of the policy options

Direct benefit

The direct benefits of introducing biomass as biofuels and bio-feedstock arise in case of an increase in oil prices. If the oil price increases, the cost difference between the fossil based products and the biomass-based products declines. This decrease could lead to a lower compensation per unit of product and, hence, reduce total government expenditures.

Indirect benefits

The direct costs and direct benefits presented in the preceding sections are used in ATHENA, our macroeconomic model. Within this model, we treat the additional costs resulting from the use of biomass as an increase in import costs as the required biomass probably needs to be imported. The transport sector and the chemical industry are compensated by the government in terms of a reduction in excise duties or an increase in subsidies. This additional government outlay will be financed in the form of a tax increase. Athena determines the extra costs relating to this tax increase. Together with the direct costs these indirect costs are determined in terms of Net National Income.

External benefits

As end-user prices are unaffected, consumption of fuels will not alter as result of the policy option. Consequently, the measure does not incur external benefits.

3.4.5 The break-even frequency

The resulting break-even-frequency is once in every 0.1 years (table 3.7). This means that even if the oil price is permanently at a 20% higher level, the welfare effects of this option are negative. The benefits in terms of lower loss of national income and lower carbon emissions are by large not sufficient to offset the high costs of using biomass.

Table 3.7 Costs and benefits of stimulating biomass in the Netherlands (discounted effects, million euro)

Average annual costs	
Direct	121
Indirect	2
Subtotal	123
External	– 6
Total	117
Total benefits in case of one crisis	
Direct	9
Indirect	3
Subtotal	12
External	.
Total	12
Break-even frequency once every … years	0.1

A policy measure with relatively high costs could be of interest, because of its distribution effects. It appears that the costs of this measure would be paid by the households as higher income taxes would be used for financing the subsidies (see table 3.8). The benefits would accrue almost completely to the transport and chemical sectors.

Table 3.8 Effects in 2030 of costs and benefits of introduction biomass (cumulated % deviations of baseline)

	Costs	Benefits
Net national income	– .11	.02
Private consumption	– .29	.05
Production Manufacturing excl. Energy	– .02	.01
Production Energy	– .08	– .02
Production Services	– .15	.03

3.4.6 Sensitivity analysis

Table 3.9 provides the results of the sensitivity analysis. It appears that the discount rate and the shadow price of carbon dioxide emissions hardly affect the above conclusion.

Table 3.9 Sensitivity of break-even frequency to assumptions

Variant	Break-even frequency
Base case	0.118
Discount rate 5% instead of 7%	0.115
Discount rate 10% instead of 7%	0.113
Shadow price of CO_2 emissions 10 instead of 16 euro per ton	0.116
Shadow price of CO_2 emissions 50 instead of 16 euro per ton	0.126

3.4.7 Conclusion

Subsidising the use of biomass appears to be a highly expensive policy measure. Replacing crude oil by biomass as input increases production costs strongly. The direct welfare costs occur as an increase in the import bill as the required biomass has to be imported. Financing this biomass policy by raising taxes leads to an additional, indirect, welfare cost. The direct welfare gains of the biomass policy, which arise in case of a crisis, appear to be small. Comparing the costs and benefits of the biomass option shows that the costs outweigh the benefits to a large extent. Even if the crisis should occur permanently, the policy measure is unprofitable.

The European Union itself recognises the fact that substituting fossil inputs by biomass is as yet an inefficient option (see COM(2001)547). It would take an oil price of around 70 euro per barrel to make biofuels break even with conventional petroleum-derived diesel and gasoline. The Commission expects that only a part of the additional costs of biofuels would be offset by benefits due to the avoidance of CO_2 emissions and the increase in the security of supply. However, according to the Commission, the measure would generate extra benefits in terms of rural development in the European Union, employment, fiscal policy, and environmental quality. In addition to these extra benefits that would arise within the European Union, extra demand for biomass could benefit developing countries that depend on agriculture.

The question remains, however, whether these benefits, added to the climate and security benefits, fully compensate for the high production costs. After all, some of these so-called additional benefits, such as the effect on employment, are already taken into account in our analysis. Moreover, the question should also be answered whether subsidising the use of biomass is the most efficient option to realise these other policy goals.

4 Natural gas market

4.1 Introduction

As the share of natural gas within energy supply is growing, economies become increasingly vulnerable to disruptions on the natural gas market. Two separate developments are currently affecting the landscape of the European gas market: liberalisation of the European gas market and a growing dependency on non-EU suppliers. These developments pose new chances, but also new risks for the security of supply. In this chapter, we focus on the latter.

This chapter starts with describing some historic disruptions in the gas market and analysing potential risks for the near future (section 4.2). This section concludes with the definition of two conceivable crises on the gas market. Then we arrive at the core of this chapter, the cost-benefit analysis of two policy measures. First, we analyse the costs and benefits of extending the lifetime of the huge Groningen gas field as a swing producer[19] (section 4.3). Next, we conduct a cost-benefit analysis of reducing the dependency on gas of the power sector by encouraging the use of non-gas based generation techniques (section 4.4).

4.2 Analysis of risks

4.2.1 Historical evidence on risks

Up to now, the European gas market has never experienced any large-scale and long-lasting disturbances in supply (Correljé, 2003). This is primarily thanks to the 'well-managed' character of the market hitherto, with the absence of gas-to-gas competition and the use of long-term take-or-pay contracts. However, the gas system was tested for its stability on a number of occasions. Stern (2002) detected the following events:

- Strike among offshore workers in Norway and the UK in 1986 which caused a loss of around a quarter of total Norwegian supplies for several days;
- Terrorist (bomb) attack on the Trans-Mediterranean pipeline in Algeria in 1997. Due to the use of gas from storages and alternative suppliers, the attack did not have any significant effect on the gas market;
- Disturbances in the transit of natural gas from Russia across Ukraine; this country demanded a transit fee by means of 'unauthorized diversions'. Those disturbances did not result in any significant supply problem in Europe, because gas companies had sufficient opportunities to substitute the withdrawn supply;
- Transit difficulties caused some physical shortages in Turkey in 1994 and 1995.

[19] A gas field serves as a swing producer if it is capable to meet all kinds of fluctuations within the demand for gas. Technically, swing is defined as "the maximum monthly delivery divided by the average monthly delivery in a given year" (IEA, 2002a, p. 58).

Significant disruptions of supply at the natural gas market are scarce, not only in Europe but also in other regions. The largest exception is provided by the El Paso natural gas disruption in New Mexico. In august 2000, one of three parallel interstate pipelines blew up, causing the other two to temporarily shut down. This resulted in a 60 percent decrease in the usual 2 billion cubic feet per day flowing from El Paso to the gas markets of Arizona and California, for several weeks in a row. However, an EIA study (EIA, 2000) into the effects of this disruption concluded that the markets were independently able to make adjustments needed to avoid severe gas shortages as a result of the El Paso disruptions. This was accompanied by soaring gas prices at least temporarily. “The system relied on alternate transportation, gas from storage, or other non-natural gas remedies such as switching to other fuels to supplement the loss of natural gas supplies” according to EIA (2000). All in all, the ultimate effect of this disruption was not significant, partly due to the moderate weather conditions that prevailed at the time of the crisis.

On the demand side of the natural gas market, several ‘disruptions’ occurred due to extreme weather conditions. The IEA (1995) mentions the experiences in Canada during the winter of 1992/93 and in the USA in January 1994. Recently, cold weather threatened the Dutch transmission system, whereby storage facilities had to be addressed in order to continue gas deliveries. The withdrawals were sufficient to accommodate the peak in gas demand: as a result, no difficulties emerged.

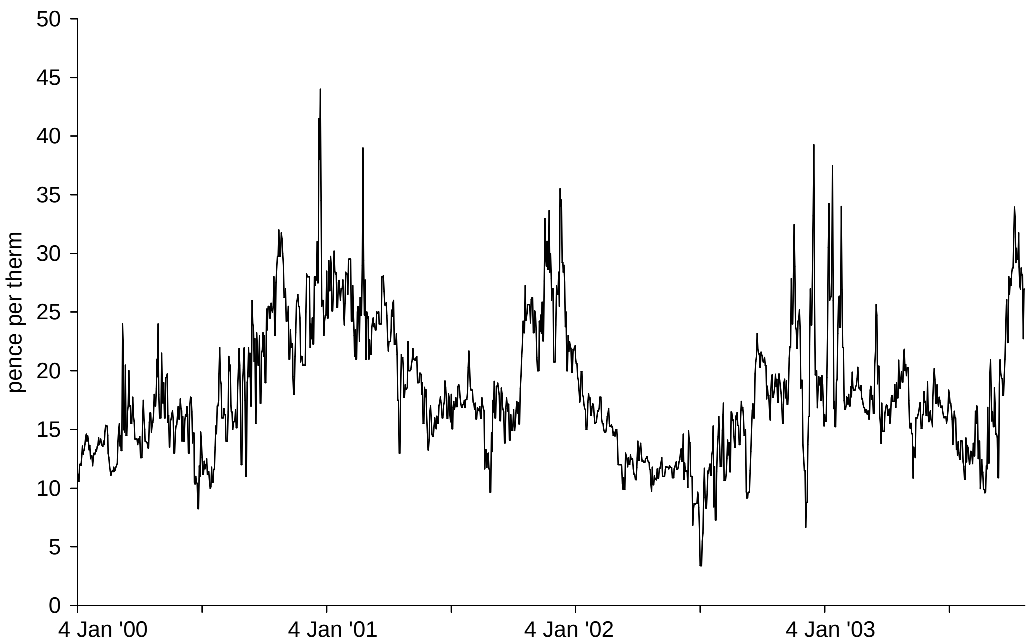
Disruptions on the supply side can have various causes, varying from technical to political. The chance of a technical failure in the (international) gas network could be significant. However, due to the well-developed network of pipelines and the existence of storage facilities, effects of these kinds of disruptions are relatively minor, as is proved by past experiences. Whenever a supply line breaks down, extra gas can be obtained either from another source or from the same source via another pipeline. Furthermore, technical failures are most of the times relatively easy to repair, with gas flowing again within a short time span.

In a deregulated gas market, such as the South-Western American gas market, “the consequences of disturbances are fully dependent on available alternative routes and surplus storage and transport capacity in the system. Eventually, imbalances translate into price movements and possibly substitution by alternative fuels and their prices” (Correljé, 2003). The volatility of the price of natural gas in a liberalised market can be illustrated by the day-ahead prices at the Net Balancing Point (NBP)[20] in the United Kingdom (Figure 4.1). These prices regard natural gas that is not sold by means of contracts. Even in liberalised markets, a significant part of gas is contracted under long-term contracts. The price of gas in these contracts will increasingly be based on gas-to-gas competition. In the United States, nearly all

[20] A UK trading hub.

gas prices are determined at the Henry Hub spot gas market in Louisiana. In the United Kingdom, gas prices in new contracts are mainly based on spot prices. At the European continent, however, indexation to the price of other energy carriers, in particular oil, still plays a significant role.

Figure 4.1 Day-ahead prices at NBP, United Kingdom, 2000 - 2003



Source: various issues of European Spot Gas Markets, published by Heren Energy.

4.2.2 Assessment of future risks

The observation that the European gas market has not been hit by a significant supply disruption until now does not provide a guarantee for the future, the more so given the ongoing liberalisation of the market and the increasing dependency on imports. Which risks are associated with the future liberalised gas market and what are the perceived chances of any significant disruption? The major risks on the natural gas market seem to be related to fluctuations in demand and the flexibility in supply to cope with these fluctuations, and the increase in market power of a small number of suppliers.

Due to the high volatility within the demand for gas, the supply side should be flexible as to prevent disruptions. This flexibility of gas production is called ‘swing’. In the past before the liberalisation of the gas market in Europe took off, governments ensured that the level of swing was permanently sufficient. “Before market liberalisation, the entire gas demand curve was largely inelastic. (…) The main requirement was that the available supply should at all times be sufficient to cover contractual demand at each location. Large suppliers such as state monopolies or companies with exclusive supply concessions were meeting this requirement." (IEA, 2002a, p. 57).

In liberalised markets, private firms are also involved in determining the level of swing capacity of the supply side. In liberalised gas markets such as in the United States and in the United Kingdom, the price mechanism is increasingly playing an important role in matching supply and demand. "As markets are being opened through third-party access, as well as by abolition of state monopolies and exclusive concessions for transport and distribution, competitive markets for gas are emerging and new gas services are being developed. Gas flexibility in its various forms is becoming a tradable service and is valued by the market."(IEA, 2002a, p. 77)

Liberalisation of the gas market might lead to underinvestment by private companies in sufficient production and swing capacity. "The introduction of liberalisation has created uncertainty by removing the all-encompassing, but extremely expensive, provision by the dominant merchant transmission companies against events of low probability but high impact." (Stern, 2002). Private companies could find it unprofitable to invest in capacity that lies idle for most of the time. In the United States, where liberalisation took off around 1980, investments in pipelines and storage facilities have risen strongly in the past decades. Nevertheless, utilisation of these facilities has also increased due to the growing demand for natural gas. "In the United States, production, transport and storage are increasingly used at nearly full capacity. (…) Further increases in demand could cause capacity bottlenecks to develop." (IEA, 2002a, p. 21 and p. 256). This development might be regarded as market failure, since private companies might not take into account all benefits to society for holding swing capacity needed for meeting extreme demand.

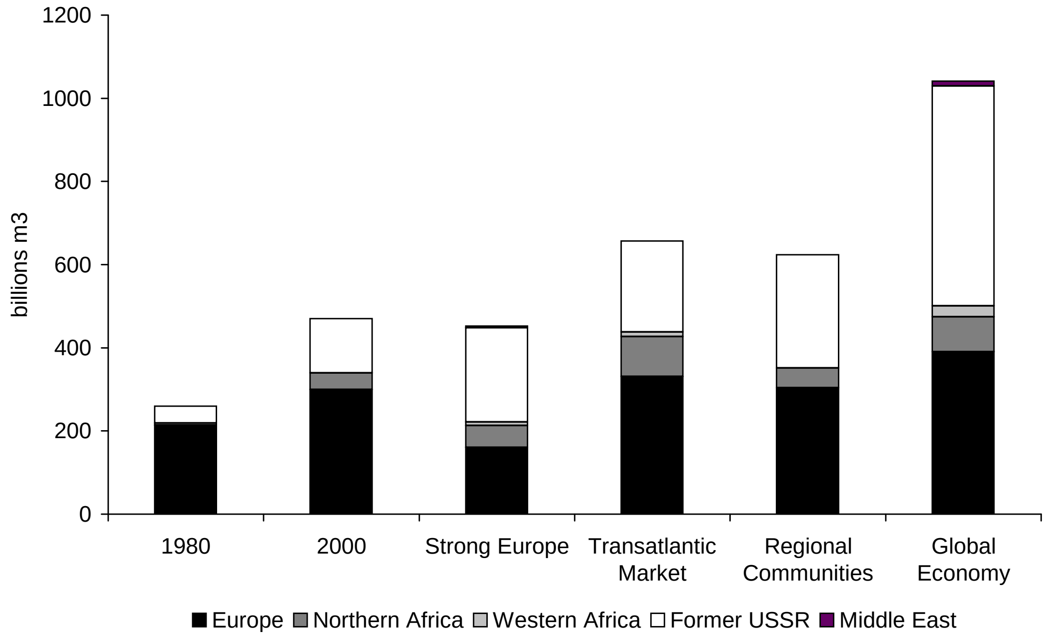
Currently, the Dutch gas system is designed to meet severe winters. The concepts used in the Netherlands in this respect are the 1976 winter and a minus 17 degrees Celsius day. "NAM guarantees Gasunie reliability for the gas supply from the Groningen system that translates into a maximum of one hour 'downtime' in fifty years" (Roels, 1999). The questions are whether private parties will maintain this target in the future, and whether this target is the optimum level from a welfare economic point of view.

The issue of the level of swing capacity in the gas market is not only raised by the liberalisation of this market, but also by the depletion of the huge Groningen gas field which serves currently as the major supplier of swing to the western European market. Due to this depletion, Groningen's capability to offer swing is declining. "Dutch production will eventually decrease as will its contribution to meeting flexibility in demand. Imports from Norway and the United Kingdom are increasing (up 140% in three years) but these offer very little flexibility."(IEA, 2002a, p. 210). As a consequence, Groningen will increasingly need the support of additional storage facilities in order to meet demand in case of extreme peak demand. Parties involved in the Dutch sector have already organised this support by starting the so-called Groningen Long-term project. “Through this latest program of compression installation, Groningen, which is already the heart of the Dutch circulation system for primary energy, will be given a new lease of life.”(Roels, 1999). The question remains, however, whether these investments and the investments in additional storage capacity will be sufficient to compensate fully for the declining capability of Groningen to deliver extreme peak flexibility.

Furthermore, a liberalised gas market means unbundling of transport and production. This may create new risks for the gas market as a whole compared with the former situation in which transport served production. Unbundled transport companies make independent judgements, not necessarily shared by producers. Consequently, “flexibility to produce a certain amount of additional supply is not in itself sufficient to meet unexpected requirements. Enough extra capacity must be available on the transmission grid to transport this increment in a timely way.” (IEA, 2002a, p. 15). On the other hand, an independent transmission company encourages competition between producers and, hence, raises the number of sources of supply to the market.

The major issue in the long run is the declining reserve base within Europe, and its consequently increasing import dependence. This enlarged dependency on imports itself poses a threat for security of supply in the sense that supply routes will become longer, and more vulnerable to shocks than is the case nowadays. Figure 4.2 illustrates this fact.

Figure 4.2 **Consumption of natural gas in European Union (including Norway) by origin, historically (1980 and 2000) and in four scenarios (2040)**



Source: Bollen et al. (2004)

The growing dependency on imports increases Europe's vulnerability for an abuse of market power by one of the major suppliers, or a coalition of suppliers. A few years ago, the major gas exporters Algeria and Russia started mutual cooperation by establishing the Gas-Exporting Countries Forum (GECF). This platform "strives for market stability" and a "sustainable development of energy industry" (GECF, 2002). However, "no definite conclusion can be drawn as to how market power and negotiation strength will evolve. In addition, the importance of the hard currency revenues earned from gas exports to the economies of the major gas exporters to Europe (…) is so great that these exporters would be reluctant to jeopardise them by adopting extreme commercial or political positions." (Stern, 2002). Nevertheless, execution of increased market power by exporting countries could result in higher import prices for natural gas.

4.2.3 Definition of potential crises

From the previous section, we define two potential crises on the natural gas market:

- a severely cold winter in Europe resulting in an extremely high demand for natural gas;
- higher prices of natural gas due to execution of market power by gas-exporting countries.

4.3 Cost-benefit analysis of introducing a cap on Groningen production[21]

4.3.1 Definition of a crisis

Above, we defined as a potential crisis a severely cold winter in Europe resulting in an extremely high demand for natural gas. Such a crisis could result in surging gas prices as well as physical shortages. In this section, we analyse both type of consequences.

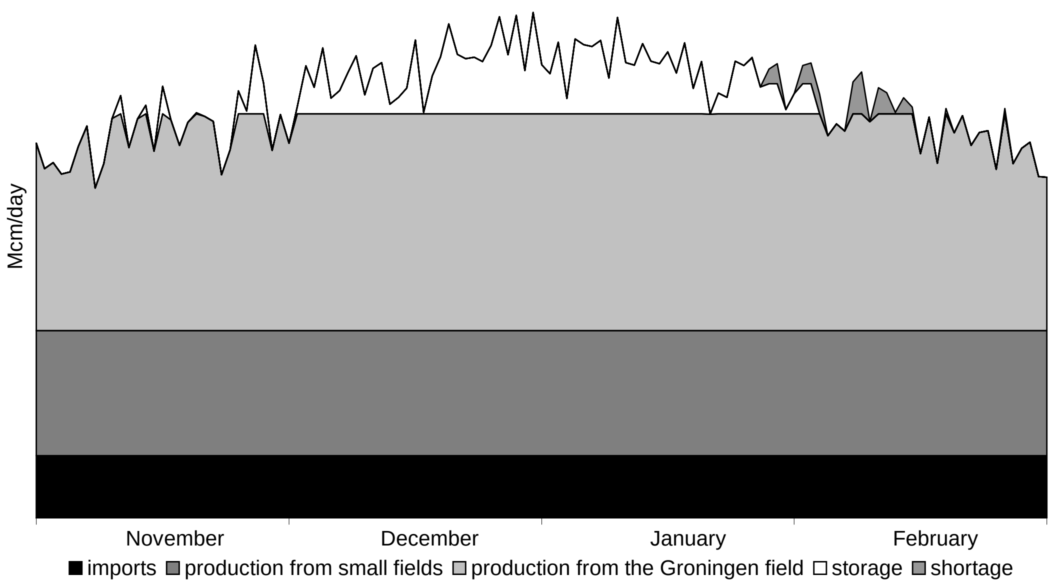
- Crisis a: upsurge of the price of natural gas:
  The severely cold winter in the North Western part of Europe causes an upward jump in gas demand. As a consequence, the price of natural gas increases to a level of about 200% of the normal winter price. We assume that the price remains at this high level for a period of four months.
- Crisis b: physical shortage of natural gas:
  Again, due to extreme demand conditions, gas becomes very scarce, causing empty storage facilities. For additional swing supply, foreign producers are approached. In contrast with crisis a, we assume that flexibility of the gas system is unable to deliver sufficient swing. In the beginning of this crisis, prices surge. If prices reach certain levels, industries might find it beneficial to interrupt their gas consumption. This may relieve the gas shortage to a certain extent. However, gas demand stems primarily from small end-users, such as residential consumers, and power companies. Some power companies might, in response to surging prices,

[21] In this analysis, we ignore differences in quality between gas from the Groningen field and gas from other sources. Taking the quality dimension into account would complicate the analysis without affecting the results significantly.

switch their fuel-use generating capacity from gas-fuelled to oil-fuelled, which could relieve the shortage. Residential consumers, on the contrary, are hardly able to reduce their gas use directly. However, the design of the Dutch gas network does allow for an ‘emergency interruption’. Such a disruption in some parts of the grid could be necessary in order to maintain the balance of the total gas network.

This process of flexibility is illustrated by figure 4.3. In the first part of a hypothetical, severely cold winter, domestic production (from Groningen and other fields) and the imports are sufficient to meet demand. Later on, gas from storages is needed. If the demand stays at a high level in the remaining part of the winter, these storages will become depleted. As a result, a part of the gas demand cannot be served anymore.

Figure 4.3 Use of flexibility options to serve extreme gas demand in a hypothetical, severely cold winter



Which region of the Netherlands would be disconnected from the gas network? In order to answer this question we have to look into the regional structure of this network. The main supplier of gas is located in the northern part of the Netherlands (Groningen). If large volumes of gas are withdrawn from the network without full compensation by new supply, the pressure within the network decreases. After a certain threshold, the pressure will be too low, making the remaining gas in the network undeliverable. Since pressure is at the lowest level at ‘the end of the pipeline’, gas shortages could loom for regions in the western part of the Netherlands.

Therefore, we assume that the regions first affected would be The Hague, Delft and Westland and Groot Rijnmond. We define the crisis happening in this region as follows: a gas shortage over a period of 24 hours with an average start-up time of 3 days.

4.3.2 Definition of the policy option

In general, several flexibility options exist for providing swing. The major options are flexibility in production, flexibility in imports and storage facilities (see appendix 5). In this chapter, we focus on the role of the Groningen gas field as swing supplier.

As explained above, the ability of the Groningen field to produce swing declines as a result of depletion. In order to maintain the current level of flexibility of the Dutch natural gas system, several measures could be taken. Recently, storage facilities have been developed in order to compensate for the declining supply from Groningen during winter periods. Moreover, a project is now under development which will add compression units to the production site of Groningen.

Another option to extend the lifetime of this swing producer is imposing a cap on the production from this field. A comparable measure is currently included in the Dutch natural gas act (in article 55 of the so-called 'Gaswet'). According to this act, the Minister of Economic Affairs proscribes the maximum level of production from the Groningen field over a period of 5 years.[22] If a cap on Groningen is imposed, other flexibility options could be necessary to serve winter demand. Consequently, this measure will affect the merit order of serving peak demand described in appendix 5.

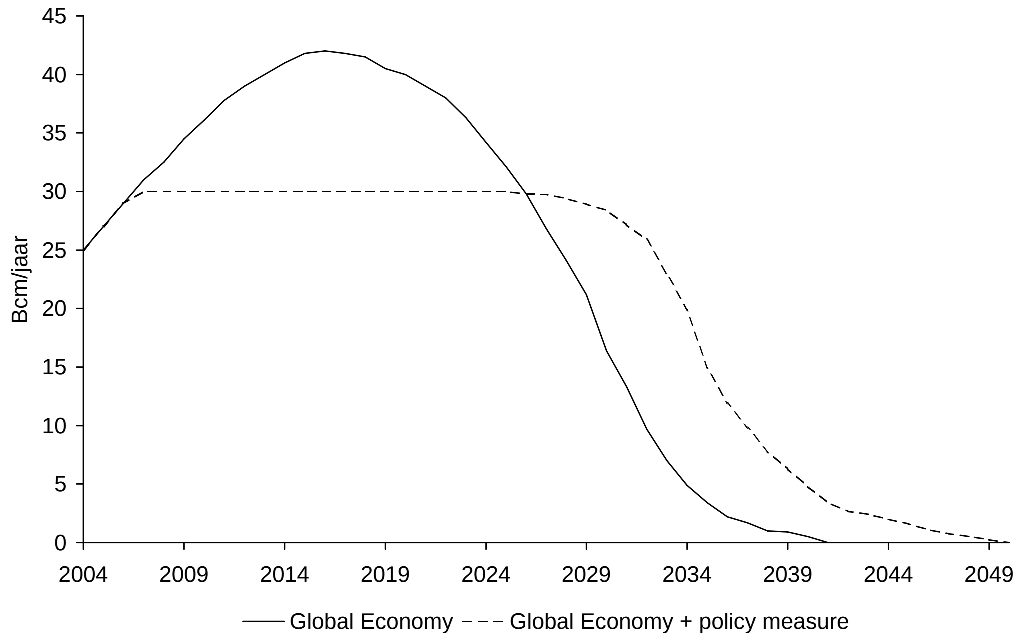
In this report, we assume a ceiling on the annual production form the Groningen field of 30 billion cubic metres.[23] Figure 4.4 describes the effect of this cap graphically. The production profile of Groningen is taken from the energy scenarios recently developed by CPB and RIVM (Bollen et al., 2004).[24] In our base case analysis, we use the Global Economy scenario. This scenario includes a relatively high growth in gas demand in combination with a full liberalisation of the European gas market. In a liberalised gas market, decisions regarding storage facilities are primarily based on opportunities to make profit. If private firms do not take into account all costs associated with insufficient flexibility, the level of flexibility could be suboptimal from societal point of view. The figure shows that the lifetime of Groningen in this scenario is prolonged with about 4 years.

[22] In his explanatory memorandum, the Minister of Economic Affairs mentions two major reasons for imposing a cap over a period of 5 years: maintaining the swing function of Groningen and giving certainty about future production levels to the gas-producing firms.

[23] The level of this cap is rather arbitrary. For this reason we will also analyse effects of alternative levels in our sensitivity analysis (see section 4.3.5).

[24] Assumptions made are: a remaining recoverable reserve of Groningen in 2004 of 1000 billion cubic metres, an average annual economic growth in Europe until 2040 of 2.4%, well-functioning and competitive markets within Europe, and absence of strong environmental policies.

Figure 4.4 Production profile of Groningen with and without cap in Global Economy (GE)



Although full depletion of Groningen will take approximately 3 decades (in this scenario), the capability to serve as a (major) swing supplier ceases much earlier. The ability to act as a swing supplier depends on several geological characteristics of the field, among which the pressure. It is a law of physics that pressure within a field decreases as the quantity of gas diminishes. The ability to supply swing depends partly on the difference between the pressure in a field and the pressure in the transport network. “If the pressure in the Groningen field becomes smaller than the pressure in the pipeline system, pouring gas in a ‘natural way’ (i.e. without instalment of compression units) through the system becomes impossible” (Peeters, et al., 2002, p. 38). This relationship between depletion and pressure implies that the swing capability decreases gradually. However, if the pressure in the Groningen field approaches the pressure of the transport network, the swing capability will be negligible, unless additional investments in compression are made. Therefore, we need to make some assumptions regarding development of pressure in order to determine the moment Groningen will not be able any more to serve as swing supplier. Given the assumptions[25], this moment will occur after about two decades.

[25] Given the current pressure within the field of approximately 180 bar, an initial pressure of 360 bar, a pressure of 80 bar in the transport network, and a current recoverable reserve of approximately 1000 billion cubic metres, we assume that the field pressure will approach the pressure of the network if the remaining reserves, which currently are about 1000 billion cubic metres, approach the level of 400 billion cubic metres.

4.3.3 The costs of the policy option

Following the framework presented in chapter 2, we distinguish three types of costs: direct costs, indirect costs and external costs.

Direct costs

Direct costs incurred by a ceiling on production follow from the delay in cash returns. Given a constant price, one would economically prefer to sell today rather than in the future. According to our long-term scenario Global Economy, the average gas price will be fairly flat at a level of about 23 eurocent per cubic metre in the coming decades (Bollen et al., 2004). Using that gas price and a discount rate of 7% (see section 2.6), we find that the total costs of pushing the benefits of selling Groningen gas further into the future amount to 10.6 billion euro. This is equal to 2.655 billion euro per additional year that Groningen's swing capability is extended (see table 4.1).

Besides these costs, the measure incurs negative costs caused by the extended lifetime of the swing function of Groningen. After all, investments in additional storage facilities can be postponed. Using data of Bos et al. (2003), we assess these discounted (negative) costs at a value of 892 million euro[26]. This is equal to 223 billion euro per additional year that Groningen's swing capability is extended.

Another potential effect of the policy measure is related to the functioning of the market. The restriction on Groningen production reduces indigenous gas supply in the European Union raising the demand for natural gas from non-EU suppliers. Additional supplies would most likely originate from Norway, Russia or Algeria. Since the European Union would already be highly dependent on these three external producers by that time, this relatively small additional supply needed from this region will likely hardly affect market outcomes. Therefore, we do not quantify this effect: it will be dealt with as a *pro memoria* item.

Table 4.1 Annual costs of policy option (discounted value in million euro)

Category	Item	Value
Direct costs	Costs due to postponement of exploiting the resource	2655
	Costs due to the delay in the building of storage facilities	– 223
	Higher European market price due to restriction on Groningen gas	p.m.
Indirect costs		p.m.
External costs		.
Total cost		2432

[26] Bos et al. (2003) reports the costs of building and operating gas storage facilities in Western Europe. Acknowledging that the costs vary quite widely with the type of storage facility (e.g. depleted gas reserve, salt cavern et cetera), calculations are based on average costs for all types of potential storage facilities and corrected for size differences. This gives us a proxy for the real costs of building and operating gas storage facilities in the Netherlands since exact data on potential gas storage facilities are lacking.

The total direct costs of prolonging the lifetime of Groningen by four years are approximately 9.7 billion euro, or 2.4 billion euro per additional year. These costs are a welfare loss for the owners of the resource as well as for the potential owners of storage facilities.

Indirect costs

Indirect costs could only follow from distribution effects, since the price of natural gas does likely not change in response to the implementation of this policy measure. The distribution effect will hardly generate affect markets. Consequently, the indirect costs of the policy option are a *pro memoria* item in our analysis.

External costs

As the price of natural gas will be unaffected by the policy option, consumption of gas and, hence, emissions do not change when that option would be implemented. Therefore, external costs are not present.

4.3.4 The benefits of the policy option

Recall that, by definition, benefits of security of supply measures only appear if a crisis occurs. In the absence of a crisis, costs of these types of measures will always outweigh benefits. In this section, we deal with direct benefits, indirect benefits and external benefits of the policy option in case a crisis does occur.

Direct benefits

If the extremely high gas demand results in surging prices while Groningen is unable to deliver swing and other flexibility options are also constrained, the Netherlands will have to import natural gas. As a consequence, domestic consumers will pay a higher price for gas to foreign producers, which decreases national welfare. However, if the policy measure would have been implemented, Groningen would be able to deliver enough swing supply as long as the crisis occurs within the prolonged period. The benefits of that policy would be the averting of that loss of welfare. The discounted value of these benefits amounts to 5.6 billion euro.

If the severely cold winter results in a physical shortage of gas, production would come to a standstill in the above-defined regions over the period of shortage. The loss of production can be measured by the so-called Value Of Loss Load (VOLL).[27] Table 4.2 provides the value of lost load (VOLL) for one hour.[28] Since we are only in the VOLL in the prolonged period of the lifetime of Groningen, average VOLL for this period is computed. This table also encompasses an estimate of VOLL for households. In valuing the VOLL of households, we follow the

[27] We remind the reader that at the background, the severe cold plays an important role. The water pipe system may be frosted and heating systems broken down. The total costs of a physical shortage could, therefore, be larger than the extent of the loss of production. We think, however, that these costs would be relatively small. Therefore, we do not quantify these effects.

[28] Our approach here is similar to SEO (2003).

approach of SEO (2003), corrected for the total number of households in our three regions. However, we recognise the difficulty of incorporating a correct value of lost production for households. Therefore, this element will be subject to a sensitivity analysis (see section 4.3.6). From table 4.2, we infer that a one-hour gas shortage means a cost to the whole economy of this region of approximately 41 million euro per hour.[29]

Table 4.2 Value of lost load (VOLL) within the COROP-regions of The Hague, Delft and Westland and Groot Rijnmond

Branch of industry	Number of annual productive hours	Average annual value added according to the Global Economy scenario over the period of 2019-2023 (discounted value in million euro)	Average VOLL as a result of the defined crisis, during the period 2019-2023 (in the Global Economy scenario, discounted value in thousand euro per hour)
Agriculture	8760	4517	516
Food and tobacco	6240	2568	412
Chemical	8760	2227	254
Non-specified	6420	2204	343
Metal- and electronics	8760	1807	206
Oil industry	8760	2266	259
Minerals	8760	1459	167
Utilities	8760	2079	237
Building and construction	2600	5671	2181
Trade and repair	2860	13153	4599
Transport and storage	3650	10956	3002
Financial services	2860	7648	2674
Non-specified services	2860	5988	2094
Health care	3374	8816	2613
Government	3374	15932	4722
Households	3386	57036	16845
Total		144328	41123

Source: own calculations based on SEO (2003) and data of CBS and CPB.

The benefits of the proposed policy option comprises the averted losses of load. In calculating the total benefits, we take into account the fact that some branches of industry produce 24 hours a day, while others produce only 8 hours a day. In this way, we assess the discounted value of the total benefits to be 509 million euro.

4.3.5 The break-even frequency

From the figures in the previous section, we can easily compute the break-even frequency (see table 4.3). This figure expresses at what frequency a pre-defined crisis will have to occur to equal costs and benefits of the policy options (see chapter 2 for more details). The break-even frequencies in cases of both crises are once every 2.3 and once every 0.2 years respectively.

[29] During daytime, on a working day.

This means that a price increase of 200% during four months (crisis 1) should occur more than once every 2.3 years to make policy efficient, whereas a gas shortage of 24 hours followed by a 72 hour 'start-up period' should occur more than once every 0.2 years.

However, since the proposed policy measure beholds a prolonging of the lifetime of Groningen with 4 years, it might be more appropriate to adjust the above mentioned break-even frequencies to this period. That is, the price increase of 200% needs to occur at least 2 times during this four-year period, whereas the gas shortage needs to occur 20 times in order to approach the break-even point of the suggested cap on Groningen.[30]

Table 4.3 Costs and benefits of imposing a cap on the Groningen gas field (discounted values in million euro)

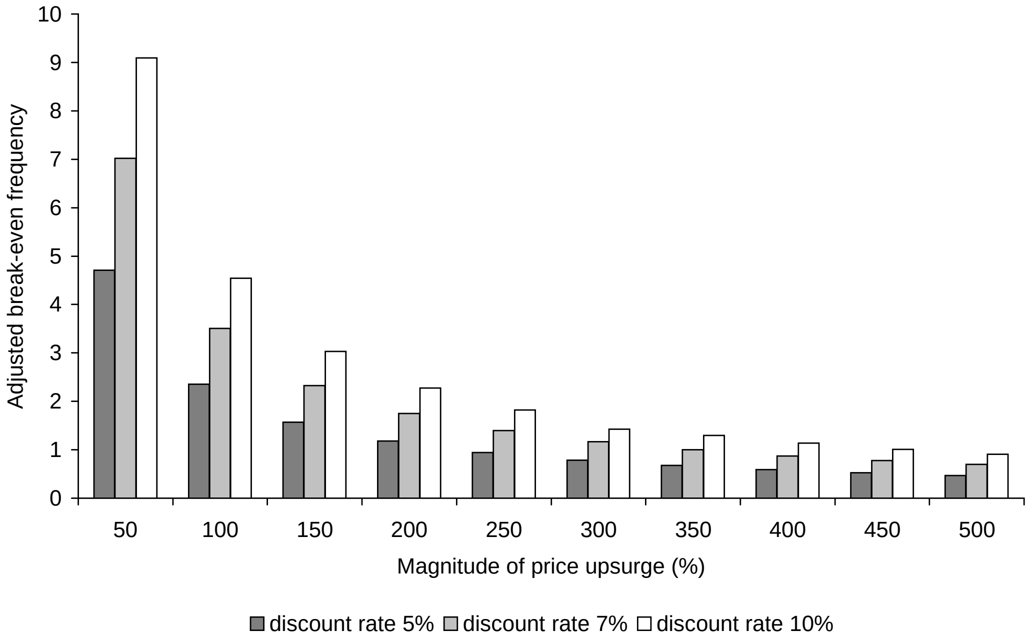
Item		Crisis a: Price upsurge	Crisis b: Physical shortage
Average annual costs			
Direct effects		2432	2432
Indirect effects		p.m.	p.m.
External effects		.	.
Total		2432	2432
Total benefits in case of one crisis			
Direct effects		5569	509
Indirect effects		p.m.	p.m.
External effects		.	.
Total		5569	509
Break-even frequency:	once every ... years	2.29	0.21
Adjusted break-even frequency:	number of times during a period of 4 years	1.74	19.11

4.3.6 Sensitivity analysis

Figure 4.5 and figure 4.6 give an indication of the sensitivity of the adjusted break-even frequencies to the discount rate and magnitude of the crises. The adjusted break-even frequency is defined as the number of occurrences of a pre-defined crisis within a pre-defined period of time at which the present value of the costs of the policy option exactly equal its benefits.

[30] Four years divided by 2.29 is 1.74 and four divided by 0.21 is 19.11.

Figure 4.5 Sensitivity of adjusted break-even frequency to magnitude of price increase and discount rate (crisis is price upsurge)



In figure 4.5, we observe that our result is rather robust. A price increase of 150% instead of 200% raises the adjusted break-even frequency to 3 times in the prolonged period, while a price increase of 250% reduces it to 2 times within the four-year period. Only a price increase above the 450% need a break-even frequency of one time in the four years to make the policy measure an efficient one. The adjusted break-even frequency appears to be more sensitive to the applied discount rate at lower levels of price increases.

According to figure 4.6, even a five days interruption of production needs occur 18 times within the prolonged period of four year. Moreover, it turns out that the applied discount rate cannot render the policy measure efficient either. Again, the resulting adjusted break-even frequencies become more sensitive to the discount rate applied if the duration is shortened.

Increasing the duration of the 200% higher price level from 4 to 5 months (in case of a price surge) reduces the break-even frequency to once every 2.9 years or 1.4 times within the four-year period (see table 4.4). In addition, assuming a scenario with a lower average gas price (20 eurocents) than so far employed (23 eurocents), reduces the break-even frequency to once every 2 years.

Figure 4.6 Sensitivity of adjusted break-even frequency to duration of the shortage and discount rate (crisis is physical shortage)

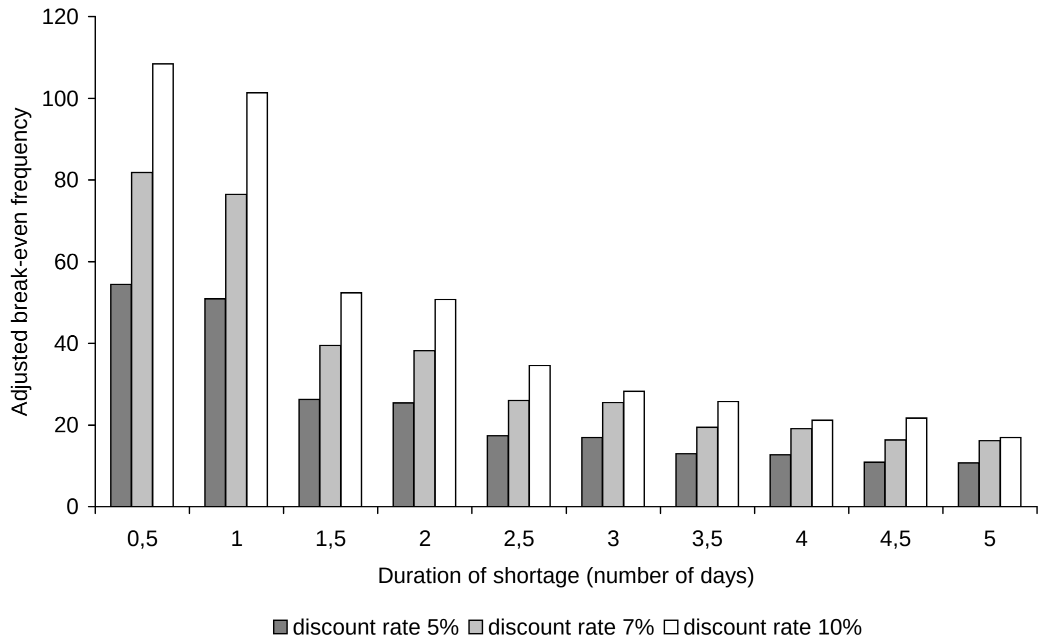


Table 4.4 Sensitivity of break-even frequency to assumptions

Variant	Crisis 1: Price upsurge Crisis needs to occur at least once every …years (A)	Crisis 1: Price upsurge Crisis needs to occur … times within four years (B)	Crisis 2: Physical shortage Crisis needs to occur at least once every …years (C)	Crisis 2: Physical shortage Crisis needs to occur … times within four years (D)
Base case	2.29	1.75	0.21	19.11
Discount rate is 5% instead of 7%	3.39	1.18	0.31	12.71
Discount rate is 10% instead of 7%	1.76	2.27	0.19	21.19
Price increase of 100% instead of 200%	1.14	3.49	.	.
Price increase of 300% instead of 200%	3.43	1.16	.	.
Duration of price increase is 3 months instead of 4	1.72	2.33	.	.
Duration of price increase is 5 months instead of 4	2.86	1.40	.	.
Duration of shortage is 3 instead of 4 days	.	.	0.16	25.47
Duration of shortage is 5 instead of 4 days	.	.	0.25	16.13
Included VOLL household production is 50% of estimate	.	.	0.17	23.41
Included VOLL household production is 0% of estimate	.	.	0.13	30.21
Average gas price is 20 eurocents instead of 23	2.14	1.87	0.24	16.39

Note: VOLL = Value Of Lost Load

Sensitivity analyses concerning the crisis of physical shortage show a different picture: the break-even frequencies vary more widely (from 13 to 31 times within the four-year period). Also noteworthy is the fact that an increase in the duration of the gas interruption to 5 days gives a 16% decrease in the number of times this crisis needs to occur within the four-year period. But still, 17 times within four years is very high. Loosening our assumptions on the lost value of household production by stating that only 50% of normal production would be lost, raises the adjusted break-even frequency to 24 times within the four-year period.

4.3.7 Conclusions

Capping production from the Groningen gas field in order to secure supply in a case of extreme demand in the long term appears to be a highly expensive measure. The break-even frequencies of surging gas prices as well as physical shortages are once in every year. Such a high frequency of severely cold winters is highly improbable. Despite this conclusion, the question remains whether capping production from the Groningen field would be efficient if this issue is analysed from a broader perspective than that of security of supply alone (see box 'The optimal use of the Groningen field'). In order to answer this question, additional research should be conducted.

The optimal use of the Groningen gas field

Economically, the optimal path of depletion of natural resources follows from the development of marginal costs, prices of the resource, and the real rate of interest (see e.g. Perman et al., 1999). Contrary to most other natural resources, the Groningen gas field has a specific characteristic that influences strongly the optimal depletion path. That characteristic is the ability to supply swing, i.e. the ability to adapt immediately the level of production to fluctuations in demand. This ability is unique and highly valued by consumers. Consequently, the owner of the Groningen field faces the question how to allocate efficiently his (scarce) resource to swing demand and normal (base load) demand. The former is valued higher, but both the reward for swing as its volume are fairly uncertain. To make things more complicated, this problem of optimal allocation is not a discrete one, but refers to a continuum of choice options. Consequently, the key question regarding the depletion of the Groningen field is not 'to swing or not to swing', but 'how many swing should be delivered'.

In the base case analysed in this report, we took a rather extreme position on the above continuum of options by focussing on the delivery of swing in case of an extremely high demand. From the cost-benefit analysis conducted in this report follows that destining Groningen for this type of swing would be highly expensive. Supplying swing on a more frequent basis, on the contrary, could be very profitable. Up to now, Groningen has primarily been used to deliver seasonal swing, while base load production is rather low. The ability of this huge gas field to deliver swing is threatened, as is described elsewhere in this chapter. The question remains, therefore, to which extent this threat should be mitigated. For instance, would it be efficient to reduce the delivery of normal seasonal swing in order to increase the future ability of meeting swing demand above the normal pattern? In order to answer that question, costs of reducing seasonal swing plus establishing alternative seasonal swing, for instance by extending the number of gas storage facilities, should be compared to benefits of delivering supra normal swing. In addition to this, attention should be given to the relationship between swing production by Groningen and production by the other, small fields. After all, extending the lifetime of the swing producer would positively affect the base load production from the other fields.

4.4 Cost-benefit analysis of substituting gas-fired electricity capacity

4.4.1 Definition of a crisis

In section 4.2.3 we identified the risk of an increasing dependency on imports as being a potential threat for Dutch security of gas supply in the long term. The specific crisis subjected to a cost-benefit analysis is a price increase: for some non-specified reason, the average European gas price experiences a 50% increase compared to the expected price level, continuing for a full year.

4.4.2 Definition of a policy option

The obvious way to reduce the vulnerability to shocks in the natural gas market is to bring down gas demand. In the Netherlands, three sectors are the major users of natural gas: electricity generation, horticulture and households. The latter two may reduce their gas use through either taxation or regulation (e.g. standards for energy use of dwellings). Gas use in the electricity sector may either be reduced through a reduction in electricity use (again through taxation or regulation) or by diverting technique choice away from gas-fired plants. Within the latter option, we distinguish between a shift towards wind energy, towards coal-fired generation or towards nuclear powered electricity. Economically, diversification of generating techniques is a more interesting case then straight regulation of energy use, since the latter has a limited scope. Therefore, we focus on the former.

The options for diversification of generating techniques have very comparable benefits, as each option may be expressed as a measure substituting an equal amount of gas-fired capacity. By substitution, we do not mean *replacement* of existing gas-fired plants by other types of plants. Instead, our analysis compares the economic consequences between investments in different *new* generation plants. Moreover, we do not devote any attention to the question *how* substitution is brought about. Rather, we assume that some policy measure succeeds in accomplishing substitution with no other costs than the ones described here.

In this analysis, we distinguish between large scale and small-scale substitution of gas-fired capacity as the costs of some of the techniques mentioned here are quite sensitive to scale effects. On shore wind energy is fairly inexpensive if favourable locations are used. After these locations have run out, costs increase rapidly, indicating that large scale expansion of wind energy comes at high costs. For nuclear power on the other hand, positive economies of scale are likely to be gained because of huge fixed costs.

For small-scale substitution, we link up with a recent proposal from the Dutch political party *GroenLinks*.[31] This proposal mentions several locations for wind turbines, adding up to a

[31] See CE(2003) for a description of this proposal.

capacity of almost 1000 megawatt. This is equivalent to the substitution of roughly 288 megawatt of gas-fired capacity.[32] These locations are taken into account by CE (2003) and prove to be fairly cost-effective.[33] In the case of large-scale substitution, we assess the effects of substitution of 1000 megawatt of new gas-fired capacity. At this size, scale economics for most techniques are exhausted.

4.4.3 The costs of the policy option

Like in the other sections in this report, we distinguish direct cost, indirect costs and external costs.

Direct costs

Obviously, costs of generation constitute a major direct cost. We use figures from OECD (1998), the only source where costs of different techniques and different countries are considered on a uniform basis. Appendix 5 offers a fairly elaborate discussion on generation cost figures. This paragraph gives only the results of that discussion. A gas-fired plant has costs of 4.2 eurocents per kWh. Costs of coal-fired generation are 5.3 eurocents per kWh, whereas the nuclear option has the highest generation costs, at 5.9 eurocents per kWh. Note that nuclear power is sensitive to economies of scale, so that costs at a scale of 288 megawatt may be even higher than the figure presented here. Generation costs for wind power are also very sensitive to scale effects. Generation costs for wind power in the small scale case are as low as 5.2 eurocent/kWh. At large scales, investments in wind energy are very likely to be off-shore investments, so we use the costs of off-shore wind electricity as an upper bound for costs. We assume that the remainder of required capacity has linearly increasing costs, ranging from the lower bound of 5.2 eurocents per kWh to the upper bound of 7.1 eurocents per kWh. Because of the assumption of linear increasing costs, average costs are defined as the unweighted average of the upper and lower bound, 6.1 eurocents per kWh. Using this figure for the remaining capacity and 5.2 eurocents per kWh from the small-scale substitution case, we arrive at an average cost figure of 5.9 eurocents per kWh.

[32] As wind turbines demand specific wind conditions – the speed has to be between a minimum and a maximum value - , we have to correct wind turbine capacity for the number of working hours normally to be expected. In the Netherlands, 1000 megawatt of wind turbines are equivalent to 1.895 TWh of production per year. As gas-fired plants are sometimes unavailable as well (OECD, 1998 mentions a settled down load factor of 75%) roughly 288 megawatt of gas fired capacity is needed to deliver this production.

[33] More precisely, all but the single smallest site proved to be cost-effective. The smallest site, with only 6 wind turbines, is deleted from our analysis.

Choosing the discount rate

In order to determine the appropriate discount rate, we use the rule of thumb discussed in Section 2.6. A policy option aiming at substituting investments from one type of plant to another is comparable to a private project of investment in generation capacity. Although investments in generation capacity are generally not aimed at decreasing the vulnerability for gas price shocks, the generation capacity build as result of this policy will primarily be used for normal production, just as any other power plant. This implies that we should use the same discount factor as in the case of usual investments in power plants. Current uncertainties in electricity markets, both with respect to future climate policies and to the effects of a further integration of European markets, urge producers to use a fairly high discount rate. The most important reliable source for electricity cost figures, OECD (1998), offers the choice between 5 and 10 percent. Given the uncertainties mentioned above, we use the figure of 10 percent here.

As wind energy is not available all of the time, it also incurs costs for backup. The effect of unavailability is already reflected in generation costs, but this does not take into account the security aspect. Although an average wind farm will produce electricity for 92% of the time, one must keep in mind that a large share of wind energy in total electricity production would make the system more vulnerability. For a wind turbine to be exactly as secure as a gas plant, a spare power plant would have to be available all of the time. To compare the techniques on a similar basis, we add costs for capacity backup: the costs of keeping a gas-fired plant of 288 megawatt available as a backup in case the wind ceases in a peak period.[34] Following the before mentioned OECD-publication, these costs may be computed to be 1.4 eurocent/kWh, regardless of the scale.

The third direct cost item to be discussed consists of the cost of legal procedures. Legal costs amount to 200 thousand euro for an average on shore wind energy project, according to CE (2003). These costs include costs of external legal assistance and environmental-effect assessment studies, as well as costs of developer man-hours and costs of advice on spatial zoning plans. As there are 6 locations for plants in the measure, we multiply these costs by 6. We assume that no legal costs apply to offshore wind turbines. Further, we assume that building a nuclear plant needs similar procedures. We take CE's upper bound of 350 thousand euro because, in that case, the procedure will probably be complicated. A single plant suffices here, so we do not have to multiply the figure.

Changing the technique mix in the market for electricity has some effects on market outcomes as well. These effects are likely to affect welfare, on top of the cost effects, mentioned before. Nuclear power, coal-fired electricity and wind power all have high capital costs and low marginal costs relative to gas-fired electricity. This influences the role of scarcity in the market and in the process of price formation, impacting both the amount and the division of welfare in the market. We use our model of the European electricity market (see Appendix 5) to assess these effects.

[34] We assume that keeping a backup requires investment costs, as well as half of the normal operation and maintenance costs.

As the costs of substitutes are higher than those of gas-fired electricity, electricity prices will rise somewhat. This effect is not caused by an increase in marginal costs, since gas-fired plants are the marginal units. The investment costs for coal, wind and nuclear power are larger than for gas power, leading to a lower level of investment, thus increasing scarcity. The increase in scarcity causes prices to rise, which in turn leads to lower quantities and, therefore, reduce welfare. Since the amount of capacity substituted is relatively small, welfare effects will be limited. For the large-scale substitution case, they are 0.4 million euro a year, for the small-scale substitution case, the effects are less than 0.1 million euro.

The tables 4.5 and 4.6 summarise the annual average of the present value of direct costs of each alternative option

Table 4.5 Average annual costs of small-scale substitution (direct effects, discounted values in million euro)

Item	Wind	Coal	Nuclear
Additional costs of generation	2.8	3.3	5.0
Costs of capacity backup	3.9	-	-
Legal costs	0.2	-	0.1
Welfare effects of changes in electricity market	0.0	0.0	0.0
Total direct costs	6.9	3.3	5.1

Table 4.6 Average annual costs of large-scale substitution (direct effects, discounted values in million euro)

Item	Wind	Coal	Nuclear
Additional costs of generation	16.6	11.5	17.4
Costs of capacity backup	13.4	-	-
Legal costs	0.2	-	0.1
Welfare effects of changes in electricity market	0.4	0.4	0.4
Total direct costs	30.6	11.9	17.9

Indirect costs

The welfare effects on the electricity market, although small, also have their effect on the economy as a whole, through higher producer prices and shifts between production factors, causing friction costs. These costs are practically zero in the case of small-scale substitution and have an annual average present value of 0.1 million euro in the case of large-scale substitution for all policy options.

Pricing external effects: the case of CO_2-emissions

As, by definition, external effects are not priced by markets, shadow prices have to be used in order to give these effects full attention in a cost-benefit analysis. Since CO_2-emissions constitute the major external effect related to the use of (fossil) energy, we would like to incorporate this effect numerically in our calculations. The key question then is which shadow price should be used?

Theoretically, three cost approaches of determining the shadow price of CO_2 emissions exist: the costs of damage, the costs of adaptation, and the costs of mitigation. In the first approach, the shadow price of the marginal unit of emissions is based on the marginal damage costs. It is hardly possible to assess these costs, as the effects of the emissions on climate and, hence, on conditions for life on earth appear only in the (very) long term and, in addition, the precise causal relationship among these quantities is all but perfectly known. Due to the fact that we have insufficient knowledge about future damage costs of growing carbon concentration in the atmosphere, calculating the costs of adaptation to new climate conditions is also problematic. Therefore, the third approach, directed at mitigation costs, is usually followed.

Mitigation costs are easier to calculate, but the marginal value and, hence, the future shadow price is fairly uncertain. This value depends, generally spoken, on expectations regarding costs of future mitigation techniques, firstly, and governmental policies directed at reducing the emissions secondly. The first component can be described by marginal mitigation cost curves showing a set of mitigation techniques ranked by the costs of reducing one unit of emission.

One of the techniques available to reduce the emissions of CO_2 is storage. The marginal costs of this technique (including the costs of removing, transporting and storing) are assessed at 6 to 16 euro per ton (UCE-UU, 2002). Although this technique is politically not accepted up to now, it is conceivable in a scenario such as Transatlantic Market.

Techniques directed at energy saving generate higher costs in the Netherlands, as many cost-effective saving options have been taken yet. The costs of reducing emissions will, however, be rather low if an international emissions trading scheme will be implemented, as is the case in our Strong Europe scenario. In that scenario, the (shadow) price of CO_2 is approximately 10 euro per ton in 2010, but will rise sharply due to the (assumed) tightening of the ceiling in the following decades.

External costs

As generation techniques differ in the extent of emissions per unit of output, diversifying the power sector incurs external effects. To compare gas-fired and coal-fired generation with CO_2-free nuclear and wind energy, we assume that CO_2 is removed (see the box ‘Pricing external effects: the case of CO_2-emissions’). The costs for removing, transporting and storing CO_2 are then added to the generation costs of coal-fired electricity, using assumptions similar to those used in OECD (1998). The DACES –database (UCE-UU, 2002) gives a cost-range for CO_2-reduction of 6 (large scale) to 16 (small scale) euro per ton. Assuming a settled down load factor of 75 percent and thermal efficiency of 40 to 50 percent, this boils down to 0.4 to 1.4 eurocents per kWh for coal. In the case of natural gas, having a lower carbon content per unit of energy, we find CO2-removal costs to range from 0.24 to 0.81 eurocents per kWh. We use the upper bounds of these outcomes. The average annual present value of the emissions of a 288 megawatt gas plant may be calculated to amount to 2.3 million euro (see table 4.7). Carbon free generation techniques avoid these costs. For a coal plant, the figure is 3.8 million euro, leading to net external costs (again, the average annual present value) of 1.5 million euro. For the large scale case, the average annual present value of the emissions amounts to 7.9 million euro for a gas plant and 13.2 million euro for a coal plant, yielding net costs of 5.3 million euro (see table 4.8).

Both gas and coal plants emit other pollutants (NO_x and SO_2), even if CO_2 is removed. We use 2010-figures from Gijsen et al. (2001, page 62) to obtain emission factors (for coal: 514 ton SO_2/TWh and 707 ton NO_x/TWh, for gas: 168 ton NO_x/TWh) and combine it with a shadow prices of 4 euro per kilo for SO_2 and 4.5 euro per kilo for NO_x (source: www.ce.nl). In the small scale case, the average net present value of these costs amounts to 1.4 million euro for gas and 6.6 million euro for coal. For the large scale case, these figures are 5 and 23 million euro respectively. The external costs from nuclear waste and the risk of accidents are already present in the generation costs figures, as they also contain costs for waste disposal and insurance, the latter reflecting the expected costs of liability claims (see appendix 6). Table 4.8 summarise the annual average of the present value of external costs of each alternative option.

Besides carbon-dioxide emissions, production of electricity can generate other external costs. Wind turbines have a negative visual impact and cause noise nuisance. Based on CE (2003), we calculate this impact to be equivalent to 2.3 million euro (0.3 if discounted over the entire period) for the small scale case (see table 4.8). We assume that the external costs for offshore wind turbines are negligible, so we use the same figure for that large scale case.

Table 4.7 Average annual external costs of small-scale substitution (discounted value in million euro)

Item	Wind	Coal	Nuclear
Costs of CO_2-removal	– 2.3	1.5	– 2.3
External costs of other pollutants than CO_2	– 1.4	5.2	– 1.4
External costs of noise nuisance and visual impact	0.3	-	-
Total external costs	– 3.4	6.7	– 3.7

Table 4.8 Average annual external costs of large-scale substitution (discounted value in million euro)

Item	Wind	Coal	Nuclear
Costs of CO_2-removal	– 7.9	5.3	– 7.9
External costs of other pollutants than CO_2	– 5.0	18.0	– 5.0
External costs of noise nuisance and visual impact	0.3	-	-
External costs of nuclear waste and risk of accident	-	-	p.m.
Total external costs	– 12.5	23.3	– 12.8

4.4.4 The benefits of the policy option

As discussed in chapter 2, we note that the benefits of the policy options occur in the case of a crisis. The crisis, as described in section 4.2.4, consists of a 50 percent increase in the price of natural gas for a full year. The benefits listed in this section are conditional on such a crisis.

Direct benefits

Two types of direct benefits follow from the policy options described here. First, the cost increase coming from the gas price surge is partly avoided. Second, welfare effects follow from the reduced increase in prices.

In case of a gas price shock, the costs of gas-fired electricity increase. In all policy options considered here, the amount of gas-fired capacity is smaller, leaving the system less vulnerable for such a price shock. The benefits of substituting a certain amount of gas capacity can easily be calculated by multiplying the substituted capacity by the increase in gas-fired costs. An increase of 50 percent in fuel costs for a gas-fired plant boils down to a cost increase of roughly 1.3 eurocent per kWh. If the gas price shock lasts for a full year and small-scale substitution should be in place, the annual benefit is 23.4 million euro; the average discounted value of this benefit equals 3.5 million euro (see table 4.9). For the large-scale substitution cases, these figures amount to 81.2 and 12.1 million euro respectively.

In the previous section we stated that the technique mix in the market influences market outcomes. This implies that the technique mix is also likely to influence the impact of a crisis on that market. Again, we use our model of the European electricity market to assess the effects. Substitution dampens the cost effect of the shock and, therefore, keeps down prices somewhat. Like in the base case, the immediate effect is fairly small, as gas-fired power remains both the dominant and the marginal technique. Keeping down prices relative to the base case implies that quantities are somewhat higher than in the base case, so that welfare is higher. Model simulations suggest that the order of magnitude is 0.3 million (present value: 0.1 million) euro for the small scale case and 2.3 million (present value: 0.5 million) euro for the large scale case.

Table 4.9	Direct benefits of small-scale substitution (discounted value in million euro)
Item	Value
Avoided increase in costs of gas-fired electricity	3.5
Welfare effects of changes in electricity market	0.1
Total direct benefits	3.6

Table 4.10	Direct benefits of large-scale substitution (discounted value in million euro)
Item	Value
Avoided increase in costs of gas-fired electricity	12.1
Welfare effects of changes in electricity market	0.5
Total direct benefits	12.6

Indirect benefits

Like before, the welfare effects on the electricity market have an effect on the economy as a whole: the indirect benefits. These benefits are high relative to their counterparts on the cost side, as a sudden shock hurts more than a gradual price increase. Nevertheless, their value is quite small: the present value of the indirect benefits amounts to less than 0.1 million euro in the small scale case; in the large scale case, the indirect benefits are 0.2 million euro.

External benefits

For the sake of completeness we take external effects into account, as we did with the costs (for computation: see section 4.4.3). The effects follow from the small (avoided) decrease in electricity consumption are well below 0.1 million euro in all cases.

4.4.5 The break-even frequency

From the figures in the previous section, we can easily compute the break-even frequency (see tables 4.11 and 4.12). This figure expresses at what frequency a pre-defined crisis will have to occur to equal costs and benefits of the policy options (see chapter 2 for more details).

The results from the table show that the break-even frequencies for all policy options are high, implying that the policy options are probably not viable. In most cases, it requires more than an annual crisis to render the policy option economically sound. Taking into account that the crisis is defined as a gas price increase of 50 percent for a full year, we may state that this is highly unlikely.

Table 4.11 Costs and benefits of small-scale substitution within the power sector (discounted value in million euro)

	Wind turbines	Coal-fired plants	Nuclear plants
Average annual costs			
Direct effects	6.9	3.3	5.1
Indirect effects	0.0	0.0	0.0
External costs	– 3.4	6.7	– 3.7
Total	3.5	10.1	1.4
Total benefits in case of one crisis			
Direct effects	3.6	3.6	3.6
Indirect effects	0.0	0.0	0.0
External costs	– 0.0	– 0.0	-0.0
Total	3.6	3.6	3.6
Break-even frequency			
Once every … years	1.01	0.35	2.59

Table 4.12 Costs and benefits of large-scale substitution within the power sector (discounted value in million euro)

	Wind turbines	Coal-fired plants	Nuclear plants
Average annual costs			
Direct effects	30.6	11.9	17.9
Indirect effects	0.1	0.1	0.1
External costs	– 12.5	23.3	– 12.8
Total	18.1	35.3	5.0
Total benefits in case of one crisis			
Direct effects	12.6	12.6	12.6
Indirect effects	0.2	0.2	0.2
External costs	– 0.0	– 0.0	– 0.0
Total	13.8	13.8	13.8
Break-even frequency			
Once every … years	0.70	0.36	2.53

4.4.6 Sensitivity analysis

The analysis in this chapter uses a great deal of assumptions, urging the need for a sensitivity analysis. We test for the sensitivity for the discount factor, the external costs related to CO_2-emissions, the severance of the shock, the gas price, the load factor of power plants and the capital costs of nuclear power. The latter is simulated by bringing down capital costs for nuclear plants by 1 cent per kWh (at a 75% settled down load factor). Because of scale economies in nuclear power, such cost savings (making a nuclear plant as less capital intensive as an average French nuclear plant) can only, if at all, be realised in the large scale case.

Table 4.13 Sensitivity of break-even frequency of small-scale substitution to assumptions

Variant	Wind turbines	Coal-fired plants	Nuclear plants
Base case	1.01	0.35	2.59
Discount factor 5% instead of 10%	0.81	0.49	1.59
Shadow price of carbon dioxide 10 instead of 16 euro/ton	0.81	0.38	1.60
Shadow price of carbon dioxide 50 instead of 16 euro/ton	– 2.77	0.27	– 1.03
Increase of gas price 100% instead of 50%	2.01	0.71	5.18
Level of gas price 10% higher than in baseline scenario	1.27	0.38	5.58
Level of gas price 20% higher than in baseline scenario	1.72	0.42	– 36.49
Settled down load factor of 90% instead of 75% (wind remains at 30%)	0.87	0.37	– 303.16

Table 4.14 Sensitivity of break-even frequency of large-scale substitution to assumptions

Variant	Wind turbines	Coal-fired plants	Nuclear plants
Base case	0.70	0.36	2.53
Discount factor 5% instead of 10%	0.60	0.50	1.58
Shadow price of carbon dioxide 10 instead of 16 euro/ton	0.61	0.39	1.60
Shadow price of carbon dioxide 50 instead of 16 euro/ton	9.14	0.27	– 1.09
Increase of gas price 100% instead of 50%	1.41	0.73	5.06
Level of gas price 10% higher than in baseline scenario	0.82	0.39	5.12
Level of gas price 20% higher than in baseline scenario	0.98	0.43	– 221.43
Settled down load factor of 90% instead of 75% (wind remains at 30%)	0.64	0.38	53.21
Costs of nuclear 1 cent/kWh lower (at 75% settled down factor)	0.70	0.36	– 3.05

The sensitivity analysis shows that the numerical values of our outcomes for wind and coal are fairly insensitive to changes in the assumptions (see tables 4.13 and 4.14). The conclusion from the break-even frequency, being that the policies are unlikely to be economically viable, is unaffected by most assumptions. Only if the carbon shadow price is at a high level, the break-even frequency becomes negative for small scale wind power. This implies that the policy is viable as environmental policies rather than security of supply policies.

The picture is somewhat more differentiated for nuclear power. Changing the assumptions on the carbon shadow price, the gas price level, the load factor and capital costs, yields a picture in which nuclear power is either cheaper than gas-fired power (negative net costs causing a negative break-even frequency), or an attractive alternative. [35] The latter is the case for large-scale substitution with a consistently high load factor: the substitution policy is viable if a crisis is expected once every 53 years.

4.4.7 Conclusion

This chapter calculated the costs and benefits of substituting investments in new gas-fired plants by investments in new wind turbines, coal-fired plants or nuclear plants, distinguishing between small (288 megawatt) and large (1000 megawatt) scale. The expected benefits of this type of substitution are that electricity prices will be less vulnerable to shocks in gas prices.

The break-even frequencies for all defined policy options are high, implying that these policy options are not economically viable. Sensitivity analysis shows that this conclusion is fairly robust for wind and coal-fired power. For nuclear power, changing some of the assumptions changes the conclusion dramatically. Investments in nuclear power plants could be efficient if the latest techniques would be used, in combination with an exceptionally high load factor.

Apart from the break-even frequency, we need to assess whether there is a reason for government intervention. In the absence of market failure private parties would be able to take care of the policy themselves. In this case, all costs and benefits are directly related to electricity production and the only market failure present consists of the external costs of electricity production. After all, the indirect effects seem to be negligible. Note, however, that ignoring the external, environmental costs would induce private parties to implement *more* substitution by coal-fired plants rather than *less*. This implies that government intervention, if any, would be to discourage this type of substitution. Wind power and, depending on the valuation of external costs of waste and accidents, nuclear power, may be encouraged from an environmental point of view, but one should keep in mind that the reason for government intervention is not security of supply in this case.

[35] See Appendix 4 for more details on electricity generation costs.

5 Electricity market

5.1 Introduction

In the ongoing process of liberalising electricity markets around the globe, concerns have risen whether supply would still be secured in fully liberalised markets. Several incidents have strengthened the fear for blackouts, urging policy makers and researchers to look for instruments to retain security of supply. Like in the other chapters, we assess the economic consequences of policy options given a well-defined design. Consequently, we do not aim at finding the socially optimal amount of capacity, which is a common feature in economic literature on capacity planning.

This chapter begins by describing some historic disruptions in the electricity market and analysing potential risks for the near future (section 5.2). The definition of two conceivable crises on the electricity market concludes this section. Afterwards, we conduct cost-benefit analyses of two policy measures. First, we analyse the costs and benefits of increasing reliability of electricity generation (section 5.3). Next, we assess the economic consequences of raising the levy on consumption of electricity (section 5.4).

5.2 Analysis of risks

5.2.1 Historical evidence on risks

The most striking event relating to a crisis in the electricity market is obviously the California-crisis in 2000 and 2001. Soaring wholesale prices, rolling blackouts and even more near-blackouts focused the world’s attention on the vulnerability of electricity production. Recent outages in the US, Canada, England, Scandinavia, Greece and Italy (twice) have emphasized the importance of electricity for modern day society. The causes of these crises vary widely. The Californian crisis was caused by a combination of weather conditions and faulty design of regulations (see the box ‘What went wrong with California’s restructured electricity market?’). Technical problems were the major cause of the huge outage in the Northeast of the US and the Southeast of Canada in 2003. In that year, an unusually hot summer contributed to several electricity crises in Europe.

In Greece, the hot summer months in 2003 boosted the sales and use of air-conditioning equipment, causing blackouts. We may interpret such a crisis as a (presumably unexpected) demand shock. Producers had anticipated a lower demand level in their investment decisions, leaving them with insufficient capacity when demand surged. The same happened in Italy, be it that supply factors played a role here: cooling water problems and technical accidents respectively.

What went wrong with California's restructured electricity market?

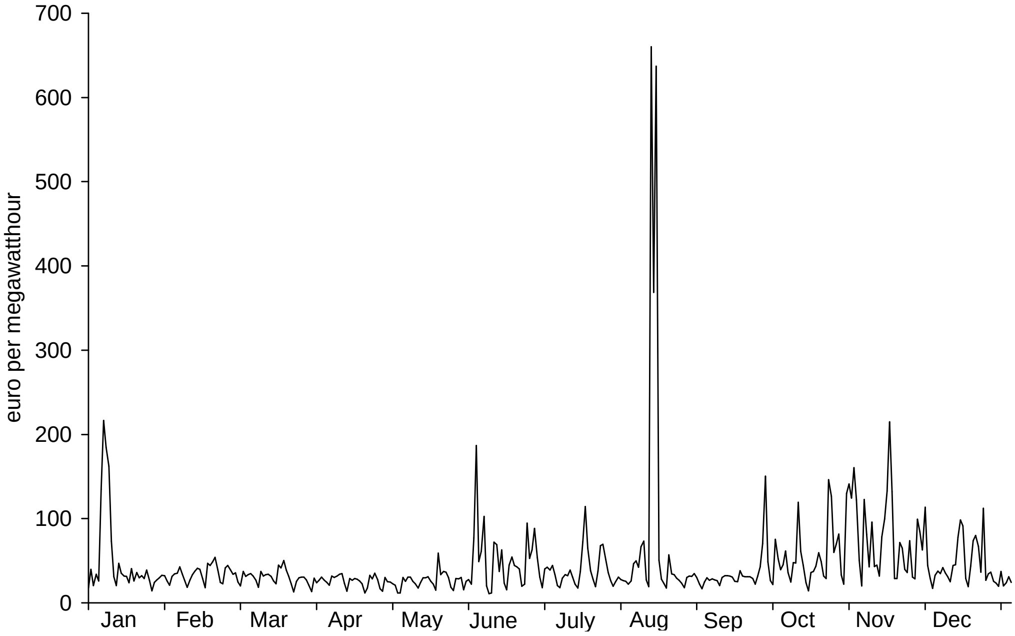
The electricity market in California was deregulated in 1998, after which wholesale trades were opened to competition, while retail prices remained to be regulated by the California utility regulator, CPUC. The market seemed to work well during the first two years. However, in May 2000 wholesale electricity prices in California exploded. High prices persisted over the summer, bringing distribution companies (IOU's) into financial difficulties. After the summer, two IOU's appealed to the CPUC to raise retail prices, but this was refused. Continuing to experience cash-flow problems, the IOU's suspended payments to electricity producers. No longer being paid for their output, producers began to shut down their units. Production unit outages, which were stable in the summer 2000, rose rapidly during the November-March period of 2000-2001. In January 2001, the California ISO had to curtail firm loads several times due to a system shortage of available capacity. Only after the California Legislature finally passed Assembly bill IX, allowing the State government to take major purchasing responsibilities from the financially moribund utilities, the situation began to stabilise. The supply crisis was largely resolved in late May. The economic consequences of the lack of sufficient competition retain.

Joskow and Kahn (2002) present an empirical analysis of the factors that caused the high electricity prices in the summer 2000, comparing to 1998 and 1999. They conclude that 'market fundamentals', such as increases in gas prices, increased demand, reduced availability of power imports, and higher prices for emission permits, contributed to significantly higher wholesale market prices in California in 2000. However, the change in market fundamentals does not fully explain high wholesale prices observed in the summer 2000. In particular, Joskow and Kahn mention the possibility that producers withheld capacity to drive the prices up. Although the latter possibility might be overstated, the point is that the market power exercised during the summer of 2000 produced financial conditions that led to supply crisis. As Bushnel (2004) describes: "…the market power of producers which exacerbated by the tight market conditions during the summer of 2000 combined with inflexible regulatory policies at the both Federal and State level to create financial crisis. The financial crisis in turn led to the blackouts experienced during the winter 2000-2001. These involuntary interruptions of service are what defined the period as a crisis, rather than just a period of market instability."

What was wrong with the market design in California? Wolak (2001) calls conflicting regulatory policies to be the primary reason why deregulation did not bring benefits to the customers. On the federal level, the objective was to create wholesale electricity markets, leading that FERC, gave electricity suppliers discretion over how they bid and operate their electricity generating facilities. At the same time, the state regulator tried to balance the competing pressure from different consumer groups and remnants of the formerly vertically integrated monopolies. In California the latter resulted in freezing retail prices and requiring that the utilities restrict their trades to the Power Exchange. As concluded by Wolak (2001): "The market conditions that result from this combination of regulatory policies create significant opportunities for generation units owners to earn enormous economic profit for sustained period of time, as occurred in California from May 2000 to May 2001."

Another example from Europe's hot summer can be found in The Netherlands. Many of the Dutch power generators are cooled using water from rivers rather than cooling towers. As the hot summer continued, temperatures of river water rised. The temperature at which cooling water is allowed to be discharged back into the rivers is regulated however, since too high levels are detrimental for fluvial life forms. Producers had to tune back their plants to limit the cooling water's temperature, thus decreasing the actual availability of electricity generating capacity. No blackout occurred here, but prices peaked on the spot markets (see figure 5.1). We interpret this crisis as an unexpected shock in availability of capacity, noting that producers were likely to have a higher availability in mind when making investment decisions.

Figure 5.1 Daily base load prices on the Amsterdam Power Exchange in 2003 (in euro per megawatt hour)



Source: Amsterdam Power Exchange

In the United States and Canada, a series of electricity plant break downs caused a huge blackout for more than a day throughout the Northeast of the US and the Southeast of Canada. Like the previous example of cooling water in The Netherlands, we may interpret this crisis as an unexpected reduction in availability of generating capacity.

5.2.2 Assessment of future risks

The abovementioned disruptions on electricity markets have raised worries about the potential impact of liberalisation of these markets on security of supply. The key issues are whether liberalisation would lead to strategic behaviour of power producers, resulting in higher electricity prices, and insufficient investments in production and transmission capacity, resulting in higher price volatility and more blackouts.

It is yet unclear whether all Europe's national electricity markets are to open up, to what extent and at what speed. A slowdown in opening up national markets is likely to hamper the formation of a single European market. The single market is needed to facilitate increased competition between producers from different countries, thus diminishing market concentration, which is currently fairly high at the national scale. As a reaction to European markets opening up, however, a process of mergers and take-overs seems to have started up among European electricity generators. Such a process would undoubtedly lead to higher concentration and thus hinder competition (Speck et al., 2003). The reaction of national and European competition authorities is mild for now, but may toughen as concentration increases further.

A necessary condition for an integrated European electricity market is a sufficient supply of trans-border transport capacity (Joskow et al., 2000). Along many intra-European borders, capacity is now expanded. It is, however, not clear yet whether expansion will continue and whether investments will indeed be sufficient to lead to an integrated European market. In addition, harmonisation of policies regarding access to the grid is needed in order to get fully competitive markets. If these conditions are not satisfied, electricity producers could be able to influence market outcomes, for instance, by withholding generation capacity which may drive up prices.

The other major risk facing the electricity market regards the level of the reserve capacity. The opening up of the European markets decreases the relative size of the necessary reserve capacity. It is, however, questionable whether private firms have sufficient incentives to invest in capacity which will hardly be used. Normal (e.g. daily) peaks may be met by generators with low fixed costs, but a supra-normal (say once-a-year) peak requires a very high price to guarantee cost recovery. Incentives in a liberalised electricity market may be insufficient to make sure that capacity will always meet peak demand (Green, 2003; Oren, 2000). The major problem in this context is that generation capacity for supra-normal peaks is uncertain to be deployed and stands idle for so often, not generating revenues for its owner. This implies that it is not economically feasible, let alone profitable, to build these plants. A lack of sufficient supra peak capacity may lead to a crisis if demand suddenly surges, or if the availability of capacity is suddenly limited.

5.2.3 Definition of potential crises

From the above assessment of future risks, we define two different kinds of crises:

- a short-living extreme surge in demand or unexpected shock in the availability of capacity, resulting in price spikes or blackouts;
- a longer lasting increase in the average level of the power price due to execution of market power by producers.

5.3 Cost-benefit analysis of increasing reliability of electricity production

5.3.1 Definition of a crisis

In the analysis in this section, we simulate a crisis in the availability of capacity. To mimic the 'Dutch cooling water crisis', we bring down the availability of all fossil-fuel fired generating capacity (about 84% of total capacity) from 75% to 65%. Our next question would be what the implications of such a crisis might be. If the market[36] responds adequately, prices will spike during the crisis, causing large distribution effects, but small welfare effects. If capacity is insufficient and demand is unable to respond to price signals in a timely manner, a decrease in the availability of operational capacity may induce a system break down, causing blackouts. These blackouts will probably be regional by nature as the network operator disconnects certain groups or regions from the grid. These blackouts cause large or even very large welfare effects. We define this crisis here as a 24-hour blackout for the Randstad area.

5.3.2 Definitions of the policy options

The obvious solution to the problem described in the previous section is to make sure that (supra-normal) peak capacity is rewarded for being available, rather than for its output alone. Three main types of measures are considered here[37]:

- capacity markets;
- reserve contracts;
- capacity payments

The first two aim at increasing spare capacity in electricity markets.[38] The third measure aims at increasing production capacity in general.

In capacity markets, the transmission system operator (or some other central actor, such as government) requires traders to back their own peak load plus a proscribed level of spare capacity with contracted capacity. Traders, formally load-serving entities, are the ones that sell the electricity to end-users, acting as intermediaries on the electricity market. Their position in the market makes them a logical point to enforce a capacity requirement. Traders are allowed to trade bilaterally units of capacity, which creates a (formal or informal) capacity market, generating revenues for production capacity, even if it is not dispatched. The market mechanism makes sure that spare capacity is offered by those producers that can do it in the most efficient

[36] 'The market' includes back-up options like variable capacity, the unbalanced market and emergency import arrangements.
[37] Dutch government also holds another option under consideration, called reliability contracts. This option will not be analysed here, as it has some aspects that are hard to analyse within our framework. Two aspects that are particularly hard to quantify are the possible effect on capital costs through a reduction in uncertainty and the possible windfall profits from gaming in the auction process that are specific to reliability contracts. See Lijesen (2004) for details.
[38] We fit the amount of spare capacity to the crisis defined in this chapter. This does not inly any statement on the optimal level of spare capacity. See also the caveats of this research discussed in Chapter 7.

way. The market mechanism also makes sure that spare capacity in excess of the requirement does not receive any payments. The combination of a requirement to hold spare capacity and allowing agents to trade units of spare capacity makes sure that spare capacity generates revenues, making it economically viable to have spare capacity available.

Recent experience in the US has shed some light on the working of capacity markets. The Pennsylvania-Jersey-Maryland (PJM) Interconnection Installed Capacity (ICAP) requirement and market is often cited in the literature. Hobs et al. (2001) conclude that under the assumption of a competitive market, the PJM-ICAP system is likely to induce sufficient capacity investment, without increasing the long run cost of power. Stoft (2000) notes that the assumption of a competitive market does not hold and that the capacity market '…has provided yet another arena for the exercise of market power.' (op. cit., p. 8). Furthermore, capacity markets could likely import price spikes from neighbouring regions without an ICAP-system in place.

The measure proposed here differs from the PJM-system. The key difference regards the fact that producers in the PJM system are allowed to use their spare capacity for exports, but these exports will be cancelled if a crisis occurs. This element of the system is hard to imagine in the European situation, where cancellation of exports would meet strong opposition. In the system described here, spare capacity is left idle until a crisis occurs. Note that this raises the security of supply, as there is no risk of exporting security, but, at the same, it decreases the efficiency of the system.

In a system of reserve contracts, the Transmission System Operator (TSO) buys production units from producers, extracting these reserves from use for generating electricity for the regular market. Prices may be set by auctioning. The system operator can dispatch the spare units in case of an emergency. The costs of keeping spare capacity are charged to consumers using the system fee. Like in the case of capacity markets, a spare-capacity requirement is set (now by the TSO), and an efficient pricing mechanism is used to make sure that spare capacity generates revenues. In this case however, the pricing mechanism is an auction rather than a market and the system operator is the one to buy the spare capacity

A system of capacity payments give generators a per megawatt payment for all capacity they hold available, regardless whether it is spare or dispatched. Systems such as this one are in place in Spain and several Latin American countries.[39] Note that payments are based on *total* capacity, rather than spare capacity. The payments work as a general subsidy on capacity, inducing a higher supply of generating capacity. Since capacity now needs a lower load factor to be profitable, construction of capacity for supra-normal peaks may become economically

[39] Oren (2000). A similar system was recently abolished in England & Wales.

viable as well. Payments are collected as a charge, increasing electricity prices in all periods. Picking the level of capacity payments is a fairly arbitrary process. Loosely following Ford (1999), we choose a level that corresponds with an initial charge of 1 eurocent per kWh.

Ford (1999) argues that capacity payments will prevent business cycles in capacity investments, thus preventing price spikes. His theoretical model, assuming perfect competition, predicts that long run prices will not rise. Oren (2000), on the other hand, shows that capacity payments are an inefficient way of promoting supply adequacy, and more efficient alternatives are almost always available.

5.3.3 The costs of the policy options

This section lists the costs of each of the policy options, distinguishing direct, indirect and external costs.

Direct costs

The direct costs comprise several cost items, in particular: capital costs of excess capacity, welfare effects of changes in electricity market, and transaction costs.

Capital costs result from the fact that a certain amount of spare capacity is retained to absorb shocks in demand or availability. These idle units generate capital costs, as the capital invested in them is not available for other (profitable) investments. In the case of reserve contracts and capacity markets, the amount of spare capacity is determined by the regulator. We assume here that the regulator sets this level at 15% of normal peak demand, boiling down to an average annual cost of 128 million euro (see tables 5.1 and 5.2). This level approximates that of the PJM-system, which is somewhat higher, but decreasing over time (from 20% in 1999 to 18% in 2003) (Hobs et al., 2003).

Note the difference between these options with respect to foreign and domestic producers. In the case of capacity markets, all suppliers of electricity are obliged to hold or contract spare capacity. Foreign suppliers (or producers, the difference is not important here), will bear the costs of ‘their’ part of this spare capacity (23 million euro per annum), no matter whether they hold the spare capacity themselves, or contract it in The Netherlands.[40] In the case of reserve contracts, all spare capacity is assumed to be located and contracted in the Netherlands. Note that end-users pay the costs for the spare capacity through a fee levied by the TSO.

With capacity payments, the amount of spare capacity is endogenous, as producers decide the optimal level of spare capacity for themselves. This level is well below that of the other policy

[40] As an extra safeguard, the regulator may require spare capacity to be located in The Netherlands. This would, however, reduce the efficiency of the measure.

options, with annual costs of 1 million euro (see table 5.3). Like with reserve contracts, end-users pay the costs for the spare capacity through a fee levied by the TSO.

Each of the systems described here incurs welfare effects as it has effects on electricity market outcomes. Prices of electricity rise in any of the alternatives[41]. The system fee is raised in the cases of capacity payments and reserve contracts. Furthermore, if capacity payments indeed trigger capacity investments, peak prices may decrease as well, because of reduced scarcity. These price effects affect welfare through demand reactions. We use our model of the European electricity market to quantify these effects (see appendix 7 for a description of the model).

The welfare effects mainly consist of transfers from end-users to producers. In the case of capacity markets, transfers are rather limited, as price increases are induced by scarcity rather than a fee. This generates an annual transfer of 31 million euro, of which 6 million euro to foreign producers. From a national point of view, the latter are welfare losses as well. Transfers are larger in the case of reserve contracts, as the transfers include the increase in the system fee. Note that the increased system fee is partly compensated by producers, bringing down net revenues from foreign producers, leading to a small net welfare gain of these transfers. The system of capacity payments causes the largest transfers, shifting an annual 489 million euro from end-users to domestic (400 million) and foreign (89 million) producers.[42]

The price effects brought about by the transfers mentioned above dampen demand, causing welfare losses as well. The increase in peak prices through induced scarcity in the case of capacity markets is a fairly inefficient way in terms of demand effects, causing an annual domestic welfare loss of 28 million euro. Reserve contracts cause a small price increase, which is divided evenly over the day, casing lower welfare losses (2 million euro). The same holds for capacity payments, although the price increase is about five times as large, yielding a domestic welfare loss of 12 million euro per year

Each of the systems described here generate some transaction costs. Presumably, transaction costs are highest in the case of capacity markets, where many bilateral transactions are needed in the market. Reserve contracts require the costs of organising a periodical auction, and capacity payments require transaction costs for making payments and monitoring of legitimacy.

[41] Note that the spare capacity is deployed only in case of emergency and not to reduce ‘normal’ scarcity. The capacity requirement in the system of capacity markets is defined in terms of a percentage of peak output. This implies that increasing peak output incurs costs on the producer, pushing up peak prices.

[42] Capacity payments make electricity production more attractive, which may induce entry into the market. The welfare effects of entry are not taken into account here.

Keeping in mind that the annual costs of the energy regulator amount to 7 million euro and the annual transaction costs of the Dutch spot market (APX) are roughly 5 million euro[43], we roughly estimate transaction costs to amount to 7 million euro per year for the case of capacity markets and of 3 million euro per year for each of the other options.

The average annual direct cost of capacity markets amount to 145 million euro (see table 5.1). Costs of spare capacity are born by producers (both foreign and domestic). Some of the costs (approximately a quarter) are transferred to end-users through an increase in prices. The price increase brings down demand, causing some welfare loss to end-users and bringing producers' profits down.

Table 5.1 Average annual direct costs of capacity markets (discounted value in million euro)

Item	End-users	Domestic producers	Foreign producers	Total domestic
Capital costs of excess capacity		105	23	105
Transfers due to higher prices	31	– 25	– 6	6
Effect of decreased demand	1	27	6	28
Transaction costs	7			7
Total	39	106	24	145

In the case of reserve contracts, average annual direct costs amount to 129 million euro (see table 5.2). As before, producers bear the costs of excess capacity, be it that all costs are carried by domestic producers. All costs are passed on to end-users through the system fee, but producers lower their commodity prices somewhat to mitigate the decline in demand. Foreign producers have to go along with the lower commodity prices but do not receive income from the reserve contracts, so that the transfers imply a net domestic welfare benefit. Like before, both end-users and producers suffer from a decrease in demand as a result of increased prices. The decrease is lower than in the case of capacity markets, as costs are spread over all hours of the day, rather than peak hours only.

Table 5.2 Average annual direct costs of reserve contracts (discounted value in million euro)

Item	End-users	Domestic producers	Foreign producers	Total domestic
Capital costs of excess capacity		128		128
Transfers due to higher prices	102	– 107	5	– 5
Effect of decreased demand	0	2	1	2
Transaction costs	3			3
Total	105	23	5	129

[43] Source: information received of the Dutch electricity regulator.

In the case of capacity payments, costs of excess capacity are very small, as capacity payments hardly induce an increase in capacity (see table 5.3). Transfers are very large, primarily because the size of the measure, adding a full cent to the price of every kWh. Just as in the case of reserve contracts, costs are spread over all hours of the day, keeping volume effects limited relative to the other effects described here.

Table 5.3 Average annual direct costs of capacity payments (discounted value in million euro)

Item	End-users	Domestic producers	Foreign producers	Total domestic
Capital costs of excess capacity		1	0	1
Transfers due to higher prices	489	– 400	– 89	89
Effect of decreased demand	4	8	2	12
Transaction costs	3			3
Total	496	-391	-87	105

Indirect costs

Price effects in the electricity market have an effect on other markets as well, as electricity is used as an input in many production processes. We use Athena, CPB’s general equilibrium model to assess these indirect effects. The annual indirect effects amount to 3 million, 45 million and 38 million euro (present value) for capacity markets, reserve contracts and capacity payments respectively. High indirect costs for the latter two are related to the large amount of transfers.

External costs

Although external effects do not play an important role in the discussion on increasing the reliability of electricity production, we take these effects into account for the sake of completeness. An increase in electricity prices decreases electricity production and, therefore, reduces associated emissions of CO_2 and other pollutants. We value the avoided CO_2-emissions at 16 euro per ton, being the upper bound of CO_2-removal and storage costs (see also section 4.4.3). For NO_x and SO_2, we use figures from Gijsen et al. (2001). The total effects on emissions are fairly small, amounting to 0.1 million euro a year in the case of capacity markets and even less in both other cases. Note that these figures are negative costs, as they represent a decrease in emissions.

5.3.4 The benefits of the policy options

By definition, benefits of security of supply policy options occur in the case of a crisis. The type of benefits from the policy alternatives depends on what would happen if a crisis occurred. If a blackout would be the effect of capacity shortage, the avoided costs of such a blackout would be the benefits of the policy option. If on the other hand, capacity shortage induces a price spike, the benefits equal the welfare effects that follow from the avoided price spike.

Direct benefits

If demand can respond to price signals, the effect of capacity shortage will be a price spike rather than a blackout. The policy options described here may either prevent or dampen such a price spike. This implies a lower peak price, preventing negative welfare effects caused by the price spike. The way in which these effects are calculated is similar to the calculation of the costs in the previous section. We entered a shock into our electricity market model to assess the effects. Tables 5.4 and 5.5 list the results in a similar fashion as before.

Table 5.4 Total benefits of capacity markets and reserve contracts in case of a price spike (discounted value in million euro)

Item	End-users	Domestic producers	Foreign producers	Total domestic
Transfers due to avoided higher prices	8	– 6	– 1	1
Effect of avoided decrease in demand	0	4	1	4
Total benefits	8	-3	– 1	6

Table 5.5 Total benefits of capacity payments in case of a price spike (discounted value in million euro)

Item	End-users	Domestic producers	Foreign producers	Total domestic
Transfers due to avoided higher prices	4	– 3	– 1	1
Effect of avoided decrease in demand	0	3	1	3
Total benefits	4	0	0	4

If capacity is insufficient and demand is unable to respond to price signals in a timely manner, a decrease in the availability of operational capacity may induce a system break down, causing blackouts. These blackouts will probably be regional by nature. Bijvoet *et al.* (2003) have conducted a thorough assessment of the costs of potential blackouts. One of their key findings is that a blackout on a weekday in the Randstad area costs about 72 million euro per hour in daytime and 38 million euro in the evening.[44] This implies that a 24-hour blackout in that region would cost roughly 1.2 billion euro (600 million if discounted to the mid-year of the period in our analysis). All costs are born by end-users.

Indirect benefits

Like in the case of costs, indirect effects result from price effects in the electricity market and again we use Athena to assess these effects. The indirect effects are larger relative to the direct effect, since a sudden shock causes friction costs. The indirect effect of the crisis is assessed to be 2.5 million euro. As capacity markets and reserve contracts entirely prevent the crisis, these

[44] The welfare costs of blackouts for leisure time in Bijvoet *et al.* (2003) are fairly high, since the option of postponing activities is not considered.

are all benefits. In the case of capacity payments, the benefits are 1.4 million euro, as the crisis is dampened rather than prevented. The distribution of benefits over branches in the economy is fairly even. Energy production sectors and households benefit somewhat more than manufacturing and services sectors.[45]

In the case of a blackout, it is hard to assess the indirect effects, as well as the external effects. It is unclear how economic actors will react to such a blackout. Will they catch up with production later so that the production loss is actually smaller than predicted by the figure mentioned above? Will some of them go bankrupt as they have received their final blow, and if so, does the bankruptcy of such vulnerable firms constitute a loss to the economy? Will factories have to start-up again, using more energy than they would have if kept in production? It is, therefore, impossible to perform a reliable assessment of the indirect and external effects of such a blackout.

Correspondingly, it is hard to predict the dynamic effects of a blackout. It is hard to say whether a single blackout will decrease the attractiveness of a region for investors. If blackouts happen regularly, this is likely to be the case, but even then it is uncertain, as individual firms may create their own back-up or take insurance at relatively low costs. Many calculations on outage costs are available, using different methods and different terminologies. Rough cost estimates of the recent black-out in the North-East of the US range from 6.4 billion dollars (AEG, 2003) to 7 to 10 billion dollars (ICF, 2003). Several more sophisticated measurements of outage costs are available in economic literature (e.g. Moeltner et al. (2002), Serra et al. (1997) and Tishler (1993)). These measurements and the rough estimates have in common that they are limited to the direct costs of outages.

Capacity payments induce a limited amount of spare capacity, rendering the policy almost certainly ineffective against blackouts. This implies that the benefits of avoided costs of blackouts do not arise in the case of capacity payments.

External benefits

For the sake of completeness we take external effects into account, as we did with the costs. Since electricity consumption is hardly affected, the total external effects are small, well below 0.1 million euro in all cases.

5.3.5 The break-even frequency

The computations above may serve as a basis for the computation of the break-even frequency (see tables 5.6 and 5.7). This figure expresses at what frequency a pre-defined crisis will have to occur to equal costs and benefits of the policy options (see chapter 2 for more details).

[45] The distribution of effects is very similar to that in the case of electricity taxation, but the effect is much smaller in size. Presenting these figures here would therefore be of little use.

Table 5.6 Costs and benefits of policy options in the case of a price spike (discounted value in million euro)

	Capacity markets	Reserve contracts	Capacity payments
Average annual costs			
Direct effects	145	129	105
Indirect effects	3	45	37
External effects	– 0	– 0	– 0
Total	148	174	142
Total benefits in case of one crisis			
Direct effects	6	6	4
Indirect effects	3	3	1
External effects	0	0	0
Total	8	8	6
Break-even frequency			
Once every … years	0.05	0.05	0.04

In the case of a price spike, the break-even frequency is very low for all policy options. Its value below one implies that a crisis would have to occur more than once a year to make the policy viable. In fact, the price spike crisis defined here would have to happen every other week. This is obviously very improbable. Furthermore, if this were the case, price spikes would be so frequent that producers would increase their capacities anyway. We may, therefore, conclude that if demand responsiveness is sufficient, none of the policy options discussed here is to be implemented.

As we noted earlier, price spikes lead to small welfare losses, but high transfers. On the other hand it should be noted that much of the costs arising from the policy options are born by end-users. Does this imply that the policy measures are to be viewed different if looked at from the point of view of end-users alone? This can easily be computed from the data above, since we have already made the distinction between end-users and producers for the direct effects and all indirect effects relate to end-users. For end-users only, the break-even frequency for capacity markets is 0.25, much higher than its initial value, but still very low (requires four weeks of prices spikes per year). For reserve contracts, the break-even frequency for end-users equals 0.07, whereas in the case of capacity payments it is only 0.01, even lower than its break-even frequency based on total welfare.

Let us now turn to the situation where demand does not respond adequately to price spikes, resulting in a blackout. Such a blackout will probably be preceded by one or more price pikes. It is however clear from our results above that the welfare costs of price spikes are low compared to the costs of a blackout.

Table 5.7	**Costs and benefits op the policy options in the case of a large blackout (discounted value in million euro)**		
	Capacity markets	Reserve contracts	Capacity payments
Average annual costs			
Direct effects	145	129	105
Indirect effects	3	45	37
External effects	– 0	-0	– 0
Total average annual costs	148	174	142
Total benefits in case of one crisis			
Direct effects	605	605	-
Indirect effects	pm	pm	-
External effects	pm	pm	-
Total benefits	605	605	-
Break-even frequency			
Once every … years	4.10	3.49	-

As we stated before, capacity payments are unable to prevent blackouts. Capacity markets or reserve contracts may prevent blackouts, but at a fairly high cost. The break-even frequencies for these options imply that even if a major blackout occurred every five years, it would be wiser, from an economic point of view, to accept the consequences of the blackout than to prevent it. How probable would a blackout frequency of once every 4 to 5 years be? This question is hard to answer. We cannot use historical evidence, since the changing institutional situation is to be the most likely cause for the blackouts. Further, note that the decrease in availability of capacity would have to be large enough to cause a blackout rather than a price spike, but small enough to be absorbed by the spare capacity installed. If the latter does not hold, a blackout will occur regardless of the policy option implemented.

The distribution of effects over the economy is similar to that in the case of energy taxation (see table 5.12). Costs are born by electricity producers. If a blackout is prevented, all benefits accrue to electricity consumers.

5.3.6 Sensitivity analysis

We made several assumptions in our analysis, including the use of a discount factor of 7 percent and valuating CO_2-emissions at their removal costs estimate of 16 euro per tonne. We test whether our analysis is sensitive to some of the assumptions used. As the break-even frequencies in case of price spikes are extremely low, there is no need to perform a sensitivity analysis here. The results for a sensitivity analysis on the case of a large blackout are shown in table 5.8.

Table 5.8 Sensitivity of break-even frequency in the case of a large blackout

Variant	Capacity markets	Reserve contracts
Base case	4.10	3.49
Discount factor 5% rather than 7%	3.98	3.42
Discount factor 10% rather than 7%	4.12	3.47
Carbon shadow price of 10 euro per ton rather than removal costs	4.10	3.48
Carbon shadow price of euro 50 per ton rather than removal costs	4.11	3.49
48 hours of blackout rather than 24	8.20	6.97

This table shows that our result is insensitive to most of the changes in the assumptions shown here. The only exception is the increase in the duration of the blackout by another 24 hours. Such a change simply doubles the break-even frequency. Note however that the interpretation of the break-even frequency changes as well, as a 48-hour blackout is less probable than a 24-hour blackout. The sensitivity analysis shows that our results here are quite robust.

5.3.7 Conclusion

We assessed the costs and benefits of three options aiming at increasing the reliability of electricity production: capacity markets, reserve contracts and capacity payments. We found that each of these options induce high costs, capacity markets and reserve contracts because generating capacity is left idle, and capacity payments because of large welfare effects induced by price increases. The policy options are not efficient in preventing price spikes, as the welfare costs of price spikes are lower than the costs of the policy options, unless price spikes occur in an implausible high frequency.

Capacity payments are unable to prevent blackouts, as they do not induce enough investments in spare capacity. Black-outs can be prevented by capacity markets and reserve contracts. The break-even frequencies for these options are 4.10 and 4.42 respectively, implying that even if a 24-hour blackout of the Randstad area would occur every five years, it would be wiser, from an economic point of view, to accept the consequences of the blackout than to prevent it. Sensitivity analysis shows that these results are quite robust.

We emphasize that the results are based on the measure design as designed in this chapter. Further research into more efficient designs of these mechanisms may improve the efficiency of these measures and thus change our results.

5.4 Cost-benefit analysis of raising the tax on electricity

5.4.1 Definition of a crisis

Electricity markets bear a high risk of insufficient competition if governments fail to regulate adequately. This risk is relatively large in our long-term scenario Regional Communities as governments, in this scenario, focus strongly on equity and environmental issues and less on the issue of efficiency. As a result of insufficient competition, suppliers could be capable to raise commodity prices above marginal cost level. In this analysis, we define a 50% rise in the electricity price over a period of one year as the crisis scenario.

5.4.2 Definition of the policy option

Governments have several options to deal with the risk of insufficient competition. Measures aiming at hindering concentration of market players and improving conditions for entrance by new firms directly affect the degree of competition in the market. A totally different approach consists of reducing the demand of electricity. This type of policy is not primarily aimed at reducing market power or preventing a crisis, but at lowering the economy’s vulnerability to such a crisis. Besides this effect, this policy measure could result in more competition as a reduced demand reduces scarcity, and, hence, market power of producers. In the long run, this effect will be mitigated as suppliers could respond to the reduced demand by adapting the extent of production.

In this report, we analyse the impact of increased levies on the use of electricity on the vulnerability to price increases. Such a policy measure would fit well in the Regional Communities scenario, as, in this scenario, governments would prefer measures that affect both security of supply and environmental consequences of economic activities. Taxation of energy use may serve both goals. Electricity taxation increases the price of electricity, thus inducing users to consume less electricity. If a crisis (more specific: a price shock) occurs at some point in time, the amount of electricity affected will be lower than it would have been without taxation, implying that the impact of the crisis will be less severe. Therefore, we define the policy alternative as an increase in the tariffs of the energy tax by 1 eurocent per kWh. As the aim of this taxation system is to regulate the use of energy (instead of funding public expenditures), we assume that the proceeds of this taxation are recycled by reductions in other taxes.

5.4.3 The costs of the policy option

Like in the other cases, we distinguish direct costs, indirect costs and external costs.

Direct costs

Table 5.9 states the costs of the policy measure, ordered by end-users, domestic producers and foreign producers. The final column gives the total for both domestic groups in the table, indicating the effect on domestic welfare. These outcomes follow from a simulation run with CPB's electricity market model (see appendix 7).

As the tax is refunded, the direct costs to electricity users are zero: an annual average of 466 million euro is paid as energy tax which is recycled by lowering other taxes. The amount of the taxes is, however, relevant for the other effects in the analysis. The rise in the electricity price generates welfare effects. As the electricity market is oligopolistic, suppliers could respond to higher energy taxes by reducing their mark up.[46] As a result, pre-tax commodity prices decline, causing an annual average net transfer of 239 million euro from producers to end-users. Since part of the transfer is paid by foreign suppliers, the domestic welfare effect is positive (42 million euro).

The net effect of taxation and price adjustments is an increase in prices, inducing a reduction in consumption of electricity. Suppliers face a reduction in their value added, which is a cost. Model simulations indicate that these costs amount to an annual average of 118 million euro for domestic producers and 25 million euro for foreign producers. The reduction in electricity consumption is a welfare loss to consumers, as they switch to less preferred alternatives. The before mentioned model simulation calculate these costs to be 10 million euro per year.

Adding and subtracting these figures yields the present value of the average annual domestic direct costs, amounting to 86 million euro. Total direct costs for end-users are negative, while domestic producers (just as foreign producers) bear the costs of the measure.

Table 5.9 Average annual costs of raising tariffs on electricity use by 1 eurocent/kWh (discounted value in million euro)

	End-users	Domestic producers	Foreign producers	Total domestic
Item				
Taxation	466			466
Transfers from price adjustments	– 239	198	42	– 42
Effect of decreased demand	10	118	25	128
Refund of taxes	– 466			– 466
Total direct costs	– 229	316	66	86

Indirect costs

The increase in the price of electricity affects the economy as a whole. Higher producer prices and shifts between production factors could cause friction costs, while market imperfections in subsequent markets may influence the outcomes of a new equilibrium. Note that these effects are not by definition welfare losses. A decrease in diseconomies of scale may for instance cause

[46] Note that this effect follows from the assumption of a linear demand curve in the model. If this assumption is replaced by the assumption of constant elasticities, no transfers from price adjustments would arise.

positive effects. The indirect effects are determined using ATHENA, CPB's general equilibrium model, and amount to an annual average cost of 31 million euro.

External costs

Electricity production is still largely dominated by fossil-fuel-fired power plants, causing emissions while producing electricity. This implies that reducing the use of electricity will reduce emissions as well. We assume a gas-fired share of 50 percent and a coal-fired share of 35 percent (leaving 15 percent for carbon-free techniques), with 50 respectively 40 percent thermal efficiency and a carbon content of 56 respectively 94 kg per giga Joule to calculate the reduced emissions. These emissions are then valued at a shadow price of 10 euro per ton CO_2, yielding annual average external costs of almost 97 million euro. Similar calculations were performed for NO_x (shadow price of 4.5 euro per kg) and SO_2 (shadow price of 4 euro per kg). The avoided average annual external costs from CO_2-emissions amount to 13.6 million euro; the combined figure for SO_2 and NO_x is 7.6 million euro.

5.4.4 The benefits of the policy option

Direct benefits

Table 5.10 depicts the effects of the crisis defined above in case of both the base alternative and the policy alternative. The crisis results in welfare losses to end-users. These losses follow from transfers to the producers as well as reduced consumption. Producers benefit from the transfers, but suffer from the reduction in consumption as it reduces their production and value added.

Table 5.10 Benefits of energy taxation in case of a crisis (discounted value in million euro)

	End-users	Domestic producers	Foreign producers	Total domestic
Crisis without policy (base alternative)				
Transfers due to higher prices	1 250	– 1 033	– 217	217
Effect of decrease in demand	277	781	164	1 058
Total effect	1 527	– 252	– 53	1 275
Crisis with policy (policy alternative)				
Transfers due to higher prices	1 077	– 890	– 187	187
Effect of decrease in demand	125	544	114	669
Total effect	1 202	-347	– 73	856
Direct benefits of policy in case of crisis	325	94	20	419

As we mentioned earlier, the policy does not prevent the crisis. What are the consequences of the crisis if the use of electricity is taxed? Due to the lower demand for electricity, both the transfers and the decrease in demand are smaller in absolute numbers. The total direct benefits of the policy measure follow from the difference in the costs of the crisis in both cases. Model simulations yield an estimated benefit of 325 million euro (present value) for end-users and 94 million euro (present value) for domestic producers. The present value of domestic benefits is the sum of both, 419 million euro.

Indirect effects

Like in the case of costs, the benefits have indirect effects as well. Reducing the impact of a crisis also means that the consequences for the entire economy will be smaller. The mechanisms here are similar to the ones described before. Calculations based on the outcomes of model simulations with ATHENA yield a present value of the indirect effects of 31 million euro.

External costs

As a side effect of the crisis, external costs will be lower because of reduced demand. Limiting the effects of the crisis also implies limiting the reduction in external costs. Using the same assumptions as before, we calculate these external costs to have a present value of million euro.

5.4.5 The break-even frequency

The computations above serve as a basis for the computation of the break-even frequency. This figure expresses at what frequency a pre-defined crisis will have to occur to equal costs and benefits of the policy options (see chapter 2 for more details). Table 5.11 shows the calculation of the break-even frequency in the case of a 50% increase in the price of electricity over a period of one year.

Table 5.11 Costs and benefits of raising the tax on the use of electricity (discounted value in million euro)

Average annual costs		
Direct effects		86.0
Indirect effects		31.0
External effects		– 21.2
Total		95.6
Total benefits in case of one crisis		
Direct effects		419.0
Indirect effects	:	13.0
External effects		– 31.0
Total		
		401.2
Break-even frequency		
Once every … years		4.2

The calculated break-even frequency is once in every 4.2 years, implying that the policy is viable if a full-year lasting price increase of 50% would occur every 4.2 years.

Apart from the costs and benefits for society as a whole, a policy measure may have distribution effects as well. ATHENA outcomes give some information of effects by branch. Table 5.12 below lists these effects. Note that the figures in the table are defined differently and, therefore, cannot be compared directly to those in other tables in this chapter. The figures merely reflect the distribution of effects over the economy.

Table 5.12 Macroeconomic effects of raising the tax on the use of electricity (2030, cumulated % deviations of baseline)

Item	Meaning	Costs	Benefits
Net national income	total effect	0.15	0.02
Private consumption	effect on households	0.18	0.06
Production Manufacturing excl. energy	effect on manufacturing	0.11	0.01
Production Energy	effect on energy production	0.30	0.04
Production Services	effect on services	0.11	0.01

The costs of the policy option are born mostly by electricity producers. Households contribute somewhat more than proportionally, manufacturing and services slightly less. Households reap the larger part of the benefits of the policy measures, followed by electricity producers. Overall, the differences between stakeholders are relatively small.

5.4.6 Sensitivity analysis

The above analysis is conducted against the Regional Communities scenario. In that scenario, international coordination among governments hardly exists. As a consequence, environmental policies consist mainly of national measures. In the Strong Europe scenario, however, environmental policies are to a large extent internationally implemented with a global emissions trading scheme as the prominent example. In that scenario, national systems of energy taxation could be abolished as far as environmental policies are concerned. After all, the coexistence of an international trading scheme and domestic environmental measures reduce the efficiency of both measures. But, would coexistence make sense from the perspective of security of supply?

The immediate effect of raising domestic electricity taxes while an international emissions trading system exists is that the purchase of permits is partly replaced by domestic mitigation measures. Firms would reduce their use of electricity first, in order to equalise the marginal costs of reduction to the (marginal) price of electricity. Further reductions depend on the difference between the remaining marginal reductions costs and the price of the permits. If the latter are higher, firms will reduce further until both quantities are equalised. If, on the contrary, the permit price is lower, firms will buy permits as needed for expanding activities.

Since marginal reduction costs in the Netherlands are relatively large, many Dutch firms will probably buy emissions permits instead of reducing their own emissions. Raising domestic electricity taxes would, therefore, raise the costs of environmental policy. The extent of these costs depends on the difference between the permit price and the marginal reduction costs. The worst case scenario would be that the tax has no environmental effects on top of the effects of the international trading scheme. We may simulate this effect in our analysis by setting the annual prevented external costs to zero, increasing the break-even frequency to once every 3.5 years. Some of the other assumptions used here, may also be tested quantitatively in a sensitivity analysis. Table 5.13 summarises its results.

Table 5.13 Sensitivity of break-even frequency of electricity taxation to assumptions

Variant	Value
Base case	4.2
International CO_2-emission trading scheme	3.9
Discount factor 5% rather than 7%	3.8
Discount factor 10% rather than 7%	4.9
Shadow price for carbon dioxide of 5 euro per ton rather than 10 euro per ton	4.0
Shadow price for carbon of 15 euro per ton rather than 10 euro per ton	4.4
Price increase by 100% rather than 50%	8.4
Price increase by 25% rather than 50%	2.1

The results are somewhat sensitive to the use of the discount rate, and hardly sensitive to the valuation of CO_2-emissions. The relationship with the magnitude of the price increase is linear.

5.4.7 Conclusion

Taxing electricity may impact supply security indirectly. Taxation cannot prevent a crisis, but it may reduce energy use, and thus decrease the economy’s vulnerability to price shocks. Our analysis shows that a price increase of 50% during one year should happen at least once every 4.2 year to make the policy efficient. The result is fairly robust to changes in assumptions; it suggests that the policy is not viable from a supply security point of view. The welfare effects of raising electricity taxes are reduced further if an international emissions trading system exists.

6 Electricity networks

6.1 Introduction

In this chapter we analyse risks and policy options regarding reliability of network services, and their effect on security of supply. We focus on electricity networks.[47]

Reliability of service is one of the most important dimensions of quality in the electricity industry. It refers to the degree to which buyers can be supplied without interruptions. Electricity networks provide a crucial link in getting electricity to consumers – their good functioning is as important as the good functioning of generation facilities. Unfortunately, similarly to generation facilities, electricity networks may experience failures that may cause interruptions of electricity supply.

Another important dimension of network quality, in particular in liberalised markets, relates to the market facilitation function of networks. Network in the electricity sector represents an essential facility for transportation of the commodity (electricity) traded by market participants. Independence of networks may be important for normal functioning of electricity markets. A failure to ensure independence of networks may create conditions under which some market participants can exercise market power. Although such a development may not result in supply interruption, it may still jeopardise the security of electricity supply, artificially raising electricity prices above the competitive level.

In this chapter we focus on both reliability of network services and the implications for security of electricity supply. We begin with a description of risks attached to electricity networks in section 6.2. We first address risks related to the market facilitating function of networks and then those related to network reliability. We summarise policy options in section 6.3, which we analyse in section 6.4. Section 6.5 presents the conclusions.

[47] Notice that the content of this chapter cannot be automatically extrapolated to other energy networks, such as gas networks. Despite similarities between the electricity and gas industries, many issues that arise in electricity are not identical to those in gas. Differences in characteristics of the transported commodity and in the legal settings may imply different risks and different policy options. For example, a break of a gas distribution pipe leading to a large release of gas may cause a much larger disaster than a power outage at the distribution level. Therefore, there may be a different approach to regulation of reliability in gas.

6.2 Analysis of risks

6.2.1 Historical evidence on risks

Table 6.1 offers an overview of power outages in the Netherlands since 1976. This overview is based on the data from the Nestor database, established in 1975 with the purpose to collect data on failures of network components. Given the increasing attention of the regulator and politicians to network reliability, the outage registration system gains more and more importance.

Table 6.1 shows a slight decrease in reliability in the period 1996-2000 comparing to the period 1976-2000. According to the recent publication by EnergieNed (2003), the average reliability in 1998-2002 was around that in 1996-2000, with the average interruption time of 27 minutes per customer. Most interruptions originate at the medium voltage level.

Table 6.1 Overview of power outages in the Netherlands

	As a consequence of outages in the			
	LV-net	MV-net	HV-net	Total
2000				
Expectation of outage (no. per year)	0.021	0.202	0.190	0.410
Average duration (minutes)	186	86	29	65
Total annual duration (min. per year)	3.8	17.4	5.6	27
Average 1996-2000				
Expectation of outage (no. per year)	0.016	0.211	0.146	0.370
Average duration (minutes)	184	80	47	71
Total annual duration (min. per year)	2.9	16.9	6.8	27
Average 1976-2000				
Expectation of outage (no. per year)	0.016	0.201	0.103	0.320
Average duration (minutes)	202	72	38	67
Total annual duration (min. per year)	3.2	14.5	3.9	22

Note:
LV = Low Voltage (< 1kV)
MV = Medium Voltage (between 1 kV and 50 kV)
HV = High Voltage (above 50 kV)
Expectation of outage is measured by CAIFI (Customer average interruption frequency index), which shows the average number of interruptions for an average customer per year. Average duration is measured by CAIDI (Customer average interruption duration index), which is the average annual duration of interruptions for an average customer, expressed in minutes per interruption. Total annual duration is the product of CAIFI and CAIDI.

Source: KEMA (2002, p.8).

Transmission and distribution

An electricity network typically consists of transmission and distribution networks. Transmission networks are normally high voltage networks, serving for long-distance transport of energy. Distribution networks are of lower voltages. They deliver energy to final customers. Central generation and export typically feed at the transmission level. There is no strict rule about the voltage at which the network is split into the transmission and distribution segments. It varies per country and per region. In the Netherlands, the division between transmission and distribution is mostly at 110 kV.

To date, the electricity network in the Netherlands is represented by one national Transmission System Operator, TenneT, and a number of regional network operators. TenneT operates the so-called 'extra high voltage network' (220/380 kV). Regional network operators operate lower voltages in the corresponding regions. The largest regional network companies provide both services: regional transmission (mainly 110/150 kV) and regional distribution (lower voltages). Given the large population density in the Netherlands, distribution networks typically serve highly populated areas, and, therefore, are underground, while transmission lines are mostly overhead.

Since the electricity flow is typically from higher voltages down to lower voltages, interruptions that originate at high voltages have larger impact: all final customers downstream from the place in which the interruption occurs get disconnected. Therefore, higher voltage networks typically have higher technical security standards than those for lower voltages, making interruptions there less likely. In particular, in the Netherlands reliability of transmission grid is to a large degree secured by implementing the so-called 'N-1 security standard'. (See sections 1.4.5 and 1.4.6 of the Network Code for a description of requirements to the design of high voltage networks.) The latter means that even if one of the N components that constitute the network fails, the remaining N-1 component should still do the job. The most important transmission connections may be subject to higher than N-1 security standards (e.g., N-2). As a consequence of such security standards, regional transmission networks in the Netherlands hardly experienced outages caused by network failures. The national TSO TenneT reports 0 interruption minutes already for a number of years. Dutch distribution networks are normally not subject to the N-1 standard. It is only implemented for the most important pieces of distribution networks.

Table 6.2 places the situation in the Netherlands in an international context. Although the international comparison is not without caveats, it has been acknowledged that the reliability of electricity networks in the Netherlands is the highest in Europe.

Table 6.2 International comparison

Country	Annual duration of interruption (minutes) in 1999
The Netherlands	26
France	57
UK	63
Sweden	152
Norway	180
Italy	191

Source: CEER (2001, table 3.2-A.).

6.2.2 Assessment of future risks

We discuss two major groups of risks regarding electricity networks. The first group relates to competition in the electricity market. The second relates to the network reliability itself.

Risks related to competition

As we have explained in the introduction, network independence is crucial for normal functioning of an electricity market.[48] Therefore, in the beginning of liberalisation electricity networks were unbundled (legally) from the companies to which they previously belonged (Electricity Act, 1998).[49]

Legal unbundling means that networks become separate companies: they have separate management and maintain their own accounts. Separate accounts are meant to ensure proper tariffs for network services and to prevent cross-subsidisation between the network and competitive activities. Moreover, some additional policy measures have been implemented to secure the independent functioning of network operators, such as the territorial separation of control rooms of network operators from the offices of their former affiliates.

Despite this, there are concerns that the implemented measures may be insufficient. This is because regional network companies still belong to the same utility holdings as before. The utility holdings perform a wide range of activities, for example, generation and electricity retail. It is difficult to control if a network company indeed performs independently, or it takes the interests of the holding to which it belongs into account. For example, it may be difficult to verify that there is no information stream between the network and the rest of the holding. Thus, there is the risk that the superior information position of the network may be misused, which may affect the market outcome.

Furthermore, when network companies are part of larger groups of companies (utility holdings), the financing of a network company is also part of a larger financing. Utility holdings invest also in other activities, e.g. in competitive activities. There is a concern that this introduces extra risk with respect to the financing of the investment in the network, which provides another argument in favour of complete separation of network businesses. Financial stability and the feasibility of investment are important to mitigate risks that relate to network infrastructure, which we address in the next section.

[48] See, e.g., OECD (2002, p.30-31) for a discussion of practical problems that arise if a transmission company owns generation assets.

[49] Originally network activities were performed by regional utility companies, which also performed other activities, in particular, electricity generation and electricity retail.

Risks associated with the condition of network infrastructure

On the network side, interruptions may occur for several reasons, being caused by both internal and external circumstances. Network failures can, for example, be caused by insufficient capacity or maintenance of the network (internal causes); or result from third parties' intrusions into the area of the network (external causes, e.g., construction or other work involving digging in the area of the network).

Most important risks with respect to reliability of networks are the following. First, insufficient investment in capacity by network companies may affect reliability and security of supply. This risk is typical for transmission grids, but may also be present at the distribution level. Shortages of transmission capacity do not always result in physical interruptions of electricity supply. Yet, they are harmful because of their effect on security of supply. In particular, transmission bottlenecks may create market conditions under which local electricity producers could exercise market power.

Second, insufficient maintenance of network may result in malfunctioning of network. As any physical asset network infrastructure requires timely maintenance, without which it cannot function properly. If interruption occurs, a network operator should be able to fix the problem within a short time.

Third, insufficient information regarding the location of cables in the ground may lead to physical damage of the network by third parties. At present the latter is the origin of about 25% of network interruptions.[50] A recent publication in 'NRC Handelsblad' (April 19, 2003) refers to a confidential report of Rijkswaterstaat regarding the current situation to advocate the necessity of introducing compulsory central registration of all underground cables and pipes to minimise this risk.

Finally, extreme weather conditions or other unexpected events may cause network failures. Any infrastructure is built to function in a certain location with certain typical conditions, and may be unable to bear extreme events. This risk is natural for any infrastructure and may impact the design of network. However, in the case of the Netherlands, a country with rather mild climate and very dense population, such risks have only a secondary impact on cost. The major cost driver is the necessity to put the network in the dense areas under the ground, which is 7-10 times more expensive than installing overhead lines. Since the majority of the Netherlands is rather densely populated, practically all distribution networks are underground.

Given the last remark, we find the first three risks to be most important from the policy perspective. Therefore, in section 6.3.2 dealing with reliability issues, we mainly concentrate on

[50] EnergieNed (2003) reports that digging in the area of cables is responsible for 28% of interruptions at the low voltage level and for 23% of interruptions at the intermediate voltage level.

the analysis of policy options regarding these risks. The first two risks relate to the decisions made by the companies and thus ‘internal’ to them. These two risks are interrelated, since a company faces trade-offs that involve decisions affecting both risks simultaneously. For example, when a line is systematically overloaded its condition worsens, implying a need for more maintenance and sooner replacement. The third risk is ‘external’. It arises due to the interference of third parties. Still, network companies can do something to minimise this risk, for example, by providing better information about the location of cables in the ground.

6.2.3 Definition of potential crises

On the basis of the above analysis of future risks, we define two potential crises:

- Execution of local or regional market power due to lack of independence of networks;
- Technical failures of networks.

6.3 Analysis of policy options

6.3.1 Overview

Deregulation of the electricity supply industry has brought attention to reliability issues in many countries. Here we review some international experiences (in particular, of the UK and Norway) with respect to the policies directed at electricity networks. We have chosen these countries with the longest history of deregulation and high-powered incentive schemes, to be able to observe the effect of their policies. However, it should be noted that the reliability level in the Netherlands is higher than the reliability level in both Norway and the UK.

Deregulation of the electricity industry in the UK went parallel with privatisation that began in 1989. The electricity network comprises the network of the National Grid Company, NGC, and 14 regional networks. Originally, the regional companies provided both transportation and supply services, but they were unbundled in 2000, in accordance with the Utility Act 2000.

The responsibility of network operators in the UK is set out in the standards of performance. There are two types of standards: guaranteed standards and overall standards. These standards include not only standards on network reliability itself, but also standards on some aspects of service quality (e.g., time of the investigation of a complaint). Guaranteed standards set service levels to be met for each individual customer and specify fines for underperformance. For example, there is a standard regarding restoration of supply, requiring that supplies should be restored within 18 hours; otherwise a payment must be made. The current payments are 50 pounds for domestic customers and 100 pounds for non-domestic customers, plus 25 pounds for each following 12 hours. Overall standards specify a certain average level of performance for a particular service (e.g., minimum percentage of supplies to be reconnected within 3 hours following faults). In addition, in 2002 Ofgem[51] introduced an incentive scheme, which penalises or rewards distribution companies dependant on their performance against the targets for customer interruptions and customer minutes lost. Given the changing role of regional networks, caused by the introduction of competition and the development of distributed generation in many regions, Ofgem is currently undertaking efforts directed towards the development of a regulatory framework for dealing with this issue. A recent report published on the Ofgem's website identifies a number of the possible measures that address reliability of network services and financial stability of network operators in the changing environment (Ofgem, 2003 and Frontier economics, 2003).

The United Kingdom has a long history of monitoring the reliability of network services. According to Ofgem, reliability has been improving over the years. "Many distribution companies have made a substantial improvement in quality of supply performance since 1991/92, with the average number of power cuts per 100 customers having fallen by 11% and the average duration of power cuts per customer having fallen by at least 30%." (Ofgem, June 2003, p.2.)

The electricity sector in Norway has now been deregulated for 10 years. Similarly to the Netherlands, the national TSO, Statnett, performs the transmission of energy on the national level, while a number of regional distribution companies operate regional transmission and distribution networks. Until 2001 the major regulatory measures with respect to regional electricity networks were directed at cost reductions: the networks were subject to revenue caps. In contrast to the UK, Norway has not introduced enforced minimum standards on reliability. Recognising that the downward pressure of incentive regulation on cost may affect quality, the Norwegian Water Resources and Energy Directorate, NVE, required annual reporting of interruption data for network companies in 1995. In 2001 new regulatory arrangements were introduced. The companies' revenue caps are now adjusted in accordance with the customers' interruption cost. The latter is calculated as the product of average interruption cost rates and energy not supplied (ENS), which is estimated on the basis of the data on interruptions and load profiles of the customers (Langset et al., 2001). For the moment, the system distinguishes four cost rates: for residential/agricultural and commercial/industrial customers with different rates for notified and non-notified interruptions.[52] However, ongoing projects by NVE aim at the development of a more diversified system of cost rates. In addition, NVE may evaluate a necessity of introducing minimum standards.

[51] Since 1998, the regulatory duties have been performed by the Office of Gas and Electricity Markets, Ofgem.

[52] The cost rates used by NVE are as follows: 6.67 euro/kWh for non-notified interruptions for commercial and industrial customers, 0.53 euro/kWh for residential and agricultural customers. For notified interruptions the corresponding numbers are 4.67 euro/kWh and 0.4 euro/kWh. (Source: http://www.nve.no.) .

Analysing the performance of the Norwegian companies over the period of 1995-1999, Heggset et al. (2001) observe that the number of interruptions per delivery point was almost constant over the period, while the annual ENS showed a decreasing tendency, mostly due to a reduction in ENS for notified interruptions. This phenomenon may be explained by reduction in preventive maintenance work as a result of the cost reducing efforts of the companies. However, it is still too early to draw conclusions regarding the overall effect of regulation on quality. According to Heggset et al. (2001, p.6.), a tighter quality monitoring and regulation might have resulted in the development that “many of the network companies have eventually started using the collected fault and interruption statistics to prioritise investments and reinforcements in different parts of their network.”

6.3.2 Domestic options

As explained in the beginning of the report, policy options in energy markets can be directed either to the prevention of disturbances, or to the reduction of vulnerability to a crisis, or to the moderation of its effect. This is because risks in energy markets often relate to uncertainty regarding energy resources. In contrast, the major policy options for networks focus on the prevention of crises.

Options regarding market failure due to networks

We first discuss policies directed towards independence of network operators. As said, separation of network companies from competitive activities is desirable to mitigate market imperfections. Although the European Commission Directive 96/92/EC required only managerial independence of transmission networks, many countries went further and completely unbundled (ownership unbundling) TSO’s from the rest of the industry (OECD, 2001). Also in the Netherlands, TenneT is an independent company, owned by the state.

Regional network companies in the Netherlands belong to the regional utility holdings that perform different activities, in particular, generation and supply. As said, this may introduce risks related to the independent functioning and financing of the networks. Since regional networks are in public hands, privatisation issues play role here. Different privatisation modes have been mentioned by press, politicians and policy advisers (e.g., AER, 2003) [53]. Our analysis does not go into the privatisation discussion, but focuses on mitigating risks with respect to reliability and security of supply. One possible solution to secure the independence and financial stability of networks businesses is to completely unbundle them from the holdings. Given the special role of the transmission segment of the network in the market, we discuss two more policy options that may be effective for regional transmission.

[53] The recent publication by the General Energy Council (AER, 2003) discusses options with respect to privatisation of networks and urges for a careful consideration of these issues. AER (2003) argues that a further fragmentation of the Dutch energy sector may weaken its position in the European context. On our side, we raise the questions how joined ownership of competitive and network businesses may affect financing of the network, which implications this may have for reliability, and what will be the overall effect on consumer welfare.

Our analysis covers the following options with respect to regional transmission. The base alternative is the current situation. The first policy alternative is to create a number of independent regional transmission companies. This alternative assumes a separation between regional transmission and distribution businesses, and complete unbundling of regional transmission from the holdings. The second policy alternative is merging regional transmission networks with TenneT. This option may be important, given that there could be economies of scale associated with merging all transmission companies together.

Options related to regulation of reliability of network services

This section is devoted to policy options with respect to regulation of reliability of network services. We begin with a description of the currently implemented regulation. This will be our base alternative. As the first alternative policy option, we consider the recent proposal of the Dutch Energy Regulator, DTe, regarding new regulation of distribution networks. Furthermore, we touch upon the option of maintaining the present reliability level.

The base alternative is the current policy. At present, in accordance with section 31(1)(f) of the Dutch Electricity Act, the regulation of quality is as follows. Quality criteria and compensations for their violation are proposed by the sector and set out in sections 6.2 (criteria) and 6.3 (compensations) of the Network Code. In particular, the current Network Code stipulates that a network company is required to pay a customer a fixed amount of compensation for interruptions of supply that last for longer than four hours. The amounts differ per customer group and vary from 35 euro for a household to the maximum of 91.000 euro for the largest customers.

The first policy alternative is an integration of reliability and tariff regulation. Such a scheme was recently proposed by DTe. Following DTe (2002), we will refer to it as ‘PQRS’ (price-quality regulation system). According to this scheme, network companies should compensate their customers for interruptions by repaying them for the ‘disutility’ caused by interruptions.[54] The underlying logic is as follows: when the companies perceive the customers’ utility losses as their own cost, they have incentives to optimise the relationship between their cost and reliability. If the current level of reliability provided by a company is too high so that the marginal cost of providing such a high reliability level exceeds the customer valuation, the company will reduce its expenses on reliability.

[54] The estimates of the customer’s value of the fact and of the duration of an interruption will be revealed from an econometric analysis based on the survey of a representative sample of Dutch customers.

On the contrary, if reliability is too low, the company has to pay to its customers large compensations; and will be better off if invests in reliability.[55, 56]

The second policy alternative is maintaining the pre-liberalisation level of reliability. Public speakers and press sometimes express the opinion that ‘the more quality the better’. Interviews with network companies’ representatives show that the companies generally consider the industrial average or their own average as a reasonable target on reliability (KEMA, 2003, p.25). Therefore we would like to touch upon this option, and explain why this option may be inferior to the first alternative.

6.4 Cost-benefit analysis

6.4.1 Peculiarities of networks as reason for a different approach

We choose to analyse the policy options considered only qualitatively, since a quantitative analysis is hardly feasible and would require heavy technical assumptions. Complications with performing such an analysis arise for several reasons.

First of all, it is not always possible to find out the relationship between the realised reliability and its causes. In particular, it is difficult to distinguish between the origins of network failures (e.g. if a failure occurred due to bad maintenance or for other reasons), since the involved parties may act strategically and not reveal all information. It is no coincidence that in many practical situations it appears to be difficult or impossible to conclude whom to blame for a failure.[57]

Secondly, there is not much information regarding the exact relationship between the cost of maintenance and reliability, or between the age of equipment and its reliability. Although it is possible to make a computation regarding the level of investment that would be necessary to replace all network equipment above a certain age by new equipment (which reduces the risk of failures), it will still remain a question whether such a replacement value indeed gives the

[55] Compensating each individual customer for each interruption is not always technically possible. It is feasible for larger customers (large firms). For small customers (households) it is currently simpler to ‘socialize’ the compensation for quality in their tariffs. This is a fair scheme as long as the customers are affected in the same way. To prevent that some customers persistently experience a higher interruption rate, the policy should be accompanied by maintaining individual minimum standards and compensations similar to those described in the ‘base alternative’. However, in the future it may be technically possible to implement individual compensations. Then the need for the individual minimum standards may fall out.

[56] The DTe approach relies on two practical conditions. First, the data should be available and good: therefore, a robust data collection procedure should be in place. Secondly, the existing legislation should be amended to allow for the proposed quality regulation.

[57] For example, regarding the recent outage in Italy on September 28, 2003, BBC news has reported: “The blackout appears to have been triggered by a minor accident on a power line in neighbouring Switzerland, causing a domino effect in French lines which affected Italy. Parts of the Swiss city of Geneva were also blacked out… Switzerland and France have blamed Italy for failing to take action that would have limited the scale of the problem, while Italy said France was at fault.” (BBC news, September 30, 2003).

optimal value of the necessary investment to secure reliability of the currently installed equipment.[58]

Finally, even if the optimal value of replacement and expansion investment would be known, this by itself may still not secure reliability. For example, according to Ofgem (the press release of September 30, 2003), the recent outages in the UK – in particular, the London outage on August 28, 2003 and the Birmingham outage in September 2003 – arose due to the incorrect installation of equipment, while the level of investment was considered to be sufficient.

Given the above reasons, we restrict the analysis in this chapter to a theoretical discussion of the factors that contribute on the cost and benefit sides, providing arguments in favour and against of different policy options.

6.4.2 Policy options regarding competition

As said, there are risks with respect to independent functioning and financing of the network businesses that are part of holdings. This speaks in favour of complete unbundling of networks from the holdings. The role of the transmission segment of the industry is especially important. Therefore, in this report, we analyse options that focus on regional transmission in more detail. In this section we first discuss the pros and cons of splitting regional transmission networks from distribution. Secondly, we present arguments in favour and against of merging regional transmission with TenneT.

As explained, historically regional distribution companies in the Netherlands operate also a part of transmission grid. Given important differences existing between transmission and distribution businesses (e.g. differences in processes and in impacts that the two businesses exert on the electricity market), it may be reasonable to separate the two.

This would bring a number of advantages. First, it would provide more transparency regarding costs associated with each activity and thus would facilitate controllability and comparability of the companies' performance. Furthermore, the current proposal of DTe regarding the regulation of the transmission system operator, TenneT, features some special characteristics, different from those for distribution companies ('revenue cap' instead of 'price cap'[59]). It may make sense to study the possibility of extending the latter proposal to regional transmission grids. The latter becomes technically feasible as soon as regional transmission is unbundled from distribution.

[58] See 'NRC Handelsblad' (February 8, 2003) for more detail regarding the age of electricity networks in the Netherlands.
[59] The proposal is outlined in the DTe Consultation Document on TenneT. The legislative basis necessary for the implementation of this proposal has still to be made.

On the other hand, although economically reasonable, such a major restructuring of the networks may appear to be difficult to implement (as any highly political issue, this may raise opposition and possibly involve high transaction costs). Also, it may appear that there are some operational reasons for keeping regional transmission to be integrated with regional distribution. In this sense, interviews with representatives of the industry and DTe may be helpful. It is also useful to look at the choice of other countries regarding this issue. For example in Norway, some part of regional transmission is done by distribution companies.[60]

Notice also that TenneT has already taken over one regional transmission network,[61] and might be planning to buy some other transmission networks in the future. Therefore, it is good to evaluate the option of merging the transmission networks with TenneT against the option of creating independent regional transmission companies. We discuss the pros and cons of these two developments in the reminder of this section.

There are two advantages of allocating all transmission activities to the national transmission system operator, who is also the major electricity-market facilitator in the Netherlands and the owner of the Amsterdam Power Exchange (APX). First, this would secure a good coordination of national and regional transmission businesses and their complete independence of production and retail businesses. Secondly, given that the economic literature points out economies of scale in transmission (e.g., Dismukes et al., 1998), it is likely that efficiency gains may arise from the synergy.

On the other hand, the option of merged transmission network presents difficulties for evaluating the performance and for regulation of regional transmission. The regulator may not be able to benchmark, thus would have to resort to a less high-powered regulation regime than yardstick competition.

The issue of privatisation of distribution companies has triggered a political debate in the Netherlands. In connection with this, we notice that the option of merging transmission networks is more feasible to implement, when distribution companies are still public. Regional transmission businesses and the corresponding assets (‘shares’) could be simply reallocated to TenneT, while remaining owned by the local authorities. In such a way, the local authorities

[60] The issue of joined ownership of regional transmission and generation has been discussed in Norway, however from a different perspective. The Norwegian electricity supply system is dominated by hydropower, which provides some flexibility to shift production over time. This may allow a dominant producer to exploit potential bottlenecks strategically, which causes welfare losses. For example, Skaar and Sørgard (2003) analyse the effects of acquisitions of electricity plants in the presence of transmission bottlenecks.

[61] ”As a result of this transaction, TenneT now owns some 40% of the national transmission grid, the remainder being owned by five regional grid administrators. It is TenneT’s ambition for efficiency reasons to amalgamate these five grids as well, as this would enable the central management of monitoring, maintenance and investment,” according to the press release of December 18, 2003 (http://www.tennet.nl).

together with the State would become co-owners of TenneT. Restructuring network businesses with private companies is probably to involve much higher transaction costs, since in the latter case the shares would have to be bought from private parties.

6.4.3 Policy options regarding regulation of reliability of network services

It has been recognised that reliability has a value for a customer. However, it is not straightforward how to estimate the benefits of reliability. In particular, many efforts in economic literature were devoted to this issue (Caves et al. 1990). Given that customer valuation may vary per region and over time, we begin this section with reviewing recent empirical results on the consumer value of lost load in the Netherlands, and then turn to the analysis of policy options with respect to reliability of networks.

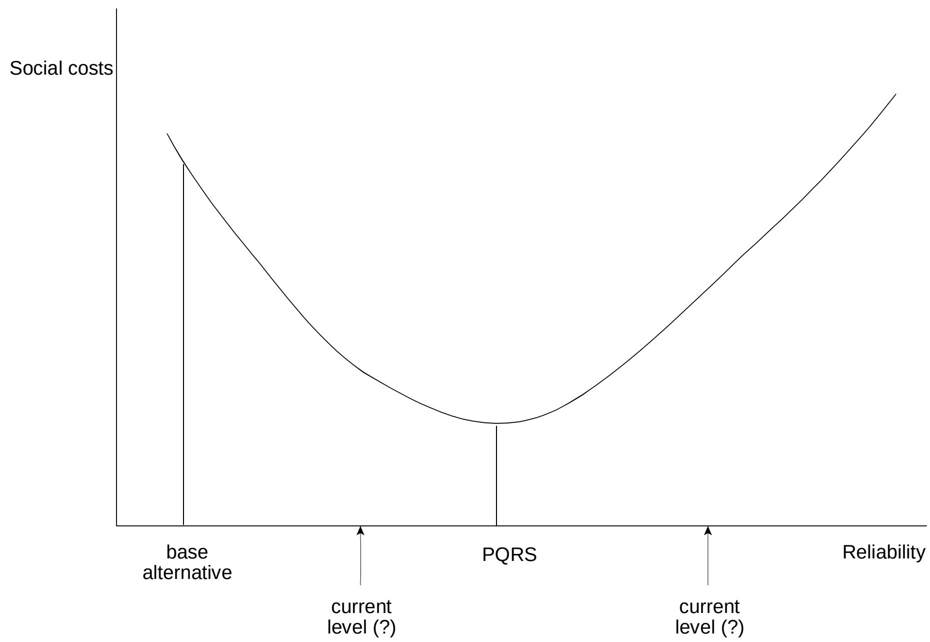
The valuation of the consumer interruption cost may be helpful for network companies to prioritise their actions. The Dutch TSO TenneT has recently commissioned a study to investigate the consumer value of lost load for different regions and different customer groups in the Netherlands. The study shows that there are discrepancies in the estimates of lost load for different regions and across industries, and between industry and households. On the basis of the comparison of the total cost of a one hour supply interruption, Nooij et al. (2003) concludes: “The damage is largest in the regions with the largest Dutch cities. The large number of people living in these areas and the large size of the service sector causes the cost to be especially high in and around the large cities.”

Let us proceed with the analysis of the three policy options that we introduced in section 6.3.2. First, we notice that the base policy does not provide incentives to optimise the relationship between cost and quality. On the contrary, it provides incentives to the companies to reduce cost by degrading quality downwards to stay just above the minimum standard. If for a particular interruption a threshold of four hours has been overrun, there is no sufficient pressure to resume the service as soon as possible. Although one could object to this that employees of network (still public) companies have a strong intrinsic motivation to keep quality high, this consideration may not survive the increasing pressure of economic incentives.

Benefits of the first alternative policy are associated with eliminating incentives to both over- and underinvestment by network companies; and, therefore, with optimising the investment patterns of network companies to maximise social welfare. Therefore, PQRS is superior to the base alternative. Figure 6.1 illustrates this point. The graph shows the relationship between reliability and the total social cost (including consumer disutility from interruptions) of provision of one unit of service. The cost is minimal if companies take into account customer preferences regarding reliability, which corresponds to the first alternative policy (PQRS). The graph also shows that the base alternative is associated with higher social costs and is expected to result in a deterioration of reliability.

Regarding the second alternative, it is unclear whether the current level of reliability is below or above the socially desirable level. Therefore, the policy of maintaining of the current (pre-liberalisation) reliability level may be also suboptimal.

Figure 6.1 Illustration of the relationship between reliability and total social cost, including consumer



The theoretical analysis shows that the overall effect of the first alternative is likely to be welfare improving. However, we do not have sufficient empirical evidence to test this and to quantify the effect. As said, integrated price-quality regulation with similar features has been by now implemented in Norway (in 2001). Given the time lag existing between the moment of ‘investment in quality’ and the moment when it will show up in reliability statistics, we do not have sufficient historic data regarding the effect of this policy.

6.5 Conclusions

In this chapter we have analysed risks related to electricity networks and policy options to mitigate these risks. We identified two groups of risks. First, there are risks that relate to the role of networks in facilitation of competition in electricity generation and supply. The second group of risks is associated with the condition of the network infrastructure. We stress the importance of independence and financial stability of networks, as well as the importance of regulation design in mitigating these risks.

We first address the issue of independence and financial stability of network operators and corresponding policy options. The current situation in the Netherlands is that the regional network companies belong to the regional utility holdings that perform different activities, in particular, electricity generation and supply. This introduces risks related to market functioning and to financing of network investment. We stress the importance of independent functioning of networks in mitigating these risks. We discuss two policy options that focus on increasing independence of regional transmission networks: creating a number of independent regional transmission companies and merging regional transmission with the Dutch Transmission System Operator (TenneT). Both options would involve a restructuring of the industry. Qualitatively, we highlight the trade offs that arise with respect to these two options. A deeper analysis and consultations regarding all options, including the option not to split regional transmission from distribution, would be needed to assess their overall effect on social welfare.

Furthermore, we discuss policy options with respect to regulation of reliability of regional networks. We consider three policy options: the current regulation of reliability, the new DTe proposal, and the option of maintaining the pre-liberalisation level of reliability. The base policy, which is currently in place, specifies minimum quality standards and compensations for their violation. The first alternative, the new DTe proposal, integrates tariff regulation with regulation of reliability, and relates the fines for interruptions to the customer disutility. The second alternative imposes the pre-liberalisation reliability level as a target. On the basis of the theory, we can say that the base policy option (currently in place) does not safeguard reliability and may eventually lead to reliability decreases below the optimal level. The new DTe proposal is more effective. The alternative policy option of maintaining the pre-liberalisation reliability level is also suboptimal to the DTe proposal.

7 Concluding remarks

7.1 Introduction

This chapter summarises the main results of the cost-benefit analysis (section 7.2), depicts a few caveats of this analysis (section 7.3), and describes our main conclusions regarding the efficiency of security of supply policies as well as the usefulness of the analytical framework developed (section 7.4).

7.2 The cost-benefit analysis of eight policy options

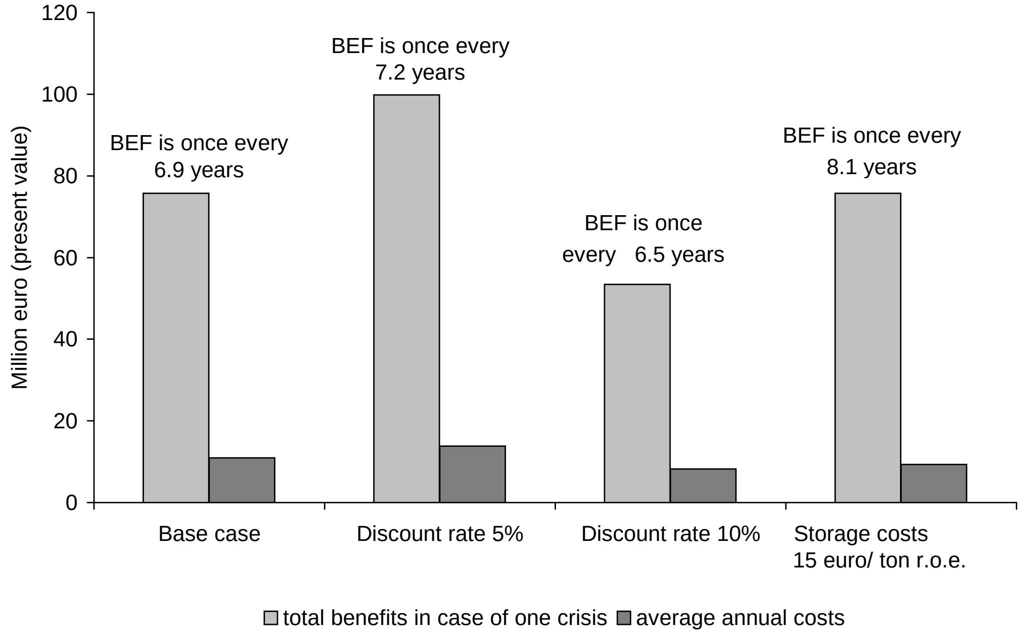
7.2.1 Policy measures regarding risks on the oil market

The major risks on the oil market consist of adverse geo-political events leading to a surging oil price during a short period of time, and execution of market power by oil-producing countries resulting in a longer lasting rise in the oil price. An obvious measure directed at the former crisis is investing in strategic oil stocks in order to release oil and, hence, to reduce price effects of the crisis. In this report, we looked into the cost and benefits of extending the strategic oil stocks by 33%, as is recently proposed by the Commission of the European Union (COM, 2002). The second risk could be dealt with by a measure which reduces the vulnerability to oil price movements, such as stimulation of the use of biomass in the transport and chemical sectors.

Extending the emergency oil stocks

The benefits of additional investments in strategic oil stocks depend heavily on the frequency, duration and extent of disruptions in the supply of oil. An expansion of the stocks by 33% would need a disruption of 10 million barrels a day at least once in every 7 years (see figure 7.1). Although the frequency of disruptions on the oil market was higher than 7 in the past decades, the extent of the disruptions was much smaller. In the future, however, larger disruptions could be expected. In particular political unrest in major Middle East countries could result in a large and sudden decline in oil production. We conclude that extending strategic oil stocks internationally is not an efficient policy measure, unless one appraises the risk of a long-lasting crisis as a relatively high one.

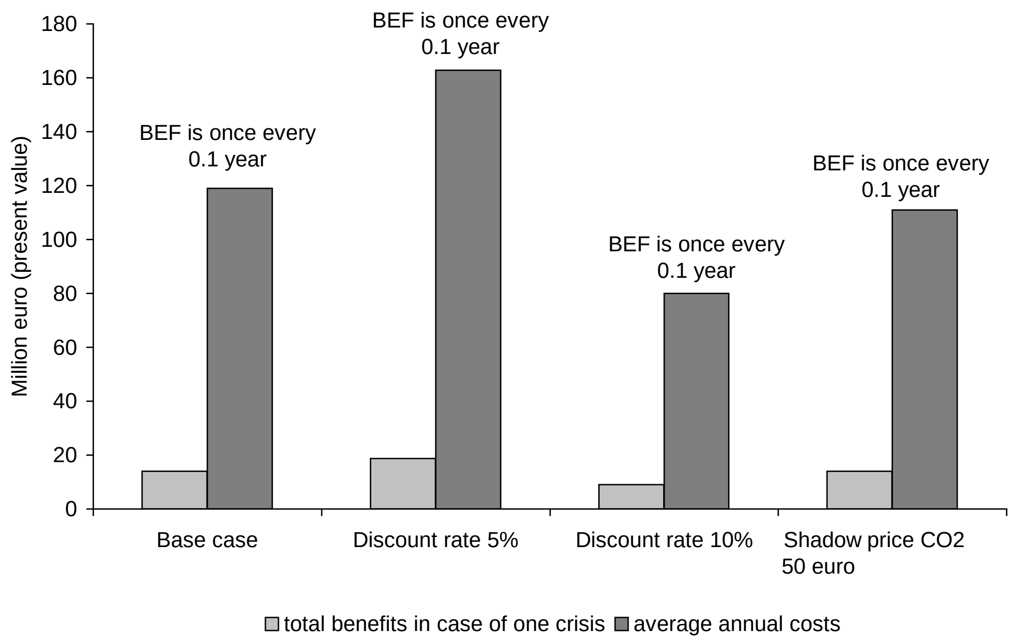
Figure 7.1 Break-even frequency of expanding the emergency oil stocks



Subsidising the use of biomass

Matters are quite different for the case of subsidisation of the use of fuel in transport and the chemical industry as a means to reduce the dependency on oil. Even if the crude oil price would permanently be at a 20% higher level, this option entails high losses to welfare. The benefits in terms of less loss of national income and less carbon emissions are, by and large, not sufficient to compensate for the high costs of using biomass. This conclusion does not change if we alter key assumptions underlying the calculations (see figure 7.2).

Figure 7.2 Break-even frequency of subsidising the use of biomass



7.2.2 Policy measures regarding risks on the natural gas market

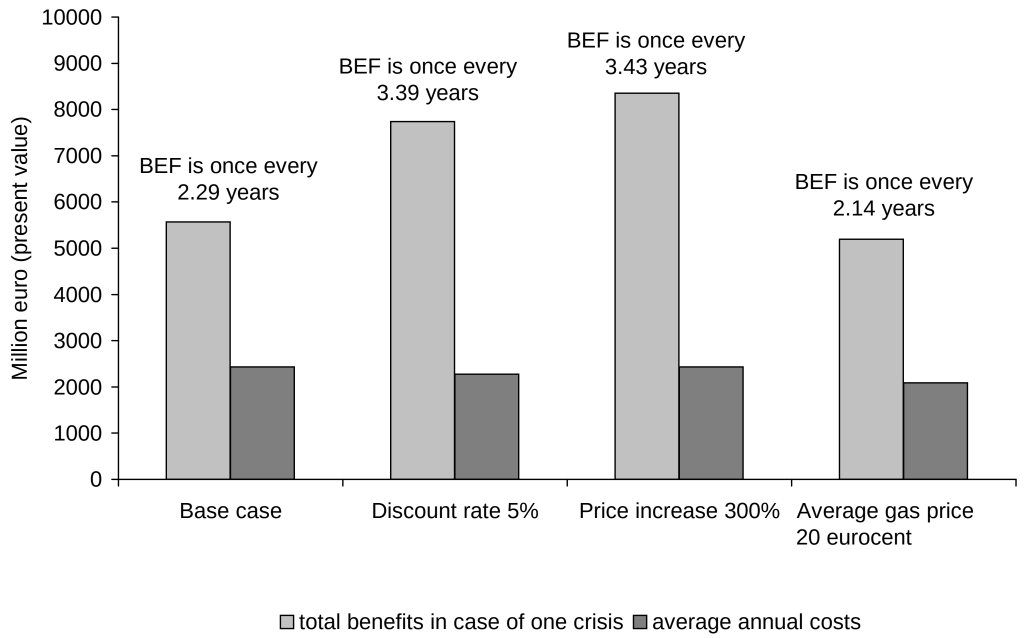
The natural gas market faces two major risks: insufficient swing capacity and execution of market power by gas-producing countries. The former risk stems from introduction of competition in the natural gas market, making investments in flexibility options dependent on private profitability concerns, and the continuing decrease in the swing capabilities of the Groningen natural-gas field. The risk of market power is caused by growing dependence of Europe on a relatively small number of non-European natural-gas producers.

A policy option to reduce the risk of insufficient flexibility within the natural gas market is capping production from the Groningen field. The consequences of the execution of market power by producing countries could be dealt with by decreasing the use of natural gas. An example of such a measure, which we analysed, is encouraging diversification within the power sector. Market power will hardly be affected by that measure, but vulnerability of the economy to the consequences of executing market power (i.e. higher prices) would be decreased.

Capping the production from the Groningen field

Extending the lifetime of the huge Groningen gas field as a swing supplier by capping the annual production at 30 billion cubic meters incurs the costs of postponing realisation of resource rents. The discounted value of these costs is about 2.4 billion euro as is observable in figure 7.3.

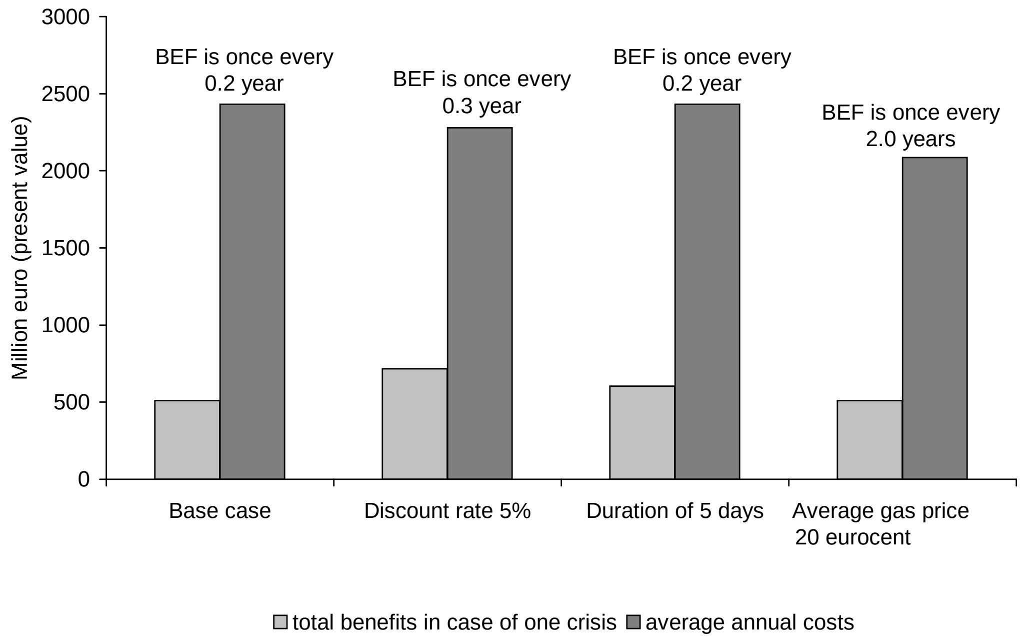
Figure 7.3 Break-even frequency of capping the production from the Groningen field (crisis: price upsurge)



Imposing this cap on production from the Groningen field means that the swing function of Groningen would be prolonged by about four years. This proposed policy measure would generate benefits if disturbances on the natural gas market occur during the additional lifetime of the Groningen swing function. If a severely cold winter led to surging prices and the Groningen field is unable to supply swing, the Netherlands would have to import natural gas at rocketing prices which would yield a loss to welfare. The discounted benefits of the policy measure, in case of a doubling of the natural gas prices over a full winter season, are assessed at about 5.6 billion euro. As a result, the break-even frequency of that crisis is once every 2.3 years. Varying the discount rate, the magnitude of the price increase or the underlying gas price scenario does not significantly alter the break-even frequency.

A severely cold winter could lead to physical shortages. The (discounted) costs of a blackout of the gas network during 24 hours in the South-West of the Netherlands, followed by a three day period in which damage to pipeline and heating systems is mended and production is started up again, are about 509 million euro (see figure 7.4). If a cap on production from Groningen would be installed, such a crisis could be averted if it would occur within the prolonged period of four years. However, this crisis needs to occur about 5 times a year to make the policy measure efficient. Such a high frequency of severe cold winters is not probable, making the measure extremely expensive. This result is highly insensitive to changes in discount rate, duration of the shortage and assumed gas price scenario. Despite this conclusion, the question remains whether capping production from the Groningen field would be efficient if this issue is analysed from a broader perspective than that of security of supply alone. In order to answer this question, additional research should be conducted.

Figure 7.4 **Break-even frequency of capping the production from the Groningen field (crisis: gas shortage)**

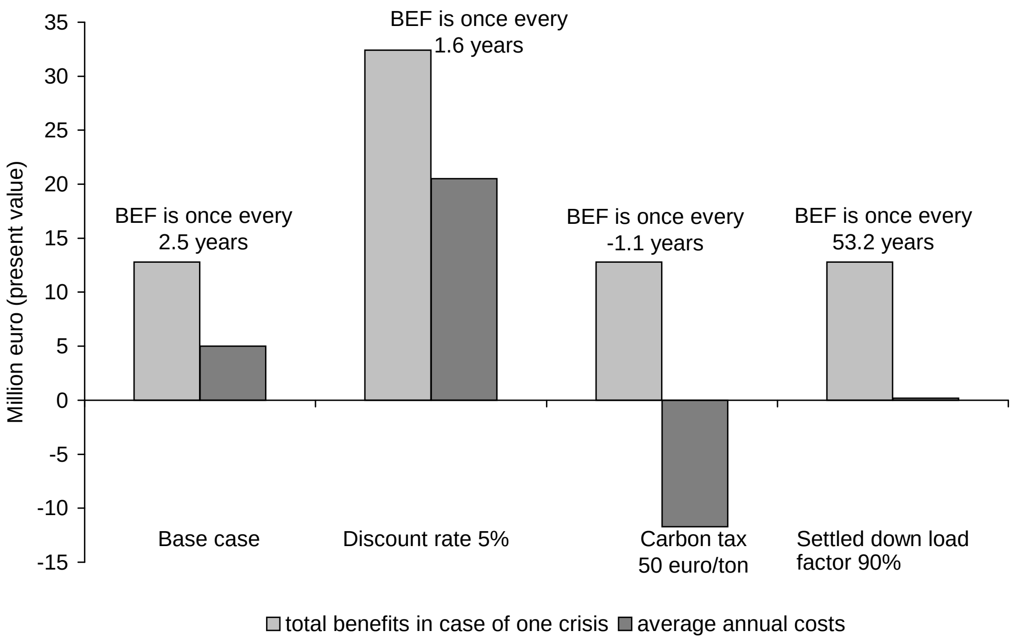


Encouraging diversification within the power sector

Substitution of gas-fired plants by wind turbines, coal-fired plants or nuclear plants appears also to be expensive. This type of policy is meant to reduce effects of a gas price surge for electricity prices. The least expensive option, substitution by nuclear plants has annual average costs of 5 million euro (see figure 7.5). The benefits in case of a crisis, defined as a 50% rise in gas prices for one year, amounts to 12.8 million euro. As a result, the break-even frequency is once every 2.5 years.

The discount rate has a minor impact on the outcome, while using a higher valuation for carbon emissions would lead to negative costs for the option, implying that it is viable by itself, i.e. even without a crisis. If we assume a considerably higher load factor for electricity plants, the policy option of substituting gas-fired power generation by nuclear power would be viable at a frequency of a gas price spike of once every 53 years.

Figure 7.5 Break-even frequency of diversifying the power sector from gas-fired towards nuclear generation plants (large scale)



7.2.3 Policy measures regarding risks on the electricity market

The key risks on the electricity market refer to the ability of the power sector to meet demand at all times, and the threat of execution of market power by producers.

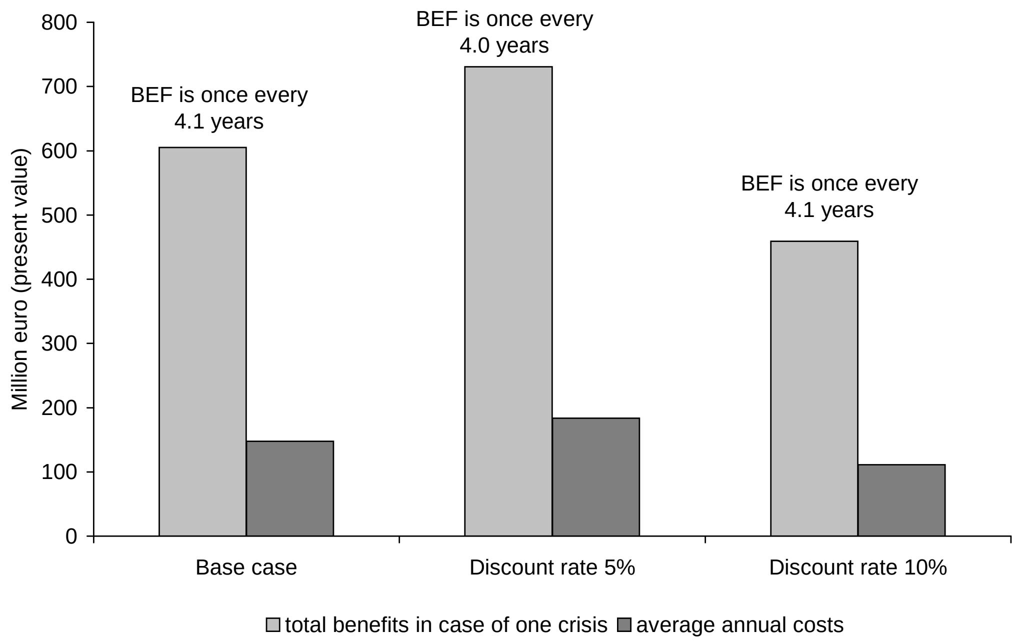
Measures such as capacity markets, reserve contracts and capacity payments can give power producers additional incentives to invest in peak capacity. Consequences of execution of market power (i.e. high prices) can be softened by reducing use of electricity. We analysed the effects of raising taxes on the use of this energy carrier.

Creating incentives for investments in generation capacity

We analysed several instruments aimed at rewarding (supra-normal) peak capacity for being available, rather than for its output alone. These policies are aimed at inducing the formation of spare capacity that may be used in case of capacity shortages. These measures (capacity markets, reserve contracts and capacity payments) are not efficient, as the costs to welfare of price spikes are lower than the costs of the policy options, unless price spikes occur in an implausible high frequency.

Capacity payments are unable to prevent blackouts, as they do not induce enough investments in spare capacity. Blackouts can be prevented by capacity markets and reserve contracts. The break-even frequency for the most cost-effective of these options (capacity markets) is once every 4.1 years, implying that even if a 24-hour blackout of the Randstad area occurred every four years, it would be wiser to accept the consequences of the blackout than to prevent it (see figure 7.6). Varying the discount rate between 5 and 10 percent does not affect this result.

Figure 7.6 Break-even frequency of establishing a capacity market in the power sector



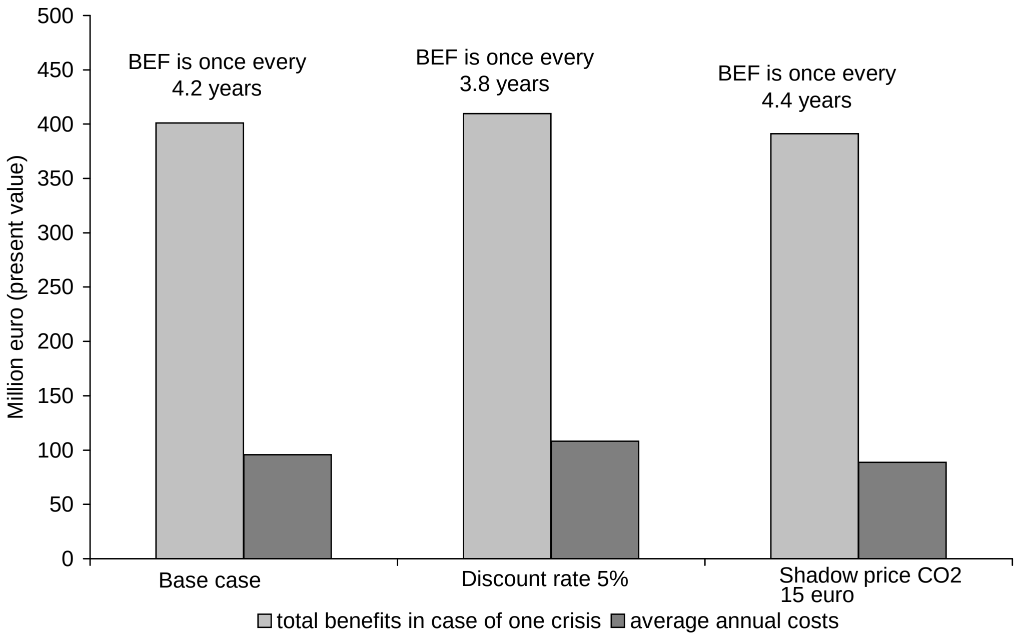
Given the design of the measures encouraging power producers to invest in peak capacity, we conclude that they incur relatively high costs. The high costs of capacity markets and reserve contracts follow from the fact that generating capacity is left idle; capacity payments appear to be expensive because of large welfare effects induced by price increases.

Raising the levy on the use of electricity

Taxing electricity may impact supply security indirectly. Taxation cannot prevent a crisis, but it may reduce energy use, and thus decrease the economy's vulnerability to price shocks. Our analysis shows that a price increase of 50% over a period of one year should happen at least once every 4.2 year to make the policy efficient (see figure 7.7).

The result is fairly robust to changes in assumptions and suggests that the policy is not viable from a supply security point of view. The welfare effects of raising electricity taxes are reduced further if an international emissions trading system exists. A lower discount rate would change the break-even frequency to once every 3.8 years, whereas higher valuations of carbon emissions lead to a slight decrease of the break-even frequency.

Figure 7.7 Break-even frequency of raising the levy on the use of electricity by 1%



The costs of the policy option are borne mostly by electricity producers. Households contribute somewhat more than proportionally; manufacturing and services slightly less. Households reap the larger part of the benefits of the policy measures, followed by electricity producers. Overall, the differences between stakeholders are relatively small.

7.2.4 Policy measures regarding risks on the electricity network

Within electricity networks, we identified two groups of risks. The first group of risks consists of risks that relate to the role of networks in facilitation of competition in electricity generation and supply. The second group of risks is associated with the condition of the network infrastructure.

We address the issue of independence and financial stability of network operators and corresponding policy options. The current situation in the Netherlands is that the regional network companies belong to the regional utility holdings that perform different activities, in particular, electricity generation and supply. This introduces risks related to market functioning and to financing of network investment. We stress the importance of independent functioning of networks in mitigating these risks. We discuss two policy options that focus on increasing independence of regional transmission networks: creating a number of independent regional transmission companies and merging regional transmission with the Dutch Transmission System Operator (TenneT). Both options would involve a restructuring of the industry. Qualitatively, we highlight the trade offs that arise with respect to these two options. A deeper analysis and consultations regarding all options, including the option not to split regional transmission from distribution, would be needed to assess their overall effect on social welfare.

Furthermore, we discuss policy options with respect to regulation of reliability of regional networks. The base policy, which is currently in place, specifies minimum quality standards and penalties for their violation. The first alternative, the new DTe proposal, integrates tariff regulation with regulation of reliability, and relates the fines for interruptions to customer disutility. The second alternative imposes the current (pre-liberalisation) reliability level as a target. On the basis of the theory, we can say that the base policy option (currently in place) does not safeguard reliability and may eventually lead to reliability decreases below the optimal level. The new DTe proposal is more effective. The alternative policy option of maintaining the pre-liberalisation reliability level is also suboptimal to the DTe proposal.

7.3 A few caveats

The set of policy options analysed has primarily been chosen because of methodological reasons: to develop and apply the framework of cost-benefit analysis. In order to fully assess the role of governments in the field of security of supply, several other options have to be analysed as well. Moreover, we analyse the costs and benefits of each option given a defined design instead of searching for the optimal design. Theoretically, the latter is more appealing. In practice, however, defining the optimal design of a policy option requires a far more profound analysis than has been conducted in this report. This implies that this project does not give the final answer regarding the role of governments.

Results of a cost-benefit analysis offer only part of the information needed for decision making. Some effects are not measurable and accounted for as a *pro memoria* item. In the decision making process, these effects should be assessed, however. Moreover, the distribution of costs and benefits within society generally play an important role in that process. In our analysis, we analysed the distribution effects at a fairly aggregate level only.

These two caveats hold for any cost-benefit analysis. If applied to risks, an additional caveat should be mentioned, being the risk attitude of decision makers. If governments are risk averse, for instance because of a suspected effect of a crisis on the reputation of politicians, or if societies as a whole are risk averse, the interpretation of the break-even frequency shifts in favour of the policy measures.

Finally, as is the case with any research, the results of the analysis are based on several assumptions, among which assumptions regarding the design of the policy measure. In order to assess the impact of assumptions chosen on the outcome, we analysed the sensitivity. It appears that the results are generally fairly robust for changes in the assumptions.

7.4 General conclusions

7.4.1 Energy policies and risks on energy markets

The general picture following from the cases studied is that security of supply policy is hardly ever beneficial to welfare. From an economic point of view, it would be often wiser to accept consequences of supply disruptions than to pursue security of supply at any price. This implies that governments should execute caution in imposing measures regarding security of supply. If serious market failure is detected, careful attention should be paid to the design of the measure.

Looking at the cases from a higher abstraction level, we notice two types of solutions to supply security problems. The first solution is the formation or extension of stocks, either in the form of energy stocks or stocks of production capacity. The second type of solution is bringing down demand of specific energy types, in order to reduce the economy’s vulnerability to shocks in the price of that type of energy.

The first type of solutions includes oil stock formation, prolonging the lifespan of the swing function of the Groningen field and measures aimed at increasing spare capacity in electricity production. These options have in common that they set aside a proportion of potentially productive assets, which makes the options very costly. They also have in common that they do not intervene too strongly in the market, leaving room for allocative efficiency. This implies that the costliness of setting aside the productive assets is the main drawback, the magnitude of which is directly related to the magnitude of the policy measure. The above suggests that the optimal design of the first type of solutions lies in finding the right size of the policy measure. In other words, both market failure and government failure regard the *level* of stocks.

The second type of solutions aims at reducing demand for specific energy carriers and includes energy taxation, substitution of oil products by biomass and substitution of gas-fired power plants by other forms of electricity generation. These solutions do intervene in the energy markets concerned, and often in a drastic way. Whether this is a real problem also depends on two things. First, the (un)desirability of the available substitutes matters, as we can see by comparing the case of substitution of gas-fired plants to the case of substitution of oil by biofuels. The second aspect concerns the side effects of the measure. Substituting away from environmentally harmful fuels decreases external costs and thus lowers the net costs of the policy option. The larger the reduction in external costs is, the larger the chance is that the policy is economically viable.

The results of our analysis show that in some cases markets fail to deal with all costs and benefits of security of supply measures. The oil market is an obvious example. Benefits of investments in strategic oil stocks do not fully accrue to the investors, but also to other parts of the economy. As a result, private firms will invest less in these stocks than governments. In most other cases, however, markets succeed in realising a sufficient level of security of supply. Moreover, in several cases where market failure is detected, costs of government action are often higher than benefits generated. This is especially the case for policy options concerning subsidisation, i.e. capacity payments and substitution of oil products by bio-fuels. As we analysed only a number of policy options instead of covering the total range of options, additional research would be necessary to arrive at more well-founded conclusions.

If markets function well, prices will give producers incentives to invest if supply becomes scarce, while at the same time consumers are encouraged to reduce demand. This price mechanism enables markets to match supply and demand. Well-functioning markets may be prone to price spikes, as our cases of both the gas and electricity markets suggest. Note however that welfare effects of price spikes in these cases are small in comparison to the costs of policies directed at preventing these spikes. If prices do not reflect real scarcity or producers or consumers are not able to respond to changes in prices, security of supply problems could appear. Therefore, establishing and maintaining well-functioning markets appears to be an efficient approach in realising a secure supply of energy.

Market design plays a crucial role here and includes the removal of entry barriers, securing equal access to essential facilities, such as networks and storage, and solving information problems. The example of the crisis in California shows how tremendous the consequences of flaws in ‘market architecture’ can be.

7.4.2 Cost-benefit analysis

The framework for cost-benefit analysis developed in this report offers a straightforward way of analysing costs and benefits. Calculating the break-even frequency appears to be a fruitful approach in dealing with risks. The cost-benefit framework enables researchers and politicians to think systematically about consequences of security of supply measures. In addition, the framework includes definitions of key elements of the cost-benefit analysis, making it easier to apply the framework to new cases. This does not imply that any new application of the framework is as easy as a routine job. In every cost-benefit analysis, researchers have to analyse specific characteristics of risks and policy measure(s) at stake.

What are the conditions for a useful application of the framework? Above all, the policy measure should be well defined. If the description of the measure is vague about the direct effects of the measure, it is impossible to conduct a cost-benefit analysis. Secondly, it must be clear to which type of disturbance(s) the measure is directed. Next, one should be able to compare the computed break-even frequency with the probability of occurrence of the disturbance(s) in reality. If these conditions are satisfied, the framework can be used in assessing policy measures. The results of the analysis indicate which policy options contribute to welfare and which do not. Whether the government should implement options remains a political decision that involves taking into account other aspects, in particular the attitude of society towards risks.

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Appendix 1 Risks on energy markets and energy policies[1]

Risks on energy markets

Horsnell (2000), in his analysis of the probabilities of oil market disruption, distinguishes two types of *discontinuities* and three types of *disruptions*. A *policy discontinuity* arises from the consequences of changes in producer policies, in countries with spare production capacity. A *fundamental discontinuity* arises from the dynamics of supply and demand and involves the inability of the supply system to meet the level of national demand. As Horsnell argues, the first oil shock was close to a fundamental discontinuity, but it was made manifest through an export restriction disruption. He refers to three types of supply disruptions, defined as a sudden truncation of supply. First, the inability of a producing country to export because of either internal (civil unrest or war), or external conditions, are called a *force majeure disruption*; an example of this is the second oil shock. Secondly, *export restriction disruption* is a deliberate restriction of exports by a producer, or group of producers, for political or strategic ends. Finally, the *embargo disruption* is a restraint placed by consuming countries on the oil exports of specific countries, such as for example during the Gulf Crisis of 1990.

Reasons for intervention by governments

Security of supply has always been - and still is - an ambiguous phenomenon, drawing on two different ratios: the paradigms of *free trade* and of *independence*. The former is the economic rationale, grounded in international trade theory. This rationale highlights the efficiency and welfare gains of specialisation and international division of labour. Accordingly, the several types of energy should be produced in those countries that are able to provide those at the lowest relative cost. This requires that goods, including energy, can be traded and transported freely from one country to another. National energy markets are to be integrated to the extent that the process of producing and trading energy is not confined to the national territory. This implies that two conditions have to be fulfilled: firstly, the trade regimes of countries should not place any explicit restrictions on international trade but should provide for a dismantlement of implicit barriers; secondly, it requires the presence of physical infrastructure to efficiently transport energy between and within countries, such as pipelines, ports, railroads.

Yet, however rational the logic of international trade may seem, it can be observed that, historically, free trade in energy has been a fairly uncommon phenomenon (Clarke 1990). Indeed, most of the time and in many countries and regions, trade in energy has been limited and restricted by all kinds of rules, regulations, conditions and concessions. Often the construction of international transport infrastructures has been (and is) blocked by or - at least – controlled by national and international political interventions. Moreover, it was (and still is)

[1] This appendix is based on Correlje (2003).

customary that countries devote large amounts of capital and resources to the indigenous production of comparatively expensive energy, despite the fact that more convenient and lower cost substitutes are readily available in the world market or even in neighbouring countries. So, there must be good reasons why countries reject the economic efficiency rationale and decide to strive for a certain degree of independence in energy supply. One reason is the idea that dependency on external resources might become a strategic disadvantage in times of war or could be used as a weapon in trade conflicts. Moreover, it would make countries vulnerable to price fluctuations in international markets, cause disturbances in their balances of payments, etc.

Another class of arguments often refers to security of supply issues, but the underlying motivation is the protection of the activities and interests of the national industrial energy sector, plus the workforce and technology clusters involved. An additional reason might be the fact that the state collects revenues from the exploitation of such ventures. Finally, it is often heard that the resource endowments of a country should be exploited to the "benefit of the nation" and be reserved preferentially for use by its nationals - as if these nationals have a ‘natural’ exclusive right of access to these resources.

Appendix 2 Exploration of future risks on the global market for oil, coal and uranium[1]

The aim of this study is to investigate the future risks to supply for the global markets for oil, coal and uranium. The study forms part of an integrated project by the CPB Netherlands Bureau for Economic Policy Analysis, which is developing a framework for a cost benefit analysis of energy supply security policy. This study is divided into four sections. The first section deals with the issues and definitions that relate to the meaning of security of supply. The following three sections deal in turn with the risks to future supply for oil, coal and uranium.

The analysis has examined the impact that supply disruptions have had in the past, the events that have disturbed energy supply and the affect that they have had on prices, on the economy and on society. For each commodity we have analysed the political, economic, institutional and technical risks and have qualitatively assessed the impact that each might have on the two price scenarios provided by the CPB. We also discuss the policy responses that governments have adopted in the aftermath of supply disruptions.

The report commences with a discussion of the definition of security of supply and the link to the potential for supply disruptions. The analysis shows that the political concept of ‘security’ applied to supply does not cover all cases of significant price rises. Security seems to refer more particularly to situations free from physical interruptions of production or distribution due either to political factors and events or to accidents. Security is a matter of probability: the greater the chances of these accidents or events occurring the weaker the security. But price rises may occur because of depletion, miscalculations about the rate of investment required, flawed policies, shifts in demand and a host of other causes. One need, therefore, to consider the issue in a broader framework than primarily suggested by the term ‘security’ unless it’s meaning is stretched so wide that it becomes both all-embracing and devoid of analytical power. It is for this reason that in this study we have examined the issue of supply disruptions in the context of economic, technical, institutional and political factors.

Our conclusions for the potential for supply disruptions for oil show that in the short term under both the ‘High Growth’ and ‘Low Growth’ scenarios, the most probable disturbance that may occur in the near future will be due to a war in Iraq. The immediate impact will be a loss of 2 million b/d of Iraqi oil in the world petroleum market. Should Iraq succeed in retaliating on oil installations in Saudi Arabia or Kuwait (probability 10 per cent) oil prices will quickly rise to the $40 per barrel level. If major damage is caused to these installations prices may well move higher, that is close to $45 or $50 per barrel and depending on the damage the duration of the price rise will be of the order of several months. If Iraq fails to attack its neighbours, the

[1] This text is the summary of the report written by the Oxford Institute for Energy Studies (OIES, 2003).

military operation ends quickly and Saddam Hussein does not set the oil wells on fire, oil prices will quickly fall from the current $25 per barrel level to $20 or even $18 d/b. Under both the ‘Low Growth’ and ‘High Growth’ scenarios, terrorist action against oil instillations or tankers is possible (probability 30 per cent for oil fields, 60 per cent for pipelines, tankers and other isolated plants) but the probability of major disruptions is low (less than 5 per cent).

In the medium term the potential for supply disruptions to oil under both the ‘Low Growth’ and ‘High Growth’ scenarios, include the probability of a crisis in Saudi Arabia and indeed in other major Gulf countries (including Iran) increases with the passage of time. But the period from 2005 to 2010 is one during which additional supplies may be reaching the market from the Caspian, the West African offshore and perhaps from a pacified Iraq. Russian output would have built up in the immediately preceding years. While the probability of a crisis increases the magnitude of the impact on prices may be mitigated by the increase in supply. Terrorism will continue to represent a threat (similar probability as for the short term) but the risk of serious damage is likely to diminish because of improved security measures.

In the medium term, however, certain political forces relating to human rights, environmental issues, or an anti-corruption drive may have gained momentum. Other things being equal these may restrict investments in capacity and restrict supplies. Economic difficulties in certain countries, not only in Latin America, Africa or Indonesia but also in Russia or the Caspian could restrict investment. The overall supply situation will thus depend on the magnitude of the positive shifts due to new capacity compared with the negative shifts due to insufficient investment in new capacity or in workovers needed to fight natural decline in old fields.

Our view of the medium-term is one of fairly weak oil prices with the possibility of a price spike resulting from a political incident in Saudi Arabia. During that incident whose probability is in the order of 20-25 per cent prices could well climb to $50 per barrel. The risk of a political incident in Saudi Arabia is more likely under the ‘Low Growth’ scenario, which envisages flat real oil prices

The very long-term problem is one of oil depletion and the rate at which fuel substitutes and new fuel-using types of engines are developed and enter the market. But this is a problem that will begin to be felt around 2020 or a bit later. The period between 2015 and 2020 or 2025 could witness the beginnings of a tighter supply situation because the big increases from Iraq, Russia, West Africa and Venezuela would have occurred in earlier years. Oil prices will then rise and stimulate R & D substitutes, actual substitution and reduction in demand. In other words this would be a period leading to major adjustments in the longer term (2025 – 2040). The risk of supply disruption in the longer term due to depletion is much more likely under the ‘High Growth’ scenario than under the ‘Low Growth’ scenario.

With regards to the policy response to disruptions of oil supply, our view is that governments are always inclined to favour fiscal policies as a means to limit the demand for oil and, other things being equal, to reduce imports. The first reaction to a crisis is, therefore, likely to be an increase in excise taxes on automotive fuels. This is preferred to subsidies to alternative fuels or research and development since taxes bring in revenues whereas subsidies are an expense. There are instances, however, where encouraging new supplies may be more effective than discouraging demand.

Coal still makes a significant contribution to primary energy demand and is at present only exceeded by oil. Although coal reserves are vast and are widely dispersed, consumption is increasingly concentrating in a small number of countries and in a few major uses. Nearly two-thirds of total world coal consumption is accounted for in just four countries namely China, United States, India and Russia. However, the volume of remaining reserves remains high with OECD countries accounting for over 60 per cent of exporting countries. In addition, the USA is expected to remain the swing producer for coal in the longer-term. As a result, concerns over coal supply security are likely to remain minimal especially as almost half of current reserves are located in OECD countries.

The key potential supply disturbance that we have identified relates to environmental pressure and the impact that this could have on demand. Coal is particularly vulnerable as it contributes 38 per cent of the world's total carbon emissions from commercial fuels, and is also a major source of sulphur dioxide and nitrous oxides emissions as well as particulates and other environmental hazards. The greater the environmental pressure on the industry the greater the likelihood that this could lead to downward pressure on prices in the medium-term. In the longer-term this could affect investment decisions and put upward pressure on prices. However, this upward pressure could be fully mitigated by improvements in technology, the constant pressure to reduce costs combined with the vast resource base available.

With regards to uranium, current demand can be met by primary production and by secondary sources from stockpiles and inventories. The uranium resource base is large enough to support even the most optimistic of demand assumptions and the reserves are located mainly in OECD countries. In the near-term, primary and secondary uranium resources will be able to meet both optimistic and pessimistic demand forecasts. In the medium-term, secondary sources will be depleted but current production and current developments of primary uranium should be sufficient to supply both optimistic and pessimistic demand forecasts. In the long-term, significant new sources of uranium will need to be developed to meet rising demand. This will require significantly higher prices to justify new investment.

In the near term, the real risks to supply could come from disruptions in secondary supplies of uranium. Such disruptions are likely to be short-lived and cause spikes in the uranium price. In the longer term, economic factors are more likely to cause supply disruptions if prices do not recover to levels that justify new investment decisions. However, political factors and the introduction of new technology could suppress demand for uranium if the nuclear industry goes into decline.

Appendix 3 Policy options directed at securing the supply of energy [1]

Policies for security of energy supply can be shaped in many ways and can be applied at different points in the supply chain. For example, policies could focus on prevention of potential disturbances of energy supply or policies could focus on reduction of negative economic impacts of an actual disruption of energy supply. In order to structure the different policy goals and instruments for supply security, we distinguish the following three points of application for policy intervention:

- preventing disturbances;
- reducing vulnerability of the economy;
- mitigating adverse effects of disturbances.

Within each of these three categories, governments could achieve different policy goals through *national* policies or *international* policies. We distinguish three types of national policies:

- regulation;
- market based instruments;
- voluntary agreements and provision of information.

In the tables below, we present different types of policy options for four types of risks for energy security. The four risks distinguished are:

- Increasing market power of oil supporters;
- Increasing dependence of gas supply from Russia and the Middle East;
- Insufficient investments in generation capacity;
- Insufficient investments in power and natural gas networks.

[1] This appendix is based on CE(2003).

Policy options dealing with risks of disruption of supply and price volatility due to increasing dependence on Middle East oil exporters

Policy goal	National policy instruments Regulation	Market-based	Voluntary agreements / information	International policy instruments (agreements, partnerships)
Preventing disturbance				
Preventing international economic and political crises				Organising dialogue with OPEC (through IEA or EU)
Increasing oil stocks (reduces impact of OPEC actions)				Strengthening oil stock mechanism (EU and IEA)
Expanding oil trade				Opening new markets through WTO
Encouraging additional oil supply from other regions (e.g. Africa)			Promoting investments by Western companies in new regions	Providing development aid to these regions
Reducing vulnerability				
Encouraging energy saving	Imposing energy efficiency standards (EPN, EPL)	Raising tax on energy	Negotiating agreements on long-term targets and benchmarking	
Reducing oil intensity	Improving spatial planning procedures for new wind and gas sites	Subsidising use of biofuels		Extending or intensifying the ACEA convenant
Ensuring access to external oil supplies				Creating partnerships, conserving of EU oil resources, and investing in pipelines (e.g. to Caspian Sea)
Mitigating effects				
Reducing negative socio-economic consequences	Imposing demand constraints (e.g.’car-free days’) and reducing levies on fuels			

Policy options dealing with risks of disruption of supply and price volatility due to increasing dependence on gas supply from Russia and the Middle East

Policy goal	National policy instruments			International policy instruments (agreements, partnerships)
	Regulation	Market-based	Voluntary agreements / information	
Preventing disturbance				
Preventing international economic and political crises				Organising dialogue with Russia and Middle East
Conserving domestic natural gas reserves	Imposing a national production cap	Subsidising production from small fields	Negotiating agreement on minimum storage capacity	
Increasing competition on international natural gas market / expand rate	Promoting harmonisation of gas markets in EU countries			Opening new markets through WTO, and promoting liberalisation of Russian gas market
Encouraging additional natural gas supply from other regions (e.g. Africa)		Supporting investment		
Reducing vulnerability				
Encouraging energy saving	Imposing energy efficiency standards (EPN, EPL)	Raising tax on energy	Negotiating agreements on long-term targets and benchmarking	
Reducing gas intensity	Improving spatial planning procedures for new wind and biomass sites, and regulating minimum share of coal-fired power plants			
Ensuring access to external gas supplies		Supporting LNG facilities , and investments in interconnections		Creating partnerships, conserving of EU gas resources
Mitigating effects				
Reducing negative socio-economic consequences	Regulating prices of natural gas			

Policy options dealing with risks of disruption of supply and price volatility due to insufficient investments in power generating capacity

Policy goal	National policy instruments Regulation	Market-based	Voluntary agreements / information	International policy instruments (agreements, partnerships)
Preventing disturbance				
Improving market functioning (in EU countries)	Harmonising policy in EU countries and creating stock market for installed capacity		Creating information system for long-term demand, supply, import / export (monitoring)	Organising dialogue within EU to speed up de-regulation in other countries
Ensuring minimum reserve capacity	Imposing capacity requirements	Imposing reserve capacity payments		
Increasing interconnections	Promoting competition	Charge on each kWh transported to finance reserve capacity on interconnections		Agreements with other EU countries
Reducing vulnerability				
Encouraging energy saving	Imposing energy efficiency standards (EPN, EPL)	Raising tax on energy	Negotiating agreements on long-term targets and benchmarking	
Promoting substitution		Supporting industry for investing in co-generation		
Mitigating effects				
Reducing negative socio-economic consequences	Regulating prices of electricity			

Policy options dealing with risks of disruption of supply due to insufficient investments in power and gas distribution grids

Policy goal	National policy instruments: Regulation	Market-based	Voluntary agreements / information	International policy instruments (agreements, partnerships)
Preventing disturbance				
Improving market functioning (in EU countries)	Harmonising transport tariffs in EU countries	Internalising external costs of disruptions	Creating information system for long-term demand, supply, import / export	Organising dialogue within EU to speed up de-regulation in other countries
Ensuring minimum reserve capacity and quality	Imposing capacity requirements, minimum standard disruptions, and output standard disruptions	Imposing reserve capacity payments, congestion charge, and charge on each kWh transported to finance reserve capacity		
Increasing interconnections	Promoting competition			Agreements with other EU countries
Reducing vulnerability				
Encouraging energy saving	Imposing energy efficiency standards (EPN, EPL)	Raising tax on energy	Negotiating agreements on long-term targets and benchmarking	
Promoting decentralised generation and substitution		Subsidising investments in decentralised generation, dual-firing techniques and household micro-generation		
Mitigating effects				
Reducing negative socio-economic consequences	Giving financial compensations for disruptions within the network			

Appendix 4 Costs of producing biofuels

Current level of costs

NOVEM (2003) assesses costs of directive 2003/30/EC regarding the blending of fossil fuels and biofuels. Based on a survey of international literature, various estimates of additional costs of blending biofuels with their fossil counterparts are provided. For every production process, NOVEM chooses the 'best estimate'. These estimates are used to determine the extra costs per litre of blending, according the percentages in the EU directive. The table below shows the resulting additional costs of a 2% and 5.75% blend.

The EU requirement of 2 and 5.75% blend is defined in terms of energy content. This implies a higher share in terms of volume as the energy content of the biofuels is smaller than from fossil fuels. The shares in terms of energy content and volume are given in columns two and three of the table. The necessary duty reductions and the corresponding costs to the government are determined for two cases: 'equal litre price' and 'equal GJ price'. In the first case, the buyer of the blended fuel is only compensated for the higher price per litre of the blend. In the second case, the buyer is also compensated for the fact that he has to buy more litres in order to compensate for the lower energy content of the blend. In this case, the additional cost to the buyer (compared with the first case) consists of the price of the extra litres of the blend and the appropriate excise duty.

Necessary excise duties reductions in the Netherlands to achieve equal pump price, in volumetric and energy terms (current levels)

Blends	Share biofuel		Additional costs (= excise duty reduction)		Total costs (total excise reduction	
	energy	volume	equal litre price	equal GJ price	equal litre price	equal GJ price
			eurocent/litre		million euro/year	
Bioethanol/gasoline	2.0	2.9	0.8	1.7	10	60
Biodiesel/diesel	2.0	2.2	0.8	1.0	54	62
Total					64	122
Bioethanol/gasoline	5.75	8.2	2.2	4.7	29	176
Biodiesel/diesel	5.75	6.2	2.4	2.8	155	179
Total					184	355

Note: costs of bioethanol are based on average costs of conversion of wheat, sugar beat and residues; costs of biodiesel are based on conversion of RME (Rapeseed Methyl Ester).Source: NOVEM (2003) and own calculations

Columns four and five of the table show the extra costs of blending. To prevent price differences at the pump, the government should reduce excise duties by the same amount. The figures in the last two columns present the net effect on the government budget. As we assume a complete compensation for fuel consumers, the cost figures in the last column are used in our cost-benefit analysis. These costs to the government are the balance between the effect of lower excise duties per litre and the extra duties intake because of the larger volume sold. These total costs are based on the volumes of gasoline and diesel sold in 2002.

Future development

For the longer term various studies provide a wide range of possible production costs. RIVM (2003) provides an overview of recent studies on future production costs. In some cases cost estimates for the long-term differ by more than 300%. The table below is taken from RIVM (2003).

Production costs of fossil fuels and biofuels/bio-electricity (USD/GJ)(well-to-fuel, long-term)

Primary energy source	Fuel	Novem (1999b) (long-term)	IEA/AFIS (1996) (long-term)	Johansson (1996) (by 2015)	Faaij et al. (2000a) (long-term)	De Jager et al. (1998) (by 2010)	UNDP (2000) (long-term)
Crude oil	gasoline	6	18	–	8	–	8–11
	diesel	6	16	–	–	–	8–11
	LPG	6	16	–	–	–	–
Biomass	ethanol	9–21	25	14–33	6	17	6–7
(cellulose)	methanol	13	17	15–20	10	19–20	7–10
	DME	12	19	-			
	hydrogen	19	22	15–19	10	17–18	6–8
	FT-diesel/				10		
	gasoline	19–22	–	–			
	electricity	–	–	29	–	–	11–17
Biomass (starch/sugar)	ethanol	21	38	23-35	25	–	8–25
Biomass (oilseeds)	biodiesel	23–57	30	23–41	20–25	24–40	15–25
Biomass (all)		9–57	17–38	14–41	6–25	17–40	6–25

Source: RIVM (2003)

In the longer term, production costs of a new technique decrease because of learning effects, technological developments, or scale effects. So-called experience curves show the influence of learning by describing the relationship between production costs and the cumulative production or use of a technology (IEA, 2000). In many cases, data show a progressive decrease in costs through cumulative sales. The latter are generally used as the measure of the experience accumulated within the industry.

NOVEM (2003) expects costs for producing bioethanol on the basis of wheat to decline by 8 % up to 2010. Costs for producing bioethanol on the basis of RME (Rapeseed Methyl Ester) are expected to decrease by 3% in this period. This implies a yearly cost reduction for bioethanol of 1.2% and for biodiesel of 0.4%. Compared to cost reductions realised with other energy technologies these reductions seem to be rather small. One has to bear in mind, however, that cost reductions only pertain to specific parts of the production process. Parts based on already well developed technologies will only show small cost reductions or no reduction at all (see also IEA, 2000, page 12, 13).

The U.S. Department of Energy (DOE/EIA, 2000) estimates that the cost of producing bioethanol could decrease by 17-66% up to 2015 due to steady improvements in cellulosic conversion techniques. However, at present, converting cellulose-based feedstocks is still far more expensive than converting corn or starch. Regarding the latter, the U.S. Department expects only limited further cost reductions as these conversion processes are already mature techniques.

Using the present cost levels of currently already fairly mature techniques (i.e. wheat-based techniques and RME-based techniques respectively), we assume an overall yearly cost reduction of 2%. Compared to the above NOVEM figures, this is a rather high rate of cost reduction. In addition, we use a constant price for biomass over the scenario period. Increasing demand for biomass will likely have an upward effect on biomass prices, whereas an increase in the scale of production would have an opposite effect. Consequently, we use quite optimistic assumptions regarding the development of biomass costs.

In our Transatlantic Market scenario, the yearly volumes of gasoline and diesel sold over the period up to 2040 increase by 50%. Up to 2010, the increase in volumes is somewhat lower than in the scenario used by NOVEM (op. cit.). Therefore, in our calculations, without taking into account the yearly cost reduction, total costs to the government in 2005 and 2010 of introducing biofuels are a little lower than in NOVEM (op. cit.) (table 8.2, page 182).

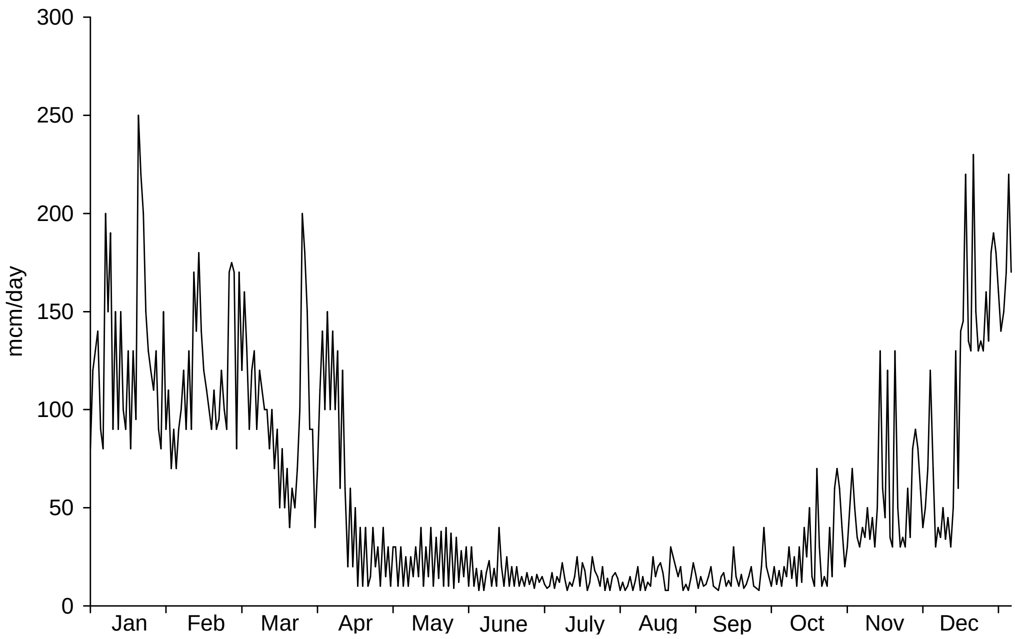
Appendix 5 Flexibility options in the natural gas market

Swing in production

Swing in production is an important option to meet volatility within demand. Some gas fields have certain geological characteristics (such as high pressure and high permeability) that enable firms to economically adjust production levels to quantities needed. The major example of such fields is the huge Groningen gas field in the Netherlands; another example is the Morecambe field in the United Kingdom. Most fields, however, need to be depleted with a high load factor in order to realise a profitable production.

The figure below shows the large variation in daily production of Groningen in 2000. From this figure, we may infer that current maximum daily output is about 250 – 300 million cubic metres a day.

Production profile of Groningen in 2000



Source: IEA (2002a)

Groningen delivers swing throughout Western Europe

The swing capacity of the Groningen reservoir is not only used to accommodate fluctuations in Dutch gas demand for gas, but also to accommodate fluctuations in demand in other West-European countries. The table below, depicting the swing in gas imports of various Western-European countries, illustrates that the Netherlands (Groningen) provides the highest swing of the gas-exporting countries. The swing in exports from the Netherlands to for instance Germany was 1.94, while the swing in Norwegian exports to this country was 1.38. The Netherlands offers a swing to Belgium of 1.69, to France of 1.54 and to Italy of 1.20.

Supply and demand of swing in Western Europe, 2000

Destination of swing	Origin of swing						
	Algeria	Denmark	Netherlands	Nigeria	Norway	Russia	Domestic production
Belgium	1.21	-	1.69	-	1.57	-	-
France	1.38	-	1.54	-	1.31	1.21	1.18
Germany	-	1.74	1.94	-	1.38	1.08	1.44
The Netherlands	-	-	-	-	1.34	-	1.69
Italy	1.20	-	1.20	1.26	-	1.17	1.14

Note: Swing is defined as the ratio of the maximum gas monthly delivery divided by the average monthly gas delivery.
Source: IEA (2002a).

The United Kingdom, which is still a large gas-producing country, hardly offers any swing to the continent since it produces primarily for the domestic market. As the British fields are in the declining phase, Groningen can be used to export swing services to the United Kingdom in the near future. Currently, Gasunie Trade & Supply is developing a pipe line to the United Kingdom in order to deliver these services. That line enables transport of natural gas up to 10 billion m^3 per year. The United Kingdom will also increasingly receive gas and swing from Norway as the British network is going to be linked to Norway’s Sleipner Platform in a few years time. That connection will raise further the swing function of Norway within the West-European market.

Swing in imports

Some swing is usually provided for in standard contracts. For a contracted (higher) price, an additional trench of gas can be obtained from the contracted supplier. This upstream swing capacity can only be realised if adequate downstream transport capacity is available. As stated above, the Netherlands offers swing to neighbouring countries, but it does also use imports as a flexibility tool for the domestic market. In 2000, the swing in the gas imports of the Netherlands was 1.34. In absolute terms however, the contribution of imports to the Dutch flexibility is small.

Swing through storage facilities

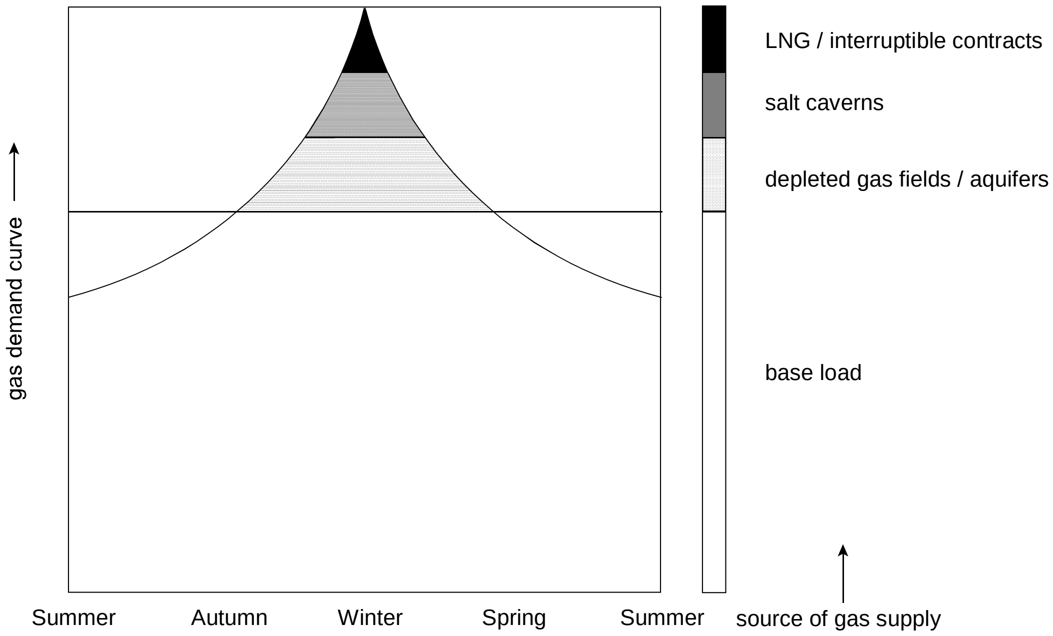
In many countries, gas storage facilities play a major role in meeting the volatility in gas demand. Natural gas can be stored in depleted gas fields, salt caverns, aquifers, liquefied natural gas (LNG) peak shavers, surface tanks and pipelines (line-pack). Each has its own advantages and disadvantages:

- Depleted gas fields generally have the lowest deliverability and injection rates. Moreover, they typically use quite large amounts of base gas. Therefore, these facilities are mostly used as single cycle facilities.

- Salt caverns, on the contrary, tend to have high deliverability and injection rates, making them very suitable as high cycle facilities. Base gas requirements are also considerably lower than depleted reservoirs.
- Aquifer facilities fall in the middle of above mentioned storage facilities; both in deliverability and injection rates. The major disadvantage of aquifers is the high base gas requirements (as high as 80%). LNG peak shaving facilities are designed for extreme demand circumstances. These facilities play an important role in offering flexibility in countries, such as Belgium and Spain, where geological options for underground gas storage are limited.
- Line-pack can be defined as storing gas inside the pipeline network by boosting the network pressure above the delivery pressure. Line-pack is a limited tool as it requires some time for the pressure to build up. It is, therefore, a more suitable measure when for instance some degree of scarcity is forecasted (e.g. the prediction of a cold weather front up ahead). In the Netherlands, this tool enables to shave 3% of maximum demand per hour in extreme cold days. In practice, this tool is most often used in countries where underground gas storage opportunities are scarce.

Until recently, the Netherlands had hardly any storage facility. The only facility was a peak shaving LNG-unit designed for exceptional cold days. Because of the declining capabilities of Groningen to meet all fluctuations within demand, additional storage facilities have been built. These consist of the depleted gas fields in Norg, Grijpskerk and Alkmaar. Those facilities are developed to meet normal seasonal variations in demand.

The figure below shows the merit order of the various options for supplying flexibility in a stylised way. The base load is the quantity of gas supply that is being imported or produced with a constant load factor all year long. In summertime, the surplus of base load in relation to demand is used for filling storages facilities thereby anticipating higher winter demand.



Source: Arentsen et al. (2003)

In the Netherlands, the order by which the several facilities are used is as follows: Groningen, Norg, Grijpskerk, Alkmaar, and finally the LNG-units. The decision to let Groningen provide swing supply is taken on an hourly basis and is in fact ‘transport driven’. Delivery of gas requires a certain amount of pressure in the pipeline network. Any time that demand is higher or supply is lower than forecasted, the pressure in the network decreases. This is the signal for Groningen to provide swing supply. It is only when maximum swing supply of Groningen is insufficient to reach the required level of pressure that storage facilities are put to use.

[1] Source: Arentsen and Künneke (2003)

Appendix 6 Costs of generating electricity

Reliable cost figures for electricity generation are fairly scarce. In this study, we use data from OECD (1998). This Appendix discusses the scope of these data and assesses the comparability with other available data.

The Nuclear Energy Agency (NEA) and the International Energy Agency (IEA), both agencies of the OECD, published a comparative study of the projected costs of base-load electricity generation, commercially available in the first decade of this century. It uses a consistent framework for various production techniques in different countries. Costs are calculated using an agreed common methodology, with common assumptions on technical and economic parameters.

The technical assumptions in the methodology concern the commissioning date (2005), the economic lifetime of the plant (40 years) and the settled down load factor (75% for fossil and nuclear plants). The economic assumptions include the discount rate for decision-making. OECD (1998) distinguishes between 5 and 10 percent. We focus on the latter, as we a 5 percent discount rate does not reflect the uncertainties in Europe's newly liberalised electricity market) and the currency unit (US-dollars as of 1 July 1996).

The methodology strives for full cost coverage: all technology and plant specific cost components are taken into account, distinguishing between three types. Investment costs include pre-construction, construction, major refurbishment and decommissioning costs. Operation and Maintenance (O&M) costs consist of costs for consumable materials other than fuel, emission control catalysts and waste disposal costs. Fuel costs include all costs related to fuel supply to the power plant. Apart from the commodity price of the fuel at stake, it comprises fuel-specific taxes, pre-treatment costs and transport costs.

Despite the use of common assumptions, some of the outcomes vary widely between countries. Total costs for nuclear generation in Japan for instance are more than twice as high as the same figure for China. Both for coal-fired and gas-fired plants, similar differences can be found: production from a Danish gas-fired plant is over two times as expensive as production from a US gas-fired plant, whereas Portuguese coal-fired power is twice as expensive as its US counterpart. As these figures are computed using common assumptions, these differences reflect actual cost differences. The major sources for these differences come from the accessibility of fuels, costs following from environmental regulations and country-specific factors affecting costs, such as population density and geological factors.

OECD (1998) lists Dutch figures for gas-fired and coal-fired plants, but not for nuclear plants and renewable sources of electricity. Cost figures for wind are given only for Denmark (onshore and off-shore) and Italy (off-shore only). As off-shore figure for Italy and Denmark hardly differ, we feel save to use the Danish figure for both.

In the case of nuclear power, it is much harder. Since no country in the world has any recent experience in building new nuclear reactors at current levels of European safety and environmental regulations, all available cost estimates are just that: estimates. Nuclear cost estimates of three European countries are presented in the study. The French figure (4.9 dollar cents/kWh) is remarkably low, partly due to fairly light environmental and safety regulation, and partly due to economies of scale. The French units considered are 50% larger than the other European reactors and have 4 units per site, enabling them to share costs. Cost estimates for Finland (5.6 dollar cents/kWh) and Spain (6.4 dollar cents/kWh) are based on single unit-sites. In our analysis, we use the Spanish figure, as we feel that the highest figure is the most relevant one for the Dutch situation, with a high population density and a reputation of relatively strict environmental regulations.

The Spanish figure for costs of nuclear power in OECD (1998) may be compared to the Light Water reactor figure in the DACES 2050 database. This is a database of options which are relevant for a clean energy supply in 2050, constructed by the Utrecht Centre for Energy research (UCE). The methodology of the studies is not comparable, but the major cost components can be compared, as is done in the table below.

Comparison of costs components of nuclear power, OECD vs. DACES

	Share in total costs/kWh, OECD	OECD 1998, Spain	DACES 2050
Construction costs(€/kW)	70%	2052	2200
O&M costs (€/kW/year)	14%	50	46
Fuel costs (eurocent/kWh)	16%	1.01	1.05

The OECD- and DACES figures are very much in line with each other. OECD's estimate for Spain is somewhat lower for investment and fuel costs, and higher for O&M-costs. Taking cost shares into account, we find that applying the OECD framework to the DACES-figure would yield a total costs figure of about 4.5% above that of OECD's estimate for Spain, implying that the latter is probably not an overestimation of costs in The Netherlands.

There is one more thing to be said about nuclear power cost figures. Recently, Finland has decided to allow the construction of a new nuclear plant and a private firm, TVO, expressed its interest in building and exploiting such a plant. Why would a private firm be interested in such an adventure, if costs statistics show that nuclear power is relatively expensive? We have no way of knowing the exact answer, as the decision process of the plant is still in a very early stage. At this moment, it is unclear if and under what conditions private banks will be willing to finance the plant. Preliminary cost figures suggest that TVO perceives investment costs to be at a fairly low level (5 percent below that of the French estimate in OECD, 1998) because of the large scale (1600 megawatt) of the plant. Furthermore, TVO may have optimistic expectations on future government policies affecting the profitability of the plant (one may think of favourable regulations for the plant, or of a carbon tax, affecting the competitive position for fossil fuel-fired plants), as Finnish government has expressed its preference for nuclear power as a source of carbon free energy.

The figures used in this study are summarised in the table below. OECD (1998), offers the choice between discount rates of 5 and 10 percent. Given present uncertainties in the electricity market regarding market developments and climate policy, a discount rate of 10 percent is probably more appropriate. OECD figures are converted from 1996 US dollars to 2002 euro using the 1996 exchange rate and the cpi for the Netherlands, combining to a multiplication factor of 0.95.

Cost figures used in this study (euro per kWh)

	Investment costs	O&M costs	Fuel costs	Total costs
Gas-fired	1.2	0.3	2.6	4.2
Coal-fired	2.3	0.8	2.2	5.3
Nuclear	4.2	0.8	1.0	5.9
Wind onshore	4.5	0.7	0.0	5.2
Wind offshore	6.2	0.9	0.0	7.1

Appendix 7 The electricity model

In several cases in this study we use CPB's electricity market model to assess the effects of policy measures in the electricity market. Before we turn to the model itself, we devote some attention to the distinctions made in the model and the notation used.

The model distinguishes between capacity and output. We denote capacity related variables by upper case letters, whereas lower case letters are used for output-related variables. Several other distinctions are made by using subscripts. Subscript *h* denotes hour of the day. The output model is based 24 hours on an average day, implying that each hour in the model represents 365 similar hours in a year.

Subscript *i* denotes individual producers, who are assumed to be identical. Each producer is based in a supply region (subscript *k*) and delivers to one or more demand regions (subscript *l*). Both for supply and demand, we distinguish between two regions: The Netherlands and "other Western Europe", the latter including Belgium, France, Germany, Luxemburg and Switzerland.

Although the model does distinguish between generation techniques (coal, gas, nuclear, large scale hydro, other renewables), there is no need to express this distinction in a subscript in this chapter. The production mix is given at the start of any time path and may be altered exogenously for policy analysis. The model does not predict any technique choice, but simply assumes that all new capacity will be gas-fired. (See Ford (1999) for a more extensive argumentation). Techniques are used in the model to derive the marginal cost curve. This derivation requires techniques to be numbered consecutively in order of variable costs, also known as the merit order. The place in the merit order is denoted by subscript *m*.

The model uses five different subscripts, as summarised in the box below. To keep the model readable, we omit subscripts if a variable is summed over one or more of the subscripts (e.g. $q_l \equiv \sum_h \sum_i \sum_k q_{hikl}$). Apart from subscripts, the model also uses superscripts. *L* denotes large users, whereas *S* denotes small users.

Subscripts in the model

The following subscripts are used in the model:

h	hour of the day	(1,2,…24)
i	individual producer	(1,2,…*n*)
k	supply region	(Netherlands, Other Western Europe)
l	demand region	(Netherlands, Other Western Europe)
m	place of technique in merit order	(1,2,…5)

The remainder of this appendix is organised as follows. First, we describe how the model derives optimal capacity and output and how these are interlinked. Afterwards, we describe technique choice and derive the marginal cost function from the capacity outcomes.

Optimal capacity and output

Let us first turn to the derivation of optimal output. Any local market *l*, at hour *h* may be described by a linear inverse demand equation for large users, who are able to observe real time prices:

$$p_{hl}^{L} = a_{hl}^{L} - b_{hl}^{L} q_{hl}^{L} \qquad (1)$$

For small users, the case is a little less straightforward. Small users do not observer real time prices, but react to average annual prices:

$$p_{l}^{S} = a_{l}^{S} - b_{l}^{S} q_{l}^{S} \qquad (2)$$

with:

$$p_{l}^{S} = \frac{\sum_{h} p_{hl} q_{hl}^{S}}{\sum_{h} q_{hl}^{S}} + rm^{S} \qquad (3)$$

with rm^S denoting the retail margin and q_{hl} being a fixed proportion of q_l. This implies that small users have a fixed load pattern in our model. For notational ease, we define

$$q_{hikl} \equiv q_{hikl}^{S} + q_{hikl}^{L} \, .$$

A producer maximises short run profits of its existing plants at every hour of the day:

$$\pi_{ikh} = \sum_{l} p_{hl} q_{hikl} -, \sum_{l} c(q_{hikl}, Q_{ik}) q_{hikl} - (C_{ik} Q_{ik}) / 24 \qquad (4)$$

where $C_{ik}Q_{ik}$ are fixed costs related to capacity and *c(.)* denotes the short run variable cost curve. Its first derivative will be described in detail in the next section, for now we simply note that the level of capacity influences marginal costs. Note that we measure capacity in the same units as output (kWh), so that we can easily compare these figures. This implies that fixed cost parameter C_{ik} is measured in €/kWh, implicitly assuming a constant overall utilisation rate.

As we mentioned in section 3.2, we use an approach similar to conjectural variations to account for mixed strategies. Following the theory of conjectural variations, any firm acts as if it faces residual demand, with the slope of its inverse described by $\frac{\partial p_{hl}}{\partial q_{hikl}}(1+r_{out})$, where r_{out} denotes the conjectural variation term for output. We assume that all reactions are symmetric. It can easily be checked that $r_{out}=0$ yields the Cournot outcome, whereas the Bertrand or competitive outcome is reached when $r_{out}=-1$. Optimal quantities are derived by differentiating short run profits with respect to q_{hikl}, which implies equating marginal costs to marginal revenues, yielding $h \times i \times k \times l$ first order conditions .[1]

$$p_{hl} + (1+r_{out})\frac{\partial p_{hl}}{\partial q_{hikl}} q_{hikl} = \frac{\partial c(q_{hikl}, Q_{ik})}{\partial q_{hikl}} q_{hikl} + c(q_{hikl,} Q_{ik}) \quad (5)$$

Let us now turn to the optimal level of capacity. Firm *i*'s annual profits are determined by summing hourly profits over *h*, yielding:

$$\Pi_{ik} = \sum_h \pi_{ikh} = \sum_h \sum_l p_{hl} q_{hikl} - \sum_h \sum_l c(q_{hikl}, Q_{ik}) q_{hikl} - C_{ik} Q_{ik} \quad (6)$$

with all parameters defined before. Differentiating this equation with respect to Q_{ik}, yields a set of $i \times k$ first order conditions for long run profits

$$\frac{\partial \sum_h \sum_l p_{hl} q_{hikl}}{\partial Q_{ik}} = \sum_h \sum_l \frac{\partial c(q_{hikl}, Q_{ik})}{\partial Q_{ik}} q_{hikl} + C_{ik} \quad (7)$$

The next question is what the marginal revenue of an additional unit of capacity is. Investments in additional units of capacity will only generate revenues if capacity restrictions are binding. If this is the case, more capacity will facilitate more output, and thus earn revenues. If capacity is a binding restriction however, it is unlikely to be binding at every hour of the year. So how do we determine marginal revenues of capacity investments?

First, let us recall that the hours of the day are ordered based on the load, so that the hour with the highest load is indexed 1, Now define H_l, such that $\sum_l q_{hikl} = Q_{ik}$ for all $h \leq H$. Note that this requires us to appoint capacity to demand regions, implying that we differentiate the profit function by Q_{ikl} rather than Q_{ik}. Appointing capacity to demand regions is artificial, because

[1] Note that we assume regional markets to be independent, i.e. $\frac{\partial p_{hWE}}{\partial q_{hNL}} = \frac{\partial p_{hNL}}{\partial q_{hWE}} = 0$

there is no technical need to divide these capacities: they may actually belong to the same plant. For each hour $h<H_l$, the marginal revenue of an increase in capacity equals the marginal revenue of an increase in output, albeit that we allow conjectural variation term to differ between output and capacity. We may now rewrite the first order condition for capacity:

$$\sum_l \sum_{h=1}^{H_l} p_{hl} + \left(1 + r_{cap}\right)\frac{\partial p_{hl}}{\partial q_{hikl}} Q_{ikl} = \sum_h \sum_l \frac{\partial c\left(q_{hikl}, Q_{ik}\right)}{\partial Q_{ik}} q_{hikl} + C_{ik} \tag{8}$$

A special case of the equation above is the case of sufficient capacity. If capacity restrictions are never binding, H_l will be zero for all l and the entire left hand disappears from the equation. This implies that if spare capacity in peak periods exists, investments take place if and only of its variable cost savings outweigh its capital costs. Note that this may influence output through its influence on marginal costs.

The first order conditions of the long run and the short run model have a similar structure. Note that the conjectural variation term for capacity is likely to be lower than that for output, as we argued above. Combining the FOC's and solving them for q_{hikl} and Q_{ikl} yields optimal capacities and outputs. The commodity price of electricity for region l at hour h can now be determined by substituting the summation of optimal q_{hikl} over k and i into the inverse demand equation.

The solution of the model does not take into account the current level of capacity, which may at any time exceed the optimum. It is implausible that capacity will be dismantled in such a case, especially since electricity demand is likely to continue to grow over time. Therefore, we impose that capacity is the maximum value of optimal capacity and existing capacity

$$\overline{Q}_{ik} = \max\left(\sum_l Q_{ikl}, \overline{Q}_{ik,t-1}\right) \tag{9}$$

Derivation of the marginal cost function

As the graphical analysis in the previous chapter suggested, the marginal cost function is built up from the merit order. In this section we derive the marginal cost function. First, we simplify notation somewhat. We denote marginal costs by mc, rather than $\frac{\partial c\left(q_{hikl}, Q_{ik}\right)}{\partial q_{hikl}} q_{hikl} + c\left(q_{hikl}, Q_{ik}\right)$, which would be consistent with the model as outlined in the previous section. Let subscript m denote the place of a technique in the merit order, with m=1 representing the technique with the lowest marginal cost and m=5 denoting the technique with the highest marginal cost. To mimick the use of individual plants within techniques, we define a slope line through the 'stairs' of the merit order. Marginal costs at quantity q, belonging to technique (or step in the merit order) m are defined as:

$$mc(q \in m < 5) = \tfrac{1}{2}\left(c_m + c_{m-1}\right) + \frac{\tfrac{1}{2}\left(c_{m+1} - c_{m-1}\right)}{\overline{q}_m - \underline{q}_m}\left(q - \underline{q}_m\right) \qquad (10)$$

In this equation, c_i denotes the cost level of the current step in the merit order (the marginal technique) and c_{m+1} and c_{m-1} are the cost levels for the next and previous technique in the merit order respectively. The capacity of the marginal technique is given by $\overline{q}_m - \underline{q}_m$, with $\underline{q}_m = \overline{q}_{m-1}$.The obvious problem here is that c_{m+1} is not defined for the technique with the highest marginal costs. We solve the problem by stating that the difference between c_{m+1} and c_m equals that between c_m and c_{m-1}, so that $c_6 = c_5 + \left(c_5 - c_4\right)$. We can now write the equation for the marginal cost of a unit in the upper step of the merit order:

$$mc(q \in 5) = \tfrac{1}{2}\left(c_5 + c_4\right) + \frac{\left(c_5 - c_4\right)}{\overline{q}_5 - \underline{q}_5}\left(q - \underline{q}_5\right) \qquad (11)$$

These two equations form an upward sloping kinked marginal cost curve for all output values between zero and full capacity.