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## Increasing the reliability of electricity production

A cost benefit analysis

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## Abstract

This report analyses three instruments aimed at increasing the reliability of electricity production. In the system of *capacity markets*, the transmission system operator (TSO) requires traders to back their own peak load plus a prescribed level of spare capacity with contracted capacity, the latter being tradable at secondary markets. With *reserve contracts*, the TSO contracts spare capacity from producers, holding it to be dispatched in case of a crisis. *Capacity payments* are a subsidy on capital costs, giving producers an incentive to build more capacity.

These measures prove to be in efficient in preventing price spikes, as the welfare costs of price spikes are lower than the costs of the policy options, unless price spikes occur in an implausible high frequency. Capacity payments cannot prevent black-outs, as they do not induce enough investments in spare capacity. Black-outs can be prevented by capacity markets and reserve contracts, but at a high cost. Even if a 24-hour black-out of the Randstad area occurred every five years, it would be cheaper to accept the consequences of the black-out than to prevent it.

## Korte samenvatting

Dit rapport geeft een analyse van drie instrumenten gericht op het vergroten van de betrouwbaarheid van de elektriciteitsproductie. Bij een systeem van capaciteitsmarkten stelt de netbeheerder de eis dat handelaren de capaciteit voor hun piekvraag plus een vooraf bepaald niveau van reservecapaciteit contracteren. De gecontracteerde capaciteit is verhandelbaar op een secundaire markt. In een systeem van reservecontracten contracteert de netbeheerder de reservecapaciteit rechtstreeks bij de producenten en houdt deze achter de hand om in te zetten in geval van nood. Capaciteitsbetalingen zijn een subsidie op kapitaalkosten, bedoeld om producenten te prikkelen om meer capaciteit te bouwen.

Deze maatregelen zijn inefficiënt om prijspieken te voorkomen, omdat de kosten van prijspieken in termen van welvaart lager zijn dan de kosten van de beleidsopties, tenzij de pieken in een onwaarschijnlijk hoge frequentie optreden. Capaciteitsbetalingen zijn niet in staat om black-outs te voorkomen, omdat ze onvoldoende reservecapaciteit genereren. Capaciteitsmarkten en reservecontracten zijn wel in staat om black-outs te voorkomen, maar tegen hoge kosten. Zelfs als er iedere vijf jaar een black-out van de hele Randstad zou optreden, zou het goedkoper zijn om de kosten ervan te accepteren dan om de black-out te voorkomen met een van deze instrumenten.

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# Preface

Since the California crisis, the security of electricity supply gained a central place in the minds of policy makers in the field of energy. Preventing outages seems to have become an important policy goal, but it also incurs costs. The main question in this field should therefore refer to the optimal level of supply security. A related question is whether markets succeed or fail in realising that level. In the latter case, government involvement could be welfare improving.

In order to answer these questions, a cost-benefit analysis should is required. In contrast with other domains of government policies, only a few examples exist of studies analysing costs and benefits of security of energy supply measures. The Netherlands' Ministry of Economic Affairs asked the CPB to develop a framework for cost-benefit analysis in the field of security of supply of energy. In addition, it asked to apply that framework to a number of policy measures. This document is a spin-off from the project in which the framework is developed. The cost-benefit analysis of measures aimed at increasing the reliability of electricity production is one of the cases in applying the framework. The full report of the main project, *Energy policies and risks on energy markets: a cost-benefit analysis,* is published simultaneously with this report.

During the project, we were advised by a steering committee from the Ministry, composed of Bert Roukens, Klaas-Jan Koops, Jeroen Brinkhoff, Hans Cahen, Tom Kolkena and Jaco Stremler. In addition, we received highly useful comments on draft versions from energy market specialists working by several organisations. In particular, we want to mention the contributions given by Emiel Rolink (Ministry of Economic Affairs), Michiel de Nooy (SEO), Martin Scheepers and Michiel van Werven (ECN), Laetitia Ouillet and colleagues (Nuon) and Laurens de Vries (TU Delft).

We thank them all for their useful contribution. The responsibility for this report is, of course, entirely ours. Feedback from within the CPB was given by Taco van Hoek, Carel Eijgenraam, Paul Besseling, Ruud Okker and Bert Smid.

The cost-benefit analysis reported in this document was conducted by Mark Lijesen. The work benefited greatly from insights from the larger project, teamed by Jeroen de Joode, Douwe Kingma, Mark Lijesen, Machiel Mulder and Victoria Shestalova. Arie ten Cate contributed greatly preparing the electricity model for the simulations.

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director

# Summary


Supply security of electricity has been taken for granted in the western world for many years. The confidence of a secure supply of electricity suddenly shattered with the occurrence of the California crisis in 2001. Soaring wholesale prices, rolling black-outs and even more near-black-outs focussed the world's attention on the vulnerability of electricity production. Recent outages in the US, Canada, England, Denmark, Greece and Italy have emphasized the importance of electricity for modern day society.

The growing concern for a new crisis to happen induced many policy options for securing electricity supply. In performing a cost-benefit-analysis to these policies options, one should keep in mind that disruptions of energy supply come at low frequencies and high costs. This implies that, in order to assess the effects of policies aimed at different types of energy crises, we need to build scenarios around a fairly large number of possible crises, each of which has a small but unknown probability. The uncertainty precludes the possibility of computing probabilistic outcomes. As an alternative, we compute 'break-even frequencies', the expected frequency of a certain crisis at which the benefits of a policy option just match the costs.

We define a crisis as a limitation in the availability of capacity. If demand is responsive enough, a price spike will occur, giving rise to distributional effects and welfare losses. If demand is unresponsive or the response is not timely enough, physical shortages may arise, defined here as a 24-hour black-out for the Randstad area.

We analyse three instruments aimed at rewarding (supra-normal) peak capacity for being available, rather than for its output alone. These policies aim to induce the formation of spare capacity that may be used in case of capacity shortages. In the system of *capacity markets*, the transmission system operator (TSO) requires traders to back their own peak load plus a prescribed level of spare capacity with contracted capacity, the latter being tradable at secondary markets. With *reserve contracts*, the TSO contracts spare capacity from producers, holding it to be dispatched in case of a crisis. *Capacity payments* are a subsidy on capital costs, giving producers an incentive to build more capacity.

These measures prove to be in efficient in preventing price spikes, as the welfare costs of price spikes are lower than the costs of the policy options, unless price spikes occur in an implausible high frequency.

Capacity payments cannot prevent black-outs, as they do not induce enough investments in spare capacity. Black-outs can be prevented by capacity markets and reserve contracts. The costs of a black-out are defined as the loss of production plus the loss of consumer welfare due

to the impossibility to engage in activities that require the use of electricity. The burden is born mainly by households and the services sector. Emergency services like police and hospitals are assumed to have adequate back-up facilities. A reliable assessment of the indirect and external effects of a blackout cannot be performed. Correspondingly, it is hard to predict the dynamic effects of a blackout. Empirical studies, both precise measurements and rough estimates, are limited to the direct costs of outages.

The break-even frequency for the cheapest of the options of preventing a black-out (capacity markets) is 4.10, implying that even if a 24-hour black-out of the Randstad area occurred every five years, it would be cheaper to accept the consequences of the black-out than to prevent it. If governments are risk averse, for instance because of the effect of a crisis on the reputation of politicians, or if societies as a whole are risk averse, the interpretation of the break-even frequency shifts in favour of the policy measures.

# 1 The issue of reliability in electricity markets

## 1.1 Setting the scene

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

The most striking event relating to a crisis in the electricity market is obviously the California-crisis in 2000 and 2001. Soaring wholesale prices, rolling blackouts and even more near-blackouts focus the world's attention on the vulnerability of electricity production. Recent outages in the US, Canada, England, Scandinavia, Greece and Italy (twice) have emphasized the importance of electricity for modern day society

The causes of these crises vary widely. The Californian crisis was caused by a combination of weather conditions and faulty design of regulations (see the box 'What went wrong with California's restructured electricity market?'). Technical problems were the major cause of the huge outage in the Northeast of the US and the Southeast of Canada in 2003. In that year, an unusually hot summer contributed to several electricity crises in Europe.

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

**What went wrong with California's restructured electricity market?**

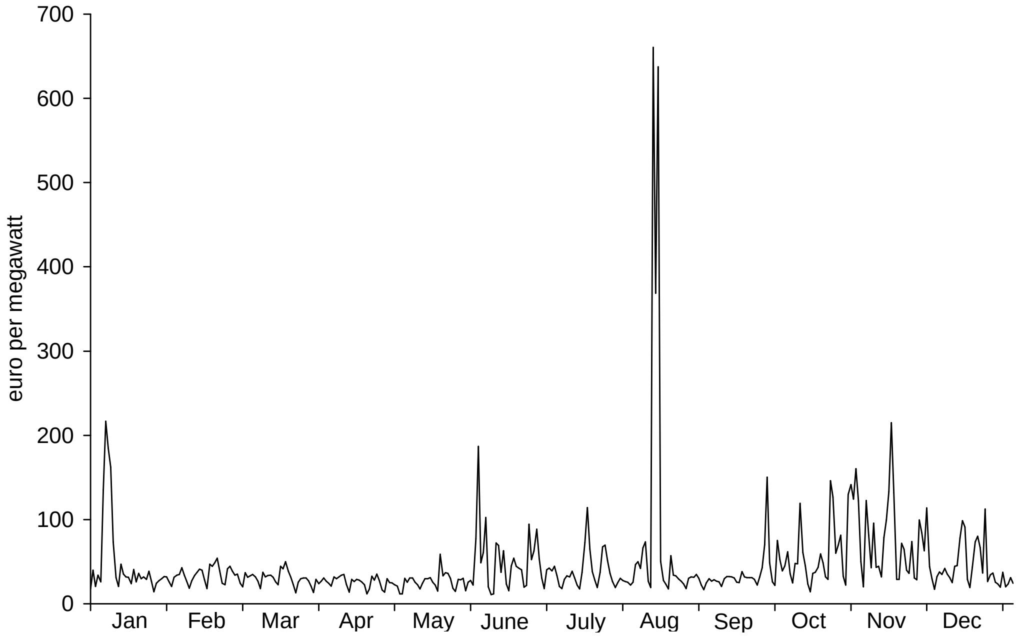
The electricity market in California was deregulated in 1998, after which wholesale trades were opened to competition, while retail prices remained to be regulated by the California utility regulator, CPUC. The market seemed to work well during the first two years. However, in May 2000 wholesale electricity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

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

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

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

**Figure 1.1 Daily baseload price on the Amsterdam Power Exchange in 2003 (in euro per megawatt hour)**




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

## 1.2 Assessment of future risks

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

It is yet unclear whether all Europe's national electricity markets are to open up, to what extent and at what speed.[1] A slowdown in opening up national markets is likely to hamper the formation of a single European market. The single market is needed to facilitate increased competition between producers from different countries, thus diminishing market concentration, which is currently fairly high at the national scale. As a reaction to European markets opening up, however, a process of mergers and take-overs seems to have started up among European electricity generators. Such a process would undoubtedly lead to higher concentration and thus

[1] See Speck et al. (2003) for an up-to-date overview.

hinder competition (Speck et al., 2003). The reaction of national and European competition authorities is mild for now, but may toughen as concentration increases further.

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

The other major risk facing the electricity market regards the level of the reserve capacity. The opening up of the European markets decreases the relative size of the necessary reserve capacity. It is, however, questionable whether private firms have sufficient incentives to invest in capacity which will hardly be used. Normal (e.g. daily) peaks may be met by generators with low fixed costs, but a supra-normal (say once-a-year) peak requires a very high price to guarantee cost recovery.

Incentives in a liberalised electricity market may be insufficient to make sure that capacity will always meet peak demand (Green, 2003; Oren, 2000). The major problem in this context is that generation capacity for supra-normal peaks is uncertain to be deployed and stands idle for so often, not generating revenues for its owner. This implies that it is not economically feasible, let alone profitable, to build these plants. A lack of sufficient supra peak capacity may lead to a crisis if demand suddenly surges, or if the availability of capacity is suddenly limited.

# 2 Framework of the analysis

## 2.1 Introduction

This chapter unfolds the theoretical framework for assessing the costs and benefits of increasing the reliability of electricity production. The framework comes from a larger project regarding the cost benefit analysis of security of supply policies. A more detailed description of the framework may be found in the main report from that project.[2]

The remainder of this chapter is organised as follows. Section 2.2 sheds some light on the main factors in assessing security of energy supply policies. The computation of the break-even frequency, the outcome of our analysis, is introduced in section 2.3, followed by a brief description of the five steps of the framework in the final section.

## 2.2 Uncertainty and market failure

Uncertainty and market failure are the two key components in appraising governmental actions in the field of security of energy supply.

The first component (uncertainty) tells us that the (expected) profitability of measures in this field depends on the (expected) occurrence of disturbance. A measure can be regarded as a security of supply measure if the occurrence of a disturbance is a necessary condition for profitability. This fact has two implications. The first one is that measures which are profitable without the occurrence of a disturbance do not belong to the category of security of supply measures. To illustrate this: an investment in strategic oil stocks is only efficient if the oil price will rise sometimes, while the encouragement of energy saving could be efficient without any change in energy prices, albeit a rising price would enhance the profitability of that measure. The second implication is that measures which do belong to the above category should always be assessed against the background of disruptions on the energy market at stake.

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

[2] De Joode et al., 2004.

## 2.3 Break-even frequency

Disruptions of energy supply come at low frequencies and high costs. This implies that, in order to assess the effects of policies aimed at different types of energy crises, we need to build scenarios around a fairly large number of possible crises, each of which has a small but unknown probability. The uncertainty obstructs the possibility of computing probabilistic outcomes. As an alternative, we compute 'if-then' outcomes. These outcomes are then used to compute 'break-even frequencies', the (decrease in a) expected frequency of a certain scenario at which net benefits are exactly zero.

Consider a policy option with annual cost C, aimed at preventing a crisis that would cause damage D if it occurred.[3] Suppose that the policy option is successful in preventing the crisis, so that the benefits of the policy equal the damage of the prevented crisis. In a normal cost-benefit analysis, we would multiply D by the expected frequency of the crisis and compare the annual costs to the expected prevented damage.

As the expected frequency of a crisis is unknown, we can not use this approach. As an alternative, we divide the annual costs by the damage of the crisis if it occurred. This yields the break even frequency, the frequency at which the costs of the policy option exactly equal the benefits. The break-even frequency will be higher if the costs of the project are higher: a policy with high cost 'needs' a higher expected frequency to be viable. If on the other hand the damage of a crisis is larger, a lower break-even frequency suffices to make the project viable.

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

[3] For the ease of interpretation we refrain from discounting costs and benefits in this explanation. Our analysis does take this in account however.

## 2.4 The five steps of the framework

The framework developed for the cost-benefit analysis in the field of security of supply consists of five steps:

### Definition of a crisis on an energy market

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

### Definition of a policy measure

In the next step, the appropriate policy measure has to be defined. Size and duration are the main attributes of this definition.

### Calculation of the costs of the measure in a disturbance-free scenario

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

### Calculation of the benefits of the measure in a crisis scenario

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

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

Both costs and benefits should be discounted, using the appropriate discount rate. The break-even frequency (BEF) is calculated by dividing the discounted average annual costs by the discounted benefit. This frequency expresses in how many years the defined disturbance should at least occur once in order to make the policy measure economically viable. If the BEF of the crisis is lower (higher) than the expected frequency, the welfare effects of the policy measure are negative (positive). If the BEF is smaller than one, the crisis should occur more than once a year or in a greater size once each year.

# 3 Definition of crisis and measures

## 3.1 Introduction

This chapter conducts the first two steps of our framework. We define a crisis in section 3.2, followed by an overview of three policy options in section 3.3. Dutch government also holds another option under consideration, called reliability contracts. This option will not be analysed here, as it has some aspects that are hard to analyse within our framework. We will however discuss the option qualitatively in section 3.4.

## 3.2 Definition of a crisis

In the analysis in this section, we simulate a crisis in the availability of capacity. To mimic the 'Dutch cooling water crisis', we bring down the availability of all fossil-fuel fired generating capacity (about 84% of total capacity) from 75% to 65%. Our next question would be what the implications of such a crisis might be. If the market[4] responds adequately, prices will spike during the crisis, causing large distribution effects, but small welfare effects. If capacity is insufficient and demand is unable to respond to price signals in a timely manner, a decrease in the availability of operational capacity may induce a system break down, causing blackouts. These blackouts will probably be regional by nature as the network operator disconnects certain groups or regions from the grid. These blackouts cause large or even very large welfare effects. We define this crisis here as a 24-hour blackout for the Randstad area.

## 3.3 Overview of policy options

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

- capacity markets;
- reserve contracts;
- capacity payments.

[4] 'The market' includes back-up options like variable capacity, the unbalance market and emergency import arrangements.

The first two aim at increasing spare capacity in electricity markets.[5] The third measure aims at increasing production capacity in general.

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

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

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

In a system of reserve contracts, the Transmission System Operator (TSO) buys operational reserves from producers, extracting these reserves from use for generating electricity for the regular market. Prices may be set by auctioning. The system operator can dispatch the spare

[5] We fit the amount of spare capacity to the crisis defined in this chapter. This does not inly any statement on the optimal level of spare capacity. See also the caveats of this research discussed in Chapter 7.

units in case of an emergency. The costs of keeping spare capacity are charged to consumers using the system fee. Like in the case of capacity markets, a spare-capacity requirement is set (now by the TSO), and an efficient pricing mechanism is used to make sure that spare capacity generates revenues. In this case however, the pricing mechanism is an auction rather than a market and the system operator is the one to buy the spare capacity

A system of capacity payments give generators a per megawatt payment for all capacity they hold available, regardless whether it is spare or dispatched. Systems such as this one are in place in Spain and several Latin American countries.[6] Note that payments are based on *total* capacity, rather than spare capacity. The payments work as a general subsidy on capacity, inducing a higher supply of generating capacity. Since capacity now needs a lower load factor to be profitable, construction of capacity for supra-normal peaks may become economically viable as well. Payments are collected as a charge, increasing electricity prices in all periods. Picking the level of capacity payments is a fairly arbitrary process. Loosely following Ford (1999), we choose a level that corresponds with an initial charge of 1 eurocent per kWh.

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

## 3.4 Reliability contracts

Reliability contracts are a financial rather than a physical instrument to secure supply: a contract consists of a financial call option combined with a (sufficiently high) penalty for non-delivery. In a system of reliability contracts, the TSO (acting on behalf of all consumers) buys call options that entitle the TSO to receive from the seller the (positive) difference between the strike price and the spot market price for all capacity defined in the option contract. This implies that the TSO will never pay more than the strike price for the contracted electricity, as any difference between the spot price and the strike price will be compensated by the seller of the option.

The seller on the other hand will never receive more than the strike price for its output, even if the spot market price would be much higher. Nevertheless, such a system may be interesting for electricity producers, because they receive a fee for the contract. This fee acts as a lump sum income, replacing the volatile and uncertain income that would have been generated by spot market prices levels above the strike price.

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

The system, described in more detail in Vázquez *et al.*, 2002, has some important advantages compared to the other systems described in this chapter. The most important advantage is that the system lowers revenue volatility for electricity producers. Selling a call-option as defined in this system lowers the producer's risk, as it stabilises a fraction of his revenues. This is especially important for supra-peak units. As we stated in section 3.2, these units are uncertain to be deployed and therefore uncertain to generate revenues, rendering it economically unviable to build them. Selling a call option on these plants would create stable revenues for this plant, thus reducing the risk associated to revenue volatility and making the plant a more attractive investment.

Furthermore, as risks are reduced, risk premiums in capital costs are likely to be reduced. This lowers costs of capacity, thus inducing a higher level of capacity investment. The reduction in capital costs, looked at in isolation, would not only increase supply security, it would also lower day-to-day electricity prices, as scarcity is reduced. There is one more advantage to be mentioned here. As the instrument is a financial instrument, there is no need to have power plants stand idle, waiting for a crisis to happen. Contracted plants may be in use all of the time, as long as a possible positive difference between the spot market price and the strike price is remunerated. This greatly reduces the costs of the option.

It is however not all roses here, reliability contracts also have drawbacks. A limitation on demand response is one of them. As the price of contracted electricity will not rise beyond the strike price, prices will no longer reflect scarcity and demand can no longer react to prices. This may sound futile for people who believe that electricity demand is inelastic, but one should be aware of the fact that very large users, such as aluminium smelters, postpone production during extreme price peaks, selling their contracted electricity on the spot market. If price spikes never occur this type of demand response will not occur either. There are ways around this however, such as incorporating large users in the system, so that demand responses like the one described here will become part of the system Nevertheless, one should keep in mind that demand responsiveness is an issue to take care of when implementing reliability contracts.

Another drawback lies in the procedure determining the call option fee. The TSO or the regulator determines the strike price, the penalty for non-delivery and the amount of options bought. The latter is based on expected demand and the desired level of security. Electricity producers then submit bids to the reliability auction. Each bid consists of an amount of quantity and the fee the producer wants for the option. These bids are placed in ascending order of fees and the lowest ones are selected until the predetermined amount of options is reached. The fee of the last accepted bid is then the fee paid to all producers.

To deliver security, the number of options should exceed expected demand, similar to the spare capacity in the cases of capacity markets and reserve contracts. This implies that the fee should be sufficiently high to compensate for the idle time of a plant that is rarely used. The same fee is paid for a contract relating to a plant that is fully utilised with all its output sold in long-term contracts.[7] For this plant, and all other plants than the one in the last accepted bid, the system generates windfall profits. The magnitude of these profits depends on the desired level of security.

In a perfectly competitive market, profits from reliability contracts may be recycled to consumers through lower per unit prices. The mechanism for lowering prices is clearly available, as all contracted capacity can offer its output at the spot market. The market for electricity production is however not a perfectly competitive market, so that profits may be retained by producers, creating both transfers and welfare effects.

A final drawback to be mentioned is the risk of regulatory failure. Reliability contracts require the regulator to set both price and quantity variables, whereas the other systems discussed here require the regulator to set either price (capacity payments) or quantity (reserve contracts, capacity markets) variables. Not only does this increase the probability of regulatory failure, it also limits the possibilities for the market to correct regulatory failure.

[7] This is an important difference with reserve contracts, in which fees are paid only to the plants that are kept in reserve.

# 4 A model of the electricity market

## 4.1 Introduction

This chapter lays out the formal model of the electricity market used to calculate many of the outcomes in chapter 5. The model distinguishes between two regions: the Netherlands and “other Western Europe”, the latter including Belgium, France, Germany, Luxemburg and Switzerland.

The remainder of this chapter is organised as follows. Section 4.2 describes how the model derives optimal capacity and output and how these are interlinked. It is a fairly technical section, but the main mechanisms of the model should be clear from the text for readers that want to skip the math. Section 4.3 briefly discusses how the crisis and policy options are taken into account by the model.

## 4.2 Optimal capacity and output

We use an approach similar to conjectural variations to account for mixed strategies. Following the theory of conjectural variations, any firm acts as if it faces residual demand, with the slope of its inverse described by $\frac{\partial p_{hl}}{\partial q_{hikl}}(1+r)$, where $r$ denotes the conjectural variation term. We assume that all reactions are symmetric. It can easily be checked that $r=0$ yields the Cournot outcome, whereas the Bertrand or competitive outcome is reached when $r=-1$. The values for the conjectural variation term are -0.9 for output and -0.8 for capacity, implying a fairly, but not totally competitive market.

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

$$p_{hl}^{L} = a_{hl}^{L} - b_{hl}^{L} q_{hl}^{L} \tag{4.1}$$

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

$$p_{l}^{S} = a_{l}^{S} - b_{l}^{S} q_{l}^{S} \tag{4.2}$$

where the average annual price is a weighted average of hourly prices. This implies that small users have a fixed load pattern in our model. We define $q_{hikl} \equiv q_{hikl}^{S} + q_{hikl}^{L}$ for notational ease. A producer maximises short run profits of its existing plants at every hour of the day:

$$\pi_{ikh} = \sum_{l} p_{hl} q_{hikl} -, \sum_{l} c(q_{hikl}, Q_{ik}) q_{hikl} - (C_{ik} Q_{ik}) / 24 \qquad (4.3)$$

where $C_{ik}Q_{ik}$ are fixed costs related to capacity and *c(.)* denotes the short run variable cost curve.[8] Its first derivative will be described in detail in the next section, for now we simply note that the level of capacity influences marginal costs. Note that we measure capacity in the same units as output (kWh), so that we can easily compare these figures. This implies that fixed cost parameter $C_{ik}$ is measured in €/kWh, implicitly assuming a constant overall utilisation rate. Optimal quantities are derived by differentiating short run profits with respect to $q_{hikl}$, which implies equating marginal costs to marginal revenues, yielding $h \times i \times k \times l$ first order conditions.

$$p_{hl} + (1 + r_{out}) \frac{\partial p_{hl}}{\partial q_{hikl}} q_{hikl} = \frac{\partial c(q_{hikl}, Q_{ik})}{\partial q_{hikl}} q_{hikl} + c(q_{hikl,} Q_{ik}) \qquad (4.4)$$

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

$$\Pi_{ik} = \sum_{h} \pi_{ikh} = \sum_{h} \sum_{l} p_{hl} q_{hikl} - \sum_{h} \sum_{l} c(q_{hikl}, Q_{ik}) q_{hikl} - C_{ik} Q_{ik} \qquad (4.5)$$

with all parameters defined before. Differentiating this equation with respect to $Q_{ik}$, yields a set of i×k first order conditions for long run profits. The next question is what the marginal revenue of an extra unit of capacity is. Investments in additional units of capacity will only generate revenues if capacity restrictions are binding. If this is the case, more capacity will facilitate more output, and thus earn revenues. If capacity is a binding restriction however, it is unlikely to be binding at every hour of the year. So how do we determine marginal revenues of capacity investments?

Hours of the day are ordered based on the load, so that the hour with the highest load is indexed 1, Now define $H_l$, such that $\sum_{l} q_{hikl} = Q_{ik}$ for all $h \leq H$. This requires us to appoint capacity to demand regions, implying that we differentiate the profit function by $Q_{ikl}$ rather than $Q_{ik}$. Appointing capacity to demand regions is artificial, because there is no technical need to divide these capacities: they may actually belong to the same plant. For each hour $h < H_l$, the marginal revenue of an increase in capacity equals the marginal revenue of an increase in output, albeit that we allow conjectural variation term to differ between output and capacity. We may now rewrite the first order condition for capacity:

[8] We denote capacity related variables by upper case letters, whereas lower case letters are used for output-related variables.

$$\sum_{l}\sum_{h=1}^{H_l} p_{hl} + \left(1 + r_{cap}\right)\frac{\partial p_{hl}}{\partial q_{hikl}} Q_{ikl} = \sum_{h}\sum_{l}\frac{\partial c\left(q_{hikl}, Q_{ik}\right)}{\partial Q_{ik}} q_{hikl} + C_{ik} \tag{4.6}$$

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

The first order conditions of the long run and the short run model have a similar structure. Combining the FOC's and solving them for $q_{hikl}$ and $Q_{ikl}$ yields optimal capacities and outputs.[9] The commodity price of electricity for region $l$ at hour $h$ can now be determined by substituting the summation of optimal $q_{hikl}$ over $k$ and $i$ into the inverse demand equation.

## 4.3 Crisis and policy measures, the main mechanisms

In this section, we devote out attention to the question how each of the policy options brings about a higher level of supply security. Before we do so, we turn to the mechanism that drives the crisis, as defined earlier.

We have defined the crisis as a (sudden and unexpected) limitation in the availability of capacity. This affects market outcomes in two ways. First, it has an effect on marginal costs, as the limited availability of plants urges the use of more expensive plants, since plants are dispatched in ascending order of marginal costs (note that *c(.)* in equation 4.3 is a function of output *and* capacity). A limitation in the availability of capacity therefore increases marginal costs. Second, output is limited by the level of capacity for at least part of the day. If the availability of capacity decreases output decreases as well, causing prices to rise.

*Capacity payments* effectively decrease capital cost for producers, making it more attractive to invest in capacity, as implied by equation 4.6 in the previous section. The increase in capacity lowers prices because of reduced scarcity, causing demand to grow. The increased user fee to finance capacity payments reduces demand however. *Capacity markets* work in the opposite direction. Requiring producers to hold (or contract) spare capacity induces scarcity at peak times, simultaneously suppressing demand and increasing the profitability of new capacity investments, as capacity becomes binding for more periods ($H$ increases in model terms).

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

*Reserve contracts* do not change market outcomes by themselves, as the spare capacity is contracted outside the electricity market itself. The increased user fee to finance spare capacity does reduce demand however.

# 5 Costs, benefits and break-even frequency

## 5.1 Introduction

In this chapter we conduct the third, fourth and fifth step of the framework. Section 5.2 lists the costs of the policy options considered here. The benefits in case of a crisis are presented in section 0, followed by the computation and interpretation of the break-even frequency in section 5.4. We conclude this chapter with a section reporting the results of the sensitivity analysis.

## 5.2 Costs of policy options

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

#### Direct costs

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

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

Note the difference between these options with respect to foreign and domestic producers. In the case of capacity markets, all suppliers of electricity are obliged to hold or contract spare capacity. Foreign suppliers (or producers, the difference is not important here), will bear the costs of 'their' part of this spare capacity (23 million euro per annum), no matter whether they hold the spare capacity themselves, or contract it in the Netherlands.[10] In the case of reserve contracts, all spare capacity is assumed to be located and contracted in the Netherlands. Note that end users pay the costs for the spare capacity through a fee levied by the TSO.

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

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

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

Each of the systems described here incurs welfare effects as it has effects on electricity market outcomes. Prices of electricity rise in any of the alternatives[11]. The system fee is raised in the cases of capacity payments and reserve contracts. Furthermore, if capacity payments indeed trigger capacity investments, peak prices may decrease as well, because of reduced scarcity. These price effects affect welfare through demand reactions. We use our model of the European electricity market to quantify these effects (see Chapter 4 for a description of the model).

The welfare effects mainly consist of transfers from end-users to producers. In the case of capacity markets, transfers are rather limited, as price increases are induced by scarcity rather than a fee. This generates an annual transfer of 31 million euro, of which 6 million euro to foreign producers. From a national point of view, the latter are welfare losses as well. Transfers are larger in the case of reserve contracts, as the transfers include the increase in the system fee. Note that the increased system fee is partly compensated by producers, bringing down net revenues from foreign producers, leading to a small net welfare gain of these transfers. The system of capacity payments causes the largest transfers, shifting an annual 489 million euro from end users to domestic (400 million) and foreign (89 million) producers.[12]

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

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

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

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

Keeping in mind that the annual costs of the energy regulator amount to 7 million euro and the annual transaction costs of the Dutch spot market (APX) are roughly 5 million euro[13], we roughly estimate transaction costs to amount to 7 million euro per year for the case of capacity markets and of 3 million euro per year for each of the other options.

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

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

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

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

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

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

[13] Source: information of the Dutch electricity regulator.

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

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

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

**Indirect costs**

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

**External costs**

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

## 5.3 Benefits policy options

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

**Direct benefits**

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

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

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

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

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

If capacity is insufficient and demand is unable to respond to price signals in a timely manner, a decrease in the availability of operational capacity may induce a system break down, causing blackouts. These blackouts will probably be regional by nature. Bijvoet *et al.* (2003) have conducted a thorough assessment of the costs of potential blackouts. One of their key findings is that a blackout on a weekday in the Randstad area costs about 72 million euro per hour in daytime and 38 million euro in the evening.[14] This implies that a 24-hour blackout in that region would cost roughly 1.2 billion euro (600 million if discounted to the mid-year of the period in our analysis). All costs are born by end-users.

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

**Indirect benefits**

Like in the case of costs, indirect effects result from price effects in the electricity market and again we use Athena to assess these effects. The indirect effects are larger relative to the direct effect, since a sudden shock causes friction costs. The indirect effect of the crisis is assessed to be 2.5 million euro. As capacity markets and reserve contracts entirely prevent the crisis, these are all benefits. In the case of capacity payments, the benefits are 1.4 million euro, as the crisis is dampened rather than prevented. The distribution of benefits over branches in the economy is fairly even. Energy production sectors and households benefit somewhat more than manufacturing and services sectors.[15]

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

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

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

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

**Benefits: external effects**

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

## 5.4 Break-even frequency

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

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

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

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

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

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

**Table 5.7 Costs and benefits op the policy options in the case of a large blackout (discounted value in million euro)**

| | Capacity markets | Reserve contracts | Capacity payments |
|---|---|---|---|
| **Average annual costs** | | | |
| Direct effects | 145 | 129 | 105 |
| Indirect effects | 3 | 45 | 37 |
| External effects | 0 | 0 | 0 |
| Total average annual costs | 148 | 174 | 142 |
| **Total benefits in case of one crisis** | | | |
| Direct effects | 605 | 605 | - |
| Indirect effects | pm | pm | - |
| External effects | pm | pm | - |
| Total benefits | 605 | 605 | - |
| **Break-even frequency** | | | |
| Once every … years | 4.10 | 3.49 | - |

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

## 5.5 Sensitivity analysis

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

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

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

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

# 6 Concluding remarks

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

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

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

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