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Investment, Unbundling, and Vertical Governance in Electric Power Systems

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by

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Abstract

Unbundling, the vertical separation of electricity networks from generation and retail, and liberalization have been common features of electricity market reform around the world. As a consequence, the structure of electric power systems is becoming increasingly decentralized. Electricity supply is an interrelated system that requires careful coordination between supply and demand. This applies especially to system operation. But also in the long term coordination exhibits considerable benefit since the siting of generators has considerable influence on the network and may defer/ or increase investment need. With unbundling, firm-internal coordination across the entire supply chain is no longer possible. Coordination problems can arise because of lacking information or because of incentive problems. Since lack of coordination can cause efficiency losses, alternative governance mechanisms are needed to restore coordination in a market environment.

This PhD thesis explores the coordination problem and possible solutions in five related articles. The first paper focuses on operational coordination and analyses the option of an independent system operator as a governance form for future actively managed smart distribution networks. The second paper examines whether costless information exchange (”cheap talk”) can achieve coordination of investment decisions. Cheap talk may fail because of incentives problems. However, deep charging can serve to restore incentive compatibility. The third paper studies locational charging as price mechanism to coordinate distribution network and network users analytically. The fourth paper extends the theoretical analysis with a more in-depth investigation of the possibilities for locational pricing in Germany based on contractual solutions between network operator and user. The fifth paper shows that such optional and voluntary contracts can achieve a pareto-improvement.

Declaration on Joint Authorship

This thesis contains several articles which are joint work. The following paragraphs lay out for each article the contributions of the several authors.

The first article "Governing Smart Grids - the case for an Independent System Operator" is single-authored by Nele Friedrichsen.

The second article "Vertical unbundling and the coordination of investment – can "cheap talk" alone solve the problem or do we need "deep charging"?" is joint work with Gert Brunekreeft. The authors developed the topic of the article and the set up of the cheap talk game in interactive discussion based on an idea by Gert Brunekreeft. Nele Friedrichsen was in charge of the model and the calculations. When writing up the article, Gert Brunekreeft drafted a first version of the paper consisting of the description of the model and the results. Nele Friedrichsen contributed the background on cheap talk, the coordination problem in liberalized electricity markets, and network charging. The revisions of the paper were realized jointly by alternating the draft between both authors.

The third, fourth and fifth article are work realized as part of the project IRIN - innovative regulation for intelligent networks - funded by the German federal ministry of economics. All three papers are joint work with Christine Brandstätt and Gert Brunekreeft. The content of the papers was developed interactively in discussion among the three authors within the project.

For the third paper "Locational signals to reduce network investments in smart distribution grids: what works and what not?" Nele Friedrichsen drafted a first summary of the main discussion points of the different pricing schemes. The paper was then jointly written by the three authors and the argumentation was refined based on interactive discussion. Nele Friedrichsen contributed the background on coordination need in electricity supply and the growing demand for locational pricing as coordination device. Furthermore, she contributed the background on smart grids.

For the fourth article "Smart pricing to reduce network investment in smart distribution grids - experience in Germany" Nele Friedrichsen contributed the country experiences from New Zealand and the US. She was also responsible for the details of the German framework. The paper was then jointly written by the three authors and the argumentation was refined based on several discussion sessions.

For the fifth paper "Improving investment coordination in electricity networks through smart contracts" Nele Friedrichsen developed the model in close discussion with Christine Brandstätt. The refinements of the cases have been developed in discussion among the three authors. Nele Friedrichsen also contributed major parts to writing the first draft of the paper. Refinement and improvements were realized by circulating the draft among the three collaborating authors.

Contents

1 Introduction

Unbundling, the vertical separation of electricity networks from generation and retail, and liberalization have been common features of electricity market reform around the world with clear benefits for competition and efficiency. However, the forced separation of the vertical supply chain may lead to coordination problems. Lacking coordination can cause efficiency losses. Negative effects can occur for example with respect to network investment or the integration of renewable generation. Hence, coordination problems may hinder the necessary decarbonization of electricity supply. New, firm-external, governance mechanisms are needed to restore coordination in a market environment.

The following paragraphs present introductory information on electricity markets and possible coordination problems in electricity supply. Section 1.2 presents the framework of analysis and the research approach. Section 1.3) outlines the motivation for the research. Section 1.4 presents a summary of the content of the thesis and the main conclusions. Section 1.5 summarizes the main contributions made in this thesis.

1.1 Background

1.1.1 Structure of Electricity Supply

Electricity supply can be seen as a four stage industry: generation, transmission, distribution and retail. Generation can be large centralized power plants such as nuclear, coal, or gas stations that feed into high voltage networks. Increasingly generation is also provided by smaller decentralized generators. These generators are typically connected at lower voltages. Transmission and distribution networks form the network infrastructure, which is an essential component to transmit power to the customer. The term transmission refers to higher voltage lines that are used for long distance transport of electricity. Distribution is used for lower voltage lines ($\approx\leq 100$ kV) that distribute power regionally and locally to final consumers. Retailing refers to the local supply function. Various retailers can offer to supply customers and either produce the power themselves or buy it in the market.

The network is usually considered a natural monopoly while in generation and retail of electricity competition seems possible. Historically, the electricity industry has been organized as vertically integrated undertakings. Typically, generation and transmission were organized within one firm. Also distribution and retail have often been integrated. Partially, the integration even encompassed the entire supply chain, i.e. generation, network stage, and retail supply were organized within one and the same firm in a regional monopoly.

1.1.2 Electricity Restructuring for Competition – the Pro of Unbundling

Since the end of the 20^{th} century electricity reform has become a common theme around the world. In the course of electricity restructuring, the hierachical structure that had characterized electricity supply disappears. Instead more room is given to decentralized governance mechanisms with strong reliance on market coordination (Joskow, 1996).

Restructuring aimed to increase competition and thereby efficiency. Apart from privatization, the reform typically included breaking up the integrated monopoly (Joskow, 1996). The separation of monopolistic networks from potentially competitive areas like generation and retail is considered to enhance competition in the energy business. This argument originates from the possible anticompetitive motivations for vertical integration (Perry, 1989). Integrated network companies could possibly exploit their monopolistic position in the network to hinder competition at the other stages and create or protect market power. This can for example materialize in delayed network connection of new competitors or cross subsidies between network and competitive stages. Furthermore, an integrated network firm may have insufficient incentives to invest in interconnector capacity. If neighbouring areas exhibit cheaper generation, an integrated network company has incentives to withhold investment in interconnector capacity to limit imports and thereby protect its local generation (Balmert & Brunekreeft, 2010; EC, 2007b). For distribution networks, however, the argument does not apply because they are usually isolated subnetworks connected at singular points to higher voltage networks without any interregional linkages.

Network ownership unbundling eliminates incentives and potential for discriminatory behaviour at the network stage (EC, 2007a,b). Thereby network unbundling lays the ground for fair competition at the other supply stages, namely generation and retail. Competition is desired because it frequently encourages efficiency and innovation in the competitive areas. Furthermore, if generation and retail are opened to competition and separated from the monopoly, the regulatory activity can be concentrated on the monopolistic network.

1.1.3 Status-Quo of Unbundling: the Third Package of the European Commission

Most restructured electricity markets feature some form of network unbundling. Even within Europe, the degree varies considerably – from legal unbundling to complete ownership separation. In 2005, the European Commission launched an inquiry into the competition in gas and electricity markets. The final report (EC, 2007b) blamed a lack of unbundling as one of the reasons for unsatisfactory progress regarding the development of competition and of the internal market for energy. This led to a proposal for the third legislative package on European energy market liberalization. The proposal favoured the introduction of ownership unbundling. Such a proposal is drastic and interferes with company ownership rights. It raised a big debate on appropriateness and adequacy of ownership unbundling. The debate ended with a political compromise; the finally adopted third legislative package allows three options for transmission unbundling (EC, 2009):

Full Ownership Unbundling Ownership unbundling prohibits joint ownership of network and generation or retail assets within one firm. This is expected to completely eliminate any discrimination incentives and abilities of the network firm and thereby benefit competition.

Independent Transmission Operation (ITO) The ITO model is also known as Efficient and Effective Unbundling (EEU) or 'third way'. This option basically requires a strengthening of the current legal unbundling rules.

(Deep) Independent System operation (ISO) Operational activities in the network need to be carried out by an entity not active in generation or retail. Network ownership can stay with an integrated company. The prefix *deep* indicates that the ISO is authorized to decide on network investments. This is necessary since otherwise a network owner with generation affiliates could protect its home market by not investing in interconnecting network lines with adjacent generation areas. The allocation of investment decision and financing to different parties in the deep solution is considered problematic (Balmert & Brunekreeft, 2010, pp. 34-35).[1] [2]

1.1.4 Coordination: Information and Incentive Problems – the Con of Unbundling

Transaction cost economics describes vertical integration as welfare enhancing organizational choice in cases where the cost of market transactions are higher than within firm organization (Coase, 1937). This suggests that there might have been well founded reasons for the emergence of electricity supply as vertically integrated structure.[3] A separation may then also bring about certain drawbacks such as the elimination of vertical synergies. Unbundling will therefore face a trade-off between the positive and negative effects of vertical separation.

Electricity supply presents strong interdependencies between the different supply stages, for example generation and network. Due to these interdependencies, changes in one part of the system may affect all the others as well. A disintegration of the supply stages may negatively impact the efficiency of the whole system because interdependencies are not accounted for properly. Hence, coordination may have been an important advantage of

[1] The third legislative package on the European internal market for energy consists of two directives, concerning common rules for the internal market in electricity and gas, 2009/72/EC and 2009/73/EC respectively, and three Regulations, one establishing an Agency for the Cooperation of Energy Regulators, 713/2009, and two on conditions for access to the electricity and natural gas transmission networks, 714/2009 and 715/2009 respectively. They are published in EC (2009).

[2] For a discussion of the different options to vertically separate EU electricity markets see e.g. Brunekreeft (2008)

[3] Asset specificity might have been an important point: both power plants and networks required large investments that were highly specific, once built there was little to none alternative utilization possibility. Such specificity carries the risk of hold up and may therefore discourage investments. Vertical integration may have emerged as a response to mitigate these problems. Newer developments such as the introduction of spot markets and the scale reduction in generation technology at least partially reduced the risk of hold-up (Chao *et al.*, 2005).

vertical integration in the electricity supply chain (Chao *et al.*, 2005). A forced divestiture of the integrated structure may cause coordination losses and decrease efficiency. As Joskow & Schmalensee (1983) who pioneered the work on efficiency consequences of restructuring electricity markets stress: although the stages of electricity supply can be differentiated very exactly, it may be mistaken to assume that they are "distinct in any economically meaningful sense" and could be "operated independently [...] by separate firms coordinating their activities using only the price system, without any loss in economic efficiency" (Joskow & Schmalensee, 1983, p. 25).

Efficiently operating the whole system in the short and in the long run requires coordination at two levels:

- **short term system operation:** coordinated operation enables centralized dispatch of generation and transmission to achieve least cost operation. Emergency procedures and system reliability are under clear responsibility.
- **system design and investment decisions:** "one coherent investment strategy" (Chao *et al.*, 2005) enables maintaining and building the generation mix that results in long-run efficiency and to co-optimize transmission grid and generator location. Thus, optimal substitution possibilities between local generation and transmission access to distant generation can be exploited.

Unbundling makes the interaction between generation and network more complex and might thereby hinder coordination. This is nicely illustrated by a quote from the "Ten Year Network Development Plan" of the organization of European transmission network operators (ENTSOE, 2010, p. 38): "the most important source of uncertainty came as the consequence of the more complex coordination between generation and transmission planning due to the unbundling of the industry". One problem is the lack of information on the overall generation capacity. The second concern is the siting of projects. Network operators are obliged to respond to connection requests, however, "a large number of these [connection] requests do not materialise into concrete projects and there is no requirement for developers regarding the transparency of their portfolio evolution. This portfolio often encompasses projects in very different locations" (ENTSOE, 2010, p. 38). This aggravates network planning.

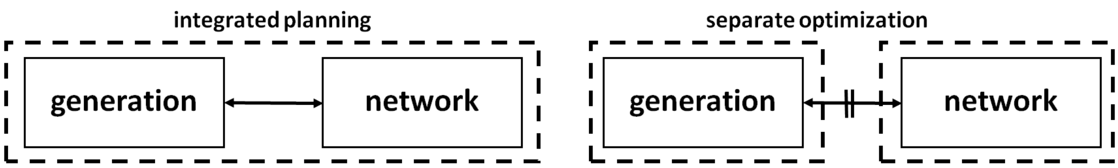

Figure 1.1: Integrated vs. separate system optimization

Obviously, lack of information on upcoming generation projects and their location is a core problem for network operators to prioritize network development. Hence, regulators could prescribe detailed information exchange including projected time schedules and location between investors and grid operators at an early stage of planning (this was proposed by ETSO, 2003, p. 19 as a necessary tool to mitigate difficulties in network planning caused by uncertainties).

Unfortunately, this may not help in all cases because of incentive problems. Generators may for example have incentives to overstate the project's realization probability to ensure that sufficient network capacity is realized even if the project should fail. Also, preferences of network and investor with respect to the optimal location of a new power plant are unlikely to coincide. Siting of generators has important consequences for the network. Decentralized generation for example can have positive or negative effects on the network. In other words, new generation may defer network investment needs, but only if placed in accordance with the network conditions. This requires coordination.

The situation can be seen as a principal-agent-problem in which the network operator, here the principal, depends on the action of the generator. "The individual taking the action is called the agent. The affected party is the principal." (Zeckhauser & Pratt, 1985, p. 2). Problems in such a situation arise when incentives differ. This was already recognized in Knight (1921, p. 62) who mentions the problem to "secure effective unity of interest" if tasks cannot be carried out by a single person anymore.

When the vertical supply chain of electricity was unbundled tasks were split up. In vertically separated electricity supply systems, several principal-agent problems can be conjectured. I give two examples:

- Assume the network is the principal and the generators are agents. The objective of the network-principal is the least cost system development; this includes the co-optimization of network and generation since the siting of generators is relevant for network planning. For optimal system development the network would want to steer the actions of the generators, i.e. the siting decision, to the desired locations. Theoretically, this can be achieved by contracts that compensate generators for their additional cost if they choose locations that are advantageous for the network. However, generators are better informed about their cost of siting at different locations. The information asymmetry may lead to moral hazard: generators do not have incentives to minimize cost for siting and connection if they know they will be compensated for their expenses based on stated cost, which cannot be verified.
- Another possible problem is moral hazard in teams (Holmstrom, 1982). Reliability in electricity networks depends both on grid maintenance and system operation. Separated transmission ownership and operation (as in an ISO model) reduces accountability. Each party has weaker incentives to feel responsible for the outcome. Hence, investments in grid maintenance are expected to be suboptimal, because responsibility for increasing failure rates cannot be attributed clearly (Joskow & Tirole, 2005, p. 259–262). Integrated companies, in contrast, are assumed to invest adequately in maintenance because low reliability levels would damage their affiliate companies in the same way as others.

Principal-agent theory studies contracts between the principal and one or several agents.[4] The aim is to identify contracts that induce the agent to undertake the action desired by the principal while minimizing inefficiency.

With regard to the coordination between generation and network, theoretically, prices on network usage can induce generators to take their network impact into account. Thereby, a market mechanism may induce efficient coordination. Currently though, generators in Germany, but also in many other jurisdictions, are exempt from paying network charges. Hence, the network operator is currently unable to use prices as a tool to steer the generators.

This illustrates that formal rules influence and delineate the space in which economic activity takes place and the scope for decisions by firms. This is why institutional economists underline: "institutions matter" (Williamson, 2000). This thesis starts from a new institutional economics perspective on electricity network unbundling.

1.2 Methodology

1.2.1 Framework of Analysis: the New Institutional Economics

Institutions are important at several levels in social analysis starting from informal institutions such as norms, traditions, and values (level 1). Following Williamson (2000) the second level comprises the formal institutional environment such as laws or property rights, i.e. the "rules of the game". Level three is concerned with the economics of governance, "the play of the game". Level four is the domain of neoclassical optimization (Williamson, 2000, p. 597-600).

Unbundling regulation intervenes at the second level. The regulation may subsequently trigger a need for adaptations in governance, i.e. the third level. Coming back to the coordination problem introduced above: the forced organizational change eliminates firm internal coordination and hence requires adjustments to efficiently govern coordination under the decentralized structure. However, the interaction is not only in one direction. It may also be that efficient governance structures are hindered by the formal institutional framework. Efficient sector organization then requires an adjustment of the formal rules. For example coordination in the electricity sector can be improved by more cost-reflective pricing. However, such price differentiation is limited by law in some countries such as in Germany. Modifications in the institutional framework are recommendable as addressed in chapters 4, 5, and 6.

Furthermore, technology is an important factor when analysing the institutional arrangements governing electricity networks. Though Williamson (2000, p. 600) points at the importance of technology, this perspective is considered to be insufficiently integrated in transaction cost economics. The technology perspective is added in the framework of coherence theory. The investigations explore the interrelations of technology and institutions in infrastructures with a focus on critical technical functions that are relevant

[4] For a fundamental and extensive treatment of principal-agent problems in regulation and procurement see Laffont & Tirole (1993).

for sector performance (Künneke *et al.*, 2010; Finger *et al.*, 2005). This perspective is taken up in the analysis of suitable governance structures for smart grids in chapter 2.

1.2.2 Research Approach

The research is analytical and the thesis follows an applied micro-economics approach. Both theoretical and applied work are reviewed and linked to the problem at hand, namely coordination in unbundled electric power systems.

The thesis incorporates inputs from various strands of literature. New institutional economics lays the ground for the analysis as the theoretical framework. Additionally, I draw on applied research and literature in the field of regulation, smart grids, (transmission) network pricing, and electricity market organization. The thesis applies theoretical concepts to the concrete (and novel) situation of restructured electricity sectors with a focus on distribution networks. With regard to network pricing the thesis conducts an analysis of existing network pricing approaches and their suitability for smart distribution grids. Based on the analysis the thesis argues in favour of contractual solutions as novel approach.

In addition to the mostly literature based analysis, this thesis builds an economic model to investigate the specific problem of coordinating network and generation investment. A game-theoretical model is used to formalize the problem. To investigate costless information exchange as a possible solution to the coordination problem, it employs the concept of "cheap talk".

1.3 Motivation

The starting point for this project was the proposal of the European Commission to introduce ownership unbundling for transmission networks. The motivation behind the proposal has been the energy sector inquiry that had diagnosed several shortcomings in European electricity markets. One of the findings was "that it is essential to resolve the systemic conflict of interest inherent in the vertical integration of supply and network activities, which has resulted in a lack of investment in infrastructure and in discrimination" (EC, 2007b, p. 325). The report proposes to "decisively reinforce the current inadequate level of unbundling" which "would, in turn, also facilitate cooperation among network operators" (EC, 2007b, p. 325). Clearly, unbundling has positive effects. Most importantly, it is expected to eliminate discrimination incentives of network companies by creating independence from the generation stage. This levels the playing field among incumbents and new entrants and thereby enhances competition.

Around the world renewable energies and distributed generation receive support to increase their share in electricity generation as a measure to fight climate change. Those generators might directly benefit from unbundling if they are built by third parties. Notwithstanding the benefits of vertical separation, there may also be drawbacks of splitting up an interrelated supply chain.

There is particular concern that unbundling distorts the development of distributed generation (DG). DG describes generators which are connected to the distribution network rather than to higher voltage transmission networks. Distributed generators are typically small scale, often rely on renewable sources such as wind, solar, biomass and hydro, or smaller combined heat and power (CHP) plants. Since DG connects to the distribution network, distribution networks operators could be best suited to build and site generation within their networks. If they are exempt from those activities the total DG activitiy may suffer (Brunekreeft & Ehlers, 2006; Murray, 2006).

Importantly, renewable generation poses new challenges to the distribution networks. Volatility of feed-in and increased bottom-up flows require adjustments in system operation. It is yet unclear what the optimal organizational form of future smart distribution network will be. The topic seems to be insufficiently addressed in research so far. This thesis tries to fill this gap and discusses distribution unbundling with a focus on future smart grids in the first article (chapter 2).

New siting patterns and lack of information on generation projects complicate strategic network expansion and system development. Incentive or information problems may impede efficient coordination and distort investment decisions. These negative effects of a vertical separation seem to have received only limited attention in the debate on introducing unbundling. Furthermore, the definition of coordination inefficiencies remains vague without further defining what the coordination losses are and where exactly they occur. This thesis aims to shed light on one aspect of inefficiencies, namely possibly inefficient investment, thereby contributing to a better understanding of the effects of unbundling (chapter 3).

The rapid development of renewable generation is currently causing significant investment need in both transmission and distribution networks. The European Network of Transmission System Operators for Electricity (ENTSOE, 2010, p. 14/15) projects some €25 billion transmission network upgrades until 2015 for Europe. In German distribution networks additional investment in the order of €25 billion until 2020 is estimated for the network integration of electricity generation from wind turbines and photovoltaics (BDEW, 2011). Network capacities become increasingly scarce which calls for coordinated operation to use the existing network as efficient as possible in the short run. Furthermore, the call for efficient investment is immediate since network investment needs in both transmission and distribution to integrate DG and RES-E are high.

In practical terms efficient investment requires investment coordination to exploit the trade-offs between the location of generation or demand units and network expansion. The question is how this coordination can be achieved in liberalized markets in which hierarchical coordination inside a vertically integrated firm is eliminated. A price-based solution could be realized in the form of locational pricing. While this is discussed and also practically experienced for transmission networks, it is only recently becoming a topic in distribution (see e.g. Li *et al.*, 2005). This thesis contributes to advancing the discussion of locational price signals to reduce distribution network investment with three closely related papers (chapters 4, 5, 6).

1.4 Contents of the Thesis

European regulation increased the limitations for cross-involvement in electricity networks and generation, in particular for the transmission networks. The so called unbundling limits integration between firms in the monopolistic network stage and in generation or retail where competition is considered possible.

Parallel to this development, climate change drives the transformation of electricity supply towards renewable, low-carbon supply options. This causes an increase of decentralized generation that feeds into the distribution networks. The rapid growth of decentralized generation challenges the traditional network operation paradigm in distribution networks. Firstly, power flows become bi-directional: in times when local supply exceeds local demand power flows bottom-up, in contrast power flows top-down when electricity is supplied from higher voltage levels to customers. Secondly, the organizational structure changes. Traditionally the entire electricity system, including large, central generation, was managed by integrated companies. Renewable and distributed generators are typically owned by third parties.

Both the increase in distributed generation and unbundling are fuelling a decentralization of the electricity supply chain. Firm-internal coordination and optimization of the entire supply chain from generation to end-customer supply falls away. However, electricity supply comprises interdependencies between the supply stages. Network and generation are complementary in providing electricity to the final customer. But in some cases they can also be used as substitutes to a certain degree. This happens when customers can be supplied either by building a new line to distant generation or by building new local generation.

As a consequence of the interdependencies, coordination is necessary for efficiency, if not indispensable for reliable system operation. Unbundling is suspected to cause coordination problems. This may lead to losses in system efficiency and performance and in the end impair social welfare. Hence, with the introduction of unbundling, new coordination mechanisms are needed to create efficient vertical governance of the relations among the supply stages in electricity.

The analysis of the coordination problem can roughly be divided into two aspects:

- specifying the coordination problem: optimal network investment depends on generation expansion (Baldick & Kahn, 1993). Firstly, coordination may be hampered by an information problem: In a disintegrated setting network operators may simply not have access to the relevant information which complicates network planning. Secondly, there might be an incentive problem hindering coordination. Coordination losses from vertical separation are confirmed empirically (see Meyer, 2011, for a survey). Vertical economies can arise from several sources such as for example effects of market risk and hedging or coordination of investments and thereby better optimization of capital inputs without further specification. However, the exact specification often remains vague. This thesis contributes to a better understanding of the coordination losses by investigating investment coordination more in detail. A central problem seems to be rooted in the inadequate incentives for generators to take their system effects into account. This is because in many jurisdictions generators do not pay for using the system or charges are not cost-reflective. Generators have external effects on the network for which they are not charged. If generators can benefit individually for example from capacity expansion but costs are socialized, this implies that generators have an incentive to free-ride.

- addressing the coordination problem: depending on the source of the coordination problem, suitable counter measures to remedy coordination losses can be designed. In cases where coordination is only hampered by information problems, simple information exchange could solve the problem. In cases where an incentive problem is also present, simple information exchange might not be possible. Additional measures are needed to enable coordination. This can either be achieved by creating a situation in which incentives are compatible with information exchange. Alternatively, incentive structures can be targeted to directly coordinate generation with the network via differentiated price structures. The idea is that cost-reflective price signals help steering network users to better fit with spare network capacity, thereby avoiding congestion and the need to build new lines.

This PhD thesis addresses different aspects of the coordination problems that might arise from the increasing decentralization of the electricity supply chain in five related papers:

1. The first paper, **Governing Smart Grids - the Case for an Independent System Operator** (chapter 2), addresses the coordination problem in smart distribution networks. Some technical aspects of electricity supply require thoroughly coordinated reactions on a very short time scale. If such aspects are critical to the performance, such as stable system operation in electricity, centrally coordinated operation is beneficial. Importantly, a central operator may have potential and incentives for discrimination. This paper proposes an independent system operator as optimal solution in the trade-off between coordination need and discrimination concerns.

2. The second paper, **Vertical Unbundling and the Coordination of Investment – Can "Cheap Talk" Alone Solve the Problem or Do We Need "Deep Charging"?** (chapter 3), specifies one concrete aspect of the coordination problem. Suboptimal network expansion resulting from a lack of coordination causes a cost of unbundling. The paper illustrates that the coordination problem between generation and network investment is not uniquely rooted in a lack of information but complicated by an incentive problem. The paper explores locational (or deep) charging as a tool to restore incentive compatibility for information exchange ("cheap talk").

3. The third paper, **Locational Signals to Reduce Network Investments in Smart Distribution Grids: What Works and What Not?** (chapter 4), takes up the discussion on locational pricing to improve coordination among network

and generation. Locational pricing reflects the network topology, transportation and congestion into the prices, either network charges or electricity prices. Locational prices send more cost-reflective price signals to network users. The reflection of network conditions can help steering users to locations with spare capacity and thereby reduce network investment need. The analysis focuses on distribution networks. While the paper focuses on generators, the discussion extends to the demand side.

4. The fourth paper, **Smart Pricing to Reduce Network Investment in Smart Distribution Grids - Experience in Germany** (chapter 5), starts from the theoretical analysis in the previous paper. It then offers a detailed analysis of the specific situation in Germany. Several options in the current institutional framework show potential for locational differentiation. The paper proposes optional contractual solutions between the network operator and network customer as a favourable way forward. Based on voluntary participation such 'smart contracts' allow targeted signals to be sent to network users without the need for a system reform. Specific recommendations are made for improving the current regulatory framework in Germany.

5. The fifth paper, **Improving Investment Coordination in Electricity Networks Through Smart Contracts** (chapter 6), is rather technical and complements the textual analysis of smart contracts. With a three-node network it illustrates how smart contracts could achieve a pareto-improvement compared to the benchmark case of network expansion.

The following paragraphs develop the content of the papers and their relationship more in detail.

1.4.1 Independent System Operation for Smart Grids

The strengthened unbundling regulations in the third legislative package focus on transmission networks and do explicitly not address distribution networks where the current legal and functional unbundling rules are considered sufficient. This might change in the future. With the development towards smart grids that more actively integrate decentralized generation, active demand side customers, and storage, unbundling is increasingly becoming relevant for distribution networks, too. This topic is addressed in the first article called "Governing Smart Grids - the Case for an Independent System Operator".

Smart grids are considered an essential component of a sustainable low carbon electricity system since they enable smarter network and system management and thereby improve the integration of intermittent renewable generation and flexible demand. Markets and advanced pricing can help activating users and support smart grid functions. However, tapping the full potential of smart grids, such as accessing network benefits of demand side management, benefits from a central operator. More importantly, coordinated system operation is necessary to maintain certain critical technical functions such as system reliability and balancing.

Critically, such central control incurs a discrimination potential. Smart grids are likely to incorporate demand customers and (small scale) generators into network management. An integrated company could exploit the central control potential to discriminate against competitors. The threat of discrimination may discourage participation in otherwise beneficial smart grid concepts. Hence, smart grids reinforce the need for effective vertical separation. Non-discrimination is essential for system operation in future smart grids that consist of a diversity of actors that are envisioned to be actively integrated in system management. I propose an independent system operator to strike a balance between separation and coordination needs. The ISO could even be combined with the information function that is central to smart grids and also needs to be organized independently.

Note that the problem of investments in interconnectors, which led to the construct of deep ISOs at transmission level, is not relevant for distribution. Hence, a counter argument to the ISO solution, namely the need for a deep ISO with an akward split between investment decision and financing, falls away. Incumbent network firms could retain investment authority.

While independent system operation as a key of the ISO concept is clear, the governance structure remains an important issue for further research. Open questions remain with regard to the ownership and detailed tasks of ISOs that have to comply with EU limitations on cross-involvement in network and generation (respectively retail) actitivities.

1.4.2 Coordination Problems and Information Exchange

Notwithstanding the benefits of vertical separation, especially for competition, the forced split of integrated firms may have some drawbacks. Splitting up an interrelated supply chain can create incentive or information problems that may impede efficient coordination and distort investment. One particular problem is the coordination of network expansion and generation development. The coordination problem potentially results from an information problem: the network operator does not know about planned generation projects and vice versa. Such a problem could be solved by information exchange. However, additionally, there might be an incentive problem which can render information exchange ineffective because of incentives to lie. Assume a generator and a network operator. The generation project is not yet build, but it is already known that connecting the generator requires expansion of the existing network. Building the line takes longer than realizing the power plant. To be sure that its production can be fed into the grid, the generator would want the line to be built even if there is some risk that the project might fail. In contrast, the network operator would want to build a line only if it was really needed. In such a case even though the network operator could ask the generator whether the higher capacity would really be built, the stated information may be useless. It cannot be trusted since the generator has an incentive to always affirm the building of high capacity even if this is not true.

Because of such incentive problems requiring simple information exchange as proposed by European Transmission System Operators (ETSO, 2003) might fail to solve the coordination problem. In the case of coordination between network and generators, the underlying reason for the incentive problem seems to be an externality: generators are not charged for the effects they have on the network. The obvious solution would hence be to charge generators in accordance with their network impact to make them internalize the externality. Concerning electricity networks, this is known as deep charging.

The second article called "Vertical Unbundling and the Coordination of Investment – Can 'Cheap Talk' Alone Solve the Problem or Do We Need 'Deep Charging'?" uses a formal approach to illustrate why simple information exchange might not suffice to achieve coordination. We use a three-stage profit-optimized investment model with a (regulated) monopoly network and two asymmetrical Cournot-type generators. We rely on cheap talk to model information exchange. Formally, this leads to a game theoretical analysis of the credibility of cheap talk in a game with incomplete information and positive spillovers. The model illustrates suboptimal investment as a result of unbundling. It shows that costless information exchange cannot be relied on to achieve coordination because of incentive problems. The paper thereby specifies the argument of costly coordination problems resulting from unbundling. The underlying problem is lacking incentive compatibility. Adequate deep charging might serve to correct the incentive problem and restore the possibility for coordinating cheap talk.

1.4.3 Locational Signals to Achieve Coordination and Reduce Network Investment

A dominant problem hindering efficient coordination between network and generation in a market environment is the lack of locational signals. Locational pricing can be the lever to steer network users according to network needs thereby economizing on network investment. This is highly relevant to ensure that the network does not become a barrier in the process of achieving a low-carbon electricity supply. The investment need in distribution networks is high. The driving factors are ageing assets, the tremendous development of renewables and decentralized generation, and the transformation towards smart grids. In light of these developments efficient network investment gains crucial importance.

The discussion of locational pricing is known from transmission networks but has only recently become a topic in distribution networks, too. Articles three to five explore the potential for locational signals in distribution networks.

The third article "Locational Pricing in Distribution - What Works and What Not" explores different approaches to implement locational pricing and evaluates their suitability for distribution networks at a theoretical level. The dominant models known from transmission network are locational energy pricing (LEP) and locational network pricing (LNP). With LEP the energy prices vary by location thereby also reflecting the network cost. If the differentiation is by nodes and includes the time component, this is known as locational marginal pricing or nodal spot pricing. With LNP, the locational differentiation is implemented in the network charges, i. e. connection or use-of-system charges.

Locational energy pricing is considered to send optimal signals for system operation but lack efficient long run signals. Locational network pricing sends strong reliable long run signals but has only little effect in the short run. More importantly, both LEP and LNP require a system change and explicit regulatory intervention. This might prohibit implementation in distribution networks, especially in Germany where over 900 distribution networks are active. We define smart contracts as optional agreements between network operator and network users. They are based on voluntary participation. A regulated default tariff exists as fall back solution. We propose smart contracts as a flexible, low transaction cost solution that does not require a system change. Furthermore these contracts allow combining both long and short run signals.

The fourth article "Locational Pricing to Reduce Network Investment - the Experience in Germany" explores the potential for locational signals with an in-depth analysis of the (indirect) potential for locational signals in the current framework in Germany. We find that currently locational signals in distribution networks are still scarce though more dynamic pricing, both with regard to the locational differentiation but also with regards to time of consumption and capacity demand, increasingly becomes a topic.[5] In particular in the context of smart grids more differentiation is considered essential. In Germany, several mechanisms exist that could potentially defer network investments. However, they are not yet fully used in that potential and have not originally been invented for that purpose. Still the scope is very limited. To enable efficient smart contracts that reduce network investment the regulatory framework needs to be adjusted. This does not require a system change but only a flexibilization of already existing regulations. More precisely, we propose to flexibilize three instruments:

- contributions to construction costs (*Baukostenzuschüsse*). These charges are currently used mainly with the purpose to prevent excessive requests for (demand side) connection capacity. A more detailed differentiation for example by including locational aspects within one network area or time-variance could improve the instrument to reduce network investment.

- individual network tariffs. Currently individual network tariffs can only be offered if the behaviour differs significantly from specified peak loads. A flexibilization to include other aspects that impact the network, such as local congestion, is advisable.

- call and curtail agreements (*Zuruf- und Abschaltvereinbarungen*). Such agreements are already allowed mainly with a purpose to reduce the occurence of negative spot prices and maintain system stability. They could further be used to minimize network cost or avoid network congestion.

[5]The UK just recently introduced systematic locational differentiation for extra-high voltage distribution networks. EU legislation on energy end-use efficiency and energy services (Dir 2006/32/EC) demands smart meters that reflect electricity consumption and time-of-use thereby furthering time-differentiated tariffs.

In addition to the flexibilization of the rules, but not of less importance, the regulatory framework needs to be adjusted to incentivize efficient network investment such that network operators benefit from avoiding network investment by smart contracts.

The recommendation of articles three and four is to implement locational signals in distribution networks using flexible, contractual solutions. The key characteristic of such smart contracts is that they are based on optionality and voluntary participation. Hence, network customers have to benefit from entering a smart contract since otherwise it would be rational to stay with the default tariff. Apart from achieving efficiency improvements it is possible to design smart contracts that achieve a pareto-improvement: no one is worse off while at least one party is made better off. The fifth article "Improving Investment Coordination in Electricity Networks Through Smart Contracts" is a technical complement to the previous papers showing with a three-node model that smart contracts can achieve pareto-optimal improvements compared to the status-quo based on optionality and voluntary participation.

1.5 Main Contributions

Vertical separation has been a standard component of electricity restructuring. The positive effects for competition are well understood. However, possible adverse effects and necessary complementary measures to address these have received too little attention in the literature.

This thesis contributes to filling this gap. More complex coordination as one of the core problems that might result from unbundling is the core topic of all papers.

The first paper makes recommendations on governance in future smart grids. Smart grids are politically desired and supported. However, the lack of clear expectations on the regulatory framework, unbundling rules, and operation create uncertainty for the actors. To avoid negative effects for the development of smart grids a better understanding and the development of clear regulatory recommendations is necessary. Chapter 2 contributes to this new discussion.

The second paper examines the incentive compatibility of information exchange as simple coordination device. It applies a cheap-talk model to shed light on one aspect of "coordination losses" from vertical separation, namely inefficient investment. Costless information exchange ("cheap talk") may not achieve coordination because of lacking incentive compatibility. The paper further investigates deep charging as instrument to restore incentive compatibility. The paper thereby contributes to the understanding of the exact effects from unbundling. This is necessary to develop instruments in order to mitigate negative effects. The paper also proposes one instrument to remedy the coordination problem, namely deep charging.

The papers three to five deal with locational pricing for distribution networks as a means to reduce the investment need. They contribute to the debate on efficient network investment and coordination in smart grids. Smart contracts as volunatry agreements to increase efficiency are developed and explored as a novel alternative to institutionalized locational pricing systems.

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2 Governing Smart Grids - the Case for an Independent System Operator

Nele Friedrichsen†

The next years should bring about a rapid transformation of the electricity sector towards high levels of renewable generation. Smart grids are seen as the silver bullet responding to the challenge of integrating renewables, managing flexibility, and keeping the costs down in distribution networks. Network unbundling on the other hand is essential for competition in the liberalized electricity industry. It forces independence of the networks and thereby eliminates concern that incumbent integrated (network) firms discriminate against new entrants. With smart grids the unbundling questions become relevant for distribution networks because active control in smart grids entails discrimination potentials. However, smart grids exhibit coordination needs for system efficiency and unbundling eliminates firm-internal coordination. An independent system operator seems to be an appropriate compromise solution. It eliminates discrimination incentives and serves coordination needs, thereby striking a balance between both competition and efficiency goals.

Keywords: smart grid, unbundling, governance, coordination, independent system operator

JEL-classification: L43, L94, D23, L22, L51

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2.1 Introduction

Climate and energy policy are shaping the future electricity system. The goal of a low carbon electricity system causes increasing shares of renewable energy sources (RES) and distributed generation (DG).[6] The growth of intermittent, decentralized generation puts distribution networks under stress. It overhauls the paradigm of top down energy flow with central controllable generation. This requires adaptations in system planning, management, and expansion. Growing demand or ageing assets are additional challenges in some regions (Veldman *et al.*, 2010). In the European Union distribution network operators expect massive network investment over the next years to accommodate these challenges (Veldman *et al.*, 2010; BDEW, 2011; Ofgem, 2010). Simultaneously they face increasing pressure to enhance energy efficiency on the demand side and in network operation.

Smart grids are considered to help electricity distribution network operators[7] avoid part of the network investment by enabling more intelligent and flexible network management (Veldman *et al.*, 2010, p. 297f). Voltage problems for example are a main problem of DG connection in (weak) distribution networks that can be addressed by targeted feed-in of reactive power, regulation of demand and/or generation, or automatic voltage management at the substation (cf. WIK *et al.*, 2006, p. 54).

Since smart grids facilitate efficient integration of DG and RES, they receive substantial financial and political support[8]. However, full benefits of smart grids can only be reaped if decentralized users and network coordinate. It is not yet clear how this can be achieved, and what the allocation of roles and responsibilities in smart grids will be. This article addresses the necessary degree of unbundling as one aspect of institutional organization of smart grids that is of particular importance.

'Network unbundling', the separation of generation and retail activities from the network business, has been introduced to guarantee non-discriminatory network access for third parties and to foster fair competition. For transmission networks, a big debate on unbundling found its preliminary end in 2009 with the adoption of the third legislative package for Europe's electricity and gas markets that contains measures to ensure more effective unbundling of transmission networks (EC, 2009c).[9]

[6]DG can but does not have to be RES. Large parts of DG are combined heat and power (CHP) plants fueled with natural gas.

[7]This article focuses on the European discussion of smart grids in distribution networks where smart grids are seen as a necessary tool to address the challenges of a low carbon electricity supply and integration of renewable energy sources (RES). In the US also the national transmission system plays an important role when talking about smart grids (see e.g. DoE, 2009). This is driven by an explicit investment need and reliability concerns that the system is facing (Coll-Mayor *et al.*, 2007, pp. 2456; 2461). Recently the discussion started to involve smart gas grids and the combination of different resources to smart poly grids or smart systems (see e.g. Hinterberger & Kleimaier, 2010).

[8]In the European Union this materializes in the renewable directive, the internal market directive, and the directive on energy end-use efficiency and energy services respectively Directive 2009/28/EC, Directive 2009/72/EC, and Directive 2006/32/EC. All these directives encourage intelligent networks or intelligent metering (EC, 2009a,b, 2006). Financial support within the Seventh Framework Programme for research and technological development (FP7) for research and development (R&D) in smart grids, microsystems & ICT, and Green Cars & electromobility amounts to roughly €1.5 billion. FP7 runs from 2007 to 2013. (Cordis, 2009)

[9]The third legislative package on the European internal market for energy consists of two Directives, concerning common rules for the internal market in electricity and gas, 2009/72/EC and 2009/73/EC respectively, and three Regulations, one establishing an Agency for the Cooperation of Energy Regulators, 713/2009, and two on conditions for access to the electricity and natural gas transmission

Distribution networks are still only subject to legal unbundling. This might change in future. I argue that smart grids require a revisiting of the unbundling question for distribution networks. Two aspects are central: First, vertical integration of networks with downstream activities incurs discrimination potentials that an integrated incumbent could exploit to hinder competition. Second, separation inhibits firm-internal coordination. This can induce adverse effects on operational efficiency and hinder the coordination of network development and (distributed) generation. Clearly these aspects represent a trade-off. More organizational integration enables distribution network operators to actively manage and coordinate the complete system. At the same time discrimination becomes increasingly a problem in actively managed smart grids. In a recent communication the European Commission recognizes that smart grid technology gives DSOs "detailed information about consumers' consumption patterns" which could lead to competitive distortions. The commission diagnoses that the "regulatory setting will need to ensure that these risks are properly addressed" (EC, 2011, p. 10). The question is how to best strike a balance between competition goals and coordination needs.

The article investigates theoretical arguments in the debate on unbundling and smart grids in the framework of transaction cost economics. The main conclusion is that smart grids do require unbundling to prevent discrimination. However, they form complex systems that need coordination. Therefore, I argue that a compromise solution between vertical integration and ownership unbundling, an independent system operator (ISO), is a good governance model. The ISO is not suspect to discrimination incentives but would still enable system wide coordination. Hence, this solution consolidates both competition goals and coordination requirements while avoiding the difficulties of a forced ownership change.

The paper is organized as follows. Section 2.2 presents two opposing perspectives on unbundling: the competition policy perspective and the transaction cost economics perspective. Section 2.3 gives a brief introduction to smart grids. Section 2.4 analyses the institutional form for a smart grid in view of the pros and cons of unbundling. Section 2.5 concludes.

2.2 Background: Vertical Integration and Unbundling

Electricity supply in most countries has traditionally been realized by vertically integrated undertakings in regional monopolies.[10] This has been changing since the end of the 20th century when countries around the world started restructuring their electricity sectors. Privatization and vertical unbundling were two main ingredients of reform (Joskow, 2008). Restructuring aimed to improve sector performance by relying more strongly on competitive forces in power generation and retail supply. The network as physical infrastructure essential to transport power to customers remained regulated because it constitutes a monopolistic bottleneck.[11] Vertical integration of networks with generation and retail is seen with suspicion because of possible anticompetitive effects. While unbundling certainly has positive effects for competition policy there is another side of the coin. Transaction cost economics draws attention to the possible negative effects of unbundling underlining positive effects from vertical integration. The following paragraphs describe the advantages and disadvantages of unbundling in turn.

networks, 714/2009 and 715/2009 respectively. They are published in EC (2009c).

[10] Joskow (2008) gives an overview of electricity sector reform. Detailed country studies are collected in Sioshansi & Pfaffenberger (2006).

[11] For an overview on the theory of monopolistic bottlenecks and the consideration of competitive versus regulated markets see Knieps (2006).

2.2.1 Advantages of Unbundling: Competition Effects

Vertical integration between the networks and generation or retail can be motivated by anticompetitive behaviour (Perry, 1989). Integrated companies could possibly exploit their position in the network monopoly to hinder competition at the other stages and create or protect market power. Even under the assumption that regulation prevents direct price discrimination in the access charges, incumbents could engage in non-price discrimination or 'raising rivals' costs' (Beard *et al.*, 2001). In the case of electricity supply this can be hindering and delaying network connection or cross subsidies between network and competitive stages.[12] The European Commission identified vertical integration as a major obstacle to achieving the benefits of a competitive electricity market and subsequently introduced network unbundling to prevent such anticompetitive behaviour and create a level playing field for new entrants vis-a-vis incumbents (EC, 2007).

Furthermore, an integrated network firm may have insufficient incentives to invest in interconnector capacity. Assume a country A with low cost generation and a country B with high cost generation. The interconnection between A and B is congested. Assume further a vertically integrated utility in B. Expanding the interconnector enables generators from A to supply customers in B intensifying competition for B. Therefore the integrated company has incentives not to invest in interconnector capacity to protect its home market. This so-called 'strategic investment withholding' has been another significant argument for transmission unbundling because insufficient interconnection hinders the development of the European internal market for energy (Balmert & Brunekreeft, 2010; EC, 2007). For distribution networks, however, the argument is irrelevant because they are usually isolated subnetworks connected at singular points to higher voltage networks without any interregional linkages.

2.2.2 Disadvantages of Unbundling: Transaction Costs and Coordination

Anticompetitive motivations for vertical integration are the main argument in favour of unbundling to enhance competitiveness and in the end social welfare. Notably, there is another side of the coin. Transaction cost economics (TCE) describes integration as organizational choice to enhance efficiency (Coase, 1937; Williamson, 2000). TCE assumes that the 'transaction costs' of using the market mechanism, such as effort for information search, negotiation, or contracting, determine the make-or-buy decision. Vertical integration or more generally within-firm organization of transactions is chosen if this is more economical than market transactions. A forced unbundling would in this case sacrifice vertical economies of scope.

Indeed such integration economies are present in electricity supply because of complex interrelations across the system. Efficient management of the electricity supply system requires careful coordination across the vertical stages of the supply chain both in operation and with respect to investment decisions. This has been analysed in detail for transmission networks in the seminal work of Joskow & Schmalensee (1983) and confirmed empirically (see for example Nemoto & Goto, 2004; Kwoka, 2002; Kaserman & Mayo, 1991). Meyer (2011) provides a recent empirical and theoretical overview of vertical synergies at transmission level.

In smart distribution networks similar interactions can be expected because the generation feed-in in distribution networks is increasing. As a consequence, power flow in distribution networks is not anymore unidirectional top-down, but increasingly also bottom-up. This development triggers a change to more actively managed distribution networks, similar to the present management at transmission level.

[12] The existence of cross subsidies in electricity network practice is disputed. The Dutch regulator did not find evidence for cross subsidization in Dutch network companies (NMa, 2007).

This article analyses unbundling and smart grids from the perspective of transaction cost economics. More specifically it relates to the research on coevolution of technology and institutions in infrastructures. This approach, also referred to as coherence theory, widens transaction cost economics by the integration of the technological dimension (Künneke *et al.*, 2010). Künneke *et al.* (2010) identify critical technical functions that determine demands on the organizational form. They argue that the degree to which institutional form and technological practice are coherent impacts system performance. Coherence theory posits that different organizational arrangements might be needed to fulfill the coordination needs of different technical functions in the electricity system. Furthermore, the necessary scope of control and speed of adjustment with respect to the critical technical functions are important characteristics to determine the organizational form (Künneke *et al.*, 2010, p. 503). Functions that exhibit a need for system level control and a high speed of adjustment call for direct central control. In cases that allow longer time for adjustments decentral coordination and guided planning can be sufficient.

In electricity networks the most obvious 'time'-critical technical function is system management: reliable operation of the power system requires a balancing of supply and demand at every point in time. A lack of coordination can cause operational problems and may in the end impair system reliability. Since the time period in which the balancing has to take place is very small with less than a second to react, market mechanisms are unsuited to ensure reliability, but a central coordinating entity is needed. For system development on the other hand, coordination can take longer time. Hence market coordination and guided planning may be sufficient.[13][14]

2.2.3 Status-Quo of European Policy on Unbundling

Transmission Unbundling

The European Commission proposed ownership unbundling for transmission network. However, no consensus on this strict option was found. The outcome is a political compromise represented in directive 2009/72/EC that leaves three options to comply with stricter unbundling requirements:

Full Ownership Unbundling prohibits joint ownership of network and generation or retail assets within one firm.

Full ownership unbundling is expected to completely eliminate any discrimination incentives and abilities of the network firm and thereby benefit competition. However, ownership unbundling eliminates firm-internal coordination along the vertical supply chain. External coordination is necessary to avoid adverse effects on system reliability and efficiency. Since ownership unbundling forces a divestiture of integrated firms, the legal acceptability has sometimes been questioned (e.g. Pielow *et al.*, 2009; Talus & Johnston, 2009).

Independent Transmission Operator (ITO) The ITO model is also known as Efficient and Effective Unbundling (EEU) or 'third way'. This option requires a strengthening of the current legal unbundling rules. It allows companies to retain both network ownership and

[13] On the European level, we observe a tendency for long term (central) planning for system development with the 10-year-network-development-plan (TYNDP), published by the European network of transmission system operators (ENTSO-E). At a national level, long term development statements published by network operators (Ofgem, 2007b,a) are elements that move in this direction. They can increase transparency and promote coordination of developments.

[14] Theoretically, also simple communicationcan enhance coordination: the network could ask generators about their plans to adapt its network expansion to the developments at the generation stage. Unfortunately simple information exchange might fail due to strategic behaviour (Brunekreeft & Friedrichsen, 2010).

management, but it puts strong limitations on cross-involvement of employees to assure independence of the network (Brunekreeft, 2008; Wachovius, 2008; Schmidt-Preuss, 2009). ITOs are not considered further in this paper because, if applied strictly, they come near to an ISO concept. More likely though, they are an inferior solution since they might still leave room for discrimination due to inherent information asymmetries between the integrated firm and any controlling agency.

(Deep) Independent System Operator (ISO) An ISO requires that an independent entity takes over operational activities in the network. The network ownership can stay with the integrated or any other firm. The ISO is not allowed to be active in generation or retail businesses. The prefix *deep* indicates that the ISO is authorized to decide on network investments. This is necessary to address the problem of strategic investment withholding. Otherwise the network owner with generation affiliates could still protect its home market by not investing. However, the deep solution allocates investment decision and financing to different parties; the network owner has to carry out the desired investments or open the way to another investor. This split between decision maker and risk bearer might come with other problems (Balmert & Brunekreeft, 2010, pp. 34-35).

The ISO concept addresses discrimination concerns without requiring ownership changes. Importantly, because discrimination is not an issue anymore, an ISO can be left freedom to coordinate system actors from a central perspective, at least partially. This is not an argument against ownership unbundling, but only the claim, that it might not be required to go that far unless structural separation involves other benefits. This is important when judging whether the degree of separation required is proportionate.

Distribution Unbundling

Distribution networks are currently only subject to legal unbundling. This includes unbundling of accounts, operations and information. Similar to the ITO concept legal unbundling only encompasses administrative separation though in a less restrictive form. Eventually a discussion to strengthen the rules for distribution networks is likely to start for two reasons.

- First, European regulation has shown increasing rigor over time for transmission networks. In 1996 unbundling of accounts was introduced (Dir 96/92/EC). Legal unbundling, including informational and operational separation was added in 2003 (Dir 2003/54/EC). In 2009 the third legislative package mentioned above expanded the requirements even further (Dir 2009/72/EC).
- Secondly, recent developments with respect to smart grids and the immense development of DG make the unbundling question increasingly interesting because of discrimination concerns and coordination needs.

2.3 Smart Grids

Smart grids is an umbrella term, which is used for several concepts including demand side management, generation management, targeted black outs instead of whole area failures, and smart metering (Granger Morgan *et al.*, 2009). In this article smart grids are referred to via their goal, improving network management and efficient integration of DG, RES, and demand side flexibility which are key challenges for today's distribution network operators. This is assumed to relax the need for network investment (Veldman *et al.*, 2010, p. 297f). As commonly understood, smart grids apply information and communication technology (ICT) to achieve this goal.

Many components of smart grids are already known from transmission networks where most equipment allows remote supervision and control. In contrast, distribution networks are largely still operated relying on local personnel. Advancing and transferring the technology from transmission to distribution networks is a central part of making the distribution grid smart. Furthermore, smart metering in combination with dynamic pricing is expected to mobilize the demand and generation side and thereby increase efficiency. One point which is not settled yet is the level of control in smart grids. The polar cases are central and decentral control.

Decentral control Smart grid tools can support conventional re-active system management. This can be improvements in the knowledge of the network operator on the system conditions in any, even remote locations of his network, or remote control in substations and distribution automation. Furthermore, flexible load and generation can be integrated via more dynamic price systems and innovative contractual solutions.

Load and generation control remain decentralized with the respective actors. Therefore such a decentralized approach to control needs to be complemented by a coordination mechanism. First, coordination is necessary to guarantee critical technical functions. Second, it is required to achieve system efficiency. Uncoordinated behaviour is unlikely to fully exploit the individual flexibility for system optimization because each actor acts in its own interest without taking into account the system perspective. This system perspective however is necessary to exploit the full potential of smart grids for improving system efficiency (WIK *et al.*, 2006, p. 140).

Central control Other smart grid concepts foresee a central, holistic system management. The overall aim of such a concept is to reduce network losses, defer investment or support reliability. These concepts typically include active control of generation and demand resources by the network or system operator which effectively entails a centralization of control rights. For resources that are not under the ownership of the operator the respective owners would need to transfer control rights to the network operator.

Anecdotal evidence suggests that the complication of the necessary arrangements in liberalized markets hinders direct control (Bertram, 2006). One possible reason is the disintegration of the supply chain. When network operation and supply are not under the same responsibility, the arrangements necessary for load control including a network focus become more complex. Interruptible contracts and ripple control for example are a common instrument to enhance system reliability or provide reserve services. They offer a financial compensation or rebated tariffs for participating customers. However, if supplier and network are separate entities and have diverging objectives, it is far from obvious how network concerns enter the supply contracts and who has the responsibility to send the control signal.[15]

2.4 Governance in Smart Grids: the Case for an ISO

The structures of actors and technology become increasingly decentralized by the growth of distributed generation and demand side flexibility. In future smart grids, demand and generation will be active components in system optimization. Even with efficient network expansion, congestion can occur in some instances on some lines. In those cases the system operator has to balance the system which requires, at least partially, central control. Furthermore, coordinated siting and local balancing of load and generation allows better use of existing capacity and enhances system

[15] There may also be other motivations to discontinue ripple control: regulatory pressure to save cost can represent a disincentive for load control since cost for installation of the control equipment are one place to save fixed costs (Stevenson, 2004, p. 4). Furthermore, experience from New Zealand suggests that commercial suppliers abandoned ripple control which was widely used in monopoly times, to benefit from demand driven price spikes (Bertram, 2006, p. 204, footnote 2).

efficiency by reducing network losses. Modern ICT and intelligent control technically enable and support the incorporation of decentralized resources into the management of smart distribution networks. Using these technological advances might require adaptations in the mode of organization. The desired governance model needs to strike a balance between coordination need and discrimination concerns in system operation and system development.

The most relevant point where coordination is indispensable is system operation. Clearly system operation requires certain central control to satisfy the need for real time coordinated actions in balancing. Furthermore, even with advanced market coordination, a system operator is needed to realize dispatch decisions that come out of market mechanisms. A central controller may also be beneficial to integrate small-scale flexibility potentials that are not economically accessible via market coordination. However, the central controller is naturally endowed with enormous power that is linked to the ability to discriminate.[16] Therefore the central system operator needs to be neutral.

Apart from the operational level, further benefits can be generated by coordination of network and generation investment because "piecemeal" connection is frequently less efficient than coordinated system planning[17] (Baldick & Kahn, 1993). Connection of DG can cause system benefits or cost increases, depending on local system conditions (cf. Ackermann, 2004, Ch. 5). Especially for increasing shares of DG a cost increase is likely Niesten (2010). Therefore, system efficiency mandates coordination of network and generation to exploit the trade-offs between network expansion, generator siting, and operational management (Strbac, 2008, p. 4422). In contrast to system operation, coordination of system development does not need to happen in real time. Hence, no central coordinator is needed. Planning might well be sufficient. Also with regard to network connection discrimination can be a problem when the network operator is integrated. However, it seems that this problem can be and is already adequately addressed with the existing rules on non-discriminatory network access. Possible discrimination can be revealed and punished more easily which makes it 1) easier to control and 2) less attractive in the first place.

Hence, the important question in smart grids relates to system operation: who decides which generators and/ or demand units to control to restore system balance? A governance structure is needed that balances discrimination concerns and coordination need. I suggest that an independent system operator can be the adequate middle way. The following paragraphs explain why. Drawing on the discussion of transmission network organization presented in section 2.2.3, three possible governance models are differentiated: full ownership unbundling, independent distribution operation, and independent system operation.

2.4.1 Full Ownership Unbundling

Separating the network completely from generation and retail creates an independent distribution network operator (DNO). The DNO would own and operate the networks and have no affiliations to any generators, retailers or customers. This most effectively addresses discrimination concerns. However, similar to the debate at transmission level, it is debatable whether such a measure would be proportionate. Furthermore, the exploitation of coordination benefits under ownership

[16]While discrimination can be welcome in some cases such as favouring sustainable energy production over conventional generation, in general discrimination is considered undesirable as it may impede fair competition. Kruimer (2010) gives a detailed analysis of (non-) discrimination in the context of energy system operation.

[17]Baldick & Kahn (1993) illustrate the investment interdependency with a three node network. They show that a lack of coordination may cause inefficiencies because network expansion critically depends on the development of generation.

unbundling is not obvious. While vertically integrated firms could coordinate generation and network decisions firm-internally,[18] the decentralized structure of liberalized electricity markets carries the risk of network operators disregarding these benefits in favour of network investments (Piccolo & Siano, 2009). Furthermore, network users may lack incentives to take their impact on the system into account. Hence, an external coordination mechanism is needed.

The price is the standard coordination mechanism for decentral activities in economic theory. Applied to smart electricity grids, a market that could provide system coordination needs to unify all different actors, including the network operator. Generators, consumers and prosumers[19] typically control their energy consumption or production themselves.[20] Imagine a couple of electric vehicles that charge driven by low spot market prices. Without further coordination, they might charge all at the same time and cause local network congestion. Efficient prices would reflect this scarcity of network capacity and thereby signal network customers to reduce their demand. Hence, prices for electricity would differ across location and time depending on the network losses and local congestion. Equilibrium prices would then send signals such that individual behaviour yields system optimality. Importantly, control remains decentralized with individual actors in this case. At present, most retail customers receive flat, averaged tariffs that are neither differentiated by time nor by location. More refined pricing and metering (smart meters) would have to accompany future markets for smart grids if prices are supposed to coordinate customers.

There are three critical points to make on decentral coordination of electricity (distribution) systems.

1. The first problem of market pricing to assure optimal coordination is the assumption that prices reflect all relevant characteristics. Cost-reflectivity creates incentives for customers and generators to participate in system management. Several approaches to efficient network pricing exist (see e.g. Schweppe *et al.*, 1988; Hogan, 1992). The debate is very advanced at the transmission level (for an overview see Brunekreeft *et al.* (2005)) but only recently becoming a topic at the distribution level, too (cf. Li, 2007; Prica & Ilic, 2007; Pudjianto *et al.*, 2007; Brandstätt *et al.*, 2011). For some characteristics like network congestion cost and cost of losses, market coordination has been successfully realized in practice via nodal pricing.[21] However, it is debated whether prices are able to reflect all relevant system aspects. Nodal prices mainly send short run signals, signals for investment decision are considered to be insufficient (Brunekreeft *et al.*, 2005). Furthermore, the value of reliability and the trade-offs between network expansion and generator siting seem to be critical but difficult to reflect in prices (Brunekreeft *et al.*, 2005).

2. The second critique is motivated by transaction cost economics: some real world characteristics limit the efficiency and effectiveness of possible coordination via the free market. Theoretically, decentral coordination via a market should be able to exploit the same optimization strategies as firm-internal control: actors could trade-off flexibility potentials in the market and transfer the necessary rights to a coordinator. Then the coordinator would regulate some demand or generation to reduce network costs if this is efficient. The

[18] This is a simplifying assumption. Even within an integrated firm, problems of coordination among the different division and supply stages are frequently present. A whole strand of literature deals with agency problems in firms. For an overview see Miller (2005).

[19] Prosumer refers to a customer who both consumers and produces electricity at its connection point.

[20] In future self-control will be assisted by automation devices. The user programmes the automation device to switch appliances on or off based on electricity prices.

[21] At transmission level, several markets around the world rely on nodal pricing, most prominently PJM in the US.

network operator would buy this service of flexibility or the associated transfer of control rights in the market.

However, this equality of market outcome and firm-internal coordination is only true for a world with perfect information and costless transactions. In the real world with transaction costs the outcome of decentralized coordination may deviate from the centralized optimum for two reasons.

- First, prices or contracts are likely to not include all the relevant information as mentioned above. This implies that operators might be insufficiently informed about control potentials at the customer side and the customer's willingness to accept control interventions.
- Secondly, individual actors might benefit too little from being active in the market compared to paying standard tariffs. Transaction costs in the form of time spent, knowledge acquisition, and effort might be higher than expected benefits.

Hence, transaction costs are a barrier for efficient decentral coordination. With contracts and market transactions, it can be infeasible to exploit the same optimization strategies as under integration.[22]

Future developments are expected to reduce transaction cost of market participation. This includes for instance automation technology that assist users in reacting to prices and new market actors that aggregate smaller participants to larger units such as virtual power plants. Such tools are projected to enable near real-time coordination (Kok, 2010). Thereby technological developments together with market and pricing innovations increase chances for decentralized self-organization of electricity supply (Kiesling, 2009). Hence, in future the scope for market coordination in smart electricity systems might increase. Currently though, the relevant markets do not yet exist but are a topic for research and development (see e.g. the projects E-Energy in Germany or Gridwise in the US[23]).

3. Furthermore, and this is the third point, technical characteristics demand some degree of central control. Despite far reaching market coordination a system operator equipped with certain control rights is still necessary to oversee and ensure emergency system balancing (Künneke *et al.*, 2010, p. 499).[24] The components of an electricity system or specifically the smart grid are interdependent. System reliability is a critical technical function with a necessity for fast adjustments. Central coordination is therefore indispensable for technical system coordination in the balancing area. Hence, even with an increase of smaller decentral actors and decentral coordination facilitated by advanced automation and new markets, a party is needed that bears the responsibility for system stability – a system operator. This party will retain certain central control rights for emergencies and basic ancillary services.

Taken together I conclude that the price mechanism is not sufficient to address all coordination needs in smart grids even though the potential for decentral coordination and self-organization[25] increases in smart grids with advanced information, communication, and automation technology.

[22] This parallels the findings of Coase (1960). Assume a good that benefits different parties. Coase (1960) investigates the effect that the allocation of rights on that good has on the final outcome. Under standard economic assumptions including zero transaction costs the rights' allocation does not affect the final outcome. In a world with costs of market transactions, it does.

[23] see "www.e-energy.de/" and "www.gridwise.org" or "www.gridwiseac.org" for further information.

[24] System balancing is currently a task of the transmission system operator. Whether or not with s mart grids some tasks shift to distribution system operators is still open.

[25] Recent research addresses bottom-up self-organization in infrastructures and decentralized coordination of electricity supply (see e.g. Kiesling, 2009; Egyedi *et al.*, 2007). Agent based systems are the technological grounds for decentralized coordination (see for example Kok, 2010).

2.4.2 Legal Unbundling – Independent Distribution Operation

If system coordination via a central entity is still necessary over and above market coordination, the first intuition would be to leave this responsibility with the legally unbundled network operator. This corresponds to the ITO model for transmission, which is legal unbundling complemented with additional behavioural prescriptions to safeguard against discrimination concerns. This article argues that this will become unfavourable in smart grids. It might be unattractive to the network operators because of high transaction cost to guarantee non-discrimination. Importantly, the notion of legal unbundling used here does not stop with the separation of the network into a separate legal entity. It is understood explicitly to include informational and operational separation.

Apart from safeguarding reliable operation, sector organization has to guarantee non-discrimination and neutrality. The system operator balances generation and load at every point in time subject to the capabilities of the network. He may therefore control generation or load resources to manage congestion or restore system balance. Neutrality is a precondition for a network operator that takes such coordinating actions to avoid any discrimination. While traditionally the problem in distribution was minor, in smart grids discrimination can become a problem because the scope and necessity for control interventions increase. Along with the ability to control third party resources, comes the potential to use them to the own benefit and disadvantage of others. If the central controller is an integrated company that owns generation it could for example turn on/ off third party generation more frequently, which increases wear and tear, and run own generation at optimum.[26] Therefore, non-discrimination in control interventions and in the respective contract design is vitally important.

In integrated firms not every discrimination potential can be prevented by behavioural prescriptions and supervision. The integrated firm will always have an informational advantage over third parties. Therefore, the central controlling entity needs to be neutral and independent so as to avoid any *incentives* to discriminate. Today the total effects of possible discrimination are likely to be limited since generation in distribution networks is only a small percentage and active integration of demand is still rare, but the shares are likely to grow. Hence, smart grids reinforce the need for effective unbundling at distribution level.

Legal unbundling already aims to ensure neutrality of the network operator. But in smart grids, it might be impossible to guarantee this neutrality if the network operator still has affiliated retail and/ or generation activities. The high number and small size of actors and transactions makes it extremely difficult to prove neutrality in the choice of control actions. If neutrality cannot be guaranteed and tested with the status-quo, it can be advantageous to move to a truly neutral operator. Otherwise, the threat of discrimination can hinder smart grids because actors and investors are less willing to participate in innovative concepts that involve coordinated control.

Of course the law already prohibits discrimination and legal unbundling curbs the potential to discriminate. However, the burden of proof can be a significant obstacle for small actors in discrimination cases because they need to show that they have been discriminated. This is detrimental if it overly disadvantages the possibly damaged parties in comparison to the possibly discriminating actor. A measure to remedy discrimination concerns with legal unbundling can therefore be to allocate the burden of proof with the network operator. In Germany, for example, the network operator has to justify unequal treatment with regard to network access and proof that its behaviour has been non-discriminatory (Bundeskartellamt, 2001). The line of argument is that the network operator is better informed and generally suspected of discrimination es-

[26] The same could be true for customers: preferential treatment of customers of the affiliated retailer in case of curtailments or control actions. However, stakes are small at the retail stage compared to generation.

pecially when negating access to its network or charging unusually high prices. The European Commission proposed a similar approach in its white paper on damages actions for breach of the EC antitrust rules (Cook, 2008; EC, 2008). Applied to network operation, this could imply that network operators are under continued threat. If it is indeed difficult to prove discrimination or non-discrimination, they might find it favourable themselves to opt for an independent system operator structure to avoid unnecessarily high cost if customers claim damages from discrimination.

2.4.3 Independent System Operation

An ISO allows centralized coordination while ensuring non-discrimination for all actors. At the same time it avoids complex behavioural and informational separation prescriptions. The ISO is the responsible party to physically manage the system implementing market outcomes as far as possible, give feed back on physical constraints, and assure balancing. The ISO model allows network owners to engage in the generation business. This can be a new and attractive business opportunity[27] but it could also enable efficiency gains from coordinated investment in lines and generation.[28] Furthermore, system operation can be combined with the information function in smart grids.

Obviously the information infrastructure is a vital component in smart grids. Especially decentralized approaches towards control reinforce the demand on information and communication across the system. This is likely to generate extensive data flow. These data are on the one hand price information flowing to consumers and thereby informing them about system conditions. On the other hand it is information about current status of generation, load, substations, other system components, or the system conditions such as voltage or frequency. In the simplest case diverse users could jointly use one common information infrastructure for diverse purposes: network information, demand side management, virtual power plants, and smart metering (WIK *et al.*, 2006, p. 121).

Importantly, such an information grid, similar to the electrical grid, needs to be operated independently with regulated, non-discriminatory access to information to prevent competitive distortions. A key point to contain the discrimination incentives is the neutrality of the information entity. Since this is also a key requirement for system operation, the idea lies near to combine both functions and give the information function to an independent distribution system operator. An ISO can bundle information handling with system operation which requires extensive and largely similar information. This combination extends the idea of Künneke & Fens (2009) who proposed a central independent agent for information processing. Such centralization re-simplifies the information streams that have diversified dramatically during restructuring. Künneke & Fens (2009) assumed ownership unbundling plus an independent information entity. An ISO solution further simplifies the structure by combining system operation and information tasks and avoids the duplication of information infrastructure. It also secures the access to the relevant data for the system operator which is important on reliability grounds.[29]

[27] Traditionally, in Germany many municipal utilities did not own a lot of generation capacity but examples show that this might change. EWE (after takeover in 2009 including SWB), Stadtwerke München, and MVV, three of the bigger utilities after the 'big four', all invest in renewable energy projects, CHP, and smart grids, and position themselves as innovative, forward looking, and environmentally conscious companies (SWM, 2008; MVV, 2010; EWE, 2010).

[28] With this line of argument, unbundling regulation in New Zealand was loosened for distribution network operators (MED, 2006).

[29] Furthermore, information handling needs to fulfill requirements on data privacy and security (for more information see e.g. McDaniel & Smith (2009)).

Obviously, an important precondition for a functional ISO solution is that it has the correct incentives to optimize the system and behave neutral towards all participants. The ISO can for example be created as club solution or as completely independent entity (Brunekreeft *et al.*, 2007). Details are likely to matter when creating such entities which is an important topic for future research.

The club solution for example is known from the US in the service areas of PJM and New England-ISO (Brunekreeft *et al.*, 2007). The club consists of all different stakeholders: network owner, generators, traders, and customers. They elect a board of independent representatives; hence their impact is only indirect. However, such a concept could conflict with current EU legislation that prohibits significant cross-involvement in network and generation (respectively retail) activities. Hence, the participation of these actors in board elections may be problematic.

Standards for data format, information handling, and transfer protocols are another important requirement to assure easy and system wide exchange.[30] It is self-evident, that the process of standard setting bears large potentials to distort competition and hence needs to be neutral. The European Union has recognized the importance of standardization and pushes for their development and implementation (EC, 2011, p. 6).

2.5 Conclusions

Smarter network and system management improve the integration of intermittent renewable generation and flexible demand. Smart grids are therefore considered essential for the rapid decarbonization of the electricity system needed to fight climate change.

Smart grids develop their full potential of advanced system management if they integrate the whole supply chain. Importantly, in a liberalized and unbundled market no actor has an inherent interest to optimize the whole system. Theoretically, an adequate price system could set incentives such that the system is optimized based on decentral decisions. However, this might be difficult in practice, because of transaction costs and infeasibilities to implement full cost-reflectivity. More importantly, in electricity certain critical technical functions such as system balancing require central control even if large parts of system coordination can be realized in a market. Therefore, a central coordinating operator is needed.

The problem of decentralization does not uniquely lay in unbundling, but rather in sector liberalization and the increasing competition which is beneficial. Hence, the argument cannot be to reverse unbundling as this does not solve the problem.[31] Rather, smart grids reinforce the need for unbundling because of discrimination concerns. A governance structure is needed to balance both discrimination concerns and coordination need.

Tapping the full potential of smart grids is considered to require some delegation of control for efficient system management. Capturing network benefits of demand side management e.g. requires allocating control to the network operator. This speaks in favour of central control approaches because differentiated retail tariffs alone are not suited to induce the desired effects as long as they do not incorporate a network component. However, central control concepts incur discrimination potential and therefore increase the need for effective unbundling. The network in its enabling function for DG and competition in generation and supply should therefore be operated independently.

Given these characteristics of smart grids, independent system operation seems to be the most

[30] Standards also benefits competition in the markets related to metering and information software and hardware as the product and services become more homogeneous.

[31] Strbac (2002) even argues that DG inevitably leads to unbundling and a changing role of the network operator.

adequate unbundling concept for distribution networks. The question how to address interconnector investments, which is a significant concern of ISOs at transmission level, is irrelevant in distribution. Therefore, the argument against ISOs, the necessity of the problematic deep ISO solution, falls away and incumbent network firms could even retain investment authority. No ownership unbundling is necessary to achieve the goals of unbundling. Furthermore, an independent distribution system operator can perfectly be combined with the information function that is central to smart grids. Hence, the ISO simultaneously addresses discrimination concerns and coordination requirements and could fulfill the challenge of bringing more active management to distribution networks.

Importantly, the governance structure of the ISO is another important issue which should be addressed in further research. The key of an ISO clearly is the independence of network operation, hence the immediate question is: how is the ISO owned and controlled? But it is not yet sufficiently clear how an ISO for smart grids should optimally be structured and what its tasks should be. An ISO can for example be created as a club solution representing all different stakeholders or as completely independent entity (Brunekreeft *et al.*, 2007). Critically, such a concept needs to fit with EU requirements that limit cross-involvement in network and generation (respectively retail) activities.

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3 Vertical Unbundling and the Coordination of Investment – Can “Cheap Talk” Alone Solve the Problem or Do We Need “Deep Charging”?

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This paper provides a formal analysis on the investment coordination problem in a vertically separated electricity supply industry, although the analysis may apply also to other network industries. In an electricity system, the investment decisions of network and power plants need to be coordinated. In unbundled markets, firm-internal coordination no longer applies. We develop a formal approach to examine whether simple information exchange (“cheap talk”) could restore coordination. We adopt a three-stage profit-optimized investment model, with a (regulated) monopoly network and two asymmetrical Cournot-type generators. To analyse credibility of cheap talk we apply the concept of self-signalling in a game with incomplete information and positive spillovers. We show that cheap talk cannot generally solve the investment coordination problem and as a result separation may actually cause a costly coordination problem. We propose cost-reflective, locational network pricing as a coordination device to internalize the incentive problem.

Keywords: cheap talk, unbundling, game theory, network, investment, coordination, network charging

JEL-classification: C72, D23, L22, L51

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3.1 Introduction

Liberalisation of network industries like electric power markets is meanwhile well established in many countries around the world. To promote competition, we observe a tendency towards vertical separation of monopolistic networks from commercial businesses. There are different variations and names of vertical separation; we follow the recent debate in European energy markets where vertical separation of networks is called “network unbundling” (see European Commission, 2007, p.226). The most extreme form of unbundling is ownership unbundling where vertically integrated companies are forced to divest the network from the commercial businesses. One of the consequences of unbundling is a decentralisation of decisions, including investment decisions. In large technical systems, the vertical stages in the production chain are complements and usually the decisions, actions and investments require careful coordination. With vertical separation, firm-internal coordination falls away and should be replaced by external coordination of the market.

In this paper, we will apply our ideas to the electricity sector. In the specific case of electricity supply, ownership unbundling means to separate the transmission network from the generation power plants.[32] In practice, the investment coordination problem is getting urgent. In many countries, the sector faces substantial investment needs in network and generation. Enforced by climate change policy, the electricity sector awaits large uncertain changes in technology and fuel mix. In particular, we observe plans for large-scale expansion of offshore wind, solar energy, small-scale decentralized generation, clean-coal and nuclear power. These developments have large impacts on the design and expansion of the high-voltage transmission grids. Exactly this is the root of our problem. The optimal development of the network depends crucially on the location and capacity of the power plants to be connected to the network. However, the network needs to be planned years ahead of the planning of new power plants. In the liberalized world an investment in a power plant is commercially strategic information, which appears to be confirmed in practice as experienced by institutions such as NERC (cf. Brunekreeft & McDaniel, 2007, p.332/333). In the “Ten Year Network Development Plan”, the group of European TSOs, ENTSOE (2010, p.38) states: “As a matter of fact, the most important source of uncertainty came as the consequence of the more complex coordination between generation and transmission planning due to the unbundling of the industry enacted in 1999” and that “a large number of these [connection] requests do not materialise into concrete projects and there is no requirement for developers regarding the transparency of their portfolio evolution. This portfolio often encompasses projects in very different locations”. Firm-internal coordination has fallen away and the question then is, how does the market coordinate the simultaneously optimized investment decisions of the network and the power plants?

If the problem is that the network planner does not know the investment plans of the generators, the obvious answer would be that the network planner simply asked the generators.[33] The obvious counterargument would be strategic behaviour of generators, who might have an incentive to lie. The coordination problem may thus be an information problem or an incentive problem or both. In this paper, we examine the coordination problem in a formal model and

[32] In practice, one should distinguish the debate on the high-voltage transmission network from the low-voltage distribution network. Although the debates are actually different, we note that the main insights of the paper apply to both types of network unbundling. For convenience, we concentrate on the better known debate on high-voltage transmission networks.

[33] The European Transmission System Operators proposed exchange of detailed information about projected time schedules, exact location or connecting point as well as project plan and electrical configuration between investors and grid operators at an early stage of planning as necessary tool to mitigate difficulties in network planning caused by uncertainties (ETSO, 2003, p.19).

ask whether simple exchange of information can solve the investment coordination problem. In more formal terms, we examine whether "cheap talk", as game theoretical concept for costless communication, is credible and can solve the investment coordination problem. The pay-offs in the decision-matrix are formally derived from a profit-optimized, two-stage vertical model (a monopoly network and a two-firm Cournot generation duopoly). Our cheap-talk credibility criterion relies on the "self-signalling" concept as defined theoretically by Aumann (1990) and Baliga & Morris (2002).

In this paper we put forth two propositions. First, we show that cheap talk cannot generally solve the investment coordination problem and that this can be bad for social welfare. Therefore, we cannot generally rely on information exchange to solve the coordination problem. Efficient network planning requires more. One option is locational network pricing. Second, we show that optimal locational prices need not be equal to full-cost deep charging. Most likely and certainly for relevant cases, the optimal locational network price is lower than full-cost deep charging

We stress that we do not make conclusions on the total effects of vertical unbundling. We have explicitly not modelled the benefits of unbundling and thus we cannot make an assessment of the net effects. We merely argue that an undesirable side-effect of unbundling are coordination costs that should be addressed with market coordination in the form of locational network prices that reflect network investment costs.

This paper is organized as follows. Section 3.2 briefly reviews the relevant background literature. Section 3.3 outlines the model and section 3.4 brings the results for cheap talk and shallow charging. Section 3.5 then investigates locational pricing. Finally, section 3.6 gives a discussion of the results and concluding remarks.

3.2 Literature

3.2.1 The Investment Problem in the Liberalized Electricity Supply Industry

Electricity market organization changed dramatically over the last decades. The incumbent vertically integrated monopolies have been restructured in many countries to foster competition. Vertical network unbundling of the energy sector was fiercely debated by the European Commission in 2008/9. Unbundling of monopolistic networks from generation and supply activities has been introduced to promote competition and improve incentives for network investment by network companies (European Commission, 2007; Balmert & Brunekreeft, 2010). On the other hand, network unbunding decentralizes the decisions in the vertical production chain. Electricity supply is a complex and highly interrelated system. Any required network upgrading critically depends on generation expansion and system optimization needs careful coordination (Joskow & Schmalensee, 1983). Baldick & Kahn (1993) illustrate in a three node network how optimal transmission investment depends on the division of generation capacity expansion among two locations. The important lesson is that the lack of information about investment plans in generation complicates network planning and possibly leads to inefficiencies. Empirical studies confirm diseconomies of vertical separation in electricity networks (e.g. Meyer, 2011; Nemoto & Goto, 2004; Kwoka, 2002). We focus on inefficiencies resulting from a lack of coordination, which we call "coordination costs".

One particular form of coordination costs arises if poor coordination results in an inefficiently large network. No single firm would know this individually, but the empirical studies would pick it up. The coordination problem of network development and generation expansion is currently highly relevant because huge amounts of new generation plants and especially renewable generation in often remote locations are planned to be constructed. E.g. ENTSOE (2010, p.14/15) foresees some €25 billion transmission network upgrades up till 2015 for Europe alone. Small mistakes will quickly add up to large sums.

The problem is that usually network costs are socialized to the end-users which means that investors in generation capacity mostly do not pay for the costs of network reinforcement they cause. If network tariffs were cost-reflective, they could signal the network impact and make investors internalize the network impact they cause. Network tariffs that signal users their network impact are of particular relevance in cases where simple information exchange cannot achieve coordination due to incentive problems which we investigate with the cheap talk model in the first place. Cost-reflective tariffs can target the network connection charges by making them deep or shallow. “Shallow” charges allocate only the connection cost to the next grid access point to the user. “Deep” charges include reinforcements that become necessary deeper in network as a consequence of connection. “Deep” charges, while signalling network impact to network users, which is considered favourable, are problematic to implement (cf. Brunekreeft *et al.*, 2005; Scheepers *et al.*, 2007). In practice we observe mostly shallow-ish charging and deep charging only in exceptional cases (see Cambridge Economic Policy Associates Ltd, 2011). This is surprising since the coordination problem between generation and network is present in many countries but only few adress the externality that seems to at least partially cause the problem.

The debate started at transmission networks, but as result of the increased amounts of distributed generation similar problems are meanwhile arising in distribution networks. The UK energy regulator, Ofgem, therefore commissioned investigations into cost-reflective charging approaches in dsitribution networks to enhance economic efficiency. Those approaches should direct users away from congested network parts and encourage usage where there is surplus capacity (cf. Li *et al.*, 2005; Li, 2007; Strbac & Mutale, 2007; OFGEM, 2009).

3.2.2 Coordination Problems and Cheap Talk

Cheap talk as a game theoretical concept describes communication between players that does not directly influence payoffs. Cheap talk is neither costly nor binding and players may tell the truth or lie, and may or may not believe each other (cf. Aumann & Hart, 2003, p.1619). We use cheap talk as a formal model of information exchange as a coordinating device. Cheap talk is a costless information signal, hence credibility of the signal is not backed-up by the cost of the signal. Whether or not information can be transmitted and cheap talk is credible depends on the structure of the problem. The credibility of cheap talk has been studied extensively in the literature. We refer the interested reader to Farell & Rabin (1996) for a good overview.

The literature distinguishes two credibility criteria. First, *self-committing* (Farell, 1988) and second, *self-signalling* (Aumann, 1990). Farell (1988, p.212) suggested that a message were credible “if the suggested move be rationalizable when others are expected to follow the suggestion”. This has been referred to as self-committing cheap talk: the expectation that the cheap talk statement is believed creates an incentive to act according to the signal (cf. Baliga & Morris, 2002). This concept has been challenged as being insufficient for credibility because if a player has strict preferences over the others’ actions he wanted him to take a certain action independent of what the own intended action is. Hence, the signal does not convey any information (cf. Aumann, 1990, p.616). Following Aumann (1990) *credible* cheap talk conveys information about the desired behaviour of the opponent *and* about the own intended action. Hence, by signalling to play a certain equilibrium and wanting the message to be believed, the sender is also signalling that he intends to stick to his signal. This condition for credibility of cheap talk is known as self-signalling: the sender would want the signal to be believed if and only if it was true (cf. Farell, 1993; Baliga & Morris, 2002).

Our approach follows Baliga & Morris (2002), who study coordination via cheap talk under the existence of spillovers in a game with two players and incomplete information. A positive spillover means that an investment by player 2 also benefits player 1. Baliga & Morris (2002, p.457) claim that self-signalling is the stronger credibility criterion and argue that “with incomplete information” [...] “the need for self-signalling and the incentive problems created by positive spillovers emerge naturally from the equilibrium analysis”. Indeed, the self-committing concept as in Farell (1988) applies to complete information in simultaneous games where signalling would then be the way out of a genuine coordination problem. The game developed by Baliga & Morris (2002) relies on incomplete information and one-sided signalling. Whereas player 1 has all the information on the pay-off structure, player 2 does not know the characteristics of player 1. Therefore, player 2 must rely on the signals from player 1. As Baliga & Morris (2002) show, there can be situations where player 1 may lie to trick player 2 into an action it would not choose if player 1 were truthful. This would be a violation of the self-signalling conditions, following definition 3 in Baliga & Morris (2002, p.455). If this is the case, even for only a small subset of all outcomes, cheap talk breaks down generally, because player 2, who does not know the payoff structure, can never know whether player 1 is lying or not.

3.3 The Model

We use a formal model to evaluate whether cheap talk can achieve coordination of network and generation investments. We model the situation where the network planner must decide on expanding the network, depending on announced capacity investment in generation. The network investor has to rely on the signals from the generators because network investment has to take place ahead of generation investment. Finally, the generators decide on realization of investments after knowing the capacity choice of the network. We model a positive spillover of network investment assuming that a larger network lowers the production costs of the generators or, to put it more realistically, lowers the probability of not being able to produce due to a congested network.

Our game tree relies on three sequential steps. First, the generators signal whether they will invest in low or high generation capacity. Second, the network planner uses these signals to decide irreversibly whether to invest in low or high network capacity. Third, after the network investment decision is made and known to all, the generators decide on the generator investment, whereby this decision may differ from the previously given signal. The capacity decisions are made under demand uncertainty. Nature determines whether demand is low or high after the irreversible investment capacity decisions have been made, after which short-term production decisions are made, markets clear and profits are known.

In the following section 3.3.1, we first set out the game structure and develop the credibility criteria. The pay-offs that determine the game's structure are derived in a profit-optimized two-stage vertically-related model in section 3.3.2. Our analysis proceeds in two steps: first, we optimize short-term production decisions conditional on capacity choices for both generators and network. Weighing the pay-offs for the different states of demand, we then use these conditional production choices to determine optimal capacity choices, which then together construct a pay-off matrix to evaluate incentive-compatibility of cheap talk to coordinate capacity choices.

We use the following notation.

Strategic players are denoted with the following subscripts:
A - network owner/investor
B_i - generators $i = 1$ and 2

The parameters and variables are as follows:

P	- price
P_I	- price for the intermediate product I, (i.e. energy, without the network charge)
E	- end users
μ_E	- network charge payable by end-users E
μ_B	- network charge payable by B_i for $i = 1, 2$
μ	- total network charge $\mu_E + \mu_B$
Q	- output, with Q_A, Q_{B1} and Q_{B2} resp.
K^s_A	- capacity of network A
K^s_{Bi}	- capacity of generator B_i
s	- capacity choices low or high, with $s \in \{L, H\}$; s can be different for Q and K: s_Q and s_K
σ^s	- cheap talk signal by B_1 on planned capacity choice
n	- state of demand, decided by nature $n \in \{L, H\}$
α	- probability of the state of high demand $n = H$ and $(1 - \alpha)$ for low demand $n = L$
H, L	- denote "high" and "low" resp.
c_A, c_B	- short-run marginal cost (on output Q)
β_A, β_B	- long-run marginal costs - i.e. capacity expansion costs
γ_1, γ_2	- network scarcity cost increase factor for B_1 and B_2 respectively (where we dropped the B for ease of notation)
z_1, z_2	- "deep" charges payable by generators B_1 and B_2.

3.3.1 The Game

		B_1	
		B_1 low	B_1high
A	low	Π^{LL}_{B1} / Π^{LL}_A	Π^{LH}_{B1} / Π^{LH}_A
	high	Π^{HL}_{B1} / Π^{HL}_A	Π^{HH}_{B1} / Π^{HH}_A

Table 3.1: General structure of the payoff matrix for A and B_1.[34]

The central question of the paper is whether cheap talk can coordinate investment decisions among generators, B, and network planner, A. We assume three players: a network planner A, and two generators B_1 and B_2, but only A and B_1 are strategic players that choose capacity. B_2 simply adjusts non-strategically.[35] The capacity choice problem is illustrated in table **3.1**, which gives the profits for A (down left) and generator B_1 (top right) for capacity choices low and high. Our approach uses three stages. Decisions of actors are sequential and only one-way communication, B_1 signalling its capacity plan, is possible. Lying is explicitly allowed.

Stage 1: B_1 signals its investment decision (its capacity choice): $\sigma^L(K_{B1})$ or $\sigma^H(K_{B1})$.

[34]Note, that B_2 does not show up as a strategic player in the table as it does not choose capacity (but of course, the pay-offs do reflect optimization of Q_{B2}). This means that $\gamma_2 = \overline{\gamma}_2 > 1$ and $K_{B2} = \overline{K}_{B2}$ are constants and are not variables within the control of the firm B_2.

[35]If B_2 also chooses capacity, the number of cases in our decision tree would increase from $2^2 = 4$ to $2^3 = 8$, without gaining additional insight.

Stage 2: using the signal from stage 1, the network planner A, decides irreversibly on the capacity of the network: K_A^L or K_A^H.

Stage 3: knowing the capacity of the network, B_1 chooses its capacity K_{B1}^L or K_{B1}^H.

A does not know the payoff structure of B_1 and has to rely on the signal given by B_1. We explicitly allow the possibility that B_1 lies; i.e. we allow $\sigma(K_{B1}) \neq K_{B1}$. Capacity choices are binary: either high or low capacity. In all stages, we assume optimal short-run output decisions (Q) conditional upon capacity. Capacity choices for all players are under uncertainty. Nature decides on low or high demand at the end of the game after all capacity choices have been made. Importantly, we introduce an asymmetry with a positive spillover from network expansion that only benefits B_1 by decreasing its production cost. Thereby B_1 can gain a competitive advantage over B_2 if the network is expanded.

We solve the problem backwards: first, players optimize output conditional upon capacity, and then capacity choices are made using optimal conditional output choices.

Incentive Compatibility

Exchanging information might solve the investment coordination problem: A can simply ask B_1 what it will do and B_1 could respond accordingly. However, if B_1 may lie, the information may not be credible. Therefore, the information exchange may be ineffective if A does not know whether he can believe B_1 or not.

We specify the "cheap-talk" problem using table 3.1. The relevant case happens when B_1 prefers a large network K_A^H, while B_1 wants to invest in low capacity K_{B1}^L itself (given a large network K_A^H), and at the same time, the network operator, A, would only invest in a large network if B_1's capacity is high, and would invest in a small network if B_1's capacity is low. In this case, B_1 has an incentive to lie. It would signal to invest in high capacity, $\sigma^H(K_{B1})$, to trigger a large network, but would actually invest in low capacity, K_{B1}^L, after investment in a large network has been irreversibly made. This situation, where incentive compatibility is violated and thus cheap talk is not credible translates into two conditions:

Condition 1: No dominant strategy for the network.

This requires that neither $\{\pi_A^{LL} \geq \pi_A^{HL}, \text{ and}, \pi_A^{LH} \geq \pi_A^{HH}\}$, nor, $\{\pi_A^{LL} < \pi_A^{HL}, \text{ and}, \pi_A^{LH} < \pi_A^{HH}\}$ exists.

Formally, for condition 1 we require:

$$\{\pi_A^{HH} > \pi_A^{LH}, \text{ and}, \pi_A^{LL} > \pi_A^{HL}\} \tag{3.1}$$

Note that the alternative constellation of non-dominance for the network: $\{\pi_A^{LL} < \pi_A^{HL}, \text{ and}, \pi_A^{HH} < \pi_A^{LH}\}$ does not exist.[36]

Condition 1 is not directly related to incentive compatibility, but secures that the problem is non-trivial. If the network owner would face a dominant strategy, the problem would be gone and information exchange would be useless and meaningless.

Condition 2: Violation of incentive compatibility for B_1, (given that condition 1 is fulfilled). This condition requires that:

$$\{\pi_{B1}^{HL} > \pi_{B1}^{LL}, \text{ and}, \pi_{B1}^{HL} > \pi_{B1}^{HH}\} \tag{3.2}$$

[36] $\pi_A^{LL} < \pi_A^{HL}$ would require $2(1-\gamma_1)c_B > (a^H - a^L)$, which is never true as $\gamma_1 \geq 1$ and $a^H \geq a^L$. Therefore we can conclude that the alternative condition for non-dominance does not exist.

If condition 2 is fulfilled, B_1 will signal high capacity $\sigma^H(K_{B1})$, enforcing a large network (if A believes the signal), K_A^H, and then, given the large network, B_1 will actually invest in low capacity K_{B1}^L. Note that B_1 must lie to get to this result. If it signals low capacity, A will invest in a small network (due to condition 1).

The two legs of condition 2 are equivalent to definition 3 in Baliga & Morris (2002, p.455), but then formulated as a violation rather than a confirmation of incentive compatibility. For cases where conditions 1 and 2 are fulfilled cheap talk does not work, and simple information exchange does not adequately address the investment problem. We show in the section 3.4, that these cases, where lying is profitable, do exist, and that an integrated solution would be different and would in fact be welfare improving.

3.3.2 Determination of Pay-Offs

Final Demand

We define inverse demand of end-users:

$$P^n(Q) = P_I + \mu_E = a^n - bQ \text{ with } n \in \{L, H\} \tag{3.3}$$

Assume the following relation:

$$Q_E^s = Q_A^s = Q_B^s = Q^s, \text{ where } Q_B^s = Q_{B1}^s + Q_{B2}^s \tag{3.4}$$

This implies that the network cannot be by-passed. Irrespective of location, the generators will have to use the network and pay network charges. As long as network costs are socialized, there is no locational pricing per definition and network charges are the same irrespective of location.

Note that in this formulation of demand, it does not matter whether the network charge is paid directly to the network owner or indirectly to the energy supplier, who subsequently passes it on to the network owner. Note also that there is only one price; and that this price relies on used Q only. Therefore, in principle charges in the network and energy prices have the same effect. There is no multi-part tariff. Uncertainty on demand (low or high) results in a parallel shift of linear demand.

Network Expansion and the Assumption of Asymmetry: the Role of γ_1.

The "network scarcity cost increase factor" (γ_1, γ_2) is a critical factor which deserves some attention. We assume that $\gamma_1 = 1$, $\gamma_2 > 1$ if $K_A = K_A^H$ and $\gamma_1 = \gamma_2 > 1$ if $K_A = K_A^L$. The assumption creates a positive spillover. It says that if the network is small, it gets congested causing higher costs for network users (the generators); or the other way around, expansion of the network lowers production cost for network users. However, importantly, we introduced an asymmetry. The network expansion benefits generator B_1, but not B_2.

This assumption has a straightforward interpretation. Following e.g. Joskow & Tirole (2005), assume a North (N)-South (S) situation where N is a low-priced area and S is a high-priced area. The transmission line between the two areas is constrained. If the transmission line capacity is expanded, prices in N will go up and prices in S will go down. Therefore, generators in N would gain and generators in S would lose from the line expansion. The 2-node North-South example is only a stylized example of the effects of interconnector capacity and of what happens with nodal and zonal pricing.

The Network Owner: A

The cost of the network are formulated as follows:

$$C_A(Q^{s_Q}, K_A^{s_K}) = c_A Q^{s_Q} + \beta_A K_A^{s_K}, \qquad \text{for } s_Q, s_K \in \{L, H\} \text{ and } Q^{s_Q} \leq \min\{K_A^{s_K}, K_B^{s_K}\} \tag{3.5}$$

and network revenues are:

$$R_A(Q^{s_Q}) = (\mu_B + \mu_E)\, Q^{s_Q}, \qquad \text{for } s_Q \in \{L, H\} \text{ and } Q^{s_Q} \leq \min\{K_A^{s_K}, K_B^{s_K}\} \tag{3.6}$$

We assume that the level of network charge is regulated, $\mu_B + \mu_E \leq \overline{\mu}$.[37] The "regulation" reflects a revenue cap or price cap, but we allow non-negative profits: $\overline{\mu} \geq c_A + \beta_A$. Note that the network charge μ_B is the same for both generators which means that μ_B is not locationally differentiated. The key notion of this paper is to argue that we need locational price signals to coordinate investment and therefore we first show what happens without locational pricing. Further below, we make the step towards locational signals with a locationally differentiated deep charging component "z" in addition to μ_B.

More interesting is the cost of a network expansion. Here we use what is known as the "used-and-useful" criterion. In other words, the revenue driver for the network is output Q, and not capacity K. Therefore, if network expansion is actually used, it is paid for, but if it is not used, it will not be paid for. Hence, the network owner bears the risk. Apart from being a realistic assumption, this formulation sets incentives for the network investor to make a decision on network expansion at all. Otherwise the expansion cost would be automatically passed through and it would (almost) always be profitable for the network owner to expand the network, which makes the problem trivial.[38]

The Network Users: Generators B_1 and B_2

We assume that the generators at B are asymmetrical in γ,[39] but symmetrical in all other parameters ($c_{B1} = c_{B2} = c_B$ and $\beta_{B1} = \beta_{B2} = \beta_B$). We use the following approach for "locational pricing" (LP). Define an additional network charge, z, to be paid by B. z is a regulated (arbitrarily high) number. We maintain the idea that the capacity expansion is financed by the normal charge μ. In contrast, we formulate a LP such that it only serves as a locational signal and does not contribute to financing the expansion. Therefore, we formulate the LP such that it is revenue neutral. Formally, the LP is then defined as:

$$z_1 = -z_2 \tag{3.7}$$

where $z_1 \geq 0$, and $z_2 \leq 0$; $z_1, z_2 = 0$ for $K_A = K_A^L$ and for $K_A = K_A^H$ $z_1 > 0$, $z_2 < 0$. Obviously, by comparative statics, $z_1, z_2 = 0$ in case of shallow charging. Also, note that by the assumed revenue neutrality, z_1, z_2 do not show up in A's profit function.

Define the cost function at B_1 as:

$$C_{B1} = (\gamma_1 c_B + \mu)\, Q_{B1}^{s_Q} + z_1 + \beta_B K_{B1}^{s_K}, \qquad \text{for } s_Q, s_K \in \{L, H\} \text{ and } Q^{s_Q} \leq \min\{K_A^{s_K}, K_B^{s_K}\} \tag{3.8}$$

[37] We might add the split μ_B/μ_E for completeness, but note immediately that by cost-incidence it does not have effect and drops out in our formulation.

[38] The reader may realize that this is the key regulatory problem of "efficient investment". The alternative is full cost-pass-through, which makes the problem of overinvestment worse.

[39] The asymmetry does not refer to the value of γ, but rather to the fact that γ_1 reduces to 1 for high network capacity, while $\gamma_2 > 1$ persists.

the revenues for B_1:

$$R_{B1} = P^n(Q)Q_{B1}^{s_Q}, \text{ for } s_Q \in \{L, H\} \text{ and } Q^{s_Q} \leq \min\{K_A^{s_K}, K_B^{s_K}\} \tag{3.9}$$

and B_1's profit function:

$$\pi_{B1} = R_{B1} - C_{B1} \tag{3.10}$$

Functions for B_2 are defined accordingly. Note how the end-users' network charge μ_E automatically drops out, as claimed above. In this formulation the split μ_B/μ_E is irrelevant.

Short-Run Constrained Optimization under 2-Firm Cournot

We assume generators B_1 and B_2 to behave as Cournot competitors. The generators at B optimize output under the Cournot assumption for end-user demand conditional upon μ_B, $K_A^{s_K}$, and $K_B^{s_K}$. Moreover, $Q^{s_Q} \leq \min\{K_A^{s_K}, K_B^{s_K}\}$. Using the usual Cournot optimization, then gives B_1's and B_2's reaction functions:

$$Q_{Bi}^* = \frac{1}{2b}\left(a^n - (\gamma_i c_B + \mu) - bQ_{Bj}^*\right) \text{ for } n \in \{L, H\} \text{ and } i, j \in \{1, 2\}; i \neq j$$

Substituting and solving, we obtain Cournot equilibrium:

$$Q_{Bi}^* = \frac{1}{3b}\left(a^n - (2\gamma_i - \gamma_j) c_B - \mu\right), \text{ for } n \in \{L, H\} \text{ and } i, j \in \{1, 2\}; i \neq j$$

Define $Q^* = Q_A^* = Q_{B1}^* + Q_{B2}^*$, which then gives total equilibrium values:

$$Q^* = \frac{1}{3b}\left(2a^n - (\gamma_1 + \gamma_2) c_B - 2\mu\right), \text{ for } n \in \{L, H\} \tag{3.11}$$

and

$$P^* = \frac{1}{3}(a^n + 2\mu + (\gamma_1 + \gamma_2) c_B) \text{ for } n \in \{L, H\} \tag{3.12}$$

The Size of Capacity

We need to make assumptions on the size of the capacities. These might be exogenously chosen arbitrary numbers, but in order to allow larger generality and express capacity choices in parameter values, we use optimized quantities for the relevant cases as initial capacity choices as detailed in the appendix.

Recall that we assumed above that capacity is not a variable for B_2. Therefore $K_{B2} = K_{B2}^L$, which says that, as an arbitrary choice, B_2's capacity is always the optimized capacity of the low demand case.

For the low capacity case, we assume that capacity sizes are:

$$K_A^L = Q_A^{L*}, \ K_{B1}^L = Q_{B1}^{L*} \text{ and } K_{B2} = Q_{B2}^{L*} \tag{3.13}$$

where outputs are optimized outputs and $Q_A^{L*} = Q_{B1}^{L*} + Q_{B2}^{L*}$. Note that due to K_A^L, the values of $K_{B1}^L = Q_{B1}^{L*}$ and $K_{B2} = Q_{B2}^{L*}$ rely on $\gamma_1 > 1$.[40]

For the high capacity case, we assume that capacity sizes are:

[40] In some cases optimized output Q^* is larger than available capacity. In these cases, we use a "pro-rata"-rationing rule. The pro-rata rule reflects possible asymmetry ($\gamma_1 \neq \gamma_2$), which would be neglected with an "equal-split" rule.

$$K_A^H = Q_A^{H*},\ K_{B1}^H = Q_{B1}^{H*} \text{ and } K_{B2} = Q_{B2}^{L*} \tag{3.16}$$

where outputs are optimized outputs and $Q_A^{H*} = Q_{B1}^{H*} + Q_{B2}^{L*}$. Here, because network capacity is high, $\gamma_1 = 1$.[41]

3.4 Shallow Pricing and Cheap Talk

We are now ready to present and discuss the main results in formal propositions. As we argue that cheap talk does not work, it suffices for our proof to show a case where cheap talk is not credible. Therefore, a numerical example suffices.

Parameters			
a^L	300	n	2
a^H	320	c_A	12
b	1	β_A	30
α	$0,6$	c_B	5
z_1	0	β_B	30
z_2	0	γ_1	$1,4$
μ	63	γ_2	$1,4$

Table 3.2: Parameter values used for proposition 1.

Proposition 1 *There exists a situation where 1) cheap talk is not incentive compatible, and 2) where the (profit-optimized) non-integrated outcome differs from the (profit-optimized) integrated outcome, and 3) where the integrated situation is welfare-improving (in social surplus) as compared to the non-integrated situation.*

Proof: Table 3.3 gives the profits for players A and B_1 depending on capacity choices.[42] B_1 would maximize its profits in the cell bottom-left (i.e a large network, but low generation

Define

$$\omega_{B1} = \frac{Q_{B1}^*}{Q^*} \text{ and } \omega_{B2} = \frac{Q_{B2}^*}{Q^*} \tag{3.14}$$

Denote "**" as the contrained optimized (post-rationing) outcome. Then:

$$Q_{B1}^{**} = Q_{B1}^* - \omega_{B1}(Q^* - K_A) \text{ and } Q_{B2}^{**} = Q_{B2}^* - \omega_{B2}(Q^* - K_A) \tag{3.15}$$

Note that the rationing rule is only relevant for the low network-capacity case (K_A^L). In the high network-capacity case (K_A^H), capacity constraints cannot occur by construction.

[41] Note however, that even in the high capacity case we use the "low" capacity for B_2 because we assume that B_2's capacity is fixed at the low level, which implicitly relies on $\gamma_1 > 1$.

[42] First note that the table fulfills condition 1, because the network investor does not have a dominant strategy; its optimal choice depends on B_1.

		B_1	
		B_1 low	B_1high
A	low	4498 / 3220	4443 / 3220
	high	4651 / 2980	4499 / 3238

Table 3.3: Profits for A and B_1.

		Joint profits	
		B_1 low	B_1high
Social Welfare	A low	12216 / 23971	11976 / 23731
	A high	12129 / 23884	11827 / 24379

Table 3.4: Producer surplus (joint profits of A, B_1 and B_2; top right) and social welfare (bottom left).

capacity). However, if it reveals this preference and signals low generation capacity, A will invest in a small network and the game ends up in the cell top-left (low-low). The only strategy for B_1 is to lie: it will signal high generation capacity, triggering A to invest in network expansion, and then B_1 will not invest in high generation capacity. Therefore, under these parameters (detailed in table 3.2) cheap talk is not incentive compatible.

Table 3.4 presents profits for the integrated case (top right) and social welfare (bottom left) for the same parameters.

For the vertically integrated approach we take joint-profit maximization, for which we simply use the sum of the profits of the separate parts. We do not separately optimize for the integrated solution. The reason is that using the sum of separate parts allows for better comparison of pure separation effects. In a new, separately optimized joint-profit solution, we lose competition (among B_1 and B_2), in which case it is no longer clear what exactly is being compared. Vertical separation may cause costs of coordination which may be offset by improved competition, and therefore we would lose information on the coordination problem, which is the focus of this paper. For social welfare we follow convention and calculate the unweighted sum of consumer and producer surplus. We do not maximize social welfare; we only compare the profit-driven solutions under vertical separation and vertical integration and compare these outcomes on social welfare.

It is clear from table 3.4 that the fully integrated firm would opt for the low-low outcome, as this maximizes the sum of profits. A will not expand the network if it would know that generation capacity will be low. Since the outcome under vertical separation will be high network capacity and low-generation capacity provided that A believes B_1's signal (see table 3.3) and the integrated outcome will result in low network capacity and low generation capacity (see table 3.4), the separated outcome will be different from the integrated outcome. Applying table 3.4, we immediately see that the top-left is welfare-improving as compared to bottom-left. Thus we conclude for these parameters that separation decreases social welfare. **End of proof.**

This proposition is crucial. It implies that the outcome achieved with lying can actually be bad for social welfare. This is important, because in principle, even if we have an uncoordinated, not incentive-compatible outcome, and even if this differs from the integrated solution, the outcome might still be better for social welfare than the integrated case. Proposition 1 shows that this is not generally the case and that there is at least one case where separation would decrease social welfare. In this case, we thus have a genuine case of costly coordination due to vertical separation.

We have to conclude that network unbundling can indeed cause an investment coordination problem, that is not easily resolved by simple exchange of information, and that is welfare decreasing. Put differently, there are costs of coordination due to a suboptimal outcome.

Proposition 1 states that we cannot generally rely on straightforward information exchange to solve the investment coordination problem that is created by unbundling. The fact alone that cheap talk may not be incentive compatible means that we can never be sure whether information exchange works or not, because A would never know whether B_1 lies or tells the truth. This is essentially proposition 10 in Baliga & Morris (2002, p.462).[43] Therefore, an external coordination device is necessary to address the problem adequately.

We should stress though that proposition 1 does not make a general statement about the pros and cons of network unbundling. It merely states that unbundling can cause coordination costs. We have only shown that problems may arise in case of positive spillovers. Moreover, we have explicitly not modelled the positive effects on competition. Therefore, proposition 1 does not make a statement on what happens on balance.

3.5 Locational Pricing and Deep Charging

The problem above is essentially that B_1 may benefit from a costly network expansion without paying for it. If this is the problem, then the straightforward approach is to signal the effects of new connection on the network to the investors with "locational pricing" (LP). This can take different forms. For locational network charges, it may be a connection charge or a Use-of-System charge. It is customary in electricity markets to distinguish "deep" and "shallow" charges. A deep charge applies if the newly connecting party pays not only for direct connection but also for the cost of network upgrades beyond the point of connection (i.e. "deeper" in the network). A deep charge is thus a fully cost-reflective locational price. In contrast, in case of shallow charges, all cost are socialized, and we say that the locational price is zero. At first glance we would expect that a full-cost deep charge will solve our problem; this is not so. We will argue in this section, that if the problem is to solve the incentive compatibility problem, the optimal locational signal can be higher or lower than the full-cost deep charge. We also argue that it is likely to be lower: an effective locational signal does not have to be full cost-reflective. The locational signal only needs to address the spillover effect.

In our approach above, we introduced a LP z_1 for B_1; simultaneously, by definition, the LP is a deep compensation z_2 for B_2, in order to establish revenue neutrality for the network A. The most important effect of the LP, z_1, can be seen for table 3.1, by comparing the profit expressions for π_{B1}^{LL} and π_{B1}^{HL}(as detailed in the appendix), which corresponds to condition 2. If z_1 is increased (stronger LP), the profit for generator B_1, in the case high network capacity, π_{B1}^{HL}, goes down, whereas π_{B1}^{LL}, in the case of low network capacity, is not affected (because under LL the network is not expanded). In other words, increasing the LP, z_1, makes it more likely that

[43] It may be noted that the structure of the problem above mirrors the structure of the high-cost situation in figure 6 in Baliga & Morris (2002, p.458), where "truth-telling is no longer an equilibrium". As the structure is the same, the claim should be the same as well and therefore, proposition 10 in Baliga & Morris (2002, p.462) applies, which mirrors our proposition 1.

cheap talk is incentive compatible. This is intuitive, because it is less attractive to free-ride if you have to pay for the ride.

How high should the LP z_1 be to solve the incentive problem? Contrary to expectations, a full-cost deep charge does not exactly solve the problem. We address this point in proposition 2.

Proposition 2 *The minimum locational price that internalizes the incentive compatibility problem need not be equal to full-cost deep charging.*

Proof: In total we have to show the conditions 1 and 2 specified above.

First, we specifiy condition 1:

1.1. $\pi_A^{HH} > \pi_A^{LH}$
1.2. $\pi_A^{LL} > \pi_A^{HL}$

Using the profit equations in the appendix, equalizing and working out then gives for condition 1.1:[44]

$$(\varepsilon - 1)(c_A + \beta_A) \quad > \quad \frac{(1-\alpha)\left[\left(a^H - a^L + (\gamma - 1)\, c_B\right)\right]}{(a^H - a^L + 2(\gamma - 1)c_B)} \tag{3.17}$$

We define $\varepsilon = (c_A + \beta_A)/\mu$, with $\varepsilon \geq 1$. Above we have allocated the risk of not fully utilizing the network expansion to the network owner. Therefore,we must allow a "risk-premium" $\varepsilon \geq 1$, otherwise it will never be profitable for the network owner to expand the network. For very small ε the basis for an incentive problem vanishes and the solution becomes trivial since it is not profitable for A to build the bigger network and A will always choose low capacity. Examining eq. 3.17 we see that ε should be sufficiently high otherwise the condition cannot be fulfilled. Assuming that ε is sufficiently high, we find that the condition is not unambiguously fulfilled. The following three points can be made:

- if α (the probability of high demand) increases, it becomes more likely that the condition is fulfilled. The higher the probability of high demand, the better the chances to use full capacity of network expansion.
- if ε increases, it becomes more likely that the condition is fulfilled. The higher the rate of return on investment, the more profitable the investment is.
- if γ increases, it becomes more likely that the condition is fulfilled. The higher the benefits of the beneficiary of the expansion, the higher the (derived) benefits for the nework owner.

The requirement for condition 1.2 is:

$$\left(a^H - a^L\right) > 2(1-\gamma)c_B \tag{3.18}$$

which is always fulfilled as $\gamma \geq 1$ and $a^H > a^L$.

Second, and more importantly, we specify condition 2 (as formulated here as a violation of incentive compatibility). B_1 has incentives to misrepresent if conditions 2.1 and 2.2 are fulfilled:

[44] As γ is either $\gamma_1 = \gamma_2 > 1$ or $\gamma_1 = 1$ and $\gamma_2 > 1$ we have simplified expressions dropping γ_1 whenever $\gamma_1 = 1$ and writing γ whenever $\gamma_1, \gamma_2 > 1$ appears.

2.1 $\pi_{B1}^{HL} > \pi_{B1}^{LL}$
2.2 $\pi_{B1}^{HL} > \pi_{B1}^{HH}$

Condition 2.2 specifies the cases in which own capacity investment does not pay off for B_1. This occurs if capacity costs are higher than the possible profit increase from expanded output corrected for effects from price changes.[45]

For condition 2.1, we want to find the optimal LP, z_1^*, which we define as the value of z_1 which exactly establishes incentive compatibility. In other words, z_1^* equalizes both sides of condition 2.1. Using the expressions in the appendix and solving for z_1^*, then gives:

$$z_1^* = \frac{a^L - \gamma c_B - \mu}{3b}(\gamma - 1)c_B \tag{3.19}$$

To solve the problem of incentive compatibility, z_1 has to be sufficiently high, i.e. $z_1 > (\gamma - 1)c_B \frac{(a^L - \gamma c_B - \mu)}{3b}$, which is the same as $z_1 > (\gamma - 1)c_B K_{B1}^L$.

We now compare the incentive compatible charge z_1^* with the expansion costs $\left(K_A^H - K_A^L\right)\beta_A$ (which would the base for a full-cost deep charge). Since $K_{B1}^L = \frac{1}{2}K_A^L$, and $z_1^* = K_{B1}^L(\gamma - 1)c_B$, we find that $z_1^* < \left(K_A^H - K_A^L\right)\beta_A$, implies

$$K_{B1}^L(\gamma - 1)c_B < \left(K_A^H - K_A^L\right)\beta_A \tag{3.20}$$

which solves to:

$$(\gamma - 1)c_B < 2\beta_A\left(\frac{K_A^H}{K_A^L} - 1\right) \tag{3.21}$$

This inequality is not unambiguously fulfilled as can readily be seen. All the terms are positive and if we assume $\beta_A = 0$, it is then clear that the inequality is not unambiguously true. Therefore, proposition 2 holds: the LP that restores incentive compatibility can be higher or lower than (full-cost) deep charging. **End of proof.**

The result of proposition 2 is important. The structure of the cheap-talk problem does not perfectly coincide with the effects on the cost of network expansion. This is intuitive. The ultimate reason for the incentive-compatibility problem is the positive spillover, and not the network expansion costs. The effect of the spillover depends on the cost advantage (γ_1) and competitive conditions. It is clear from eq. 3.21, that if γ increases, it becomes less likely that $z_1^* < \left(K_A^H - K_A^L\right)\beta_A$. In other words, the higher the spillover effects, the stronger the LP must be to internalize the effect.

A closer look at the conditions derived above suggests the following. If β_A is low, z^* is likely to be larger than network expansion costs and thus the LP would be higher than the network expansion costs. At the same time, if β_A is low, the coordination problem stops being relevant, simply because a too large network would not be costly and therefore the distortive effect would be small. If β_A is high, the condition above is more likely to be fulfilled and it is more likely that

[45] Formally the condition implies $\beta_B\left(a^H - a^L + 2(\gamma_1 - 1)c_B\right) >$
$\frac{\alpha}{3}\left[\left(a^H - a^L\right)\left[2\left(a^H - a^L\right) + (5\gamma_1 - 2)\,c_B\right] - \left(a^L - (2 - \gamma_2)\,c_B - \mu\right)\gamma_1 c_B\right] +$
$\frac{1}{3}c_B\,(\gamma_1 - 1)\left(a^L - (4 - 2\gamma_1 - \gamma_2)\,c_B - \mu\right).$
The probability of high demand plays an important role as only then capacity expansion does translate in equivalent output. In case of low demand only a marginal increase over low capacity can be realized as a result of the positive spillover.

z^* is smaller than network expansion costs. This appears to be the more realistic case. Therefore, we conclude that normally the minimal LP is lower than network expansion costs, or, where this is not the case, there is no relevant problem. The approach above seems to suggest that overall a "deep-ish" charge might work perfectly well and mitigate strategic signalling.

3.6 Dissussion and Concluding Remarks

This paper provides a formal analysis on the investment coordination problem in a vertically unbundled electricity supply industry. Thereby the paper specifies the argument that vertical unbundling causes "coordination costs". While we focus on the high-voltage transmission grid in the electricity sector, we note that the analysis may also apply to low-voltage distribution grids and to other network industries. This paper does not make a conclusive statement on the balance of costs and benefits of (ownership) unbundling. We focus on some aspects of the costs of coordination and do not analyse the competition effect of unbundling.

The problem we examine is the following. In an electricity system, network development depends on the location and capacity of the power plants connected to the network and the other way around. In other words, to optimize the system, the investment decisions of network and generators need to be coordinated. In unbundled markets the investment decisions are decentralized. Therefore, firm-internal coordination no longer appplies and should be replaced by external market coordination. The coordination problem is twofold: an information problem and an incentive problem. If the problem is that investment plans of the generators are unknown to the network planner, the straightforward approach would be that the network planner would simply ask the generators. The obvious counterargument is that the generators might have an incentive to lie. We develop a formal approach to examine whether simple information exchange could address the investment coordination problem. In other words, can "cheap talk" solve the investment coordination problem?

To address this question we adopt a profit-optimized investment model, with a (regulated) monopoly network and two asymmetrical Cournot-type generators. The game has three stages. In stage 1, the generators signal whether they invest in high or low generation capacity. In stage 2, the network planner uses this signal to decide whether to invest irreversibly in large or small network capacity. In stage 3, having seen the network investment decision, the generators decide whether to invest in large or small generation capacity. Importantly, the generators may lie. The model then formally examines whether the generators have an incentive to lie at all. Formally, this leads to a game theoretical analysis of the credibility of cheap talk. We follow Aumann (1990) and Baliga & Morris (2002) for self-signalling as our lead criterion to evaluate credibility of cheap talk. Reflecting the practical problem we address, our approach is a cheap-talk game with one-way communication, incomplete information, and positive spillovers.

We show in proposition 1 that cases exist that violate the self-signalling condition of cheap-talk credibility, that an integrated (profit maximizing) firm would act differently, and that the integrated situation would be welfare improving compared to the case of separation. Therefore, unfortunately, cheap talk as a coordination device breaks away. With this we have shown that cheap talk cannot generally solve the investment coordination problem and that as a result separation may actually cause a costly coordination problem.

We stress that these conclusions do not make a conclusive statement on the balance of the costs and benefits of ownership unbundling. The mere point is that there may be an investment coordination problem. We did not include the competition benefits of unbundling in our analysis and therefore we cannot draw conclusions with regard to the overall effect.

The underlying problem for the incentive-compatibility problem of cheap talk is what Baliga & Morris (2002) call a positive spillover. In our case the positive spillover is that network expansion benefits the generators which creates an incentive to signal large investment plans to trigger network expansion, even if generators do not actually plan to invest in large generation capacity. Intuitively cost-reflective charging for network reinforcement (deep charging) could be expected to solve the problem by making generators pay for the network cost they cause. We examine what is known as “deep charging” in the last part of our paper. Underlying the incentive-compatibility problem of cheap talk is what Baliga & Morris (2002) call a positive spillover. Our positive spillover is that network expansion benefits the generators. Therefore, the generators have an incentive to signal large investment plans to trigger network expansion, even if they do not actually invest in large generation capacity. If this is the problem, then the obvious solution is to make generators pay for the network expansion on their behalf. Cost-reflective charging for network reinforcement to facilitate new generator connections is called “deep charging”. With proposition 2, we show that full cost-reflective deep charging, most unfortunately, does not repair the problem that cheap talk fails. The problem of failing cheap talk is the spillover, not the cost of network reinforcement. More precisely, there is a range where the deep-ish charge which would repair incentive compatibility of cheap talk is below full cost-reflective deep charging. This is good news, as full cost-reflective deep charging is problematic in practice.[46] This situation where the incentive-compatible deep charge is lower than full cost underlines the idea that the spillover is the problem and not the network reinforcement cost. Instead of deep charging, one could consider a “down-payment” for generator investment signals as a self-commitment device; if a generator signals high capacity which requires network reinforcement the network owner could ask for a down-payment. If later, the generator steps back on its decision and actually invested in low capacity, the down-payment would be lost. A well-chosen down-payment could internalize the incentive problem and could thus serve as an investment coordination device.

[46]Unfortunately though the reverse may also hold: the deep-ish charge which would repair incentive compatibility of cheap talk is above full cost-reflective deep charging. However, this case does not seem to be very relevant.

3.7 Appendix

This appendix lists the analytical solutions for the profits in table 3.1.

First, analytical expressions for the solutions of capacities are:

$$
\begin{aligned}
K_{B1}^{H} &= \frac{\left(a^{H}-(2-\gamma_2)c_B-\mu\right)}{3b}\\
K_{B1}^{L} &= \frac{\left(a^{L}-(2\gamma_1-\gamma_2)c_B-\mu\right)}{3b}\\
K_{B2} &= \frac{(a^{L}-(2\gamma_2-\gamma_1)c_B-\mu)}{3b}\\
K_{A}^{L} &= \frac{\left(2a^{L}-(\gamma_1+\gamma_2)c_B-2\mu\right)}{3b}\\
K_{A}^{H} &= \frac{\left(a^{H}+a^{L}-(2-\gamma_1+\gamma_2)c_B-2\mu\right)}{3b}
\end{aligned}
$$

Note that we have left the expressions γ_1 and γ_2 to avoid confusion, although it can be further simplified. Either $\gamma_1 = 1$ which has been substituted in these expressions or $\gamma_1 = \gamma_2 > 1$, which has not been (but can be) substituted. Therefore, where γ_1 shows up in the expressions below, it necessarily means that $\gamma_1 = \gamma_2 > 1$.

Note that γ_1 still shows up in the case of high network capacity. This is because $K_A^H = Q_A^{H*} = Q_{B1}^{H*} + Q_{B2}^{L*}$, where Q_{B2}^{L*} relies on $\gamma_1 > 1$.

The deep charge becomes $z_1, z_2 = 0$ in the case of low network capacity $K_A = K_A^L$ and has then been dropped for simplicity.

Below we present the calculated analytical expressions for profits. To get the final outcome, low and high demand outcome have been summed up weighted with α for the high demand solution and $(1-\alpha)$ for low demand. In the background calculations, sometime for technical reasons we have to distinguish different cases depending on whether $(\gamma_1 - 1)\,c_B$ is larger or smaller than $\left(a^H - a^L\right)$. For the expression below, we use $(\gamma_1 - 1)\,c_B \leq \left(a^H - a^L\right)$ as the more likely condition for a wide set parameter values of γ, c_B, a^H and a^L; the other options of the case differentiation have been dropped for simplicity. The resulting solutions for the respective profits are listed below:

Low network and low generation investment, π^{LL}

$$\pi_A^{LL} = \frac{(\mu - c_A - \beta_A)(2a^L - (\gamma_1+\gamma_2)c_B - 2\mu)}{3b}$$

$$\pi_{B1}^{LL} = \left(\alpha(a^H - a^L) + \frac{(a^L - (2\gamma_1-\gamma_2)c_B - \mu)}{3} - \beta_B\right)\frac{a^L - (2\gamma_1-\gamma_2)c_B - \mu}{3b}$$

$$\pi_{B2}^{LL} = \left(\alpha(a^H - a^L) + \frac{(a^L - (2\gamma_2-\gamma_1)c_B - \mu)}{3} - \beta_B\right)\frac{(a^L - (2\gamma_2-\gamma_1)c_B - \mu)}{3b}$$

Low network and high generation investment, π^{LH}

$$\pi_A^{LH} = \frac{(\mu - c_A - \beta_A)(2a^L - (\gamma_1+\gamma_2)c_B - 2\mu)}{3b}$$

$$\begin{aligned}\pi_{B1}^{LH} = &\left(\alpha(a^H - a^L) + \frac{(a^L - (2\gamma_1 - \gamma_2)c_B - \mu)}{3}\right) \\ &\cdot \frac{a^L - (2\gamma_1 - \gamma_2)c_B - \mu}{3b} \\ &- \beta_B\left(\alpha\frac{a^L - a^H - (2\gamma_1 - 2)c_B)}{3b} + \frac{(a^H - (2-\gamma_2)c_B - \mu)}{3b}\right)\end{aligned}$$

$$\begin{aligned}\pi_{B2}^{LH} = &\alpha\frac{(3a^H - 2a^L + (\gamma_1 - 2\gamma_2)c_B - \mu)}{3b}\frac{(2a^L - (\gamma_1+\gamma_2)c_B - 2\mu)}{(a^H + a^L - (\gamma_1+\gamma_2)c_B - 2\mu)} \\ &\cdot \frac{(a^L - (2\gamma_2 - \gamma_1)c_B - \mu)}{3b} \\ &- \alpha\frac{(a^L - (2\gamma_2 - \gamma_1)c_B - \mu)}{3}\frac{(a^L - (2\gamma_2 - \gamma_1)c_B - \mu)}{3b} \\ &+ \left(\frac{(a^L - (2\gamma_2 - \gamma_1)c_B - \mu)}{3} - \beta_B\right)\frac{(a^L - (2\gamma_2 - \gamma_1)c_B - \mu)}{3b}\end{aligned}$$

High network and low generation investment, π^{HL}

$$\begin{aligned}\pi_A^{HL} \quad = \quad &\frac{(\mu - c_A)\left(2a^L - (\gamma_1+\gamma_2)c_B - 2\mu\right)}{3b} \\ &-\beta_A\frac{(a^H + a^L - (1+\gamma_2)c_B - 2\mu)}{3b}\end{aligned}$$

$$\begin{aligned}\pi_{B1}^{HL} \quad = \quad &\left(\alpha(a^H - a^L) + \frac{(a^L + (\gamma_1+\gamma_2-3)c_B - \mu)}{3} - \beta_B\right) \\ &\cdot\frac{a^L - (2\gamma_1 - \gamma_2)c_B - \mu}{3b} - z_1\end{aligned}$$

$$\begin{aligned}\pi_{B2}^{HL} \quad = \quad &\left(\alpha\left(a^H - a^L\right) + \frac{(a^L - (2\gamma_2 - \gamma_1)c_B - \mu)}{3} - \beta_B\right) \\ &\cdot\frac{a^L - (2\gamma_2 - \gamma_1)c_B - \mu}{3b} - z_2\end{aligned}$$

High network and high generation investment, π^{HH}

$$\begin{aligned}\pi_A^{HH} = &\alpha\frac{(\mu - c_A)(a^H - a^L - (1-\gamma_1)c_B)}{3b} \\ &+ \frac{(\mu - c_A)(2a^L - (1+\gamma_2)c_B - 2\mu)}{3b} \\ &- \beta_A\frac{(a^H + a^L - (2 - \gamma_1 + \gamma_2)c_B - 2\mu)}{3b}\end{aligned}$$

$$\pi_{B1}^{HH} = \alpha \left(\frac{(2a^H - a^L - (\gamma_1 + 2 - \gamma_2)c_B - \mu)}{3} \right) \frac{(a^H - (2 - \gamma_2)c_B - \mu)}{3b} + (1 - \alpha) \frac{(a^L - (2 - \gamma_2)c_B - \mu)^2}{9b} - \beta_B \frac{(a^H - (2 - \gamma_2)c_B - \mu)}{3b} - z_1$$

$$\pi_{B2}^{HH} = \left(\alpha \frac{(2a^H - a^L - (\gamma_1 - 2 + 2\gamma_2)c_B - \mu)}{3} - \beta_B \right) \cdot \frac{(a^L - (2\gamma_2 - \gamma_1)c_B - \mu)}{3b} + (1 - \alpha) \frac{(a^L - (2\gamma_2 - 1)c_B - \mu)^2}{9b} - z_2$$

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4 Locational Signals to Reduce Network Investments in Smart Distribution Grids: What Works and What Not?

Christine Brandstätt, Gert Brunekreeft, Nele Friedrichsen†

Locational pricing can reduce the investment needs arising in distribution networks from the transformation towards smart grids with high shares of renewable generation. We analyse different approaches. Locational signals in a general tariff plan for either energy or network pricing require substantial system reform which impedes feasibility. We propose smart contracts with locational elements as hybrid form. System reform is only modest since contractual solutions emerge in smart grids anyhow. The responsibility for tariff setting stays with the network operator. The regulator's task is limited to incentivizing efficient network investment and allowing network operators maximum flexibility in contract design.

Keywords: network investment, distribution networks, locational pricing, smart grid

JEL-classification: D23 D43, L22, L51

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4.1 Introduction

Distribution networks are in a process of transformation driven by climate policy and the move towards sustainable electricity production. The share of decentralized and intermittent generation feeding into distribution networks is steadily increasing (see figure 4.1). This is a desired and in many countries politically supported development, but requires adaptations in the respective networks. The intermittent nature of wind and photovoltaic generation and the reduced predictability of feed-in present new challenges for network management which needs to guarantee the balance of generation and demand at every point in time. Furthermore, the distributed feed-in can reverse power flows, cause voltage rise or increase fault levels; developments which the network operator must countervail to maintain system reliability and quality standards. Parallel to the stormy development of generation in distribution networks, demand becomes more flexible.

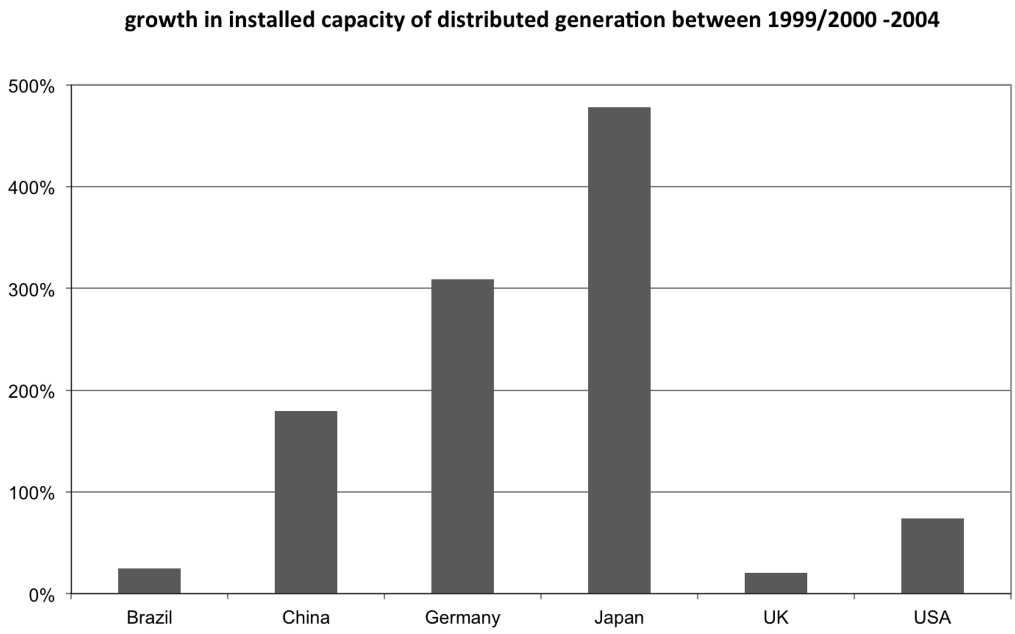

Figure 4.1: Percentage growth of distributed generation capacity between 1999/2000 and 2004. Source: (data from WADE, 2003, 2005, 2006).[47]

These trends introduce quite a number of new actors that actively participate in the electricity supply sector. In view of the challenges ahead with respect to adapting the networks and coordinating the different network users, hopes are high that smart grids will ensure efficient and

[47]In WADE (2003) the capacity data is aggregated for 1999 and 2000, hence no specific starting point of the analysis is given. As the UK is not represented in WADE (2005), data was taken from WADE (2006), extending the observation period to 2005 for the UK case. Very low starting levels can potentially results in misleading high growth rates. It may be noted here, that Brazil (2.8 GW) and the UK (4.9 GW) which had very low percentage increases in capacity also had the lowest starting levels. The US (46 GW) and China (30 GW) had the highest installed capacities, followed by Germany (11 GW) and Japan (6.8).

reliable supply. These smart grids evolve from the current system by addition of flexible users, network reinforcement and expansion, and the implementation of advanced information and control structures. This enables an efficient integration of new components such as e-mobility, storage and decentralized generation. With the advent of smart communication in electricity supply the development of new market places that serve to coordinate the diverse actors in the system can start. The discussion is mostly centred on distribution grids as they take up decentralized generation and interact with demand and electric vehicles.[48] The integration of all diverse actors into a vital and smart system is a challenge in itself and triggered the debate on regulatory requirements on unbundling, new market structures and compatible business models (e.g. Friedrichsen, 2011; Leprich *et al.*, 2010).

The trend to distributed generation (DG) requires significant network investment. The strong impact of the location and timing of production and demand on the network seems to be of particular relevance. Required or possibly deferred network investment caused by new DG depends largely on size, type or location. Effective coordination across the system is necessary to optimize system development and operation (cf. Shaw *et al.*, 2010). The lack or inadequacy of locational signals causes a lack of coordination which can be accompanied by inefficient network investment and in the end leads to inefficiently high cost for network users. Network and energy pricing can be the leverage to attract the right kind of investment in terms of volume, timing and location and set operational incentives in order to keep the cost of electricity supply low and the system efficient in the future. However, the charging system in many countries is not suitable to minimize necessary investments.

In actively managed smart grids with high shares of DG and flexible demand, locationally differentiated pricing might naturally develop, driven by two factors. First, smart metering enables more targeted tariff setting and second, its advantages in steering system participants increase. We focus on pricing schemes that include locational signals to represent location-specific constraints for operation and investment decisions. Consequently we examine the potential that such a change in network charging and energy tariffs at distribution level has for guiding network usage and generator investment and thereby avoid unnecessary network investments.

The next section illustrates the development of distribution grids towards smart systems and the distribution network investment ahead. Section 3 presents different locationally differentiated pricing schemes, namely locational energy pricing (LEP), locational network pricing (LNP) and smart contracts. Starting from a reference case that does not exhibit locationally differentiated prices[49] and comparing it to locationally differentiated energy and network pricing as alternative approaches, section 4 analyzes the potential of locational pricing and outlines a possible change towards smart contracts. Section 5 concludes and our main conclusions are as follows. LEP is largely ineffective when part of the feed-in would not be subject to market prices due to renewable support schemes. Locational network charging works well to guide investment, but does little for short term system operation, which is crucial in smart grids. Both such explicit schemes require a substantial system reform which impedes feasibility. With smart contracts we propose a hybrid form. They are developing in smart grids anyhow and will incorporate locational elements. The regulator's task would then be restricted to incentivizing the network operator for efficient network investment and allowing maximum flexibility. Therefore, required system reform is modest.

[48] The concept of smart grids is more recently also discussed with respect to the transmission level (see e.g. Battaglini *et al.* (2009)) and concerning gas grids (see e.g. Hinterberger & Kleimaier, 2010). In this article we focus on smart grids for electricity distribution networks.

[49] This is partially still true in many countries, but more specifically this reference case has been inspired by our observations of the German situation.

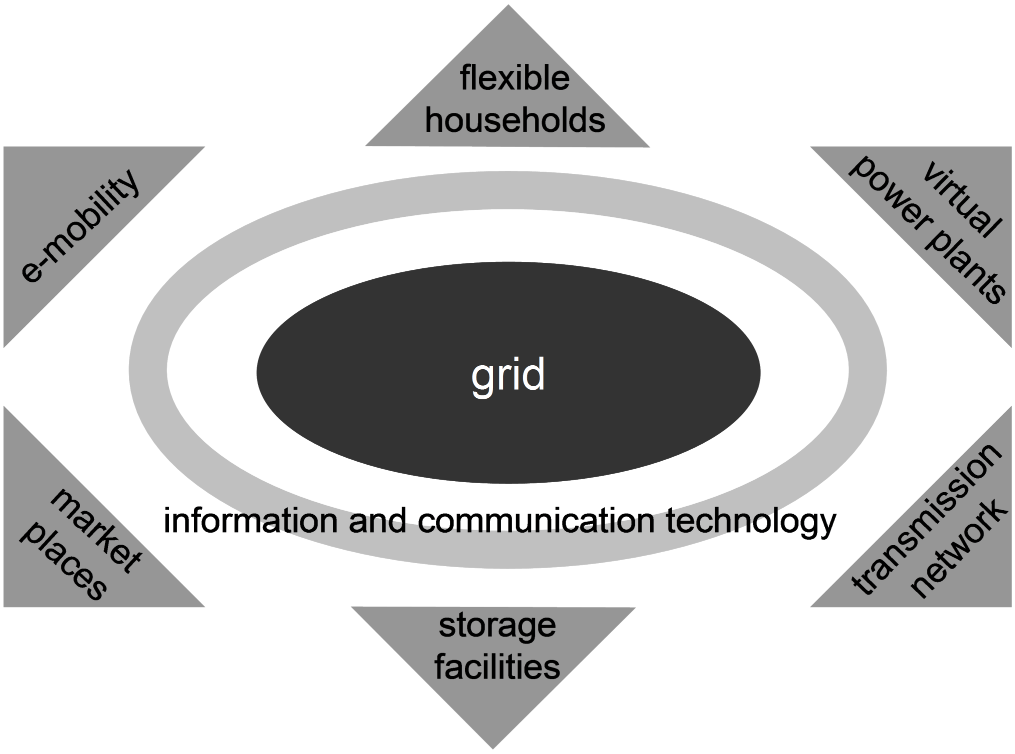

Figure 4.2: Smart distribution grids.

4.2 Background

The motivation for our analysis is the necessary transformation towards smart grids that integrate increasing amounts of generation from renewable energy sources (RES) combined with the observation of significant investment needs in distribution which might be reduced by coordination of investments. We abstract from the discussion of time-differentiated pricing which has been extensively treated in the literature (for example Faruqui *et al.*, 2009, 2010) but instead focus on locational differentiation in electricity tariffs.

4.2.1 Smart Distribution Grids

Smart grids as a buzzword have many meanings. In the European debate the term usually refers to distribution networks and summarizes functions that are enabled by the addition of information and communication technology to the electricity network. Figure 4.2 illustrates possible system constellations in the smart grid context. One approach to tap the potential of smart grids is distribution automation, meaning the installation of automatic monitoring and control across the distribution network, in substations, and remote locations. This facilitates detection and localization of disturbances in the network and improves restoration and system reliability. Better monitoring and control also serve to integrate increasing amounts of DG without investing in network capacity since the existing capacity can be used more extensively with continuous supervision (Veldman *et al.*, 2010).

A second approach usually understood as smart grid is the installation of smart metering for customers together with the introduction of advanced dynamic pricing structures. Automation technology can enhance customer responsiveness to price signals. Customers can programme certain devices to automatically react to price changes. Such devices have recently been tested in different countries for example in the city of Mannheim or within the Gridwise testbed project on the Washington Olympic Peninsula (Buchholz *et al.*, 2009; Kiesling, 2009). Another motivation for the installation of smart meters is the reduction of theft as has been the case in Italy (Wissner, 2009).

Thirdly, smart grids can enable more functions for the distribution system operator to actively manage the system. Smart meters and targeted switches enable selective load control and management of DG. This can improve system reliability and reduce the impact of network blackouts: not a whole area has to be cut off supply but selectively certain services can be maintained (Granger Morgan *et al.*, 2009). Furthermore, the management of generation decreases the need to expand network capacity for the connection since the feed-in can be controlled and coordinated according to demand or parallel feed-in from other sources.

4.2.2 Investment Needs

Many distribution network owners and operators (DNOs) are expecting a need for significant new investments. Partly this is caused by ageing assets since in many countries a large share of distribution investments dates back to the seventies of the last century. With lifetimes of 20-40 years this means that the assets approach the end of their lifetime and component failures are increasing. This implies that DSOs need to replace assets on a major scale or find alternative ways to maintain system reliability and cater the demands posed to the networks (Veldman *et al.*, 2010).

Additionally, the current system transformation towards a more sustainable electricity system imposes new challenges on distribution networks and triggers investment needs. Climate change and the depletion of fossil resources call for a more efficient energy use and a move towards energy production from RES. On the generation side this leads to increasing shares of distributed and generation from RES feeding into the distribution networks (e.g. biogas plants, micro scale combined heat and power (CHP), photovoltaic generators, or wind energy). These generators present technical challenges for the balancing of the system since they are partially intermittent (for example wind energy) or determined by external factors (e.g. heat demand of CHP generation). Due to their distributed feed-in they also fundamentally change the traditional system management in which electricity used to flow top-down only. The feed-in at lower voltage levels can cause operational problems such as voltage rise. Maintaining system reliability levels may require major grid reinforcements. However, the exact impact of the generation depends on the location of the connection and the local system conditions. It may well be that in certain areas additional DG has beneficial effects and defers investment need since it can serve local demand. In contrast, in a remote area with little demand, generation may require reinforcement or expansion of the network. These countervailing effects of DG connections are illustrated in Figure 4.3.

The demand side is also likely to change. The future might bring an increasing consumption of electric vehicles and heat pumps. At the same time households may be equipped with smart

[50] The study models the impact of micro-generation on British distribution networks using generic network types that represent typical load densities (Mott Mac Donald 2004): urban (load density > 4.0 MVA/km^2), sub-urban (load density: 1.0 MVA/km^2 - 4.0 MVA/km^2), rural: (load density: 0.0 MVA/km^2 - 1.0 MVA/km^2). The figure results from a scenario with high penetration of micro-generation amounting to 39.2 TWh (15.8 GW installed) in 2020 which would represent 11-13% of total energy demand (21-25% of peak load) on the GB TSO.

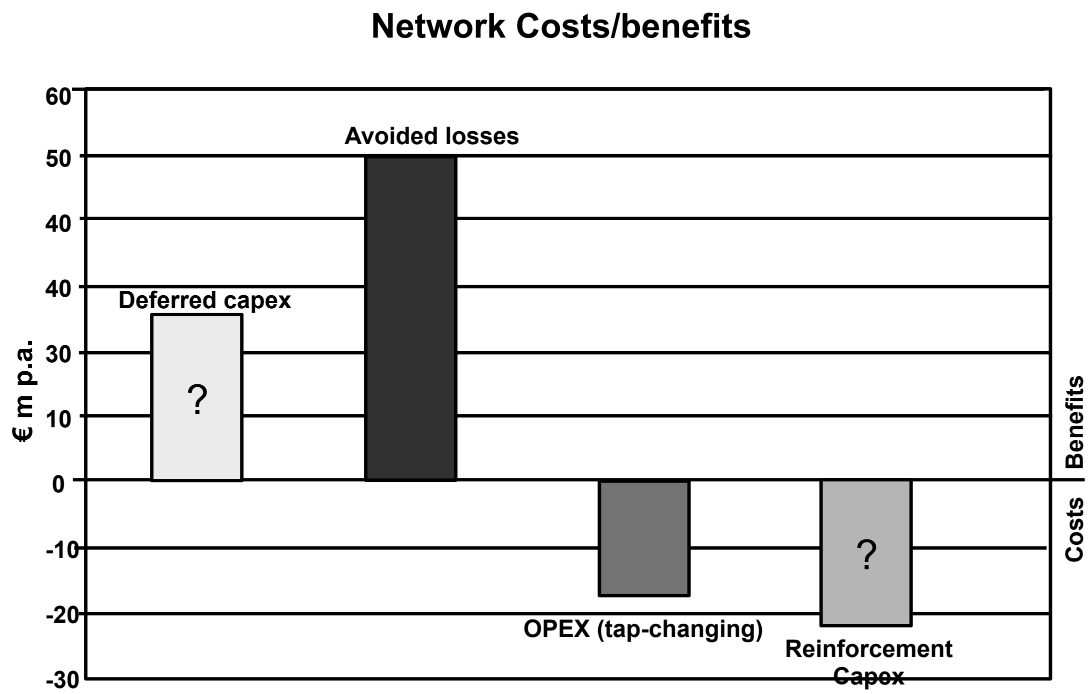

Figure 4.3: Impact of DG-network integration on network investment. Source: Mott MacDonald (2004).[50]

appliances that react to changing system conditions or energy prices and that facilitate energy conservation. Hence, the flexibility of demand and thereby the opportunities to manage load are also expected to increase.

This leads to another area where significant investment is necessary: the above mentioned smart grids. While needing investment in ICT and smart system components, they then also offer the chance to reduce or defer the investment necessary for conventional network expansion, as smarter management of the grid can increase the capacity utilization. The ability to detect and localise network faults together with distribution automation can support system reliability without relying on extensive network investments.

In view of these significant investment needs in distribution networks, it becomes increasingly relevant to make investments efficient and avoid unnecessary expenditure by making better use of the existing network capacity. Cost reflective network charging is a method to signal network users where there is surplus or tight capacity and thereby direct their use. This can serve to reduce the overall investment that has to be made. As the British regulator Ofgem (2009b) recognizes:

> "More cost reflective charging is very important for customers. DNOs expect to make high levels of expenditure (around £1.5bn to £2bn of load related reinforcement investment) over the 2010 to 2015 period to reinforce the network where capacity is tight and demand is growing. Some of this expenditure could be avoided if charges directed customers away from congested parts of the network and reflected the lower cost of using those parts of the network where there is surplus capacity."

4.3 Network and Energy Pricing

The core of our investigations is locational tariff differentiation in the electricity system. We investigate different approaches and point to positive and negative experiences. As a point of reference we use a system that does not comprise locational features as it has traditionally been the case in many jurisdictions and is still today the dominant form in distribution networks (van der Welle *et al.*, 2009). While examples for the assumptions of the reference case can be found in many countries we note that it directly applies to the German case which inspired our thinking.

Energy and network pricing have historically often been uniform with a general network tariff calculated as a postage-stamp fee per voltage level. The costs of operating the network including congestion cost are socialized through the network use of system charges. These charges can theoretically be levied from generation and/or load, but usually the G/L-split has been 0/100, in other words: it is common that generators are not charged for using the network. Independent of the proportion to which generation or load are charged there is generally little or no locational differentiation in use of system charges. Additional to use of system charges we typically observe connection charges that cover the cost of providing the connection and the associated assets. The dominant share of connection charges is shallow which means that charges cover only the direct cost of a connection. The alternative would be deep connection charges that also cover costs of reinforcements deeper in the network that become necessary as a result of the connection. Only the deep charges are able to send locational signals by reflecting the impact of a connection. If neither connection nor use of system charges are sufficiently locationally differentiated, generators have no incentives to coordinate their siting decisions with network development.

We note another characteristic in distribution networks which is relevant to judging locational tariff systems. DG is most often from RES or CHP and as such may be exempt from the general tariff rules. Many countries apply special promotion schemes for generation from RES to spur their development. This implies that general tariffs cannot display any impact on these generators. We refer to fixed feed-in tariffs as a support mechanism that is considered as highly effective but essentially isolates the generators from the market. Hence they do not receive any locational signals even if these were implemented in the tariff system.

Several countries around the world have implemented some form of locational differentiation into electricity and/or network tariffs to reflect different states of the network and thus guide investment and operation, but almost only at transmission level (see Brunekreeft *et al.*, 2005). With DG and with smart grids, the drivers for this development now become relevant at distribution level, but in distribution networks locational pricing is hardly ever applied at all and where we do find examples, they tend to be unsystematic (van der Welle *et al.*, 2009). However, triggered by the massive network investment needs due to generation developments this seems to be changing (Olmos & Pérez-Arriaga, 2009). Locational incentives in distribution tariffs reflect scarcity of network capacity and could thereby minimize network investment to an efficient and necessary level (Ofgem, 2009c; Li, 2007; Prica & Ilic, 2007) and guide least cost integration of generation from RES into the electricity system (Barth *et al.*, 2008). This is important to prompt system transformation to a low-carbon electricity future (Pollitt & Bialek, 2007; Jamasb *et al.*, 2005). After regulating the DNOs' revenues appropriately, the allocation of distribution cost via tariffs to generation and load in a way that sends correct signals is the second important step to maximize efficiency and social welfare (Jamasb *et al.*, 2005). Due to informational disadvantages at the side of the regulator it might be favourable to let the DNO design tariffs such as to reduce its network cost instead of prescribing a general tariff system. This is what we investigate under the term smart contracts. The network operator can be motivated to apply such instruments by an incentive mechanism that grants the network operator part of the savings compared to a baseline without smart contracts.

Importantly, locational tariff differentiation can be discussed for both demand and generation network users which might lead to different arguments. The socialization of distribution network cost to demand only was justified when shares of generation in distribution networks were low. As increasing amounts of DG often drive network cost, it becomes relevant to incorporate generators in the cost recovery process for the network. Distribution tariffs for demand customers were usually average-based and a move to more cost-reflectivity could significantly increase efficiency in the network utilization (Rodríguez Ortega *et al.*, 2008). An important point is, however, the politically motivated equality principle which might interfere with locational tariff differentiation within one network area.

The locational signals can basically appear in either the energy price which we refer to as LEP or in the network tariff (LNP) or both. Additionally we differentiate between models that use a general tariff plan such as LEP or LNP and an individual market-based model which we call "smart contracts". General tariff plan refers to a regulated charging methodology which applies the same tariff across customer groups whereas smart contracts give discretion to the network operator to implement individual charging agreements although this does not necessarily refer to unique contracts per customer. Most likely such contracts will be designed in a semi-standardized fashion based on network user characteristics including location.

4.3.1 Locational Energy Pricing

Locational signals can be realized in the energy prices which is known from transmission networks as locational marginal pricing (LMP) or nodal spot pricing (Stoft, 2002; Schweppe *et al.*, 1988; Hogan, 1992). This methodology calculates energy prices on a nodal basis including marginal network cost (losses and congestion). LEP is considered to send signals for operational optimization and hence promote short run efficiency. The key point is that the differences between nodal energy prices reflect the network constraints. Such pricing systems have been implemented in New Zealand and some US markets such as PJM, ERCOT and CAISO (Leuthold *et al.*, 2008).

Electricity networks typically consist of a deeply meshed bundle of nodes and links. To show how nodal spot pricing functions we use a simple three-node AC network with generation at two nodes and demand at the third node. In an AC-network we encounter so-called loopflows, i.e. the power flow from one node to another divides itself over the available lines inverse proportional to the impedance of the lines. The following figure 4.4 shows a simple three-node network; all lines are assumed to have the same impedance. G1 and G2 each have generation at cost of 30€ /MWh and 50€ /MWh respectively, but no load. D3 has only load.

Nodal prices are calculated by determining the marginal costs for the system of supplying 1MW additional load at each node, taking the loop flows into account. If all lines were unconstrained (Figure 4a) the entire load of 900 MW at D3 is satisfied by G1 for 30€ /MWh and the price is the same at all nodes. As the long route from G1 to D3 over G2 is twice the distance of the direct link, impedance is twice as much as well and therefore 2/3 of the power flows over the direct link. Assuming that the line between G1 and G2 is constrained at 100 MW (Figure 4b) the optimal dispatch would be 600 MW from G1 and 300 MW from G2. Nodal spot prices are now 30€ /MWh at G1 and 50€ /MWh at G2, which in this case are simply the respective production costs. Incremental costs at D3 are 40€ /MWh because each additional demand unit has to be produced at least half at G2 not to violate the existing transmission constraint. We note in passing that LMPs can be strongly different from marginal production costs at a node.

It is widely accepted that LMPs do send optimal short run signals for use of a congested network (Stoft, 2002) but long run locational effects on investment in power plants and load are less favourable. LMPs alone may not suffice to guide investment because they only reflect

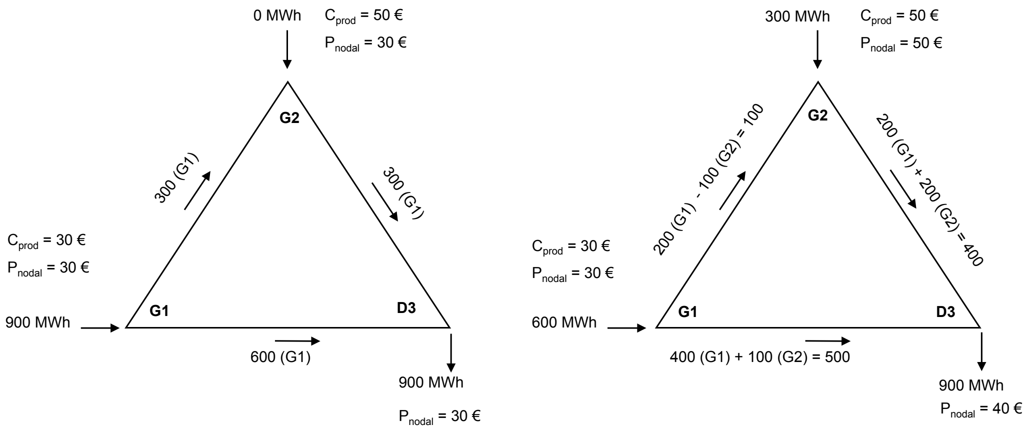

Figure 4.4: Nodal pricing in a three-node AC network. Source: (Brunekreeft, 2004).

Figure 4.5: Choice of generator location with nodal pricing.

variable construction cost. In the analysis below we show this for the example of power plants; the principles are the same for load.

Assume that the grid operator invests generator driven, meaning that generators decide on sites and are then connected by the grid operator who upgrades the network if necessary. The generators are rewarded by nodal spot prices. The situation is depicted in Figure 4.5. Facing load growth of 100 MW at point S, the options are to invest in new generation at S, or at the remote point N which requires building a transmission line S–N.

Assume that the cost function for the generators G_S and G_N at S and N are $C(G_S) = 100 + 4G_S$ and $C(G_N) = 100 + 2G_N$, where G is the generator capacity. Suppose for both S and N, $G = 100$. Assume the cost function of reinforcing the line S–N is $C(T) = F + \beta T$, where T is the line invested capacity, β is the variable cost factor of line construction, and F are fixed construction costs. And assume that $\beta = 2$. This function reflects long run economies of scale in line construction. Prices at S and N are P_S and P_N respectively.[51] In the optimum the price difference between S and N, $P_S - P_N$, equals the variable cost factor, i.e. β.

C_S the cost of building at S is 500 (i.e. $C(G_S)$ only). The cost of building at N is $C_N(G_N + T) = C(G_N) + C(T) = 100 + 2G_N + F + \beta \cdot T$, where T is G, i.e. 100 MW. Hence, costs at N are $500 + F$. Therefore, if $F > 0$, then the power plant should be built at S and not at N, reflecting the fixed costs of building the line. Optimum nodal prices reflect the variable construction costs

[51] In the real world, prices will fluctuate according to generation output. Here we assume a static setting with output at invested capacity.

only and therefore any new power plant does not take account of the fixed construction costs. Hence, under LMPs, an investor would inefficiently invest at N and ask the network operator to upgrade the line. Therefore, if we assume economies of scale, nodal prices will not provide optimal investment signals. Furthermore, nodal prices will typically only recover part of the network cost[52] because of reliability constraints in network planning as well as indivisibilities and economies of scale in line construction (Pérez-Arriaga *et al.*, 1995). In order to set prices with optimal investment signals and enabling cost recovery for the network a price component will be needed in addition to the nodal price in case of new connections. This leads over to the discussion of network charges.

4.3.2 Locational Network Pricing

Network revenues from use-of-system charges and connection charges usually should recover three cost items: cost of infrastructure, balancing and reserve costs, and system losses. The economic difference is mainly determined by the tariff structure, meaning the time-base for the charge (one-off, annually, hourly, etc.), and the driver (the event of the connection, MW, kWh, etc.). Both the connection charge as well as the use-of-system charge can be deep or shallow. As deep charges reflect the cost of network reinforcements, they are locational per definition. If a new connection does not require network reinforcement, the deep charge is low, signalling a good location from the network's perspective, and vice versa. While effectively signalling the network impact, deep charges tend to be problematic in implementation (cf. Brunekreeft *et al.*, 2005). First, it is difficult and ambiguous to calculate the network effect from a particular source. Second, allocation of the deep costs of the upgrade with more than one user is difficult. Stoft (2002) calls the problem the "last straw". There is a sequencing problem, if network reinforcement exhibits scale economies. If the first new connection pays the full reinforcement, subsequent new connections would not require reinforcement and would not have to pay a deep charge. This causes free-riding incentives. Third, it is not easy to attribute the cost of network reinforcement to various new connections efficiently. Fourth, from the perspective of the generator, the procedure to calculate network effects is necessarily opaque, as it requires an overview of the flows on the network.

Deep charges can be negotiated or administrative. Full cost reflectivity requires that the network effect of new connections is calculated on a case-by-case basis and taking account of the true circumstances. In practice, this means that investors have to wait and see what their deep charge will be. It turns out that investors are systematically at a bargaining disadvantage by lack of information and that transaction costs are high. Therefore the system suppresses DG development. The UK had such a system of deep charging for DG at DNO level but abandoned it for precisely these reasons (cf. Ofgem, 2003).

Alternatively, deep charges can be administrative and ex ante. The network impact can be simulated for different scenarios of new connections and administrative "deep" charges can be calculated from these simulations; these can be connection charges as well as use-of-system charges. It is crucial that the charge is locationally differentiated and thus reflects locationally different network impacts. The key advantage is that the system is simple, transparent and robust, and more importantly stable and predictable.

For instance, the UK has a system of administrative locational network charges at transmission level. The transmission network use of system (TNUoS) charges are calculated for different zones into which Great Britain is divided at the beginning of every price control period. At the moment there are 21 generation zones and 14 demand zones (National Grid, 2011). The situation in the

[52] Pérez-Arriaga *et al.* (1995) find for transmission networks in Argentina, Central America, Chile, Spain and England & Wales the percentage of network cost recovered by marginal cost pricing to be only up to 30 %.

UK is that generation is concentrated in the north (west), whereas the load is in the south (London), therefore additional generation in the north and or additional load in the south puts additional stress on the network and the other way around. This leads to high generator and low load charges in the north and vice versa in the south. The TNUoS charges contain a split between generation and load of approximately 27:73 (cf. National Grid, 2011). It should be noted that in some countries, generators do not actually contribute to the network: the so-called 0:100 generation-load split.[53]

Currently, also the distribution use of system (DUoS) charges in the UK are subject to review, aiming to introduce incentives to defer network investment within a new system for DUoS charges. For the low, medium and high voltage levels, the system works with the Common Distribution Charging Methodology (CDCM) (see Ofgem, 2009b). This is a forward looking system to estimate the cost of network development based on expected DG and load by means of the so-called "distribution reinforcement model". The costs are then translated into network charges, which are socialized to all network users. The CDCM does not contain a locational component but the system differentiates demand and load-dominated networks. DG charges are negative for load-dominated networks, implying that DG is actually paid for connection.

At extra high voltage the introduction of the Extra High Voltage Distribution Charging Methodology (EDCM) is planned (see Ofgem, 2009a). At the moment, the DNOs can opt to apply either forward cost pricing or long run incremental cost (LRIC) pricing. The first basically calculates socialized forward looking charges per network-part (defined such that network parts are not directly connected). The locational component is thus limited to these network-parts. Under the latter method, the impact of new DG and new load connection on the network LRIC is calculated for each network node, resulting in node specific charges that can be positive and negative. Under the EDCM-LRIC, the locational signals are strong and explicit. These charges are administrative and ex ante. They may vary over time, but at the moment of investment, the charges are known, and therefore create certainty and transparency. This mechanism is similar to the zonal LRIC approach for the transmission level in the UK.

Li *et al.* (2009) make a quantitative comparison of the effects of different pricing models. According to their calculations the effects of locational signals are significant while the differences of simulated prices at different nodes are substantial and generally negative for DG. Moreover, the calculation suggests that some £200 million can be saved on network investment for the UK as a whole over the next 20 years.

4.3.3 Smart Contracts

The pricing systems above need to be designed explicitly. The case of nodal spot pricing clearly demands explicit man-made market design. But also LNP requires at least the regulators approval. An alternative to the implementation of locational differentiation in a general tariff plan as it is the case with LEP and LNP is the development of rather individual smart contracts between the actors concerned. While most customers are served according to the same common tariffs, a big potential for achieving flexibility in the system lies in customer-specific contracts that reflect the situation of the network and make use of the specific characteristics of a customer or customer group.

With the development towards smart grids, or more broadly speaking smart systems, we observe the emergence of new market places as well as new pricing and contracting models at DNO level attempting to make the smart system work. In other words, for instance for effective load management consumers need to be incentivized to participate. Pricing or contracting is needed

[53] A system of locationally differentiated connection charges is compatible with a 0:100-split as long as the sum of the generation charges is zero.

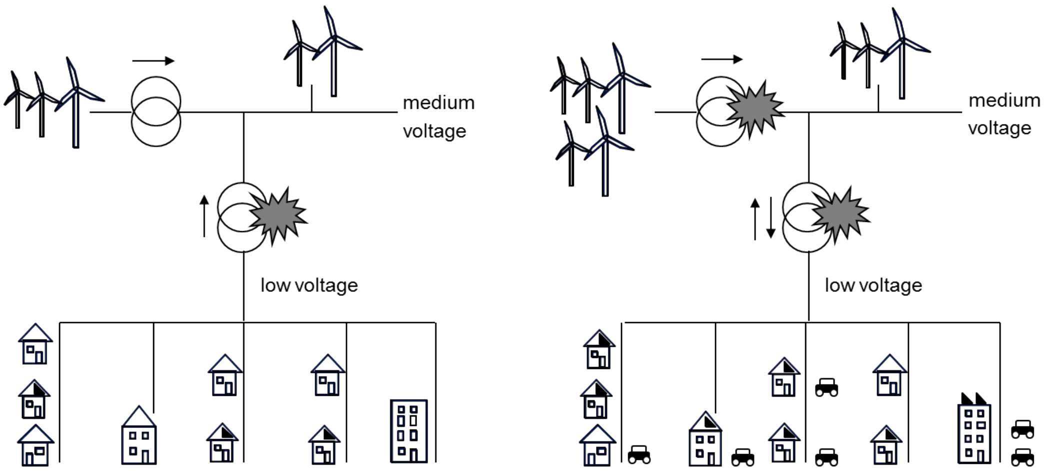

Figure 4.6: Distribution network constraints under DG and load management. Source: own illustration based on EWE (2010a,b).

to achieve just this. We call such measures smart pricing and smart contracts. In the context of efficient network investments these smart contracts that emerge naturally could perhaps contain sufficient locational signal to make the more explicit forms of LNP and LEP redundant.

Figure 4.6 illustrates the problems that DNOs face currently and in the future due to the changes in their network structure.

While in a system with only few generation at medium voltage level (left side of figure 4.6) the wind farm on the left would not congest the network, it can be congested with the additional wind farms (right side of figure 4.6). Taking into account the structure of the network the DNO would want to set a signal that new wind should be located to the right and not to the left. The bottom part of the figure depicts that DG and end user behaviour can congest or relieve the line that connects lower branches of the network to the medium voltage level. The households with photovoltaic installations on the right (left side of figure 4.6) inject electric power into the network that needs to be transmitted to higher voltage levels and thereby congests the line upward. In the right side of figure 4.6 electrical cars take up their feed-in and thus relieve the line in the centre while at the same time balancing intermittent supply. Conversely if all these electrical cars were loaded at the same time, the line could get congested downward.

Within a smart system, there will be many appliances feeding power into and taking power off the system. The total system needs to be balanced carefully at any point in time. This is exactly the purpose of a smart grid. In order to do so adequately, the generators and loads need to be managed one way or the other. Either authority over feed-in and take-off is allocated to the system operator by government order, or, more elegantly, market design secures that market parties have adequate incentives to find prices and contracts that make the system work. To stick with the example in figure 4.6, if the line is congested upward, due to photovoltaic feed-in, and assuming an appropriate regulatory framework, the DNO will have an incentive to redirect new PV installations to other parts of the network, attract more controllable electrical cars into the lower branches, or will want to pay for curtailing additional feed-in to avoid expanding the line. If the line is congested downward because too many electrical cars are loading simultaneously, the DNO will have an incentive to ensure that not all the cars are loading at the same time. It is in the interest of the DNO to offer contracts that optimally queue for loading the electrical cars to avoid inefficient line expansion. Location in the network and possible flexibility are valuable to the network operator and therefore important to determine the conditions of a smart contract.

The key point is that with the development towards smart grids contracting will become far more refined anyhow, and therefore, locational components may emerge as a side effect. The DNO will have an incentive to use signals for the parts of the network where lines are constrained and need to be expanded, but will not need to do so for other parts where the connection line is not congested. The only regulatory intervention would be to allow the flexibility to implement these signals where necessary.

Negotiated charges that are fixed in individual contracts are not a completely new instrument. The DNOs in New Zealand for example employ very diversified contracts to network customers depending on the respective utilization patterns and their controllability and special discounts are offered to customers under load management (cf. e.g. Vector, 2009). Also in Germany, individual network charges are possible for customers with utilization patterns that significantly deviate from the average or for special customer groups such as customers with electric storage heaters or heat pumps. The latter may even benefit from specific electricity tariffs. Further developments towards energy market places for smart grids and advanced contractual solutions take place within innovative research programmes and with respect to time-differentiated pricing in many countries. A major research programme in Germany uses field tests in 6 model regions to try out key technologies and business models for smart grids (BMWi, 2008). In the US both technology and customer integration are tested within the Gridwise demonstration project (Gridwise, 2007).

While the main idea of smart pricing and smart contracts is evident, a number of, mainly institutional questions still need to be resolved. One crucial issue is concerning the actors that engage in these measures. Who actually should implement these contracts? The network owner as well as the system operator or the traders could potentially offer smart contracts to the end users. The selection of actors involved will directly influence the scope of the contract and thus the degree of smartness in the system. Furthermore, it is still unclear how much regulatory freedom the involved parties need to have in order to implement optimal prices and also how especially the regulated parties, i.e. DNOs, can be incentivized adequately to find and implement these optimal prices. This relates to the debate around efficient incentives for investment and innovation under regulation (see e.g. Bauknecht & Brunekreeft, 2009; Bauknecht, 2010; Müller *et al.*, 2010). In addition, if a mix of locationally differentiated network and energy prices is optimal, then this might interfere with recent unbundling efforts that separate network and commercial businesses.

4.4 Analysis of Different Pricing Methods

In the following the different pricing models presented above are compared according to a set of criteria which we define below. The baseline to which we compare any changes following from locational differentiation is the status quo in many countries, i.e. a system which does not contain locational tariff differentiation.

4.4.1 Requirements for a Pricing Model

The first and for theoretical analysis often most relevant criterion for an incentive-compatible charging model is economic *efficiency*. Following convention in standard micro-economics, with economic efficiency we mean social welfare as defined as the sum of consumer and producer surplus. Efficiency then captures the power of the incentives the pricing model offers to the involved parties with regard to system improvement. In order to capture the different aspects in our models we distinguish short- and long-term efficiency. The former refers to the immediate effects of the charging model on dispatch and operation, while the latter refers to system development and thus investment and siting decisions. In sum a signal that is efficient in short term fosters a dispatch that avoids strain on the network wherever possible (better use of existing network capacity). In contrast, a long term efficient model is capable of guiding investments in such a way that unnecessary network investment is avoided.

A second important criterion for a desirable system is its *effectiveness*. Even if an instrument may have the correct direction, it may lack serious impact, or the cost may be higher than the benefits. In either case, we say that the instrument is not effective. We distinguish the local impact on generators (and more specifically DG) on the one hand and demand on the other hand. For the local effects it is crucial what impact the charging model can have compared to other decisive factors. Concerning the effectiveness of the charging approach for distributed generation the central aspect is whether the situation of small plants, mostly using RES, improves or deteriorates. This determines the impact of the model on climate policy goals and the development of smart grids. Clearly, this has to refer to the overall situation. At certain locations generation may be undesired, even if it is renewable generation, which is reflected in high charges. The overall situation for DG can still improve if this is compensated by lower charges or subsidies at other locations.

Another criterion is what we call market compatibility. This criterion captures two aspects. First, to what extent does a charging model or tariff system rely on market forces or, conversely, require extensive regulation. In general it is assumed that market-based systems are preferred over regulatory intervention. Second, the criterion examines whether the charging model is compatible with electricity markets and trading beyond pure network considerations.

Whenever the charging approach changes, it is likely that some parties will lose while others gain, implying *effects of income redistribution*. We examine the distributive effects for the main affected parties: generators, consumers (including tax payers) and the network. Parties can improve their position either by receiving additional income or by paying less than in the reference case. If the system in total becomes more efficient and a surplus can be distributed it is also possible that all parties gain from the change in charging.

Besides the direct monetary effects, the additional effort due to the new charging model has a stake in the different groups' approval of it. We therefore attempt to assess the *bureaucratic costs* of the different models for the regulator and the network users.

Lastly, the compatibility with current *legislation* plays a crucial role. The less reform an alternative requires, the higher the chances for political feasibility. While the implementation of a new model in almost any case requires additional legislation, some aspects of the models that are analysed might even contradict with existing laws or principles.

4.4.2 Locational Energy Pricing

The main aim and benefit of LEP is short-term efficiency. Including network aspects into the energy price formation sends efficient signals for optimal short term system operation. In doing so, LEP will also send signals that impact investment decisions and thereby improve the system in the long run. However, as argued above, LEP is insufficient to incentivize efficient investment. The signal works in the right direction but only imperfectly because of economies of scale in network expansion and generation (Brunekreeft *et al.*, 2005). Therefore, the impact on long term efficiency may be low. Moreover, there is no experience with LEP in distribution networks (in contrast to transmission networks) and its functioning is uncertain at this level. Furthermore, price volatility is a problem. The risk can possibly not be hedged adequately because of illiquidity in the relevant markets.[54]

[54] The experience from New Zealand suggests such an interpretation. After the introduction of nodal transmission pricing most generators integrated with retailers and independent retailers left the market. This has been explained by the illiquidity in hedge markets motivating the actors to opt for

A system change towards energy prices that include the network cost will cause redistributive effects compared to a situation where network users were charged without regard to network or location. In order for generators to receive price signals they will have to at least partially contribute to network cost recovery and socialisation to only demand would fall away. Demand is likely to benefit if generators are also charged since the cost are distributed over a larger group of network users. Also the cost reflective tariff incentivizes more efficient network usage and thereby the overall network costs are expected to be lower than in a reference case without locational signals.

Despite its favourable short-term efficiency effects, LEP seems unlikely to be implemented in distribution networks. It requires significant changes in the existing legal framework in systems that relied traditionally on uniform pricing. Problems may arise with respect to the equality principle when users with similar initial characteristics are charged differently according to their location especially if the tariff applies to the demand side. In many countries average uniform pricing is used traditionally. This demonstrates that locational pricing, if applied to all system users, has a social dimension.

Countries that have a fixed feed-in tariff as a support mechanism for renewable energy will find it difficult to combine LEP with such a system. Maintaining a feed-in tariff for generation from RES deteriorates the effectiveness of price signals as large parts of generation are exempt from the price mechanism. Conversely, giving up the feed-in tariff exposes the whole generation portfolio to the signals of LEP and thus would increase its effectiveness, but might have negative impacts on generation from RES. Since support systems for the use of RES relying on fixed feed-in charges are popular (especially for small RES), introducing LEP in the distribution network may be a conflicting policy. In addition, the implementation costs are relatively high since a complex model is needed to calculate LEPs in distribution networks (Pollitt & Bialek, 2007) and due to the explicit need for financial instruments to hedge price risks.

4.4.3 Locational Network Pricing

By mechanism, LNP has particularly favourable properties for long-term efficiency. It is designed for this purpose. Network prices transmit stable and reliable signals that influence investment and especially siting decisions of network users. Short-term efficiency is rather low due to the lack of explicit short-term signals. There is only an indirect effect since the impact of network charges on siting decisions also has a positive influence for network use. However, there is no direct short-term effect as existing capacities were decided upon when there was no LNP. Whether or not signals are effective then depends very much on the prevalence of other locational factors. Particularly for generation from RES other factors such as wind speed, availability of roof space for PV, or proximity of heat customers might dominate the siting decision. The dominance of other locational factors in siting decisions has been shown by Lewis (2010) for LMP and would likely also apply to LNP since their financial impact on generators is even smaller.[55]

LNP can address both generators and demand and hence, at first glance, distributive effects for generators are negative compared to a system where they do not participate in financing the network. Many countries have a 0/100 generation-load split. However, network tariffs for generation could be designed as zero-sum-game which essentially means some pay, others benefit. Overall, generation would still contribute 0, but there would be differentiation among generators.

physical hedges (Bertram, 2006).

[55] If for example generators decide to accept higher charges this implies that network expansion is cheaper than the foregone revenue from re-location. Marginal effects will arise when considering flexibility or timing and capacity of investment. Introducing locational price signals leaves it to the market to discover the feasible effects.

While thereby some locations come out worse than without locational differentiation, others that were not profitable before can become attractive. Such a scheme can be designed in a way that overall improvements for generators are larger than negative effects. Since cost-reflective tariffs should serve to enhance efficiency the overall impact on system costs should be positive. This implies an explicit differentiation of demand and supply side.

The implementation efforts are likely to be moderate. There is a one-off cost of changing the system, building the appropriate calculation models and adapting decision processes. Once the system is in place, the effort should be small and procedures uncomplicated because prices do not change very often. The network users do not incur implementation costs at all. The regulatory effort depends on the specific design of the pricing system. An implementation as incentive mechanism could have the advantage that the task of designing locationally differentiated tariffs can be assigned to network operators so that regulatory effort is reduced. Possibly, however, the sum of LNPs exceeds the regulated revenue, which would violate the regulatory constraint. The regulator would have to rescale the LNPs to secure revenue matching, which is an additional regulatory task. Conflicts with the equality principles might arise; in some countries, LNP are simply not allowed by current legislation.[56] Therefore, LNP would actually require legislative changes making explicit LNP quite unlikely.

4.4.4 Smart Contracts

Smart contracts offer the potential to combine in a less explicit, but possibly more effective way, components from LEP and LNP and thereby send short term signals for efficient operation as well as long term signals for efficient investment decisions. At the same time, smart contracts will reduce transaction cost by only targeting those customers with critical characteristics for grid operation or supply. Hence they can have a better efficiency than LEP or LNP alone. The fact that they target only specific customer groups that are significant for network operation and planning helps to at least partly avoid the disadvantages that LEP and LNP in the form of general tariff plans generate for small users or DG. This results in a high effectiveness of smart contracts. The idea is that customers are rewarded for grid-friendly behaviour or compensated for giving away control competencies to the network or system operator.

Smart contracts between those parties offering and demanding flexibility have high market compatibility. First, the locational signals can develop in parallel to distributed energy markets that are emerging anyhow. The design of these markets, which is as yet uncertain, will affect the scope and shape of additional locational network signals. Therefore, it seems wise to align the developing market design and network pricing. Second, we have argued above that some pricing systems may conflict with other policies like the fixed feed-in charge for generation from RES. In such cases, the network operator will have to be creative to try to set alternative signals. For instance, one could imagine the use of LEP components for generation from non-RES and LNP components for electricity from RES.

Importantly, in a system with smart contracts the regulatory framework needs to provide for an alternative tariff or standardized charging procedure that every customer could fall back on, if they opt out of their smart contract. Then any such contract is voluntary (optional) and there are no negative distributive effects to be expected as compared to the baseline. After all, market participants would only agree to enter a contract if it was for their better and if the benefit of the contract exceeds the transaction cost. This means that some network users would improve their situation through smart contracts while for the others things remain as usual. Thus all

[56] In Germany for example §17 of the ordinance for network charges (German: *Stromnetzentgeltverordnung, StomNEV*) prohibits all charging methodologies that are not mentioned in the ordinance.

stakeholders, meaning generation and demand as well as the network operator, could at least preserve their situation if not even benefit from smart contracts.

There is a tendency even within general tariff plans to offer a menu of individual tariff categories. Examples for this can be found in California (cf. Faruqui *et al.*, 2009) or in Germany with the previously mentioned electric heating or heat pump tariffs. Similar to this smart contracts are most likely to be semi-standardized according to a set of relevant criteria including location (cf. Brandstätt *et al.*, 2011). This approach avoids excessive implementation effort and complexity in contract design on the side of contract parties, such as network operator and network users, but still allows capturing most of the benefits. At the same time this means that it is only a small step from a subdivided general tariff plan to a system with smart contracts.

The legislator's or regulator's task is small, but non-trivial. Contract flexibility should be allowed. There are numerous examples of pricing and contract mechanisms that make perfect economic sense, but are prohibited anyhow. The main points are firstly, social and discriminatory concerns with differentiated pricing and secondly, impediment of generation from RES. In order to increase effectiveness, the system operators need to have control on the feed-in side, which is mostly from RES. This may well contradict environmental policy and therefore authorities may hesitate to allow contract flexibility. The critical point is that the role for the legislator or regulator can be passive, instead of pro-active.

However, two regulatory difficulties emerge, which are topics for further research. First, there should be incentive mechanisms in place that effectively incentivize the network or system operator to find and implement optimal contracts. On the one hand this means to avoid perverse incentives for unnecessary investment by the network operator while, on the other hand, any necessary investment should not be impeded by regulation. Second, the optimal contracts will likely contain both energy- and network-pricing components. It is not immediately obvious that this is compatible with unbundling rules (which split the network from trading activities). There may be conflicting policies here, which require additional coordination between the unbundled actors. LEP will be the primary task for a supplier, who will not be particularly interested in avoided network investment; the latter is the benefit of the network owner, whose main responsibility is the locational network prices. The main question then is whether the network owner can incentivize the suppliers to implement locational energy prices.

4.5 Conclusions

The development towards smart grids, relying on distributed generation and load management, causes high network expansion investment. Locational pricing in the distribution network can potentially defer network investment and can thereby make a useful contribution to a low-carbon smart distribution grid at least cost. In the paper we examine different approaches to locational pricing in the distribution grid and assess these on a variety of criteria. In particular, we distinguish LEP (say nodal spot pricing), LNP, and smart contracts. With smart contracts we mean a set of locationally differentiated prices and contracts used by market parties to reduce the need for network investment. Of course, these smart contracts will have energy and network components. The point is to incentivize market parties to seek for least cost solutions and allow these to be implemented. With smart grids, all kinds of creative contracting take place anyhow, and therefore they might as well develop with a locational component.

Our analysis finds smart contracts to be most compatible with the expected developments towards smart grids, the decentralization in the electricity sector and the upcoming investment needs since they start off from developments that are already under way and enable a combination of short term and long term signals to those users where the signal is of most use. We stress that we undertake this analysis for the distribution networks, where the usual arguments for the transmission network do not always apply.

Theoretically the concept of LEP is attractive as it encourages short term optimization and indirectly also improves the system on the long run. The long-run effects however are deemed insufficient to guide investment. Also, concerning implementation several concerns arise. The calculation effort at distribution level may be prohibitively high. Importantly, LEPs are not compatible with a support system for RES relying on fixed feed-in charges. Installed in parallel to a special support regime that isolates large parts of DG against locational energy prices are not effective. The alternative of changing the support system requires profound legislative changes and can prove less favourable towards DG and generation from RES.

In contrast, LNP promises stable and long term signals that are taken into account in investment and especially siting decisions, but it does not send short term signals for operation of existing plants and facilities. Therefore, LNP does little for short term system management and optimization, which is a crucial feature of smart grids. Implementation is easier than for LEP, since calculation efforts are lower and the impact on system users is better manageable as prices are more stable.

Both LEP and LNP as described above foresee the implementation of locational signals in a general tariff plan. This requires significant regulatory involvement for tariff design or at least approval. Smart contracts between the individual actors concerned can be a simple but effective alternative. Smart contracts evolve from the current system and can continue to support the smart grid development without bigger legislative changes. Necessary change is basically restricted to allowing flexibility. This concerns in particular flexible control of feed-in (including that from RES) and differentiated pricing. Furthermore, smart contracts provide the tool to combine LEP and LNP and thus provide short- and long term signals. The elegance however is that voluntary contracts burden only those system users for whom mutually beneficial interaction can be expected. This significantly reduces transaction cost and increases efficiency.

We see the following issues for further research. First, it needs to be studied more carefully whether the locational signals in smart contracts as they would develop voluntarily are indeed efficient and whether the signals are strong enough to be effective. Second, the compatibility between smart contracts with energy and network components and unbundling rules deserves more attention. Furthermore possible interactions between the optimization of transmission and distribution level and hence the consistency of price signals in smart contracts and the spot market are important. There might be mismatches between the local network congestion and the situation in transmission networks. Lastly, an incentive mechanism for network regulation should secure the right incentives for efficient network investment.

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5 Smart Pricing to Reduce Network Investment in Smart Distribution Grids – Experience in Germany

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Integrating large amounts of decentralized resources into future smart grids requires significant distribution network investment. Smart pricing enhances coordination of network, generation, and load. It can thereby substantially reduce the network investment need. Locational signals can be implemented in general tariff plans, but also in individual smart contracts. The chapter gives a brief overview of theoretical concepts and international experience with locational pricing with a focus on distribution networks. The authors then present an in-depth analysis of the German case. Taking account of political feasibility, small reform steps are proposed to implement locational signals gradually, basically by applying already existing legislation more flexibly.

Keywords: network investment, distribution networks, locational pricing, smart grid

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5.1 Introduction

Around the world a change in electricity generation is desired in order to fight climate change and increase energy security. Consequently renewable energies and distributed generation (DG) receive support and their shares in electricity generation are rising. As described in a number of chapters in Sioshansi (2012), both the transmission and distribution networks play a key role when integrating large amounts of distributed and intermittent renewable generation. One of the problems experienced in this context is that the increasing renewable shares may cause congestion in distribution networks.[57] The introduction of large numbers of electric vehicles could create similar problems. An example is illustrated in figure 5.1. As a result considerable investment is required for expansion and replacement of the existing grid as well as in information, communication, and coordinating technology.

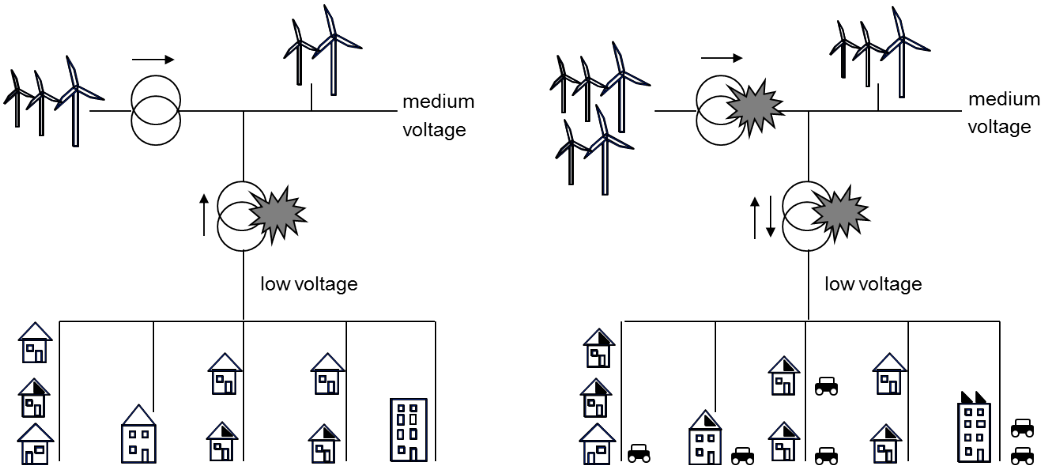

Figure 5.1: Distribution network congestion with distributed generation/electric vehicles. Source: Authors based on EWE (2010a,b).

The development of smart energy systems requires significant initial investments. The main cost triggers are the network expansion needs from the integration of distributed and renewable electricity generation and the information and communication technology required for smart grids. Table 5.1 illustrates the investment needs in the US, UK and Germany. With such large numbers the need for efficient investment is immediate. Optimizing the use of the existing network improves efficiency in the short run. Long term efficiency requires coordinated investment decisions. In practical terms investment coordination exploits the trade-offs between the location of generation or demand units and network expansion.[58] DG benefits from investment deferral are in the range of 1 % to 15 %, depending on location and power factor (Wang *et al.*, 2008). In a rural network with long lines, the savings from reduced line losses and operational gains can be over 30 % as (Sotkiewicz & Vignolo, 2006) illustrate for a case study in Uruguay. In the context of smart grids, flexible generators or storage, can create significant benefits for the network if they are located and operated adequately (EPRI, 2011). The anecdotal evidence suggests that

[57]Other problems may include the intermittency of generation from renewable sources and the lack of dispatchability. These are not the focus of this chapter.

[58]Siting of generators according to free network capacity economizes on line losses and avoids network capacity expansion.

the current framework is suboptimal for efficiently integrating future distributed generation resulting in higher than necessary cost. Smarter pricing can reduce the investment need. Table 5.1 sums up the figures and estimates for the US, UK, and Germany.

Country	Investment need (million \$ per year)*	Potential savings (million \$ per year)*	Percentage savings
US	$10,000 - 15,000^a$	$800 - 2,000^b$	$5 - 20\%$
UK	$4,944^c$	15.5^d	0.3%
Germany	$3,315^e$	n.a.	n.a.

* Investment need refers to estimated additional distribution network investment for DG integration and smart grids. Savings refers to reduction potential from smarter operation and smarter pricing. We used the conversion factors \$1 US = £0.64731 and \$ 1 US = €0.75464.

a: EPRI (2011) estimates transition to smart distribution networks in the US to cost \$ 200 to 300 billion over the next 20 years. Roughly 40 % of this is attributed to accommodating load growth, the other 60 % account for technology upgrades.

b: Smart grid benefits of \$ 8-20 billion on deferred transmission/distribution capacity investment over 20 years EPRI (2011).

c: Network cost for the transition towards a low carbon energy supply are estimated at £32billion (Ofgem, 2010b).

d: Li *et al.* (2009) estimated savings in network investment cost in the range of £200 million over 20 years from better locational coordination.

e: Estimated cost of integrating electricity produced from wind turbines and photovoltaics in distribution networks are approximately €25 billion until 2020 (BDEW, 2011). This does not include optimization of network investments or coordination of development plans across network levels or with the projected generation developments.

Table 5.1: Network investments and savings from smart grids. Source: (BDEW, 2011; EPRI, 2011; Ofgem, 2010b; Li *et al.*, 2009).

Within a liberalized market, decisions are decentralized requiring a coordination mechanism. Often attention is paid to time differentiated, sometimes called dynamic pricing[59] as a means to match demand and generation and to mitigate network usage in peak periods. This chapter focuses on the locational, rather than the time differentiated dimension of the problem and on the potential this has to increase investment efficiency. The implementation of locational pricing results in socially-beneficial investment based on locational coordination of investments as further described in Brandstätt *et al.* (2011b).

This chapter examines smart pricing as a means to defer distribution network investment. After a brief overview of the theoretical concepts and international experience with locational pricing in section 5.2, an in-depth analysis of the German case is provided in section 5.3. It is argued that the precise details of smart pricing and smart contracts should be left to the market participants, in particular the network owners, as much as possible. The task for legislators and regulators is to provide market parties with incentives for efficient investment. Section 5.4 describes schemes to implement smart and more differentiated pricing that improve investment coordination. The main message is for flexible application or allowance of already existing rules and regulation. In that case, significant system reform would not be necessary and it would be left to market parties (especially network owners) to see whether it actually pays off to implement a more differentiated system.

[59] Faruqui (2012) among others, discusses dynamic pricing.

5.2 Locational Pricing

The cost of electricity supply consists of an energy- and a network-component. The first remunerates the generation of the electricity used and the latter compensates for the availability of the grid infrastructure. Charges at transmission and distribution, as well as wholesale and retail level are passed on through the different stages and incumbents. The tariff system is what connects different stakeholders across different voltage levels. Locational signals embedded in this tariff structure can thus serve as a means to better coordinate network users and direct them away from congested parts of the network.

Network charges typically include connection and use-of-system (UoS) charges. A one-off connection charge accounts for the establishment of the connection to the network. Ongoing UoS charges recover the running cost of the network such as losses, balancing services, and maintenance. Even though both generators and consumers use the network, in many jurisdictions UoS charges are allocated entirely to consumers (CEPA, 2011), i.e. the so-called generation-load split is 0/100. Generators are charged only for their connection to the network. This can be a market distortion if generators have asymmetrical effects on the network, whilst the effects are socialized symmetrically.

Final customers usually receive a composite or bundled tariff, including not only the charges for network usage, but also for energy consumed. While many countries use uniform pricing and hence do not internalize network conditions, some states, such as the UK, use locational price signals in the network or energy charge. Section 5.2.2 presents country examples where locational differentiation is in use.

5.2.1 The Theory Behind Locational Pricing

Locational signals can be introduced in network and energy charges. They reflect the locational differences of making the infrastructure available for both load and generation. A zonal approach to network or energy price differentiation would, for example, have low prices for generation and demand in remote regions, which would attract further demand. In contrast, prices in densely populated regions with concentrated demand would be high to attract additional generation. More specific signals can be achieved by refining these zones up to branches or even nodes. The challenge is to assess the actual system conditions at a specific location.

Locational Network Pricing

Siting decisions of generators influence the topology of the network. A new network user, be it generation or demand, can either cause or defer considerable investment depending on where in the network it is located.[60] Connection charges typically cover the additional costs of lines, transformers and other equipment needed to hook up a new user to the grid. Connection charges that reflect the connection conditions potentially influence the siting decision and thus optimize the system.

Basically, connection charges can be either shallow or deep. With shallow charges, the network user only pays the direct cost of establishing a new connection to the next connection point to the existing grid. Deep charges also include part of the reinforcement that becomes necessary in other, "deeper" parts of the existing network - hence the term. For instance additional generation at a remote site without corresponding demand may require upgrade of transformers or lines in

[60] For a detailed analysis of the potential positive and negative effects (see e.g. Piccolo & Siano, 2009; Ackermann, 2004).

existing parts of the grid to enable the distribution of the additional electricity. As a rule, deep charges tend to be higher at congested sites making the location less attractive.[61]

While elegant and logical, deep charging is not easy to implement. Due to lack of transparency, an investor may not know at the time of decision the cost variation at different sites. The cost of reinforcement depends largely on the actual condition of the local grid, which is difficult to assess. It is typically not fully disclosed to the network user and even for the network operator it is not trivial to determine non-discriminating, i.e. fair, deep charges as further described in Brunekreeft *et al.* (2005). Hence, the benefits of deep charging, namely full cost recovery for the system operator and targeted signals, have to be weighed against substantially higher transaction cost in establishing the charges.

In addition to connection charges, UoS-charges can convey locational signals to the investor. However, traditionally this has not been the case. UoS-charges were often average based for each voltage level and further differentiated by the extent of use. This does not capture all of the effects that network use may have on operation and expansion cost. In order to guide investment, network charges have to reflect the actual condition of the network at a specific site and the impact of the network user. This impact is different for feed-in and take-off of electricity and so should be the charges. Often UoS-charges are allocated to demand customers only, as traditionally the same incumbents planned generation in big power plants and the respective network. With the introduction of wholesale and retail competition in electricity markets, often accompanied by unbundling, better coordination through market prices is needed. Even with a 0:100-split where generators do not bear network cost, locational signals can be implemented as long as the sum of the generation charges is zero.

Incremental cost pricing with a long-run perspective) is a tool to include the expansion cost of the network in UoS charges. In particular it deals with the stepwise cost increase that comes with bulky network investment (Li *et al.*, 2005). Changes in the constellation of network users at a specific location directly influence the respective charges (Li & Tolley, 2007). In other words the charges signal the urgency of network investment. If siting at a certain location defers network investment, charges are low. In contrast, charges are high if new connections cause network reinforcements.

Locational Energy Pricing

In most networks, the largest part of the bundled energy charge on the consumer's bill stems from the energy part and only a small part originates from the network.[62] In Germany for example energy cost make up for about 35 % of the final price, the second biggest share are taxes and concession fees with over 30 % and network cost account for only roughly 21 % of the final electricity price on average (see figure 5.2).[63] Therefore locational signals would be strongest if implemented in the energy part of the charge if not even in both parts.

Electricity prices that vary in different zones reflect the scarcity of interconnection between regions. This would encourage generators to connect to the network where prices are high, i.e. electricity is scarce. Load is incentivized to connect in regions with excess supply where prices are low. This avoids the need for additional interconnection. Moreover, differences between regions will incentivize network owners to expand in areas where prices are high. In practice, however, it can be difficult to demarcate the price zones, as further described by (Björndal & Jörnsten,

[61] See for a more detailed discussion e.g. Woolf (2003).

[62] The specifics, of course, vary from one place to another.

[63] The proportions of network and energy cost are different according to customer group. For industry both the final price (12.29 €ct/kWh) and the share of network cost (13 %) are significantly lower significantly lower than for household customers (23.42 €ct/kWh and 25% (BNetzA, 2011b).

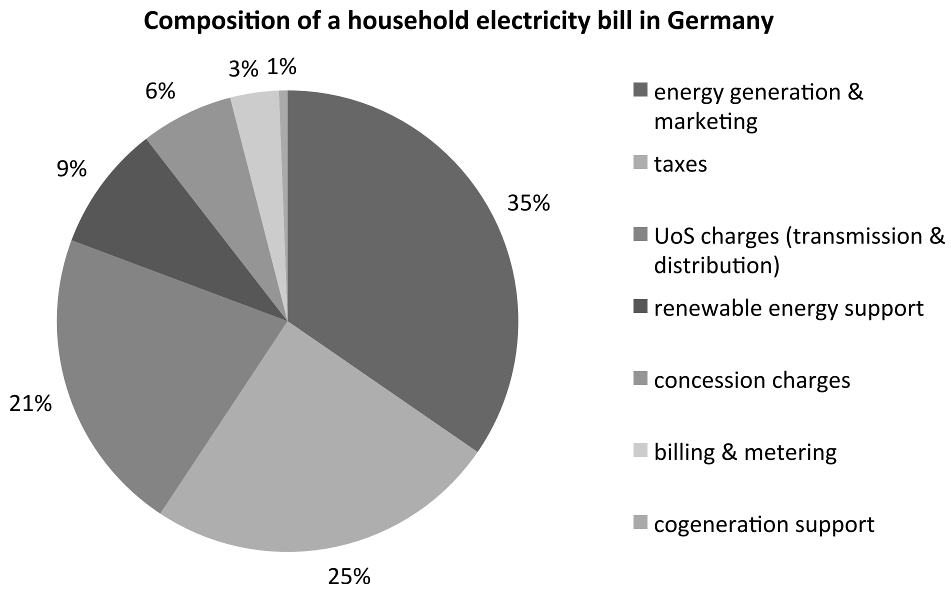

Figure 5.2: Composition of a household electricity bill in Germany. Source: Authors based on data from BNetzA (2011b).

2001). More precise locational signals originate from nodal spot pricing, also known as locational marginal pricing (LMP) (for further explanations see Hogan, 1992; Schweppe *et al.*, 1988).

A nodal pricing scheme assigns the overall cheapest supply option to the demand units at each node. Nodal prices are calculated by determining the marginal cost for the system of supplying one additional MW of load at each node; taking loop flows into account (Stoft, 2002). It reflects the topology of the system in detail and thereby takes into consideration losses and congestion. It has been shown that nodal prices send efficient signals for short-term optimization, but insufficient long-term signals. In other words, they send good signals for the optimization of operation (Stoft, 2002; Hogan, 1992), but since they do not reflect fixed network cost, signals are not sufficient to guide efficient investment decisions (Brandstätt *et al.*, 2011b; Brunekreeft *et al.*, 2005).

Nodal spot pricing is often deemed the optimal methodology for network pricing since it gives first best signals for system operation, particularly in terms of congestion management. Indeed, a recent study based on data from US market areas indicates significant benefits for the move towards nodal pricing (Neuhoff & Boyd, 2011). The benefits typically outweigh the one-off implementation costs within the first year. However, it seems that this is true for big ISOs but might be problematic for entities within small market areas. For the UK, Green (2007) estimates the benefits from moving to locational marginal pricing to be in the range of 1 to 3 % of the generators' revenues. He points out, that the effects strongly depend on the specifics of a given market but concludes that the gains might be "worth pursuing". Today however, these price differentiations most often only impact industrial customers since usually retail customers receive flat tariffs from their suppliers. This may change with more advanced technology, more granular information on networks costs, and other functionalities of the so-called "smart grid", described for example in the introduction in Sioshansi (2012) and in chapter 6, the smart grid vision for California (Sanders *et al.*, 2012).

5.2.2 International experience with locational pricing in distribution networks

In practice, the development towards locational pricing has thus far concentrated mostly on transmission and wholesale level while applications in distribution networks are rather rare (Brunekreeft *et al.*, 2005). However, distribution networks are moving towards smarter systems that efficiently integrate both intermittent generation from renewable and distributed energy sources and a more flexible demand side. These developments increase the necessity for smart pricing.

Currently, most countries apply *shallow* connection charges that convey only little locational signals.[64] However, one can find examples of *deep* connection charges or network charges with locational elements in UoS charges. Yet generation is often exempted from UoS charges and therefore receives too little locational signals. In general, there is a trend towards more flexible, less standardized network charges and negotiated agreements. Figure 5.3 depicts the different approaches for distribution network charging in EU-15.

An exception is the UK, which uses a more advanced system of cost-reflective locationally differentiated distribution use-of-system charges. The UK abandoned deep charging for connection charges. It was feared that high transaction cost due to negotiations and informational disadvantages might hinder the development of distributed generation (Ofgem, 2003). Locationally varying UoS-charges were implemented in transmission networks to re-establish the locational signals that disappeared with the elimination of deep charging. They are accompanied by *shallowish* connection charges that cover the connection cost plus a proportion of the reinforcement cost.[65]

The distribution UoS charging methodology in the UK is currently subject to transformation towards higher cost-reflectivity. To enhance transparency the charging methodologies are published after obtaining regulatory approval[66] (Ofgem, 2003). For low, medium and high voltage levels, a Common Distribution Charging Methodology started in April 2010 (Ofgem, 2009a).

With the so-called "distribution reinforcement model", network operators estimate the cost of network development based on expected growth of DG and load. These are the basis for the calculation of network charges, which are socialized among network users. The model does not feature location-specific components. Yet it differentiates between demand and load dominated network areas. In the latter the installation of local generation relieves system stress and avoids network expansion. Accordingly, the charges for distributed generation are negative, in other words DG is rewarded.

In the charging methodology for extra high voltage distribution networks, more explicit locational components are to be introduced by April 2012 (Ofgem, 2010a).[67] Network operators can choose between forward cost pricing and long run incremental cost pricing. The first method calculates average forward looking charges for different network-parts that are not directly connected. Hence the locational signals are limited to distinct sub-networks. The latter method in contrast calculates the impact of new DG and new load connection on the long run incremental

[64] In some countries connection procedures include a queuing process for connection requests which can also be interpreted as locational signal (van der Welle *et al.*, 2009). In an area with already many other pending connection decisions a request will typically take longer to be fulfilled if the queue is long. Also the cost allocation may depend on the queue position as for example in the US (SGIP, 2006).

[65] In future, the connection charges might be revised further and become shallow.

[66] This is a European requirement to strengthen the customer's position. (EC, 2003, Directive 2003/54/EC)

[67] The implementation was originally planned for September 2011 (see Ofgem, 2009b), but the process has been postponed to give network operators more time to develop satisfactory proposals.

Figure 5.3: Distribution charging approaches in the EU-15.
* shallow charges cover direct connection cost only, deep charges also cover cost for upgrades in the existing network. Source: compiled by authors from various sources.

cost of the network for the differential load at each network node. The resulting node specific charges can be positive and negative. They are scaled by adding a fixed component to ensure cost recovery while complying with regulatory prescriptions on maximum allowed revenue.

The resulting locational signals are strong, administrative and ex-ante. Although charges may vary over time, they are known at the time of investment and hence create certainty and transparency. Real world experience with this approach still has to be seen, but the positive effects from such signals are believed to be substantial. Simulations suggest savings in the order of £200 million over the next 20 years for the UK network. With projected investment in distribution networks of £3.2 billion per year over the next 20 years (Ofgem, 2010b), this sounds rather low, however, the implementation cost are estimated to be moderate and the gains might still be worth pursuing (Li *et al.*, 2009).

Explicit use of locational energy pricing – say, nodal or zonal spot pricing – does not seem to exist at distribution level at all. All the known examples are at transmission level. This might suggest that in the past locational signals at distribution level have not been worth the effort. However, this is changing as more and more generation enters at distribution level. This changes the paradigm of top-down energy flow and potentially causes congestion in the distribution network. Therefore benefits from steering network demand and generation customers to better use existing network capacity increase. On a theoretical level Pollitt & Bialek (2007) discuss in favour of locational energy pricing for UK distribution networks in the context of regulating for a low carbon future. They argue that for distribution networks the differentiation of several price zones might be a reasonable initial step, which captures much of the benefit of more refined locational differentiation.

There are promising developments in the field of demand side management. Retailers in New Zealand and the US, for example, offer special tariffs for customers on load control. In the US, where more and more system operators are offering demand control programs, the regulator has recently strengthened the position of providers of demand response (FERC, 2011). From 2012 providers of demand reduction will be entitled to receive a remuneration equal to the market price for generation, when that reduction balances supply and demand and is cost-effective. As the wholesale prices in organized US markets are locationally differentiated, this incentivizes flexible users where they are needed. The US has therefore made a move towards locational signals within the general pricing system. On the contrary, the development in New Zealand is rather decentralized and flexible, leaving the decisions with the retailers. But also in the US, at state level additional regulations may exist that further allow individual solutions. In California, for example, utilities are allowed to offer contracts that ensure the installation of distributed generation at the right time and in the right location.[68]

As it is the case in New Zealand, most countries have some implicit way to allow steering investments into distributed generation to reflect the effects on the distribution network and generally maintain uniform charging. So does Germany, as will be described in the next section. Partly for other purposes and partly for exceptional cases, locational pricing can be applied with strong restrictions by current legislation. The next steps would then be obvious: to allow more locational signals, lift the restrictions. If the network owners are adequately incentivized to defer unnecessary network investment, they will seek locational signals if allowed.

5.3 Locational Distribution Pricing in Germany

In Germany the share of distributed generation and generation from renewable sources in general has increased rapidly in recent years. This was mainly triggered by the highly effective feed-in tariffs for renewable generation (RES-E) and combined heat and power (CHP) (EEG, 2009; KWKG, 2002). Like many other countries, Germany is actively promoting smart grid development and more flexible pricing schemes. It has now also become clear that facilitating generation from photovoltaics and wind at distribution level requires substantial network expansion. Most studies estimate the investment need at around €25 billion until 2020 (BDEW, 2011; Moser, 2011), which may be on the conservative side. For comparison: in 2008 the overall expenditure

[68]Such contracts can also aim at size or physical assurances needed to enable a utility to defer a distribution capacity addition. Interestingly, this possibility for targeted contracting was seen to obviate the need for additional locational signals in the general tariffs. The contract system is considered to retain most of the efficiencies locational charges while avoiding "the complications of reversing the long-standing policy of uniform pricing" (CPUC, 2003).

of distribution network operators amounted to €5.57 billion (BNetzA, 2009c).[69] Yet, neither locational network prices, nor locational energy prices are implemented explicitly at the moment. Nor is there political consensus to move in this direction.

Politicians argue for equal, non-differentiated tariffs to prevent unfair disadvantages for higher price regions, which become less attractive for industry. The argument is that renewable and distributed generation create social benefit and hence their integration costs - including network investment costs - should be socialized. When related to network charging we observe another problem. Varying network charges, especially related to peak usage, are not intuitively understood since the underlying costs are assumed to be constant. However, peak usage drives the required capacity and thereby network costs. Of course opportunity cost considerations are the rationale for differentiated tariffs but often not perceived reasonable by customers. Such positions are a major barrier for locally differentiated prices. Looking into existing legislation, however, possibilities exist for introducing locational signals as further described below.

5.3.1 The Challenge: Increasing Renewable Generation in an Inflexible System

As a result of ambitious feed-in tariffs, Germany has a high share of renewable electricity amounting to 16.4 % of total gross electricity consumption in 2009 (BMU, 2010). This share is projected to increase to 38.6 % by 2020 (German Federal Government, 2010) and reach 80 % in 2050 (BMWi, 2010b). Figure 5.4 shows the development of electricity generation from renewable sources in Germany since 1990.

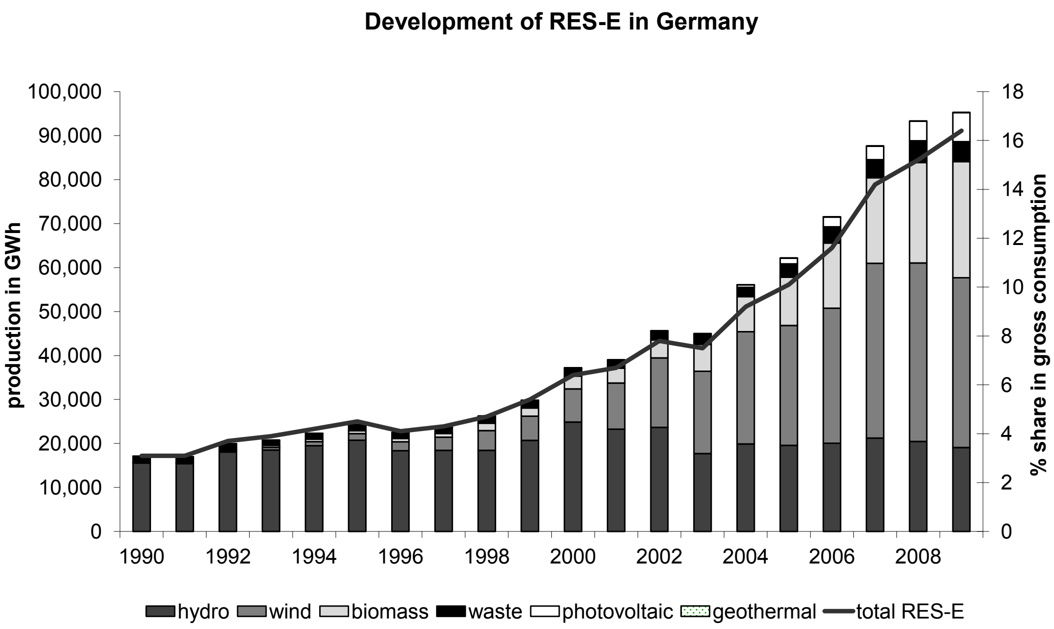

Figure 5.4: Development of generation from renewable sources in Germany. Source: Brandstätt *et al.* (2011a).

[69]This includes operation & maintenance, replacement,, expansion, and investments in new control and information technology (BNetzA, 2009c)

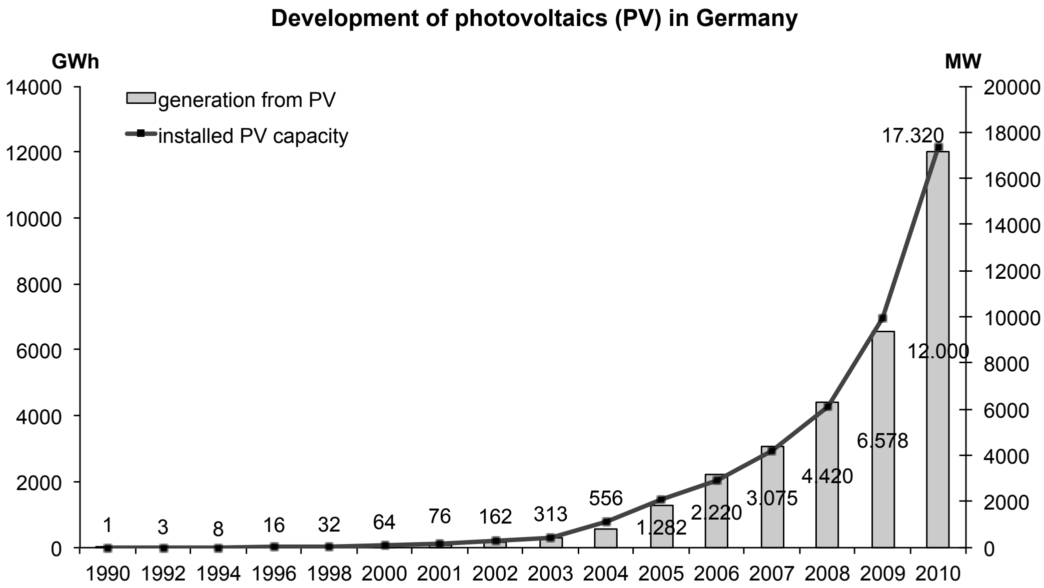

Figure 5.5: Development of photovoltaic electricity generation and installed capacity in Germany. Source: Authors based on BMU (2010).

Increasing shares of volatile wind generation are a major driver of network investment in the German transmission networks. The electricity needs to be transported from windy, coastal areas, mostly in the North, to load centres, mostly in the South. Projected cost for network upgrades are in the range of €946 million per year (DENA, 2011). Main factor is the rapid development of wind both onshore and offshore. Meanwhile in distribution networks too, problems are arising from the growth of distributed generation. The sum of installed electricity generation capacity from renewable sources in distribution networks was around 33.2 GW in 2008 (BNetzA, 2010a) and rose to 40.5 GW in to 2009 (BNetzA, 2011a). Decentralized generation changes the traditional model from top-down electricity flow and requires major changes in the system paradigm and management as described in a number of chapters in Sioshansi (2012). The integration costs for generation from renewable energies in the distribution network are projected at €25 billion (BDEW, 2011). A principal cause for the investment need is the boom of photovoltaic installations experienced in the last years as shown in figure 5.5.

One problem is the lack of flexibility with generation and demand in the current system. The increasing shares of inflexible and fluctuating renewables can cause regional congestion or voltage problems in distribution networks, especially if reinforcement work is behind schedule. Distributed generation is one of the main drivers of the investment need but hardly receives any market signals nor participates in system management for two main reasons:

- First, distributed generation is often from renewable sources and therefore prioritized under fixed feed-in tariffs and exempted from market prices; and
- Second, generators in distribution networks are often too small and not equipped with the technology and characteristics to offer their capacity for system management purposes in the balancing markets. Consequently, a large part of distributed generation does not receive the locational signals simply because they are not subject to energy prices.

Furthermore, the price signals for distributed generation that does not receive support from feed-in tariffs are one-sided. Such generators are incentivized with a premium for avoided network charges as a consequence of substituting supply from higher voltage levels. The reasoning is that local generation reduces the reinforcement needed at transmission level. Consequently the distribution network operator (DNO) pays lower charges to upstream networks and passes the savings through to DG connected to its network. This argument, however, becomes problematic in systems with high shares of DG for at least two reasons:

- First, while DG avoids or reduces network charges in upper levels, it also entails higher network cost in the level it is connected to - namely at the local, low-voltage levels; and
- Second, in systems with high shares of DG, local generation may in times exceed local demand, thus putting an additional burden on the network since it must now balance the load and generation by relying on neighbouring distribution and transmission systems.

The premium for avoided network charges accounts only for the avoided network charges at higher voltage levels and is therefore uniform across one distribution network area. This means that the bonus does not relate to site-specific avoided investment needs; the local network situation is ignored. DG may at the same time trigger higher cost in the local network but nonetheless receive a bonus.

Two further issues hinder coordinated investment into generation, demand and networks:

- First, in Germany generators do not pay for network use and therefore it is not obvious how to implement effective locational signals; and
- Second, the network operators are obliged to expand the network to accommodate privileged generation from renewable sources, unless this is not economically feasible, which applies only rarely. The issue of economic feasibility of network investment is clearly critical, but has not been defined so far. As a result network operators are obliged to accommodate as much decentralized generation as is offered, and to invest accordingly, passing on the costs to all network users.

Within the current regulatory framework in Germany the integration of electricity from renewable sources and the respective investment requirements exhibit high regional variance. While distribution network operators in regions with a high share of electricity generation from photovoltaics or biogas face enormous investment, other regions might not be affected in the same way. Currently, network costs are recovered via "postage stamp" tariffs within each network. Tariffs from higher voltage levels are subsequently passed through to lower network levels, but not equalized horizontally with other networks of the same voltage level. Hence, RES-E-driven investment costs cause a regional variation of tariffs. Importantly, unlike locational charging this does not send locational signals for system optimization. The locational distribution of the burden does not incentivize more beneficial siting decisions for generators who do not contribute to running network cost as feed-in of electricity is presently free of charge (for details see StromNEV, 2005, §15). Consequently, consumers alone bear the cost of the network and face higher network cost in regions with high shares of renewable generation. Recently this has led to a proposal to equalize the network tariffs nationwide (see BR 868/10, 2010). The uniform assignment of network cost to demand prevents locational differentiation and is supported by fairness consideration.

5.3.2 Potential for Locational Network Pricing

Currently, the general approach to connection charging in Germany is of the *shallow* variety. However, there are two ways to by-pass the shallow approach and have some locational network signals. First, the so-called "contributions to connection and construction costs" and second, the option in the network ordinance (StromNEV, 2005, §19.2.3) for individualized network charges and compensation for deferred network investment.

Contributions to Connection and Construction Cost

Network operators may, but do not have to, charge a contribution to the cost of building the network to new connections, which introduces a deep component. The so-called "contributions to connection cost" -in German *Netzanschlusskostenbeitrag*- and the "contribution to construction cost" - in German *Baukostenzuschüsse*- allocate a share of the network connection or expansion cost to the customer. The regulations require that contributions be cost-oriented, non-discriminatory, transparent, and proportionate. Importantly, contribution to connection cost may only be charged for network investments that are not economically feasible without contribution from the connecting party. However, the term 'economically feasible' has not been defined unambiguously. The contributions to construction costs can be charged generally from every customer to cover the cost of the existing network.

The cost-reflective allocation of the infrastructure cost triggered by a new connection has an important function in steering the capacity demand of customers.[70] It is expected to limit the requested capacity to a realistic demand-oriented value and thereby to contribute to needs-based network expansion while avoiding over-dimensioning. Hence, this element is directly targeted towards efficient network development and a promising development towards locational differentiation.

Despite the requirement for cost-based calculation, certain averaging across network areas and charging based on typical cost of comparable cases is allowed. Theoretically, also the regional differentiation in network sub-areas and the charging of distributed generation is possible,[71] although in practice this does not seem to happen. Network operators rather rely on uniform contributions across their network. It can also be observed that while regulation does not prescribe it, network operators typically only use standard calculation for contributions to construction cost. This might be motivated, amongst other reasons, by practical considerations of using a standardized approach. There are two calculation methods that are generally deemed acceptable, one published by the regulator and one by the industry association (VDN, 2007; BNetzA, 2009a). Both are robust against regulatory scrutiny while other, more flexible individual solutions may be targeted for control. Importantly also, these existing calculation methods rely on the traditional model of unidirectional electricity distribution, from central power plants 'down' to end customers. In areas with distributed generation the current calculation even leads to higher contributions for demand, which is inappropriate. Increasing shares of DG and the development of smart grids call for adapted, more sophisticated calculations to take these issues into account.

The assignment of contributions to construction cost is limited to demand customers and non-prioritized distributed generation[72] although network operators rarely charge the latter. This de facto-exclusion of distributed generation from contributions to construction cost is problematic. As they account for large parts of the investment need, cost-reflective allocation of the resulting

[70] They do not have a financing function. Network operators have to resolve contributions to construction cost they received from demand over 20 years as cost-reducing factor in the general tariff calculations. Contributions received from generators have to be resolved on a connection-specific basis over 20 years.

[71] For high voltage networks generator connection regulations prohibit the collection of contributions to construction cost (KraftNAV, 2007).

[72] KraftNAV (2007) prohibits contribution to building cost for generators bigger than 110 MW and connected to networks of 110 kV and more. KWKG and EEG exempt generators from contribution to building cost.

investment cost seems justified to internalize those cost in the networks customers' decisions. Furthermore, time-differentiated components in contributions to construction costs may be necessary to provide targeted incentives that account for utilization patterns that strongly deviate from the average as, for example, off-peak demand. However, the current connection regulation (NAV, 2010, §11) does not allow for time-differentiated contributions to construction costs in low voltage networks.

In conclusion, the contributions to construction costs give a possibility for more differentiated network charges. Further locational and time differentiation of contributions to construction costs as well as an inclusion of other agents such as smaller customers or distributed generators seems desirable to enhance the effectiveness of the instrument. This requires regulators to give more freedom to network operators and encourage case-specific calculations if they incentivize more efficient network development. These developments towards more individual solutions and negotiated contracts are already known. Experience from New Zealand and the US indicates that regulated defaults or standard conditions are recommendable to maximize benefit from flexible solutions while avoiding negative effects for small generators and customers.

Individual Network Use-of-System Charges

In general UoS-charges are uniform in a network area, but in special cases German network operators are required to offer non-standardized, individually designed network tariffs (StromNEV, 2005, §19.2). Standard network charges typically consist of two components, a standing charge based on capacity and a variable charge related to the energy distributed to the respective connection. A coincidence function factors in to which degree the network users contribute to system peak.

This serves cost reflectivity since the capacity demand at system peak is a main driver for infrastructure cost. Individual network tariffs have to be offered if users are expected not to contribute to system peak because their peak demand differs significantly from standard characteristics or for exceptionally large customers.[73] The individual tariff has to reflect the cost savings of deferred network investment, but cannot be less than 20 % of the standard tariff[74] (BNetzA, 2010b).

In addition, it may not lead to substantial increase in the remaining network charges. The contract for an individual network charge is subject to approval by the regulator. If approval fails or preconditions fall away, the standard charges apply. It is important to note, that the individual tariffs can only be lower than the regulated default charges and customers can only improve.

If applied accordingly by the network operator such individual tariffs can be a tool to attract network users with characteristics that are favourable for network development at specific locations. However, the focus of such tariffs on off-peak consumption reduces its effect dramatically as also other characteristics would justify a reduction in network charges. In some cases even consumption during peak times can benefit the network, if for example a lot of photovoltaic feed-in is available during peak periods. Another obstacle for the effectiveness of the tool is its limitation to demand. This results from the fact that feed-in of electricity is presently free of charge (StromNEV, 2005, §15); UoS-charges are borne by demand only. In principle, this tool could also steer generators if these were subject to use of system charges as it is the case for example in the UK.

[73] Individual network tariffs are generally possible for users with 7,500 utilization hours per year (7,000 h as from 2011) and consuming more than 10 GWh per year (StromNEV, 2005, §19).

[74] Until 2010 a threshold of 50 % applied (BNetzA, 2009b).

Recent publications by the German regulator show a tendency to increase the scope for such individual agreements between network operators and customers. The regulator has acknowledged that increasing administrative routine and additional experience justify lowering the preconditions for approval of individual network tariffs at least in some areas (BNetzA, 2010b).

5.3.3 Potential for Locational Energy Pricing

Currently, there are very few locational signals in energy pricing in Germany. There is some discussion at transmission level to implement two zones, north and south, because wind in the north causes frequent network congestion. Yet, it seems that political consensus towards a zonal approach is still a long away ahead. In practice, a discussion on explicit locational energy pricing at distribution level has not started yet. Nevertheless there are loopholes in current legislation that would allow locational signals in energy pricing.

Voluntary Curtailment of DG

In 2009, situations with a lot of wind and low demand caused negative wholesale prices as shown in figure 5.6. This triggered a debate on how to deal with negative prices, and more specifically, whether RES-E, in this case wind, could be curtailed.

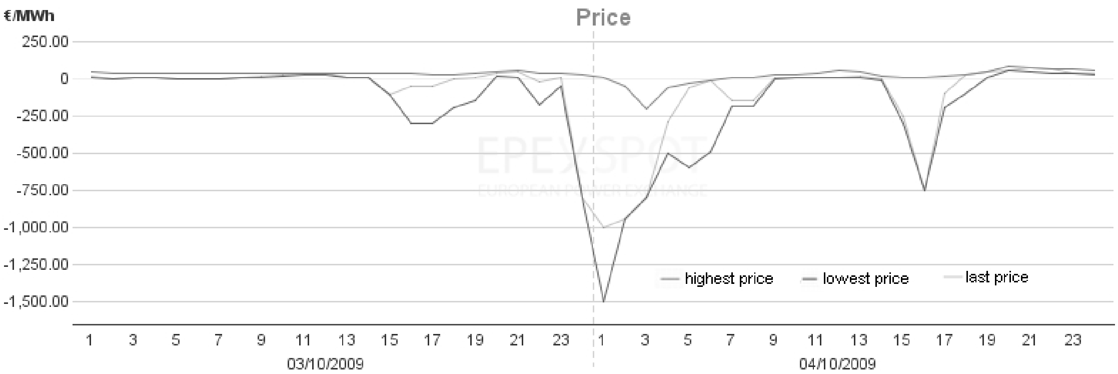

Figure 5.6: Intraday-prices in Germany on October 3-4, 2009. Source: (Epexspot.com, 2011).

The RES-E support scheme in Germany is a feed-in system with take-off obligation and RES-E priority in case of network congestion. Moreover, an inflexibility of the system in Germany is that the possibilities for curtailment of RES-E production are very restrictive by law. Basically, it is not allowed to curtail wind, while a conventional plant still produces unless in must-run status or required to operate for system reliability. In other words, all RES-E must be taken into the system with thermal units ramping up and down for system balance and stability.[75]

Clearly then the system constrains the two leverages for the market to operate efficiently: prices and quantities. Prices are fixed through feed-in tariffs – with the result that RES-E suppliers do not respond to market signals – and quantities are fixed by the priority rule and the restrictions on curtailment. The current policy debate is about how flexible the use of RES-E curtailment

[75]Similar principles apply in many other jurisdictions, where renewable generation is treated as "must take" by the grid operator when available.

should be with policy makers typically preferring to maximize renewable generation to meet environmental protection targets.

After heated debate, the authorities loosened the rules for voluntary RES-E curtailment somewhat, as set out in the guidelines by the regulator (BNetzA, 2011c). Nevertheless, it is still restrictive. Two major obstacles stand in the way to flexible voluntary curtailment of RES-E:

- First, RES-E curtailment is effectively only allowed as a last resort and not for efficiency reasons; and
- Second, for the DNO, if in case of network congestion parties agree on compensated voluntary RES-E curtailment, an obligation to expand the network automatically follows. This practice distorts efficient investment, because it does not allow trading-off between generation and network.

This trade-off is important. A DNO can defer network investment to some extent if allowed to enter into flexible voluntary curtailment agreements. Basically, the network owner would somehow offer compensation for avoided feed-in and foregone revenue and in return save on network investment cost. If parties are properly incentivized this increases overall economic efficiency.

Brandstätt *et al.* (2011a) argue that the overall performance of the system would improve significantly by lifting the restrictions on the use of voluntary curtailment agreements, while retaining the priority rule as such. Since generators of RES-E can only improve under this system reform, investment conditions improve, leading to higher installed RES-E capacity. This in turn implies that reduced wind output due to curtailment can actually be offset by higher wind output in all periods in which there is no problem.

This nice property for environmental goals actually creates a problem for locational signals. There might be a perverse incentive to invest more at this particular location, which is what the signals aimed to avoid in the first place. It can be expected that if the network owner would expect perverse incentives to occur, he would not compensate the feed-in for curtailment but support storage options at these locations. The storage would get paid in times of network congestion and would sell to the system if the network is unconstrained. In these cases, the network owner would want to support storage instead of compensating curtailment. Wang & Wang (2012) look into the details of integrating intermittent renewable generation through storage and Hindsberger *et al.* (2012) describe the combination of electric vehicles and wind generation. It can be concluded that both the legal possibilities and the awareness to apply curtailment exist. The recommendation is to allow more flexibility in the application of the scope to increase flexibility in the system which can be either curtailment agreements but also investment in storage options.

Remuneration for Location-Specific Flexibility: Call and Curtail Agreements

According to current German legislation, network operators are responsible for system stability. In case of emergencies they are expected to take adequate measures to maintain reliability. Apart from network management, this includes market oriented measures such as balancing and reserve energy, contracted load interruptions such as demand response and congestion management (EnWG, 2005, §13). Rewards are given for the provision of reserve capacity and/or via energy prices for produced or curtailed energy, respectively. Again prioritized generation from renewable sources and CHP is exempted and can only be curtailed as an emergency measure in cases of congestion (EEG, 2009, §11) and not for system optimization.[76] Participation in

[76] Curtailed generators of electricity from renewable sources or CHP in most cases still receive the feed-in tariff.

balancing markets is theoretically possible but most, especially small plants, do not qualify for technological reasons. Generation management of prioritized generation is strongly linked to the obligation to expand the network. Whenever renewable or CHP generation is curtailed for network stability, this entails the requirement to expand the network in order to avoid this curtailment in the future. In other words, the system operator cannot avoid network expansion by targeted generation management that avoids network congestion. Generators only receive compensation, if the network operator is liable for the congestion in the sense that it did not sufficiently expand the network. As mentioned in section 5.3.1 it is problematic that regulation does not sufficiently stipulate generation and load management to optimize the system or defer network investment but instead relies on network expansion.

The most interesting of the recent developments in the field of flexibility agreements are so-called "call and curtail" agreements -*Zuruf- und Abschaltregelungen* in German - that can appear in two different forms. They can be part of an agreement for an individual network tariff or can be established for reliability management (EnWG, 2005, §13).

In the first case the agreement assures that a customer is not consuming during the identified peak period. In practical terms this means that the agreement obliges the customer to reduce its demand when called upon or to allow the network operator to reduce consumption via remote control. A call and curtail agreement only qualifies for an individual network tariff if it refers to the peak periods. If this is not the case the precondition of atypical usage, generally outside peak periods, would not be fulfilled. In that case the system operator can conclude contractual agreements with generators or load on the provision of balancing power or curtailable load. The parties agree on an individual payment for the provision of such flexibility potentials. Importantly, the usual network tariffs still apply but are offset against the individually agreed payment. These agreements do not have to go through the regulatory approval process (BNetzA, 2011a).

Both generation management and call and curtail agreements provide the network operator with additional flexibility. Crucially, the management of generation from renewable sources is limited to emergencies. It would be beneficial to allow voluntary curtailment agreements between network operators and renewable generators for the system benefit. Brandstätt *et al.* (2011a) show that this would improve system efficiency while also benefiting renewable generators.

Furthermore, flexible agreements in their current form are only possible for customers that individually cause lower network cost. Achieving the full benefit from customer flexibility would require including also smaller customers that can reduce network cost as a group. This would be a form of demand side management for network purposes. In New Zealand we already observe this in the form of special tariffs for controlled customers thus rewarding their flexibility potential. In this case customers delegate control to the network operator. However, the example of dynamic retail pricing in the US (Kiesling, 2009) indicates substantial system benefits from more cost reflective pricing even with decentralized control.

Also in Germany further developments towards more dynamic pricing for flexibility, including the network dimension are within the scope of current smart grid research. The German government commissioned a major research programme called "E-Energy - Smart Grids made in Germany" to support research and demonstration of smart grid solutions in 6 model regions. One part of the research is the implementation of smart grid enabling technologies and functionalities. Among the main objectives of the project is to develop markets that enable the realization of smart grid benefits in a liberalized market (BMWi, 2010a).

5.4 Conclusions

Experience with locational distribution pricing is still scarce, but shows a trend to more flexible pricing structures. In distribution networks, locational differentiation appears in network tariffs if at all. In the future smarter tariffs can be expected to gain further importance. The energy system becomes more flexible with high shares of renewable generation and flexible demand in smart distribution systems. A flexible tariff structure is necessary to exploit the benefits of smart grids.

Locational pricing distinguishes locational network pricing and locational energy pricing. The former includes deep connection charges and locationally differentiated use-of-system charges. The latter includes nodal and zonal spot pricing. In between is a field that, in this chapter, is referred to as smart contracts. If network owners are incentivized they will find innovative contractual ways to steer feed-in and load to defer network investment. In these cases, the authorities do not have to design the markets but rather simply allow flexible use of smart contracts.

For Germany this can materialize in a further flexibilization of the location-specific connection charges and more individualization of network tariffs. Additionally, adaptations in the current regulatory framework are needed to ensure that network operators have the incentives to use flexible arrangements as an alternative to network expansion.

Several of the mechanisms presented so far, could potentially help defer network investments but to date are not used to their full potential. In principle there are two possible reasons for this. Either the current regulation is too restrictive and does not leave enough freedom to develop smart contracts further or network operators do not receive adequate incentives to develop the smart contracts that are needed to optimize the system. Consequently some further development of the existing framework is desirable. This chapter discussed four possible targets for loosening the current legislation.

Contributions to construction costs are presently used only to prevent economically not feasible capacity requests. Adjustments to the tool should include application to a broader range of customers, determination in a less standardized way and address of prioritized generation. Also more detailed differentiation, for example within one network or according to time patterns is desirable.

For individual network tariffs presently only very big network users or those with an uncommon peak-behaviour are eligible. Other characteristics that can serve to defer network investment, as for example local reliability and voltage support, do not qualify. Also generators and smaller users could contribute to system optimization. For overall efficient network operation it is recommendable that network operators are allowed to offer individual tariffs to all users with beneficial characteristics.

Following recent episodes of negative wholesale prices, it is now possible to enter into voluntary curtailment agreements with RES-E suppliers. Application of this option is too restrictive to be effective in deferring network investment. Allowing more flexible use of voluntary curtailment agreements for RES-E suppliers would create further potential without requiring system reform.

The same reasoning applies to the 'call and curtail' agreements that are strongly restricted for renewable generation. This limits the effectiveness of this instrument for the management of smart distribution as large parts of generation in distribution grids are exempted. Consequently further flexibilization of these tools and the inclusion of renewable generation are highly desirable.

There are two issues for further research. The regulator needs to think about network investment incentives. Without appropriate incentives the network operators will not exploit the structural optimization potential. While network operators are obliged to expand the network to the bitter end there is not much scope for efficient network development. Also the fact that expansion cost is passed through as long as the regulator approves, prevents creativity for investment optimization. Therefore an adjustment of the regulatory framework to provide more incentives for efficient system transformation is necessary.

Another crucial point is market integration.Generation from renewable sources and distributed generation are focal elements in the future smart grids and yet do not or not sufficiently participate in the markets.[77] Presently there are only few locational signals and those that do exist do not reach these critical actors. Additionally, the remuneration for avoided network cost in higher voltage levels that exhibits some form of locational differentiation sends the wrong signals. They are presently mainly a general support scheme for distributed generation. Small changes, however, could make them reflect the local situation better and could thus help regional networks with locational steering.

[77]Market integration of generation from renewable sources and the adequate design of support schemes is currently a big debate. For more information see e.g. Klessmann *et al.* (2008).

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6 Improving Investment Coordination in Electricity Networks Through Smart Contracts

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Smart contracts based on voluntary participation and optionality can be a low transaction cost solution to implement locational signals in distribution networks and thereby avoid network investment. This paper examines the efficiency properties of smart contracts. Based on a three-node example network we show that cases exist in which smart contracts can achieve a pareto-improvement compared to the status-quo even with voluntary participation. With the pareto improvement at least one party is better of under a smart contract without worsening the situation for anyone else. We note that this requirement is very restrictive and leaves significant potential for efficiency improvements by smart contracts untapped. We then discuss the implementation of smart contracts with incentive regulation. There are two main tasks for the regulator: allowing network operators flexibility to offer such contracts and incentivizing network operators to do so.

Keywords: network investment, distribution networks, locational pricing, smart contracts

JEL-classification: D23, D43, L14, L22

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6.1 Introduction

Distribution network operators face several challenges that result in increased investment needs. Apart from ageing assets an important factor is the significant volume of distributed generation that is built in distribution networks. The increase in distributed generation can cause congestion since lines have not been built for large bottom-up flows. Most often distributed generation is renewable or combined heat and power generation which may add intermittency. Yet, this generation is an important aspect of climate policy and likely to increase even further. These developments change the operational paradigm of centralized, controllable generation and top-down power flow. It requires investments in order to upgrade transformers and guarantee voltage stability. Furthermore, the development of smart grids[78] brings about a more decentralized and active user structure. There are for example prosumers that are both producing and consuming energy or electric vehicles that present a locationally and temporally variable load.

The diversity of users feeding in and taking off electricity from the grid needs to be managed to guarantee system stability at every point in time. Since lines only have limited capacities local clustering of load or generation can cause congestion. The exact effects depend on the local network conditions, size, type, location as well as the utilization pattern of the installation. The impact can go in both directions: new demand or distributed generation can relieve network stress and defer investments at some locations while it increases network investment need at others (Piccolo & Siano, 2009; Ackermann, 2004). Hence, the coordination of network and network users in space and time can release efficiency potentials and avoid network investment. Large parts of distribution networks date back to the 1970s. They are about to reach the end of their lifetime and replacement becomes necessary. Therefore coordination of network investments efficiently with the development of network users and thereby reduce the necessary investment could directly have a positive effect.

Currently network expansion policies are often oriented towards maximum demand. Once a situation with insufficient network capacity is observed, the network will be reinforced or expanded. In economic terms this may be inefficient since the network is extended to prevent any possible constraint. Essentially there is no balancing between cost and benefit that stops network expansion at the efficient level. Especially in cases where the capacity limit is only exceeded in few occasions per year management of generation or demand might be more efficient than network investment.

However, currently users do not have an incentive to take network conditions into account. Distribution networks in many countries rely on uniform pricing and network cost are often socialized to demand (see Brandstätt *et al.*, 2012). Prices do not convey signals on the network conditions and network impact remains an externality to network users. Locationally differentiated pricing can be a tool to internalize the network conditions and signal network users their network impact. The price system can help steering them according to network needs. Locational signals can appear in the network or energy charge as well as in a combination of both. As discussed in Brandstätt *et al.* (2011b) in distribution networks the realization of general tariff plans that include locational differentiation is fraught with problems. We proposed smart contracts instead as a tool to send locational signals in a low transaction cost and flexible way. Smart contracts are voluntary agreements between the network operator and network customers,

[78] We use smart grids to refer to electricity distribution networks with a high share of decentralized generation, an active demand side, and additional flexibility via storage. An information and communication infrastructure connects the diverse actors in the smart system and enables advanced control and coordination approaches. Recently smart grids are also discussed with respect to gas grids (see e. g. Hinterberger & Kleimaier, 2010) or concerning the transmission networks (see e. g. Battaglini *et al.*, 2009).

i.e. demand, generation, and storage that realize a trade-off between investment into the grid and into demand and generation. We argued that smart contracts are more beneficial in smart distribution networks than locational signals in a general tariff plan for the following reasons (Brandstätt *et al.*, 2012, 2011b):

- Network operators can flexibly design these contracts to better adapt customer behavior to network capacities when this is cheaper than network investment.
- More refined pricing structures have to emerge in smart grids anyhow and we already observe developments in this direction. Location would be one additional aspect that might be beneficially added to tariff design.
- Smart contracts do not require a reform of the entire pricing system and need only little regulatory intervention. This implies that the implementation is more likely and less burdensome than a complete overhaul of the pricing scheme.
- Participation in smart contracts is voluntary. If combined with a default tariff, this ensures that customers are protected against exploitation by the network monopolist in the negotiation of a smart contract.

An improvement of the overall situation and incentive compatibility of smart contracts (as the key notion of smart contracts is voluntary participation starting from the current state of affairs) have not been shown yet. In this paper, we provide a numerical example where smart contracts improve some stakeholders without worsening the situation for any of the others. This illustrates how smart contracts can achieve a pareto-improvement and are thus also incentive compatible and improve overall economic efficiency. Hence with a small change in the regulatory framework towards allowing more flexibility in contract design at least one party can become better off while no party is harmed. Importantly, network operators need incentives to pursue smart contracts as an alternative to network expansion. This implies that they should be entitled to part of the benefits from the avoided investment. It is the task of the regulator to a) allow network operators the flexibility to design smart contracts and b) to incentivize network operators such that they carry out efficient network investment and will offer smart contracts where investment can better be avoided.

The paper is organized as follows: Section 6.2 briefly reviews locational pricing in distribution networks and outlines smart contracts as favorable option for implementation. Section 6.3 presents the model and two specific cases of smart contracts. The results and the implications for the regulatory framework are discussed in section 6.4. Section 6.5 concludes.

6.2 Locational Pricing in Distribution Networks

In theory locational pricing is a powerful tool to steer network utilization and thereby avoid investment. Locational signals that appear in the energy price are known as locational marginal pricing or nodal pricing. This method is successfully applied e.g. in US transmission networks. Congestion is reflected in prices at both sides of the constraint: lower energy prices at the generation dominated side make feed in less attractive and incentivize consumption while higher prices at the other side do the opposite. Alternatively, the locational signal can appear in network charges. In this case areas with scarce network capacity would exhibit higher charges for generators thereby dis-incentivizing new utilization. Areas with spare capacity would feature comparably lower tariffs. Price signals are expected to steer users away from areas with scarce capacity or incentivize generation close to load (see e.g. Ofgem, 2009). This can enhance system efficiency for example by avoiding capacity expansion and reducing losses. While nodal spot pricing needs explicitly designed markets, locational network pricing requires at least regulatory approval of the tariff methodologies to ensure that locational differentiation is not used to conceal other discriminatory intentions. Hence, both locational energy and network pricing are general tariff plans and require regulatory reform. In contrast, smart contracts are an instrument to set locational incentives with little regulatory intervention and high flexibility.

6.2.1 Locational Network Pricing

Locational signals in network charges can appear in connection charges and use-of-system (UoS) charges. The connection charges typically cover the costs of lines, transformers and other equipment needed to connect a new user to the grid. Connection charges are called shallow if the network user pays only the direct cost of connecting to the next connection point in the existing grid. Charges that also include the reinforcement that becomes necessary in other parts of the existing network are called deep charges. An example for a deep component is the upgrade of transformers or lines in the existing grid to enable the distribution of additional electricity generated at a newly connected site. In areas with scarce network capacity, new connections likely trigger network investment. Deep charges reflect this effect making congested sites less attractive.[79] Deep charges are a powerful tool for cost-reflective locational signals. However, implementation is difficult because the determination of fair and transparent deep charges is a non-trivial exercise as further described in Brunekreeft *et al.* (2005).

UoS-charges cover the running cost of the network such as losses and balancing energy. Typically UoS-charges are not locationally differentiated but average based for each voltage level and differentiated further by the extent of use. This practice does not reflect the actual condition of the network at a specific site. However, locational differentiation in distribution networks has been achieved for example in the UK where incremental cost pricing includes the expansion cost of the network into the UoS-charges. It thereby introduces a long run perspective (Li *et al.*, 2005). If siting at a certain location defers network investment, charges are low. In contrast, charges are high, if new connections cause network reinforcements. Hence, the charges reflect the urgency of network investment.

6.2.2 Locational Energy Pricing

Energy prices that incorporate the locational dimension are known as locational marginal prices (LMP) or nodal spot prices (Hogan, 1992; Schweppe *et al.*, 1988). Nodal prices display the marginal cost of supplying load at each node. In addition to standard spot prices nodal spot prices reflect the topology of the system and take into consideration the transportation cost of electricity, i.e. losses and congestion. Zonal pricing is a less detailed variant of locational energy pricing. It differentiates prices by zones rather than per node (for further considerations see e.g. Björndal & Jörnsten, 2001).

Nodal spot pricing is considered to send first best signals for short-term system optimization, i.e. for operation (Stoft, 2002; Hogan, 1992). Long-run signals are weak since nodal prices do not reflect fixed network cost. Although they lead in the right direction, they are insufficient to guide efficient investment decisions (Brandstätt *et al.*, 2011b; Brunekreeft *et al.*, 2005). Furthermore, today most retail customers are on uniform tariffs and therefore do not receive nodal price signals.

[79] See for a more detailed discussion Woolf (2003).

6.2.3 Smart Contracts

Smart contracts are additional agreements to the standard regulated, possibly uniform tariff and thus represent a way to implement targeted locational signals without the need to reform the general tariff plan. Network operators could offer contracts to flexible customers in order to make use of their flexibility for the benefit of the network. This is in line with developments expected in the course of the transformation towards smart grids: While the technical potential for inclusion of load and generation into distribution system management is enormous, the respective actors need to be incentivized to participate. Prices and contracts are the way to achieve just this. In view of efficient network investment, these smart contracts can obviate the need for more explicit locational signals in network or energy general tariff plans.

Importantly, smart contracts are voluntary; customers can always fall back on a default tariff. This ensures that no negative distributive effects compared to the baseline have to be expected. After all, market participants would only accept a smart contract if it was for their better and if the benefit of the contract exceeds the transaction cost. In other words: some network users will improve their situation by entering smart contracts. For other network users things remain the same. This resembles the findings of Willig (1978) who showed that non-linear tariffs can achieve a pareto-improvement compared to a uniform price above marginal cost. Optionality is the key component to improve not only consumers in aggregate but each individual. In Willig's work network users can choose between a two-part tariff and the uniform price. In a similar way network operators can design smart contracts in addition to a regulated default tariff. Relevant characteristics of customers that might be targeted by smart contracts are for example location, size, and flexibility. The most relevant target group for smart contracts may be the bigger distribution network customers such as commercial customers or generators or user clusters since their impact is more pronounced and the relative transaction cost are lower.

6.3 Model

The concept of smart contracts is based on the assumption that network users will only enter the voluntary contract if this is beneficial and otherwise will stick to the regulated tariff. This guarantees that the contracting parties can only improve since this is the precondition for offering respectively entering the contract. The analysis in this paper will show exemplarily that this is possible even without harming any other stakeholder in the system who cannot influence whether or not the contract takes place.

We use a three-node example network to illustrate our case. The model illustrates how smart contracts can achieve pareto-improvements compared to a situation with uniform pricing and an obligation to expand the network. Our starting point is a situation in which one line in the network is congested. The benchmark solution to congestion is network expansion. We then present several opportunities to relieve congestion with smart contracts avoiding network investment and analyze the effects. The pareto-improvement considers the changes in surplus for the following agents:

- network operator
- generators (at different nodes)
- load (at different nodes and including storage where applicable)

The network operator is responsible for system operation and network investments. Network operators recover the cost for network operation and investment from demand customers via use of system and connection charges. In our benchmark case, socialization of cost is to demand side customers only and generation does not pay use of system charges. We assume a market price P_E for electricity above generator marginal cost C_G. Practically speaking, this reflects a contribution to fixed cost of capital and formally speaking this ensures a positive outcome for generators when producing although we assume constant marginal cost (making the difference to indifference).[80]

Moving to a system with smart contracts creates additional financial flows in both the network operator's expenses and the network customer's income. With the aim to steer behavior and avoid network investment, the network operator could grant a rebate or pay a bonus to its customers. We assume that even if existing generation is not charged connection charges, nonetheless, they could receive a bonus via a smart contract.

symbol	meaning	unit
P_E	energy price	€ /MWh
P_N	network charge	€ /MWh
I_N	network expansion cost	€
D	ntotal demand	MWh
D_n	demand at node n	MWh
D_{Sn}	demand from storage at node n	MWh
G_n	generation at node n	MWh
G_{Sn}	feed-in from storage at node n	MWh
G_{Cn}	curtailment at node n	MWh
C_G	generation cost	€ /MWh
P_{E_peak}	energy price in peal periods	€ /MWh
P_{E_off}	energy price in off-peak periods	€ /MWh
U	utility of electricity consumption	€ /MWh
α	reduction on network charges for demand at desirable locations	€ /MWh
β	rebate on network charges for storage	€ /MWh
δ	premium for curtailed generation	€ /MWh
γ	bonus for network (connection) at desirable sites	€ /MWh
ω	reduction of the utility at second choice location	€ /MWh

Table 6.1: List of variables in the model.

6.3.1 The problem

For illustration purposes we simplify the problem to a three-node network in which the cheapest dispatch to supply the given demand at a certain point in time is not compatible with the physical capacities of the network as shown in figure 6.1.

Assume that generation at node 1 is renewable generation (e.g. wind) which receives priority feed-in. Assume further that in cases where renewable generation cannot feed-in because of limited network capacity the network operator is obliged to expand the network[81] and that the

[80]Usually, marginal cost is assumed to be increasing, which would leave generators with a positive outcome even under marginal cost pricing. For our purpose this would only make calculations more complex without adding additional insights. For our purpose of illustrating how smart contracts can achieve a pareto-improvement, the assumption of constant marginal cost seems sufficient.

[81]Such assumptions are inspired by real-world renewable support schemes as they can be found for

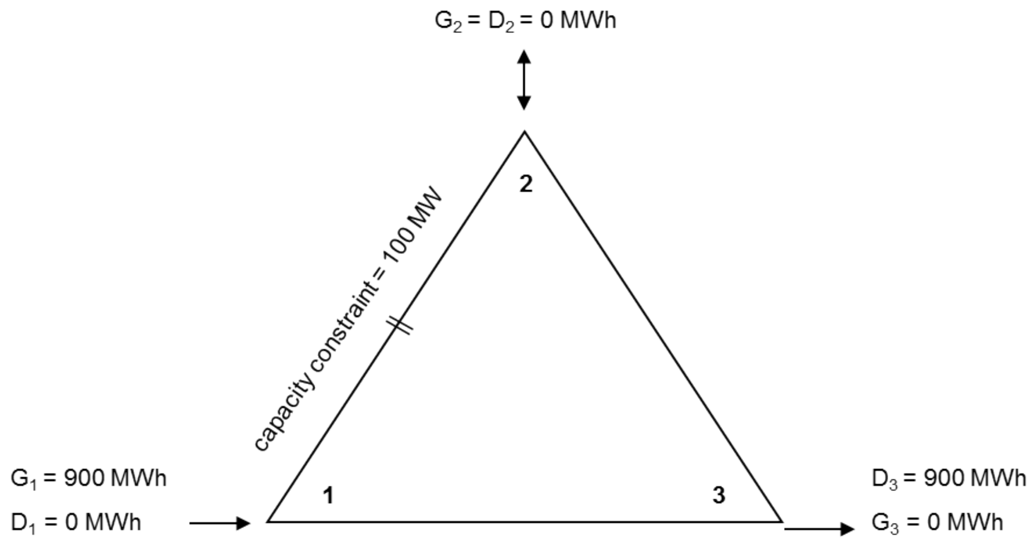

Figure 6.1: Infeasible dispatch under given capacity constraint.

line between node 1 and 2 is limited to a maximum capacity of 100 MW. Generation at node 1, G_1, is 900 MWh and load at node 3, D_3, amounts to 900 MWh. Node 2 is balanced between generation and demand and therefore appears as net flow of 0. Although the situation is generally balanced, it is technically not feasible as the flow between node 1 and 2 would exceed the capacity of the existing line: the current dispatch causes congestion.[82] The situation can be solved with network expansion (copper solution). Alternatively, a different constellation of feed-in and take-off can ease the situation. Controllable generation leaves the network operator with the freedom to regulate feed-in. Alternatively, in case load at node 3 is comprised of electric vehicles that are potentially flexible in time and location of consumption, the network operator can influence take-off. At any case the network operator would need to incentivize network users to change their behavior and thereby defer network investment. We present selected solution scenarios in turn.

Reference Case: Network Expansion

The "investment solution" to capacity constraints in the network is the expansion of the respective lines as depicted in figure 6.2. This will serve as a reference case for the smarter solutions presented below.

Expanding the capacity of the line from 1 to 2 with 200 MW to a total capacity of 300 MW relieves the congestion. Assume network expansion cost I_N to be €27000.[83] Whenever smart contracts are able to relieve congestion at a lower cost than the necessary network investment, they can achieve an improvement compared to the status quo. Assume furthermore that the costs

example in Germany. In Coasian terms, the network users have the property right of unconstrained network access.

[82]Following Kirchhoff's laws, in an AC system, the 900 MW injected in G_1 splits 600 MW between G_1 and D_3 and 300 MW G_1-G_2-D_3, which is not possible due to the line constraint.

[83]The precise number of 27000 € has no meaning; it is a fictive value of normalized network investment.

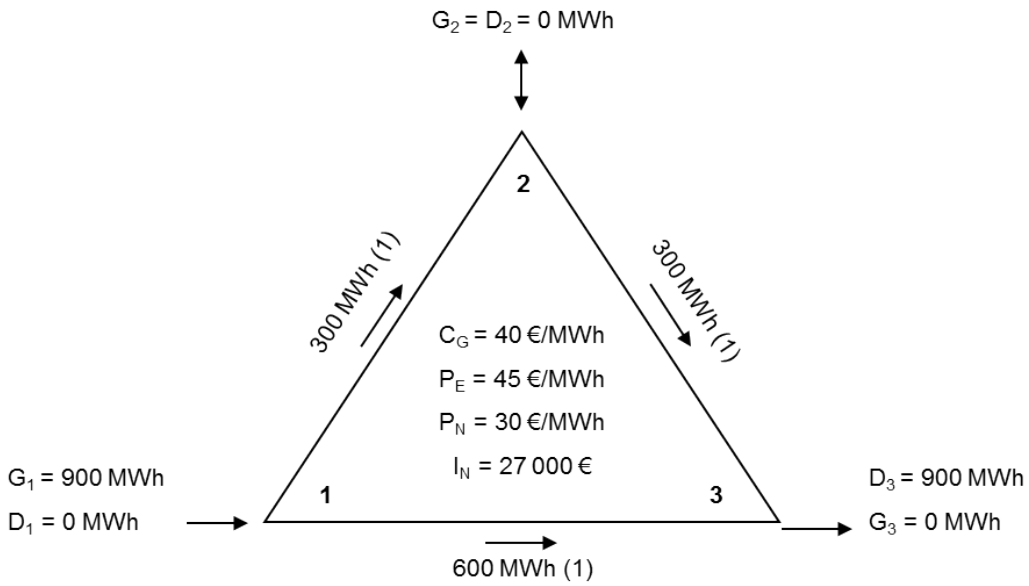

Figure 6.2: Reference case: network expansion.

of network expansion are allocated to network users via network charges.[84] Socialized to demand only this results in a network charge P_N of 30 € /MWh for demand customers.[85] Additionally, customers pay an energy charge P_E of 45€ /MWh which in this case covers generator cost C_G at 40€ /MWh and includes a generator surplus of 5€ /MWh. We assume that consumption of electricity provides the customer with a certain utility U (which is assumed to be sufficiently large to keep consumers connected).

Income distribution in the reference case which is used as a benchmark to evaluate the performance of smart contracts is displayed in table 6.2.

	profit functions	pay-off
network	$P_N \cdot D - I_N = 30€\,/\text{MWh}\cdot 900MWh - 27000€$	0€
generation (G_1)	$(P_E - C_G)G_1 = (45€\,/\text{MWh}-40€\,/\text{MWh})900\text{MWh}$	45000€
generation (G_2)	$(P_E - C_G)G_2 = (45€\,/\text{MWh}\ -40€\,/\text{MWh})0\text{MWh}$	0€
demand (D_3)	$(U - P_E - P_N)\,D_3 = (U - 45€\,/\text{MWh}-30€\,/\text{MWh})900\text{MWh}$	$U - 67500€$
demand (D_1)	$(U - \omega - P_E - P_N + \alpha)\,D_1$	
	$= (U - 0€\,/\text{MWh}-45€\,/\text{MWh}-30€\,/\text{MWh}+0€\,/\text{MWh})0\text{MWh}$	0€
storage	$\left(P_{E_{peak}} - P_{E_{off}}\right) D_S = \left(P_{E_{peak}} - P_{E_{off}}\right) 0\text{MWh}$	0€

Table 6.2: Income distribution in the reference case.

[84] The socialization can incorporate both consumers and generation. Since the common practice in distribution networks is the socialization to demand only we assume the generation/load-split to be 0/100.

[85] This abstracts from other components in the network charges such as losses, maintenance, and personnel.

Alternative: Network Investment Deferral

In cases where the maximum capacity is needed only for very few occasions, network expansion is not efficient (Stoft, 2002). Alternatively, changes in generation and demand can solve the constraint and defer network investment. Assume that the network regulation is such that if the investment costs are deferred the network operator can keep (part of) the avoided expenses. As a consequence, the network operator could make use of these avoided expenses to incentivize network users to change behavior such that network investment is deferred. This can be achieved by smart contracts for both, demand and generation side. The network operator, being best informed about problems in his network can target those customers that have a relevant impact on the network. It seems plausible that, if left freedom to do so, he will offer efficient contracts to defer network investment.

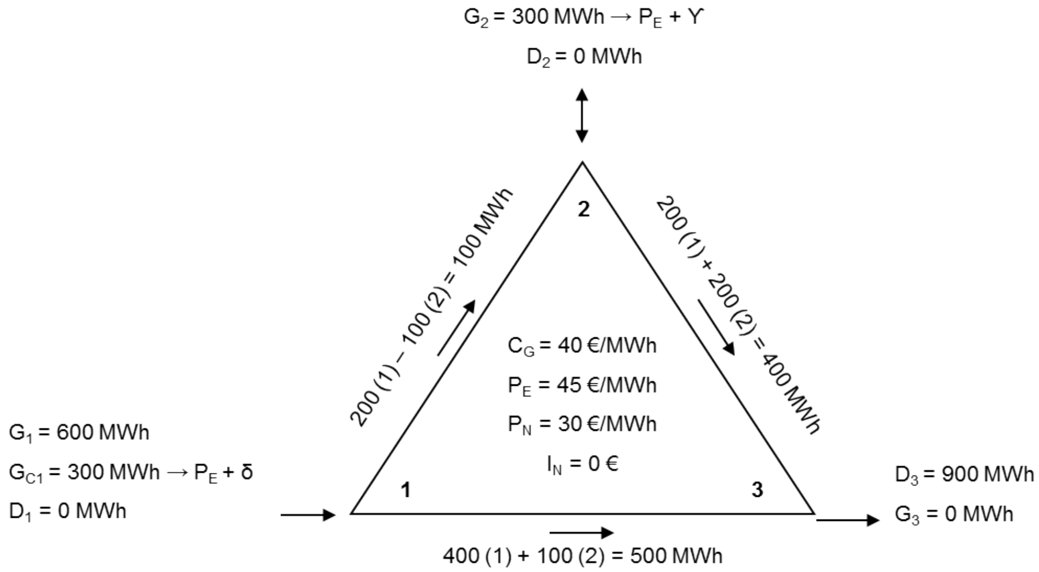

Figure 6.3: Alternative 1: Smart contracts for generation.

Alternative 1: Smart Contracts for Generation

One solution is to relieve congestion with purely generation oriented measures. For the illustration of this we draw on the example from figure 6.1 and figure 6.2. A shift in the generation pattern as illustrated in figure 6.3 can relieve congestion as follows: partial curtailment of the generation at node 1 (G_1) to 600 MWh and feed-in of an additional 300 MWh of generation at node 2 (G_2). Generation at node 1 might be prioritized generation and curtailment politically difficult.[86] What is essential here is that we assume generators enter curtailment agreements voluntarily, whilst retaining the right to produce (priority feed-in under fixed feed-in tariff). That means they continue to receive the P_E for voluntarily curtailed power and receive a premium δ on top.[87]

[86]This is a realistic assumption for many countries with feed-in systems e. g. Germany.

[87]Typically the continued payment of P_E in case of curtailment would be adjusted to the variable cost of the generator. The underlying logic is that for example fuel cost does not need to be compensated for since in case of curtailment no fuel is spent. For reasons of simplicity we assume that C_G is only fixed

The δ incentivizes generators to accept such a contract when otherwise they could be indifferent between producing or not. Brandstätt *et al.* (2011a) illustrate how such voluntary curtailment for generators can be beneficial for the system while not negatively affecting climate goals.

However, in the long run the curtailment premium creates perverse incentives. If generators in congested regions receive a premium for not producing this attracts generators to connect in already constrained regions because these regions promise additional income from curtailment contracts. Hence, the locational signal for generators goes in the wrong direction. Note, that this is the discussion of perverse incentives known from counter trade: curtailment compensation leads to improved investment conditions "behind" the constraint (see e.g. Dijk & Willems, 2011). Under the presence of perverse incentives, the network operator would be worse off with the price differentiation under smart contracts: the constraint would increase in the course of time and expansion will become even more necessary. If the network operator foresees increased investment needs resulting from smart contracts, he will always invest directly in network expansion and smart contracts will not work. Alternatively, perverse incentives could exist but are compensated by a mechanism that prevents new siting at already congested locations such that smart contracts remain feasible. This can be relatively lower network charges at desired locations by paying out a bonus γ as explained above. Also, available sites for new generation in the congested area might be scarce making the problem relatively small in itself since the limitation on available sites constrains the additional generation capacity that can be built.[88] Alternatively, the network operator might want to incentivize storage in situations where smart contracts with curtailment compensation create perverse incentives for generators. This can also relieve the constraint (see below section 6.3.1) by enabling the needed flexibility and it does not incur the risk of worsening the constraint.

Although theoretically cost-reflective (positive) network charges can be calculated such that they equal out exactly the "false" positive incentive at congested locations, this is not possible in a situation where generators do not pay network charges. Furthermore, it rules out a pareto-improvement since it would deteriorate the situation of generators that did not pay before. Therefore we assume a network bonus, γ, that is paid at non-congested locations to make these more attractive vis-á-vis congested locations. The bonus can in principle be granted as one-time rebate on the connection charge or as ongoing payment for feed-in. The γ serves to steer new users to locations with spare capacity rather than to congested locations which promise curtailment compensation. The additional incentivized feed-in at node 2 needs to make up for the curtailed generation at node 1 (G_{C1}).

The additional generation at node 2 can be from new or existing generators. If existing (conventional) generators at node 2 did not produce before because of congestion created by RES-E production, curtailment enables this generation to become active. It does not receive the network bonus γ because these generators already made the siting decision and paid for their connection. They do not need additional incentives to site at node 2. Intuitively, the bonus should only be granted to newly connecting generators. However, this might raise concerns on price discrimination. In particular if the bonus is a per-unit payment and thus affects marginal costs and might thus distort competition. This speaks in favor of bonus payments to all generators at favorable locations without differentiating between existing and new installations. The following table 6.3 gives an overview of the income balance for the different actors in a system with smart contracts as described above.

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cost that incurs regardless of actual electricity generation, so that curtailment compensation with the full P_E is justified. This assumption is realistic for example for photovoltaic or wind generation.

[88] Hence, the customer groups are not exogenous at each location. This violates the condition of 'no arbitrage'. which is necessary for an effective pareto-improving non-linear pricing scheme, as known from the literature on price discrimination.

	profit functions
network	$P_N \cdot D - (P_E + \delta)G_{C1} - \gamma \cdot G_2 = 30€/\text{MWh}\cdot 900\text{MWh} - (45€/\text{MWh} + \delta + \gamma)300\text{MWh}$
generation (G_1)	$(P_E - C_G)G_1 + (P_E + \delta)G_{C1}$ $= (45€/\text{MWh} - 40€/\text{MWh})600\text{MWh} + (45€/\text{MWh} + \delta)300\text{MWh}$
generation (G_2)	$(P_E - C_G + \gamma)G_2 = (45€/\text{MWh} - 40€/\text{MWh} + \gamma)300\text{MWh}$
demand (D_3)	$(U - P_E - P_N)D_3 = (U - 45€/\text{MWh} - 30€/\text{MWh})900\text{MWh}$

Table 6.3: Income distribution for alternative 1.

Summing up, we note that smart contracts that induce voluntary curtailment require the network operator to pay P_E plus an additional δ. Furthermore, also new generation at node 2 has to be paid a bonus γ on top of the regular remuneration. While the remuneration for produced electricity is obviously paid by final customers that consume the energy, the smart contract payments appear at the network operator side. These additional expenses have to be lower than the network investment that can be avoided. Otherwise it would be better to expand the network. Hence, if smart contracts should be cheaper than network expansion, the additional expenses for δ and γ may not exceed 45 €/MWh. Generators are always better off because they receive a bonus payment on top of the market price in both locations: at node 1 for curtailment and at node 2 to incentivize siting. The following table 6.4 details the payoff of alternative 1 in comparison to the reference case.

	pay-off base case	pay-off case 1	improvement
network	0€	$13500€ - (\delta + \gamma)300\text{MWh}$	if $(\delta + \gamma) \leq 45€/\text{MWh}$
generation (G_1)	4500€	$16500€ + \delta \cdot 300\text{MWh}$	always
generation (G_2)	0€	$1500€ + \gamma \cdot 300\text{MWh}$	always
demand (D_3)	$U \cdot 900\text{MWh} - 67500€$	$U \cdot 900\text{MWh} - 67500€$	0€

Table 6.4: Improvement with alternative 1.

Alternative 2: Smart Contracts for Demand and Storage

Another solution to relieve congestion is the use of demand-side oriented measures and storage. In smart systems this aspect will be of particular relevance. The increasing complexity of the system resulting from the diversity of actors, bi-directional power flows and intermittent generation is expected to require extensive flexibility. Storage can provide such flexibility. Extending the definition of storage beyond pure physical storage, it can also incorporate demand flexibility or demand response as "virtual storage". While conventional storage and demand are immobile and can only provide flexibility at a certain location, electric vehicles are mobile and can therefore potentially better address locational problems.

Storage

Assume the problem results from the priority feed-in of wind at node 1 that congests the network. Instead of curtailing wind, the network operator can use storage capacity at node 1 to relieve the constraint. It offers the additional benefit of unloading the storage in times of low wind generation thereby leveling the feed-in profile of wind generation. Note that storage appears as additional demand at node 1 (D_{S1}) in our example. Importantly as in alternative 1 this requires additional feed-in at node 2. Figure 6.4 displays the new situation.

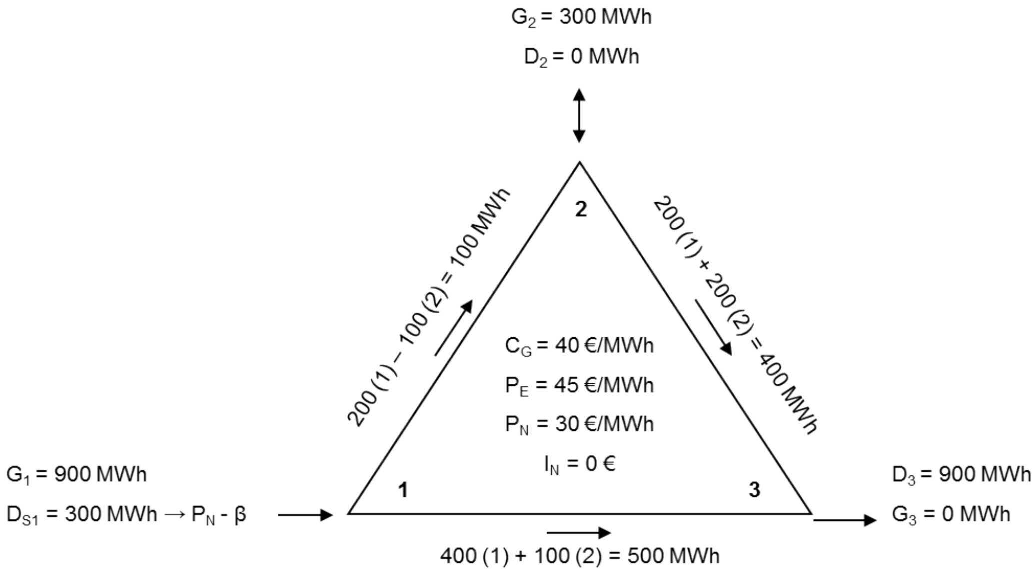

Figure 6.4: Alternative 2a: Smart contracts for storage.

	profit functions
network	$P_N \cdot D_3 - \beta \cdot D_S$ = 900MWh·30€ /MWh$-\beta \cdot$ 300MWh
generation (G_1)	(45€ /MWh−40€ /MWh)900MWh
generation (G_2)	$(P_E - C_G)G_2$ = (45€ /MWh−40€ /MWh)300MWh
storage (D_{S1})	$\left(P_{E_{peak}} - P_{E-off} + \beta\right) D_{S1}$ = (45€ /MWh−45€ /MWh+β)300MWh
demand (D_3)	$(U - P_E - P_N)\, D_3 = (U -$ 45€ /MWh−30€ /MWh)900MWh

Table 6.5: Income distribution for alternative 2a.

Storage operators buy electricity to resell later at a higher price. They do not incur network charges for the stored energy.[89] We abstract from losses and other operation cost. Hence, the difference between buy price and sell price determines the income of the storage operator. In order to incentivize flexibility in the system the network operator grants storage facilities a bonus of β. Compared to the reference of network expansion this is feasible as long as β is less than 90 € /MWh. Table 6.5 details the payoff functions for all actors in case 2b.

While the situation of the generator at node 1 remains unchanged the generator at node 2 incurs an additional profit from producing when he was not producing in the reference case. Since storage receives a bonus (β) that was not available in the reference case its situation improves as well.

Note, that this situation is a snapshot view only. While storage acts like demand in some hours it would feed power back into the grid in other hours and thereby appear as producer. The question then is: what happens in this second period? Assume storage is built with the particular

[89]This assumption is realistic. For example the German government decided to exempt new storage from paying use of system charges in the context of needed flexibility. Paying network charges would represent a significant barrier for new investments in storage.

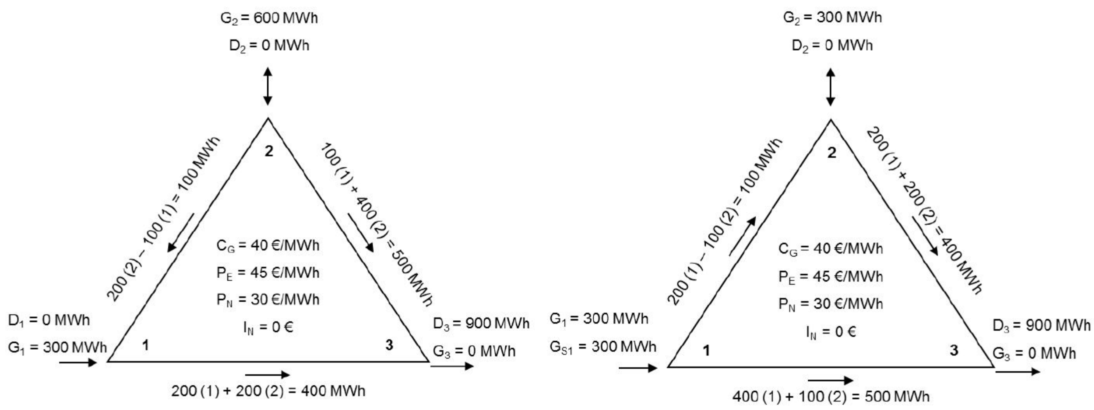

Figure 6.5: Second period – storage feeding back to the grid.

	pay-off base $1^{st} + 2^{nd}$ period	pay-off 2a $1^{st} + 2^{nd}$ period	improvement
network	0€ +27000€	54000€ $-\beta \cdot$ 300MWh	if $\beta < 90$€ /MWh
generation (G_1)	4500€ +1500€	4500€ +1500€	0€
generation (G_2)	0€ +3000€	1500€ +1500€	0€
storage (D_S)	0€	$\beta \cdot$ 300MWh	if $\beta > 0$€ /MWh [90]
demand (D_3)	$2(U \cdot$ 900MWh$-$67500€)	$2(U \cdot$ 900MWh$-$67500€)	0€

Table 6.6: Improvement with alternative 2a - 1^{st} and 2^{nd} period.

purpose of leveling out intermittent wind production. Storage can take up wind production when feed-in exceeds capacity and feed back to the grid when wind production is very low. Hence, we assume a base case with only 300 MWh wind feed-in. This requires 600 MWh of generation at node 2 to supply demand which is still at 900 MWh. Figure 6.5 displays the base case for the second period (left) and the respective changes with storage (right). Table 6.6 compares base case and alternative 2a over both periods.

It can be seen that feed-in from storage reduces the need for additional generation at node 2. Hence, while these generators benefitted in period 1 when they could produce more in comparison to the base case, they can produce less in period 2. Both effects level out.

We note that the overall effect is positive if periods with low generation at node 1 occur that allow storage to feed back into the grid without causing additional constraints. If this is not possible, storage can be to the detriment of generation at node 1 since feed in from storage would compete with G_1. In this case generation needed to be curtailed and the generator at node 1 would be worse off than in the base case with network expansion. Hence, driving the criterion of pareto-improvement to the extreme, G_1 should receive curtailment compensation as in alternative 1. It is obvious that at some point this may render smart contracts undesirable because numerous compensations not only in the current but also in future periods arise. It is then a question of how far the criterion will be understood and what will be taken as baseline. The pareto-

[90] Note that the economic viability of storage depends on the spread between peak and off-peak price unless there are other benefits (such as leveling out wind production). For the storage to receive a positive pay-off, $(P_{E\_peak} - P_{E\_off} + \beta) > 0$. Furthermore, since we assume prices to be equal in 1^{st} and 2^{nd} period, storage does only make profit from β but not from the price spread.

improvement is a good starting point as it minimizes reluctance against those arrangements since no player is harmed. Even if it were relaxed voluntary and optional smart contracts realizing efficiency improvements are still possible improving only the parties involved in the contract but not necessarily everyone else. Also the above the situation of storage competing with existing generation may be a virtual problem. In many cases, with fluctuating generation storage can feed back to the grid without the need for curtailment. There may be only some extreme hours in the year that cause local network congestion.

Locational demand shift

The problem of congestion on the line between node 1 and 2 results from concentrated demand at node 3 in combination with concentrated generation at node 1. A locational shift of demand from node 3 to 1 where electricity is produced would relieve the system stress. Therefore, as an alternative to network expansion, some of the electric vehicles could be incentivized to load at node 1 instead of 3 as displayed in figure 6.6.

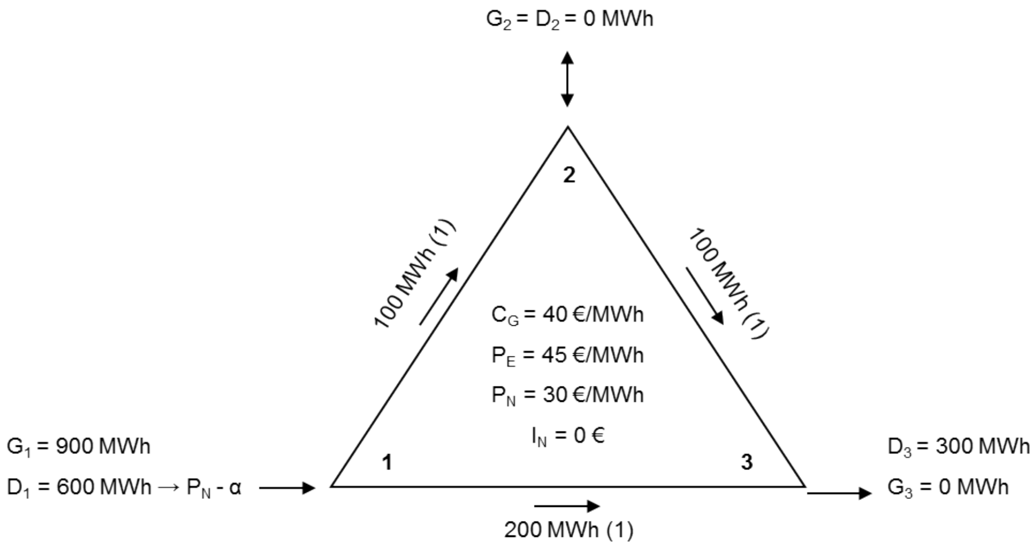

Figure 6.6: Alternative 2b: Smart contracts for locational demand shift.

	profit functions
network	$P_N \cdot D - \alpha \cdot D_1 = 30€/\text{MWh}{\cdot}900\text{MWh}{-}\alpha \cdot 600\ \text{MWh}$
generation (G_1)	$(P_E - C_G)\, G_1 = (45€/\text{MWh}{-}40€/\text{MWh})900\text{MWh}$
generation (G_2)	$(P_E - C_G)\, G_2 = (45€/\text{MWh}{-}40€/\text{MWh})0\text{MWh}$
demand (D_1)	$(U - \omega + \alpha - P_E - P_N)\, D_1 = (U - \omega + \alpha - 45€/\text{MWh}{-}30€/\text{MWh})600\text{MWh}$
demand (D_3)	$(U - P_E - P_N)\, D_3 = (U - 45€/\text{MWh}{-}30€/\text{MWh})300\text{MWh}$

Table 6.7: Income distribution for alternative 2b.

The incentives in this case can come from an additional payment of α for load at node 1. With a composite tariff of network and energy charges, a payment related to the MWh consumed is the same as lowering the electricity cost (and thereby the fuel cost for the EV) by α, even if in

	pay-off base case	pay-off case 2b	improvement
network	0€	27000€ $-\alpha \cdot$ 600MWh	if $\alpha \leq$ 45€ /MWh
generation (G_1)	4500€	4500€	0€
generation (G_2)	0€	0€	0€
demand (D_1)	$U \cdot$ 900MWh−67500€	$(U-\omega+\alpha)$600MWh−45000€	if $\alpha > \omega$
demand (D_3)		$U \cdot$ 300MWh−21000€	0€

Table 6.8: Improvement with alternative 2b.

reality it is a reduction of the network charge. However, it does not necessarily need to be MWh-based, it may just as well be a flat standing charge that only varies by location. Since demand originally located at node 3 we must assume some benefit from locating at node 3 rather than 1. This reflects in a change of the utilization value by ω. The benefit α paid for charging at another location must make up for the foregone benefit ω when locating at node 1. Otherwise demand would not enter the respective smart contract. For this alternative the income distribution is as described in table 6.7.

As long as the premium α paid to demand is below 45 € /MWh the network operator retains a benefit as compared to network expansion in the reference case. The situation of generators and the remaining demand at node 3 is not altered. For the demand that changes location from node 3 to node 1 an improvement is possible as long as the payment of α outweighs the utility loss of ω. This is summed up in table 6.8.

6.4 Discussion

6.4.1 Efficiency of Smart Contracts

The three alternatives to network expansion presented here represent applications of smart contracts where all involved parties improve and all affected parties at least remain indifferent if not even improve as well. Hence it becomes clear that it is possible to achieve a pareto-improvement through smart contracts. However, what does this mean for (economic) efficiency? The first thing to note is that a pareto-improvement logically always secures an efficiency-improvement. However, what happens to efficiency in cases where a pareto-improvement does not exist?

Firstly, there may be cases where smart contracts for load shift or storage are too expensive or the perverse incentives on generator siting cannot be compensated profitably from avoided investments. In those cases the network operator has to expand the network and incur the capital expenditure. We would expect that in most cases where network expansion actually takes place, it is actually the efficient outcome. If network expansion is the cheapest option, it will be hard to incentivize others for the more expensive alternative.

Secondly, it should be stressed that for the examples in this paper we made two important assumptions on the possible smart contracts:

- they should represent a pareto-improvement
- they cannot include positive charges to generators

Both these assumptions set limitations that cause some inefficiency, since the network operator can only set positive incentives, which is always additionally costly. While this is justified when compensating generators for positive external effects, it excludes the possibility of charging for negative external effects. The claim for a pareto-improvement takes into consideration effects on all actors in the system. This can be a very restrictive concept. Numerous smart contracts are possible that improve efficiency while causing negative effects on third parties. If the situation for network operator and contracting party improves they can conclude such a contract on a voluntary and optional basis if allowed. A limitation to only such contracts that represent pareto-improvements might be too restrictive. It narrows the potential for efficiency enhancing smart contracts.

Furthermore, the criterion of a pareto-improvement will be hard to enforce. In practice, the criteria of voluntary participation and optionality will apply to active players (those who make choices; incentive compatibility only applies to active players); all those who do not choose do not benefit from optionality and voluntary participation. Unless some actions are explicitly prohibited their interests may be adversely affected: following the arguments above, this impedes the criterion of pareto-improvement, but may actually increase economic efficiency.

Incentives to defer investments within the regulatory framework Above we have argued that voluntary and optional contracts offered by the network operator to network users may increase overall system efficiency by avoiding avoidable network investment; this in turn reduces the need for the regulator to implement a price system. This approach raises the question whether the network operator actually has incentives to avoid inefficient investment. In other words, which incentives does the regulatory framework set?

The current regulatory framework in Germany already contains such incentives. Within the regulatory period, the system is incentive-based and allowed revenues are fixed. It is only in the review for the new period that allowed revenues are adjusted to costs. This means that within the regulatory period firms will have incentives to reduce expenditure and these avoided investments translate into profits. In addition, there is an automated network expansion factor for DG, meaning that newly connected decentralized capacity raises the revenue constraint with a fixed factor. Again, this is incentive-based and sets incentives to avoid inefficient investment. In addition to these components, inefficient investment affects the benchmarking results negatively and will thus increase the X-factor, again setting correct incentives. The effects change with the cost-based review, which implies the classical Averch-Johnson effect. If companies make profits with an increased capital base, they will want to make investment. The overall effect depends on the length of the regulatory period, which determines how long companies can retain profits from reducing expenditure.[91]

The analysis above extends to approaches to repair the investment problem. If the time-delay problem is solved by an automatic cost-pass-through of investment, like e.g. in Austria, the incentives to avoid inefficient investment are low. These incentives will then only be counterbalanced by benchmarking.

Ex-ante investment allowances are more promising. They do not suppress necessary investment (as they allow the revenue constraint to be raised) while at the same time they retain the incentives to avoid inefficient incentives as companies can keep the avoided expenditure. If it is considered that it is unreasonable that the companies retain 100% of avoided expenditure, a sliding-scale mechanism would split the savings between consumers and companies. This would weaken the incentives but nevertheless retain some of its power. We should note however that investment allowances are a problem within the setting of the German regulatory framework due to the large number of networks,

Another institutional issue concerns system governance or more specifically network unbundling. With network unbundling any kind of internalization of spill-over effects falls away and all co-ordination must be done with prices and contracts. It will be difficult to capture all spill-over costs and benefits efficiently in regulated network revenues and therefore we should expect some

[91] Not surprisingly, these effects are the exact opposite of the investment problem: the same incentives may cause underinvestment (i. e. withholding necessary investment).

inefficiency to remain. More problematic may be the following issue. Above, we argued that smart contracts will have network components as well as energy components, depending on the precise details to be addressed. In an unbundled setting, the network owner cannot charge an energy component as it is not a supplier. Therefore, the network operator would have to try to incentivize the suppliers, who in turn should incentivize the network users. While this may be possible theoretically, it is evident that it creates a governance problem.

6.5 Conclusions

Distributed generation and smart grids present a challenge to distribution networks. In particular the integration of renewable generation will require significant investment. In some cases network investment can be deferred by steering generation and/ or demand coordinating them with available network capacity. This coordination can be realized with institutionalized locational network or energy pricing. In systems where currently uniform pricing is in use and generators do not pay use of system charges, this would require major regulatory reform. We proposed smart contracts as an alternative tool to achieve this coordination. They can send locational signals in a low transaction cost and flexible way. Smart contracts are optional and voluntary agreements between the network operator and network customers that realize a trade-off between investment into the grid and changes at the demand or generation side.

Network operators can flexibly design these contracts to better adapt customer behavior to network capacities when this is cheaper than network investment. Since participation in smart contracts is voluntary customers are protected against exploitation by the network monopolist in the negotiations of a smart contract. They can always fall back on a regulated default tariff.

In this paper, we formally show with a numerical example that cases exist in which smart contracts can achieve a pareto-improvement. In other words, smart contracts would improve the situation for at least one party without worsening the situation for any of the others. This also illustrates how smart contracts are incentive compatible and improve overall economic efficiency.

We pick up three examples to defer network investment by using smart contracts. The first smart contract is a voluntary curtailment agreement with generators. They are compensated with the foregone revenue from curtailment plus a bonus δ to make the difference between "not-producing" and "producing". Since this creates perverse incentives encouraging new siting at a constrained location, additional smart contracts for new generators are needed to steer them to locations with free capacity. In cases where the expenses for the diverse smart contracts exceed the expected investment cost, the network operator will expand the network which will be the efficient solution. We then also investigate smart contracts for storage and for electric vehicles inducing a locational demand shift. We find that in both cases beneficial smart contracts can be concluded without facing a problem of perverse incentives. Furthermore, storage flips between take-off and feed-in to the grid. In one period excessive production can be taken up to relieve the network. However, this energy has to be fed back at a later point in time potentially worsening the constraint and negatively affecting other network customers. In the strict sense this would violate the condition for the pareto-improvement. This might still enhance efficiency.

We conclude that smart contracts are useful as they allow a pareto-improvement in some cases (and wouldn't be used in case where the contracting parties worsen their situation). They are easy to implement and do not require large regulatory reform. Hence, smart contracts are an attractive solution for efficiency enhancing locational pricing in smart distribution networks.

We note that while pareto-improvement represents a good starting condition, this requirement might be too restrictive and leave significant potential for efficiency improvements untapped. This applies in particular since only bonus payments can be given out while negative externalities have to remain uncharged for. Furthermore, in practice the criterion will be difficult to implement if the network operator and a customer can conclude a smart contract that benefits both. They are unlikely to take all external effects into account.

Importantly, network operators need incentives to pursue smart contracts as an alternative to network expansion. This implies that they should be allowed part of the benefits from the avoided investment. It is the task of the regulator to a) allow network operators the flexibility to design smart contracts and b) to incentivize network operators such that they carry out efficient network investment and will offer smart contracts where investment can better be avoided.

Smart contracts raise further issues with regard to governance. We assume contracts can incorporate energy components. It is obvious that with unbundling this is not an easy task since network operators can only give incentives to suppliers which would than in turn design incentives for customers.

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Declaration

I, Nele Friedrichsen, confirm that this dissertation is my original work and a product of my own research endeavours. It includes outcome of work done in collaboration with Gert Brunekreeft and Christine Brandstätt as declared in the preface. All sentences, passages or illustrations quoted in this dissertation from other people's work have been specifically acknowledged by clear cross-referencing. A full list of the references employed has been included.

I further declare that this dissertation is not and has not been submitted at any other university for review.

Nele Friedrichsen

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