Dutch energy policies from a European perspective

Major developments in 2003

An ECN Publication

Credits

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Preface

ECN is not only active in technological research and development; it also plays a major role in policy research and development. Since national energy policy is increasingly influenced by developments at the European level and vice versa, ECN is shifting its attention from a national to a European focus. More and more, national energy and environmental policies are implemented within the framework of EU directives, while reversibly the success of European policies is dependent on harmonised national actions in a liberalised European energy market.

To demonstrate this shifting research orientation towards a European position ECN decided to highlight four major national topics that dominated policy discussions in the Netherlands during 2003 in this special publication.

- The first topic concerns changes in national renewable energy policy. Earlier policies had led to a dramatic increase in imports of renewable electricity with major fiscal consequences and it was decided to redress the balance towards stimulating domestic investment in renewable energy capacity.
- In the summer of 2003 extreme weather events led to an electricity supply crisis providing a short-term argument to look into the policy options for preventing shortages. The opportunities and limitations of demand side response to electricity supply shortages is the second topic addressed.
- Regarding climate change policies the most notable development undoubtedly concerns the impending implementation of a greenhouse gas emissions trading scheme. The focus in this chapter is on the interaction between the EU directive on emissions trading and the Dutch approach.
- As a relatively small country the Netherlands has always found it difficult to make appropriate energy research and development choices. During 2003 new directions in RD&D policies were determined. Apart from the optimal choice of nationally relevant research priorities, an additional vexing problem concerns the relative amounts of public resources spent for promoting RD&D versus stimulating market deployment. This problem is addressed in the last chapter.

Finally, for the benefit of those unfamiliar with the major facts on the Dutch energy sector, we have added a selection of statistical figures as a general reference source.

We hope that these capita selecta of energy policy developments in the Netherlands provide an appealing impression of the Dutch policy arena in 2003 while at the same time demonstrating the European scope of the policy research at ECN.

Ton Hoff
Chairman of the Board of Directors

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CHAPTER 1

SHAPING THE EU RENEWABLE ENERGY MARKET: WHICH ROAD TO HARMONISATION?

Authors: Theo de Lange and Martine Uyterlinde

This chapter evaluates the EU Renewables Directive and the complications in implementing it, by examining the Dutch case. In the past the Netherlands had a system of ecotax exemption for renewable electricity. This incentive led to a huge increase in the demand for renewable electricity, which was however largely met by import. In 2002 and 2003 the Netherlands made a shift to stimulate production capacity and to discourage import: the ecotax exemption was reduced and eventually phased-out, the production subsidy was abolished and feed-in-tariffs (MEP) were introduced. The authors of this first chapter discuss whether the Dutch government has found a balance between the stimulation of international trade and the protection of the Dutch market. Is the Dutch approach exemplary for all Member States? How do national approaches mesh with the implementation of the Directive and the establishment of a harmonised renewable electricity market?

The EU renewable electricity market: 15 different incentive schemes

For many years, renewable energy technologies have received financial and political support within the European Union and its Member States. The reasons have differed, ranging from security of supply and local employment to emission reduction. In 1997 the EU has issued the Renewable Energy White Paper. This White Paper proposes an overall target of 12% for the contribution by renewable sources of energy to the European Union's gross inland energy consumption by 2010 and provides for a strategy and action plan to realise the target. Furthermore it calls for a more detailed framework including indicative targets to be set for the individual Member States. This framework has been provided in 2001, with the issuing of the Directive on the promotion of renewable electricity (2001//77/EC).

This Renewables Directive is meant to facilitate a significant increase in the generation of electricity from renewable energy sources (RES-E) in the medium term, by setting an indicative target for renewable electricity in the total EU electricity consumption of 22.1% for the year 2010. This target is broken down into differentiated indicative (non-binding) percentage shares for each Member State. In September 2003, the Directive has been amended to include indicative targets for the Czech Republic, Estonia, Cyprus, Latvia, Lithuania, Hungary, Malta, Poland, Slovenia and Slovakia. Finally, the Directive gives a regulatory framework that might form the basis for a harmonised European renewable electricity market.

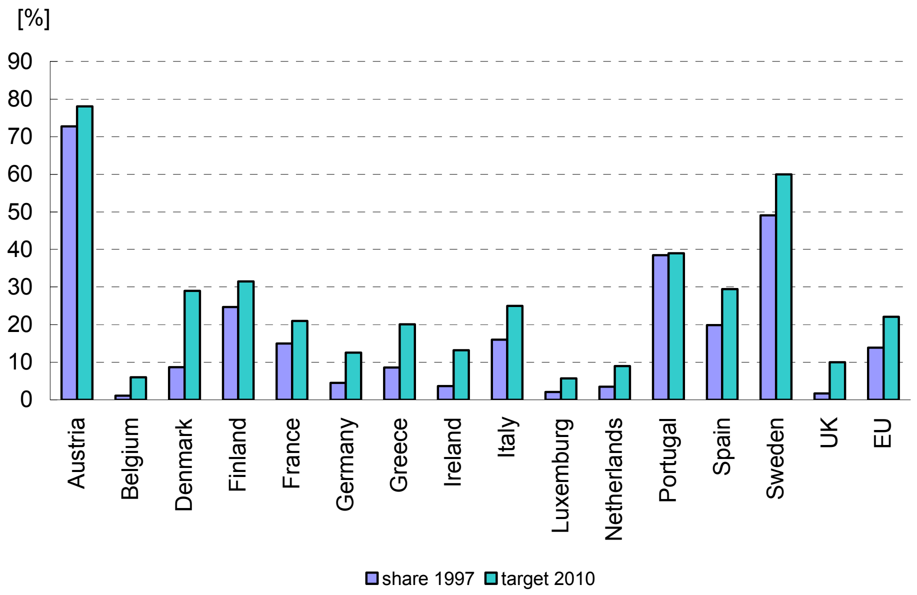
The current European market for renewable electricity is far from harmonised. Due to the diversity of policy objectives among Member States, the support schemes also greatly differ among countries and technologies. Many support schemes are exclusively meant for domestic producers, thereby introducing large differences in market value of RES-E between countries, and resulting in a fragmented international market.

Which types of support schemes are presently used in the EU? Investment subsidies are the oldest, and still the most common type of schemes. They are usually granted on a capacity basis (in euro/kW) additionally to operational support (in euroc/kWh). Regarding operational support, a trend can be observed towards two main instruments, feed-in tariffs and Renewable Portfolio Shares (RPS, or quota obligations) supported by a system of tradable renewable energy certificates (TRECs). These certificates provide an accounting system to register production, authenticate the sources of electricity and to verify whether the quota has been met. Other instruments employed in several Member States are bidding systems and fiscal incentives.

The main items in the Renewables Directive

The EU Member States are supposed to implement the Directive in national legislation by October 27, 2003. One of the requirements is to adopt the indicative targets (see figure 1.1) in their national policies and to report every two years on the progress being made. If this non-binding approach does not prove to be satisfactory, the Commission will propose binding targets.

Figure 1.1 Targets for year 2010 as stated in the Renewables Directive compared to the contribution in 1997 (% in gross national electricity consumption)



The Commission may propose a harmonised community framework for support schemes in an evaluation report of Member State RES-E support systems, due no later than 27 October 2005. Harmonisation will only be proposed if the (cost)effectiveness of current support schemes is regarded insufficient in relation to the indicative targets. The main reason for harmonising support schemes would be the consistency with one of the overall objectives of EU energy policy, namely to create an internal electricity market. In the final decision on the adoption of the Directive, the Council, the Commission and the European Parliament have stated that 'one of the ultimate objectives of this Directive is the eventual preparation of an EU Framework Directive regarding support schemes for renewable energy.' The Directive indicates that a proposal for such a harmonised framework should:

- 'contribute to the achievement of the national indicative targets
- be compatible with the principles of the internal electricity market
- take into account the characteristics of different sources of renewable energy, together with the different technologies, and geographical differences
- promote the use of renewable energy sources in an effective way, and be simple and, at the same time, as efficient as possible, particularly in terms of cost
- include sufficient transitional periods for national support systems of at least seven years and maintain investor confidence.'

The non-binding approach and the fact that national support schemes are allowed up to 7 years after the introduction of a harmonised Community framework clearly limit the impact of the Directive and leave much room for strategic behaviour of individual Member States. Governments have the opportunity to optimise the national benefits without being accountable for the progress being made in realising a harmonised EU market for renewable electricity. On EU level it is far from clear if the Member States will implement the Directive in the way it is meant to be, along which routes harmonisation will take place, which national policy schemes will prove to be successful and which ones less so.

Other features of the Directive are:

- It gives a clear definition of renewable energy. Notable is that this definition includes the biodegradable fraction of waste, although it is stressed that Member States must comply with EU waste legislation. For instance, the incineration of non-separated municipal waste should not be promoted under a renewables support system.
- Member States are to introduce 'Guarantees of Origin' (GOs) by 27 October 2003 at the latest. These GOs should ensure that the origin of electricity from renewable energy sources can be guaranteed throughout the EU according to objective and non-discriminatory criteria. Member States are not (yet) required to recognise the purchase of a guarantee of origin from other Member States or the corresponding purchase of electricity as a contribution to the fulfilment of a national target. Recital 11 to the Directive states that GOs 'should be clearly distinguished from tradable certificates'. Yet, the GO requirement – if implemented in a consistent way throughout the Union – can be seen as a first step towards a possible introduction of a Community-wide scheme of tradable renewable energy certificates.
- Better access is to be provided to electricity distribution networks, including streamlining and expediting authorisation procedures at the appropriate administrative level. Member States are to report on actions taken to improve grid access no later than 27 October 2003.

The Directive is certainly a first step towards a harmonised European renewable electricity market. Yet, the time-schedule does not raise high expectations on the short or even medium term. If the Commission indeed proposed a Community Framework Directive on support schemes for renewable energy in 2005, a harmonised market could start in 2013 at the earliest, taking into account the 7-year transition period.

How do Member States react?

After the entry into force of the Renewables Directive, most Member States have started the implementation, although not all countries will meet the deadline of 27 October 2003. For instance, only four Member States had passed legislation on Guarantees of Origin by early October 2003. The Directive gives a further boost to national initiatives by stressing once more that renewable energy will remain on the political agenda at least for the next decade and thus convincing national policy makers and investors to take further actions in this field. In the meantime, the discussion on targets for renewables towards 2020 has started. This is one of the main subjects of debate at a conference on renewable energy organised by the European Commission and the German government in January 2004 in Berlin.

However, the long-term perspective of the Directive, the way towards a harmonised renewable electricity market, is only of limited importance in many Member States. The Directive is usually regarded as a set of boundaries. Given the legislative character of the Directive, these boundaries are accepted by Member States, but within the boundaries most Member States are focussing solely on their own territory, stimulating own industries and generation capacity in their own country. There are however some exceptions, Member States with a more internationally orientated approach, but still watching carefully their own interests.

In general, two main groups of countries can be distinguished. Those that choose for a (technology specific) feed-in tariff and those that opt for a Renewable Portfolio Standard in combination with in most cases a parallel system of Tradable Renewable Energy Certificates.

The first group of countries, using a feed-in tariff, are focussing completely on realising the national target within their own country. Countries such as Germany and Spain opposed the seven-year transition period for countries to keep their own support system and originally proposed a ten-year period. The main argument these countries use for applying feed-in tariffs is the effectiveness of this incentive in terms of installed capacity. The second group of countries, having introduced (recently) an RPS in combination with an obligation, such as the UK, Belgium and Sweden, are focussing on establishing a national support system on the short-term. At the same time these countries are open for an international approach, under the condition that there is a sound level-playing field. However, the creation of such a level playing field is not regarded as an important issue for the short-term. Countries are not willing to be the pioneer in this field and limit themselves to carefully monitoring the developments in other countries and to react on those in case they might result in negative side effects for the own market.

The Dutch case

In 1996-2002, renewables support policies in the Netherlands were different from what other Member States employed, both in design and in the international orientation. We will first describe the support scheme in more detail, and next evaluate the consequences of the approach in the international market.

In the past years, the Netherlands knew a system of ecotax exemption for renewable electricity, which reduced the price difference with 'grey' electricity. Moreover, the producers of renewable electricity received a production fee from the ecotax funds collected from non-renewable electricity consumers. Additionally, there were several investment-related instruments that provided for investors' tax advantages due to accelerated depreciation.

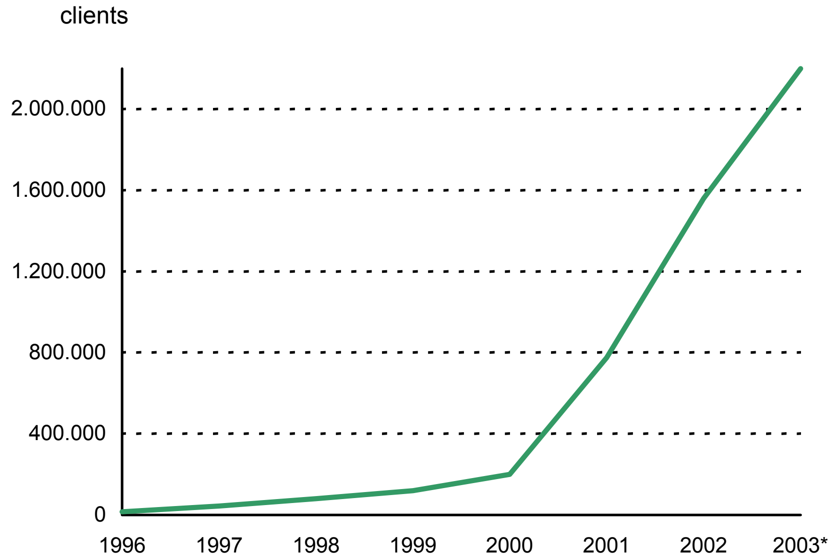
The regulatory energy tax or ecotax (Regulerende Energie Belasting, REB) was introduced in 1996 by an amendment to the Law on Environmental Taxes (Wet Belastingen op Milieugrondslag, Wbm). Since its introduction, the ecotax has been raised several times. In 2002, the total stimulation of renewable electricity amounted 8 euroct/kWh, consisting of 6 euroct/kWh (tax exemption, based on Green Certificates) and 2 euroct/kWh production subsidy (based on the contract).

Table 1.1 Regulatory energy tax (REB) for electricity per user category (in euroct/kWh)

Electricity consumption [kWh]	1996	1997	1998	1999	2000	2001	2002
0-800	0	0	0	0	0	5.83	6.01
800-10000	1.34	1.34	1.34	2.25	3.72	5.83	6.01
10000-50000	1.34	1.34	1.34	1.47	1.61	1.94	2.00
50000-10 mln	0	0	0	0.10	0.22	0.59	0.61
> 10 mln	0	0	0	0	0	0	0
Production subsidy	1.34	1.34	1.34	1.47	1.61	1.94	2.00

This incentive system led to two developments. First of all the demand for renewable electricity increased enormously from 250,000 customers in July 2001 (at the opening of the Dutch retail market for renewable electricity) to approximately 2.2 million (32% of the households) in October 2003. Due to the REB stimulation, the renewable electricity could be offered for the same price as conventional electricity. This was not only an attractive alternative for the customers, but also for the retailers as a marketing tool in a period in which the renewable electricity market was opened ahead of the retail market for conventional electricity.

Figure 1.2 Number of Dutch customers purchasing renewable electricity



* until October 2003

There were however some unintended negative effects. Having in mind a future harmonised renewable electricity market and bound by EU regulation, the import of renewable electricity was made also eligible for the ecotax exemption and the production subsidy. Being aware of the fact that realising the Dutch target for renewable electricity in the Netherlands may cause high economic costs due to limited availability of (relatively) low-cost renewable electricity potentials in the Netherlands, the Dutch government decided to aim for a certain percentage of imported renewable electricity. Although there were some restrictions concerning the reciprocity for trading with the Netherlands, the total incentive level made the Dutch renewable electricity market a very attractive export market for producers in Austria, Finland, Germany, Norway, Sweden and the UK.

The result was an increase of imported renewable electricity from 1,4 TWh in 2000 to approximately 7,7 TWh in 2001. The total REB-stimulation in terms of reduced tax-income for the Dutch government is estimated to be some 205 million Euro for 2001 and more than 300 million Euro over 2002, of which the majority went to imports.

Despite the 'missed' tax revenues, the stimulation did not lead to substantial investments in additional production capacity, neither in the Netherlands nor abroad. Domestic producers had to compete against low cost imports and were reluctant to invest because they expected that this kind of stimulation could not be sustained and would be changed on a short term.

In 2002 these adverse effects led to an amendment of the electricity law in which the shift was made to a 'dual system'. The ecotax exemption was reduced substantially, the production subsidy was abolished and feed-in tariffs (MEP) were introduced.

Table 1.2 Categorisation and MEP feed-in tariffs for renewable electricity in 2003 (all amounts in euroct/kWh)

Technology-energy source	MEP feed-in tariff	Ecotax exemption	Total support
Landfill gas and digestion	0	2.9	2.9
Pure biomass	4.8	2.9	7.7
Mixed streams*	2.9	0	2.9
Onshore wind**	4.9	2.9	7.8
Offshore wind	6.8	2.9	9.7
Stand-alone bio-energy installations < 50 MW_e	6.8	2.9	9.7
Solar photovoltaic	6.8	2.9	9.7
Wave energy, tidal energy	6.8	2.9	9.7
Hydropower	6.8	0	6.8

* Includes municipal solid waste. The MEP feed-in tariff is granted in proportion to the degree of biologically degradable material. The production subsidy only applies to installations with a minimum total energy efficiency of 26%.
** During a maximum period of 10 years, up to 18,000 full load hours.

The intention of this change in support system was threefold:

- providing more certainty for investors to realise projects within The Netherlands
- making the import of renewable electricity less attractive in order to decrease the amount of imported renewable electricity, thus preventing the unintended loss of tax-income
- due to the reduced, but still substantial ecotax exemption, there is still room for the dynamics of a renewable electricity market and green certificate trading.

Shortly after these changes had been put into operation by July 2003, the council of ministers submitted a new proposal to the parliament to phase-out the ecotax exemption by January 2005, which was indeed accepted. The total support level (see Table 1.2) will not change, because the MEP tariff will be increased. This implies that the Netherlands will switch to a classic system based on feed-in tariffs, exclusively supporting domestic production. It should be noted that although the level of the ecotax exemption will be set to 0 in 2005, the possibility to increase this level again in the future is still maintained.

The main driver for this change is the expectation that in spite of the reduced ecotax exemption, the import of renewable electricity will remain at a high level on the short term. As long as the level of the ecotax exemption is well above the price of green electricity in other countries, it is attractive to export large quantities to the Netherlands. This also results in a competition with local producers, because the price they will receive for their green certificates is much more related to the price of the imported renewable electricity than to the level of the ecotax exemption. On the other hand there is the awareness that in terms of cost effectiveness it is attractive to have part of the national target covered by imported renewable electricity.

In the long term the imports might decrease substantially as other countries are expected to increase their efforts to reach their targets. In these countries this might even result in a price for renewable electricity that is well above the level of the ecotax exemption. In that case Dutch producers might opt to export their renewable electricity to other countries, leaving the Dutch government no other option than to increase the level of the ecotax exemption in order to realise the national target. This example shows that the quantity of imports is very sensitive to the level of the ecotax exemption. If the ecotax exemption is too high, large quantities of renewable electricity will be imported in the Netherlands. On the other hand, if the ecotax exemption is too low, there is a possibility of exporting too much. For the Dutch government this leads to a situation in which they continuously will face the need to change the level of ecotax exemption and in which they have no guarantee that the national target will be reached.
All in all, it is clear that it is very difficult for the Dutch government to find the proper balance between the stimulation of international trade and protecting the own market. Therefore this

case clearly shows the complications of creating a harmonised market for renewable electricity in Europe. The present situation, characterised by a lack of a level playing field, results in a very protective attitude of national governments. On the one hand they need to implement the Directive, but at the same time they try to reduce the dependency on the policies of other EU Member States as far as possible.

Is there a way towards a harmonised renewable electricity market in Europe?

Ideally spoken, a Community harmonised support framework would have to be based on the introduction of EU-wide generic Renewable Portfolio Standards in combination with a Tradable Renewable Energy Certificates (TREC) system. Such a system would permit Member States with high-cost potentials to cover part of their target by purchasing certificates in Member States with relatively low-cost potentials. Both Member States benefit from this approach. The Member State with the low-cost options will be able to generate additional income from exports and the Member State with the high-cost options will be able to meet its target against lower costs.

It is possible to extend this system to technology specific RPSs. This allows very expensive but at the same time promising RES-E technologies (e.g. building-integrated PV) to be supported under the harmonised support framework, complemented by R&D subsidies. Specific RPSs would stimulate market development of promising high-cost technologies, provide valuable market price information, but at the same time limit the total additional costs.

Analysis using the ADMIRE-REBUS model clearly shows the benefits of this approach.

A first scenario is based upon the continuation of the present policies and compliance with the EU-Directive by the year 2010. The analysis with the ADMIRE-REBUS model shows that most

Short model description

The ADMIRE REBUS model is based on a dynamic market simulation in which national RES-E supply curves are matched with policy-based demand curves. The supply and demand curves are constructed as follows:

- Future potentials are estimated for all technology bands within a country, based on a consistent approach, which allows for technology development and learning effects through time. In the model, realisable potentials are used, meaning that all restrictions except economic ones are accounted for. An endogenous cost calculation module determines the costs of renewable technologies, using a net present value calculation. Based on technology, market and political risks, a technology and country-specific risk adder is calculated. Thus, supply curves, based on costs and potentials, are constructed, and their development is simulated through time.
- In parallel, all support policies providing a financial incentive to RES-E production, such as feed-in tariffs, or quota obligations on consumers or suppliers, are translated into country or technology specific demand sections, adding up to national demand curves.

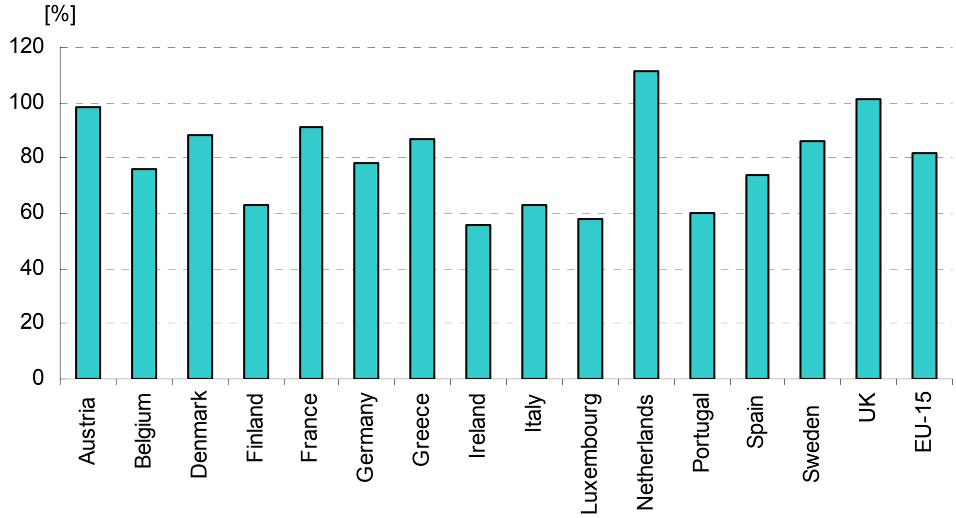
Demand and supply are matched in a market simulation, which takes into account the discriminative characteristics of some policies. Because of the different levels and conditions of national support schemes, different sub-markets may emerge. The model calculates the price of TRECs, where appropriate, and also provides a projection of the evolving RES-E generating mix per Member State and for the EU, including notably the production of renewables-based electricity.

Member States will not be able to meet their target. Under this scenario the EU will only reach

82-89% of its target. Total annual government and end-user expenditures will amount to approximately 8-10 bln euro for the period 2004-2010.

Of course there is a large uncertainty connected to the assumption that countries will continue their present policies. In this scenario, based on the situation early 2003, the Netherlands reaches its target partly through imports from countries not achieving their own target, which in fact has become very unlikely with the latest changes in the Dutch support scheme. Furthermore, the analysis of individual countries demonstrates that not the type of support scheme but rather the way it is implemented and the level of support determine its effectiveness, although the efficiency might differ.

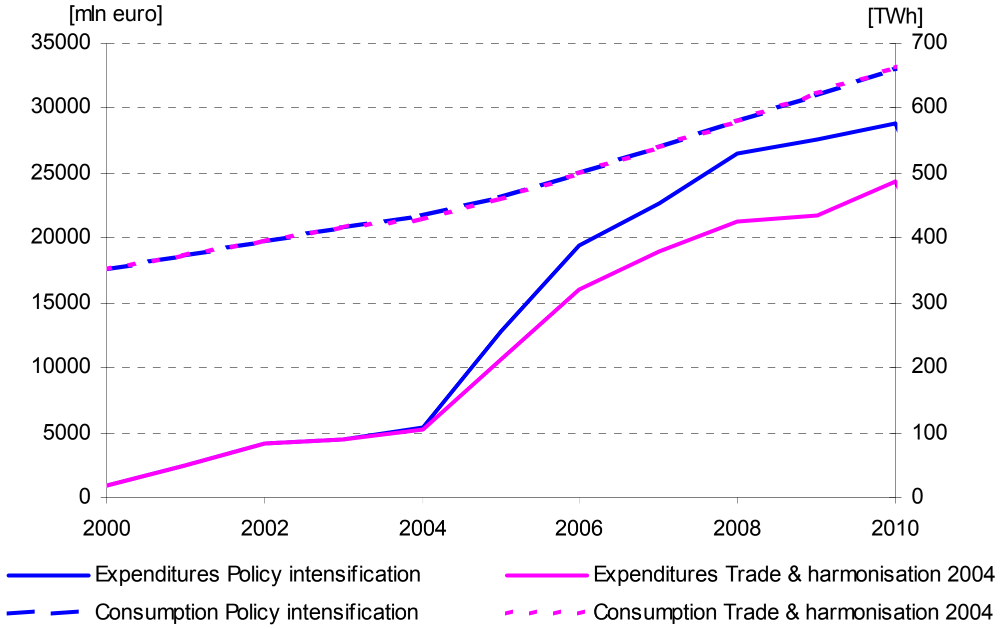
Figure 1.3 Continuation of the present policies: most countries will not meet the targets



In a scenario in which full trade is being introduced in 2004 in combination with quota obligations for all EU Member States, the targets can be met. The ADMIRE REBUS analysis clearly shows that this would also be the least cost option to implement the Directive, with clear advantages for all EU Member States. In this scenario the total expenditures will range between 11 and 25 bln. euro. The upper value relates to modestly increasing prices on electricity wholesale markets, due to a continuation of existing overcapacity in the power sector and a negligible carbon premium. The lower value is based on a scenario with substantial price rises on the electricity wholesale markets (sharp reduction in generating overcapacity and a significant carbon premium).

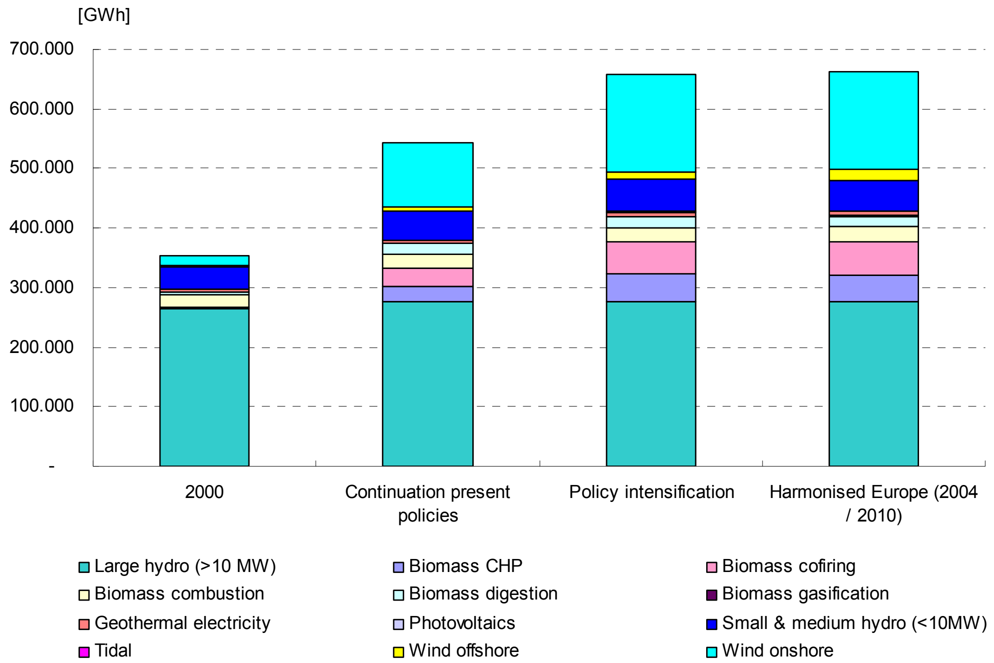
A more realistic scenario of a further intensification of present policies without much trade between Member States before 2010 shows that the EU target can be realised, but not according to the present national targets. Some Member States will do more, others less. The overall annual costs will be much higher, some 29 bln. euro in 2010.

Figure 1.4 Comparing production and total (government and end-user) support expenditures in two scenarios



In all scenarios, the dominant technologies are biomass, wind onshore and large hydro. The contribution of the latter is stable – mainly already existing capacity – but it may generate up to 50% of the EU target. The role of offshore wind until 2010 seems limited; this largely depends on the type and the ambition level of support schemes. Until 2020, solar PV almost entirely relies on dedicated policies, and for this reason, it thrives best in the scenario with the continuation of present policies.

Figure 1.5 EU-15 RES-E technology mix in 2010 under different scenarios



The main conclusion that can be drawn from these analyses is that there is a clear relationship between the costs of realising the EU target and the way harmonisation will take place. From cost perspective it would be preferable to create a level playing field and introduce full trade throughout Europe on the shortest term possible. However, given the reluctant attitude of most Member States, this does not appear to be a likely scenario.

Will the Renewables Directive result in a harmonised market?

The former paragraphs show that it is not very realistic to expect a very close co-operation between Member States on the short term. On the other hand the course has been set and the ship is slowly increasing speed. There is no doubt that - in the context of the liberalising electricity market - the role of international trade in renewable electricity will grow. The introduction of the Guarantees of Origin may be an important stimulus. Because a level playing field is not yet in place, countries will introduce reciprocity requirements, but at the same time the developing international market will also lead to requests of trading companies for more activities to create a level playing field.

In terms of cost-effectiveness, it is important that international trade will be facilitated as soon as possible and that *de facto* trade barriers, emerging from discriminating provisions in national support schemes, will be eliminated. By doing this, a harmonised EU renewable electricity market will be established step by step. It is important to notice that this process does not necessarily lead to a harmonised incentive scheme, although it could be imagined that the countries that are presently using a quota-based TREC system harmonise their frameworks and open their markets. Also, the RECS (Renewable Energy Certificate System) initiative from the market has already started paving the way for a European system of tradable renewables certificates.

A Community-wide harmonised support scheme cannot be expected to emerge from the Member States, but will require a clear decision by the Commission after the evaluation in 2005. Given the resistance in some Member States against giving up their national - preferred - support schemes, there is still much uncertainty on this. On the other hand, the fact that the Commission has scheduled their report on progress towards the indicative targets in April 2004, instead of October 2004 as required in the Directive, does indicate the weight given from the side of the Commission to the implementation of the Directive.

Apart from the way along which the harmonisation process moves forward, there are several external developments which could have a direct influence on the prospects for renewable electricity in Europe. The drivers for a European renewable electricity market also depend on developments in the field of emission trading and the development of a biofuel market, both of which are also driven by EU legislation. Moreover, the impact of the accession of 10 new Member States by May 1, 2004 on the market for RES-E is not yet clear. Preliminary analysis indicates that although the total contribution of the acceding countries to the production in the EU-25 is relatively small, the emergence of a net export flow of biomass-based electricity from Eastern Europe to Western Europe may have a cost reducing effect.

In the introduction, we started with the question whether the Directive will be implemented in the way it is meant to be, along what routes harmonisation will take place, which national policy schemes will prove to be successful and which ones less so. This chapter shows that notwithstanding the reluctance of Member States to co-operate, we expect the EU Directive to be implemented and a harmonised renewable electricity market to be established on the longer term. However, a lot of effort is still needed to convince the Member States to co-operate and to facilitate international trade. The sooner they start to co-operate in establishing a level playing field, the less the overall costs for the EU and its individual Member States will be.

CHAPTER 2

ADDRESSING THE THREAT OF INSUFFICIENT ELECTRICITY SUPPLY: CAN DEMAND RESPONSE HELP TO AVOID SHORTAGES?

Authors: Michiel van Werven and Martin Scheepers

In 2003 the Netherlands experienced extremely hot and dry weather. Generators were put on short allowance of cooling water and the supply of electricity dropped whereas peak demand increased. The amount of regular reserve capacity dramatically declined from 700 MW to approximately 100 MW. A crisis was nearby. The Dutch TSO TenneT proclaimed 'code red' and appealed to customers to moderate their electricity consumption. The extreme weather may have been an incidental phenomenon - but then again, it may not. The authors of this chapter consider the usefulness of demand response as a concept to mitigate the issues and to enhance the functioning of the electricity market when supply is tight.

Introduction

There are concerns that adequacy of supply in the Dutch electricity market will decrease to a possibly insufficient level. On the one hand this is a question of enhancing the long-term investing climate, i.e. incentives to invest in new generating capacity in time. On the other hand, it is a question of the short-term functioning of tight electricity markets with little available reserve capacity. The Dutch electricity market currently has difficulties with balancing demand and supply in times of scarcity, which results in volatile prices, occasionally occurring high price peaks, and an increasing probability of service interruptions. The fundamental choice of liberalising electricity markets implicitly means that scarcity will occur more often, because (superfluous) reserve capacity is structurally disposed of. One could say that the more efficient an electricity market will become (by discarding inefficient reserve capacity), the more the market will be 'living on the edge'. High price spikes will occur more often and the chance that the market does not clear at all will increase. Demand response is a concept to mitigate these issues and to enhance the functioning of the electricity market during tightness in the short run by making demand more price-elastic. Improving demand response, by making a reduction in demand more cost-effective for consumers when wholesale spot prices are high, will make it easier and cheaper to meet demand reliably and will reduce price volatility. In this way, improving demand response can offer a safer way of living on the edge, but, if the investment climate is not enhanced, it cannot keep the market from falling off in the long run.

Code red in the Dutch electricity market

Because of the enduring hot and dry weather in the Netherlands in the second week of August 2003, generators were put on short allowance of cooling water. The supply of electricity consequently dropped whereas peak demand increased particularly due to additional electricity consumption by cooling and air-conditioning systems. The amount of regular reserve capacity that TenneT, the Dutch TSO, could fall back on in case of a sudden power plant failure had dramatically declined from 700 MW to approximately 100 MW. A crisis was nearby. TenneT proclaimed 'code red' and appealed to customers to moderate electricity consumption during periods of peak demand. Furthermore suppliers asked large industrial consumers to interrupt their production processes - a rather alluring request as electricity prices reached extraordinarily high levels at the Amsterdam Power Exchange (up to about 2000 euro/MWh, where prices of 25-50 euro/MWH are common). In order not to be completely dependent on the demand side, generators requested exemption to drain high temperature cooling water.

Eventually the supply of electricity could be maintained in the normal way, the above-mentioned example however clearly demonstrates the importance of demand reduction during tight electricity supply. When the market is tight, demand response is crucial in preventing the TSO from using more drastic remedies, such as proclaiming emergency capacity, calling upon foreign UCTE capacity, and, finally, curtailing the demand by disconnecting parts of the electricity network.

The Dutch government has recognised that adequacy of supply may be insufficiently guaranteed in the long run and therefore considers the stimulation of investments in generating capacity, for instance by reserve or reliability contracts or by introducing a capacity market.

Stimulating consumers to reduce their electricity consumption during scarcity is another option under deliberation. The Dutch Ministry of Economic Affairs established the special project group E4E (Electricity for Ever) that is to specify the announced measures focussing on stimulating investments and increasing the price-elasticity of demand.

Before 1998, the year in which liberalisation of the Dutch electricity market started, the electricity market's greatest bottleneck was the lack of incentive for efficiency. Because of the so-called cost-plus principle, the electricity sector, which was unhampered by any form of competition, was hardly cost-efficient. All investment costs could be charged to the consumers. In addition, there was no need to co-ordinate between production and consumer needs.

Since then the market system has developed from a strongly supply-oriented into a far more demand-oriented market. Co-ordination between demand and supply is no longer based on planning but on (bilateral) contracts. Moreover, production is unregulated and competition has been introduced. The main target of the liberalisation is to decrease prices by reducing inefficient overcapacity.

However, there are concerns that the available generating capacity will decrease too much in this new climate, and that too little is invested in new capacity. With the introduction of liberalisation in the electricity sector, the decision process on future power plants has completely changed. The 1998 Electricity Law starts from the idea that production of electricity should be left to the open market instead of to central planning. This entails that producers of electricity can deploy and decommission generation units at their own discretion. Because demand is assumed to grow continually in the future, investments in generating capacity are needed sooner or later. If investments remain (barely) forthcoming, the amount of reserve capacity that is needed to ensure long-term adequacy of supply will become too low, resulting in higher and more frequently occurring price spikes and a higher probability of service interruptions.

As already mentioned above, the fundamental choice of liberalising electricity markets implicitly means that scarcity will occur more often, because (superfluous) reserve capacity is structurally disposed of. One could say that the more efficient an electricity market will become (by discarding inefficient reserve capacity), the more the market will be 'living on the edge'. High price spikes will occur more often and the chance that the market does not clear at all will increase.

On the one hand, this is a question of investing climate, i.e. incentives to invest in new capacity in time. Enhancing this investment climate contributes to the continuity of electricity supply in the long run. On the other hand, it is a short-term question of the well functioning of tight electricity markets with little available reserve capacity. Living on the edge may be efficient, but liberalised electricity markets (even the ones with a perfect investment climate) also have to deal with periods of scarcity more often. In order to protect the market from extremely high price spikes and service interruptions during these periods of scarcity in the short term, the vulnerable equilibrium between supply and demand necessitates structural solutions that focus on enhancing the price-elasticity of demand, i.e. reducing demand during increasing market prices. This article focuses on the possibilities to enhance the functioning of tight electricity markets in the short run by making demand more price-elastic. But first the investment problem, the long-term element in guaranteeing adequacy of supply, is discussed in more detail.

The long run investment problem: an economic introduction

The electricity market differs from other markets in a number of ways, because of at least two typical characteristics of electricity. In the first place, large-scale storing of electricity, other than in pumped-hydro facilities, is commercially unfeasible. But when demand and supply are imbalanced because of a shortage or a surplus of supplied electricity, the integrity of the whole system is endangered which may result in widespread service interruptions. This means that supply has to respond instantaneously to changes in demand. In order to guarantee adequacy of supply, it is therefore necessary to retain a certain reserve margin in electricity production.

The second characteristic of electricity is that the short-term price-elasticity of demand is extremely low. Experience has shown that the demand for electricity in tight electricity markets does not decrease appreciably as the price for electricity rises. In other words, the demand for electricity appears to be inelastic in the short-term to increases in price. Most consumers have no insight in the actual prices, and thus do not gear their consumption patterns to changing prices. They are hedged against actual market prices by contracts with fixed prices and are not accustomed to react on a declining electricity supply.

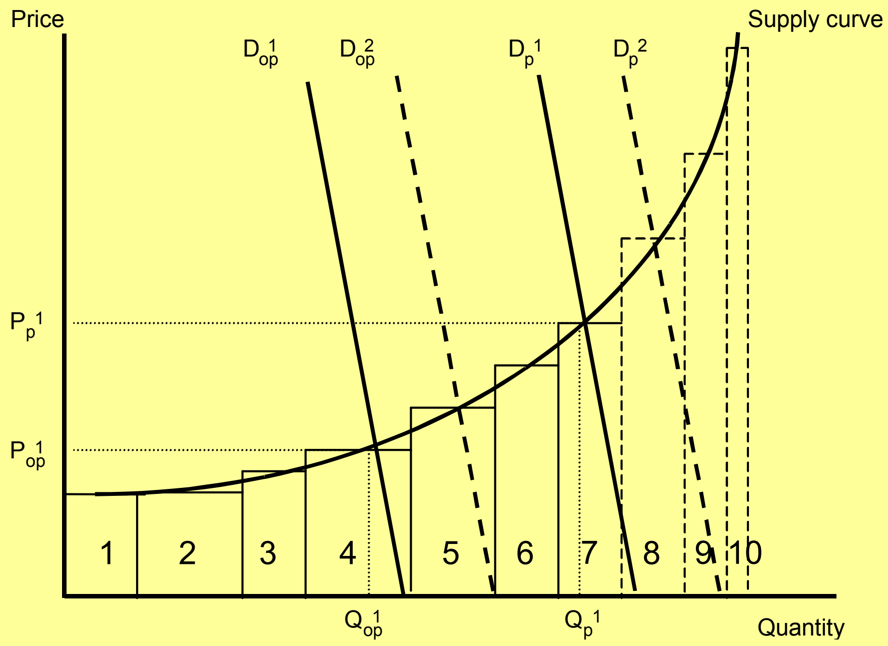
Moreover, there are hardly any available substitutions for electricity. The producers' price elasticity of supply during peak periods is very low as well (on the short term). In a well functioning competitive electricity market, an increasing demand leads to a gradually increasing marginal cost function (see also the frame 'Settlement of electricity prices in the short-term'). Power plants are put into operation in order of increasing short run marginal costs. But if all available capacity is in use, marginal increase in the short run is impossible. At that moment, the marginal cost curve ends with a perfectly price-inelastic section. When the available reserve capacity is little because of (extreme) peak demand and/or calamities on the supply side, these characteristics of electricity and the resulting instability of the tight electricity market will lead to highly fluctuating prices, which do not necessarily reflect production costs anymore.

Furthermore, there is a chance that the market does not clear at all: the generating capacity is not enough to meet demand. The price mechanism then fails to ration demand and the Dutch system operator TenneT has to manage shortages by applying a different rationing method: random service interruptions, also known as rolling blackouts. TenneT then artificially reduces demand by curtailing groups of consumers. In a liberalised electricity market, fluctuating prices are needed to provoke reactions on the supply as well as the demand side. But extremely high electricity prices, as occurred in the second week of August 2003, are a symptom of the absence of adequate response. The frame below explains how electricity prices are settled in a well functioning competitive electricity market.

Settlement of electricity prices in the short-term

The picture below shows the settlement of electricity prices in a well-functioning competitive market of demand and supply. The power plants are represented as numbered blocks. The height of each block reflects the short run marginal costs (the variable costs of the power plant, which are mainly determined by fuel costs). The width of each block reflects the amount of electricity to be produced. In a well-functioning electricity market, power plants are put into operation in order of increasing short run marginal costs. An increasing demand thus leads to a gradually increasing marginal cost function (supply curve). Electricity demand varies between periods of low demand (off-peak, D_{op}^1) and peak demand (D_p^1). This is indicated with Q_{op}^1 and Q_p^1. The equilibrium price accordingly varies between the off-peak price (P_{op}^1) and the peak load price (P_p^1). The demand curves for off-peak periods (D_{op}^1) and peak periods (D_p^1) have a steep slope, which indicates low price elasticity.

A structural increase of demand will shift the demand curve to the right (D_{op}^2 and D_p^2). In the short term, when no new power plants are built, the additional demand has to be covered by plants that formerly belonged to the reserve capacity (i.e. plant 8 in the figure). Electricity prices will rise and become more volatile, especially during peak periods. Even though investment becomes more attractive, considering the higher price level, scarcity of supply will not disappear in the short run, because of the lead-time of building new capacity.



The Dutch electricity market: an energy-only market

The Dutch electricity market can be characterised as an energy-only market. This means that the (expected) price of electricity is the only driver for capacity investment. The number of hours that production units are operating and the average electricity price during these hours determine the producers' revenues. The system relies on the market to provide the investment incentives. Because electricity is a vital product with hardly any available substitutes, consumers are willing to pay high prices for it. When the market is tight and both demand and supply curve consequently have a steep trajectory, high price spikes can occur and peaking units are put into operation to guarantee adequacy of supply. Peaking units are costly but operate only a few hours. These price spikes are therefore necessary to recover the investment costs of the peaking units.

In capital-intensive industries, such as the electricity sector, short-run scarcity rents (payments to suppliers that exceed the actual costs of supply) must be large. Generating companies need to forecast the height and frequency of the price spikes to be able to predict the profitability of investments in peaking units. Theoretically, a perfectly competitive energy-only market (with perfect foresight) can, in order to guarantee adequacy of supply, rely upon price spikes to signal the need for peaking capacity.

However, in reality prices are difficult to predict, especially for the short, incidentally occurring periods when peaking units are put into operation. Errors in the forecasts of the height and frequency of the price spikes are easily made, which makes investing in peaking units a risky undertaking. This exactly creates the investment problem, as generating companies act risk-averse. If generating companies invest too much in generating capacity, the resulting overcapacity causes prices to fall to a level of short run marginal costs. At this price level, recovering investment costs is impossible, especially for short operating peaking units. Moreover, some peaking units are not deployed at all.

On the other hand, if producers invest insufficiently, their risk is limited to a small loss of market share. If all producers make the same analysis and together invest less than the social optimum, they will however maintain their market share, while the resulting scarcity will result in higher average prices. For generating companies it is thus less harmful to invest too little in generating capacity (it probably results in even a higher profit), then to invest too much. But a relatively small demerit of the system, with interruptions as a possible result, can have large negative social impact on society as a whole. An important principle behind this investment problem is the fact that the reliability of the electricity system, which is provided by reserve capacity, can be identified as a public good.

In the present market producers earn money with the electricity they actually deliver to consumers. Unused capacity does not yield any profit. It is plausible that producers dispose of unused reserve capacity, as it merely engenders costs. In other words: (unused) capacity has no price in the current market, although it contributes to the reliability of the electricity system. In addition to the risk-averse behaviour of the generating companies, the current market differs from the theoretic perfect market in a number of other ways as well, all contributing to potentially insufficient investment in capacity. Imperfect information, a lack of transparency, regulatory uncertainty, and obstacles impeding the acquisition of necessary permits are among these factors.

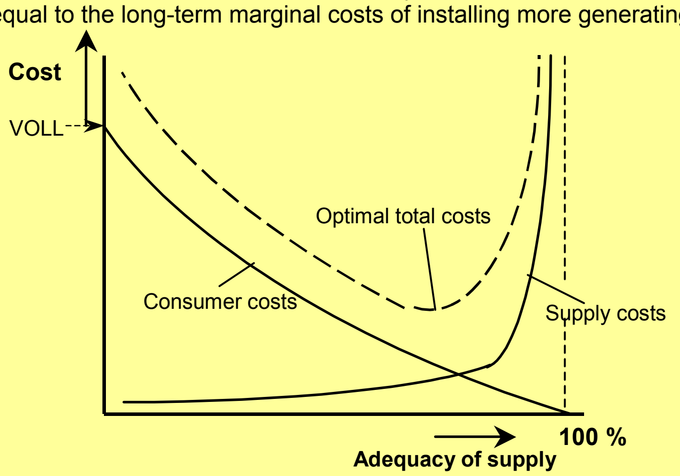
In addition to this, another fundamental problem stemming from the current structure of the Dutch electricity market is the existing risk of price manipulation, or 'gaming', during periods of scarcity. When the market is tight, the still available capacity is in hands of a limited number of generating companies. Because of the inelastic demand, a small withholding of generating capacity in a period of slim capacity margin or shortages leads to severe increases in price. Even a small market share may already result in enough market power to enable the producer to manipulate prices by withholding a small amount of generating capacity.

A last reason that causes producers to invest less in generating capacity is the relatively low priced import (and available interconnection capacity). However, it is plausible that reserve margins in surrounding countries will decrease for the same reasons as it does in the Netherlands. By importing foreign electricity, the Dutch electricity sector imports uncertainty about foreign adequacy of supply as well.

Recapitulating, a liberalised electricity market seems to work in theory, but there are well-founded reasons to assume that the Dutch electricity market, left to its own devises in the current conditions, will fail to attain a favourable level of investment to guarantee adequacy of supply in the long term. For a discussion of the optimal level of adequacy of supply, see the frame below.

Optimal adequacy of supply

The following figure shows that, with respect to adequacy of supply, the optimal situation implies a reliability of the electricity system of less than one hundred percent. The costs of making the system completely secure, by installing so much capacity that the chance of service interruptions would be reduced to zero, would exceed the social benefits of the associated reduction in the probability of service interruptions. In an economically optimal equilibrium, the marginal costs of interruptions are equal to the long-term marginal costs of installing more generating capacity.



VOLL = value of lost load

Demand Response

This paragraph discusses the short-term element in guaranteeing adequacy of supply (as opposed to the long-term investment element): the question of the well functioning of electricity markets during peak periods, when little reserve capacity is available. Demand response is a concept to enhance the functioning of tight electricity markets in the short run by making demand more price-elastic. This paragraph first focuses on the short-term effects and concludes with some critical notes about the long-term impacts of demand response.

Electricity markets currently have difficulties balancing demand and supply in times of scarcity, due to, among other things, the low demand price-elasticity. The balance between demand and supply in an electricity market can be maintained by the constant availability of sufficient supply in relation to peak demand. Marginal costs of production could, however, be considerably higher than the economic value of marginal peak demand. To favour the economic efficiency of the electricity systems, Demand Side Management (DSM) was developed as a tool to stimulate consumers in reducing their electricity consumption. The concept was already developed in the days of the centrally planned market and is based on the fact that marginal costs of production could be higher than the economic value of marginal demand. It is, then, economically more efficient to reduce demand instead of deploying additional generating capacity. In a liberalised market the market mechanism should also be susceptible to this principle.

DSM, however, not only focussed on the reduction of peak demand, but also aimed at general energy savings and changing the consumption patterns. One consequence of the liberalisation of the electricity market is the evanescence of direct interest of suppliers in the vertical optimisation of the electricity system. DSM may reduce peak demand, but, because of the general energy savings, it also reduces overall sales and this may adversely affect short-term profits of suppliers. The interest in DSM was lost. Market players in the liberalised electricity market put high value on the flexibility of supply and demand, since deficient balancing results in high balancing costs.

The central ideas of influencing electricity demand, which were developed within the framework of DSM, therefore recur in a different form: demand response. Because most consumers do not have access to real-time prices, they cannot exhibit their actual willingness to pay and do not substantially lower their electricity consumption during peak periods. The price mechanism does not work. The concept of demand response facilitates this mechanism by passing on the market-based price incentives to demand. This leads to an enhancement of demand price-elasticity and therefore to a more stable market equilibrium when the electricity market is tight. In this way, demand response is a concept that may keep the market from high price spikes and possible service interruptions during scarcity in the short term. Because, as claimed before, scarcity will occur more often in liberalised electricity markets, demand response offers a safer way of ‘living on the edge’.

In this article demand response at its most general level is defined as follows: *Demand response is the ability of electricity demand to respond to variations in market prices in real time. It is a concept that seeks to lower peak demand during specific, limited time periods of scarcity, by temporally curtailing electricity usage, shifting usage to other time periods, or substituting another resource for delivered electricity (such as self-generation), focusing on when energy is used and its cost at that time.* Demand response is about decreasing peak demand during specific, limited time periods of scarcity by making use of the flexibility that consumers can provide.

Examples: two different types of demand response

Demand Side Bidding (DSB)
DSB is a mechanism that enables the demand side to actively participate in the trade of electricity. DSB or buyback programs are available when the customer is willing to forego using electricity at a price. The supplier sends price signals and information on buyback rates to the customer, for example, through internet-based programs or simply by phone calls. If profitable, the consumer can take appropriate actions to manage peak loads and sell back its unused energy to the supplier. The unused electricity can be bought back by suppliers at differently determined offering prices:

- The buyback rate can be determined as a fixed percentage of the real-time wholesale spot market price. The percentage depends on whether the supplier wishes to recover administrative costs and earn a margin. Possibly, the fixed percentage can be adjusted to specific system and market conditions (and consequently can better be entitled as a variable percentage).
- A second possible way of determining buyback rates is to agree a fixed price, whereby the customer determines what amount of load it will provide at a specified price at the beginning of the program. Then the supplier can call on those customers agreeing to the lowest buyback prices first and call on others as needed.
- A third possible option is to let the customer determine a variable price for each event or within a range agreed upon with the supplier. When the customer bids in response to a supplier's request, the supplier can rank the bid loads and prices in order to decide how much to take and from which customers.

DSB programs are typically voluntary, since the customer has a choice about whether and to what extent he wishes to participate on any particular day.

Direct Load Control (DLC)
DLC programs are especially applicable to small (residential) customers. Suppliers target them with equipment that can be turned off or cycled by the supplier for relatively short periods of time. The supplier is authorised to do so for a limited number of hours and for a limited number of occasions, as return of a payment for participation. Possible applications are airconditioning systems and laundry and dry applications. Receiver systems must be installed on the customer's equipment to enable communications from the supplier controls. DLC programs reduce transaction costs, because, once accomplished, suppliers do not have to negotiate with customers about prices and buyback rates. DLC programs are typically mandatory, once a customer decides to participate. Voluntary participation is now an option for some programs with more intelligent control systems and override capabilities at the customer facility. Of course, such voluntary behaviour may be reflected in lower payments for participation.

Short-term benefits of demand response

Recent research performed at the International Energy Agency (IEA) has indicated that improvements in demand response will lead to increased network security and improves economic efficiency in liberalised electricity markets. The following categories of benefits in the short term can be distinguished:

Enhanced system adequacy
As mentioned above, demand response can improve the reliability of the electricity system during periods of generation shortages or transmission congestion by providing reductions in consumption. This is one of the main objectives of demand response. The market makes use of consumer flexibility that is encouraged by demand response programs.

Mitigation of market power
Demand response programs help mitigate market power of generating companies. This is especially the case when demand response can occur essentially coincident (i.e. in near real time) with tight supplies that might lead to market power.

Smoothing of price spikes
Because demand becomes more price-elastic, the demand curve will topple downwards and, in the short term, demand response can therefore lower market-clearing prices and mitigate price volatility.

Market efficiency
When consumers receive price signals and incentives, usage becomes more aligned with costs. To the extent consumers alter behaviour and reduce or shift peak usage and costs to off-peak periods, the result is more efficient use of the electricity system. Because some peak load is shifted to off-peak periods (baseload), the load-factor of baseload capacity increases, which improves efficiency (baseload units are more efficient than peaking ones). Situations of marginal costs of production being higher than the economic value of marginal demand will occur less often. Furthermore, costly (and difficult to site) new generation or transmission capacity may be deferred.

Risk management
Suppliers purchase power in wholesale markets where prices can vary dramatically from day to day, and hour to hour. They can use demand response to substantially reduce their risk in the market. Suppliers can hedge price risks by creating callable quantity options (i.e., contracts for demand response) and by creating appropriate price offers for those customers who are willing to face varying prices.

Environmental benefits
Demand response may have a positive environmental impact because some peak load is shifted to more efficient baseload units. Environmental benefits are, however, not achieved if the peaking units, which are gas fuelled in the Netherlands, are substituted with (less clean) coal fuelled baseload units. Furthermore, new additions to electricity generation (and/or transmission and distribution) are deferred.

Thus, the main benefits of demand response in the short term relate to the functioning of the market. Demand response causes market power to mitigate, it contributes to less volatile prices, and it makes the probability of service interruptions decline. In other words: demand response offers a safer way of living on the edge.

Critical notes on demand response in the long run

Flexibility of demand however has its limits and cannot offer a structural solution for the long term. Demand response reveals the amount of capacity that consumers can curtail (or shift) and that generating companies do not have to offer during times of scarcity. When producers know how much demand can and will be reduced, they incorporate that knowledge in their future investment plans. They will not realise capacity that, because of demand response, probably will not be used (and consequently does not generate income). The market becomes accustomed to the declining demand during scarcity. It is possible that demand response will increase as the electricity market becomes tight more often again, but sooner or later the flexibility of demand will reach its limits, having no answer left to high price spikes. So in the long run, demand response may only lead to a small reduction in the level and volatility of peak prices.

Only if they underestimate future demand response, producers will provide ‘too much’ peak capacity. The level and volatility of peak prices then (temporarily) decrease to a level at which producers cannot earn enough profit to recover their investment costs, creating (transient) windfalls for consumers and losses for producers. Producers will then adjust their strategy accordingly by decommissioning power plants or deferring investments. So much of the curing power of flexibility of demand, and consequently of demand response, may perish in the long run.

Huge drops in peak and average prices, which are often cited as reasons to encourage demand response, may thus not be realised in the long run. Large decreases in price are indeed impossible, as producers’ costs are not substantially reduced by demand response. Therefore, after an increase of demand response, average prices must sooner or later get back up to about where they would have been if demand response had not increased. Long-term average prices paid by consumers will only decrease because demand will be relatively lower during the high-price peak periods. This load-factor effect is, however, much smaller than the immediate drops in peak and average prices (to the level of short run marginal costs) that may occur in the short term.

In conclusion, one has to be truly aware of the fact that price spikes are, as discussed earlier, normal and even essential in energy-only markets. As long as generating companies are perceived to be taking advantage of or even creating price spikes that serve no useful purpose, reducing prices and transferring rents from producers to consumers may of course be regarded as desirable. But regarding all or even most of the rents during price spikes as money that really belongs to consumers is incorrect.

Will we fall off the edge?

The Dutch electricity market currently has difficulties balancing demand and supply in times of scarcity, which results in volatile prices, occasionally occurring high price peaks, and an increasing probability of service interruptions. Although (especially industrial) consumers appear to respond to imminent shortages, there is hardly any form of structural demand response in the Dutch electricity market. The response seems to have an ad hoc character. Structural demand response, like contractual agreements between suppliers and consumers about reducing electricity demand during periods of (extreme) peak demand, is lacking.

Demand response should be improved to make it easier and cheaper to meet demand reliably and to reduce price volatility. Before implementing demand response options, it could however be helpful to conduct practical experiments in order to gain experience with the technological aspects of demand response and to gain insight into the response of consumers. Although it is a worthy goal to improve demand response as much as possible, in the long term, as flexibility will reach its limits, demand response alone cannot keep the market from approaching the edge. To keep the Dutch electricity market from falling off in the long run, the investment climate must be structurally enhanced as well.

Possible solutions for the investment problem

The Dutch regulator DTe has advised the Minister of Economic Affairs to implement a central capacity mechanism in order to stimulate investments in new capacity: the creation of a market for ‘reserve contracts’ in the short term and for ‘reliability contracts’ in the longer term. These mechanisms will lead to a separate price making process for the availability of generating capacity and in this way, demand for adequacy of supply (reserve capacity) is made explicit. Investments in peaking units are stimulated, as generating companies receive fixed revenues for available capacity. Consequently, these markets cannot be characterised as energy-only markets anymore.

Reserve contracts
By means of an auction, the system operator periodically (e.g. daily) contracts a certain amount of operational reserves at generating companies. The reserve contract determines that this capacity should be held in reserve, i.e. is extracted from the market. The mechanism entails a certain capacity that is maintained by producers as reserve and that can be deployed when the market gets tight. Price spikes will be smoothed resulting in a more stable investment signal.

Reliability contracts
In this mechanism, the system operator and the producer make an agreement (contract) for one or more years to keep capacity available as reserve. The agreement defines under what specific conditions during scarcity this capacity should be deployed. The reliability contract works like a call option and gives the system operator the right to call upon generating capacity at a determined execution price. The generating company that has written the call option commits himself to offer his capacity to the spot market (APX) at this execution price. In this way, price spikes above the execution price will be capped, resulting in a stable and very well predictable investment signal.

In these capacity markets, the regulator or system operator determines the needed amount of reserve capacity. However, this is economically inefficient if the value that consumers attribute to the adequacy of supply is not known and, consequently, neither is the optimal size of the production reserve. Therefore, it is even better if the amount of reserve capacity is based on individual needs of consumers.

Capacity subscriptions
Consumers subscribe to a certain amount of capacity, which is bought in a capacity market, that they wish to receive in case the electricity market gets tight. When a shortage arises, the system operator limits the available capacity to the subscribed amount. In this mechanism, the electricity system is balanced by adapting the price-elasticity of demand instead of solely keeping available a certain amount of reserve capacity, like capacity markets do.

Monitoring adequacy of supply

With the introduction of liberalisation, generating companies no longer put data at the disposal of the system operator (TenneT) about the availability of installed generation capacity. Hence, it is nearly impossible to gain insight into the amount of reserve capacity and the probability of service interruptions.

TenneT has proposed a new assessment method to monitor the reliability of supply. A first analysis indicates that, if investments in generating capacity are not forthcoming, the structural shortage of domestic generating capacity compared to domestic demand will increase sharply after 2007.. Accordingly, the Dutch electricity market will, in an increasing degree, become dependent on foreign countries. Because it is plausible that reserve margins in surrounding countries will decrease as well (for the same reasons as in the Netherlands), it is likely that we will fall off the edge if no structural measures are taken. However, because of the current situation of sufficient available capacity and assuming that demand will respond in some degree to extreme peak prices, it is improbable that a service interruption will take place in the short run.

It is important not to focus on supply side issues alone to monitor adequacy of supply reliably. In liberalised electricity markets, demand plays a leading role as well and can, therefore, not be absent in the monitoring of (long-term) adequacy of supply. Indicators that can measure the volume of demand response should be part of it. Currently, the potential of demand response in the Dutch electricity market is unknown. This should be examined to quantify the influence of demand response on adequacy of supply.

It may be helpful to distinguish between different types of consumers (residential, industrial, and service industry). Furthermore, costs of demand response are important, as benefits are obtained by for instance changing energy-using industrial processes, which is costly. This kind of demand side aspects cannot be absent in a monitoring system if it aims to give a reliable answer to the question whether we will fall off the edge or not.

To conclude, demand response can offer a safer way of living on the edge, but, if the investment climate is not enhanced, it cannot keep the market from falling off in the long run.

CHAPTER 3

IMPLEMENTING EMISSIONS TRADING IN THE EU: HOW TO OPTIMISE ITS ECONOMIC BENEFITS?

Author: Jos Sijm

In 2005 an Emissions Trading Scheme (ETS) will be introduced throughout the EU. The major benefit of such a system is emission mitigation. The Dutch government intends to allocate one hundred percent of the allowances free of charge, at least for the first phase. Both the total quantity of allowances to be issued as well as the allocation of these allowances will be based on existing climate policies. The major advantages of the Dutch approach are that it meets several allocation criteria mentioned in the European Directive, that it fits in well within existing national climate policies, and that it enhances the political acceptability of the EU ETS among the Dutch participants. The specific Dutch approach may however also reduce the potential economic benefits of emissions trading in the Netherlands. This chapter looks at the ETS from a Dutch perspective. Will it reach the intended benefits in practice? What factors will influence its success?

Introduction

In October 2001, the European Commission published a draft Directive on establishing a scheme for greenhouse gas emissions trading in the EU. After nearly two years of intensive discussions among stakeholders, policy makers and experts, a political agreement was reached in July 2003 on an amended version of this Directive between the European Parliament, the Commission and the Council of Environmental Ministers. According to the agreed Directive, an EU Emissions Trading Scheme (EU ETS) will be introduced in all Member States – including the newly acceded countries of Eastern Europe – as from the 1st of January 2005. This implies that within less than 18 months the first international and largest ETS in the world is planned to become operational.

Table 3.1 provides a summary of the key elements of the Directive on the EU ETS as agreed in July 2003. This scheme is a so-called downstream cap and trade system covering direct emissions. The major characteristics of the scheme are:

- A cap is set on the total emissions of all participants in the scheme by allocating a certain amount of emission allowances, which is fixed ex ante for a certain period. These allowances can be freely traded among the participants.
- Participants are obliged to surrender a quantity of allowances equal to their emissions over a certain period of time. A surplus of allowances can be sold (or banked), while a deficit has to be covered by purchasing additional allowances (or paying a penalty).
- The obligation to surrender allowances is imposed on fossil fuel *users* (in contrast to an upstream system in which this obligation rests on the *suppliers* of fossil fuel).
- Emissions of electricity and off-site heat are attributed directly to power and heat *producers* (in contrast to an indirect system in which such emissions are imputed to *consumers* of electricity and heat).

In theory, the major economic benefits of an ETS are that the primary environmental objective of the scheme – i.e. emission mitigation – will be achieved for certain and at the lowest costs, while it encourages the development of cost-saving abatement technologies in the long run. Hence, in principle, this instrument meets central policy criteria such as environmental effectiveness and economic efficiency from both a static and dynamic point of view.

In practice, however, the achievement of the above-mentioned benefits depends largely on a wide variety of factors, notably:

- The scope or coverage of an ETS
- The allocation of emission allowances
- The linkages with other emissions trading and credit schemes
- The coexistence of an ETS with other related energy and climate policies.

In the sections on the next page, the importance of these factors will be discussed with regard to their impact on the potential benefits of implementing the EU ETS, illustrated by some references to the Netherlands. The final section of this article will provide a summary of the main findings and policy implications to enhance the economic benefits of the EU ETS.

Table 3.1 Key elements of the EU Emissions Trading Scheme (EU ETS) as agreed by the European Parliament, the Council and the Commission in July 2003

	Key elements of the EU Emissions Trading Scheme (EU ETS) as agreed by the European Parliament, the Council and the Commission in July 2003
Type of system	Downstream cap and trade system covering direct emissions.
Timing	Phase 1: 2005-2007. Phase 2: 2008-2012 (i.e. first commitment period of the Kyoto Protocol).
Coverage of activities (sectors and/or installations)	All combustion plants >20 MW thermal input, including power generators. Oil refineries, coke ovens, ferrous metals, cement clinker, pulp from timber, glass and ceramics. Based on the Integrated Pollution Prevention and Control (IPPC) Directive, but several IPPC sectors are excluded (e.g. chemicals, food and drink, non-ferrous metals, waste incineration). Member States may apply to the Commission for installations to be temporarily excluded until 31 December 2007, at the latest (opt-out clause). Member States may voluntarily extend the scheme to other installations, starting from phase 2 (opt-in provision).
Coverage of greenhouse gases	Only CO_2 in phase 1. Other gases may be included in phase 2, provided adequate monitoring and reporting systems are available and provided there is no damage to the environmental integrity of the scheme or distortion to competition.
Size of market	10,000-15,000 installations. About 50% of EU carbon dioxide emissions.
Allocation	Free during phase 1 with national allocation plans based on Annex III criteria and Commission guidelines. Member States have the option to auction up to 5% of allowances in phase 1 and up to 10% in phase 2. The Commission retains the right of veto over national allocation plans.
Operational rules	On the 30th of April each year, participants have to surrender a quantity of allowances equal to their emissions in the preceding calendar year. Participants are allowed to trade allowances among each other. Participants are allowed to form an emissions pool by nominating a trustee who takes on the responsibility for surrendering and trading allowances on behalf of all members of the pool.
Banking	Banking across years within each compliance period. Member States can determine banking from first compliance period (2005-2007) to first Kyoto Protocol period (2008-2012).
Links with Kyoto mechanisms*	Participants may convert emission credits from JI and CDM projects into EU allowances in order to fulfil their obligations under the EU ETS. All types of JI/CDM credits are allowed for conversion, except credits from nuclear facilities and carbon sink enhancement projects. As soon as credits amounting to 6% of initially allocated EU allowances have been converted, the Commission must undertake a review and decide whether a quantitative limit of for example 8 % could be introduced.
Links with other schemes	Agreements with third parties listed in Annex B of the Kyoto Protocol may provide for the mutual recognition of allowances between the EU ETS and other schemes.
Monitoring Reporting Verification	Common monitoring, verification and reporting obligations to be elaborated. Verification through third party or government authority.
Allowance tracking	Linked/harmonised national registries with independent transaction log. To be based on Kyoto Protocol guidelines and US Acid Rain Programme.
Compliance	Non-complying participants have to pay a penalty of 40 euro per tonne CO_2 during phase 1 and 100 euro/tCO_2 in phase 2.

* The links between the EU ETS and the Kyoto mechanisms have only recently been proposed by the European Commission in a separate Directive, which has not yet been discussed and agreed by the European Parliament and Council of Environmental Ministers.

The coverage of the EU ETS

The EU ETS covers a set of installations that emit greenhouse gases (GHGs) resulting from certain activities as listed in Annex I of the Directive and summarised in Table 3.2 *Sectors and activities covered by the EU ETS*. These installations refer particularly to combustion plants (>20 MW, including power generators), oil refineries, coke ovens and energy-intensive installations in manufacturing sectors such as the ferrous metals industries (especially iron and steel) and industries producing cement, lime, glass, ceramics, pulp, paper or board. During the initial pilot phase of the scheme (2005-2007) only CO_2 emissions of these installations are covered, while other GHGs may be included during the second phase (2008-2012), depending on the timely availability of adequate emission monitoring and reporting systems.

Table 3.2 Sectors and activities covered by the EU ETS (CO_2 emissions only)

Sector	Activities
Energy	Combustion plants >20 MW, excluding municipal waste incineration
	Mineral oil refineries
	Coke ovens
Ferrous metals	Metals ore roasting or sintering
	Iron and steel production (including casting) with capacity >2.5 tonnes/hr
Minerals	Cement production in kilns with capacity >500t/day
	Lime production in kilns with capacity >50t/day
	Glass and glass fibre production with melting capacity >20t/day
	Ceramic production with capacity >75t/day, or kiln capacity >4m^3
Other	Pulp from timber production
	Paper and board with capacity >20t/day

The definition of 'installation' in the EU ETS Directive is based on the EU Directive on Integrated Pollution Prevention and Control (IPPC), but the coverage of this latter Directive differs in some respects from the EU ETS Directive. Whereas the EU ETS Directive includes some installations *not* covered by the IPPC Directive (notably combustion plants of 20-50 MW thermal input), it excludes some sectors or sites that are covered by the IPPC Directive, particularly installations in the food and drink industries, the chemical sectors, the non-ferrous metals and waste incineration. It should be noted, however, that if these installations operate combustion plants exceeding 20 MW they are covered by the EU ETS even if they belong to, for instance, the non-ferrous or chemical sectors.

Overall, it is estimated that initially the EU ETS will cover some 10,000-15,000 installations, accounting for approximately 45-50 % of total CO_2 emissions in the EU during the period 2008-2012, and of some 36-40 % of total GHG emissions in these years. It is envisaged, however, that the scope of activities and emissions covered by the EU ETS will be gradually extended over time.

For the Netherlands, it is estimated that some 340 installations will be covered by the EU ETS (Table 3.3). Most of these installations are located in a few sectors, notably ceramics (72 installations), chemicals (60), power production (43) and other energy industries such as refineries or oil and gas mining (31). Together, these installations accounted for some 93 Mt of CO_2 emissions in 2001/2002. For these years this compares to approximately 54 % of total CO_2 emissions and some 43 % of total GHG emissions in the Netherlands. Of the total Dutch emissions covered by the EU ETS, more than 60 % is accounted for by the energy sector, notably the generation of electricity, while the remaining part is largely accounted for by the chemicals and other industries (Table 3.3).

Table 3.3 Coverage of the EU ETS in the Netherlands

	Number of installations		CO_2 emissions [$MtCO_2$]	
	Absolute	% of total	Absolute	% of total
Power production	43	12.7	43.8	46.9
Other energy sector	31	9.2	13.6	14.6
Ceramics	72	21.3	0.4	0.4
Chemicals	60	17.8	21.9	23.4
Glass	12	3.6	0.7	0.7
Paper & cardboard	27	8.0	1.9	2.0
Other industries	93	27.5	11.1	11.9
Total	338	100.0	93.4	100.0

Based on preliminary, indicative estimates for the years 2001/2002

Nevertheless, major parts of the economy will most likely remain outside the scope of the scheme, such as the household sector, agriculture, transport, services and small-scale industries. This may lead to a reduction of the potential benefits of emissions trading and to competitive distortions within sectors between installations surpassing the participation capacity limits listed in Table 3.2 and those below these limits.

In principle, these side effects may be lifted by expanding the coverage of the EU ETS. However, such an expanded scope may lead to a rapid escalation of the number of (small-scale) installations participating in the scheme and a concomitant increase in administrative demands and transaction costs of the scheme. Emissions of small-scale, non-participating entities and competitive distortions between participating and non-participating installations may be controlled more efficiently by other instruments, for instance a carbon or energy tax (although the environmental effectiveness of carbon taxation is less than carbon trading). Therefore, depending on the availability of adequate administrative systems, a balance has to be struck with regard to the coverage of the EU ETS in order to optimise its net economic benefits.

In addition, the economic benefits of the EU ETS could be enhanced by including other GHGs besides CO_2 in the scheme, partly because the non-CO_2 reduction options are generally cheaper than the CO_2 abatement options and partly because such an expanded coverage would enlarge the liquidity and trading opportunities of the emissions market. At present, however, the monitoring and verification systems of non-CO_2 GHG emissions are not adequate to guarantee the environmental integrity of the EU ETS. Therefore, expanding the gas coverage of the EU ETS can only be considered economically attractive once adequate emission monitoring and reporting systems are widely available.

The allocation of emission allowances

A highly controversial issue of any emissions trading scheme concerns the allocation of emission allowances, namely the stringency of the cap, the method of allocation (i.e. auctioning or free allocation), and – in case of free allocation – the specific rule to allocate allowances among individual participants. According to the EU Directive, Member States should allocate at least 95 % of the allowances free of charge for the first, 3-year period (2005-2007), and at least 90 % of the allowances free of charge for the second, 5-year period (2008-2012).

Decisions on the total quantity of allowances to be issued and on the allocation of these allowances among individual installations are left to individual Member States as part of designing their so-called 'National Allocation Plans'. Annex III of the EU Directive, however, provides a list of criteria that have to be met by these national allocation plans. These criteria include particularly:

- The total quantity of allowances must be consistent with the Member State's climate change programme, i.e. its obligations under the Kyoto Protocol and the EU Burden Sharing Agreement, taking into account national energy policies and the proportion of national emissions from installations covered by the Directive.
- The total quantity of allowances must be consistent with assessments of actual and projected progress towards fulfilling the Member State's contribution to the GHG mitigation commitments of the EU.
- The (total) allocation of allowances must be consistent with the (technological) potential of participating installations to reduce emissions.
- The allocation plan must be consistent with other EU legislative and policy instruments – notably with regard to renewables – while taking into account unavoidable increases in emissions due to new legislation.
- The plan shall not discriminate between companies or sectors in such a way as to unduly favour certain undertakings or activities.
- The plan shall contain information on the manner in which (i) new entrants, (ii) early action, and (iii) clean technologies – including energy efficiency technologies – are taken into account.

The criteria include a mixture of top-down versus bottom-up approaches of allocating allowances, which may not necessarily lead to the same outcome with regard to the total quantity of allowances to be allocated. Moreover, some of these criteria are still unclear or very general, which may lead to different interpretations among Member States. In order to reduce the uncertainty with regard to the allocation criteria, the European Commission intends to publish more specific guidelines on the development of a National Allocation Plan by the end of 2003.

Allocation in the Netherlands

In the Netherlands, the government intends to allocate 100 % of the allowances free of charge, at least for the first phase of the EU ETS. Both the total quantity of allowances to be issued as well as the allocation of these allowances will be based on existing climate policies, in particular voluntary agreements on energy efficiency between the government and energy-intensive industries such as the Benchmarking Covenant and the second generation of Long Term Agreements on energy efficiency.

The major advantages of the Dutch approach is that it meets several allocation criteria mentioned in Annex III of the Directive, that it fits in well within existing climate policies in the Netherlands, and that it enhances the political acceptability of the EU ETS among the Dutch participants. On the other hand, the Dutch approach has some disadvantages that may reduce the potential economic benefits of emissions trading in the Netherlands. These disadvantages refer to both the option of allocating allowances for free and to the specific approach of allocating allowances on the basis of existing voluntary agreements on energy efficiency.

Free allocation of emission allowances may have some adverse effects, depending on the case considered:

- Either the marginal costs of emissions trading – i.e. the price of an allowance – are not passed on to the end-users of electricity (and off-site heat). This case may lead to the substitution of energy sources and other inefficiencies such as the substitution of electricity for fuel use or the reduction of co-generation (CHP) and a concomitant shift towards the use of heat/power that has been generated off-site rather than on-site. Such a situation, however, will most likely be unsustainable as the generators of off-site power/heat will eventually be forced to incur the allowance price on their products in order to avoid running out of allowances allocated for free and hence being forced to buy additional allowances on the market.

- Or the costs of emissions trading are actually passed on to the end-users of electricity (and off-site heat). As a result, the power producers will benefit from an ‘economic rent’ or ‘windfall profits’ due to the free allocation of emission allowances. For the Netherlands, for instance, it has been estimated that at an allowance price of 10 euro/tCO_2 the price of electricity may rise by more than 0.4 euroct/kWh, i.e. about 15 % of the commodity or producer price, leading to windfall profits accruing to the power generators of about 400-450 million euro. On the other hand the industrial end-users of electricity are faced by higher production costs which they in turn often can not pass on to their customers due to competition from outside the EU ETS (leading to a loss of production and income).

Moreover, allocation of allowances based on voluntary agreements such as the Benchmarking Covenant (BC) is likely to imply that the socio-economic benefits of emissions trading in the Netherlands will be relatively low. For one thing such an allocation will probably supply the benchmarking sectors with an amount of allowances that largely covers their expected emissions over the years 2005-2012. Industries participating in the BC – excluding the power sector – have already planned measures to meet their estimated benchmark for the year 2012. Most of these measures are likely ‘cost-effective measures’ (with an internal rate of return >15%), implying that the marginal abatement costs of these measures are probably low – or even negative – and that, depending on the allowance price, the demand for allowances by the participating industries and the resulting trading benefits will also be low.

In addition, if the allocation of allowances would indeed be based on the Benchmark Covenant the marginal abatement costs of the participating industries would be substantially lower than those of the non-participating sectors of the EU ETS. This implies that a less ample allocation for the participating industries (and hence, a lower reduction target for the non-participating sectors) would lead to (i) an equalisation of marginal abatement costs among participating and non-participating sectors, (ii) higher benefits from emissions trading and therefore (iii) less abatement costs for the Netherlands as a whole. Despite these potential benefits from a tighter allocation of allowances to the benchmarking industries such an allocation may be politically hard to accept, partly because Dutch policy makers are concerned to protect the competitiveness of the energy-intensive industries, and partly because it has been agreed by the Covenant parties to prevent such additional CO_2 reduction measures for the participating industries as far as possible.

Finally, although the costs for determining benchmarks for over 300 products have already been made, the additional information and other transaction cost of translating benchmarks into allocation quota for individual installations may still be considerable. Therefore the potential (net) benefits of emissions trading in the Netherlands may be further reduced if allocating allowances based on the Benchmarking Covenant would turn out to be more cumbersome than other allocation methods (including auctioning).

Policy options

In order to enhance the potential benefits of emissions trading in the Netherlands, the following alternative policy options with regard to the allocation of emission allowances can be considered:

- Tightening the EU ETS cap to participating sectors
- Auctioning of EU ETS allowances.

These options will be considered briefly in the following paragraph.

Tightening the cap to participating sectors

As explained above basing the allocation of allowances on voluntary agreements to improve energy efficiency such as the Benchmarking Covenant implies that (i) the cap to the participating sectors is far from stringent, (ii) the marginal abatement costs of the participating sectors will be significantly lower than those of the non-participating sectors, (iii) the socio-economic benefits of emissions trading in the Netherlands will be relatively low and hence (iv) the total economic costs of meeting the Kyoto commitments will be relatively high. These adverse effects can be reduced by tightening the cap of allowances to the participating sectors.

The major advantage of this option is that it improves economic equity and economic efficiency. Moreover, it enhances the political acceptability of the EU ETS and other climate policies among non-participating sectors in the Netherlands. On the other hand, tightening the cap implies that voluntary agreements to improve energy efficiency will no longer be used as the basis for allocation (unless a simple reduction percentage will be applied) and that both these agreements and the EU ETS will lose political acceptability among the participating sectors in the Netherlands as it increases their abatement costs and reduces their competitive position (particularly if their competitors in other countries are not faced by similar emission restrictions). Hence this option may only become feasible in the long run, after the EU ETS has been introduced and is widely accepted and similar emission restrictions have been imposed on competing industries in other countries.

Auctioning emission allowances
Another option to enhance the economic benefits of emissions trading is to auction emission allowances rather than allocating them for free. In general auctioning has been advocated by many authors as the preferred option for allocating allowances, based on the following arguments:

- For an ET authority auctioning is relatively simple to implement and involves a minimum or zero data requirement on historical emissions or emission standards as participants themselves determine how much allowances they actually need.
- All participants, including new entrants, are treated in the same equal and fair way. Companies that have reduced their emissions in the past need to buy fewer allowances and are thus rewarded for this 'early action'. Moreover, an auction avoids both competitive disadvantages to new market entrants as well as windfall profits due to the allocation of free allowances to incumbent participants.
- Auctioning is preferable from an efficiency point of view as, if compared to free allocation, it provides the best reflection of the polluter-pays principle and therefore the best incentive for technological innovations and cost-effective adjustments in existing production and consumption patterns, particularly for carbon-intensive goods.
- Auctioning generates revenues for the public sector, which may be used to finance government expenditures to reduce existing market distortions such as taxes on labour or capital or to compensate certain target groups for the adverse effects of climate policies in general and emissions trading in particular.

A problem of this option is that, according to the EU Directive, Member States shall allocate at least 95 % of the allowances free of charge during the first phase of the EU ETS (2005-2007) and at least 90 % of the allowances free of charge during the second phase (2008-2012). Member States may at first auction only a small part of their allowances. If applied by an individual Member State, it will affect the competitive position of its participating sectors. However after the second trading phase of the EU ETS the share of total allowances to be auctioned could be raised steadily and made obligatory to all Member States.

A more fundamental problem is that even if auctioning of emission allowances is made mandatory throughout the EU ETS, it may still harm the competitive position of those (energy-intensive) industries that, due to outside competition, are not able to pass on the ETS-induced increases in production costs to their customers. More specifically, while auctioning avoids the generation of windfall profits to the power producers (in case of free allocation and higher electricity prices), it will have a dual negative impact on the performance of other (energy-intensive) industries participating in the EU ETS, for one through the costs of buying allowances in order to cover their on-site emissions and, also through higher prices for their heat/power consumption purchased off-site. As these industries are not always able to pass these cost increases (fully) to their customers, it may result in a loss of economic growth, production and income.

These adverse effects can be somewhat reduced by implementing auctioning throughout the EU ETS and recycling the auction revenues by lowering the overall, national levels of industrial taxes and economic premiums. Although this kind of recycling will, on average, improve the industrial competitiveness of EU Member States, the option of auctioning combined with a general, untargeted recycling of the revenues will still cause a shift in comparative advantage from the energy-intensive to the energy-extensive industries. Although this option may improve the overall economic benefits of emissions trading (compared to the option of free allocation), it will therefore still be resisted by the main participating sectors of the EU ETS, such as the power producers and the energy-intensive industries, as they prefer free allocation of emission allowances and/or specific, targeted recycling of auction revenues to compensate ET-induced increased in production costs.

The linkages with other emissions trading and credit schemes

The Directive on the EU ETS opens the opportunity to create linkages with other emissions trading and credit schemes. According to Article 25 of the Directive, agreements should be entered into with third countries listed in Annex B to the Kyoto Protocol, which have ratified the Protocol to provide for the mutual recognition of allowances between the EU ETS and other possible GHG emissions trading schemes of Annex B countries such as Canada or Japan.

Moreover, the EU ETS will be linked to the project-based flexible instruments of the Kyoto Protocol (JI and CDM), as recently proposed by the European Commission in an additional, separate Directive. According to this draft Directive, participants of the EU ETS may convert emission credits from JI and CDM projects into EU allowances in order to fulfil their obligations under the EU ETS. All types of JI/CDM credits are allowed for conversion, except credits from nuclear facilities, carbon sink enhancement projects and large-scale hydropower projects not meeting certain criteria. In principle, there is no quantitative restriction to the conversion of JI/CDM credits, but as soon as these credits amounting to 6% of initially allocated EU allowances have been converted, the Commission must undertake a review and decide whether a quantitative limit of for example 8% could be introduced.

Linking the EU ETS to the project-based Kyoto mechanisms is however a controversial issue as it may have a variety of diverging effects. Supporters of linking argue that it may increase the transfer of abatement technologies and project funds to less developed JI/CDM countries. Moreover, it may enhance the (static) cost-effectiveness of the EU ETS by providing participants with more options to meet their obligations at lower costs.

On the other hand, opponents of the EU proposal argue that linking the EU ETS to the Kyoto mechanisms will harm the environmental integrity of the EU ETS as genuine domestic emission reductions will be replaced by dubious projects abroad that would have been implemented in any case and that therefore do not contribute to additional, real emission reductions. Besides, they argue that linking may lead to a large inflow of cheap JI/CDM credits, thereby significantly lowering the price of a EU allowance and reducing domestic actions to cut emissions. They state that priority should be given to domestic action because emission cuts in rich countries both push the faster development of clean technologies and demonstrate the real commitment of these countries to fighting climate change. Without this demonstration, developing countries will never be persuaded to take action to limit their emissions.

Linking the EU ETS to the (project-based) Kyoto mechanisms is not only a controversial but also a delicate issue as it will affect the price of carbon within the EU and thus the potential spill-over effects of climate policies in general and emissions trading in particular. By reducing the price of carbon within the EU ETS, such a link will reduce the negative, static effect of climate policies on the competitive position of EU industries ('carbon leakage'). On the other hand, it will also reduce the positive, dynamic effect of climate policies on the development and adoption of technological innovations in the field of energy and carbon savings ('induced technological innovations'). Hence, a major policy challenge is to find an adequate balance between these spill-over effects, including an appropriate balance between reducing CO_2 emissions domestically and using the Kyoto mechanisms abroad in order to safeguard an adequate level of carbon prices within the EU ETS. At present, the empirical knowledge on these issues is largely lacking. Therefore, in order to improve the economic benefits of emissions trading, additional research is necessary on linking the EU ETS to the Kyoto mechanisms, including its impact on EU carbon prices and the spill-over effects of climate policies.

The interaction of the EU ETS with other, related climate policies

In practice, emissions trading does not operate in a policy vacuum – as often assumed – but rather in a crowded policy space with a variety of related energy and climate policies. This coexistence or interaction of policy instruments affects the performance of both emissions trading and these related policies, in particular with regard to their effectiveness and efficiency in mitigating GHG emissions.

Within the context of the EU ETS, it is important to distinguish energy policies that affect fossil fuel use (and thus CO_2 emissions) by the participating sectors versus the non-participating sectors because the effectiveness and the justification of these two sets of policies change once the EU ETS becomes operational. If a country joining the EU ETS has set a certain reduction target for its non-participating sectors, then national policies affecting fossil fuel use by these sectors are both necessary, effective and justified in order to control the emissions of these sectors and therefore to meet the Kyoto commitments. On the other hand, in the absence of market failures and once an emissions cap has been set, national policies affecting the fossil fuel use of its participating sectors are neither necessary, nor effective, nor justified to control the CO_2 emissions of these sectors in the most efficient way.

The latter statement with regard to energy policies affecting the participating sectors is based on the following two considerations:

- Policies affecting fossil fuel use of participating sectors do influence the domestic CO_2 emissions of these sectors, but they do not influence the national emissions accounts of these sectors or the country as a whole as the national quota of emission allowances allocated to these sectors is fixed. Hence, any change in the domestic emissions by these sectors is compensated by a similar change in emissions traded by these sectors.
- The operation of the EU ETS results in a situation in which the primary environmental objective of the scheme (i.e. the emissions cap) is achieved at the lowest costs by the participants themselves as it encourages these participants to adjust their abatement options and emissions trading opportunities until the marginal abatement costs throughout the scheme are equal to the international clearing price of an emission allowance.

Within the context of the EU ETS, national policies affecting fossil fuel use by participating sectors will consequently lead to (i) less CO_2 efficiency, i.e. raising abatement costs without enhancing overall CO_2 reductions, and (ii) less optimal market operations within the EU ETS, i.e. less demand for emission allowances and/or more supply of these allowances, resulting in a declining price of an allowance. This process may continue until the scarcity on the market for emission allowances evaporates fully and the allowance price becomes zero. From the perspective of CO_2 efficiency, the coexistence of the EU ETS and policies affecting fossil fuel use by participating sectors is therefore hard to justify and these policies could thus be considered redundant and worthy of repeal.

There are however basically three reasons that may justify the coexistence of the EU ETS and other policies affecting the fossil fuel use of participating sectors. A major reason is improving the static and dynamic efficiency of emissions trading by overcoming market failures. The findings above on the CO_2 efficiency of the EU ETS are based on the assumption of a perfect economy with no (policy) distortions or other market failures. In practice, however, there are a variety of cases in which market failures lead to a loss of energy/CO_2 efficiency, either in a static or a dynamic sense. In such cases, the EU ETS may be jointly used by other policy instruments – such as subsidies on energy savings, awareness campaigns, or support to renewables – in order to overcome these market failures. If these other policies are well designed to pass a cost-benefit test, they may result in an overall improvement in static or dynamic efficiency.

A second reason to justify the coexistence of the EU ETS and other policies affecting the CO_2 emissions of participating sectors is that these policies may serve to meet a variety of other policy objectives besides achieving CO_2 efficiency such as (i) raising fiscal resources, (ii) serving equity purposes, (iii) preventing other environmental effects besides CO_2 emissions, or (iv) improving security of supply.

A final justification for the coexistence of the EU ETS and related policies is that using, incorporating or accounting for these other policies may improve the design and implementation of the EU ETS and may thus lead to an improvement of its operation or political acceptability. An example is the coexistence of the EU ETS and a carbon or energy tax in order to mitigate the price uncertainty of an EU allowance by offering the opportunity to pay a tax should the allowance price exceed the tax level.

However, policies complementary to the EU ETS may at best improve the efficiency of CO_2 abatement (in case of market failures), but not the effectiveness of CO_2 mitigation (as the amount of CO_2 reductions is fixed by the cap on CO_2 emissions). Or, to put it more bluntly, *once the EU ETS becomes operational, the effectiveness of all other policies to reduce CO_2 emissions of the participating sectors becomes zero.*

Moreover, the political acceptability of policies meeting other objectives additional to CO_2 mitigation may change once it is realised that the relatively high costs of some of these policies can no longer be justified by the objective to reach CO_2 mitigation but only by other considerations such as less NO_x emissions, more rural employment or an improved energy supply security. Therefore, whatever these other considerations may be, the evaluation of the costs and benefits of national policies affecting fossil fuel use by participating sectors will clearly change once the EU ETS becomes operational. This may have far-reaching implications for these policies, including major reform or, in some cases, even repeal of these policies.

In practice, there is a variety of sound and less sound reasons why most of the existing policies affecting the fossil fuel use of participating sectors will be continued even after the EU ETS becomes operational, notably in the short term. This may even lead to a situation of 'self-fulfilling scepticism' as governments are uncertain and sceptic with regard to the performance of the EU ETS and stick to their old climate policies. Due to the coexistence of these policies and the EU ETS the performance of emissions trading may however be adversely affected, thereby confirming the policy scepticism with regard to the EU ETS.

To conclude, the EU ETS will interact with a variety of other energy and climate policies. Apart from cases in which these policies adequately correct potential market failures of the EU ETS, a major implication of this interaction is that the actual economic benefits of the EU ETS will be lower than usually assumed, as these policies will result in the implementation of more expensive abatement options without changing the cap of the EU ETS (thereby substituting cheaper reduction options resulting from emissions trading). Nevertheless, in order to optimise the economic benefits of the EU ETS coexisting with related energy and climate policies, a related implication is that over time an improved policy mix has to be developed between the EU ETS and these policies, which may imply major reform or sometimes even repeal of some of these policies.

Conclusion

During the first years of its operation, the economic benefits of the EU ETS will probably be low due to a variety of factors such as the prevalent method of allocating allowances and the interaction between the EU ETS and other, related policies. For the time being, however, the key issue of this potentially promising instrument is not so much its present features but rather that it is politically accepted by its major participants, that it implemented in time, and that it is operating for some years in order to gain experience and empirical knowledge with regard to its performance, including the linkages with other emissions trading and credit schemes. Over time, this experience and knowledge can be used to enhance the economic benefits of the EU ETS, for instance by expanding the coverage of this scheme, by changing the method of allocation, by fine-tuning the linkages with other emissions trading and credit schemes, and by optimising the interaction with related energy and climate policies.

CHAPTER 4

DUTCH ENERGY RD&D POLICY:
IS THERE A ROLE FOR TECHNOLOGY LEARNING?

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Energy research is one of the focus points of Dutch R&D. In the last few years major changes have had their influence on Energy R&D. In order to cope with these changes the Ministry of Economic Affairs recently set a process in motion to formulate a new Energy Research Strategy. The author of this chapter discusses to what extent lessons from technology learning were incorporated in this strategy. The revised Energy Research Strategy focuses pointedly on a limited number of hopeful energy technologies, but does it also consider the experiences and knowledge gained during the deployment of energy technologies? How can the effectiveness of energy policy be enhanced by the concept of technology learning and experience curve methodology?

Energy research development and deployment (RD&D)

Dutch research is traditionally stimulated with a national outlook. The Dutch government supports technology development by means of various policy instruments, such as financing of research institutes, regulation and financial incentives. Most incentives aim to support the introduction of new products. The idea behind the approach is that national interests are best served when innovations are developed and employed within national borders.

The Dutch R&D landscape has been influenced by international trends and developments as well as by changes in Dutch domestic policies during the last few years. An important domestic trend is the recent interest in transition management. The Fourth National Policy Plan (NMP4) introduced the concept of transition in Dutch environmental policy in 2001. The current unsustainable energy supply system had to transform into an economically efficient and ecologically sustainable system. Furthermore, security of supply should be guaranteed. Before such a system could be implemented various changes on various levels (micro, meso and macro) have to occur. The transition towards a sustainable energy system could be set in motion by, for instance, setting a strong energy Research, Development and Deployment (RD&D) agenda.

Various international developments have had their impact on energy research according to the energy research strategy document. The most important developments are:

- Liberalisation: the European energy market is heading towards liberalisation. This change has already led towards a shift towards more short-term energy research in countries with liberalised markets.
- Internationalisation: energy research is often no longer a domestic affair. Energy research slowly shifts from national to European or even global level. This shift is encouraged in EU framework programmes; research projects on a national level are not eligible under the current Sixth framework programme.
- Transboundary research subjects: most cutting environmental problems, such as the greenhouse gas effect, have a transboundary nature and should be dealt with on a continental or global scale.
- The changing position of national governments: in the Netherlands the role of the government has shifted from player to energy research director.

These trends have already changed some aspects of Dutch RD&D. Those changes and the relatively weak focus of Dutch energy RD&D notably increase the risk that relevant long-term energy RD&D is not carried out, which may lead to lockout of possibly important transition technologies. The Dutch Ministry of Economic Affairs has consequently decided that the present Dutch Energy research strategy had to be reconsidered with a view to stimulating key innovations in the transition towards a sustainable energy system. The revised strategy should focus on a limited number of long-term energy RD&D options. The Netherlands, being a small country, do not have the resources to stimulate the larger part of potentially useful energy RD&D through public funds. The Ministry of Economic Affairs therefore initiated a policy process to decide how available energy RD&D budgets can best be spent with maximum effectiveness.

Energy Research Strategy

With the launch of the Energy Research Strategy policy document the Ministry of Economic Affairs initiated the process of formulating the new energy research strategy (*Energie onderzoek strategie* or *EOS* in Dutch). This document revealed that the strategy should focus on a limited number of relevant energy research themes and further support dissemination and exploitation of knowledge.

During the Energy Research Strategy process (or *EOS* process) a matrix was developed to select research themes that deserve support. The chosen topics are to form the R&D portfolio to be financed by public funds during the next few years. Energy research themes were placed in the matrix depending on their possible contribution to transition towards a sustainable energy system and the knowledge position of the Netherlands on the subject.

Table 4.1 Matrix used in the EOS process

	Contribution to a sustainable energy household	No contribution to a sustainable energy household
The Netherlands belong to the international top on the subject	Priority topics	Export of knowledge topic
The Netherlands do not have a top position on the subject	Import of knowledge topic	Non relevant topics

Energy Research should focus on priority topics. Knowledge export and import topics are introduced to enable effective use of existing knowledge. Knowledge import topics involve updating existing knowledge and actively monitoring and importing knowledge from other countries. This way Dutch research networks should be able to pick up new developments quickly. Knowledge export topics involve dissemination of knowledge to other countries to enable wider use of available knowledge and international sustainable development. In 2002 energy research topics were evaluated and placed within the matrix. Seventeen research options were qualified as priority topics. These topics were classed into five focus areas (see text box *Focus areas*). These topics will be a part of the proposed RD&D portfolio and will be supported by means of specific policy instruments. Generic policy instruments, such as technology subsidies, cover the development of the other topics. This approach calls for the lists of energy research options deserving support to be updated on a regular basis.

Focus areas EOS 2003

- Industrial efficiency improvement
- Biomass
- New gas/clean fossil fuels
- Built environment
- Power generation and networks

In addition a mix of policy instruments to support energy RD&D was outlined during the EOS process. The mix is an intermediate form between the current mix of specific policy instruments and a form in which new instruments are completely integrated with generic innovation instruments of the Ministry of Economic Affairs. An outline of the mix of instruments is depicted in figure 4.1. Instruments are divided into financial instruments and generic support of energy RD&D. Financial instruments can be both specific and generic. Energy research topics will be supported according to their rating in the RD&D matrix and their distance to market introduction.

Figure 4.1 Outline of the proposed mix of policy instruments as indicated in EOS 2003

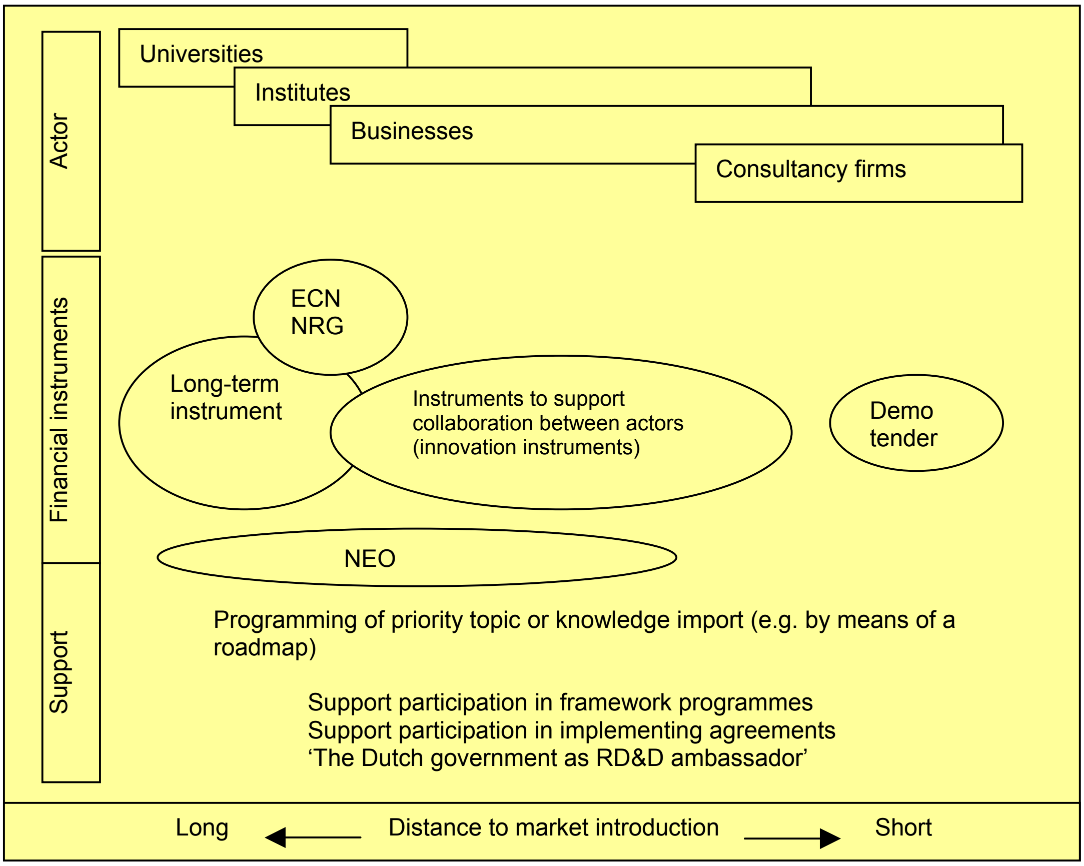


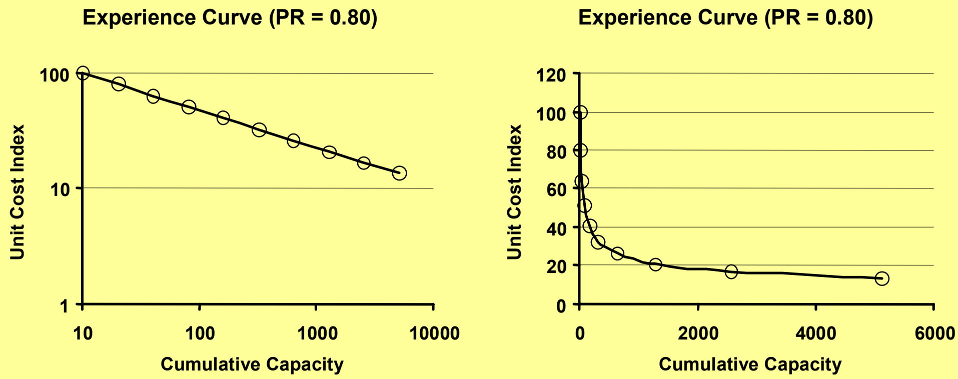
Figure 4.1 shows the succession of policy instruments and actors involved during the development of an energy innovation according to EOS 2003:

- A long-term policy instrument is meant to support innovations that are a long way off from market deployment. Only priority topics will be financed by this instrument.
- Short and middle term energy innovations will be supported by new generic collaboration instruments of the Directorate-General Innovation of the Ministry of Economic Affairs.
- The demonstration tender instrument is meant to support the demonstration of short-term energy innovations.
- The New Energy Research Programme (NEO), managed by the Ministry of Economic Affairs and implemented by Novem, is a relatively small programme meant to support wildcards: innovations that have yet to be proved but that may develop into priority topics.
- Two research institutes, the Energy research Centre of the Netherlands (ECN) and Nuclear Research and Consultancy Group (NRG), will support market parties in doing research that fits into the R&D portfolio.

Although the revised Energy Research Strategy seems to focus pointedly on a limited number of hopeful energy technologies, it does not consider the experiences and knowledge gained during the deployment of energy technologies. The strategy supports demonstration projects but not the actual deployment of technologies on the market, for instance by means of investment subsidies. The concept of technology learning and experience curve methodology teaches us that the effectiveness of energy policy can possibly be enhanced by incorporating learning possibilities during deployment.

Figure 4.2 **Experience curve methodology**

Experience curves describe how cost declines with cumulative production, where cumulative production is used as an approximation for the accumulated experience in producing and employing a technology. A specific characteristic of experience curves is that cost declines by a constant percentage with each doubling of the total number of units produced. The observed cost reduction for different technologies cover a range from approximately 35% to 0% for each doubling of the total number of units produced.



Above: experience curve on a linear scale (left) and on a log-log scale (right). The experience curve shows a 20% cost reduction of each doubling of the total number of units produced, referred to as a Progress Ratio (PR) of 0.80. The cost reductions in the experience curve refer to total costs and changes in production (process innovations, learning effects and scaling effects), products (product innovations, product redesign, and product standardisation) and input prices. All in all, gaining experience is a long-term process which represents the combined effect of a large number of parameters, which may undergo fluctuations over short periods of time. Only after many doublings of experience can the underlying pattern or trend be distinguished.

Technology learning

Technology learning refers to the phenomenon that technology costs decrease over time when technologies are applied on the market. Various studies show that there is a strong relationship between the unit cost of a technology and the cumulative number of units produced. One of the most important reasons for the decrease is that experience is gained during the production and use of technologies. The next generation profits from experiences gained, which leads to decreasing unit costs.

For a wide range of technologies a relative simple relationship between cumulative production and unit costs can be found: each time the cumulative stock is doubled, unit costs drop by a fixed percentage. The relationship between cumulative production and unit costs is a linear relationship if cumulative production and unit costs are represented on a log scale. Figure 4.3 shows this relationship for PV modules as Poponi indicated in 2003.

Figure 4.3 Relationship between cumulative production and unit costs of PV modules. Cumulative production has been represented by cumulative shipments

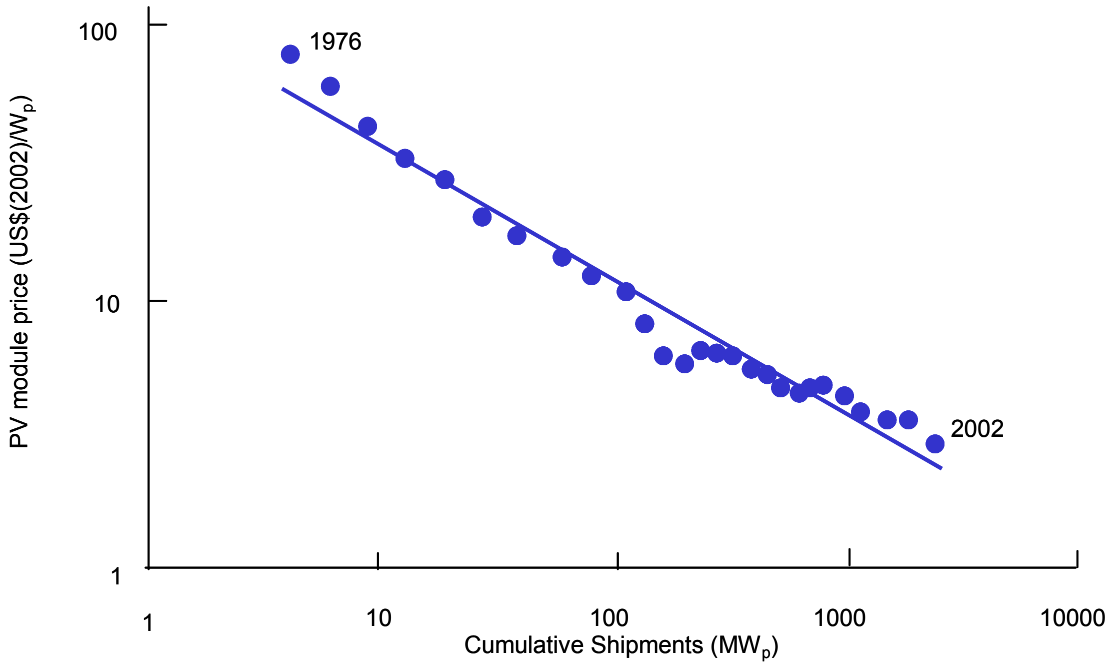


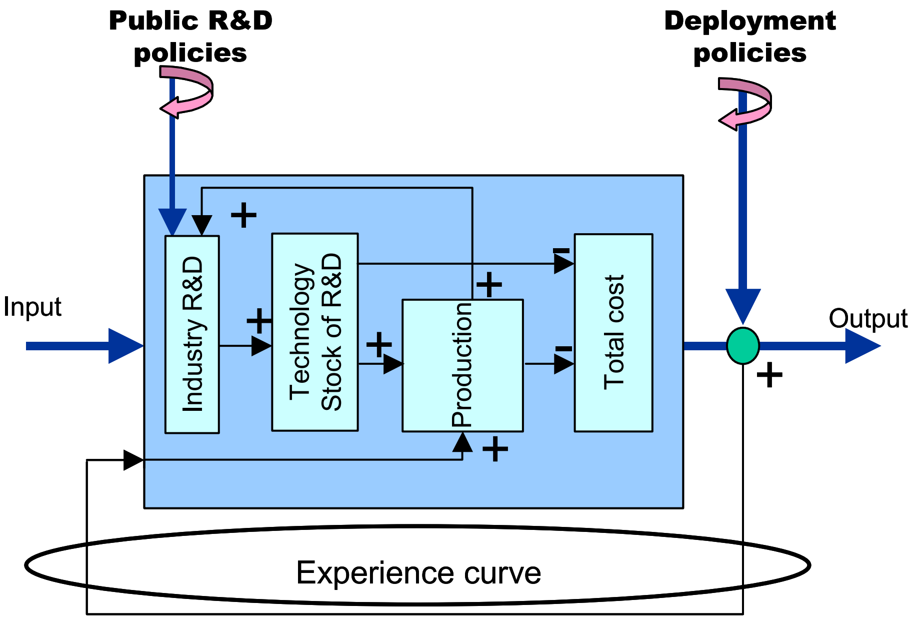
Figure 4.3 clearly shows that deploying a technology lowers its unit costs. Policy makers can influence costs of sustainable technologies, and thus the chance that technologies will be applied in the market by stimulating deployment. If the rate of deployment is high enough, unit costs of the sustainable technology decline to the cost level of conventional energy technologies. The break-even point is reached: sustainable technology can compete with conventional technologies.

Unit costs of sustainable technologies can be lowered by means of energy R&D as well as by deployment. As both mechanisms decrease costs and thus prices in well functioning markets, the question presents itself how policy makers can best support sustainable technology development. Which of these support mechanisms is most cost effective? In response to this question we need to look at the mechanisms behind technology learning.

Learning mechanisms

In 1999 Wanatabe described the mechanisms behind technology learning and experience curves. He summarised mechanisms behind technology learning in figure 4.4 shown below . Figure 4.4 shows how public sector and industry R&D interact when governments encourage industries to invest in new technologies in a market setting. The two vertical arrows depict two ways in which governments can support technologies: either by encouraging industry R&D or deployment. The lower part of the figure represents the experience curve, the relationship between the unit costs and cumulative stock of a technology.

Figure 4.4 Schematic overview of technology learning (IEA 2000, data from Wanatabe 1999): Influences on the Learning System from Public Policy



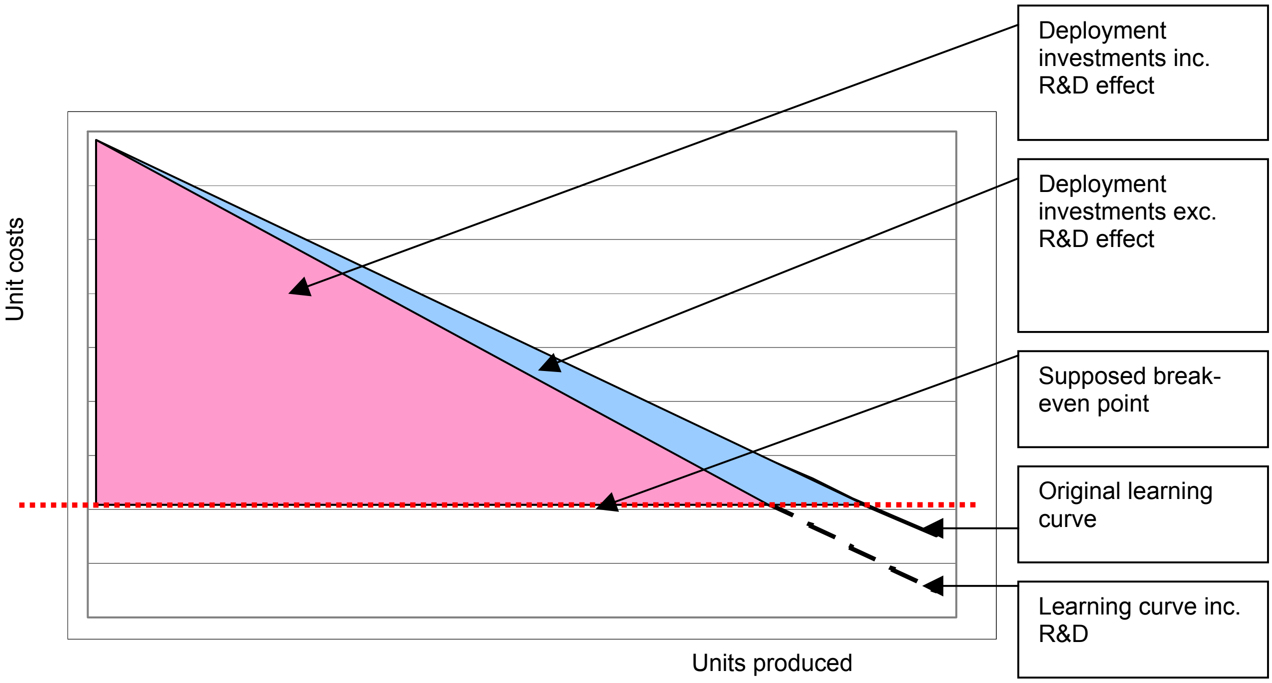
The figure shows that encouraging technology deployment has a circular effect. Increased deployment leads to increasing production and decreasing unit costs. Lower costs lead to higher deployment rates, higher production rates and lower total cost, and so on. Wanatabe's figure also shows that encouraging industry R&D seeds learning processes within industries but does not directly influence total costs. Industry R&D may lead to technological breakthroughs and increases in industry stock, but when technologies are not deployed on the market, technologies cannot learn. It is however possible that R&D leads to an improved learning rate. As a result of R&D, production methods may improve and unit costs may decrease: R&D may increase the slope of learning curves. This idea seems to be supported by the development of fuel cell technology and wind energy. The development of fuel cells is mostly supported by research and is steeply sloped. Wind energy has mostly been supported by deployment: its experience curve is less steep but its production has steadily grown in recent years. The cumulative production of wind turbines has doubled repeatedly during their development.

The ratio between market deployment and energy R&D

Mechanisms behind technology learning provide lessons on how governments can effectively stimulate implementation of sustainable energy technologies. Unit costs decrease only when innovations are deployed on the market. Governments can accelerate implementation of technologies by the use of subsidy schemes. This approach has the disadvantage that total expenses needed to stimulate innovations still far away from their break-even point are high. In some cases governments will have to subsidise deployment of innovations for years before innovations reach their break-even point.

A government may be more effective in the stimulation of sustainable innovations by taking advantages of research into account as well. Figure 4.5 shows possible effects of R&D on learning curves and expenses needed to reach the break-even point.

Figure 4.5 Effect of R&D on experience curves



R&D might increase the slope of experience curves. As a result lower cumulative production is needed to reach the break-even point; public authorities and market actors do not need to invest as much in market deployment. Depending on necessary R&D and deployment investments, it seems possible to lower total investments by deploying both R&D and deployment measures. Possible relationships between R&D expenses and progress ratios of learning curves are subject of research in several projects such as PHOTEX (on PV systems) and SAPIENTIA (on energy modelling) within the Fifth framework programme. Outcomes of these projects might be used to formulate ideas on ideal ratios between deployment and R&D for technologies considered.

Considerations for a new Energy Research Strategy

The question presents itself how Dutch energy research and deployment can profit from technology learning. The Netherlands are too small to stimulate R&D and deployment of all potential innovations. The concept of technology learning may offer help in deciding how the Netherlands can improve their energy research strategy in order to stimulate sustainable development. In our view, the Energy Research Strategy can be improved when possible combined effects of R&D and deployment and the position of the Netherlands within Europe are better taken into account.

The position of the Netherlands as member of the European research network is important. Technology development is an international process in which the Netherlands can only play a limited role. The Netherlands can use their position in the European research area to strengthen their own position and development of sustainable technologies.

From a learning perspective there seem to be two options to improve the energy research strategy:

- The strategy could strongly support research to energy technologies that are already focus points in European energy RD&D
- The Netherlands can initiate research on certain energy technologies and provide them with a pole position. Other countries or the European Union must contribute to research topics in the longer term in order to stimulate the overall learning process.

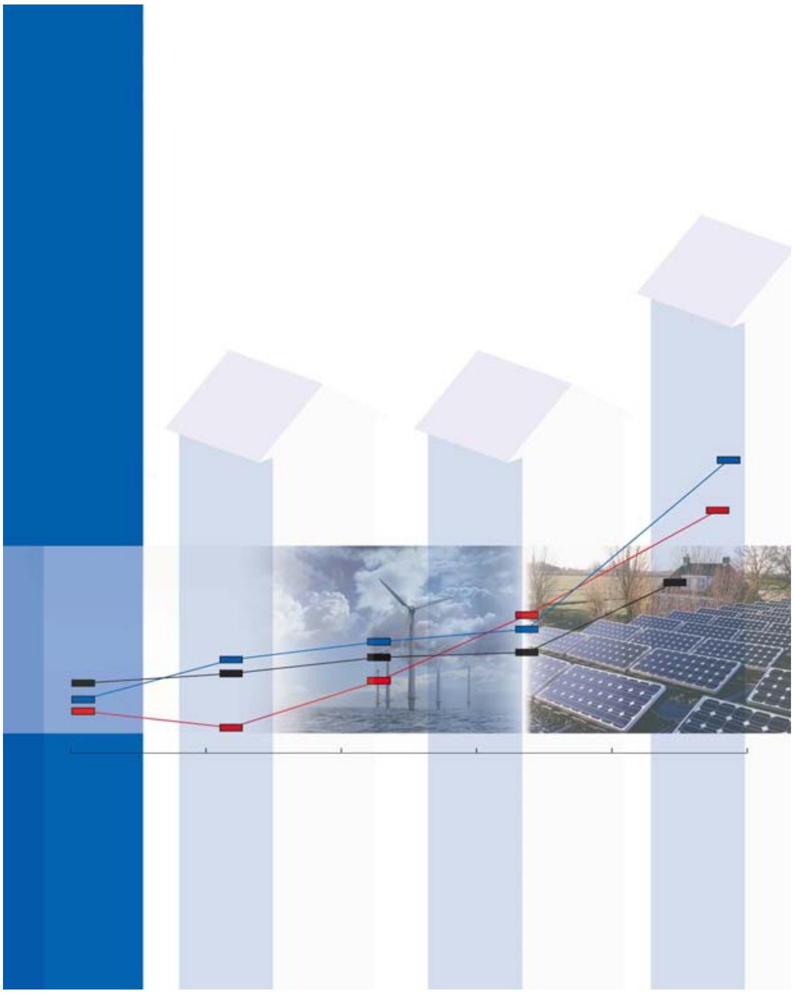
For the first option Dutch energy RD&D hitches onto developments on European level. When applied in the present situation, even more emphasis would be placed on Hydrogen in Dutch RD&D. Hydrogen is one of the focus points within the sixth Framework Program. The Netherlands are therefore able to learn from developments in other European countries and vice versa. From this point of view a European dimension should be added to the Energy research strategy matrix. Energy research topics that are already a focus point on European level deserve, from a learning point of view, a stronger position on the Dutch R&D agenda.

The second option describes the situation in which the Netherlands decide to initiate research that is not commonplace in Europe or even on a world wide scale. From a transition perspective it might be useful to invest in certain sustainable innovations, even if other countries are not interested. This possibility is already included within the energy research strategy by means of the New Energy Research Programme (NEO). This small program has been developed to support possible wildcards; technologies that might grow out to future priority topics. The development of fuel cell technology in the eighties proves that it might be useful to open up the long-term instrument for especially selected potentially very useful research subjects even if the Netherlands do not have a strong knowledge position on the subject yet. The Netherlands and Italy were frontrunners in European fuel cell research in the eighties. This strong support, and the fact that other European countries picked up the development in the years afterwards, gave the Netherlands and other European countries a pole position in further fuel cell research. In any case public authorities should consider the possible positive combined effect of both R&D and deployment in their choice of instruments when stimulating chosen research topics. Investing in sustainable technologies now is useful as external costs now and in the future possibly could be avoided.

CHAPTER 5

STATISTICAL APPENDIX:
OVERVIEW OF THE DUTCH ENERGY SECTOR

Authors: Wim van Arkel and Annette Bruyn

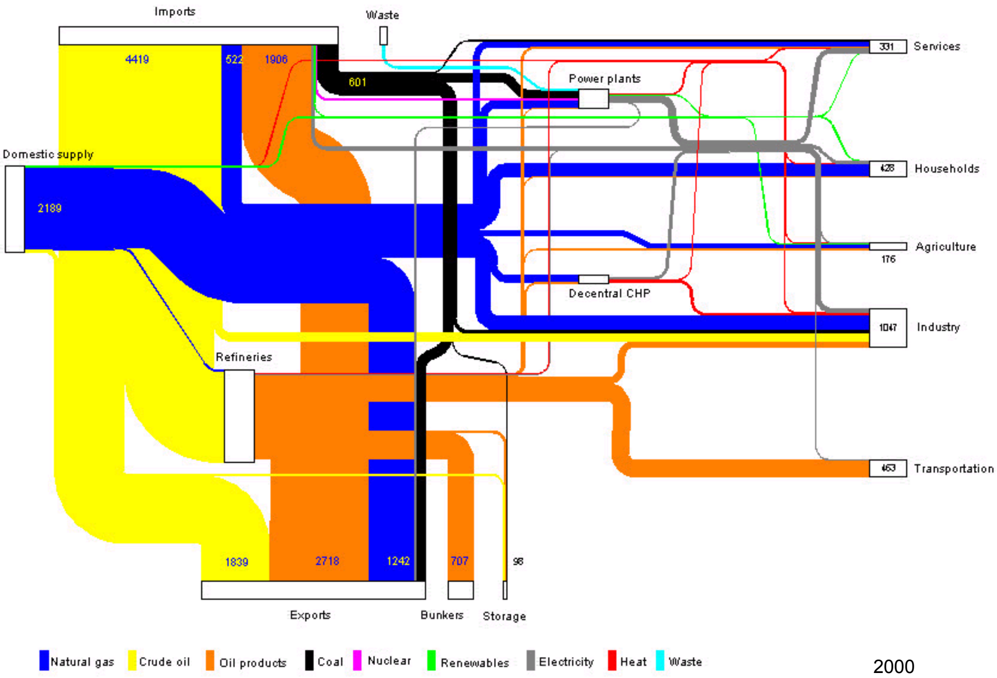


The following section presents statistical data and diagrams on energy in the Netherlands. It includes production and trade of gas, oil and electricity, capacity of refineries and emissions. A wide variety of related data can be found on www.energie.nl.

Energy flows in the Netherlands

This picture shows the energy flows in the Netherlands. Distinctive features are:

- The Netherlands have a large transit trade in oil and oil products.
- There is a significant Dutch refinery industry; it is primarily used for export destinations.
- Natural gas is very important for domestic use.

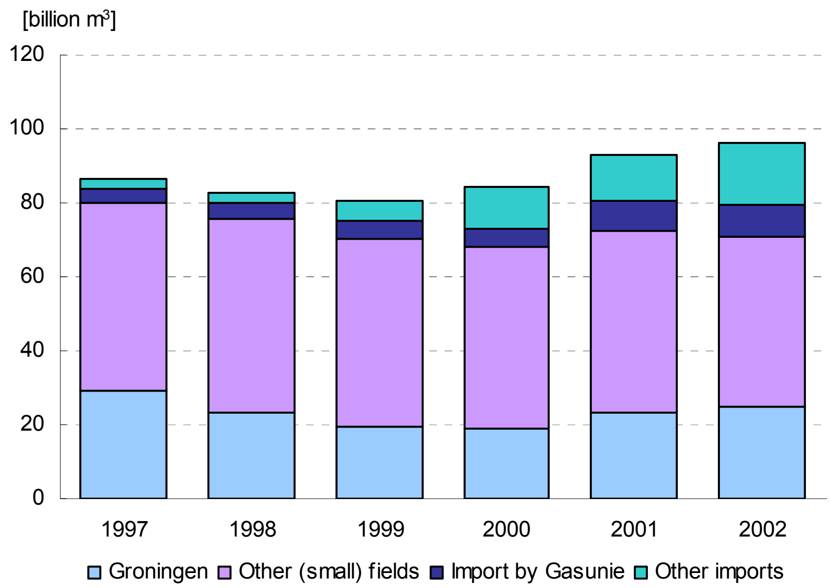


GAS

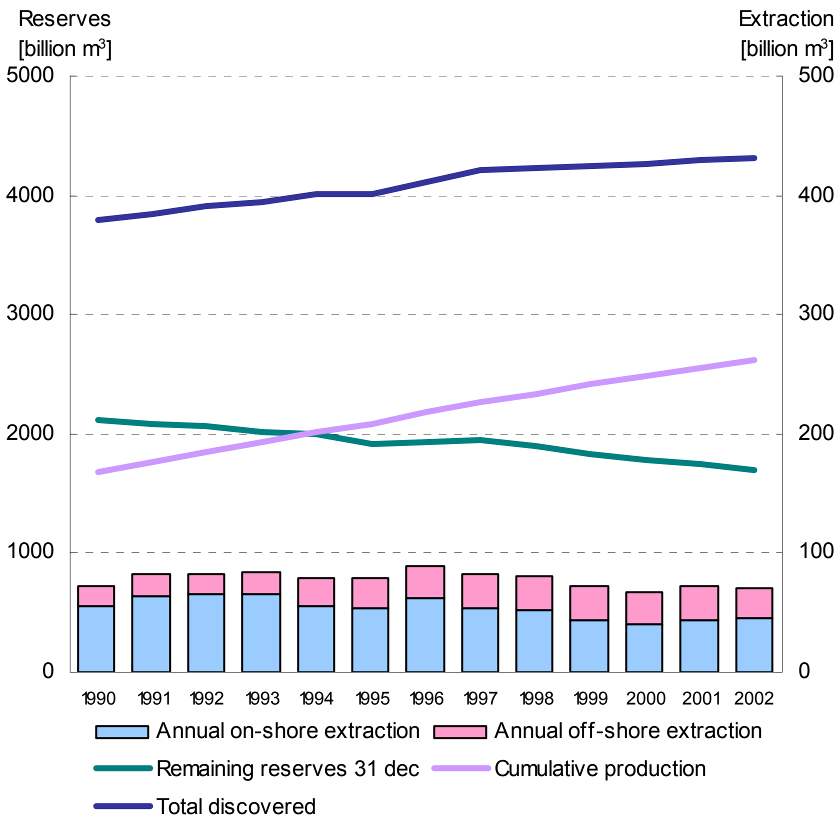
Origin of natural gas supply on the Dutch market

This picture illustrates the importance of the Groningen gas field and small gas fields.

The Dutch small field policy was developed in the seventies. Priority is given to the extraction from small onshore and offshore fields, in order to spare the large Slochteren gas field in Groningen in the north of the country.



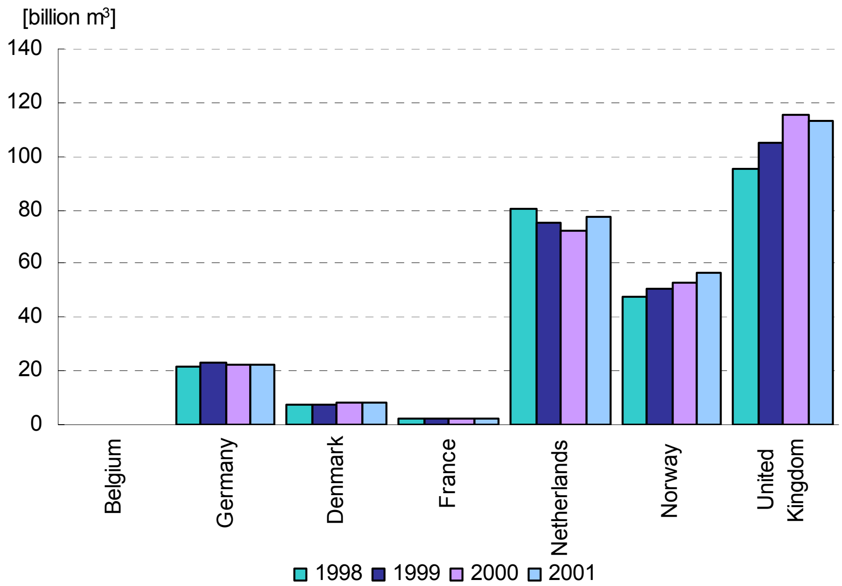
Production and reserves of natural gas in the Netherlands



The Netherlands keep 34% of the European natural gas reserves.

Over 500 million m^3 natural gas is stored underground.

Production of natural gas in the Netherlands and neighbouring countries



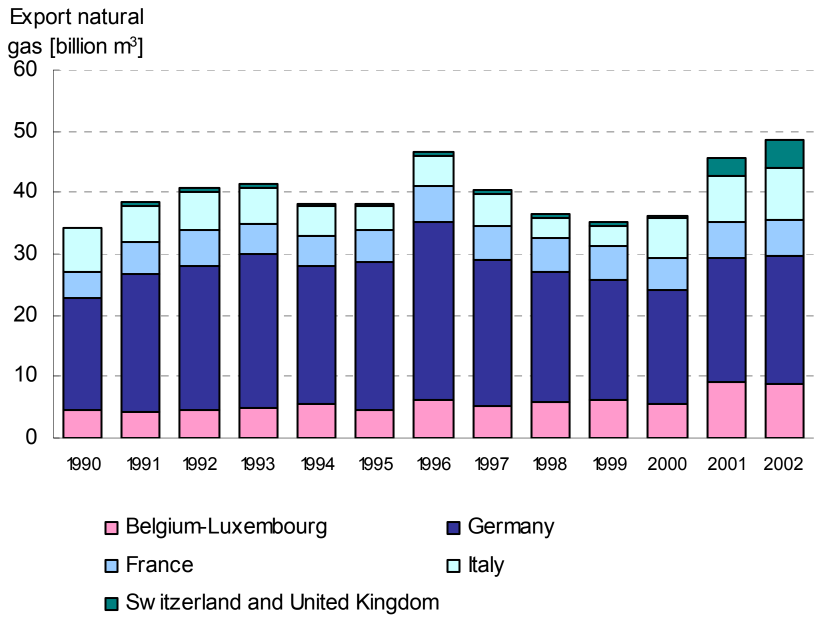
There is no significant natural gas production in the neighbouring countries Belgium, Germany, Denmark and France, which can be qualified as import countries. Norway, the United Kingdom and the Netherlands can be qualified as export countries.

With regard to the Netherlands, it should be noted that relatively high gas prices in 2000 caused the decline of gas input for electricity production.

Export of natural gas by country

The Netherlands are a very flexible gas supplier. This is primarily the result of the presence of the Slochteren gas field.

Germany is the most important destination for Dutch natural gas: they receive 44% of the total Dutch export amount.

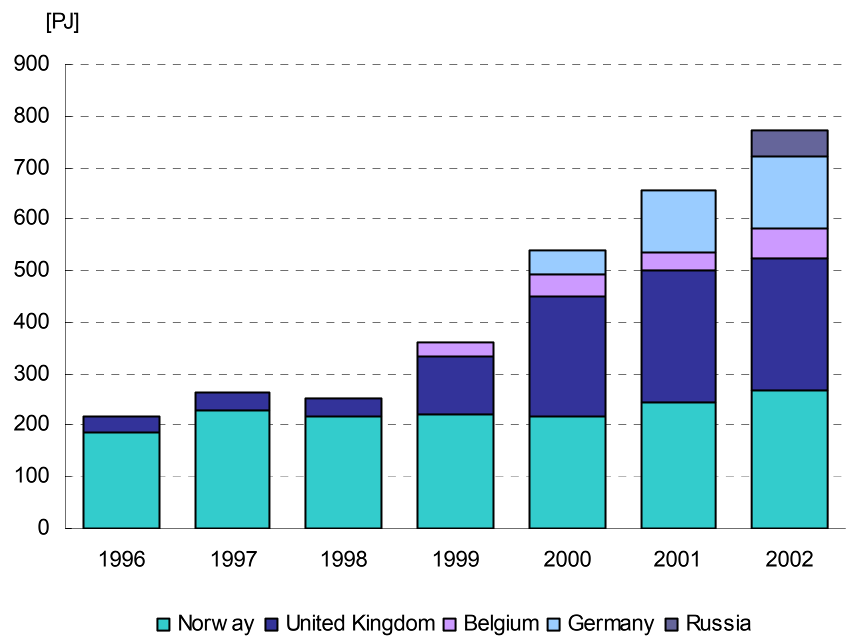


Import of natural gas

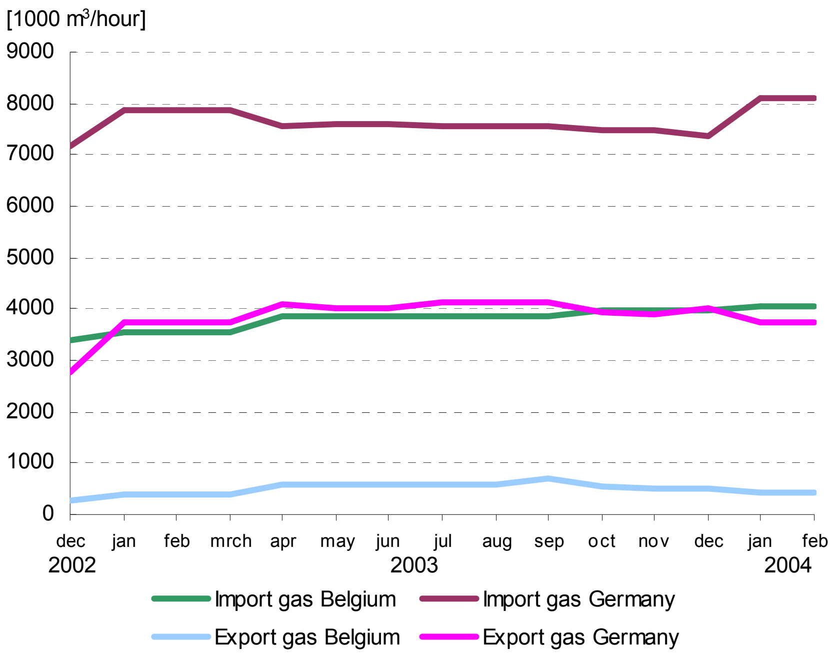
The figure shows an increase in import in recent years.

Natural gas is imported from 5 countries. It should be noted that:

- Norway and United Kingdom were and still are the most important countries of origin.
- The German gas is derived from a gas field on the German continental shelf.
- From 2002 onwards natural gas is imported from Russia at a rate of 4 billion m^3 per year.

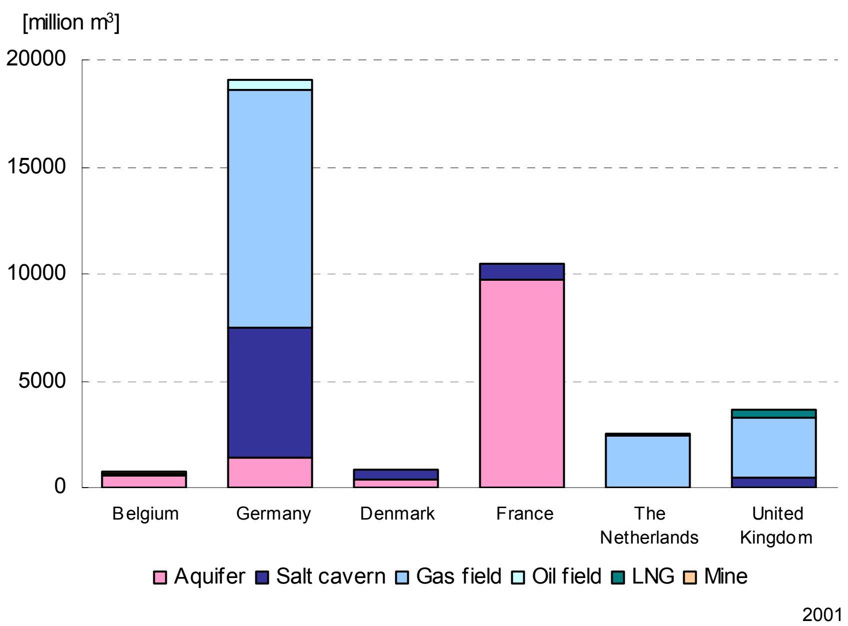


Dutch import capacity for gas



The figure shows the freely available import capacity on stations in the transport grid of Gastransport Services per December 2002. Gastransport Services is the manager of the national high-pressure gas grid. The figure shows the physical and non-physical import and export capacity. A distinction is made between stations that border on Belgium and Germany.

Storage capacity for gas in the Netherlands and neighbouring countries



Countries with minor gas production (Germany, France) use gas storage to meet seasonal fluctuations in gas sale.

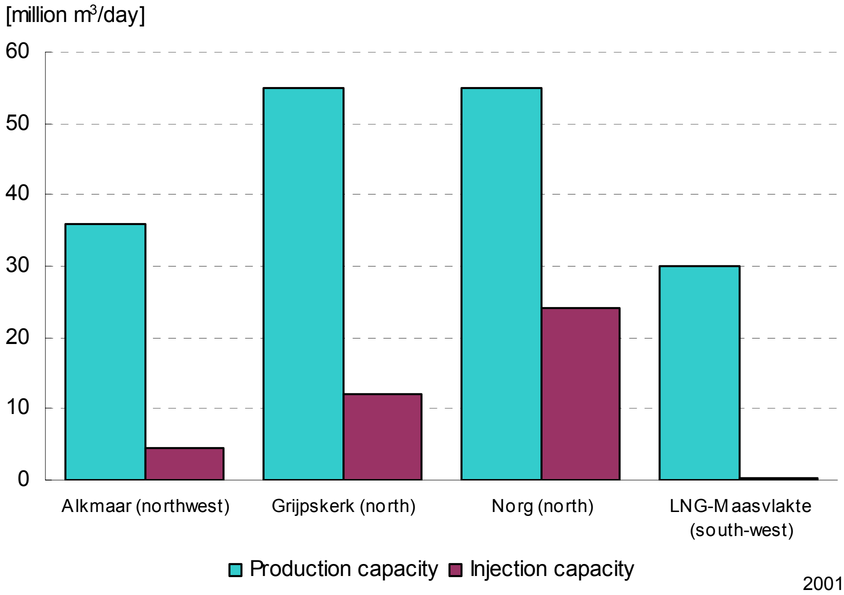
The situation in the Netherlands is quite different:

- Gas storage is mainly used to support the small field policy: the gas production from small fields can be optimised as production is maintained even when the demand is low.
- Seasonal fluctuations are covered by the production from the Slochteren gas field.

Production and injection capacity for underground storage of gas in the Netherlands

The Netherlands accomodate four storage facilities: three are underground and one is reserved for LNG.

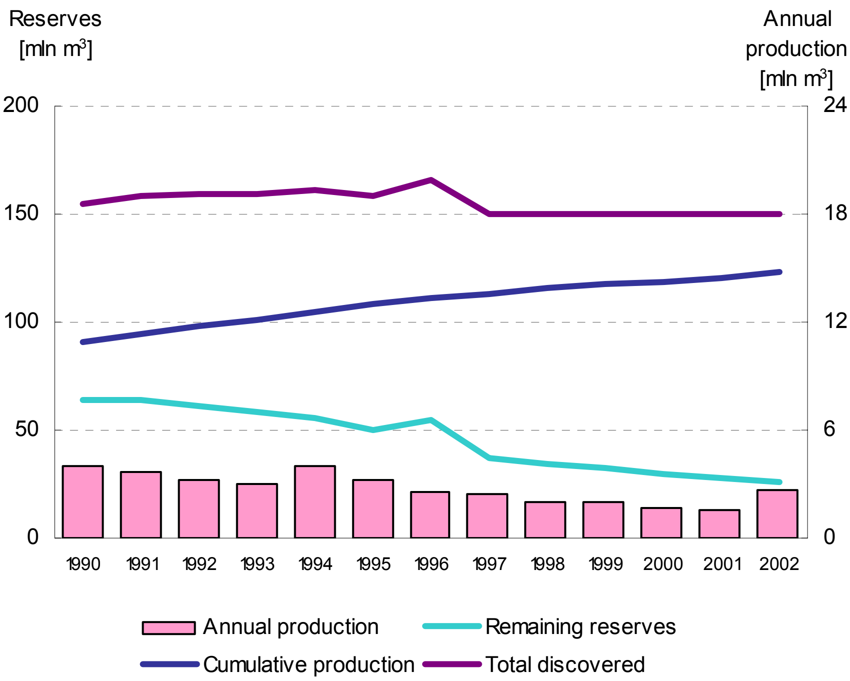
Since 2002, the facilities are open to third parties (shippers, producers) in order to create more flexibility in the gas market.



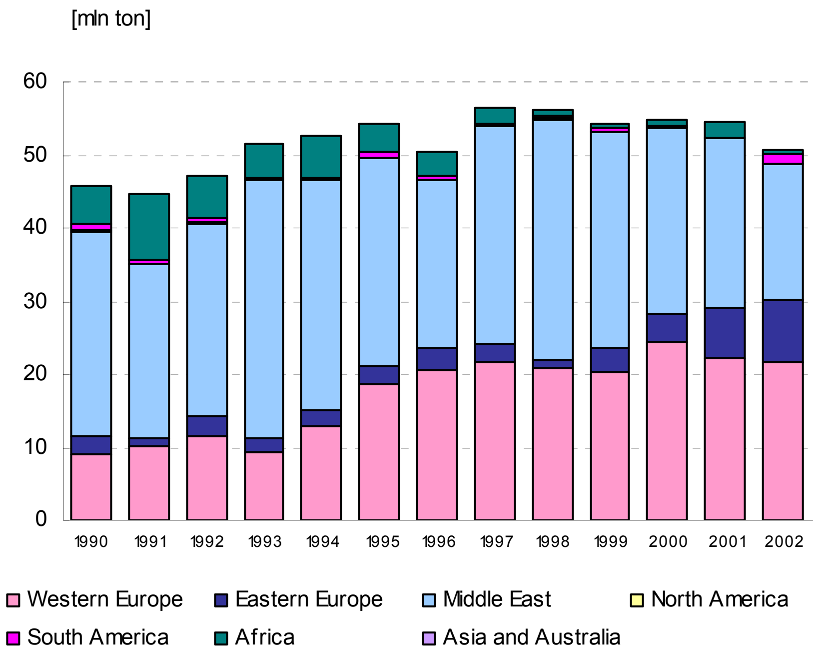
Oil

Production and reserves of oil in the Netherlands

The Dutch oil reserves are situated both onshore and offshore. 80% of the remaining reserves are situated on the continental shelf. The Netherlands have 11 producing oil fields in total, 8 of which are situated on the continental shelf.

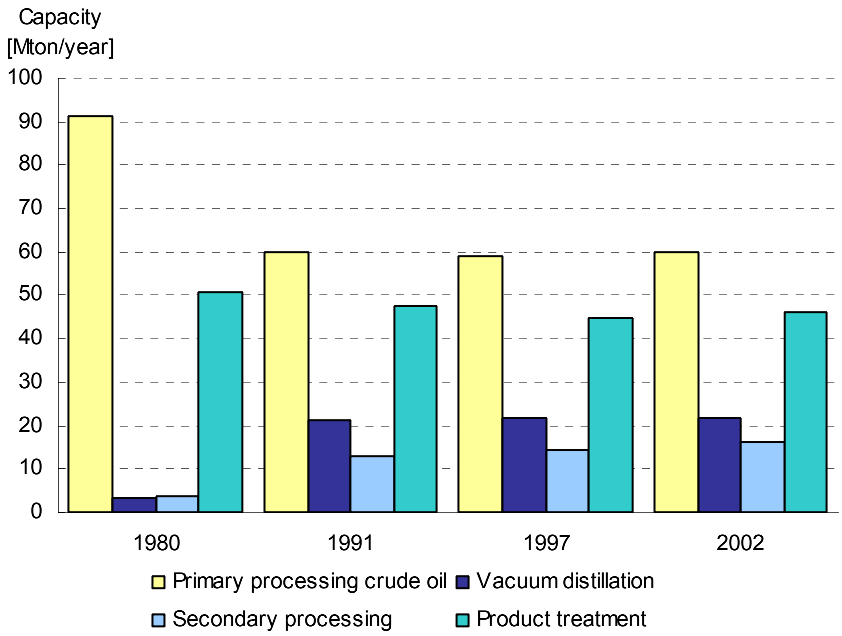


Import of crude oil into the Netherlands



The figure shows that the import of crude oil shifts from the Middle East to Eastern Europe and Africa.

Refineries in the Netherlands: types of capacity

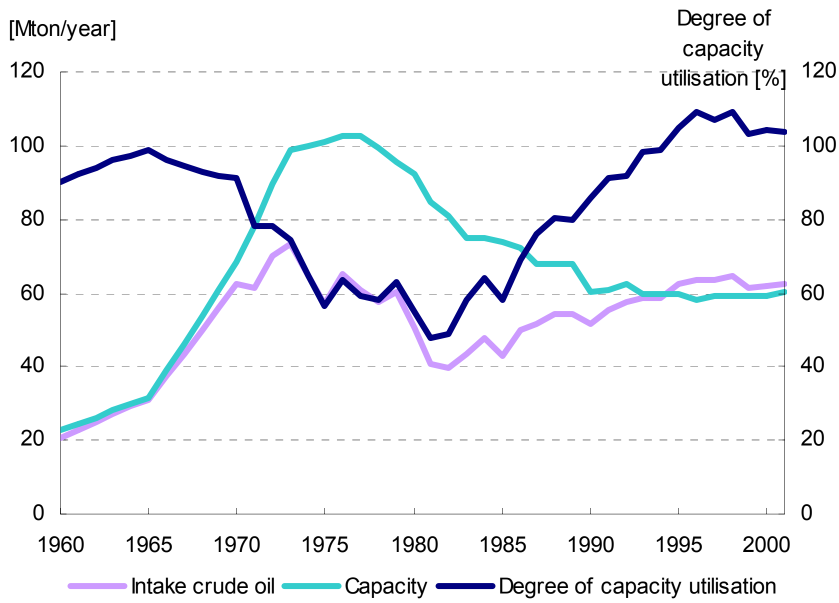


The figure indicates a change in the secondary capacity of the Dutch refineries. Several causes can be identified:

- The low market value for heavy products called for a switch to 'deeper conversion'. The demand for light products that are produced by deeper conversion (such as petrol, diesel) increased.
- Since 1990, the environmental regulations for SO_2 and NOx emissions that result from the production and use of oil products have tightened increasingly.
- Sulphur assay had to be reduced.

Refineries in the Netherlands

The Dutch refinery sector consists of six refineries with a total capacity of over 60 million tonnes crude oil per year. The capacity is currently fully used. The figure shows a clear overcapacity between 1975 and 1985; the degree of capacity utilisation was about 60% at that time.

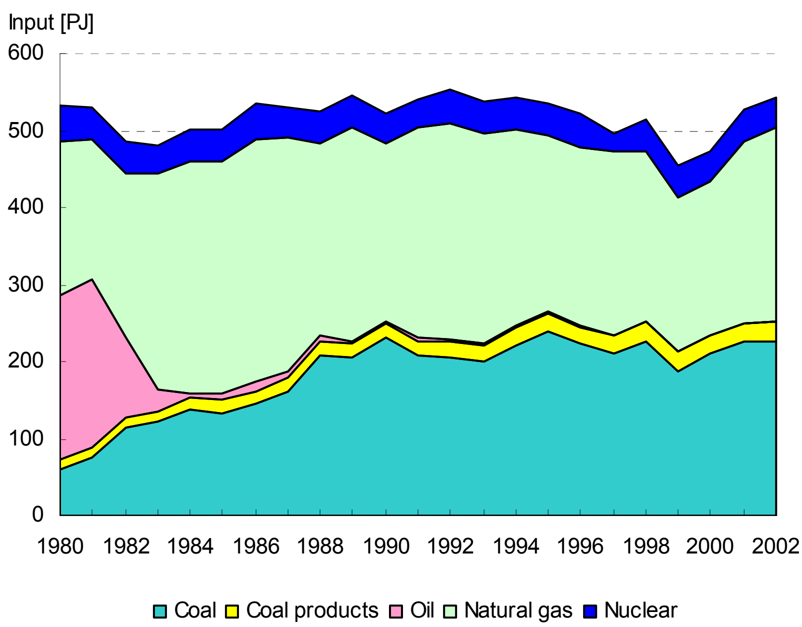


Electricity

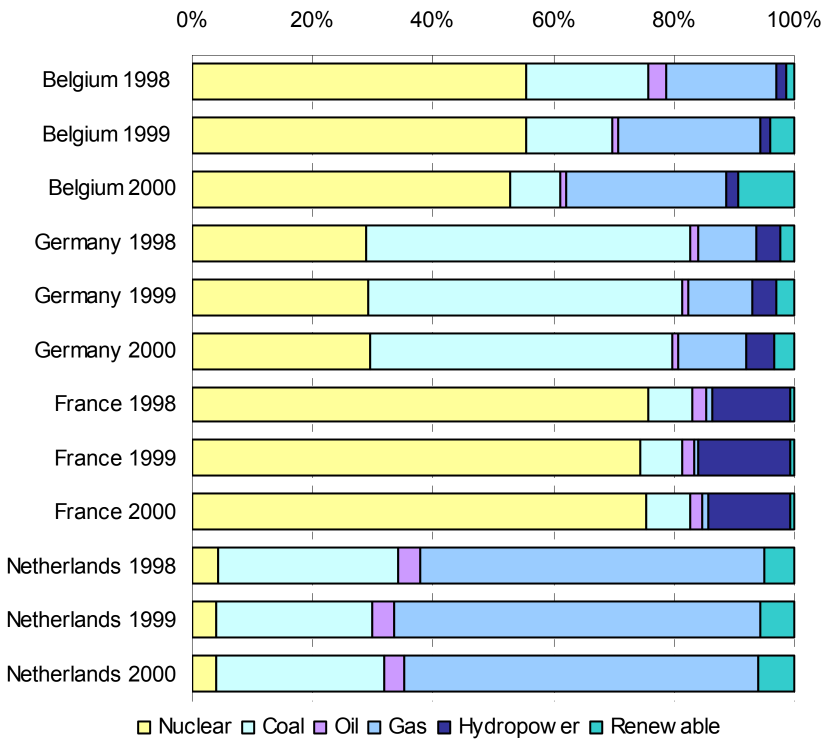
Fuels used to generate electricity in the Netherlands

The figure clearly shows the dominance of coal and gas used for electricity supply. Exceptions to the rule are the plants in Velsen (a mixture of blast-furnace gas and coke gas) and in Borssele (natural gas and phosphorus gas). Biomass is also used for coal-fired plants.

Renewables and imports are also important. It should be mentioned that imports have increased and domestic production was relatively small in 1999 and 2000.



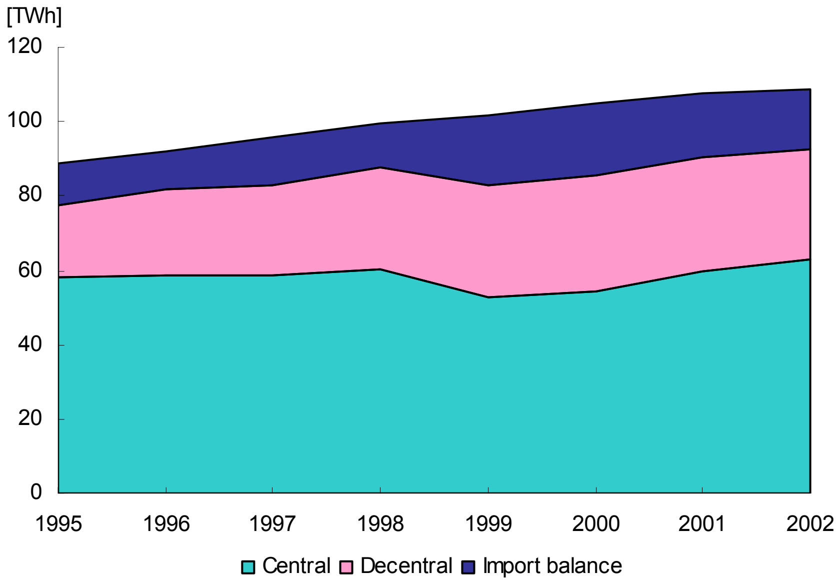
Fuel mix electricity supply in comparison



Different countries have different ways of generating electricity, depending on the availability of fuels and import prospects. The figure shows the fuel mix used for the production of electricity in 4 different countries. The production of electricity in France and Belgium is dominated by nuclear plants; in Germany both coal and nuclear are important.

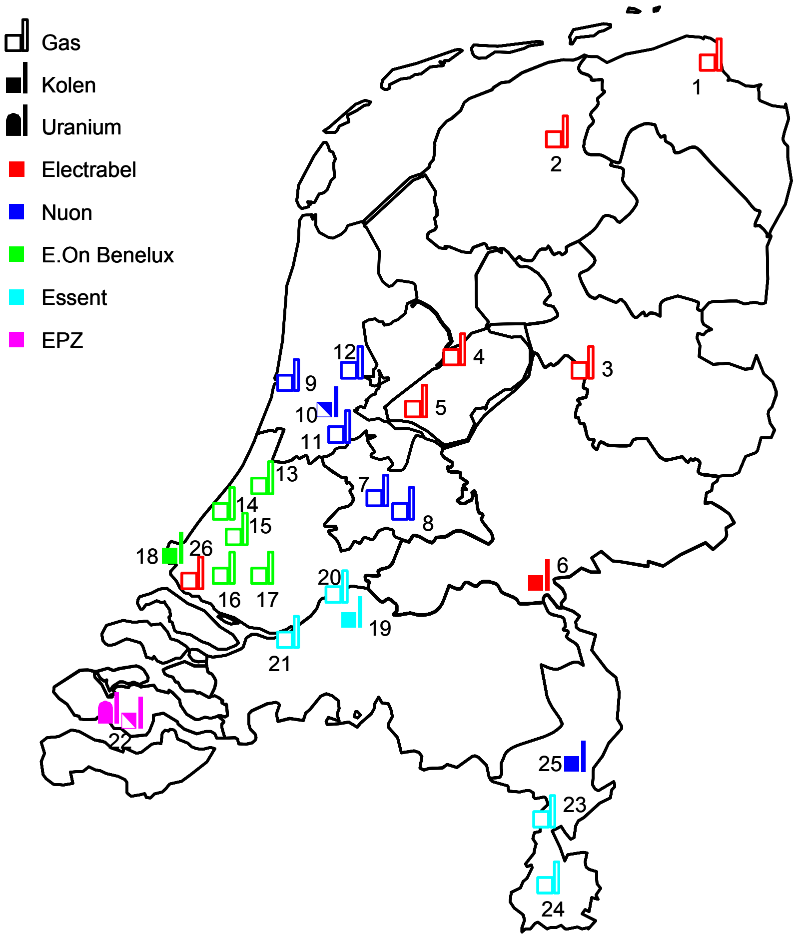
The shifts in fuel mix throughout the years are rather insignificant, which can be explained by the absence of new plants. Any small shifts (e.g. between coals and gas) are primarily the result of fluctuations in fuel prices, combined with a sensitivity to market changes.

Domestic electricity production



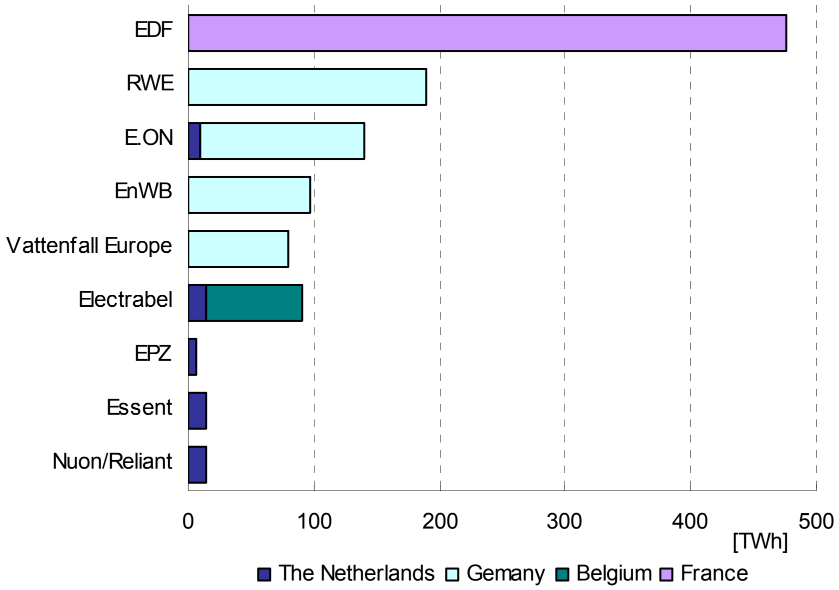
Due to electricity market liberalisation the production of electricity, both central and decentral, decreased after 1998 and imports increased. However, domestic production increased since then, in line with growth of the market.

Power plants in the Netherlands



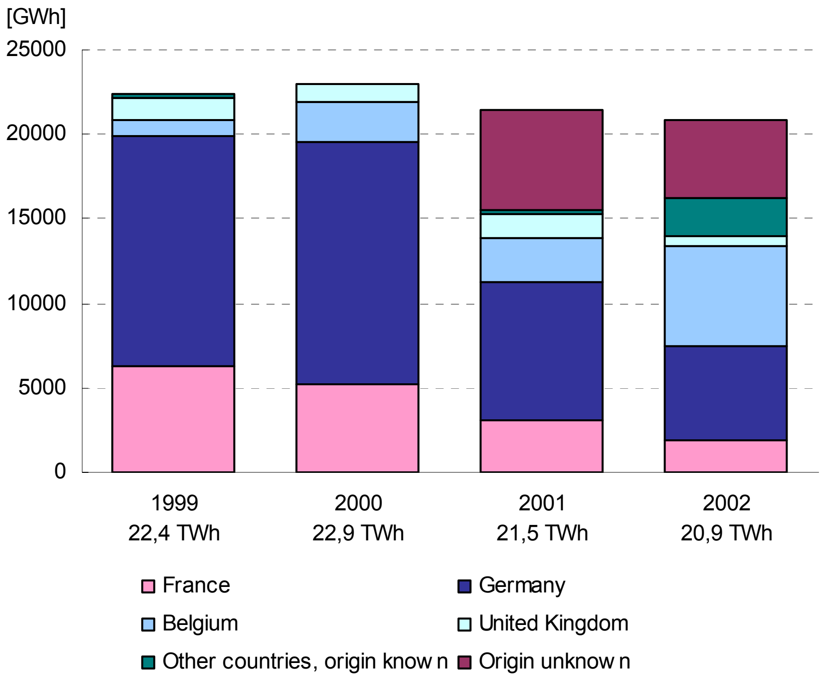
Nr	Name	Fuel	Power [MW]	Owner	Production	Note
1	Eemscentrale	Natural gas	2400	Electrabel	Electricity	
2	Centrale Bergum	Natural gas	664	Electrabel	Electricity	
3	Centrale Harculo	Natural gas	350	Electrabel	Electricity	
4	Flevocentrale	Natural gas	513	Electrabel	Electricity	Not operational
5	W/K centrale Almere	Natural gas	118	Electrabel	Electricity+heat	
6	Centrale Gelderland	Coal+biomass	602	Electrabel	Electricity	
7	Lage Weide	Natural gas	512	NUON	Electricity+heat	265 MW not operational
8	Merwedekanaal	Natural gas	416	NUON	Electricity+heat	
9	Velsen+IJmond	Furnace gas + natural gas	960	NUON	Electricity	
10a	Hemweg	Natural gas	580	NUON	Electricity	
10b	Hemweg	Coal	630	NUON	Electricity	
11	Diemen	Natural gas	249	NUON	Electricity+heat	
12	Purmerend	Natural gas	69	NUON	Electricity+heat	
13	Leiden	Natural gas	81	E.On	Electricity+heat	
14	Den Haag	Natural gas	78	E.On	Electricity+heat	
15	Delft	Natural gas	93	E.On	Electricity+heat	
16	Rotterdam Galileïstraat	Natural gas	209	E.On	Electricity+heat	
17	Roca	Natural gas	269	E.On	Electricity+heat	
18	Maasvlakte	Coal+biomass	1040	E.On	Electricity	
19	Amercentrale	Coal+biomass	1275	Essent	Electricity+heat	
20	Dongecentrale	Natural gas	121	Essent	Electricity	
21	Moerdijk	Natural gas+heat	339	Essent	Electricity	
22a	Borssele	Natural gas	18	EPZ	Electricity	
22b	Borssele	Coal+biomass	406	EPZ	Electricity	
22c	Borssele	Nuclear	450	EPZ	Electricity	
23	Clauscentrale	Natural gas	1280	Essent	Electricity	
24	Swentibold	Natural gas	233	Essent	Electricity+heat	
25	Buggenum	Coal+biomass	253	NUON	Electricity	
26	Air Products	Natural gas	43	Electrabel	Electricity+heat	

Electricity production by large power producers in the Netherlands and neighbouring countries in 2001



In the Netherlands and Germany a large part of the production of electricity is in the hands of a number of parties. In France and Belgium it is dominated by one large power producer.

Import of electricity: countries of origin

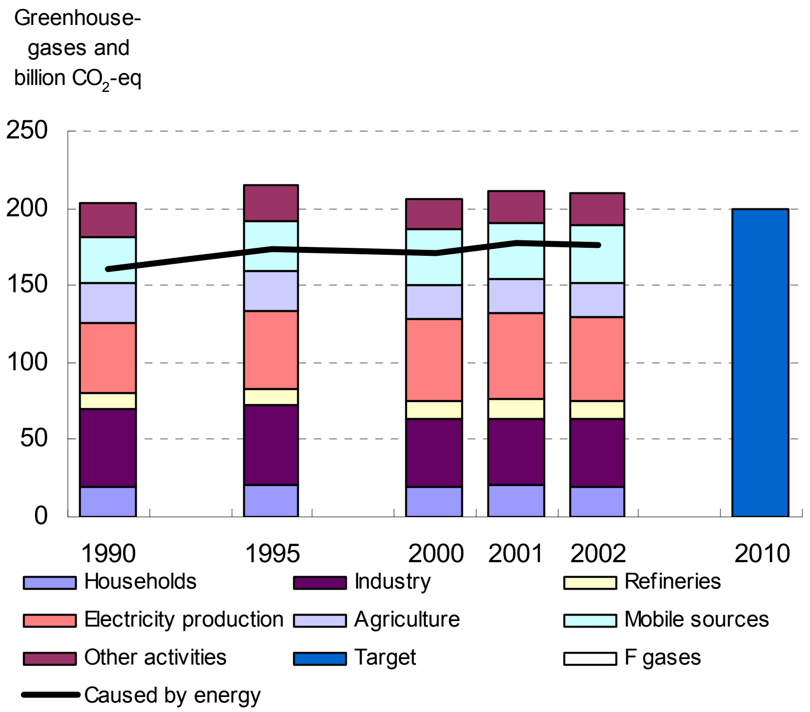


'Other countries, origin known' in the picture primarily refer to Sweden en Switzerland.

Emissions

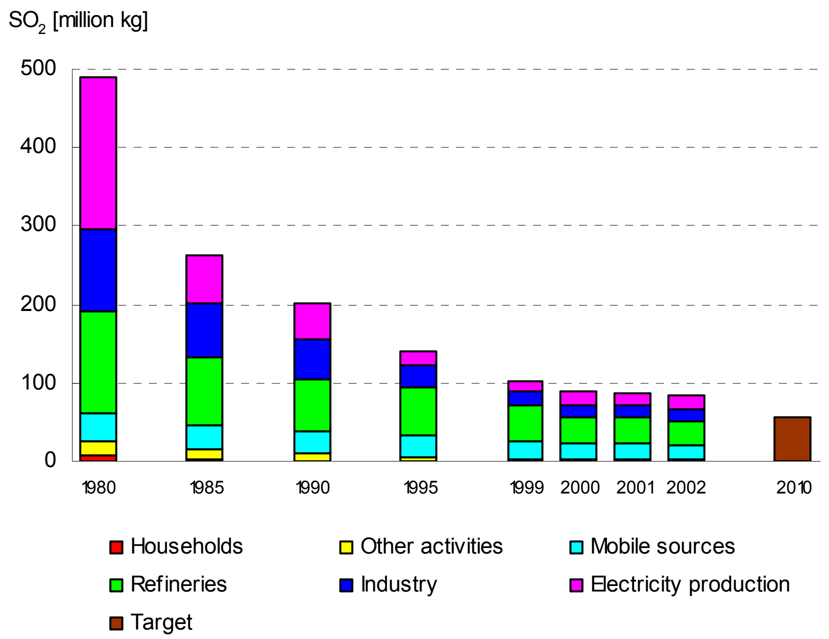
Total greenhouse gases per sector

The Kyoto target for the Netherlands involves a 6% reduction of greenhouse gases compared to the emissions in 1990, which equals 199 billion kilogrammes. The Netherlands have chosen to realise halve of the emission reduction task through the Kyoto mechanism (Joint Implementation and Clean Development Mechanism). The Evaluatienota Klimaatbeleid of the Ministry of VROM formulates the targets as follows: a domestic emission level of 219 billion kilogrammes CO_2-equivalents and an extra realisation of 20 billion kilogrammes of foreign reductions. Other targets are average per year for the period 2008-2012.

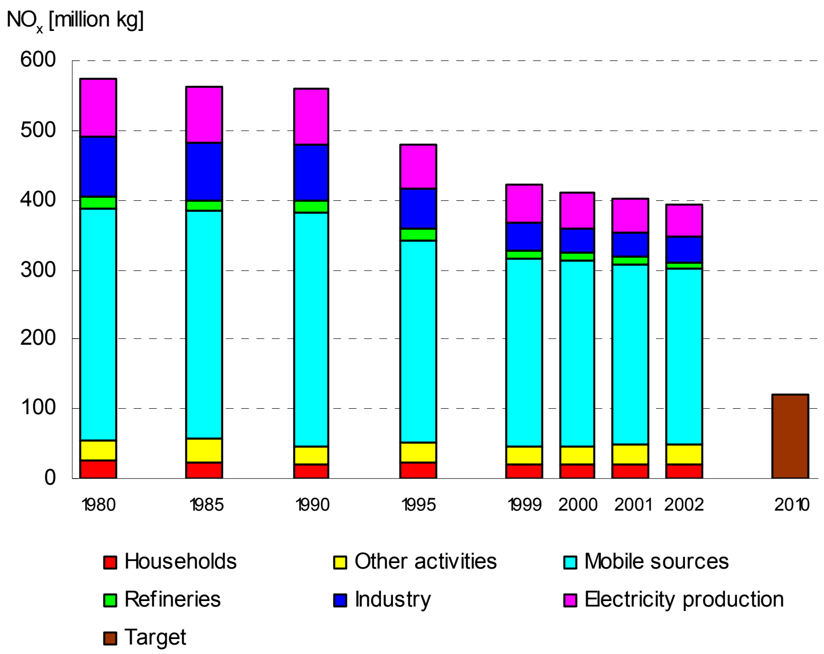


Emission SO_2 per sector

SO_2 emission in the Netherlands has decreased since 1985 at a steady pace, among other things caused by covenants and the governement decision 'Besluit Emissie-Eisen Stookinstallaties'. SO_2 emission from road traffic has significantly decreased since 1990 because of European fuel regulations for road traffic, whereas road traffic has increased by 30%. For shipping traffic and agricultural machines fuel regulations are much less strict. SO_2 emission from these sources have increased by 16%.



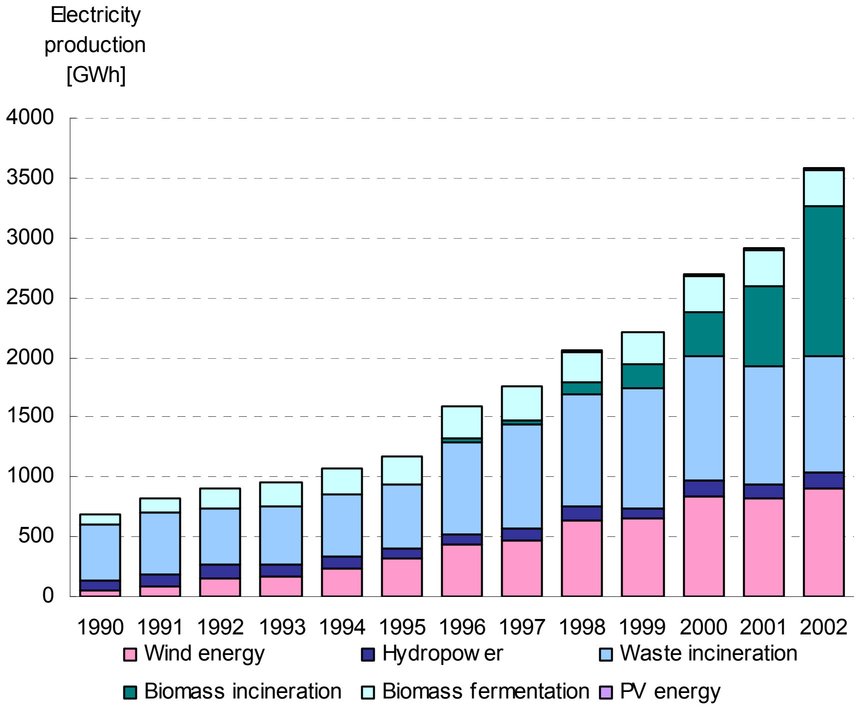
Emission NO_x per sector



NO_x emission in 2001 was approximately 30% lower than in 1985. Scientists claim that the Dutch policy on emission reduction has prevented an increase of about 35% since 1985. Emission by companies is currently no longer decreasing much as all cheap measures have already been taken and the heralded emission trading system has not yet started. It is expected that the current national emission policy will not meet the EU-target for 2010.

Sustainable

Production of electricity from sustainable sources



Most of the electricity production in the Netherlands from sustainable sources is supplied by incineration installations.

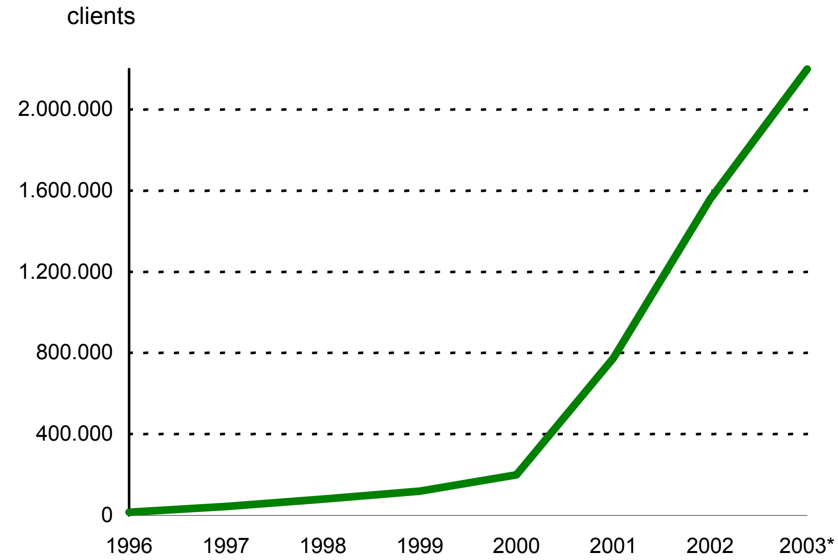
According to the Dutch Protocol Monitoring Sustainable Energy, less than half of this supply can be labelled as *sustainable*.

The import of electricity from sustainable sources has increased significantly in recent years. In 2002 it amounted to almost three times as much as the domestic production.

Dutch customers purchasing renewable electricity

The demand for renewable electricity in the Netherlands exploded from 250,000 customers in July 2001 (at the opening of the Dutch retail market for renewable electricity) to approximately 2.2 million (32% of the households) in October 2003.

The Dutch REB stimulation allowed the possibility to offer renewable electricity at the same price as conventional electricity, which is an attractive alternative for customers and a convenient marketing tool for retailers.



* until October 2003

Production of heat and power from cogeneration

The figure shows a decline in Dutch cogeneration production after 2001, as the competitive position of electricity from cogeneration became rather unfavourable. This was caused by high prices for gas, which is needed for the production. At the same time, the market price for electricity dropped because of liberalisation and overcapacity.

The receipts thus no longer covered the variable costs of cogeneration installations. Several installations were cut back in off-peak hours or even shut down.