Sosyo Ekonomi

Özel Sayı 2010-EN

Electricity Market Design for Germany

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Almanya için Elektrik Piyasası Tasarımı

Abstract

Germany has two ambitious goals: It wants to generate 20% of its electricity from renewable sources by 2020; and it wants to reach its nuclear phase-out target by 2021, according to the Atomic Energy Law of 2002. To be successful, it needs a strong transmission network that connects the offshore wind parks at the North and Baltic Sea with regions of high population and industry densities. At the same time it has to be keeping its generation capacity at a high enough level. This paper describes recent reforms in the electricity sector and makes suggestions on how to improve the current state of market performance in the industry.

Key Words : Market Structure, Industrial Policy, Electric Utilities, Energy.

JEL Classification Codes : L11, L52, L94, Q41.

Özet

Almanya'nın iki iddialı hedefi bulunmaktadır: 2020'ye kadar elektriğinin %20'sini yenilenebilir kaynaklardan sağlamak ve 2002 Atomik Enerji Kanunu'na bağlı olarak nükleer hedefine tedricen 2021'e kadar ulaşmak. Başarılı olabilmesi için Kuzey ve Baltık Denizi kıyısındaki rüzgâr sahalarını nüfusun çok ve endüstrinin yoğun olduğu bölgelere bağlayan güçlü bir iletim şebekesine ihtiyacı vardır. Aynı zamanda üretim kapasitesini yeterince yüksek bir seviyede tutması gerekmektedir. Bu çalışma son zamanlarda elektrik sektöründe yapılan reformları anlatmakta ve endüstrideki mevcut piyasa performansının nasıl iyileştirilebileceğine dair önerilerde bulunmaktadır.

Anahtar Sözcükler : Piyasa Yapısı, Endüstriyel Politika, Elektrik Kolaylıkları, Enerji.

Acknowledgement

Financial support from the Deutsche Forschungsgemeinschaft through SFB/TR 15 is gratefully acknowledged. Sebastian Scholz gratefully acknowledges the hospitality of the *Electricity Policy Research Group* in Cambridge, where parts of this paper were developed. He thanks Tooraj Jamasb, Karsten Neuhoff and David Newbery for stimulating discussions. The usual disclaimer applies.

Beyan

SFB/TR 15 vasıtasıyla Deutsche Forschungsgemeinschaft kurumundan sağlanan mali destek için minnettar olduğumuzu belirtmek isteriz. Sebastian Scholz, bu makalenin bir kısmının geliştirildiği Cambridge'teki *Elektrik Politikası Araştırma Grubu*nun gösterdiği misafirperverliği de minnetle anmaktadır. Ufuk açıcı müzakereleri için Tooraj Jamasb, Karsten Neuhoff ve David Newbery'ye teşekkür ederiz. Her zaman olduğu gibi mevcut hatalar yazarlara aittir.

1. Introduction

The European Commission opened a formal investigation of the German energy producer E.ON and French Gaz de France in July 2007, for allegedly agreeing to keep out of one another's home market, thereby thwarting competition and keeping prices artificially high. To avoid the costs of litigation and possible penalty payments, E.ON proposed to commit to sell its electricity transmission system, furthermore it committed to divest 4800MW of generation capacity to competitors in February 2008. Thereupon the European Commission closed the antitrust case against E.ON in November 2008 by formally accepting the German energy producer's commitment to sell a fifth of its power generation capacity, along with its extra high voltage distribution network. Vattenfall, who owns a transmission network of length 9,500 km, which is smaller than E.ON's 10,600km network, also wants to sell. RWE and EnBW want to keep their networks. Here, the term "network" refers to the high-voltage transmission networks, and not the distribution network that connects the final consumers to the transmission network. The timing for ownership unbundling of the transmission network in Germany is inopportune, because the infrastructure changes that are needed for the integration of offshore wind parks are immense.

This paper comments on possible future liberalization attempts of the German electricity market. We do not believe that the ownership unbundling of the transmission network will in fact increase competition.

The German generation oligopoly holds shares of many public German utilities (Stadtwerke). The liquidity of the electricity exchange (EEX) in Leipzig is small; only about 10-15% of total electricity sold in Germany goes through it. The EEX uses a uniform price auction in its spot market for day-ahead and intraday trade and a future/ option market. 85-90% of total German electricity is sold in bilateral so-called over-the-counter (OTC) contracts. These contracts are based on bilateral relations and not on economic efficiencies. Due to commercial confidentiality neither price nor quality information is revealed (WIK 2008).

The four market leaders in the power market own shares of many Stadtwerke. Hence it is not surprising that OTC contracts are so common. Legally, it would be very difficult to force generators to sell their shares of public utilities. An increase in retail competition would force utilities to contract more efficiently if they do not want to go bankrupt. 37% or 15 million households have switched their electricity contract with their old supplier, only 10% of 4 million households moved to a different retailer since the liberalization was implemented in 1999. The number has been increasing since 1999 (Rommel and Meyerhoff, 2009). Increasing the amount of electricity sold on the EEX increased market power, as shown by Müsgens (2006), whose model is described in more detail below.

A new market design that affects all parts of the electricity market, generation, transmission and distribution, is needed. This market design has to take account of many issues and we still want contracts to play an important role in it. Joskow (2001) for example shows that the advantage of trading most of the electricity volume on a contract market, and only a small fraction on a spot market, is reduced volatility. These contracts should however be in the form of either derivatives or options, and not OTC contracts, in order to guarantee efficiency. The market power of the oligopoly RWE, E.ON, Vattenfall and EnBW would decrease through entry. A higher return on new capacity, which is necessary to induce entry, would eventually pay off through lower prices in the long run. New generation capacity could be privileged in a capacity market, as we show in part four of this paper.

An increase in generation capacity would also reduce the risk of power failures. The nuclear phase-out is based on the Atomic Energy Law of 2002, which prohibits the construction of new nuclear power plants and requires the average maturity of existing plants to decrease to 32 years. Two plants were taken off the grid before 2005; four other plants will be shut down by the end of 2009. Studies such as the UCTE (2007) and the DENA (2008) suggest that there will be inadequate capacity from 2015 and 2014 respectively, due to the nuclear phase-out by 2021 and the fact that many plants are ageing. New gas and coal generation plants face fierce public opposition, which delays the issuing of building permits. The building of new onshore wind power plants has come to a halt, because there are not any more suitable sites available. The development and construction of offshore wind power plants is increasing rapidly, but a shortfall of transmission capacity from the German coast in the North to the South slows development. Approximately 400 km of the existing 380 kV grid has to be upgraded; approximately 850 km new construction is needed (DENA, 2005).

This paper is structured as follows. First, we argue that separation of generators and the transmission network is not necessary. If we want to increase competition, then we urgently need other reforms. The separation of generation and the network would take many years, during which time more important reforms would not be carried out. In Part 2 we show why we believe that ownership unbundling does not increase market efficiency. Part 3 shows why a first best competitive electricity market is impossible for either a separate or vertically integrated structure of generation and transmission. After discussing different models that have been proposed in a large literature in Part 4, in Part 5 we suggest a market design that takes care of Germany’s two problems: market concentration on the generation market; and possible capacity shortages. Part 6 concludes.

2. Ownership Unbundling

Pollitt (2008) describes five different models of transmission ownership unbundling;

1. The independent transmission system operator (TSO), e.g. National Grid in the UK. It is completely unbundled from the rest of the system and owns and operates transmission assets.
2. The legally unbundled TSO, a form that is present in Germany and France. The network is legally unbundled from the rest of system and owns and operates transmission assets. It meets the requirements of the current EU Directives and can achieve effective separation of transmission operation from the rest of the sector, while transmission assets remain under the same ownership as generation/ production or retail.
3. The independent system operator (ISO), e.g. PJM in the US and Scottish electricity in the UK. Here the system operator does not own the transmission assets but is ownership-unbundled from the rest of the system.
4. There is a hybrid model where both the ISO and the transmission owner are ownership-unbundled from the rest of the system. The ISO is assetlight, while the transmission owner has no system operation function. This is the case in the electricity supply systems in Chile and Argentina.
5. The vertically integrated utility, e.g. traditional utilities in Europe. This is the model that Europe has sought to move away from in successive directives; however, it is still in de facto operation in many European gas markets and some European electricity markets.

The European Commission has tried to move from a legal unbundling to an ownership-unbundling of the electricity transmission network. There are two proposals. One can sell the transmission network to a third party (model 1). Besides venture capitalists that are claimed to have a low incentive to invest into the grid's infrastructure, only National Grid, the British grid operator, would come into consideration. A grid operator has a better investment incentive, because the connection of two formerly separate regions and the trade which would become possible through the connection would be more beneficial, when the operator owns the networks in both countries.

Secondly, the EU has suggested handing the network over to an Independent System Operator (ISO), who independently decides on new network investments. This would reflect the third model. Owners would still receive dividends but do not influence the operational part of the business.

Germany, France and other EU member states want to retain the second model and so rejected the Commission's proposal: They suggested a strict separation of the transmission and generation parts. They would have separate managements that have not worked for the parent company for the last three years, under a strict regulatory control of a Transmission System Operator (TSO), while ownership still remains with the incumbents. The network company has to submit 10-year investments plans. The synergy loss of not having a management that understands both: generation and transmission is probably worth incurring. Social relationships might have the effect that own generating units are privileged over those of the entrants'.

In what follows we examine the theoretical benefits and disadvantages of ownership unbundling. We shall keep in mind that this study emphasises the move from legal unbundling to ownership unbundling, as opposed to the move from a fully integrated utility to a non-integrated one. We fully agree that the legal unbundling of transmission networks is necessary to allow competition on the generation market. But we doubt that ownership unbundling is meaningful for a competitive effect on the German market.

We divide our arguments into four categories: the cost effect; the competition effect; economies of scope effect; and investment incentives. We conclude with a brief outlook on what the industry structure could look like in the future.

2.1. Cost Effects

2.1.1. Costs of the Transformation

Pollitt (2008) notes that the costs of ownership unbundling depend on the timing. They are potentially smaller at the time of an initial reform. "This is because there are fixed cost elements (not least in political time) to restructuring of assets, the establishment of regulatory structures and the introduction of competition. Therefore, unbundling is likely to be cheaper when other restructurings are taking place and/ or when initial ownership structures are cheaper to change". Generation, transmission, and distribution of electricity are highly interdependent. Storing power is costly, hence power production must take place the instant it is consumed. Failure of generation to meet demand results in blackouts. The demand for electricity has both random effects and predictable demand characteristics. Distribution lines must physically reach users, and transmission lines must cover the distance between distribution and generation. For reliability, some generators must be close to consumers while for economical production others may be more distant. Investment in generation and transmission is a long and costly process, and, once in place, the equipment cannot be cheaply redeployed to some other location or use. The transaction costs of unbundling are likely to increase if new computer systems are needed to coordinate the network with completely disintegrated components.

2.1.2. Cost Savings

Cost reductions from an increase of competition are unlikely to be as significant as in the UK. Newbery and Pollitt (1997) show how reforms triggered investments in alternative technologies (gas-fuelled CCGT) and improved efficiency rates of existing power plants. We need to isolate the effects of ownership unbundling from reforms that have already taken place in Germany as the first liberalization phase started in 1998. Furthermore, the reunification of East and West Germany has already been followed by a modernization of the electricity sector (Brunekreeft and Keller, 2000).

2.1.3. Cost of capital

In the presence of the credit crunch that we have experienced since 2008, we must keep in mind that the power supply industry is one of the most capital intensive of all industries. This holds for the transmission network and generation capacity investments equally. While the former has constant returns, the latter has generally quite volatile profit streams, depending on varying input costs for construction and production. In a recent case study Finon and Roques (2008) discuss the risks of building a nuclear power plant and how they can be mitigated. The returns on capital have to be higher in the presence of a higher bankruptcy risk. Ownership unbundling creates firms with a risky portfolio. Cross-subsidies from the transmission network to unprofitable power plants become impossible. Furthermore generating companies are not allowed to use the transmission network as collateral for financing loans to build new capacity. As a result the optimal mixture of generation technologies (peak load and base load) is not achieved. Capital intensive power plants are replaced by power plants with lower fixed costs and high variable costs. Less installed capacity reduces competition and lead to higher prices as pointed out by Kreps and Sheinkman (1983). Tönjes (2005) and Mulder and Shestalova (2006) mention other issues regarding capital costs based on the Dutch market, where ownership unbundling was implemented in 2008.

2.2. Competition Effects

The European Commission argues that ease of entry of third-party generators increases the total installed capacity, because incumbents reduce their capacity by less than the added capacity. The German regulator of the transmission networks is under the jurisdiction of the Bundesnetzagentur, an independent higher federal authority at the Ministry of Economics and Technology. According to the Bundesnetzagentur non-price discrimination against entrants by delaying connection of their power plants to the network is prohibited. Even though new generators can easily enter the market, incumbents that own the network have one decisive advantage; they can guarantee supply to major corporate clients connected to the transmission network, during non-price rationing periods, by disconnecting other parts of their network.

Tacit agreements of this kind cannot be prevented by the regulatory authority, because it is in both party's interest to have an agreement of this kind. An industrial client (IC) in the steel industry for instance faces extremely high costs from long-lasting power interruptions. Tacit agreements of this kind cause an inefficiency problem and a negative externality: first, incumbents that own networks hold a monopoly in these services and cause a deadweight loss. Secondly, a pool of small consumers (SC) that is connected to the same network suffers under more frequent power supply rationing for which they are not compensated.

It is difficult to find a solution to this problem; ownership unbundling alone solves only the second problem. The service, which can only be provided by an integrated supplier, disappears together with the consumer and producer rents that are associated with it. A welfare enhancing theoretical solution to this problem is a compensation payment from the IC to the SC. The network operator could then be instructed to favor the IC during non-price rationing periods. Realistically, solving the problem is difficult; the costs of a power blackout, also called the value of lost load (VOLL) is different for each individual of the SC, the compensation is therefore hardly possible, because technically, individual rationing is impossible. Therefore the SC would have to agree on the same compensation and rationing probability for each individual (Joskow and Tirole, 2007). An IC is a major employer within the region; so that a large portion of SC might even accept the consequences of tacit contracts between the incumbent generator and the IC.

Selling the network would open the opportunity for further horizontal mergers, because it sets financial resources free. A further horizontal concentration would be very harmful for the German market, where already 80% of generation is controlled by 4 firms E.ON, RWE, Vattenfall and EnBW. E.ON market share alone is 34%.

A common view in favor of complete vertical separation is that the respective firm would in this way not be able to shift costs from the generation business to the transmission business.

But shifting costs to the network is only possible if the network is regulated using some kind of cost-plus allowance. Improved cost transparencies in network businesses will most likely not be needed when the network is regulated by the incentive regulation introduced in the beginning of 2009.

2.3. Economies of Scope

Pollitt (2007) points out that "the coincident timing of several reform steps makes it difficult to find econometric evidence capable of directly testing the effect of ownership unbundling. In particular, ownership unbundling of transmission networks may occur at the same time as privatization, the restructuring of generation or production markets, [and] the introduction of incentive regulation." In an empirical study Kwoka (2002) examines existing electric utilities in the United States, where he makes use of the advantage that utilities span the spectrum from pure distribution to complete integration of generation and distribution. He names the most important areas of cost savings to be

- Least-cost dispatch or deployment of generating units in order to achieve system minimum cost.
- Coordination of scheduled shutdowns for maintenance.
- Better information about downstream load for purposes of determining future capacity requirements.
- Conservation of reserves by supplying consumption points with diverse load patterns.
- Joint decisions regarding plant size / siting and transmission systems- for example, between a large but distant generator versus smaller generators closer to consumption points.

His data set used comprises 147 investor-owned utilities from 1989. The sample includes all the major utilities, accounting for 70 percent of revenues from all utilities. He estimates a cost function that connects the different degrees of vertical integration to differences in costs. Assume that the joint production costs $C(\cdot)$ of two products generation G and distribution D are less than the costs of separately producing each one:

$$C(G, D) < C(G, 0) + C(0, D).$$

After controlling for unique features of this industry, he finds statistically significant and quantitatively substantial efficiencies for integrated utilities relative to standalone operation. The cost penalties of standalone operation rise from a modest 3 percent for a combination of 5 million MW/h of both generation and distribution to an estimated 57 percent for combinations 25 MW/h million each. His findings cast some doubt on regulatory plans to strictly separate the transmission network from generation. Michaels (2006) gives a nice summary of eleven empirical studies that examine the effect of vertical integration, 9 studies use US data, 2 Japanese data. Unfortunately however, the studies do not distinguish between ownership and legal unbundling. It is probably too difficult to collect reasonable data on this issue, since the time span is not long enough. In most European countries legal unbundling has taken place just recently, with an exception of the UK. In addition it would be hard to find the difference between legal and ownership unbundling in the data, because the differences are too small.

2.4. Network Investment Incentives - Security of Supply

An integrated network firm invests more in its network reliability than a separated network firm as this improves the integrated firm's opportunities for commercial activities. This incentive is still present in the case of legal unbundling, but less in the case of ownership unbundling. Buehler et al. (2004) introduced a model of quality improvements of the upstream network to the literature. Under vertical separation, the upstream firm (the transmission network) decides on the quality of its service and sells the right to use the network to a downstream firm that provides the final product. The downstream firm, in turn, pays an access price which is determined according to the rules specified by the regulatory regime, but is independent of network quality.

Cremer et al. (2006) study the difference between legal and ownership unbundling with a similar setup and similar results: The upstream firm will not take into account the interests of its clients when choosing its size, because the investment in the network is not protected by a contract at the time at which it is made. This effect can be mitigated by allowing it to own parts of the downstream industry. In other words, ownership separation is more detrimental to welfare than legal unbundling. Their main results are as follows. First, with linear access prices incentives to invest are generally smaller under vertical separation than under integration. This is partly due to the familiar vertical externality argument that a separated upstream monopolist ignores the positive effect on downstream profits. The result is non-trivial, however, because the move from separation to integration also affects retail prices, which generates subtle demand effects that may work against the standard argument. Secondly, introducing downstream competition has ambiguous effects on quality. Thirdly, with non-linear access price investment incentives are the same as in the integrated case, if the network owner can set the fixed components so as to fully extract the downstream profit.

Steiner (2001) examines the impact of restructuring on the utilization rate of electricity generation plants in OECD countries using a panel data set for the period 1986-1996. Her main findings are that vertical disintegration did not reduce the prices, but increased the utilization rate.

The European Commission argues[1] that vertically integrated utilities have limited interest in investing in interconnector capacity of transmission networks. Opening their own market would reduce their market power though possible imports. These arguments have three convincing drawbacks. If an integrated utility has too little generation capacity, then it does have an interest to increase interconnector capacity to be able to purchase electricity from outside regions. A utility with excess capacity also has an

[1] *This paragraph draws on Brunekreeft (2008).*

incentive to invest in inter-transmission networks. An increase in exports of electricity can reduce competition within that region, and hence welfare.

Generally one should note that it is difficult to increase the existing electricity network in Germany, but the government is working on legislation to speed up the procedure in the future. Without its implementation, the effect of ownership unbundling of the transmission network would simply have a very small effect, because the network would not be extended.

Meyer (2008) provides a useful survey of the literature on measuring the ownership unbundling of the network from a top-down approach. A top-down approach suggests 5% of total sectoral costs, but only a small fraction of this amount is relevant, because the functional unbundling has already taken place and we would just move from the functional unbundling to a full ownership unbundling. Unbundling leads to better horizontal coordination of border transmission networks. The savings are assumed to be small though. On the other hand, the coordination of investments in networks and power plants would be flawed and lead to additional capital costs. There is a coordination problem considering investments in transmission lines either between a load node and two power plants (option 1) or between the power plants and between one load node and the power stations (option 2). The costs of the two options depend on how much power is generated by each plant separately. The investment decision will be weakly less efficient after unbundling due to a coordination problem (Baldick and Kahn, 1993). Brunekreeft (2008) conducts a social cost benefit analysis of ownership unbundling of the German TSOs and finds that the benefits of ownership unbundling are somewhere between 162-313 million € annually over the period 2010-2030, which is small compared to the size of the market. Producers lose more than consumers gain. Isolating the effect on consumers, whose welfare has been seen to be more important to the European Commission in the past, suggests that the gain is 1.8 billion € or 22€ per person per year.

2.5. Industry Structure and Future Outlook

Foreign takeovers are more likely when the number of players is increased. This might not be a problem when competition policy could disallow unwanted mergers but allow efficiency improving ones. The past has shown though that the German electricity lobby is quite strong and the ministry of economic affairs has allowed mergers against the directive of the German competition bureau.

Government interventions would most likely increase at least in case the network is kept under public ownership. We should certainly not assume public interventions to reduce even if the transmission network would be sold to a private investor.

The German federal authority “Bundesnetzagentur” would still have to ensure that the network operator does not extract monopoly rents as the high voltage network will always remain a natural monopoly.

We do not believe that ownership unbundling would have negative welfare effects. It will not increase competition though entering of new generation capacity nor decrease costs. Entry barriers have already been low after the functional unbundling. The reasons why we have not experienced entry in the power generation sector are of a different nature and will be discussed next. It is important to evaluate the electricity market as a whole though. The literature of the past 20 years has followed the influential publication of Joskow and Schmalensee (1986), who claimed that the three sectors generation, transmission and distribution have to be analyzed separately, who claim that only the second is a national monopoly. When we want to find a market design that is applicable for all three sectors, then we might come to different conclusions than when we just look are them separately. Finally, we claim that even though an ownership unbundling is not the preferred solution after an isolated analysis it might be good for the electricity sector as a whole.

3. Why Is A First Best Solution Not Feasible?

The supply and demand of electricity has to be in balance at all times. Storage is extremely expensive. Besides these technical difficulties, we next examine other problematic issues that have to be kept in mind when trying to find an appropriate market design for the German electricity market. These are demand side flaws, public good attributes of reliability, and uncertainty. Furthermore we discuss the problems that have arisen through regulatory interventions since the liberalization restructuring began.

3.1. Demand Side Flaws

The lack of real pricing of electricity and the technical impossibility of physically cutting off individual customers are the main problems that regulators are faced with since the liberalization.

Joskow and Tirole (2006) show that when consumers have real time meters and are billed on the basis of real time prices and consumption, retail competition yields the Ramsey prices even when consumers can only partially respond to variations in real time prices due to transmission costs for monitoring. On the other hand, in the case of retail consumers that are on traditional meters, which measure their aggregate consumption over relatively long time periods, neither the load service entity (LSE) nor retail consumers face the real time wholesale prices associated with the power they consume from the system. Finally, when the system operator is physically unable to cut off individual customer loads, and instead must ration on a zonal basis, individual retail customers cannot obtain their preferred priority for rationing by the system operator. Consider that it might be efficient to cut off power if the value of lost load (VOLL) is smaller than the price that the customer is willing to pay. If the system operator knows the VOLL on average in different zones, then he can cut off the one with the lower VOLL and achieve a second best solution. In the presence of retail competition, retailers have the incentive to misreport their consumers' demand for non-interruptibility, because they would prefer to free ride on the other LSE serving consumers in the same zone.

Borenstein and Holland (2007) show that welfare, both of consumers that are price-sensitive and of those that are not, increases. The more people have real time meters (RTM), the lower the equilibrium flat rate. The total cost of the system is reduced considerable during peak times, when only a small proportion of consumers have smart meters. They use data from the Californian Independent System Operator for the period between November 1998 and October 2000 and show that "with an elasticity of 0.1, putting a third of customers on RTM would cut the number of peakers by about 44% and the total installed capacity by more than 10%."

A smart grid would reduce costs enormously. The Economist (2009) recently wrote that black-out costs in America are estimated to be $80 billion a year, according to a study by the Lawrence Berkeley National Library. It has been found that people reduce their power use by about 7%, when they are aware of how much power they are using. With added incentives, people curtail their use of electricity during peaks in demand by 15%. RTM would make it a lot easier to balance supply and demand, when peak demand reduces. America's Pacific Northwest National Library (PNNL) found that there is already enough power capacity installed in the US to replace 73% of America's conventional fleet with electric vehicles if the charging is carefully managed during off-peak periods. A smart meter costs about $125 and several hundred US-dollars more to install if it has a communication device from which customers can read off the real time price. Power companies are reluctant to invest in a technology that reduces the demand for their product. It also reduces costs though; an example is Italy, where Enel its main utility has installed 30 million smart meters. It is the pioneer with 40% of worldwide installed meters. Its spending of about €2.1 million has reduced costs by about €500 million a year.

If the demand side flaws could be fixed, the demand curve would become elastic, market power would be reduced and the market design becomes simple. In the past, regulators intervened to reduce these market flaws and cause capacity shortages. A well- known example is provided by the power shortages in California following its market liberalization (Borenstein, 2000).

3.2. Public Good Attributes

Ockenfels et al. (2008) describe the public good attributes of reliability or excess capacity as that no one can be excluded from it and the benefit from investments cannot be internalised efficiently. Moreover, providers cannot benefit from prevailing extreme scarcity in the event of a blackout on account of a lack of generation. Typically, a market price does not exist or is not paid during blackouts, because during the spot market auction, there is an excess supply and an excess demand in the spot market auction - at least if all further efforts at clearing the market fail.

3.3. Uncertainty

Short run uncertainty on the demand side is caused though varying weather conditions. Long run uncertainty is due to changing demand patterns as substitute fuels that affect the oil price and hence the variable costs of a power plant. The replacement of equipment through more efficient types reduces demand, while possible increase in sales of electric powered cars would increase demand. This depends on potential government subsidies and the technological innovation in this field however. Unknown investment perspectives, the uncertainty about future electricity prices, fuel prices, and entry of new generation capacity also increase the risk and the capital costs of building new capacity. The environment can change quickly through regulatory interventions. Brunekreeft and McDaniel (2005) show that the perceived thread of regulatory intervention curbs scarcity rents and inhibits investment, which raises average prices and reduces security.

3.4. Problems Caused by the Liberalization

3.4.1. The Retail Market: Lack of Reliable Long Term Contracts

Forward contracting reduces spot prices, because the incentive to set a high spot price decreases since it affects only a portion of total production. The incentive to increase production on the spot market must therefore increase (Allaz and Villa, 1993). Neuhoff and De Vries (2004) show that when consumers and investors are risk averse, investment is efficient only if investors in generating capacity can sign long-term contracts with consumers. This is not possible in markets that have retail competition. The uncovered price risk increases financing costs, reduces equilibrium investment levels and distorts technology choice towards less capital-intensive generation. There is a lack of reliable retailers due to bankruptcy risk. When the spot price decreases to levels below the contracted price, then the retailer is not able to pass its high price over to customers fully, when these can switch retailers (Scholz, 2009). The problem could be avoided when customers buy long term contracts from retailers, which are usually less than one year long in Germany. Increasing the contract length reduces competition on the retail market and hence is not a good solution.

3.4.2. Price Caps: The Missing Money Problem

Price caps are necessary to reduce market power of generators. Generators have an incentive to take a plant out of the market that has low variable costs, when it owns plants with higher variable cost. Taking an efficient plant out of the system shifts the supply curve to the left. Less efficient plants receive a higher price through this intervention and it might pay off. Setting a price cap reduces this incentive, because the price cannot rise as much.

Price caps also make sense because demand is not elastic. The supply curve ends on the right hand side with the most expensive power plant. Since the market does not have any more expensive plants than its most expensive one, the supply curve has a vertical slope. Prices cannot adjust to the excess demand even if they rise to infinity.

Price caps cause the well-known “missing-money problem”. Prices cannot rise to reasonable levels during “scarcity hours” to generate quasi-rents that induce the right amount of investments in capacity if their upper tail is truncated. If spot prices cannot rise high enough, then forward prices that reflect expected spot prices are low. The missing money problem will become even more problematic, once the oligopoly profits have been reduced on the German market. This will eventually take place when the town utilities are forced by cheaper retailers to end their bilateral exclusive contracts with a single generator. Market power mitigation procedures imposed by the regulator are another cause for the missing money problem in the United States. Regulators use out-of-market capacities that are based on bilateral contracts with generators to reduce the price if it has reached a very high level. A last resort is to reduce the system’s voltage, which dims lights and lets engines run slower (Joskow, 2007).

The missing money problem also affects the investment mix. In New England 93% of energy was supplied by 53% of capacity, the remaining by just 7%. Peaking plants rely entirely on scarcity rents, while baseload power plants depend on scarcity rents as well, but to a lesser extent (Stoft, 2002). Hence the share of peaking load to whole capacity is reduced by caps and the optimal investment mix not achieved.

The price cap for 1MWh at the EEX is € 3000, which is quite high compared to $250 in California or $1000 in most other organised US electricity markets. Nevertheless it is completely arbitrary and lower than the VOLL, which is estimated somewhere between $2,000/MWh and $250,000/MWh. There are other mechanisms to curb market power besides price caps and market mitigations.

4. Models Proposed by the Literature

4.1. The Energy-Only Approach vs. ICAP

The Energy-Only literature assumes that the two principal capacity payment mechanisms proposed by the installed capacity (ICAP) literature – capacity obligations and capacity payments - distort the market for energy. The capacity payments are intended to solve the missing money problem. Both concepts assume that electricity supply is a bundle of two distinct products, capacity (security of supply) and energy. Generators are paid separately for the capacity allocated and the amount of energy that they supply.

Capacity payments are said to be hard to calibrate due to uncertainty and are exposed to political manipulation of stakeholders. Hence we do not suggest introducing these in Germany, at least not by letting the regulator dictate them. Utilities or retailers, called load service entities (LSE), are required to buy the capacity that would mirror their peak demand. The problem of the capacity obligation's approach in the US was that they were defined as a system wide product; the reserves were not there where needed. This was reflected by ICAP prices that fluctuated between zero, when there was excess capacity and the penalty payment that utilities were required to pay, when they did not meet their obligation. A defender of the ICAP literature is Joskow (2006). Oren (2005), an advocate of the energy-only approach, suggests forcing LSE to hold call options, which cover their peak load forecast. In case the spot price increases to levels above the strike price, which must be below the price cap, the LSE would only have to pay the strike price. This option reduces the risk for generators and LSE. They would be more expensive in areas where there is scarcity of capacity and induce investments there. Singh (2000) and Vázquez et al. (2002) also follow the call-option approach. Wolak (2004) proposes a contract adequacy approach, where forward contracts replace call options to reduce the investment risk. He claims that there are other industries that use contracts before investments are undertaken e.g. the airplane manufacturing sector. The uncertainty and public good issues would become negligible. The missing money problem though would still exist. The price of call options or forwards would be adjusted downward more if the spot price cap is lower.

Hogan (2005) tried to solve this problem and suggested changing the demand function. His figure 5 on page 14 is depicted below. He illustrates his model with two demand curves - an inner demand curve and one that is shifted to the right. Each consists of a price responsive and a price unresponsive (horizontal part), which reflects that some portion of customers face real time prices and other do not. The inner demand curve is the observed demand. In order to fix the missing-money problem, he simply shifts the demand to the left, which realizes higher spot prices for most demand realizations.

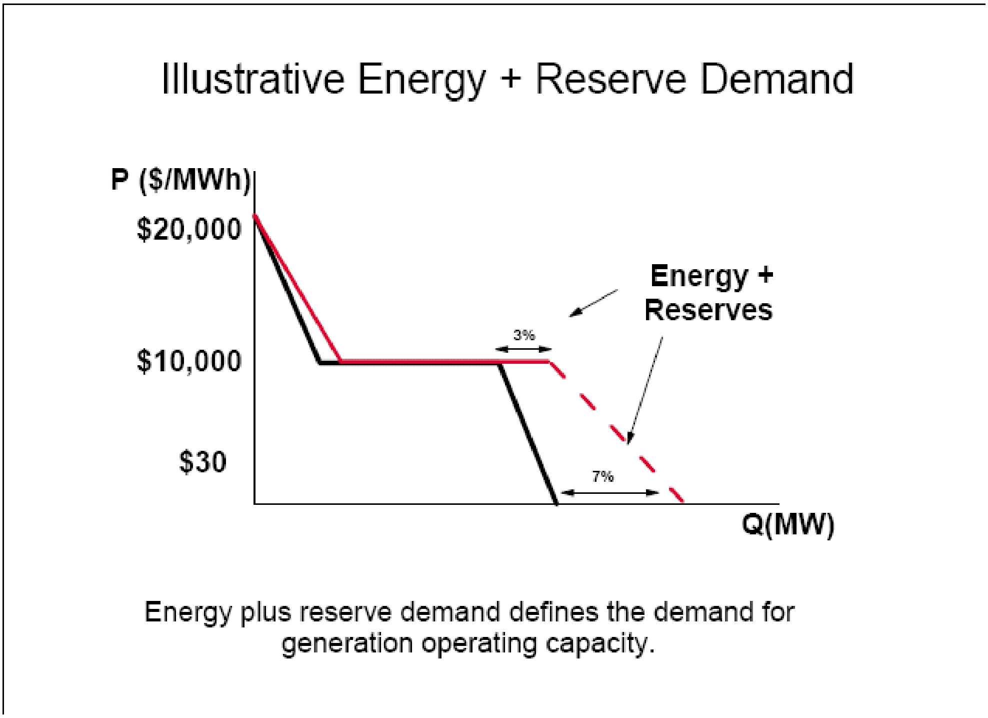

Figure 1: Replication of Hogan (2005)'s figure 5.

Stoft and Cramton (2006) rightly claim that Hogan's proposal only solves the missing money problem when the energy reserves (suggested 3% and 7%) are chosen correctly. They criticise the fact that the model does not tell us how to choose these.

4.2. The ICAP Approach with Options

Cramton and Stoft (2006 and 2008) propose a mixture of the option based energy-only approach and the ICAP models. It seems to us to be the most convincing model in the current electricity literature so far. It consists of three steps:

Step 1

First one needs to install a price cap for the spot market, to reflect VOLL. They suggest any value between €3,000 and €30,000. The nice thing about this is that it does not really matter too much how the cap or VOLL is chosen, as we will see soon. This is an advantage as we know it is difficult to find the correct VOLL.

Step 2

Reliability options (RO) at a suggested price of €300 are introduced, which hedge energy prices above this level. If the spot price rises to €1000, the generator has the obligation to serve its LSE for €300. A generator that has enough capacity to meet its contracting quantities has to buy power at a price of € 1000; hence suppliers still face the spot price, even though it is hedged. “For every MWit increases or decreases its production, its net revenue increases or decreases by € 1000.” Suppose the generator has a contract of coverage 100MW/h and the price is €1000, then it has to pay to its LSE a fix amount of € 70,000. But it receives the sport price €1000 times its installed capacity. The costs of the option are fixed but the revenue increases with the spot price. A generator that cannot perform during scarcity hours is punished by the foregone high spot price. At the same time the investment incentive increases with the spot price.

Step two reduces uncertainty, but at the same time does not reduce performance risk. C&S argue that VOLL, an unknown value, plays less of a role and “It no longer affects investment. If a higher VOLL is used, the price cap will be higher and the incentive to perform on peak will be greater, but because of the hedge, this will not increase the earnings of the generators. This means VOLL does not change investment or adequacy. . . .Because the estimation of VOLL is always controversial, this is an advantage.”

Step 3

Cramton and Stoft (C&S) complete their proposal with a capacity auction of reliability options. The expected foregone return from truncating LSE’s expenditures at €300 is reflected by the revenue from this auction. The capacity is controlled by the regulator, the price and the quality by the market. The auction is structured as follows:

Existing generators may make a zero bid if they want to sell RO, new generation capacity can bid any price they want. “The regulator bids a demand curve that intersects the target adequacy level at the most recent RO price and slopes down to the right by 5% in price for each 1% increase in capacity. It slopes up from the same point by 20% for each 1% decrease in capacity. The auction is held using a descending clock procedure [. . .]. All accepted bids are paid the clearing price, but existing generation receives one-year contracts while new generation may choose any contract length up to seven years. Once a new generator’s initial contract expires it becomes an ‘existing’ generator. If no new generation is purchased in a given year, all existing generators that bid have their contracts extended for one year”.

A generator's revenue under the proposed model of C&S is given by

$$R = P_{forward}Q_{forward} + P_{strike}(Q_{share} - Q_{forward}) + P_{balance}(Q_{RT} - Q_{share})$$

The first term is the revenue from the auction, the second from the spot market, and the third from contracting too little power and selling it to generators that cannot meet their contracts. The sum of the last term over all generators is zero and can be interpreted as payments from poorly performing generators to better performers.

5. Applicability of Cramton and Stoft's Model in Germany

The main problems of the German electricity market are high market concentration in the generation sector and future lack of capacity through nuclear phase-out. We mentioned earlier the studies that estimate a capacity shortage for Germany in 2014 /2015 but we have not shown any evidence for market power. This we do now.

We believe that the reason for high electricity prices is the high degree of market concentration at the generation sector. Borenstein, Bushnell and Wolak (2002) distinguish two approaches to the analysis of market outcomes on electricity markets. The first analyzes single companies and their bidding behaviour. Wolfram (1998) was one of the first to conduct such an analysis, using data for the electricity market in England and Wales. The second approach is at the market level. An analysis at market level compares observed prices with estimated marginal costs for the aggregated industry supply function. This approach, chosen by Wolfram (1999) was extended by Müsgens, who has taken a dynamic approach which does not neglect start-up costs. Mansur (2005) was the first to recognize the importance of dynamic effects and non-convexities, because the static approach overestimates market power. Müsgens (2006) analyzes the degree of market power in the German wholesale electricity market for 2000-2003, a period where the 8 generators merged to the four that now exist. He includes dynamic aspects and international power exchange. With a linear optimization model he quantifies market power by comparing a marginal cost-based competitive price estimate with past power prices on the electricity spot market. Strategic behavior is the main reason for the difference between marginal costs and prices. While he does not find evidence for market power at the beginning of his observation period, he finds strong evidence for market power after August 2001. In the period from September, 2001 to June, 2003, prices were on average nearly 50% above estimated costs. He also noticed that these price differences lie mainly in periods of high demand. Besides increased concentration as a potential reason for the market power, Müsgens mentions learning as another. Electricity spot market auctions repeated on a daily basis have led to more sophisticated bidding strategies. Furthermore he finds that both traded volume on the spot market, as well as strategic mark-ups, increase over time.

Generally we claim that C&S's model fits quite well for the German market, with two exceptions. Roques (2008) claims that the model is only applicable if the participants at the RO auctions do not behave strategically, as Müsgens showed for the spot market. We certainly need more participants than the four incumbents, otherwise the RO price could be manipulated easily. RO becomes effective three years after the auction to make entry possible. Second, C&S suggest that the transmission system operator (TSO) purchases RO for the LSE, which reduces the risk, since LSE could easily go bankrupt. The costs are then assigned to LSE based on their peak load during the year. LSE would then be encouraged to install RTM to reduce their peak load, which would make demand more elastic. The TSO is already aware of forward contracts, which must be scheduled. Germany does not have a TSO.

We argued strongly against the need for ownership unbundling and believe that when considering this issue in isolation, further unbundling does not make sense. The RO auctions and setting the capacity investments can be most easily done by a regulator of the German federal authority Bundesnetzagentur. The capital requirements of LSE would be reduced and competition on the retail market enhanced, which is necessary to increase overall competition (see the Introduction). Further research needs to be done in this area to set out the framework in more detail. Only if ownership bundling is necessary from a whole electricity market perspective would it be beneficial to follow the EU's proposal of introducing a TSO in the German market.

New power plants that still have to cover all fixed costs receive the required return through RO. The auctions can be used to discriminate against old capacity and finally result in the loss of market power. The regulator could easily auction plants for different technologies. Subsidies for wind and solar set up by the firms could vanish for future installments. Instead each LSE could be forced to buy a given proportion of renewable energy. There could be separate prices for power from renewable and conventional sources. The feed-in tariffs that have been used in Germany so far would become irrelevant. Feed-in tariffs have been the more successful alternative for the development of renewable energy across Europe. Winning auctions for capacity of renewable energy has often been unprofitable for firms, due to the winner's curse. The UK has had some bad experience with these in the past. If the auctioning design is linked to the requirement of buying a certain share of renewable energy, then the regulator could easily control the mixture of capacity.

In Europe national markets are connected to each other. Hence we have a forth term that needs to be added to the equation: $P_{Export}(Q_{Max} - Q_{Domestic})$

If the spot price is high in France and lower in Germany, then German generators would want to sell to France, because in Germany the maximum price is the strike price. If the price in France is larger than the price in Germany, then we assume that German generators sell as much as they can, Q_{Max}. The quantity sold in the German market, Qdom, receives the German spot price, while $(Q_{Max} - Q_{Domestic})$ gets P_{Export}. Note that the incentive to export is exactly the same as without reliability options: $P_{Export}(Q_{Max} - Q_{Domestic})$ and there is no justifiable concern that the domestic market could collapse.

6. Conclusion

This paper evaluates Germany's electricity market liberalization process. We show why ownership unbundling does not increase market efficiency and set out a market design that is compatible in the presence of vertically integrated and non-integrated networks. It solves Germany's current problem on its electricity market: market power on the generation side and its future problem of a capacity shortage under the present system. Stoft and Cramton (2006 and 2008) solve the market problems that we have presented in part 4.

The optimal level of capacity can simply be chosen by the market, because generally producers and suppliers know the price that they pay. The electricity market is perhaps the only market where consumers buy not knowing the price. Equating supply and demand to find the market equilibrium is therefore impossible. The public good attribute of reliability is taken care of by the regulator's decision on how much capacity is chosen, a choice that has to be made from outside the market system.

The uncertainty is reduced for all market participants. The transmission operator buys reliability options (RO) from generators. Load service entities (LSE, in Germany: mainly Stadtwerke) that are small and operate in a competitive environment can easily go bankrupt, long term contracts between these and generators are hence difficult to implement. Transmission operators have a larger capital base. They have to charge the LSE annually based on their peak demand, while consumers can move freely between LSE. Uncertainty for LSE is reduced through call options; if they are covered by the right number then the spot price is capped by the strike price. Once a complete market design has been installed, market participants can be assured that no further restructuring is needed and the expected risk through regulatory interventions decreases. LSE have to pay for RO according to their peak demand. They have an incentive to increase their customer base's demand elasticity through real time meters. This might be the highest efficiency gain, because the inelastic demand is the main reason why electricity markets cannot function as competitively as other markets. The price cap is set close to VOLL, which plays less of a role here. The missing money problem has been solved, because generators can cover their costs through the revenues from RO.

The model is also suitable for the German market, where a considerable share of electricity comes from renewable sources e.g. wind. We suggested introducing shares of renewable energy that LSE have to fulfill, when they buy their amount of options. Renewable power capacity would be auctioned separately from conventional capacity. The regulator can simply set some target and let the market choose the price instead of imposing a feed-in tariff, which is easily manipulated by lobbying.

Further research is needed to specify the framework and evaluate the market design under ownership unbundling and a vertical structure. Even though ownership unbundling is not beneficial when analysed under the current design, the evaluation could be different under a superior design that solved Germany's two problems of market power in the generation sector and a lack of capacity from 2015 onwards.

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