Chapter
6

Infrastructure and networks

- challenges for Nordic energy policy and regulation

Increasing electricity and energy consumption and new policy targets require new investments in energy infrastructure, on both a transmission and a distribution level. Since energy infrastructure (electricity grid, gas pipeline network etc.) has the properties of a natural monopoly, it is not efficient to leave the investment decisions to the market, and hence some form of regulation or governmental steering in the form of, for example, subsidies is required. This article describes the challenges and problems associated with infrastructure investments and the regulation thereof. Case studies from Norway are used in order to illustrate and highlight those issues that we consider to be of particular relevance.

Introduction

The increasing demand for energy and electricity, increased trade, new power generation, usually with little operational flexibility, and regional imbalances require new infrastructure in the transmission system both nationally and across borders. At the same time, new energy carriers and distribution systems (like natural gas and district heating/cooling) compete with each other and with existing infrastructure. Since energy infrastructures are often natural monopolies, due to irreversible cost and economies of scale, they require special attention from both local and central energy and competition authorities. This article describes the challenges associated with energy infrastructure investments, and highlights what policy-makers and authorities should take into consideration when designing policies and regulations for infrastructure investments.

Some of the challenges are specific to the Nordic countries or Norway in particular, while others are general. On the electricity side the focus is on bottlenecks (within and across countries) in the transmission system,

Monica Havskjold
Xrgia,
Berit Tennbakk and
Arndt von Schemde
ECON

both existing bottlenecks and those that may arise from building large-scale wind parks in, for example, northern Norway. Moreover, challenges arise with the introduction of new energy carriers requiring new large-scale investments. Establishing a natural gas pipeline grid or a district heating (DH) grid, well established in other countries, creates particular challenges for Norway.

There are good reasons why energy infrastructure investments cannot be left to the market, as energy infrastructure has usually the features of a natural monopoly, i.e. economics of scale, combined with large, irreversible investments. A suitable infrastructure policy calls for a balancing of the consequences of market failure versus the cost of government or regulatory failure. While the market failure is due to the nature of infrastructure, the government or regulatory failure is an effect of asymmetric information and the complexity of the regulation task.

Awareness and understanding of these multifaceted challenges are of common Nordic interest. As some of the problems are multi-national, it is unfortunate that regulation and decision-making are still done on a national level in the Nordic countries (as well as in the rest of Europe).

This chapter describes infrastructure investments and the challenges that policy-makers and regulators face on different levels. We distinguish between transmission investments and distribution investments because the associated problems are to some extent different. Never-the-less, transmission and distribution investments have a great deal in common (as e.g. the feature of natural monopoly), and very often the associated problems may very well be strongly interconnected. For example, the transmission bottleneck to a deficit area may be overcome by building, say, a Combined Cycle Gas Turbine (CCGT) in the deficit area, requiring a gas pipeline. This, at the same time, may make the building of a natural distribution grid profitable.

Findings

Regarding transmission investments, we focus on electricity transmission. Electricity transmission is operated and controlled by so-called transmission system operators (TSOs), also responsible for grid investments. Generally, there is no such thing as a neutral investment philosophy by TSOs in the sense that whatever investment philosophy the TSO chooses or is obliged to follow, affects market decisions and efficiency. Instead one may talk about a *passive* investment philosophy or an *active* investment philosophy.

Taking on a more active investment philosophy means acting as a more visible hand in the market. The TSO has to seek alternatives to grid investments and has a more comprehensive approach to system development. The key to realizing more optimal solutions is to be able to coordinate decisions between different market participants to a larger degree. The advantage is that we may achieve better overall solutions and lower system costs.

Instituting the TSO as a more visible hand in the market does however not remove the uncertainty and does not guarantee that the optimal solution is always reached. There are still challenges and issues to be resolved. The toolbox of the TSO has to be developed. Investments in generation should still be decided decentralized by market players. However, the TSO needs more instruments to make clear incentives. A more active investment philosophy also means that the TSO becomes more powerful. Hence, the regulation of the TSO must also be strengthened. We do not discuss the challenges regarding Nordic coordination, which the institution of more active TSOs would not necessarily solve. This is an issue that requires more research by economists as well as political scientists.

On the other hand, distribution investments (natural gas distribution grid, DH networks etc.) have a more local character, yet they also require regulation due to aspects of natural monopoly. This is complicated by the fact that different potential distribution investments may compete with each other, and, in order to achieve an efficient outcome, efficient regulatory regime would have to create a fair playground for the different competing solutions. As of today, this is not the case, and there are large divergences across regulations, laws, and support schemes. Furthermore, efficient regulation must take into account the advantages of incumbents, and to what extent effects across and along value chains are internalized by players that are vertically or horizontally integrated.

Such a "first-best" regulation, however, is unlikely to be achieved, as there are considerable information asymmetries between the regulator and the players, and as the regulator would have to solve a considerable coordination challenge that the "market" or the players may be better suited to solve. How the actual balance between regulation and market should be, and how the regulation should actually be designed, needs to be addressed by policy-makers and regulators, and will also require further research.

The challenges of infrastructure investments

In this section we describe the challenges of infrastructure investments and the regulation thereof, distinguishing between transmission investments and distribution investments. Each section is illustrated by using case studies from Norway, highlighting particular issues and their relevance for the Nordic energy policy.

Infrastructure investments, or rather the need for them, are driven by different factors. Changes in consumption or generation may create bottlenecks, increased trade following de-regulation may create bottlenecks, the introduction of generation capacity with little operational flexibility (e.g. wind) may require strengthening of the grid, or new energy sources (e.g. natural gas) may require new networks or grids.

While the factors mentioned above determine the need for investments, the infrastructure investment decisions may be driven by other factors: regulation, subsidies, uncertainties (e.g. about future revenues, political support, possibility to recover costs), and political decisions (for example CO_2 trading, green certificates, nuclear policy).

The challenge is to create a regulatory and political environment such that the infrastructure investments are in line with infrastructure needs. Neither a pure market-based system, due to failure arising from natural monopoly features, nor a pure state-controlled system, due to information and coordination problems, can solve this issue, and a balance is required.

Transmission

Investments in transmission capacity have three important general characteristics: investment projects are large and ”bulky”, there are few decision-makers, and investments are irreversible. All these characteristics imply that decisions cannot easily be left to private market players. In order to recover the cost of such transmission investments, a private investor needs to be shielded from competition. Typically, an incumbent will have a great advantage because costs are sunk and a new entrant can easily be deterred from entering. In order for the infrastructure to be expanded and utilized in an efficient way, transmission companies must be regulated (tariffs, tariff structure, access). In order for the infrastructure to be balanced, there are important system operation characteristics that must be managed. Most countries, therefore, have established one independent transmission system operator (TSO) and a system of monopoly regulation.

Even with these structures in place, it is not straightforward to determine the optimal infrastructure investments, for the following reasons:

- **Expansion projects are often cross-national interconnections.** This is particularly the case in the Nordic system since the generation mix is highly diversified among the Nordic countries. Most notably, there are substantial efficiency gains from connecting the hydropower system in the north with the thermal system in the south and east. International investments require coordination between Nordic TSOs. Efficiency gains are also the motive for further interconnecting the Nordic countries with Continental Europe and Russia. One example of modelling the outcomes from increased interconnection between Finland and Russia is given in the fact box on the next page.

- **Transmission investments are not the only investment alternative to remove or reduce bottlenecks.** A bottleneck may just as well be removed or reduced by increasing the generation capacity in the deficit area or reducing consumption. In order to achieve the overall optimal solution, investments in transmission, generation and consumption should somehow be coordinated. This could for example be done by using price

Increased imports from Russia

The VTT-EMM model was used to analyze the impacts of the increased imports from Russia to Finland on future electricity prices on the Nordic area. The assumed increase in cross-border transmission capacity was 1000 MW and it was expected to be available in 2010. It should be noted that with VTT-EMM, the new links between Finland and Estonia as well as between Norway and the Netherlands were taken into account in the base case calculations from the year 2010. The reference case assumptions were the same as for the above base case.

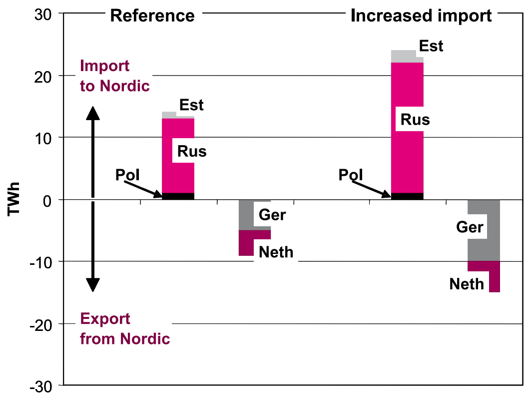
Important variables, when investigating the cross-border trade and its impacts on the Nordic electricity markets, are the expected scenarios for electricity market prices in Central and Eastern Europe. With VTT-EMM, these prices are not optimized, i.e. they are exogenous variables. The table below shows the assumed electricity prices outside the Nord Pool area with different CO_2 prices. The electricity prices were set to keep the trade with Germany and Poland reasonably low and balanced, to have more or less export to the Netherlands, to have more or less import form Estonia and to have approximately full import from Russia. However, the future trading balance is very difficult to predict due to, for example, uncertainties of investments in new and phasing-out old generating capacities, and developments of electricity demands, especially in the Eastern European countries.

Assumed import (I) and export (E) electricity prices for Russia (RU), Germany (GE), Poland (PO), the Netherlands (NE), and Estonia (ES) for the calculation year 2010 (VTT-EMM model runs)

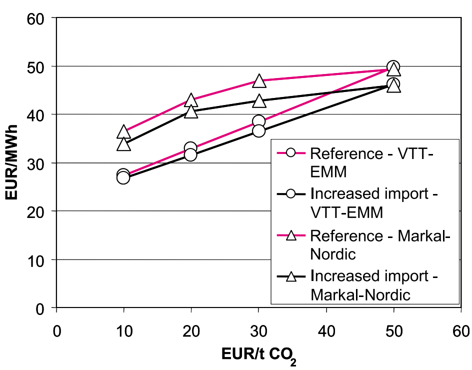
EUA EUR/t	**Electricity price, €/MWh**									
	RUI	RUE	GEI	GEE	POI	POE	NLI	NLE	ESI	ESE
10	20	10	65	25	35	20	70	30	30	20
20	22	10	70	30	40	25	75	35	35	23
30	24	10	75	35	45	30	80	40	40	26
50	28	10	85	45	55	40	90	50	50	32

Next page shows the VTT-EMM scenarios for imports to the Nordic area and exports from the Nordic area in 2010. The results indicate that the increased imports from Russia would also increase exports from the Nordic countries, especially to Germany and to the Netherlands. This is mainly due to the decrease in the Nordic electricity prices, which is shown below. The electricity prices with and without increased Finnish import from Russia were calculated with VTT-EMM and MARKAL-NORDIC. The price decrease varied between 1 and 5 €/MWh depending on the CO_2 price level and the model used. The difference between the MARKAL-NORDIC and VTT-EMM model results for low EUA-price levels is mainly due to the higher share of natural gas and renewables in electricity supply obtained from MARKAL-NORDIC calculations. With higher EUA prices the share of natural gas is increased in the VTT-EMM calculations as well, and hence electricity prices approach those obtained from MARKAL-NORDIC.

However, it should be noted that, without a more detailed sensitivity analysis for the impacts of the increased demands of Eastern Europe and other variables, final conclusions about the impacts of the increased imports from Russia on Nordic electricity markets and prices cannot be drawn.



Import to and export from the Nordic countries in 2010, for the reference case and for the case that includes increased import from Russia (both cases include base fuel-price scenario and an EUA price of 20 EUR/t. VTT-EMM model result).



Wholesale electricity prices in the Nordic market in 2010 vs. EUA prices for the reference case and for the case that includes increased import from Russia (VTT-EMM and MARKAL-NORDIC model runs; base fuel-price scenario).

signals, i.e. tariffs, price areas, in order to clarify investment incentives to different market players.

Currently, there are a number of unanswered issues in the objectives and measures of the TSOs which make the investment incentives and system expansion unclear. Our conclusion is that there is a need for increased coordination between TSOs and between TSOs and in particular generators. New measures should be developed and implemented. In addition to the invisible hand of the market, there may be a need for a more visible hand when it comes to the larger system investments.

Case studies

When the power market was deregulated, it was important to establish a clear separation between the grid as a natural monopoly which had to be regulated accordingly, and generation and consumption which should be free to meet and compete in the market place. The grid was to constitute the paving stones of the market place, making the market place available to all participants on equal terms, and market prices were to yield the optimal tradeoffs in generation and consumption. The objective of the TSO would then be to ensure fair tariffs and neutrality, i.e. offer non-discriminatory access to the market. This description is accurate and yields the correct incentives to all participants provided that grid capacity is not limited and losses are small. The description does not, however, accurately describe the situation in the Nordic grid today. Moreover, price signals in the grid only imperfectly reflect bottlenecks and losses in the grid.

The challenges may be illustrated by use of two examples from Norway, one describing a deficit area, and one describing a possible surplus area. First, however, we will briefly describe the issues by use of theory.

Theoretical description: Deficit area

Consider two areas, Area A and Area B. Area A is the deficit area. There is no generation in the area, but an import capacity of 50 from area B. Now consumption is increasing and is predicted to exceed 50. There are three alternative ways of avoiding a deficit: increase the import capacity by building a new line from area B, establish power generation capacity in area A, or reduce consumption in area A (energy conservation, alternative heating solutions, etc.).

Which solution is the optimal one, from a welfare-economic point of view, depends on a number of factors. In Norway, as in most other countries, the TSO has a responsibility to ensure security of supply to all consumers in its area. Moreover, the Norwegian TSO is obliged to implement economically optimal solutions. However, the TSO cannot invest in generation or consumption, although it may use different measures to incentivise increased generation or reduced consumption in the area.

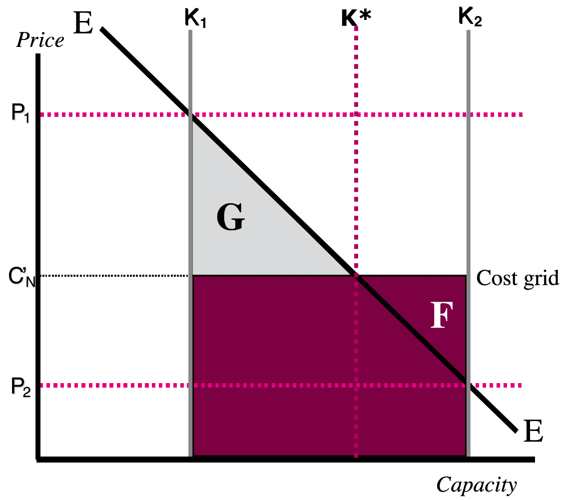


Figure 6.1: The profitability of a grid investment

Let us look at the assessment of building a new line from B to A. Figure 6.1 illustrates the decision. The ”demand” for the grid investment, i.e., the price difference between the deficit area and the surplus area for different transmission line capacities is measured along the y-axis, and the capacity of the line along the x-axis. The initial situation is the capacity K_1 (the capacity of the existing line) and the price differential P1. When more transmission capacity is added, the price differential between area A and B is reduced. Let C'_N be the marginal cost of expanding the transmission grid, for simplicity assumed to be constant. The optimal unrestricted investment is then to add K* capacity. This is the optimal solution if we only consider the grid investment and assume that the transmission capacity can be expanded continuously.

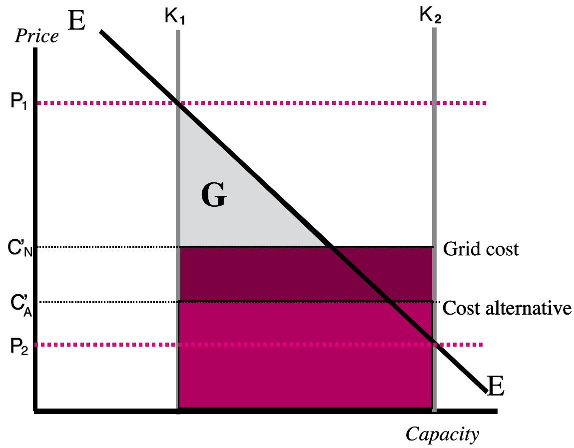


Figure 6.2: The profitability of an investment in generation capacity

Transmission capacity cannot, however, be continuously expanded. There are a (limited) number of capacities to choose from, and there are economies of scale to be taken into account. In this case the choice is between investing in capacity K_2, or not investing at all (postponing investments). If the capacity is extended to K_2, the price differential falls to P_2. The welfare surplus achieved equals $\frac{1}{2}*(P_1-P_2)*(K_2-K_1)+P_2*(K_2-K_1)$, minus the cost of investment $(C'_N)*(K_2-K_1)$. Since triangle G > F, the net welfare effect is positive. If the TSO is only considering the grid investment, and if it is obliged to implement economically optimal solutions, the decision is to invest. (Note that it is not necessarily optimal to remove the bottleneck completely.)

Now consider the alternative generation investment, cf. Figure 6.2. For the case of simpler comparison, we assume that the investment in generation capacity has to have the same capacity as the possible new line. In the example, we see that the marginal (and total) cost of the generation investment is lower than the cost of the transmission line. The cost saving is equal to $(C'_N-C'_A)*(K_2-K_1)$. All other effects are the same. The optimal, coordinated decision is to invest in generation capacity.

The optimal solution is, however, not going to be implemented in this case. Firstly, the TSO is not allowed to invest in generation capacity.

Secondly, a private investor would not find it profitable to invest since the market price after the investment, P_2, does not cover the full cost of the investment, C'_A. We can get one of two outcomes: either the TSO invests in a new transmission line, or no investments are carried out. In the first case, the cost of the investment is covered by an increase in the transmission tariff, which is then higher than it should be because the least-cost, optimal solution is not implemented. In the second case, the deficit is larger than it should be, the consumers in the deficit area are paying too high a price, and the security of supply is probably lower than it should be as well.

Case 1: Looming power crisis in Møre and Romsdal

In Møre and Romsdal, a county in the north-west of Norway, a situation like the one described above has emerged. The area has had success in attracting new industry and electricity demand is increasing rapidly, as Figure 6.3 illustrates.

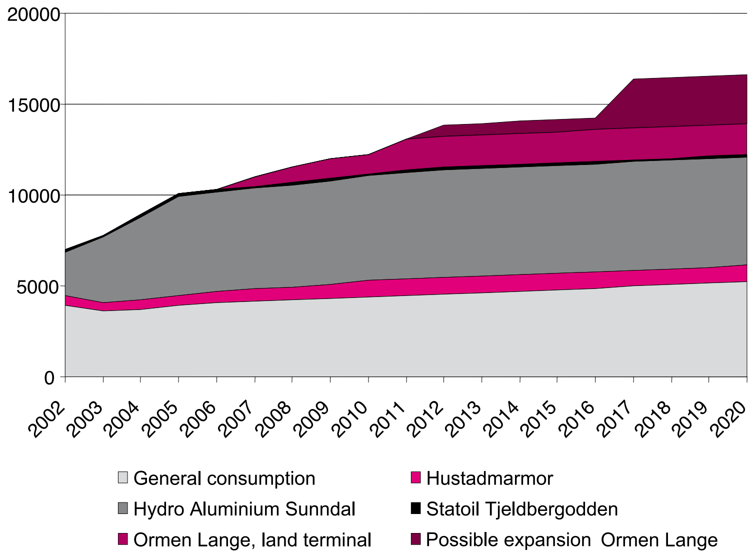


Figure 6.3: Projected Demand in Møre and Romsdal

In 2005, the import demand to the area was already 4 TWh. By 2010 it is set to increase to 6 TWh. These numbers refer to a year with normal precipitation. In a dry year, the import demand increases by 1.6 TWh. The import capacity is, however, limited, and new investments have to be made if a power crisis is to be avoided.

There are a number of alternative investment plans in the area: new gas power plant, wind power generation, transmission lines, etc. Moreover, the development has been known for quite some years. Some investments strengthening the grid have been or are being carried out, but it is unlikely to be enough to avoid high area prices or even rationing if a dry year occurs over the next 2-4 years. The large investments which might have solved the problem will not be ready in time.

The reason why this situation has occurred is of course complex, but the simplified story is this. Players in the area have published several plans to invest in new generation capacity. There is, however, strong controversy surrounding the construction of gas power capacity in Norway. Although concessions have been granted, a lot of uncertainty surrounding environmental requirements has not been settled. The latest decision is to build a gas power plant with CO_2 sequestration in connection with the Tjeldbergodden gas terminal. The CO_2 will then be deposited in oil wells off the coast, thereby increasing the oil recovery of these wells. The government has promised to support such a scheme. With these requirements, however, the time by which new power generation is on line will be prolonged. The technology is more complicated and an infrastructure for CO_2 has to be established. In the meantime, other investors in the area, who do not have a concession requiring CO_2 sequestration, are hesitant to invest because they risk a power surplus when the Tjeldbergodden plant starts generating. In view of these plans, the TSO has concluded that the optimal solution for this area is not to build a new transmission line, and has also tried to increase the incentives to establish new generation capacity through rebates in the transmission tariff.

Case 2: Wind power in Finnmark

The case of wind power in Finnmark illustrates the TSOs' dilemma when there is a need to invest to get power out of a surplus area and uncertainty about the size of the surplus and when or whether it is going to materialize.
Finnmark is the northernmost county in Norway. It has huge wind power

resources and a sparse population. A few years back, a large number of wind power projects were being planned. Without investments in the grid, increasing the transmission capacity from Finnmark down to Mid-Norway (which is a very long way) and making it possible to export power out of the area, most of these wind power investments would not be profitable. The Norwegian TSO was therefore under pressure to make the appropriate grid investments. The challenge in this case is, however, that the grid investment would turn out to be unprofitable if only insufficient wind power investments are implemented. The situation is depicted in Figure 6.4.

The figure shows the total cost of investing in wind power in Finnmark including the grid investment (upper line with bullets), and the per MW grid cost (lower solid line). If less than 100 MW of wind power is built in Finnmark, no new transmission line is needed. If a large portion of the wind power potential was to be exploited, i.e. more than 650 MW, the profitable solution would be to invest in a 420 kV line. If the TSO knew for certain that the end-situation would be either less than 100 MW or more than 650 MW, the decision would be easy.

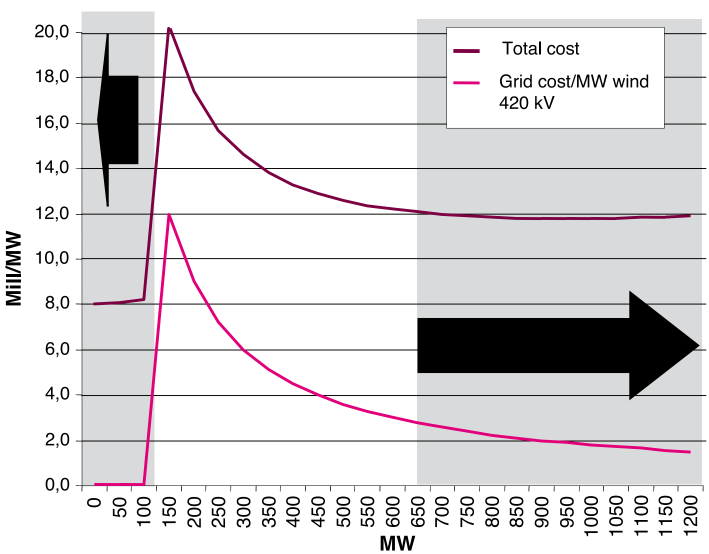


Figure 6.4: Grid Investment and Wind Power in Finmark

The construction of this line would, however, not be enough to guarantee large-scale wind power development in Finnmark. In addition, government support money would have to be made available and investors in Finnmark would have to compete with projects in other parts of the country for support money. In addition, local opposition creates uncertainty about the probability and costs of getting a concession to build. The TSO would then risk investing in an expensive transmission line which would end up having a very low degree of utilization. The cost of course would eventually have to be paid through the transmission tariff.

In this case, the question was not only whether to invest, but also how much to invest. Alternatively, a more limited capacity expansion could be made. Such an investment would entail lower average costs for the intermediate solution, but for the full-scale solution, economies of scale would have to be foregone. Here the irreversibility of grid investments plays a role: once a line is built, it cannot be expanded. Once a line is built, it is usually not profitable to replace it. If the capacity must be doubled, an additional line has to be built. The result is higher unit costs for the transmission link than if the larger-scale solution had been made initially.

In the end, the TSO decided not to go ahead with the investment, thereby effectively putting an end to most of the wind power plans in Finnmark.

Concluding remarks

There is no such thing as a neutral investment philosophy by TSOs: whatever investment philosophy the TSO chooses, or is obliged to follow, affects market decisions and efficiency. Instead we may talk about a passive investment philosophy or an active investment philosophy.

- A passive investment philosophy means that the TSO follows the market. Whenever there is a decision to build generation capacity or expand consumption, the TSO has to invest. The outcome is that investments are made regardless of grid costs. Decisions are made on a partial cost basis. The overall resource utilization is sub-optimal and system costs are excessive.

- An active investment philosophy requires that the TSO is conscious of how market participants will react to the decisions and investments taken by the TSO, and that the TSO actively uses different means and measures in order to invoke the welfare-economic optimal solution.

Taking on a more active investment philosophy means acting as a more visible hand in the market. The TSO has to seek alternatives to grid investments and has a more complete angle on system development. The key to realizing more optimal solutions is to be able to coordinate decisions to a larger degree. The advantage is that we may achieve better overall solutions and lower system costs.

Instituting the TSO as a more visible hand in the market does not remove the uncertainty and does not guarantee that the optimal solution is always reached. There are still challenges and issues to be resolved. The toolbox of the TSO has to be developed. The investment decisions should still be decentralized by market players. However, the TSO needs more instruments to make clear incentives. A more active investment philosophy also means that the TSO becomes more powerful. Hence, the regulation of the TSO must also be strengthened. Finally, we have not discussed the challenges regarding Nordic coordination, which the institution of more active TSOs would not necessarily solve. This is an issue that requires more research by economists as well as political scientists.

Distribution

Distribution infrastructure has, by definition, a local or regional character. Nevertheless, many of the general characteristics of energy infrastructure, like natural monopoly, apply also to the distribution infrastructure, such as the local natural gas network or the local district heating network.

To achieve an efficient outcome in distribution infrastructure investments, efficient regulation does not only have to account for effects along one value chain, but for effects across value chains for different energy sources; i.e. it has to account for substitutability, complementation, and externalities between different energy solutions.

For example, a gas distribution network may compete with the local district heating (DH) network, or the distribution of liquefied natural gas (LNG). Alternatively, natural gas may be used by the local DH network for heat production, and hence act as a complement instead of substitute to DH. At the same time, the situation may not be symmetric. For example, a district heating network may already be in place, while the gas network has yet to be established. All this has to be accounted for by efficient regulatory structure and implies considerable coordination and information challenges.

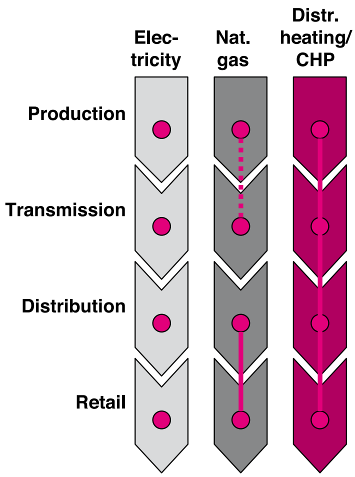


Figure 6.5: Vertical integration in value chains

When facing several (potential) distribution networks, there are – despite the general problems that arise from natural monopoly features – three factors that hinder competition and hence an efficient outcome:

1. **The Competitive Advantage of the Incumbent:** Because of large irreversible investments in the distribution grid (be it the power distribution grid, the DH grid or the natural gas pipeline grid), established players do have a competitive advantage over new players and potential entrants. The incumbent can lower prices down to marginal costs in order to compete with the entrant. Notice that the entrant may be the provider of an infrastructure similar to the existing one, or the provider of a new infrastructure for a competing energy source.

2. **Vertical and Horizontal Integration:** Depending on the degree of vertical and horizontal integration, effects along and across the value chains are taken into account by players. This may solve some of the coordination and information challenges mentioned earlier, but vertical and horizontal integration is usually seen as an obstacle to competition. For that reason, energy companies are sometimes required to split their distribution activities from other activities, or required to offer non-discriminatory third party access (TPA) in order to foster fair retail and supply competition. Having said

that, vertical and horizontal integration or the absence of TPA does allow extracting higher revenues from the markets (as it shields the investment from competition). This, in turn, reduces the financial risks that players are exposed to when making infrastructure investments. Limiting competition by allowing vertical and/or horizontal integration or limiting TPA (for a limited number of years) may therefore be a way of attracting investments in distribution networks.

3. **Imbalance between Current Policy Measures:** There is a wide spectrum of energy policy instruments. As of today, however, those measures and instruments are typically not designed to take effects across and along the value chains into account. As an example, consider public financial support for wind power in Germany. While the generation of wind power is subsidized, the strengthening of the grid in order to cope with the increase capacity with little or no operational flexibility is not. Also, the regulatory framework for different energy networks may differ quite arbitrarily, i.e., without any particular economic, technical or social reason. Some investments may require licensing, others may not. There may be subsidies for some forms of investment, for others there may be none. For some investments the investor may be shielded from competition in order to recover costs, for others the investor is not.

In the following we present a case study from Norway and assess and discuss how the three factors outlined above apply. We also discuss other factors that complicate the infrastructure investment decisions.

Case 3: Natural gas in Østlandet

In the spring of 2005 the companies E-CO Energi, Akershus Energi, Fredrikstad Energi and Fortum Heat established a regional cooperation in order to build a pipe-based network infrastructure for natural gas in Østlandet, i.e., the south-eastern part of Norway that includes, among others, the densely populated areas around the cities of Oslo, Drammen, Fredrikstad, Moss and Sarpsborg. The four energy companies operate under the name of ØGD, which stands for Østlandets Gassdistribusjonsselskap (The Eastern Country Gas Distribution

Company). The ØGD is planning to supply the distribution grid with natural gas from a planned gas terminal in the Oslofjord area, which is meant to be receiving either LNG (cooled down liquefied natural gas) or CNG (compressed natural gas) from ships.

While ØGD is planning an LNG or CNG terminal, there are also propositions for a pipeline from Kårstø, on the west coast of Norway, to Østlandet (maybe with an extension to Sweden). This would be built if there is sufficient demand at the other end of the pipeline in the form of, for example, a CCGT plant. In this case, an LNG or CNG solution would be out of date. A decision about a CCGT plant in the area, however, lies in the far future, as, for the time being, no one has signaled an interest to the authorities in building such a plant. This is due to today's gas prices compared to the electricity prices, as well as cost uncertainties arising from a potential law that would require CCGT plants to be installed with a CO_2 cleansing system (compare also Case 1).

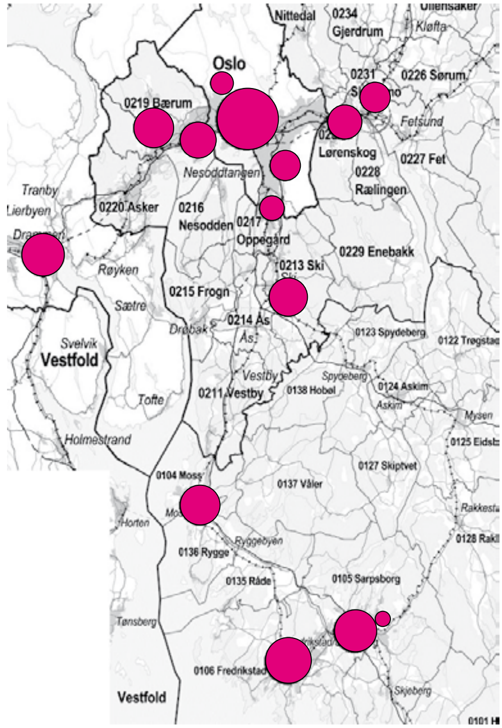


Figure 6.6: Existing heating systems

Today, the instruments to support the introduction of natural gas are limited to the exemption of natural gas from the CO_2 tax, and payment for Public Service Obligations (PSOs), offered by Enova SF, a public enterprise owned by the Royal Norwegian Ministry of Petroleum and Energy. Over the last years, some local gas distribution networks in proximity of gas terminals along the Norwegian coast have been established, for example in Haugesund near the gas terminal at Kårstø. Also, an increasing interest in LNG caused the building of an LNG terminal, and there are plans for further development.

When it comes to Østlandet, however, there are several issues that may complicate or hinder the introduction of a natural gas infrastructure. The analysis of the case follows the three factors described above.

Ad 1: The Competitive Advantage of the Incumbent

District heating (DH)is already established in many areas. There are already 15 established district heating networks in Østlandet. This does, on the one hand, reduce the potential customer base for natural gas, as DH can be seen as a competitor to a natural distribution grid. This is gravitated by asymmetries in the regulations applying to DH and natural gas (see also below). For example, most municipalities require new buildings to connect to the DH network, limiting the potential customer base for natural gas. In this respect it is worth noting that the municipalities are usually shareholders in DH companies.

Ad 2: Vertical and Horizontal Integration

Some members of the ØGD are also involved in the DH networks, and are thus in a way competing with themselves. At the same time, however, this means that they would be involved across both the value chains for natural gas and DH. This form of horizontal integration would make sense against the background that natural gas will be used in DH generation, something Viken Fjernvarme, Norway's largest DH company, says it is considering the matter. Being horizontally integrated would hence allow accounting for cross effects and solving some of the coordination problems involved. At the same time, the horizontal integration may be deployed to limit competition between DH networks and natural gas.

Ad 3: Imbalance between Current Policy Measures

Today, there is no economic regulation of domestic natural gas grids. This is due to the fact that, until now, there were only minor projects, and regulation was not seen as necessary. This creates a clear distinction between natural gas distribution and electricity distribution (area concessions and revenue cap regulation) or DH (DH concessions, connection obligations and price regulation). In this respect, the DH connection obligations for new buildings, as found in many municipalities, are a severe blow to investments in a natural gas distribution network, as they reduce the potential customer base for natural gas considerably.

It is expected that a large-scale project, like the planned project in Østlandet, will lead to the introduction of an economic regulation for natural gas, but at the moment there are no signals as to how such regulation may look. For example, it is not clear how third-party access or price discrimination (Ramsey-pricing), which would impact on the profitability and hence the possibility to recover costs, will be treated. This creates considerable investment uncertainty for the project.

As mentioned earlier, there is today no CO_2 tax for natural gas in Norway (not to be confused with the CO_2 emission quotas). It is, however, expected that the exemption from the CO_2 tax will not be sustained once large volumes of natural gas are consumed. This would create a disadvantage for natural gas for industrial use (as e.g. pulp and paper industry), as fuel oil use in industry is subject to advantageous treatment by the current tax system. This potential imbalance in the tax treatment of natural gas and fuel oil adds to the investment uncertainty.

Concluding remarks

The Østlandet case highlights the many complications and obstacles to an efficient outcome when it comes to distribution infrastructure investments. Not only is the establishment of an energy distribution network as such, like natural gas, a challenge due to its characteristics of a natural monopoly, but the case is further complicated due to the presence of already established networks. The fact that different forms of gas supply, i.e. pipeline-based LNG or CNG, are available adds to the complexity of the problem. Morover, finding an efficient solution by market mechanisms alone is in addition exacerbated by the three points outlined above: incumbents having an advantage, vertical and horizontal integration, and imbalanced policy measures.

Efficient regulation, i.e. regulation of infrastructure that provides legislation and incentives such that an efficient outcome is achieved, therefore has to account for all these factors. It would have to take into account not only the complications that arise from the natural monopoly features, but also the effects across value chains, the degree of integration of players and to what extent they ”internalize” cross effects, the position and role of the incumbents, and the imbalance between current regulations for different energy solutions. With regard to the latter, efficient regulation would have to create a ”fair playground”, and would have to be ”consistent” across different energy distribution alternatives.

On the other hand, regulation and government control face the problem of asymmetric information. That is, the players involved usually have an information advantage over the regulator when it comes to e.g. costs and market knowledge, information that may be needed in order to design efficient regulation. Furthermore, the regulator would have to solve a complex coordination problem that the ”market” or players involved may be more qualified to solve. Hence, there is a degree of ”over-the-top” regulation that would come at the risk of regulation failure.

Finding the right balance between regulation and markets is a difficult task. How the regulation should be designed, and how the balance between market mechanism and regulation should be, may in the end be different for different countries, and will depend on different factors – for example, available energy solutions, what distribution networks are already in place, and what the political objectives are.

Conclusions

We have seen above that the challenges associated with infrastructure investments and the regulation thereof are manifold. Firstly, there are the challenges that arise automatically from the natural monopoly features. Secondly, there are several other problems when it comes to transmission or distribution investments, some of which were illustrated by the case studies from Norway.

As for transmission investments, we would like to emphasize again that there is no such thing as a neutral investment philosophy by TSOs. Whatever investment philosophy the TSO chooses, or is obliged to follow, affects market decisions and efficiency. In light of the cases described above and the associated problems, the toolboxes of the TSOs have to be developed. While decisions to invest in generation capacity should still be taken in a decentralized manner by market players, the TSO need more instruments to create clear incentives to induce efficient overall investment decisions. A more active investment philosophy also means that the TSO becomes more powerful, which requires strengthened regulation of the TSO itself. The challenges that would arise from the coordination of Nordic TSOs have not been discussed, and the issue of Nordic coordination requires more research by economists as well as political scientists.

As for distribution investments, several distribution investments may compete with each other. While there are intrinsic differences between different solutions (e.g. DH networks or gas networks), different regulation and other political measures influence the competitive balance between solutions. Efficient regulation would have to create a fair playing ground for the different energy solutions. It would also take into account other obstacles to competition like the advantages of incumbents or the degrees or integration of players involved. At the same time, there is the risk of over-regulation and hence regulatory failure, as there are considerable information asymmetries and coordination challenges. The challenge for policy makers, regulators and authorities is to find the right balance between market and regulation.

Chapter

7

Development of the biofuel market - competition regarding the forest resources

Biomass is used for a number of purposes in the Nordic countries, e.g. as raw material for production of pulp and building materials, fuels for heat and electricity production, and for production of refined fuels such as wood pellets and briquettes. Biomass is used both for products subjected to international competition (e.g. pulp) and for products subjected only to local competition (e.g. heat production).

In order to promote renewable energy sources, different policy instruments are used in the Nordic countries. In Sweden, as an example, biofuels used in the energy sector receive support (directly or indirectly) through the electricity certificate system, tax on fossil fuels and the European Union´s emission trading scheme. This has made biofuels very competitive, especially for combined heat and power production. Consequently, the market is prepared to pay a high price (more than 200 SEK/MWh (22 €/MWh)). This use of biomass is to an increasing degree competing with the use of biomass for pulp production, which could lead to a general increase in timber prices (and that typical timber for pulp production instead goes to heat and/or power production). This is a problem for the pulp and paper industry, since they operate on an international market. The situation is similar in Finland, but not as evident as in Sweden.

The price of biofuels has so far not reached the levels mentioned above. (The price is however already well in the range of typical pulp timber prices.) The reasons for this are e.g. that the supply exceeds the demand and that import moderates the price increase. The import of biomass to Sweden and Finland together is already today of significant size, approximately 60 TWh/yr (15–20% of biomass as raw material for

Håkan Sköldberg
and
Bo Rydén
Profu

industry and of biofuels for heat and electricity production). The importance of biomass import, and in the future possible export, shows that when competition regarding the use of biomass is analysed, prices and willingness to pay in different sectors are of greater importance than national physical quantities of available biomass.

In the future the competition for biomass could increase even more in the Nordic countries. Two reasons for this could be the use of biomass for production of fuels for the transportation sector and export of biomass to other European countries as a consequence of political goals for reducing CO_2 *emissions.*

Introduction

Biomass is used for a number of purposes in the Nordic countries, e.g. as raw material for production of pulp and building materials, fuels for heat and electricity production, and for production of refined fuels such as wood pellets and briquettes. Biomass is used both for products subjected to international competition (e.g. pulp) and for products subjected only to local competition (e.g. heat production).

The largest source of biomass used for power, steam and/or heat production is combustion of black liquors arising in the pulp industry. This is to a great extent a matter of recovery of process chemicals and it is therefore an internal industrial process. A large part of the biomass used for power, steam and/or heat production is other by-products from the pulp and sawmill industries. However, a significant part of the biomass which is used for energy purposes is wood fuels, e.g. residues from fellings of pulp timber and saw timber. The flow of timber to different applications is a consequence of quality and the demand from different sectors (indicated by the price levels). Import of biomass is another factor that influences this balance.

Competition between energy and pulp

Historically wood fuels used for district heating production and electricity production in combined heat and power production plants (CHP), are residues from fellings of pulp timber and saw timber. In order to increase the use of renewable energy, different types of policy instruments are used.

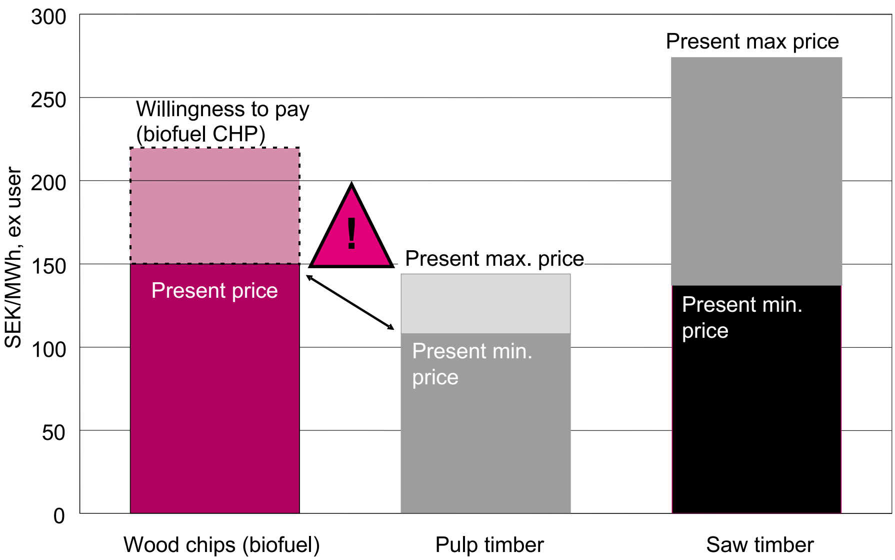


Figure 7.1: Competition regarding the forest resources in Sweden today – a price comparison, March 2006 (1 € = 9.2 SEK). (With the warning sign we merely want to focus attention on the issue of increased competition regarding the forest resources.)

These subsidy systems have changed the balance between different uses of biomass. The Swedish situation is illustrated by Figure 7.1.

The use of increasingly higher taxes on fossil fuels in Sweden (the so-called green tax shift) has contributed to the increase in the price of wood fuels in recent years. Presently the price is in the range of 150 SEK/MWh (approximately 16 €/MWh). As shown in Figure 7.1, this is a price in the same range as for pulp timber, or even above that. This leads to a situation where part of typical pulp timber instead is used for energy purposes. There are a number of indications of this, e.g.:

- When there is a long transport distance to the pulp industry, and the distance to district heating plants is short, timber more often goes to the energy sector.
- The tops of the trees are cut further down on the tree trunk, resulting in a larger part of the total tree going to energy purposes.

- Sawdust from sawmills more often goes to the energy sector, instead of to the pulp and paper industry.

The introduction of the electricity certificate system leads to increased demand for biofuels for CHP plants. This is an application which is very economically attractive. Calculations have indicated that this use of biofuels is competitive even at biofuel price levels above 200 SEK/MWh (22 €/MWh). The increased demand may increase biofuel prices above the present level and thereby increase the competition with pulp timber even more. There can also be competition with saw timber (which is typically high-quality timber). The situation in Finland is similar, but the competition is not quite as strong as in Sweden, and the reason for the competition is different (see below).

Why then are the Swedish biofuel prices not higher already today? There may be a number of reasons for this, e.g. that the supply is larger than the demand, that this is a sluggish market where the suppliers not fully have reacted to new conditions, and that import moderates the price increase.

In Finland the upward pressure for biofuel prices is a consequence of the effect of the European Unions emission trading scheme (EU ETS) on the price of peat, which is the main competitive fuel to biofuels in Finland; cf. Figure 7.2.

Policy instruments used to promote the use of renewable energy may thus contribute to increased timber prices. Heat is a product which does not compete on an international market, and increased prices can to a large extent be transferred to the customers. This is not the case with the pulp and paper industry. They compete on an international market and increasing timber costs cannot easily be transferred to the customers.

The Nordic pulp and paper industry does not only have to deal with increasing timber costs. At the same time this electricity-intensive industry has to adjust to considerably higher electricity costs, as a result of the EU ETS.

The NEP project has no view on whether the increased competition and higher timber prices are a desired development or not. We merely want to

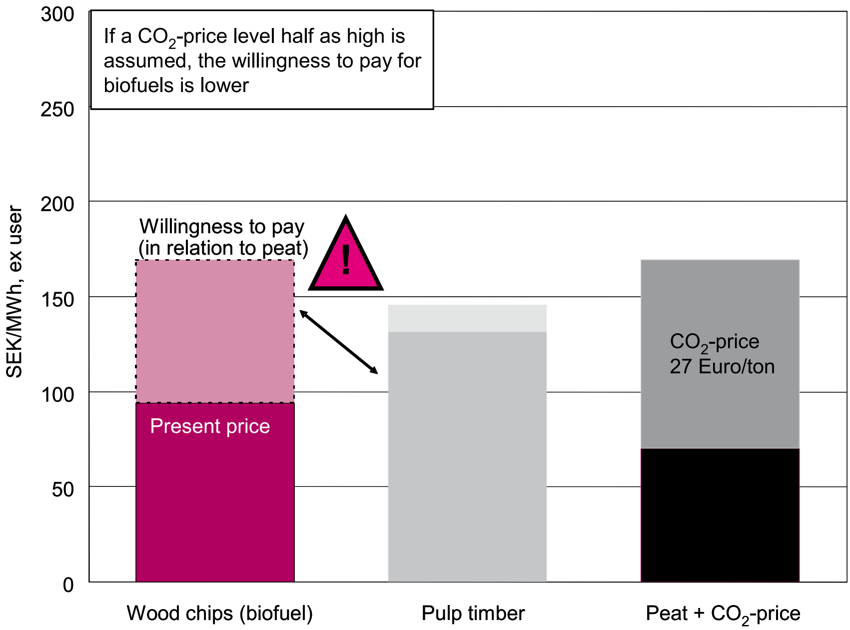


Figure 7.2: Competition regarding the forest resources in Finland today – a price comparison, March 2006 (1 € = 9.2 SEK). (With the warning sign we merely want to focus attention on the issue of increased competition regarding the forest resources.)

focus attention on the issue of increased competition regarding the forest resources.

Import of biomass

As mentioned above, import of biomass is one factor which contributes to moderating the price increase of biofuels in the Nordic countries. The import of biomass to Sweden and Finland is already today of significant size, in 2004 approximately 60 TWh. (This is the sum of import to each country. Some export goes from Finland to Sweden. Therefore the import to the two countries together is slightly smaller.) By far the largest part of this import consists of biomass to the pulp and paper industry and to sawmills. There are a number of reasons for this import, e.g. the need for specific types of timber (which are not available in the Nordic countries at sufficient quantities) and to keep timber prices low.

The direct import of biofuels to Sweden and Finland for district heating and power production in 2004 was in the range of 6 TWh. (Some of the timber import to forest industries becomes, through the industrial process, by-products which are later used for heat and/or power production. Thereby the total import of biofuels is larger than indicated by the direct import of biofuels.) The import of biomass as raw material for the forest industry and for energy purposes amounts to 15-20% of the total use of biomass for these applications.

Another type of biomass import which is considerably smaller in quantity, but larger in its share of the total use, is biofuels for the transport sector. In 2004 Sweden and Finland imported approximately 1.5 TWh, mainly ethanol, which corresponds to approximately 75% of the total use. Although this part of the total use of biomass is presently small, it could in the future grow considerably, thereby increasing the competition regarding the forest resources.

The importance of biomass import, and in the future possible export, shows that when competition regarding the use of biomass is analysed, prices and willingness to pay in different sectors are of greater importance than national physical quantities of available biomass.

Future demand?

The demand for biofuels in the Nordic countries, above all in Sweden, is presently high, which could be translated to an ability to pay a relatively high price for biofuels. This demand is a consequence of the policy instruments which are in operation. As described above, this has led to an import of biofuels to Sweden and Finland.

This could, however, change in the future. If the conditions become less favourable in the Nordic countries and if the demand from other countries increases, the Nordic countries could change from importers to exporters of biofuels. This could also lead to effects on the price of biofuel and timber.
What could cause the demand to drop in the Nordic countries? In Sweden, the price of electricity certificates could drop significantly (even down to 0 SEK/MWh) due to high electricity prices, increased competition from other renewable electricity production (e.g. lower cost for wind power due to

the experience curve effect) and a general large expansion of renewable electricity production (see also discussion in Chapter 5). The introduction of the EU ETS could also lead to decreased taxes on fossil fuels (to avoid ”double taxation”) which would decrease the competitiveness of biofuelled CHP production somewhat. A development in this direction could lead to a slower biofuel and timber price increase than described above.

What could increase the demand from countries outside the Nordic region? A number of European countries need to make great efforts in order to reduce their emissions of CO_2. Substitution of fossil fuels to renewable energy is one measure to achieve this. Biofuels are then one of the most competitive alternatives. Since these countries use a lot of fossil fuels and to a great extent lack forest resources, this could lead to a demand for import of large quantities of biofuels. (A simple calculation example shows the magnitude of quantities: if we assume that 10% of the coal which is presently used for electricity production in European power plants would be substituted by biofuels, this would correspond to a biofuel use of 250 TWh/yr.) In a number of countries, e.g. Germany, the Netherlands, Austria and Spain, favourable feed-in tariffs are already in operation to support electricity production based on biofuels.

Another source of competition on biofuels is increased demand for biomass for vehicle fuels. Large quantities of fossil fuels are used in the transport sector and there are strong political ambitions to reduce the dependency of petroleum-based fuels, both in the EU and in the Nordic countries. Presently the renewable fuels in this sector are dominated by imported ethanol. Other sources are domestically produced alcohol based on grain and upgraded biogas from digestion of sludge at wastewater treatment plants. However, in order to facilitate considerably larger production of renewable transport fuels it is likely that forest resources will have to be used. This would thus increase the competition regarding the forest resources even further. This increased demand for biofuels (as a consequence of increased demand from the rest of Europe and/or from the transport sector) could lead to even higher prices of biofuels and timber.

Chapter

8

The impact of captial budgeting practice in the development of the Nordic energy sector

One of the greater environmental challenges for the coming decade is to induce enough investments in the stationary energy system in order to comply with commitments within the Kyoto framework. In deregulated and contestable energy markets, this is assumed to be done in line with the economic imperatives framing the sector. In this chapter we look at some of the elements that are vital for assessing the economic attractiveness of an investment and how these are interpreted and used by the companies. The results show that the decision criteria used are largely based on discounted payback calculations with a fixed payback time. This is especially unfortunate when assessing infrastructural investments with long payback periods, because it places too high a cost on the invested capital. As a consequence many desirable investments will be considered unprofitable. At an aggregated level this will be an impediment for change in the stationary energy sector.

Introduction

One of the greater environmental challenges for the coming decade is to stimulate enough investments in the stationary energy system in order to comply with commitments within the Kyoto framework. In deregulated and contestable energy markets, this is assumed to be done in line with the economic imperatives framing the sector. Even though we conclude in chapter 17 that the majority of the companies in the Nordic energy market are not primarily driven by profit, but rather by other values that the owners emphasize, the perceived profitability of an investment is of decisive importance for decision-makers. In this chapter we will examine some of the elements that are fundamental for assessing the

Anders Sandoff
School of Economics
Göteborg

economic attractiveness of an investment. An important task is to clarify how today's capital budgeting practice influences the perception of profitability in production-related investments.

First we take a look at the concept of hurdle rates, what it represents and what levels are used by energy companies to discount cash-flows in the assessment of production-related investments. We then review the decision criteria that energy companies use for deciding when investments are profitable. In this discussion we give special attention to the use of pay-back time as a criterion for assessing the profitability of an investment, because of its widespread use and its inappropriateness as a decision criterion. Lastly in this chapter we examine the role and magnitude of investment horizons in production-oriented investments.

Together these three elements represent the quintessence of difficulties in capital budgeting assessment techniques, and are also the cause of serious misunderstandings – misunderstandings that hamper the possibilities of developing the Nordic energy sector.

The data for our analysis will be based on a survey directed to the CEO in all Swedish municipally controlled energy corporations. More details about the survey and its results can be found in the forthcoming report ”Corporate governance issues in Swedish municipally owned energy companies”. Still, the results presented here will most likely be valid for the majority of publicly held companies in the Nordic countries. Anecdotal evidence suggests that these issues are handled in very much the same way in all Nordic countries. When presenting the material in this chapter for managers representing energy companies form Denmark, Norway and Finland they confirm that investment analyses are made in similar ways.

Hurdle rates and the cost of capital in the energy sector

One of the challenges in estimating the profitability of an investment is to incorporate the economic effects from the investment's whole duration. There are several explanations for why a cash-flow generated today is worth more than a numerically equally large cash-flow generated a year from now.

Without going into a detailed explanation, the two main reasons stem from the fact that future cash-flows are not possible to invest today and that they are less certain. Therefore they have to be burdened with a cost-compensating forgone return from alternative investments and for having a lower expected value. This 'cost of capital', referred to as the hurdle rate in a capital budgeting appraisal, is however not so easily determined. Still, it is important to give it a fair estimate in order for the company and its investment not to destroy value. If a company demands too high a cost of the invested capital, future cash-flows might be depreciated to such an extent that the company rejects profitable investments. This will make the company less profitable than if it made a more correct assessment of this cost. Conversely, if it demands too low a cost, it might accept investments that are unprofitable, and again this will make the company less profitable.

From an aggregated societal point of view, it is harder to say what the effects of a deviation from a fair estimate would be. It is probably safe to say, though, that a general overestimation of the applied hurdle rates will generate fewer investments in each time period. (The real consequences on an aggregated level will demand a more thorough analysis. A casual analysis suggests that the costs for society will be higher if the applied hurdle rate generally overestimates the real cost of capital, since the public companies dominating the sector deliver other stakeholder values than profit, which are typically not included in the calculation of the profitability.)

Before we take a look at the levels of hurdle rate used by municipally controlled energy companies, let us say something about what to expect. Since a fair estimate of the hurdle rate depends on the type of investment, the financial structure of the company, and opinions on future cash-flows, it will be unique for each company and point of time. It is therefore hard to give a more precise estimate. However, it is reasonable to assume that hurdle rates for production-oriented investments should be between 4 and 6 percent in nominal terms. (This estimation is made by using the standard CAPM model and an estimation of a risk-free return in the range of 2-3 %, a market risk premium of 5-6 % and a beta value of 0.3-0.6.)

If we look at the hurdle rates used by Swedish municipally controlled energy companies in Figure 8.1 for such investments, we conclude that more than half of the companies fall in that range, but there is a significant portion of these companies that will reject production-related investments that deliver a return of 6 %.

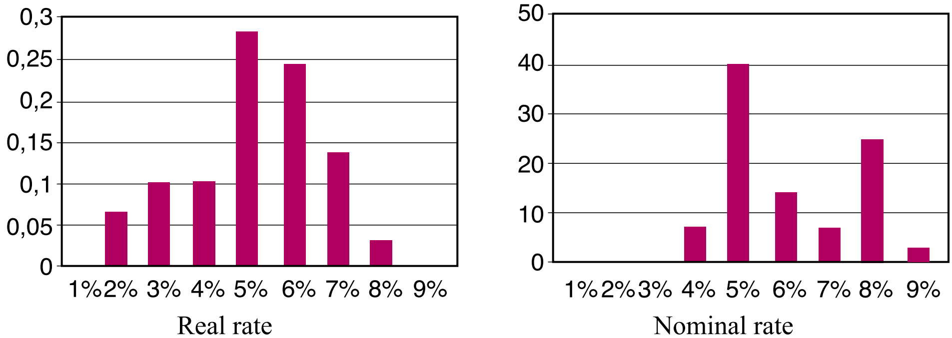


Figure 8.1: Hurdle rates used for investments in energy production

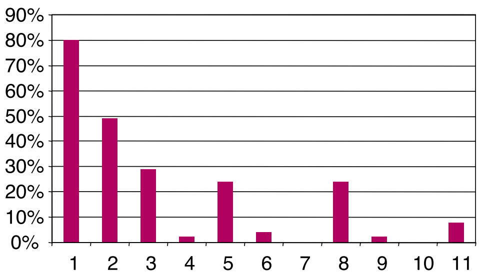
Since these companies predominantly invest in district heating, it is probably safe to say that they demand too much of an investment. Some of the circumstances that have been put forward by respondents which might explain this situation, like capital rationing, lack of funds, and high profitability in earlier investments, are hard to accept from a financial point of view.

Even though these results indicate that the majority of the companies use a reasonable level on their hurdle rate (< 6 %), this is not the case. In the next section we will show that almost none of the companies actually apply this level in their capital budgeting!

Assessing profitability in investments in the energy sector

The recommended capital budgeting technique for assessing the profitability of an investment is to calculate the net present value NPV of the investment. In short, all incremental cash-flows from the investment are discounted at the hurdle rate and then added together. If this sum is greater than the initial outlay, the investment has a positive NPV and should, in principle, be carried out. A positive NPV indicates that the investment not only meets the financial requirements (represented by the hurdle rate) placed on the company by owners and lenders, but also increases the value of the company by the same amount as the NPV. In Figure 8.2 below, we see that only half of the responding companies use this method.

Contrary to what one would expect, the hurdle rate is not the only financial requirement that energy companies put on their investments. Most often there is also a time restraint put on the investment. Let us look in more detail at the most widespread profitability criteria for assessing investments in energy production. In Figure 8.2 we see that almost all companies use pay-back time as one of the most important decision criteria.



1. Pay-back time
2. NPV (Net Present Value)
3. IRR (Internal Rate of Return)
4. NPV/initial outlay
5. Accounting based ratios
6. EVA or other value added method
7. Real options
8. Product costing or profit estimates
9. Cost based estimates

Figure 8.2: Most important decision criteria for assessing economic attractiveness of investments

In general terms, one can conclude that the widespread popularity among decision-makers of using pay-back time (the time it takes for an investment to recover its initial outlay with or without consideration to cost of capital) should indicate that it is very useful for assessing the economic attractiveness of investments. It is reasonable to assume that management and owners have long experience of using this easy-to-understand measure and that it has worked in the past. Will this not be enough in the future? If one considers the major societal importance of the industry, the monumental challenges that lie ahead and the increased public demands that we only recently have begun to see, it is far too blunt an instrument for decision-making. If the stationary energy sector is going to be truly competitive, it is imperative that the companies assess investments with greater precision.

Another aspect, besides its being simple to understand and use, is that managers find pay-back time convenient for handling their strong preferences for low risk and liquidity (Sandoff, 2003a). (Managers typically refer to the pay-back time as a reference point when the investment becomes risk-free or when the tied-up capital can be assigned to other investments). These stated preferences are not necessarily wrong, but the pay-back measure is not suitable for handling them, since it is too aggregated to make a transparent analysis of their consequences. Instead it is recommended that these preferences be stated and taken into account separately.

One strategically important consequence when using pay-back time as a decision criterion is that it encourages managers to focus on cash-flows that appear early in the project. This makes a lot of managerial sense, but is awkward given the long time period that investments in energy production are going to be around. It does not make sense to build a district heating system with a ten- to fifteen-year time frame. Infrastructural investments like these typically demand a very long capital budgeting horizon in order to be profitable, or to be able to get a complete picture of their full value. This practice will impede the discussion and understanding of the long-term strategic role of the energy company.

We have now addressed what can be said to be generic setbacks when using the pay-back method. We will now turn to a certain use of the method that has great financial consequences, very rarely known to managers. That is the widespread practice of using pay-back as a decision criterion for assessing whether an investment proposal is profitable enough to pursue. Earlier research (Sandoff, 2003b) has shown that it is common to communicate a maximum pay-back time for an investment to be seen as profitable. The results from the survey of the Swedish municipally controlled energy corporations indicate that half of the companies which use pay-back time have such a criterion. This practice stands in sharp contrast to what is theoretically recommended; that is, since the pay-back time of an investment does not include cash-flows after the pay-back time, the measure is only suitable for ranking similar and mutually exclusive projects.

Even though the pay-back method makes managers focus on the cash-flows that are generated before the pay-back time, this need not be so bad if the pay-back times used for accepting a production-related investment are very long. Unfortunately such is not the case. More than seven out of ten of these companies apply a maximum pay-back time of ten years or shorter. This practice has a dramatic impact on the perceived profitability for many investments, since such a fierce time constraint does not come free of charge! What one really demands is that the investment has to be totally repaid during the pay-back time (no residual value), instead of having the majority of its value intact, which would be a more realistic assumption after such a short time period. Not only that: since most decision-makers (correctly) use discounted cash-flows, they also burden the investment with the company cost of capital! Together this is the project's implicit internal rate of return during the pay-back time. This implicit rate of return demanded from the investment can be estimated by the annuity factor, using the applied hurdle rate (r) and stated maximum pay-back time (n).

$$\textbf{Annuity factor: } \frac{r}{1-(1+r)^{-n}}$$

To visualize the consequences of this effect, one can see in Figure 8.3 that, even when low hurdle rates are used, the effect becomes dramatic. If a company uses a 5 % hurdle rate to discount its cash-flows, and on top of that requires a maximum pay-back time of 10 years (complete retrieval of initial outlay), it uses an implicit rate of return of 13 %! This is why many energy companies de facto apply a much higher hurdle rate than they intend to.

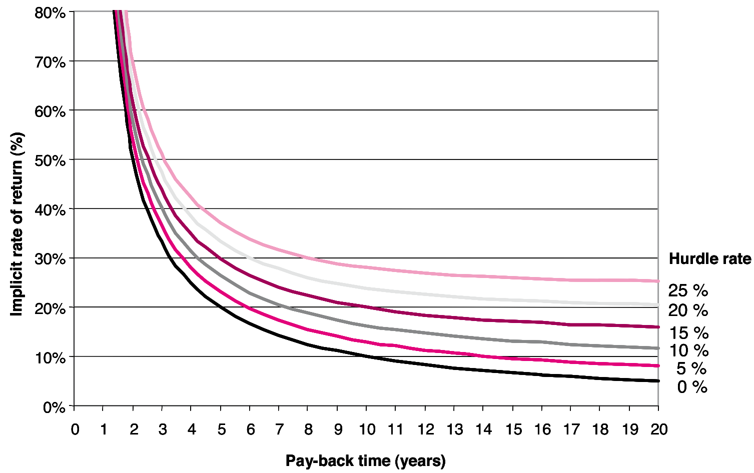
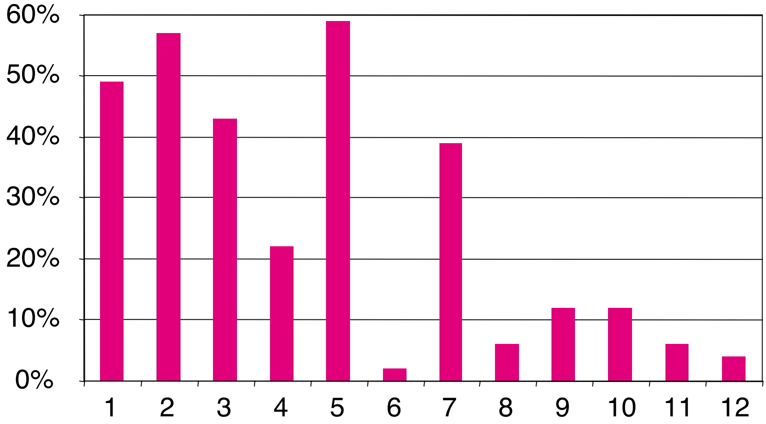


Figure 8.3: Maximun pay-back time as decision criterion

The effect will of course be even more burdensome when higher hurdle rates or shorter maximum pay-back times are applied. The opposite is also true; if companies use long maximum pay-back times (>25 years) the effect will be smaller.

So it is not enough to know and question the hurdle rates applied for investments in energy production. One also has to take into account the decision criteria used. Together they paint quite a different picture!

Even though this practice is making energy companies under-invest, there are other circumstances that make it possible for investments that do not meet the standard requirements to be accepted. In almost all companies it is possible to apply lower requirements for certain investments. Results from the survey show that many different investments can be viable for lower requirements, in terms of both lower hurdle rates and longer pay-back times. In Figure 8.4 we list different investment types viable for lower requirements. We can see that expansion in capacity and environmental improvements are investment types that more than half of the respondents can accept with lowered requirements. Even though this partially reduces the effects of the implicit rate of return described above, the practice is not to be recommended since it is based on the same misleading decision criteria although lowered.



1. Special interest for the owner
2. Environmental improvements
3. Public welfare effects
4. Strategic inv. w. large risks
5. Expansion in capacity
6. Customer facilities
7. Residential house district heating
8. Wind power plants
9. Small investments
10. Product development (energy services)
11. Same requirements for all types of invest
12. Other

Figure 8.4: Areas of investment viable for lowered requirements

Interestingly, both investments that are of a special interest for the owner and investments with public welfare effects qualify for lowered requirements in more than 40 percent of the companies. With reference to the discussion in the Chapter 17 about the motives for a municipality to own an energy company, this makes managerial sense.

The use of investment horizons in the energy sector

Even though pay-back times are very common for assessing the profitability of an investment, companies include cash-flows for a much longer time period in their capital budgeting assessments. Below in Figure 8.5 we see that twenty years is the most common time period for which the cash-flows are estimated.

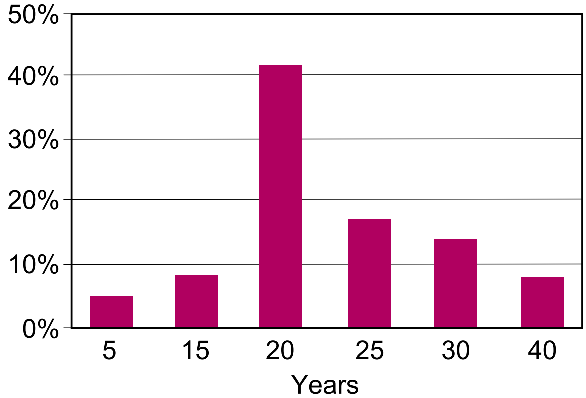


Figure 8.5: Maximum investment horizon

Twenty years is a long time period in any economic venture but, given the emphasis on the infrastructural quality of many of the investments in the energy sector, it can be argued to be rather short. The fact that more than 40 % of the companies use an investment horizon longer than 20 years is an indication of that. Also, even if some part of an investment in energy production has an economic lifespan of 20 years or shorter, this is usually not the case for the whole investment. Although it is technically possible to include cash-flows emerging after the end of the investments horizon by calculating a residual value and assigning it to the last year of the planning period, this is not likely to be done. A maximum investment horizon is just that, a maximum time span for estimation of cash-flows.

The propagation of this practice signals a somewhat casual attitude towards the problem of economic life span. It might be for administrative reasons (e.g. quicker and easier to do) or in order to avoid a misuse of too long investment horizons (in order to make investments more profitable), but the fact remains that this detached practice reduces the issue to a mere standard procedure. The economic life span of the investment will not be something that is discussed in these organizations. Still, it is the only sound criterion for deciding when it is profitable to exchange parts or to end operations, i.e. when costs (cost-based depreciation, capital cost and the cost for maintenance) exceed revenues in a certain year. (Nota bene: very often depreciation on accrual basis is incorrectly used instead of a cost-based ditto.)

Omitting economic life span from the discussion of how the company will dedicate its long-term capacity is also limiting the possibilities to optimize these resources over the plant life cycle. If every investment decision is made in isolation, based on a detached standard capital budgeting procedure, it is not possible to optimize the company's long-term capital allocation. This is especially true for re-investments and capacity expansion which are of current interest to many of the energy companies today. Old equipment needs to be upgraded and there is a strong commitment among many of the municipally owned energy companies to increase the district heating system. To make investments with the right order, pace and magnitude one has to have a strategic plan that captures the economic consequences of different alternatives. The estimation of economic life span is an important catalyst for directing attention to these matters.

It can also help in limiting the problem of comparing the profitability in existing facilities with that of new ones. Typically, managers base their estimates of the profitability in existing production plants on accounting data. Profitability estimates based on the book value of the asset rather than the market value, for long-lived assets such as plants, will commonly overestimate the profitability. The depreciation allowances regulated in the tax laws are, for these kinds of assets, larger than the depreciation calculated for costing purposes. When cash-flow-based profitability measures from an investment proposal are compared to an accounting-based measure for an existing plant, it will lead managers to over-invest in existing plants and reject profitable investments in new ones. This malpractice also makes managers demand an unnecessarily high return on their capital, which in the end will preserve existing structures and make many changes in the energy system appear unprofitable. If managers instead used market values and assessment based on the economic life span of existing plants, many of these problems would disappear.

Capital budgeting practice in line with the challenge?

We have now looked at three important factors for assessing the profitability of investments in energy production. With all three of these, we found a large number of respondents who estimate and use these factors in a questionable way. It is important to point out that, even though the results are based on a survey of Swedish municipally controlled energy companies, these deficiencies will be found in all types of companies regardless of ownership, industry and size (cf. Sandahl & Sjögren, 2005). This, however, does not mean that the energy sector can or should use the habit as an excuse for not changing its behavior. One could argue that in an industry characterized by an infrastructure business logic, strong public interests and a considerable call for change, it is even more important to address these questions in a serious and conscious way. It is hard to see how an arbitrary estimation of hurdle rates, decisions based on pay-back time, or the use of standard investment horizons would hold up for scrutiny.

Significant for investments in infrastructure is the long time period needed to capitalize the investment. The outcome of capital budgeting appraisals done for investments in energy production is therefore especially sensitive to the magnitude of the applied hurdle rate and the length of the planning horizon. Our examination shows that current practices slow down the development the Nordic energy system.