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Review of the Swedish transmission grid tariff model

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Brief summary

In this report we review the tariff model employed by Svenska kraftnät in the Swedish transmission grid on the basis of economic efficiency criteria. We find that the main structure of the model is in line with economic theory, but recommend the introduction of a neutral residual charge and changes in the basis for capacity charging, in addition to various other changes with respect to the practical implementation of the model.

About THEMA Consulting Group

Øvre Vollgate 6 0158 Oslo, Norway Company no: NO 895 144 932 www.thema.no	THEMA Consulting Group is a Norwegian consulting firm focused on Nordic and European energy issues, and specializing in market analysis, market design and business strategy.

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SUMMARY AND CONCLUSIONS

The Swedish TSO, Svenska kraftnät, is currently conducting a comprehensive review of the Swedish transmission grid tariff. As part of this effort, Svenska kraftnät has asked THEMA Consulting Group to assess the efficiency of the current Swedish transmission grid tariff, and to propose amendments if inefficiencies are identified.

The assessment is based on economic theory and a survey of transmission grid tariffs in other countries. Based on the findings from the assessment, we provide recommendations for changes in the tariff and assess distributional impacts of the proposed changes.

Basic criteria for optimal grid tariffing

Grid tariffs are to fulfil two very different objectives: On the one hand to provide efficient price signals for efficient utilization and investments in the grid, on the other to collect revenues that cover all grid costs.

According to basic economic theory, efficient prices should reflect marginal costs. Efficient prices should reflect the short-term variable costs in the existing grid. As capacity becomes scarce, prices should increase and eventually reach a level where grid investments are profitable. Due to the need to maintain security margins in the grid, investments are made before the capacity becomes scarce, and short-term efficient prices will not adequately reflect long-term marginal investment costs. Thus, in addition to prices reflecting short-term variable cost, long-term price signals should be provided. Moreover, since the grid is a natural monopoly, marginal costs are lower than average costs. The residual costs, i.e., costs not covered by revenues from efficient prices, must be covered by a "tax" that should not affect the short- or long-term decisions of grid customers.

Based on economic theory and the cost structure in the transmission grid, we conclude with the following basic criteria for optimal grid tariffs:

- Individually levied connection charges should reflect customer-specific elements only.
- Energy charges should reflect short-term variable costs, i.e. the marginal value of energy losses in the grid.
- Efficient investment signals should be provided by a general capacity charge related to the marginal long-term marginal investment costs (non-locational).
- Efficient locational signals should reflect capacity constraints in the grid, i.e., the impact on medium-term investment costs, and should take into account the locational signals provided by congestion rents.
- Residual costs should be covered by separate tariff elements that do not affect short-term use of the grid.
- As perfectly neutral residual charges are not possible, residual costs should be allocated among grid customers based on relative elasticities in order to minimize total long-term efficiency losses.

Assessment of the current transmission grid tariff

The current Swedish transmission tariff consists of three main elements:

1. Connection charges that are levied individually when new customers connect to the grid or when existing customers expand their demand for grid capacity. Connection charges include customer-specific costs and costs in the meshed grid that are triggered by that customer.
2. Energy charges that cover Svenska kraftnät's costs of energy losses. The energy charges are differentiated between nodes according to average loss coefficients and area prices.
3. Capacity charges that cover capital costs and are differentiated according to the customer's location in the grid. Capacity charges are mainly based on annual capacity subscription, but

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also on temporary subscription. An exceedance fee applies if a customer surpasses its subscribed capacity.

Overall, we conclude that the basic structure and main principles underlying the current tariff are in accordance with economic theory. We do however recommend a number of adjustments to increase the short- and long-term efficiency of the price signals in the tariff, and we recommend the introduction of a neutral residual charge.

The table below summarizes the assessment of the extent to which the current Swedish grid tariff complies with the optimality criteria.

Summary of identified inefficiencies in the current Swedish transmission grid tariff

Tariff element	Identified inefficiencies in the grid tariff	Relevant efficiency criteria
Energy charge	Energy charges are differentiated according to average annual marginal loss factors. The correction charge further reduces the efficiency of the energy charge.	Loss factors should be differentiated in line with the variation in actual marginal losses. Energy charges should reflect the marginal value of energy losses.
Connection charges	Deep connection charges that depend on the timing of connection to the meshed grid.	Connection charges should only cover customer-specific grid costs, i.e. be shallow. Shallow connection charges should be applied in combination with a uniform locational capacity charge reflecting the marginal impact on medium-term costs in the meshed grid.
Capacity charges	Current capacity charges are weakly linked to long-term marginal grid costs. The geographical differentiation based on latitude is a crude approximation to the actual differences in the impact of location in different nodes on grid investment costs. Basing charges on annual capacity subscriptions, temporary subscriptions and exceedance penalties, runs the risk of adversely affecting grid customers' short-term use of the grid. Capacity charges cover residual costs.	Capacity charges should be linked to decisions by grid customers that affect the dimensioning and thus, long-term grid costs. Capacity charges should be levied as a general charge applying to all grid customers. The charge should reflect the long-term cost of grid expansion that is largely independent of the current grid configuration and congestion pattern. A locational capacity charge should be applied that signals the differences in the impact on grid investments depending on the location in the grid. This locational signal should ideally be differentiated between nodes. Residual costs should be covered by a separate residual charge that should be as neutral as possible.

Recommended changes in the transmission grid tariff

Based on the identified inefficiencies and the efficiency criteria, we recommend an amended tariff structure for the Swedish transmission grid. The main recommended changes are:

1. In general, to establish a clearer link between marginal costs and tariff elements that are introduced to provide price signals in different time-frames.
2. To differentiate energy charges to better reflect actual losses in the grid. Such differentiation becomes more important as the share of intermittent renewable generation increases in the system.

3. To apply shallow connection charges and let the deep elements be captured by a general geographically differentiated capacity charge.
4. To base capacity charges on long-term marginal grid costs and link geographical differentiation to medium term impacts, reflecting the current grid configuration, and the general charge to long-term impacts on grid investment costs, i.e. a basis charge for access to the grid.
5. To levy capacity charges according to the load that is relevant for the dimensioning of the grid in order to relate the price incentives for grid customers more directly to the investment costs in the grid.
6. To introduce a residual charge that is distributed among grid customers according to the Ramsey principle for efficient taxation.

To consider introduction of a tariff for reactive power. The recommended structure, design and rationale of each element and the relevant cost baser are described in the table below.

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Recommended transmission grid tariff structure

Tariff element	Design and rationale	Cost base
Connection charges	Shallow, reflecting customer-specific connection costs only.	Cost of connection components that can only be used by one customer. The cost should be calculated case by case.
Energy charges	Reflecting energy losses according to variations in marginal loss factors and actual market prices. Together with zonal price differences, energy charges signal how the customers' short-term operation affects grid costs.	Loss factors differentiated according to historical data, e.g. weekly, monthly or seasonally, between night and day, and between working days and weekends. Applied loss factors should be updated per period based on estimations for the next period. Charges should be based on actual hourly zonal prices.
General capacity charge	Uniform charge reflecting the long-term impact on grid investment costs of changes in injection or withdrawal from the grid that is independent of the timing and location of the grid customer. The general capacity charge reflects the basic cost associated with a MW being connected/having access to the common grid.	The marginal cost of grid investments that is not location-specific, reflecting the lowest common denominator for the cost of access to the grid. This element could, e.g., be based on the annual cost of station capacity. The charge should be based on the customers' expected withdrawal or injection in dimensioning hours (system peak). Charges should be long-term stable but should reflect the general cost development of relevant grid components.
Locational capacity charge	Differentitated charge reflecting the medium-term impact on grid investment costs of a change in injection or withdrawal that depends on the location of the customer. The locational capacity charge incentivizes customers to make locational decisions that take into account the current configuration and congestion patterns in the grid that are not reflected in energy charges and zonal prices.	Marginal cost of grid expansion based on flow-analyses of increases in withdrawal and injection per node in the transmission grid, based on the current grid configuration. Charges should be based on the customers' expected injection or withdrawal in dimensioning hours (nodal peak). Charges could be both positive and negative. Charges should be updated in accordance with changes in the grid configuration, for example every 3 years in order to provide predictability.
Residual charge	Residual charges should cover costs not covered by the other tariff elements. Residual charges should be designed so as to not affect the short-term utilization of the grid and should affect the long-term behaviour of grid customers as little as possible. Residual charges should be allocated between generators and consumers according to relative long-term elasticities.	Residual costs = total annual costs – (revenues from other tariff elements + congestion revenues) The allocation of residual costs should be based on empirical studies of price elasticities. Generators (injection) could be charged according to annual average electricity generation over the last 5-10 years. Consumers (withdrawal) could also be charged according to annual energy consumption. Charges could be differentiated according to elasticities between consumer groups.

The recommendations do not represent a radical change in the tariff structure but implies a clearer separation of elements with different purposes and a clearer link to economic theory.

Particular aspects to observe

We have recommended changes in the tariff structure and in the cost basis for some of the tariff elements. We have also provided some examples of how the charges may be calculated. The detailed design of the tariff elements must however be more carefully considered. Some aspects to observe based on our assessment are:

- Capacity charges should be based on a measure linked to the expected load at system peak, i.e. the load that is relevant for grid investment decisions. A relevant indicator could be constructed based on the actual load in some reference hours or high load periods over a 5-10 year period. Basing capacity charges on single hours and annual data would incentivize short-term changes in behaviour without affecting long-term grid costs.
- Consumers with interruptible contracts should in general not pay capacity charges for the share of their capacity that can be interrupted. Interruptible contracts need to be sufficiently long-term to have an impact on grid investment decisions, and should only be offered if they do have such an impact. Interruptible contracts should be offered to all grid customers who could potentially provide valuable flexibility.
- Capacity charges for generators must be designed so as to not disincentivize valuable capacity and flexibility. Capacity charges for generation could for example be based on the expected winter capacity (for new generation), and for existing generation on the average injection during winter high load hours. Basing the capacity charges on only a few peak hours could yield adverse incentives leading to artificial price spikes and capacity scarcity.
- The distribution of residual charges should be based on grid customers' price elasticities. A practical approach must be adopted based on assessment of available data and statistical analysis. Distributional effects, acceptance and legal issues should probably also be considered.

Other recommendations

We recommend that joint capacity charges are still offered to regional grid customers in order to take into account the impact of transit on capacity charges. A simple solution could be to base the netting on historical data or model analysis of the typical transit patterns in the periods the capacity charges are based on.

The guarantee related to allocated capacity in the connection agreements should be made conditional, i.e. grid customers should be obliged to give up capacity if their load is permanently reduced. A requirement to report on their capacity situation could be implemented, or Svenska kraftnät could get the right to ask for documentation based on monitoring of loads, and the right to demand changes in the connection agreements. We do not recommend the introduction of a penalty fee related to unutilized capacity. A definition of "permanent reduction in capacity" must be developed.

The principles applied in the transmission tariff will be more efficient if they are also applied to customers in the regional grid. Since demand in the Swedish transmission grid is to a large extent represented by regional grid owners, the gains from a more efficient transmission tariff depends on the impact on regional grid tariffs.

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Summary of impact assessment

The table below summarizes our assessment of how the proposed changes will affect grid customers and Svenska kraftnät. It is particularly difficult to assess the impact on consumers as it depends on how transmission tariffs are reflected in regional grid tariffs.

Summary of impact assessment of proposed changes

	Incentives for generators	Incentives for consumers	Distributional effects	Consequences for Svenska kraftnät
Changes to capacity charges	Changes in the incentives for individual generators depending on location and type. Residual component based on average energy advantageous for wind and hydro vs. base-load generation.	Not relevant today as no consumers are directly connected to the transmission grid.	Not possible to assess ex ante between generation and consumption. Likely redistribution from wind and hydro to base-load generation.	Presumably more efficient investments in power generation affect grid investments. Grid costs could increase or decrease compared to the current tariff with emphasis on capacity.
Removing subscribed capacity as basis for the capacity charge	The charge for marginal injection no longer depends on temporary subscriptions or exceedance fees. Improved incentives for long- and short-term flexibility.	Not relevant today as no consumers are directly connected to the transmission grid.	Not possible to assess ex ante, but likely to be small.	Enables more flexibility on the part of generators, contributing to more efficient use of the grid capacity and more efficient investments.
Changes to the energy charge	More efficient allocation of generation in the short term and improved long-term signals.	Improved price signal, but depends on how charges are passed through to regional grid customers.	Removal of the correction factor will increase costs relatively more for generators in the north and consumers in the south.	Improved quality of price signals. Increased revenues from energy charge and reduced residual costs. More variable annual revenues from energy charges.
Possible change in the distribution of residual costs between generators and consumers	May yield somewhat weaker investment incentives if tariffs are increased, but not compared to Norway.	Indirect positive impact on consumers in the regional and distribution grids if lower tariff.	Redistribution from consumption to generation if generator tariff is increased	Indirect effect via changes in investment behaviour. Cannot be determined ex ante.
Shallow connection charges	Lower connection charge and reduced uncertainty. Total effect depends on locational capacity charges. Deep costs will not be paid up front, but distributed over time.	No change since connection charges for regional grid owners are treated as pass-through costs in the economic regulation of regional grids.	Some costs will be distributed from new generators to existing generators, but the monetary impact is uncertain.	Need to recover higher share of costs through other tariff elements. Reduced costs related to case-by-case assessments of deep grid impacts.

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1 INTRODUCTION

1.1 Background

Costs for the operation, maintenance, and investments in the electricity transmission grid are covered by transmission tariffs that are levied on grid customers. The tariff is composed of different elements that are partly designed to ensure efficient utilization of the grid capacity in the short run and efficient development of the grid in the long run, and partly designed to recover residual costs in a neutral way. Grid tariffs affect the incentives for investments in electricity generation and consumption, and thus, subsequently the need to invest in the grid.

Energy and electricity systems in Europe are going through profound changes in order to transform the system to a low-carbon future. This transformation poses new challenges to grid operation and requires large investments in the transmission grids. Hence, it is important that transmission grid tariffs are designed in a way that both facilitates transition and maintains efficiency in grid operation and development.

1.2 About the project

The Swedish TSO, Svenska kraftnät is currently conducting a comprehensive review of the Swedish transmission grid tariff. As part of this effort, Svenska kraftnät has asked THEMA Consulting Group to assess the efficiency of and propose changes to the current Swedish transmission grid tariff.

The assessment is based on economic theory and a survey of transmission grid tariffs in other countries. Depending on the findings from the assessment, we provide recommendations for changes in the tariff and assess distributional impacts of the proposed changes.

The project consists of 4 tasks:

1. Establish the theoretical basis: Here we set out the main principles for economically efficient grid tariff design.
2. International survey: Description of high voltage grid tariffs in the countries directly adjacent, and connected, to the Swedish system, i.e., Norway, Finland, Denmark, Germany, Poland and Lithuania. We also describe in some detail the structure of locational signals in the tariff model in the British grid.
3. Assessment of the current tariff and propose changes: Based on the criteria established in task 1, we identify weaknesses and gaps in the current tariff, discuss options for changes and provide recommendations for changes in the tariff design.
4. Impact assessment: Based on case studies and model simulations we carry out an assessment of the distributional effects of the proposed changes to the tariff.

1.3 About this report

This is a complete draft of the final report presenting the key elements of the analysis and recommendations for review and comments. The report has the following contents:

- Chapter 2 establishes the theoretical foundations of the analysis and define our economic efficiency criteria for the evaluation of the current Swedish model and proposals for changes.
- Chapter 3 provides an overview of the key features of the tariff models in adjacent markets, and provide a detailed description of elements in the Norwegian and British tariff models that are particularly relevant for Sweden.
- Chapter 4 describes the current Swedish transmission tariff model to provide the necessary background for our assessment.

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- Chapter 5 provides our assessment of the current tariff model according to the economic efficiency criteria.
- Chapter 6 presents our recommendations on changes to the tariff model.
- Chapter 7 provides a qualitative and quantitative impact assessment of the proposed changes.

2 MAIN PRINCIPLES FOR ECONOMICALLY EFFICIENT GRID TARIFF DESIGN

Grid tariffs serve three main tasks. They should incentivize efficient use of existing grid capacity; they should provide incentives to coordinate optimal investments in the grid, generation and consumption; and finally, they should cover total grid costs. In this chapter, we give an overview of the theoretical basis for efficient pricing of transmission grids.

2.1 Main principles for efficient pricing

In welfare economics, efficiency means that resources are used in a way that maximizes the social surplus, or net benefit to society, of the grid. The net benefit takes into account the operation and investment costs and the value of the grid to grid customers, expressed by their willingness to pay for grid services.

The optimal situation is characterized by efficiency in the short and long run. In economic terms, the short run is defined as a period when the capacity is given, while the long run provides sufficient time to make investments in the grid and thus adapt the grid capacity.

1. Short-term efficiency implies that the given grid capacity is utilized to the extent that grid users are willing to pay the short-term marginal grid cost
2. Long-term efficiency implies that the grid capacity is expanded as long as the amount that grid customers are willing to pay (the benefit) for the grid expansion is larger than the associated investment costs (total costs)

Short and long run optimality in the development of the energy system is not achieved by grid tariffs alone, but by the combined impact on energy use and generation of grid tariffs, market prices and regulatory elements, such as licencing procedures. In our assessment of the Swedish transmission grid tariffs, we therefore also take into account other relevant elements in market design, such as for example the existence of bidding zones.

Before we go into the details of grid tariffing, i.e., the pricing of transmission, we present some general economic principles for efficient short and long-term pricing. These general principles must be related to the cost structure of the transmission grid. We therefore first describe this cost structure, before we elaborate on the relevant pricing principles.

2.1.1 The transmission grid is a natural monopoly

In a competitive market, the dynamics of supply and demand result in efficient pricing. Efficient pricing implies that prices reflect the marginal cost of providing the good or service, and the marginal willingness to pay for the god or service by consumers. A competitive market and efficient pricing require however that there are many suppliers and consumers, that all market participants are well informed, that the market is not a natural monopoly, that the good is not a public good and that there are no external effects associated with production or consumption of the good. The electricity transmission grid is a natural monopoly with only one (regulated) supplier. Never-the-less, tariffs should be set according to the principles of competitive pricing.

Features pertaining to electricity transmission that make the transmission grid a natural monopoly and that are relevant for efficient tariffing, include economies of scale, lumpy investments and the need for capacity margins:

- Economies of scale: Total grid costs consist of large fixed costs that are not related to short-term flows and operation of the grid, and low variable costs. Variable costs are costs related to the short-run utilization of the grid. In the short run, marginal losses occurring when electricity is transferred in the grid represents the largest share of variable costs. Costs related to investments, operation and maintenance of the grid are fixed. With large fixed costs and low variable cost, the grid exhibits economies of scale. This cost structure makes the electricity grid a natural monopoly; in order to realize the economies of scale it is cheaper for society to have one grid provider than competing grid providers with multiple grids in the same area. The transmission grid is regulated to make sure tariffs are cost reflective and that the system operator does not exploit its monopoly position.

- Lumpy grid investments: Economies of scale and technical features of grid elements imply that investments in the grid happen in leaps. Technical features imply that it is generally not possible to develop the grid gradually (in small increments), the capacity increases step-wise. Economies of scale further imply that it is cheaper to invest in a line with double capacity than in two lines with half capacity. Thus, expected increases in the demand for transmission during the lifetime of the asset should be taken into account.
- Capacity margins: In order to ensure adequate security of supply, investments are normally made before the need is reflected as scarce capacity. Demand and supply must be balanced continuously, so the grid needs to have sufficient capacity to maintain the balance in all situations. If one component trips, there is a risk that the whole system will collapse. Thus, the grid is dimensioned in order to accommodate scarcity situation and still be able to handle trips (N-1 principle).

All in all, these features imply that the grid often has excess capacity, even in peak load situations and that efficient short run pricing (according to variable costs) does not reflect long run scarcity.

2.1.2 Marginal pricing

General principle

The marginal pricing principle is the theoretical basis for the assessment of the efficiency of tariffs. An implication of the marginal pricing principle is that all users of the same good should face the same price. Even though the electricity grid is a natural monopoly, the basic marginal pricing criterion applies to efficient grid tariffing.

The basic principle is illustrated in Figure 1 below. The demand curve reflects the willingness to pay for a good, in our case the good is transmission of electricity. The consumers with the highest willingness to pay are represented by the left-most part of the demand curve, while the consumers with the lowest willingness to pay are represented by the right-most part of the demand curve. Hence, the demand curve slopes downward from left to right. Note that the same user can have different levels of willingness to pay for different volumes of transmission and thereby may be represented by several points along the demand curve. The point is that the demand curve reflects that the value of transmission differs among customers.

The supply curve represents the cost of increased grid use and is sloping upwards from left to right. The slope implies that for each increase in load, the per unit grid cost increases. The efficient price, and optimal volume, is found where the supply and demand curves intersect. If transmission exceeds this volume, the marginal cost of providing the last transmission unit is higher than the value that the increased transmission yields for the customer (represented by its willingness to pay). If transmission falls short of the optimal volume, there are customers with a willingness to pay that exceeds the marginal cost that are excluded from the market. In the first case, the net benefit can be increased by reducing the transmission volume, whereas in the last case, the net benefit can be increased by increasing the transmission volume. Setting the price at exactly p_1 therefore maximizes short-term social welfare.

The social surplus is the sum of the consumers' surplus (CS) and the producers' surplus (PS). CS signifies the net benefit of consumers as their willingness to pay for the good or service, defined by the demand curve, is higher than the price. PS signifies the net revenue of the producers, as the market price is higher than the (short run) cost of production for the good or service. This revenue constitutes the market return on the invested capital.

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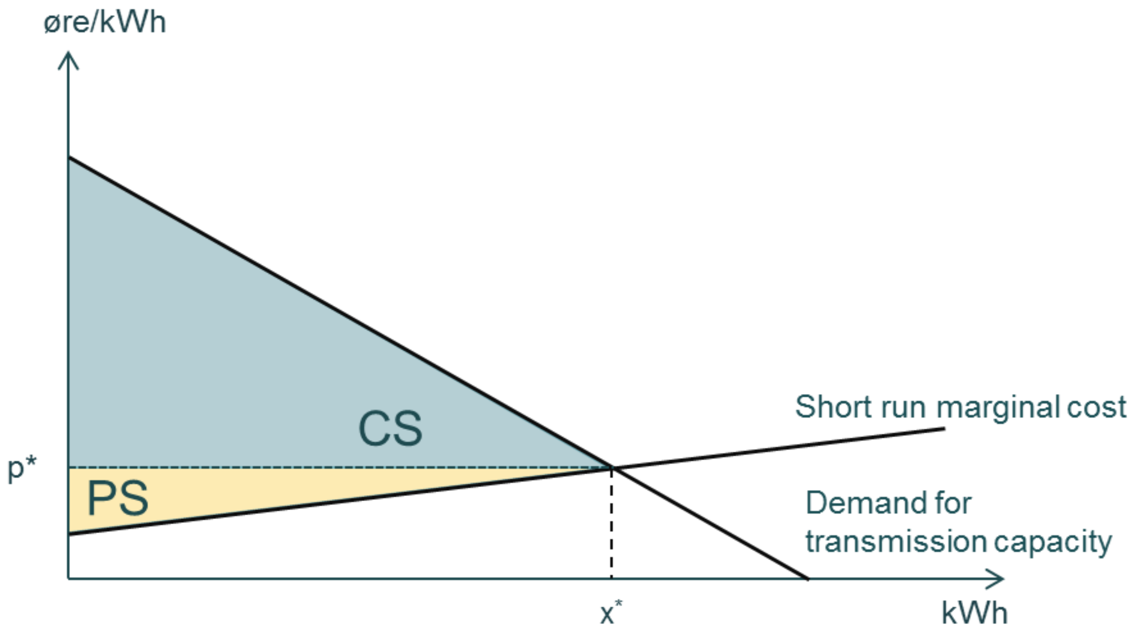
Figure 1: Marginal pricing without capacity scarcity



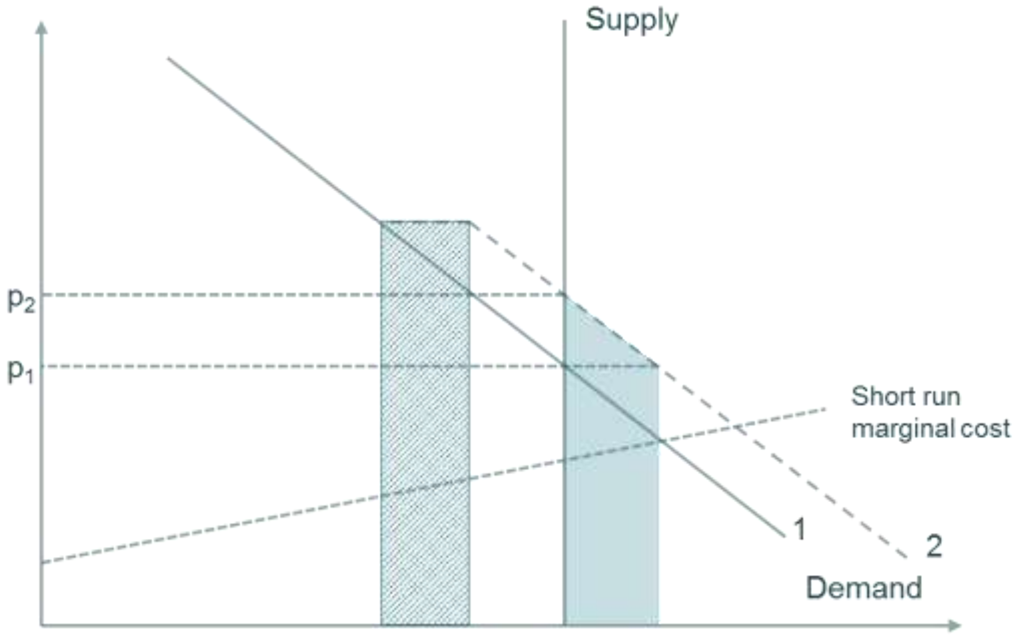
Short-term marginal pricing with capacity constraints

Now consider a situation with scarce capacity, represented by the vertical supply curve in Figure 2:.

The initial demand for capacity is Demand curve 1, and the capacity is fully used when the price is set at p_1, regardless of the variable cost. The marginal willingness to pay for the capacity is p_1. Since the capacity is scarce, this is the price that rations the scarce capacity efficiently. Now, consider the situation where a new user wants to connect. The new user has a higher willingness to pay than p_1, and the demand curve shifts to 2, and the new efficient price is p_2, as shown in the figure. The new price implies that some of the existing customers will no longer use the same capacity as before, they are displaced by grid use that has a higher value to society. The displaced demand is shown by the shaded trapezium on the right-hand side in the figure.

This means that in a situation where the grid capacity is fully used and where a new user wants to connect, this user should in fact displace an existing user with the lowest willingness to pay. The lesson is that the marginal user of grid capacity is not the last user to connect to the grid, nor the user who wants to increase its use of grid capacity. The marginal user is the user with highest willingness to pay for scarce capacity.

Figure 2: Marginal pricing – efficient rationing of scarce capacity



Long-term marginal pricing

Efficient short-term pricing implies efficient rationing of scarce capacity and signals the value of increasing the grid capacity. If the cost of increasing the capacity is lower than the willingness to pay for increased capacity, represented by the shaded trapezium in Figure 2:, it is efficient to invest in new capacity. As such, short-term pricing also signals the value of capacity expansion.

The general principle for efficient investments to increase the production capacity of any asset, is to invest when customers' aggregated willingness to pay is sufficient to cover investment costs. In a competitive market, short-term prices should reflect scarcity and thus also provide such efficient investment signals.

Similarly, long-term grid costs depend on developments in supply and demand and are driven by the associated change in maximum load, i.e., not by the annual energy flows. The capacity of different grid elements is dimensioned by the maximum load that the different elements should be able to handle. This means that most of the time, the grid capacity is typically not fully used. It also means that it is the maximum load that is the main driver for grid investments. In other words, tariffs that reduce load in periods when the grid is not fully used do not reduce the investment need in the grid. Therefore, pricing that reduces grid utilization outside of maximum load, only reduces benefits and not costs.

Due to the lumpiness of grid investments, the efficient investment criterion is that the aggregated willingness to pay is greater than the investment cost. We can imagine three possible outcomes when the connection of a new customer to the grid will require expansion of the grid capacity:

- Grid capacity is expanded and makes room for the new customer in addition to the existing ones
- Grid capacity is not expanded, and the new customer is denied access
- Grid capacity is not expanded, but existing customers are replaced by the new customer

The first outcome is efficient if the total willingness to pay for grid expansion exceeds the cost.

The second or third outcomes are efficient if the total willingness to pay is not sufficient to pay for the grid expansion. In that case, grid access should be given to the customer with the highest willingness to pay, be it the new or the old customer. This example illustrates that all customers should be faced by the price signalling the cost of grid expansion, not just the new ones.

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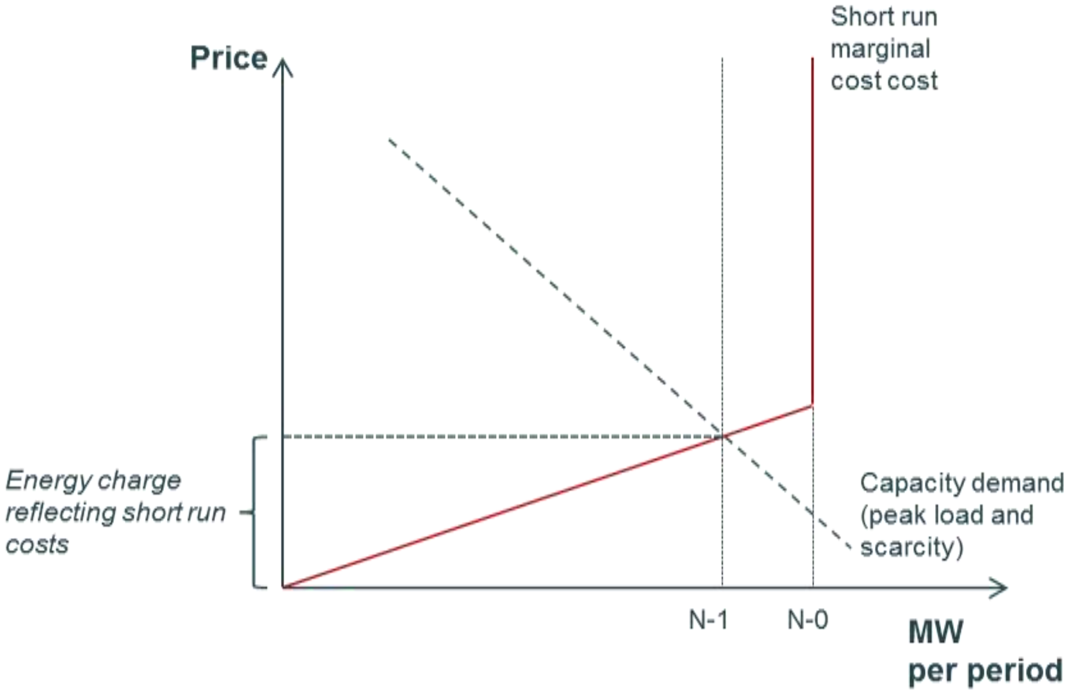
The lumpiness of grid investments and the need for capacity margins imply that once the capacity is built, there is often no additional cost associated with an increase in transmission. However, since increases in transmission will eventually lead to new investments, all grid customers should be exposed to a price signal reflecting the medium- and long-term marginal investment cost.

Figure 3 illustrates the typical situation in the grid. If a grid element is loaded to its full capacity, there is significant risk that it will trip, in which case supply is likely to be cut in a larger area to all customers connected to the grid. Therefore, grid capacity is usually planned according to the (at least) N-1 criterion, which means that the grid should be able to handle flows even if the largest grid component trips. This means that the grid is dimensioned so that even in peak load, if the grid is intact, load will not exceed the N-1 level. At this load level, pricing according to short run marginal costs (energy loss charge) does not reflect that the grid is actually at its capacity limit. If the situation is as depicted in Figure 3 and peak load is expected to grow, the capacity should be expanded according to the N-1 criterion.

If the (expected) total willingness to pay is lower than the cost of the capacity expansion, implementing some sort of scarcity pricing would increase the social welfare.

Figure 3: The impact of security margins



2.1.3 Efficient cost recovery in a natural monopoly

Efficient pricing of a natural monopoly market according to the marginal cost pricing principle is shown in Figure 4. In the figure, we have added fixed costs per unit of transmission, represented by the average cost curve. Due to large fixed costs and low variable costs (economies of scale), the average cost curve is decreasing with increased use of the grid. Without scarcity in transmission capacity, marginal losses in the transmission grid represent the marginal costs of using the grid. Grid losses increase exponentially when the capacity utilization increases, thus, the short-run marginal cost curve is linearly increasing (THEMA, 2017a).

Since the average cost is higher than marginal costs for all levels of transmission, the efficient short-term price p^{MC} does not yield full cost recovery, as shown in Figure 5. The uncovered costs are represented by the shaded rectangle. If total grid costs are to be recovered through a uniform energy charge, the price must be set at p^{AC}, as shown in Figure 5. Such pricing will however lead to an efficiency loss, equal to the yellow triangle in the figure. The efficiency loss accrues because the capacity utilization could increase, thus providing increased benefits to users, at a lower cost than the consumers' willingness to pay. Average pricing thus distorts customers' use of the grid, the capacity will be under-utilized. The size of the efficiency loss depends on the elasticity of the demand (slope of the demand curve).

Figure 4: Efficient short-term marginal pricing does not recover total costs

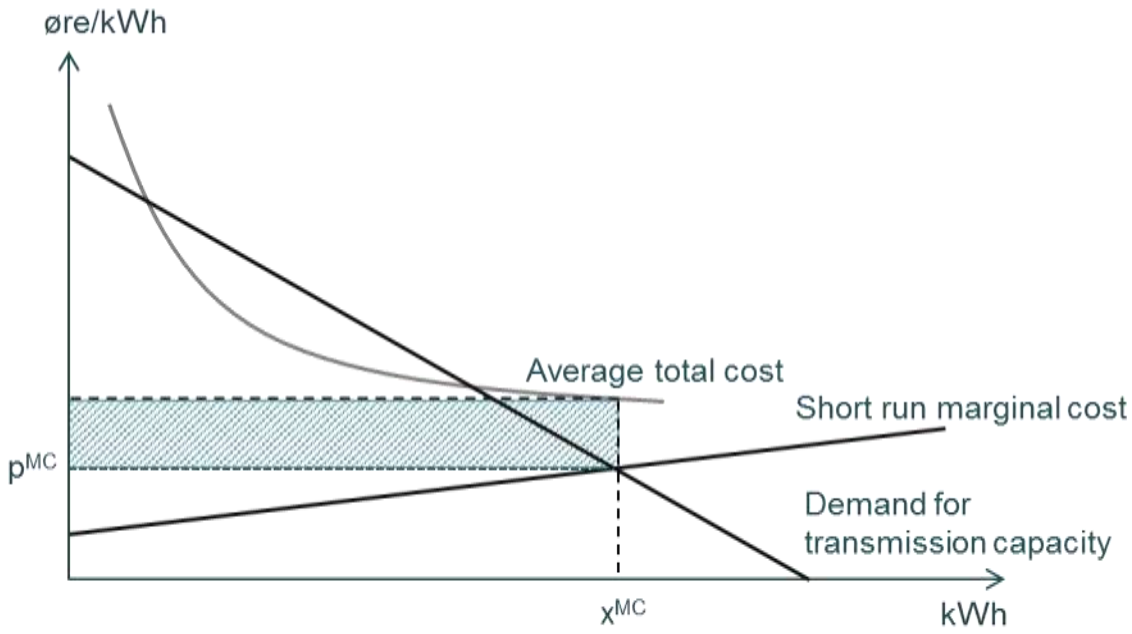
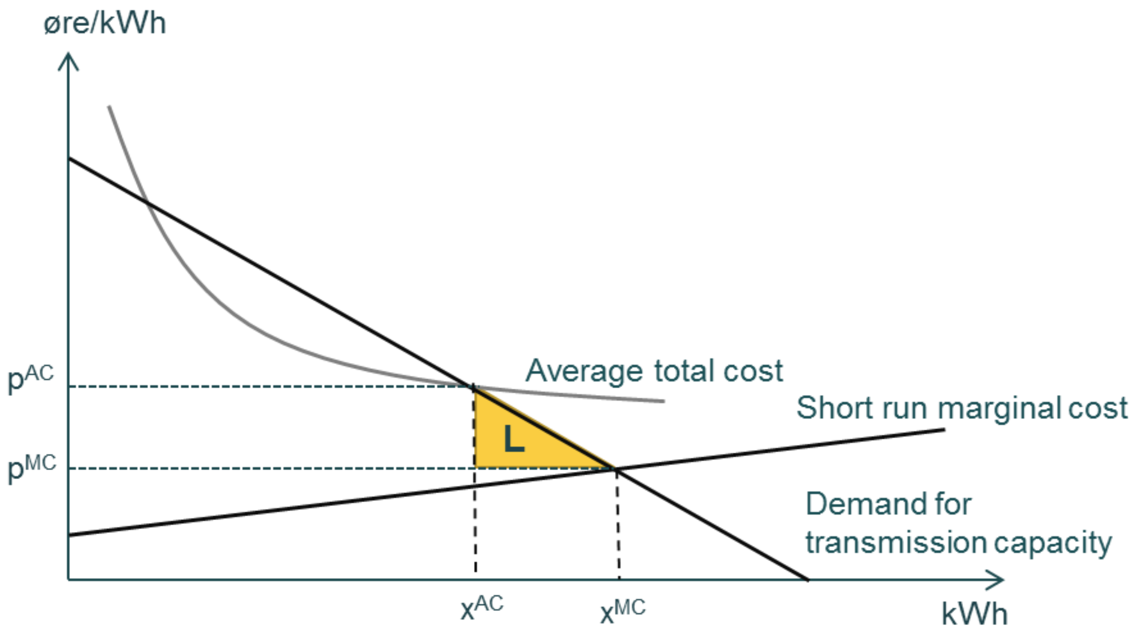


Figure 5: Average pricing yields an efficiency loss



In a natural monopoly, efficient short-term tariffs will not cover total grid costs, as illustrated in Figure 5. Tariffs that yield efficient short-term price signals only cover a share of the total grid costs, and there is still a residual need for income to recover total costs.

As long as the grid is to be fully funded by the grid customers, other tariff elements should cover residual costs, and these tariff elements should be designed so as to not affect the short-term utilization of the grid, they should be *neutral*. The theoretical ideal for recovery of residual costs is

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lump-sum pricing, which implies charges that are independent of the customers' use of the grid. Lump-sum pricing is however difficult to achieve in practice, for several reasons. Both random fixed charges and equal fixed charges would have distributional effects that would probably not be perceived as just. Random fixed charges would also increase the uncertainty for investors and as such increase costs. And even fixed charges would incentivize some users to go off-grid if possible, which is not efficient as long as they have a willingness to pay for transmission that exceeds marginal costs.

Unless the residual costs are recovered through lump-sum charges, efficiency losses will occur. The reason is that imposing fixed charges related the customers' grid use, distorts their economic decisions. When recovering residual costs, the goal should be to minimize distortions of the customers behaviour. The challenge is a general taxation problem. Residual costs in the transmission grid could be financed through general taxation similar to other infrastructure and public services provide by the government. However, general taxation also comes with an efficiency loss.

The general rule from taxation theory is that taxes should be differentiated according to the elasticity of tax objects, in order to minimize the total efficiency loss, so-called Ramsey pricing.

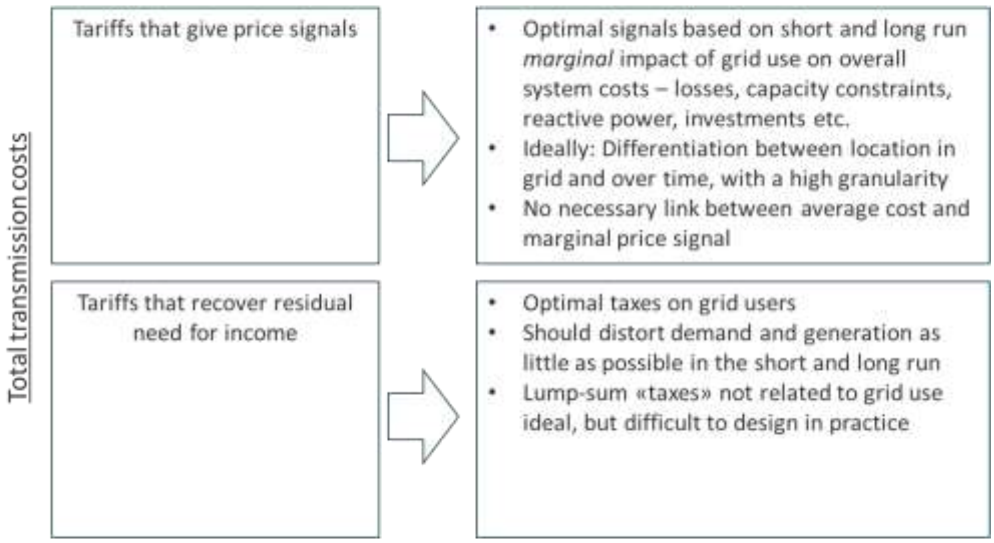
2.2 Overview of tariff elements and principles

Both residual and variable costs in the grid are covered through tariffs. As the transmission grid is a natural monopoly, marginal costs are lower than average costs. Consequently, as described above, efficient variable tariff charges do not recover the total grid costs. The share of total costs not covered by efficient price elements are called residual costs. Residual costs cannot be traced to a specific customer or recovered through efficient price elements. Residual costs represent a large share of total grid costs.

The figure below gives an overview of the main elements in grid tariffs. The first step in tariff design is to identify and define the need for short and long-term price signals and to design the corresponding tariff elements. Short-term price signals should incentivize efficient utilization of grid capacity. Short-term price signals also yield long-term price signals but may not be sufficient to incentivize efficient investment behavior, in which case additional price signals should be developed. The final step is to identify the residual need for income and decide the allocation between the customers using the grid.

Figure 6 shows the different principles for the design of tariff elements with different objectives, i.e. tariff elements aimed at providing price signals and tariff elements aimed at recovering residual costs.

Figure 6: Main elements and principles in grid tariff design



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In general, the grid tariff should yield price signals to both generators and consumers that reflect their impact on grid costs. Tariffs that gives price signals should reflect the short and long run marginal impact of grid use. The main relevant cost elements include:

- Marginal losses: All grid users should be exposed to the short-term marginal cost of the transmission grid via energy charges which reflect the change in energy losses due to changes in that customer's injection into or withdrawal from the grid.
- Customer-specific connection costs: To the extent that connection of a new customer or an increase in the demand from one customer implies investments in the grid that are only used by that customer, the cost should be levied on that customer.
- Marginal investment costs: Changes in injection and withdrawal affect medium- and long-term grid costs (investments). A bottleneck in the grid may be handled by grid investments or relocation of supply or demand. Investments and relocation are long-term decisions made by grid customers. When it is cheaper to invest in or relocate generation or consumption than to strengthen the grid, it is useful to apply prices that signal the value of such investments and relocation via the grid tariff, i.e. to provide a long-term locational signal. Ideally, such price signals should be differentiated geographically and over time.
- Residual costs: The residual cost is calculated as the difference between total grid costs and the revenues accruing from efficient pricing via the other tariff elements described above. It is not directly related to specific cost elements in the grid.

The optimal tariff design also depends on the market design, for example, the use of bidding zones. Ideally, the market should be divided into bidding zones that reflect transmission capacity constraints as accurately as possible. Zonal pricing implies that all customers within a bidding zone see the same price, both existing and new customers. Exposing all customers who are subject to the same constraints to the same price signal is one of the basic principles for efficient tariff design.

In the following sections, we elaborate on the application of the basic principles to grid tariffing.

2.3 Tariffs that provide price signals

The variable costs in the transmission grid are (mainly) energy losses. Users of the grid should therefore pay charges reflecting the marginal losses in order to make sure that their willingness to pay for the marginal unit transmitted is at least as high as the cost of the marginal energy loss.

Long-term costs are determined by the grid customers' decisions when it comes to investments in capacity and the location of capacity. Hence, it is desirable that the grid customers are exposed to price signals reflecting how marginal grid costs are affected by their investment decisions.

As we have seen above, two basic principles apply to price signals: That they reflect marginal costs and that existing and potential customers whose impact on grid costs are the same, are exposed to the same price signals. If customers face different prices for the same service, distortions and welfare losses result.

2.3.1 Short-term price signals

Energy charges

Optimal *use* of the grid is achieved by letting the price reflect the marginal cost of using the grid. Grid losses represent the largest share of variable grid costs. Grid losses occur as a natural phenomenon when electricity flows through the grid.

The losses increase exponentially with the utilization of the grid capacity. Marginal losses reflect by how much the losses in the system increase with a marginal change in withdrawal or injection in each point of the grid. The marginal loss factor is affected equally by a marginal increase in injection and a marginal reduction in withdrawal. Since the capacity utilization in different parts of the grid and the energy balance in each node varies over time, so does the marginal loss factor.

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The cost of the losses is equal to the value of the energy that is actually being lost. Efficient pricing of energy losses require that losses are charged according to the loss factor and the relevant market prices. The cost of energy losses should hence be covered through an energy charge that depends on the marginal losses in the specific node and the electricity price in the relevant bidding zone, which changes over time.

This way, the charge incentivizes optimal use of the grid. It also gives a long-term signal that electricity is worth more in some places and in some periods than in others.

Marginal losses are larger than the average losses. This implies that the energy charge based on the marginal losses is likely to cover some of the residual costs in addition to the average cost of energy losses (cf. previous section).

Congestion revenues and costs

System operators also have to manage congestions in the grid in everyday operations. Congestions occur when the transmission capacity between (some) nodes is not sufficient to accommodate the flow corresponding to generation and consumption.[1] Congestions may be managed by redispatch, by bidding zones or by nodal pricing. If congestions are managed by redispatch, the system operator incurs a cost as generators and consumers must be paid to change their generation or load.

In the case of congestions, pricing equal to the marginal cost of transferring electricity (energy losses) will yield larger demand for transmission than what the grid is capable of. Congestions could in principle be charged through a capacity element in the grid tariff, reflecting the scarcity of transferring capacity and so that the demand for transmission is reduced in the problem area. The most efficient way of managing congestions is however to let the price vary between price areas. Price variations signals surplus and deficit areas to the market actors, and provide congestion revenues to the system operator, in addition to information of the marginal social values of expanding the grid capacity (THEMA, 2017a).

Nodal pricing is the theoretical ideal solution, in which marginal losses and grid congestions are reflected in the prices in each node (Schweppe et al., 1988, is a key reference for this theory). A lower price will be established in nodes with power surplus, and opposite (given that there are congestions). This gives the market players continuous signals of capacity scarcity and will contribute to an optimal allocation of production and generation.

Bidding zone delimitation implies that several nodes have the same price, but that congestion between zones are reflected in market prices. Congestions within zones must be managed by redispatch.

While redispatch represents a cost to the system operator, nodal pricing and bidding zones provide congestion revenues for the TSO. Thus, nodal pricing and bidding zones incentivize more efficient use of grid capacity in the short term and also reflect the value of increasing grid capacity between nodes or bidding zones.

Redispatch costs increase the residual costs, while congestion rents reduce residual costs.

2.3.2 Medium- and long-term price signals

The largest cost component in the grid is capital costs, related to investments in grid capacity, including reinvestment to maintain the existing grid capacity. We may distinguish between medium-term investments and long-term investments. By medium-term investments, we refer to investments that depend to a large extent on the existing grid configuration. In the medium term, the impact of

[1] Congestion implies that all of the grid is not dimensioned according to the N-1 criterion in all situations. Congestion management is an alternative to grid expansion and is efficient in the long run if the willingness to pay for grid expansion is deemed to low compared to the cost. In the operation of the grid, congestion management generally observes the N-1 criterion, however.

changes in withdrawal and injection patterns on grid investments depend on the location of the node in whidh withdrawal and injections change. In the long-term, however, increased injection and withdrawal imply that the dimensioning of the entire grid must increase. The different time-frames are to some extent artificial, because both dynamics take place at the same time. In tariff terms, the distinction is relevant because in the mid-term, the need for investments in the grid may differ substantially depending on the location of supply and demand within the existing grid. Changes in injection and withdrawal can even reduce investments in the grid, by counteracting congestions. In the longer term, however, the very decision to consume or produce electricity affects grid costs; sooner or later, grid investments will be needed, and will be affected by the choices made by grid users, mainly the maximum capacity, flexibility and load patterns. The reasoning applies both to "new" investments and reinvestment in the grid – when reinvestments are due, the TSO must also decide wether to invest in the same capacity, reduce the capacity, or increase the capacity, depending on developments in power supply and demand.

General capacity charging

The long-term *dimensioning* of the grid depends on the development of maximum load on different grid elements. In a meshed grid, changes in load typically affect load in all parts of the grid. When generation and load increase over time, the demand for capacity expansion increases as well. The impact of a customer on long-term costs also depends on the investment criteria of the grid owner. If the grid owner is obliged to guarantee a certain capacity for all customers connected to the grid at any time, the connection of one more grid customer typically implies a higher long-term grid costs than if the dimensioning of the grid takes into account that different customers have different load patterns.

It is important to emphasize, however, that the demand for transmission capacity is not mainly determined by the *energy* that is injected or withdrawn over time, for example during a year, but by the maximum load in the system. Moreover, it is not the maximum load of individual customers that is decisive, but total peak load. It is therefore desirable to provide long-term incentives that are linked to the contributions to system load in system peak hours. It should however be noted that the dimensioning of the grid is not solely linked to system peak load (typically defined as the maximum electricity consumption during a year). The distribution of generation and consumption, and generation and consumption patterns also play a role. It may well be that some grid elements experience peak load in other hours than in system peak load. Still, it seems reasonable to assume that peak load in most parts of the system is highly correlated with system peak load.

Due to the lumpiness of investments and the need for capacity margins in the grid, short-term price signals from loss components and bidding zones will not fully reflect the cost of grid development associated with an increase in injection or withdrawal by grid customers. Exposing grid customers to a long-term price signal that reflects the long-term marginal cost of grid expansion, is therefore likely to be beneficial. Such a price element will also reduce the residual cost.

Such an element should be differentiated between injection and withdrawal and be linked to the capacity need of the grid user in system peak load (dimensioning hours). The purpose of such a tariff element would be to signal the long-term cost of grid investments in an efficient manner, i.e. it should promote the right trade-off between grid investments and investments in generation or supply. Therefore, it should be linked to parameters that impact *investments* in the grid. A tariff element that reduces the installed capacity for injection and/or withdrawal or the utilization of such installed capacity without impacting grid investments, would represent a loss of economic welfare for the system as a whole. The rationale for such a tariff element is that efficient short-term pricing does not efficiently reflect expansion costs in the grid (scarcity), mainly due to security of supply concerns and the fact that the grid is typically developed with ample security margins (more below). As such, this element can also be thought of as a payment for public good services provided by the grid, such as security of supply.

Charges reflecting long-term marginal grid costs should be designed to affect investment decisions, but should not affect the short-term decisions of grid customers. Thus, the long-term signal should

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be related to periods with maximum load in the grid (dimensioning hours) and should not affect the use of the grid when there is idle capacity in the grid, to avoid underutilization.

One needs to differentiate between the general impact on grid investments and the impact on grid investments that depends on location. As with energy losses, however, the impact of injection and withdrawal in a given point will typically have opposite effects on grid investments. We discuss locational signals in the next section.

The purpose of a *general capacity element* representing the long-term marginal cost of grid expansion is to signal that *any* connection to the grid implies grid costs in the very long run. In theory, and in a long-term optimal situation, all changes in withdrawals and injections are likely to affect grid costs. A general capacity element would imply that *all grid customers* are subject to a tariff component reflecting that their connection is likely to imply grid costs in the long run. It could be thought of as an opportunity cost of the grid capacity they occupy and should be linked to the probable impact on the dimensioning of the grid.

Discounts for interruptible consumption

Security of supply and sufficient capacity margins do not always have to be secured by expansion of grid capacity. Some grid customers may have an ability and a willingness to reduce their demand for transmission capacity in times of system stress. Such customers should react to changes in market prices, and may also be willing to alleviate grid congestions, thereby allowing for lower capacity margins in the grid. By doing so, these customers reduce the investment need in the grid, and should be compensated accordingly.

For example, grid customers with a low willingness to pay for grid use may be willing to enter into contracts implying that they can be disconnected from the grid in times of scarcity (bottlenecks in the grid). One may therefore argue that such customers do not impact investments in grid capacity and should be exempt from capacity charges altogether. The same principle may be applied to flexible consumers in general; as long as they face adequate price signals, they are unlikely to burden the grid in times of scarcity. Again, exemption should be linked to their impact on actual investment decisions.

The Norwegian TSO, Statnett, applies contracts for interruptible load as part of their congestion management. These contracts are typically made with consumers in the regional or distribution grids. Such contracts are also explicitly used to reduce or postpone grid expansions in regional and distribution grids. If interruptible contracts imply that grid costs can be avoided or postponed, customers on such contracts should be exempt for the relevant capacity charge according to their interruptible load. Interruptible load contracts will typically be related to grid investments in the medium term. Thus rebates should be made in the differentiated capacity charge, not in the general capacity charge.

Locational signals

The way in which new and existing customers in the grid affect grid investment costs varies according to the location of the customer. For example, a generator locating in a deficit area may reduce grid investment costs (in the short and medium run) while new consumption in the same area may trigger substantial grid investments.[2] Moreover, the impact on grid investment costs does not only depend on the local capacity balance but is likely to affect flows in larger parts of the grid as well. It is therefore likely to be efficient to provide locational signals reflecting such differences through the grid tariff.

Several tariff features may provide incentives when it comes to the location of investments in generation and consumption:

- Connection charges reflect the cost of connecting new demand for transmission capacity to the grid (be it by injection or withdrawal). Connection charges strictly limited to customer-specific

[2] The impact also depends on the profile of generation and load.

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grid elements are not differentiated according to the connection point in the grid. Deep connection charges should however capture at least some of the impact on investment costs in the meshed grid.

- Energy charges (cf. above) reflecting marginal losses also provide incentives for efficient location as energy losses are highly correlated with capacity utilization and thereby bottlenecks in the system. Nodal energy loss factors should reflect the impact on total energy losses in the grid.
- Bidding zones (or nodal pricing) reflect capacity constraints between zones (or nodes) and as such incentivize location in high-price areas (deficit areas) for generation and low-price areas (surplus areas) for consumption. Bidding zones and congestions therefore represent a capacity charge if there is a bottleneck between zones (or nodes) and provide locational signals that relieve grid constraints and thereby reduce the need for grid investments.

Deep connection charges

The grid tariffs should not only reflect the short-term costs the customers inflict on the grid, but also the long-term costs. This includes the investments needed to connect the customer to the grid. Charges to cover such customer-specific one-off costs are called connection charges.

Connection charges can be *deep* or *shallow*, depending on how the customer is charged to be connected to the grid. Shallow connection charges only include strictly customer-specific connection costs, such as the line connecting the customer to the nearest substation in the grid, provided that that line cannot be used by other grid customers. Deep connection charges also include other costs, such as reinforcements in the meshed grid that may subsequently benefit other grid customers.

In principle, connection charges should only cover investment costs that are specific to the customer. When it comes to investments in the meshed grid (deep investments), the charge is usually levied on the customer that “triggers” the increased investment. For example, the first customer in an area may be charged with the full cost of the connection capacity although it will not use the whole capacity. If subsequently another customer wants to connect via the same connection, this customer will not be charged the extra cost. The result may be that the first customer does not connect because the connection charge is higher than its willingness to pay. Then the next customer is the “first” customer, which may also not have sufficient willingness to pay the full cost of the connection. The connection may however be socially beneficial if the sum of both customers’ willingness to pay is sufficient to pay for the connection, and thus, it should be built. If the connection is built and a third customer wants to connect, and the capacity is not sufficient to accommodate all three customers, the capacity needs to be expanded and the third customer is charged with the expansion cost. Now, if the willingness to pay of the third customer is not sufficient to pay for the expansion, it will not connect. If however, the third customer’s willingness to pay is higher than the willingness to pay of the existing customers, it would be beneficial that the third customer replaces the existing customer with the lowest willingness to pay. In total, this would increase the net social benefit of the connection.

The first-come, first-serve solution where the timing of connection determines the connection charge of individual customers is not socially optimal. Instead, a mechanism should be implemented that ensures that the customers with the highest willingness to pay get access to the capacity (cf. Figure 2: above). One might for example imagine a second-hand market for capacity, where the new entrant pays an existing grid customer to yield. If new entrants have a higher willingness to pay for access than incumbents, they should be able to negotiate a price that is beneficial for both. The solution would also increase social welfare within the given available capacity.

An alternative, and more efficient solution, would be to expose all grid customers in a specific node to a tariff element reflecting marginal investment costs associated with location in that node. This includes customers who are already connected. Optimal tariffs are equal for all customers and should reflect the marginal cost of capacity expansion. Who causes the expansion has nothing to do with when the customer is being connected, but the one who is on the margin (the customer with the lowest willingness to pay).

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Exposing all customers to the location-specific long-term marginal cost of grid connection would achieve some of the same feature as the second-hand market, but also deter entrants with a low willingness to pay to locate in that node in the first place.

Unlike the general capacity charge, which is very long-term, a node-specific capacity charge should reflect the more medium-term expected impact on grid costs.

Brunekreeft et.al. (2005) argue that upgrades often take account of indivisibilities to over-build ahead of future demand and ask what fraction of the cost is attributable to the present connection. If capacity is typically oversized because of the asymmetry in cost of under or over-building, is it reasonable to charge this general security benefit to the new entrant? They argue that if there are benefits to encouraging entry to mitigate market power, then deep connection charges discriminate against entry (and additional generation capacity) and lose some of their attraction. Hence, they conclude that shallow charges promote new entry. We would correspondingly argue that a locational element applying to all customers is preferable to deep connection charges. Deep connection charges discriminate new entrants (von der Fehr, 2017).

Bidding zones

Bidding zones also provide important price signals for efficient location of generation and consumption (Statnett, 2017). Bidding zones also contribute to reveal information about the need for investments in the grid.

Bidding zone delimitation implies that the value of expanding the transmission capacity between bidding zones is reflected in market prices. The congestion rent can therefore be regarded as a capacity charge when there is a congestion between the bidding zones. Generators in the surplus area “pay” the capacity charge through the lower market price, while generators in the deficit area “receive” the capacity charge through the higher market price. Higher and lower prices refer to the common price without the congestion.

As such, area prices provide a locational signal; all else equal, an investor should prefer to invest in generation located in the deficit area. The price signal may be muted for two reasons, however:

- The transmission capacity will typically be expanded before zonal price differences fully reflect the value of grid expansion due to security of supply concerns, and due to the lumpiness of grid investments.
- Once new generation is established in the deficit area, prices will fall, and the generator will not reap the full benefit of locating generation in that area. Most of the welfare economic benefit will accrue to the consumers in the area who now face lower prices.

Dividing the market into bidding zones gives better short-term price signals than tariffs and redispatch. One reason is that zonal prices will dynamically reflect changes in market conditions and grid flows. Another is that congestions would otherwise have to be managed by redispatch. In the absence of bidding zones, all customers face the same price regardless of their location, and the system operator must pay customers to change their injection or withdrawal plans in order to relieve the congestion. When redispatch is applied, most customers do not face the “capacity charge” represented by the price difference (congestion rent). Thus, all consumers in the price area are not exposed to the same price signals or incentives although all are subject to the same constraint.

When the system operator applies redispatch, the TSO’s congestion revenues are negative. Costs related to the system operator handling congestions (e.g. markets for reservation and activiation of frequency restoration reserves) represent negative congestion revenues for the system operator. In principle, the cost of congestion management is the same in the short term, but the distributional effects are different and so are the incentives and the long-term cost effects. In addition, congestion revenues reduce the residual income need while redispatch increases it.

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Locational capacity charges

As demonstrated by the discussion above, energy charges, connection charges and zonal prices typically provide rather weak locational signals. Price signals provided by energy loss charges and bidding zone delimitation are muted by security of supply concerns and the lumpiness of investments, and even deep connection charges, as they are usually implemented, are likely to provide largely random incentives.

Thus, locational signals in addition to the signals provided by energy charges and zonal prices are merited. The additional locational signals should be linked to the impact of location of generation and consumption in different nodes. These price signals are about incentivizing location of generation and consumption in the areas of the grid where the location implies the lowest grid investment costs. Thus, the locational charge, unlike the general capacity charge should take the existing grid configuration into account. Efficient locational signals could be negative for consumption locating in surplus areas and for generation locating in deficit areas.

Locational capacity charges should ideally be based on flow analysis of the impact of changes in injection in withdrawal in each node.

Deep connection charges, depending on how deep they are, serve some of the same function as locational capacity charges. This means that if deep connection charges are applied, locational capacity charges should be modified accordingly. If deep connection charges are perfect, in the sense that they capture the impact of the connection on the entire grid costs, other locational signals should not be implemented in the tariff. Even perfect deep connection charges would still violate the principle that all grid customers should be exposed to the same price signal, however.

The locational tariff should moreover be adjusted for the price signals provided by energy charges and congestion revenues.

Reactive power

Reactive power is important to maintain a constant voltage level in the grid. In high load there is generally a need for injection of reactive power while in low load, there is a need for withdrawal of reactive power. In addition, reactive power needs to be provided locally. Correspondingly, injection of reactive power in low load and withdrawal in high load imply increased system costs.

Reactive power is either generated or absorbed by electric generators and this ability is often mandatory (required in the connection agreement). Provision of reactive power reduces generators' ability to generate active power. Thus, provision of reactive power comes at a cost. If different generators contribute differently to the stabilization of reactive power, i.e., are exposed to different requirements by the TSO, provision or absorption of reactive power should be compensated. Such compensation should reflect the value or cost of reactive power in the grid. If provisions of reactive power are insufficient, the TSOs may need to invest in devices in the grid that provides reactive power services or purchase reactive power services from generators.

A tariff for reactive power should reflect the actual costs that reactive power inflicts on the system. The benefits should be weighed against the costs – administrative costs in the TSO and among grid customers and take account of the extent to which pricing of reactive effect lowers total costs in the long run.

2.4 Residual charges

As explained, due to the cost structure of the grid there is a residual need for income to recover total grid costs. Provided that price signals reflect both short and long run marginal grid costs, residual tariffs should not additionally affect capacity utilization, connection or investments in generation and consumption. The principle for residual charges is that they should not affect the grid users' behavior, i.e. exactly opposite of the principle for efficient energy and capacity charges.

In the following, we discuss how to collect the residual costs with minimum efficiency losses.

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Design of residual tariffs

As explained in section 2.1.3, it is difficult in practice to design residual or fixed tariff elements that are not to some extent linked to the grid customers use of the grid, i.e., the energy transmitted or the capacity used. Such elements distort the grid customers use of the grid and imply a welfare loss:

- Residual charges levied on energy consumption (per kWh) will distort customers' energy use and overly incentivize consumers' energy savings or substitution to other energy sources and generators' short run generation costs.
- Residual charges levied on (maximum) per MW capacity utilization will distort injection and withdrawal from the grid in the customers' peak load. Thus, such charges may distort generation and load decisions.

Therefore, the basis for residual tariffs should be chosen so as not to affect the short-term behaviour of the grid customers. Residual charges related to average energy consumption over a prolonged period of time (5-10 years) would for example not impact the day-to-day production decisions of generators.

Rresidual charges, even if they are neutral towards short-term decisions, do imply a long-term cost that grid users are likely to take into account when they make investment decisions. Therefore, the distribution of residual charges between generators and consumers and among generators and among consumers is likely to have long-term efficiency implications.

According to general taxation theory, the efficiency losses related to residual charges may be minimized by applying Ramsey pricing. Ramsey pricing implies that the residual costs for a service are allocated among users according to their price elasticity. The higher the price elasticity, the lower is the share that the user should pay, and vice versa. Allocation of residual costs according to this principle will minimize the distortive effects on the total utilization and investments in the grid.

The price elasticity of a user depends on the alternatives he or she has. To illustrate, it is reasonable to expect that the electricity demand for heating is relatively elastic due to the existence of alternative heating solutions and energy efficiency measures, while electricity for lighting or electric devices is less elastic. The elasticity of businesses and industry depends on the share of electricity costs and to what extent their competitors are exposed to the same cost elements.

Price elasticity is a measure of how much the market actors respond to a price change. It is expressed in percentage terms. Demand is for example deemed to be inelastic if the response to a 1 percent increase in prices is less than a 1 percent reduction in the consumption of the good (for a given income and fixed prices on other goods). Price elasticities will vary among consumers and among generators, they may vary over time, and they typically vary along the supply and demand curves.

In theory, perfect Ramsey pricing implies that charges should be differentiated among all users of the grid according to their price elasticity. Such a tariff model is not practical for obvious reasons. Moreover, price elasticities are not easy to estimate, and they change over time. In practice, it should however be possible to assess relative price elasticities between different grid customers as a basis for differentiation, and by that, reduce the efficiency loss related to residual cost recovery. It is also a question whether Ramsey pricing meets the general criteria for objective and non-discriminating network tariffs. At the same time, we observe that several countries apply special tariff arrangements that are consistent with a Ramsey pricing approach in the sense that large industrial users with an assumed high price elasticity pay smaller tariffs per kW and/or kWh (e.g. Germany, France and Poland, cf. the appendix and THEMA, 2018). We do not discuss this issue further in this report, but note that the question of tariff differentiation based on price elasticity should also be reviewed from a legal perspective.

Split between generation and consumption

It is not obvious how residual tariffs should be split between generators and consumers, or whether the split matters when it comes to who bears the cost in the end. If, for example, the charge is levied

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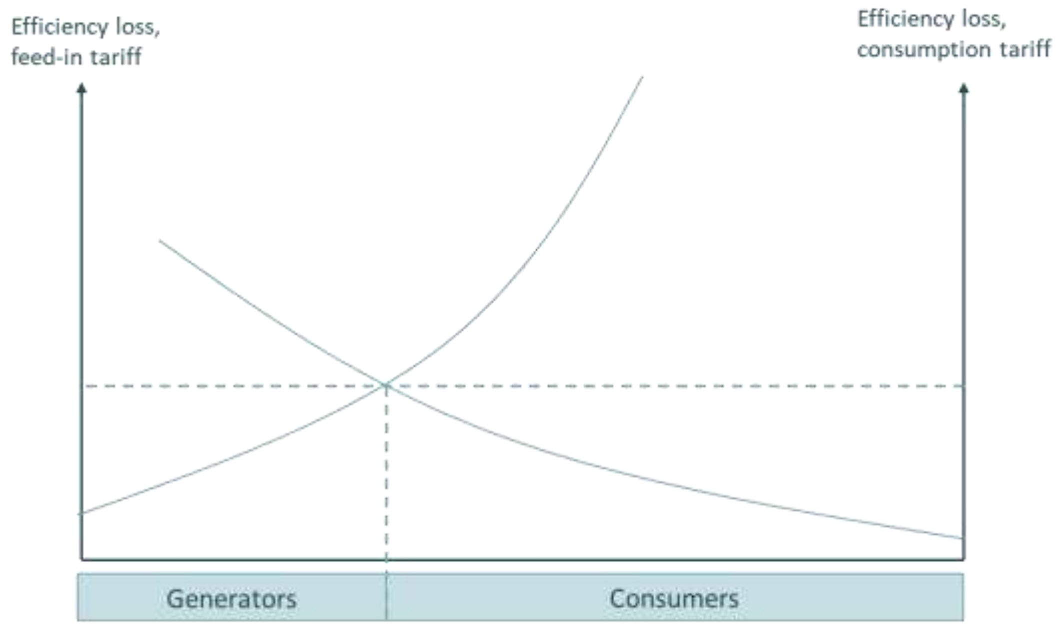
on *all* generators, they will incorporate the cost in their bidding and/or investment decisions, and the consumers will ultimately bear the cost. Although perhaps considered as unfair, applying residual costs directly on consumers (only) may therefore not actually imply higher consumer costs. When assessing the split between generators and consumers in the Swedish grid, the interconnectivity with other markets should however be taken into account.

According to von der Fehr (2017), by levying residual charges on consumers, distortions between different production technologies can be avoided. As generators compete in an interconnected international market, levying residual costs on generators in one TSO area will reduce their competitiveness towards generators in other TSO areas if residual costs are not levied on generators in the other areas. And even if residual costs are levied on generators in other areas according to harmonized principles, the charges are not likely to be uniform. The reason for this is that the residual costs will differ between TSO areas according to the specific grid configuration in that area. TSO areas are, with Germany as an exception, defined by national borders and not with regard to the distribution of grid costs.

In an interconnected system, where generators compete with generation in other grid areas (imports), higher generator tariffs (G-tariffs) in one area will distort competition among generators. Investors will be more likely to locate new generation in the area with the lower G-tariff (all else equal). The extent to which investments in generation are affected by the tariff reflects the elasticity of generation to the residual tariff. Similarly, large consumers are also likely to take total tariff costs into account when deciding where to locate production facilities. When it comes to smaller consumers (small businesses and households) residual tariffs can affect their choice of energy sources, e.g. heating solutions and the installation of local solar panels. The fact is, that residual tariffs affect the total cost of using electricity, therefore, both generation and consumption are likely to be somewhat price elastic.

Given that residual charges are likely to imply efficiency losses in whatever way they are allocated, the general principle should be that they should be allocated so that the total efficiency losses are minimized. Optimal cost allocation between generators and consumers then implies that the marginal efficiency loss of a change in the generator and consumer charges are equal (THEMA, 2017a). The relative elasticities are *inter alia* affected by the export surplus. The principle is illustrated in Figure 7.

Figure 7: Optimal allocation of residual charges between generators and consumers



Source: THEMA (2017)

Charges based on energy vs capacity

Should residual or fixed tariff elements be based on energy or capacity?

The European agency for energy regulators (ACER) recommends that energy charges should only be used to recover energy losses and ancillary services, and not to recover infrastructure costs in general. A tariff based on energy will increase the cost of generation and consumption of electricity and give rice to efficiency losses, as explained above.

A tariff based on actual *capacity utilization* will affect both short-term and long-term injection and withdrawal in the grid. A residual tariff based on a generator's *installed* capacity affects investment decisions and imply that peak-load prices increase in the long run – the marginal capacity investment will be costlier – while tariffs based on energy injection also imply higher total costs for generators but are likely increase prices in all prices marginally.

In the case of an energy-based tariff, it would be beneficial to apply a neutral measure of the basis for the energy charge. Rather than applying a per kWh charge, which may distort the incentives to generate, a fixed measure of the expected energy generation could be used, e.g., the expected or average energy production over several years. Similarly, residual charges applying to consumers should be designed as neutrally as possible.

Price sensitivity as criterion for differentiation between consumers

Price sensitivity of electricity demand is an appropriate criterion for differentiating the residual cost burden among consumers (THEMA, 2018). Distortions in behaviour will be minimized by giving consumption with elastic electricity demand low tariffs and consumption with inelastic electricity demand high tariffs.

One example of a group of consumers whose electricity demand is probably very elastic is power-intensive industry companies, because electricity costs constitute a high share of total costs and because they compete in global markets. Unlike most other cost elements, an increased grid tariff will not affect their competitors based in other countries.

The two figures below show how letting elastic demand pay a smaller price increases the utilization of the grid and lowers the average cost of the grid.

In Figure 8, we assume that all consumers pay a uniform residual tariff. The example is limited to residual costs (short-term marginal costs are covered through other charges), and it does not consider capacity expansions. We can therefore consider the impact of the residual tariff on economic efficiency in isolation. Furthermore, we consider two groups of demand, normal consumption (households, small businesses etc.) and large-scale consumption such as power-intensive industry. The demand from industry is more price sensitive, illustrated by the comparatively flat demand curve. The average price must be set to P' in order to cover the residual income need, given the resulting consumption levels per consumer category (Xpi and Xn) and the sum that equals X'. This level is significantly lower than the maximum capacity. The grid will not be fully utilized when Ramsey pricing is not applied to residual grid tariffs, leading to an economic loss (loss of consumer surplus).

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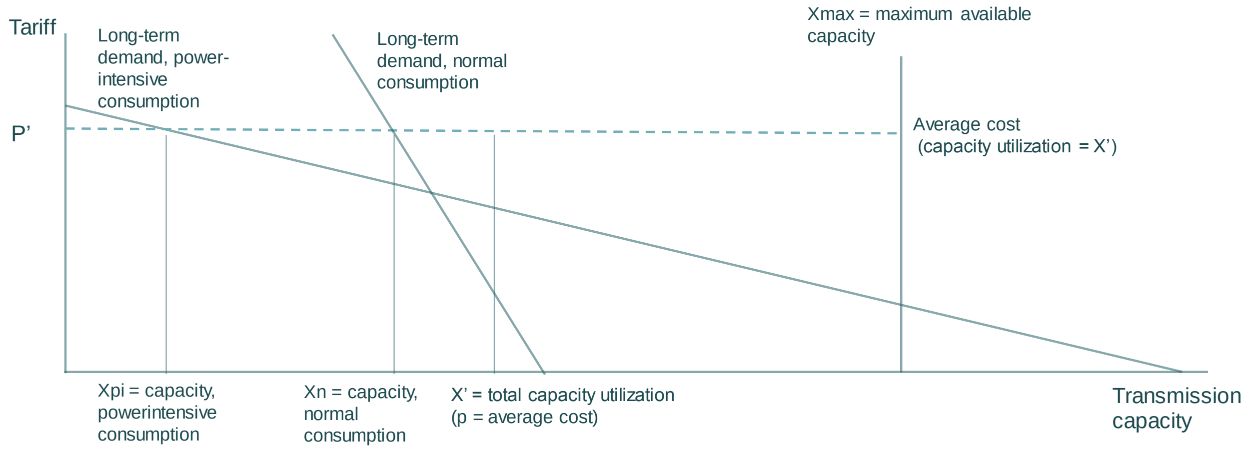
Figure 8: Average cost without price discrimination

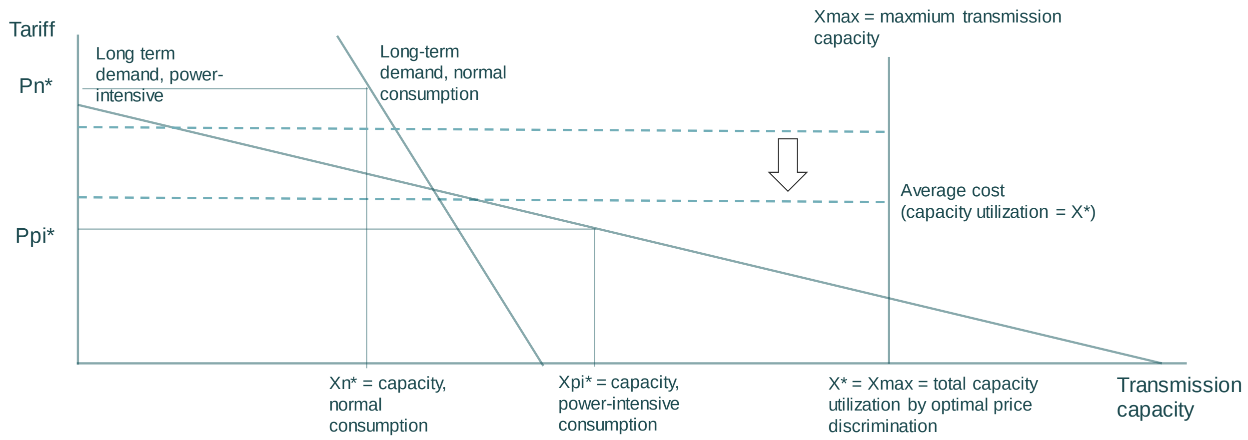


Source: THEMA (2018)

In Figure 9, we introduce the principle of price discrimination, i.e. we allow different residual tariffs for the two groups of consumers. If we set a lower price (than P') for power-intensive consumption, e.g. Ppi*, the consumption increases to Xpi*. As the demand curve is relatively flat, the consumption increase is large. Furthermore, let us assume that the price for normal consumption is increased to Pn*, resulting in a reduced consumption to Xn* compared to Xn in the previous figure. However, the reduction in the normal consumption group is relatively small. This follows from the steep demand curve, which means that the impact of a price increase on consumption is small.

In total, consumption is increased compared to the case with a uniform residual tariff. If we add the consumption levels of the two groups, the maximum utilization of available capacity is now equal to the economic optimum, i.e. Xmax = Xn* + Xpi*. Note also that the average tariff is reduced due to the higher capacity use. With a higher capacity use the tariff can be set at a lower level and still meet the revenue requirement. In the figure, this is illustrated by the area Xn* x Pn* + Xpi* x Ppi* (the total tariff revenues under optimal price discrimination) being equal to the area X' x P' (the total tariff revenues with a uniform price).

Figure 9: Average cost with price discrimination



Source: THEMA (2018)

The above theoretical analysis can be illustrated via empirically based examples as well. THEMA (2018)[3] studies the use of price sensitivity as a criterion for differentiating the grid tariff for consumers.

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[3] THEMA (2018): *Prisfølsomhet og effektiv utnyttelse og utvikling av nettet*. Commissioned by Statnett SF.

Electricity costs are seen as a whole where power and grid costs are equally important. We will here summarize two cases presented in this report; the effect of increased electricity costs for a data centre and aluminium production.

Aluminium producer

This case studies how increased electricity costs affect investment decisions in aluminium production. The average market value of aluminium is about 2,000 USD per tonne, which is about 16,000 NOK. Producing a tonne of aluminium uses electricity of about 13,000 to 15,000 kWh. A typical power price for an aluminium producer in Norway is 25 øre/kWh. Consuming 14,000 kWh then gives electricity costs of 3,500 NOK per tonne aluminium.

The case assumes that the income of 16,000 NOK per tonne aluminium gives a real before tax return on capital of 8 percent, given a life span of 20 years of the investment. Typically, the electricity costs amount to 40 percent of the total variable production costs. This equals an operating profit of 7,500 NOK per tonne aluminium, equal to the cash flow of servicing the project capital.

What happens if the electricity cost increases by 1 øre/kWh? Production costs increase by 140 NOK/tonne. This means that the profit falls from 8 to 7.75 percent. It is important to remember that the producer cannot mitigate risk like this through normal procedures of risk reduction. The increase also only affects producers in a local area. Based on these stylised examples, increases in electricity costs like this would seem likely to affect investment decisions, for example where to localize new investments, whether to reinvest in an existing production site etc. We also note the existence of special tariff schemes for power intensive industries in countries such as Norway, Germany, Poland and France (see appendix in THEMA, 2018) as a clear indicator that network costs affect investments in power intensive industries. An increase in the electricity cost of 4 øre/kWh results in a reduction of profits of one percentage point, down to 7 percent.

Data centre

Another example within the electricity intensive industry, are hyperscale data centres. These are mostly established and operated by international companies. One example is Facebook in Luleå. Using numbers from Menon (2017), the consequences of increased electricity costs are analysed in THEMA (2018). To build a data centre with three data halls has a total investment cost of 13.6 billion NOK. Assuming an average life span of 15 years, 8 percent real discount real before taxes, the yearly cost of capital amounts to 1,589 MNOK.

In total, the three data halls use 90 MW electricity annually. Assuming 8,760 hours and a power price of 25 øre/kWh, the yearly electricity cost is 197 MNOK. Other operating costs are estimated to 400 MNOK. Since the income needs to be equal to the sum of yearly capital- and operating costs, an income of 2,189 billion NOK is assumed.

If the power price increases by 1 øre/kWh, this results in a decrease in profit of 0.08 percentage points. The decrease is lower than in the example of the aluminium producer, because the electricity costs represents a smaller share of the total costs. An increase of 5 øre/kWh decreases profits by 0.33 percentage points. Changes like this should in theory be expected to have consequences for investment decisions, although the impact is likely smaller than for e.g. aluminium due to the lower electricity intensity of the production.

2.5 Conclusions: Criteria for assessment of tariffs

Based on the description of principles for efficient pricing above, we conclude with the following basic criteria for optimal grid tariffing:

- Individually levied connection charges should reflect customer-specific elements only.
- Energy charges should reflect short-term variable costs, i.e. the marginal value of energy losses in the grid.
- Efficient investment signals should be provided by a general capacity charge related to the marginal long-term marginal investment costs (non-locational).

- Efficient locational signals should reflect capacity constraints in the grid, i.e., the impact on medium-term investment costs, and should take into account the locational signals provided by congestion rents.
- Residual costs should be covered by separate tariff elements that do not affect short-term use of the grid.
- As perfectly neutral residual charges are not possible, residual costs should be allocated among grid customers based on relative elasticities in order to minimize total long-term efficiency losses.

These criteria form the basis for our assessment of the efficiency of the Swedish tariff in chapter 5. The elements and principles are summarized in Figure 10 below.

The left-hand bar in the figure shows the main cost elements in the grid. Variable costs are mainly energy losses. Capital costs are divided into location independent common investment costs, location dependent common investment costs, and customer specific investment costs. Since the grid is self-financed, the sum of tariff charges (middle bar) must cover total grid costs. The right-hand bar shows the principle for optimal tariff design. The color codes indicate the relationship between the cost elements and the tariff elements.

Energy charges should be applied according to marginal costs. Since marginal losses is an increasing function of load, energy charging according to the marginal cost principle should provide revenues that are higher than Svenska kraftnät's costs related to energy losses.

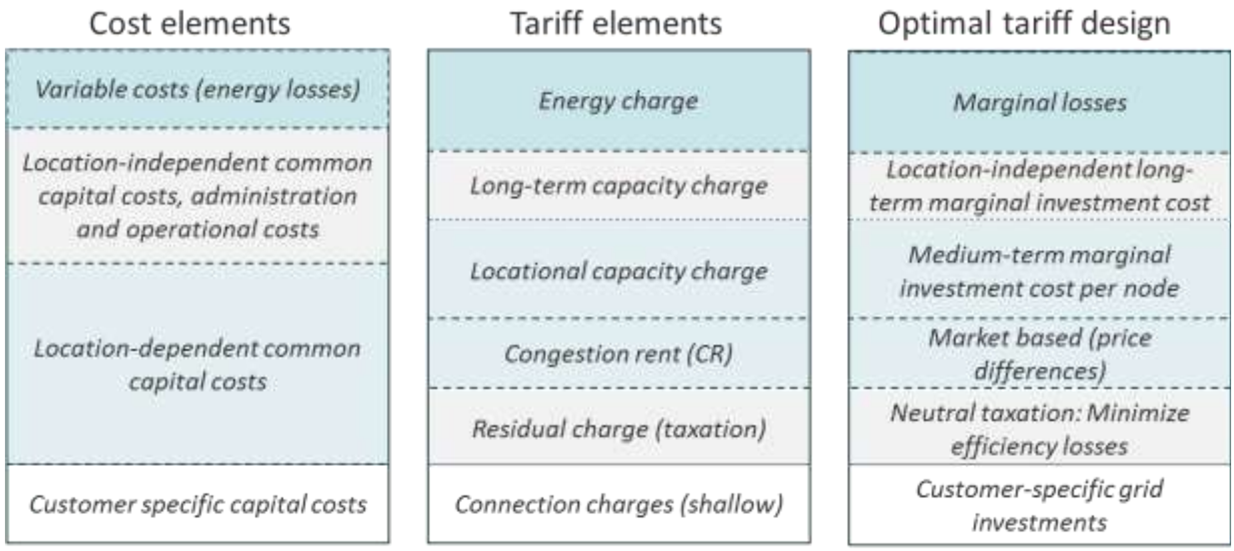
The long-term capacity charge is related to location-independent investment costs. The tariff design principle is that the charge should reflect the marginal long-term investments costs related to the increase in the demand for transmission capacity that is independent of where the new demand is located. Since marginal costs in the meshed grid are dimishing with increased capacity, this tariff element is likely to cover less than the total location-independent costs of Svenska kraftnät.

The same basic reasoning applies to location-dependent investment costs. Congestion rents express some of the location-specific long-term grid costs, the location-specific capacity charge should therefore provide an appropriate additional location signal. Since connection charges should strictly cover customer-specific costs, connection charges should be equal to the associated costs. Now the residual cost of the grid can be determined as total costs minus revenues from all the other tariff elements (including congestion rents).

The residual charge covers the common costs that are not covered by the tariff elements providing optimal short- and long-term price signals to grid customers.

We would like to emphasize that the elements are interrelated. For example, the issue of deep versus shallow connection charges is related to the existence of an efficient locational signal in the capacity charge. The main reason why we prefer a locational capacity charge to deep connection charges is that a locational charge imply that all grid customers are exposed to the same price and the same incentives.

Figure 10: Grid cost elements, tariff elements and principles for optimal design of tariff elements



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3 REVIEW OF CURRENT TARIFF DESIGNS IN OTHER COUNTRIES

Tariff designs in European countries differ significantly with respect to tariff elements, charging bases, locational signals and overall cost distribution between generators and load. In this chapter we provide an overview of current tariff designs in European countries. The countries chosen are those having interconnections to Sweden. In addition, we include Great Britain as the tariff model has some common features with the Swedish model, particularly the locational signals. The British model also includes tariffs for both generators and load.

We start by summarising the key features of the tariff models in the selected countries before reviewing some interesting aspects of the Norwegian and British tariff models that are particularly relevant to the discussion on the Swedish transmission tariff. We elaborate on the details of the tariff models in an appendix.

3.1 Overview of tariffs

Table 1 gives an overview of the main tariff elements in the countries we have studied. For reference, we also include connection charges as these are designed to fit with the overall tariff system and is part of the same legal framework in several of the countries surveyed.

Table 1: Overview of main tariff elements in selected countries[4]

Element	Denmark	Finland	Great Britain	Norway	Germany	Poland	Lithuania
Price signal related to losses	No	No	Yes	Yes	No	No	No
Bidding zones	Yes	No	No	Yes	No	No	No
Locational signals in tariffs	No	No	Yes	Yes	No	No	No
Both G and L tariffs	Yes, but small share of G	Yes	Yes	Yes	No	No	No
Accounting for other characteristics in L tariffs	No	No	No	Yes	Yes	Yes	No
Connection charges	Super shallow	Shallow	Shallow	Deep from 2019	Super shallow	Shallow	Deep
Reactive power tariff	No	Yes, if limits are exceeded	No	Yes, if consump-tion is detriment-tal to the system	Yes	Yes (excess consump-tion only)	Yes

Source: National TSOs, ENTSO-E

With the exception of Great Britain, the voltage level covered by transmission in all countries generally includes assets with a voltage higher than 100 kV. In Norway, 132 kV assets are part of the transmission grid in some places where these assets have the same functionality as the

[4] The categorization of connection charges is based on ENTSO-E (2018), and defined as follows:
«Super-shallow»: All costs are socialized via the tariff. The customer being connected to the grid is not charged.
«Shallow»: Customers only pay for the necessary infrastructure connecting them to the transmission grid.
«Deep»: Customers pay for the infrastructure connecting them to the transmission grid ("shallow") in addition to all other necessary reinforcements and expansions of the existing grid related to the specific customer being connected.

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transmission grid. As can be seen from the table, only Norway and GB have a price signal related to transmission losses in the tariff model. These countries are also the only ones with locational signals in the tariffs. G-tariffs are used in the Nordics and GB. Bidding zones are not generally used within countries, except Denmark and Norway. Germany, Norway and Poland differentiate consumer tariffs according to different criteria such as size, stability of consumption, and the electricity intensity of production processes. Finally, the connection charging models vary significantly.

In Table 2, we summarise the main elements of the tariff models in the selected countries and the estimated Unit Transmission Tariff according to ENTSO-E data (ENTSO-E, 2018). The unit transmission tariff includes generator charges where those are applicable and builds on several assumptions that make direct comparison of tariff levels for different customer groups difficult. However, the Unit Transmission Tariff gives an indication of the overall transmission cost levels in the selected countries. We also include the numbers for Sweden for easy reference. The numbers do not include non-TSO costs such as policy support costs that are paid as part of the transmission tariff.

Table 2: Unit transmission tariff (EUR/MWh) and share of Unit Transmission Tariff paid through power (capacity) charges. 2018

Element	Denmark	Finland	Great Britain	Norway	Germany	Poland	Lithuania	Sweden
Unit tariff	11.05	5.78	13.48	5.71	18.49	7.19	14.09	3.08
Share of power charges	0.0%	6.7%	80.4%	68.0%	83.0%	46.7%	72.4%	78.0%

Source: ENTSO-E

3.2 Case study: Norway

3.2.1 Features of the electricity system

Norway is a long narrow country with generation largely located in the north, west and south, and the large consumption areas mainly in the south east. Some areas in other parts of Norway have high industrial electricity consumption however. In some areas the grid is highly meshed, while in others it is characterized by long lines and structural bottlenecks. The generation is dominated by hydro, with an increasing share of wind power in recent years.The dominance of weather-dependent hydro generation implies that flows can differ significantly between seasons and between years, depending on precipitation. Being such a outstretched country, there is not necessarily a high correlation between areas when it comes to wet and dry years. Statnett is the transmission system operator for the entire Norwegian transmission grid.

Currently there are five bidding zones within Norway. Statnett may define bidding zones when structural bottlenecks occur. Structural bottlenecks are bottlenecks that are expected to last for a prolonged period of time, until they are relieved by investments in the grid, or in generation and consumption.

3.2.2 Connection charges

Until 2019, connection charges were limited to direct customer-specific connection costs, including new assets and reinforcement of existing assets, i.e., shallow. Connection charges have not been used for investments in the meshed grid unless extraordinary circumstances apply.

From 2019, connection charges will be mandatory at all grid levels, and will be deeper than before. The change implies that all investment costs triggered by increased consumption or generation, multiplied by a reduction factor of 0.5, will be charged. In addition, grid companies can charge for costs related to grid studies triggered by new generation or consumption. The reduction factor does not apply to customer-specific investments. For network assets with several users, costs are divided

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according to the capacity increase for each customer. The cost base can be reduced in special circumstances. Customers with a maximum load less than 1 MW are exempt.

Additional grid elements may be defined as production-related grid assets if they primarily serve generation, and if so, be included in the cost base for the connection charge.

With the increase in renewable generation, in particular onshore wind generation and small-scale hydro, there have been discussions related to connection charges in cases where it is uncertain to what extent a connection is likely to be used by other grid customers in the future. Statnett may refuse connection temporarily if there is not sufficient capacity in the grid. Currently, Statnett may include the full cost of a new connection, even if it is only partly used by the new customer, in the connection charge, while subsequent users are not obliged to pay once the connection has been built. Moreover, the original customer is not granted exclusive right to the connection.

3.2.3 Variable tariff elements

The energy charge is based on marginal loss calculations and market prices. Marginal loss factors are calculated weekly for each node in the transmission grid and is differentiated between day and night. Marginal loss factors are published at noon the Friday before the week commences. The maximum marginal loss factors are capped at +/- 15 percent.

Charges are symmetrical around zero for injection and withdrawal. The charges are levied according to hourly bidding zone prices and actual injection / withdrawal.

3.2.4 Fixed charges

The fixed charges are designed to recover the residual need for income, i.e. the difference between Statnett's revenue cap and income from energy charges, connection charges and congestion revenues.

Generators are charged according to average annual generation (injected energy) over the last 10 years.[5] The charge is set at the maximum allowed by ACER/EU regulations (Regulation 838/2010) at 1,1 NOKøre/kWh. New entities are charged according to expected average annual generation. In addition, a system charge set at 0.2 NOKøre/kWh is levied on generation.

Consumers are charged according to average annual load (MW) in the system peak hour (actual, determined ex post) over the last 5 years. The charge in 2018 was 360 NOK/kW. Customers with stable load and/or contracts for interruptible load get a discount, see section 3.2.6 below.

3.2.5 Locational signals

For consumption, the charging base is adjusted through the so-called *k-factor* model. In the transmission grid, the charging base for the load charges is the maximum capacity use at system peak (5-year average) adjusted for a so-called k-factor per node. The k factor is a measure of the balance between generation (available winter capacity. i.e. a derated capacity measure) and maximum capacity use in each node. The k factor also gives a locational signal. The k factor can give a maximum of 40 per cent reduction in the charging base and applies to consumption only, not generation (a maximum of 50 per cent applied until the end of 2018):

> k = Average 5-year total capacity use of all customers at the node at system peak / (Available winter capacity + Average 5-year total capacity use of all customers at the node at system peak)

E.g. if the measured consumption in a node is 100 MW and the available winter capacity is 150 MW, the k factor is calculated as 100 / (100 + 150) = 0.4, which is then adjusted to 0.6 to account for the

[5] With a lag: The tariff basis for 2019 is based on data for 2008 – 2017.

maximum reduction of 40 per cent. The charging base for consumers in the node is then 60 MW instead of 100.

Statnett is currently working on a revised model for the locational signals. In a consultation from January 2018. Statnett proposed to change to regional capacity balances (from nodal today) as basis for the locational signals and to include generation in areas with a power deficit. However, Statnett has not yet decided on a model.

Generation may get a reduced feed-in charge in areas where special grid circumstances imply that new generation should be incentivized, e.g., where assessments show that it is more beneficial to establish new generation than to strengthen the grid in order to relieve a structural bottleneck. At the moment, Statnett has not defined any such areas that are eligible for such a discount.

3.2.6 Other relevant features

The tariff level for large consumption in the transmission grid is adjusted for stability factors per customer (load factor, seasonal and hourly variation), and can give a discount of up to 75 per cent on the capacity charge rate (up to 90 per cent until the end of 2018). Specifically, the calculated according to the following parameters:

- Load factor:
  - Customer's annual consumption (MWh) / Customer's peak load (MW)
  - 5000 hours as minimum, maximum of 50% discount at 8760 hours (linear interpolation)
- Hourly variation:
  - Average absolute value of hourly change (MW) / Customer's peak load (MW)
  - 1.8% as maximum for qualifying for the discount, 0 variation gives 15% reduction (linear interpolation)
- Summer consumption:
  - Average consumption per hour in June, July, August (MW) / Average consumption per hour rest of the year (MW)
  - Minimum value of 80% to qualify for discount, 100% or more gives a 25% discount (linear interpolation)
- Total maximum discount available 75% (theoretically the individual parameters sum to 90%, but from 2019 the cap is set at 75%)
- Peak load defined as the 95% highest hour in the calendar year

Customers on contracts for interruptible consumption get a discount of up to 95 per cent on the capacity charge depending on notification time and the duration of the interruption.

Total distribution of costs between consumption and generation also on the agenda, but current EU regulation limits the scope for changes.

According to regulations, the injection tariff in the transmission grid should be the norm for injection tariffs in the regional and distribution grids as well.

3.2.7 Reactive power

Statnett has a separate tariff for consumption of reactive power in the event that such consumption is detrimental to the operation of the transmission grid. The aim of the tariff is to provide incentives for installing compensation systems. The tariff base is set to the maximum consumption during five control hours picked out after heavy (November-February) and light load periods (May-August). The minimum limit for tariff purposes is set at +/- 20 MVAr per exchange point.

3.3 Case study: Great Britain

3.3.1 Overview of the electricity system

The TSO is National Grid Electricity Transmission plc (NGET). However, UK also have three TOs (Transmission Operators). The transmission network consists of 4,474 miles of overhead line, 969 miles of underground cable and 346 substations. Great Britain and the island of Ireland consists of one bidding zone each.

Net imports of electricity to UK in 2017 was about 15 TWh. A total of 336 TWh of electricity was generated in the UK. Total final consumption was 301 TWh, losses amounted to 26.5 TWh and electricity use in the energy industry to about 26.5 TWh as well. The maximum load in UK during the winter of 2017/2018 was 52,279 MW (50,700 in Great Britain and 1,579 in Northern Ireland) (National Statistics, 2018).

Britain's electricity market has 4 GW of interconnector capacity; 2 GW towards France, 1 GW towards the Netherlands, 500 MW towards Northern Ireland, and 500 MW towards the Republic of Ireland. Interconnectors towards Belgium, Denmark and Norway are planned, in addition to further capacity towards France and Ireland (Ofgem, 2019).

Consumption is usually connected to the distribution networks. National Grid state that large consumers also can connect directly to the high-voltage transmission grid. Examples are large industrial plants, steelworks or electrified railway projects (National Grid, 2015).

3.3.2 Tariff structure in Great Britain

Transmission network charging in Great Britain is comprised of three types of charges:

- Connection charges – These cover the capital and maintenance costs of network assets used exclusively by the connecting party. Connection charges are made up of a capital component based on the initial construction cost of the assets and a non-capital component reflecting the maintenance costs. Charges are calculated annually. (£200m TO revenue)
- Balancing Services Use of System (BSUoS) charges – This is a £/MWh charge levied on the volume of energy injected or withdrawn and covers the costs of system operation, including balancing, redispatch and other ancillary services.[6] (~£1.3bn SO revenue)
- Transmission Network Use of System (TNUoS) charges – This recovers Transmission Owners allowed revenues and creates incentives for network use. It includes explicit locational signals. (£2.7bn TO revenue)

  TNUoS charges are themselves comprised of multiple components:

  1. Locational charge – This is described in further detail below and is designed to create locational incentives.
  2. Residual charge – This is effectively a large balancing item that ensures that TNUoS revenues make up the Transmission Owners' allowed revenues.
  3. Two local charges that are paid by certain generators for the use of local assets. These are the:
     a) Local circuit charge

[6] Although BSUoS is not inherently a locational charge, it is based on metered energy volumes that are adjusted to account for network location. These adjustments are inherent to the settlement system and imply that 1 MWh of electricity injected at a distant network location (with heavy transmission losses) is valued as less than 1 MWh at settlement, whereas 1 MWh injected in an area close to demand will actually be valued as more than 1 MWh. These adjustments imply that generators located in distant locations actually pay lower BSUoS, since the assessed volume of their injections is adjusted downwards through this process.A Transmission Loss Multiplier based on zonal losses has also recently been introduced.

b) Local substation charge

The charging method for demand and generation differs.

Demand for which half-hourly metering data is available is charged based on the consumer's demand in the three half-hours with the highest net system demand between November and February (inclusive) that are separated by at least ten clear days (so-called Triads). This kW figure is multiplied by both the national residual TNUoS charge and the locational charge for the relevant demand zone, of which there are 14.

For demand users for which half-hourly metering is unavailable, an energy tariff based on annual consumption between 4 and 7pm is used. The tariff level is set to make up any missing revenue from demand after accounting for forecast half-hourly demand. It also differs by demand zone.

Generators are charged based on their highest Transmission Entry Capacity (TEC) during the year, i.e. the highest amount of power they can inject. The charge is based on both the generator's type and the generator's location. There are 27 different zones, each with its own locational tariff, and this locational tariff is itself decomposed into a number of elements that are combined in different ways to reflect the generators effect on the network costs. For example, a peak security element is intended to cover the costs of meeting peak demand and only charged to non-intermittent generators, since they are expected to be largely responsible for meeting peak demand. Other charges reflect the costs of year-round supply and are variously modified by plant's load factor to avoid disproportionally charging intermittent plants.

Generators are also subject to so-called local TNoUS charges that cover the costs of the assets connecting them to the Main Interconnected Transmission System. Thus, a generator on a more peripheral branch of the transmission system, which is still shared by multiple parties, will pay a charge for the local substation and circuit connecting them to the core grid. The substation charge reflects the MW rating and voltage of the nearest substation to the generator, as well as whether the substation provides for redundancy in its design (with redundancy being rewarded with a higher tariff). The circuit charge reflects the costs of the specific circuit. These 'local' circuit and substation tariffs are distinct from the zonal 'locational' charge that is also a part of TNUoS, but both provide locational signals.

3.3.3 Calculating the locational element of TNUoS

Locational charges are derived from a model of network flows, which estimates the impact on overall transmission network flows from marginal changes in demand or supply at each node. These nodal changes are then aggregated into zonal effects, to help ensure greater stability in the level of locational charges and support administrative simplicity. Finally, the changes are monetised based on estimates for the typical cost of building and maintaining a generic stretch of transmission line. These steps are described in further detail below.

Calculating the impact on flows

The impact on flows is calculated using the DC Load Flow Investment Cost Related Pricing (DCLF ICRP) Transport Model.[7] This model simulates power flows on the transmission network given the network's forecast topology, generators' Transmission Entry Capacities and forecast demand. Two different scenarios are examined: the so-called 'peak security' and 'year round' backgrounds, which look at stylised flows at peak and more generally through the year respectively. They are defined by assumptions on the quantity of generation coming from different types of plants and the total level and distribution of demand. For example, the peak security background assumes no injections from intermittent sources of generation or interconnectors.

[7] Note that this model is freely licensed by National Grid. A description of the methodology used can be found in Part 2 of Section 14 of the Connection and Use of System Code (CUSC).

The model itself does not produce monetary outputs. Rather it aggregates the impact on the transmission network in terms of MWkm, i.e. the number of kms by which the transmission system should be expanded or reduced in response to an additional 1 MW injection. Because not all km are equivalent in terms of their cost implications, a series of so-called 'circuit expansion factors' are used to reflect the cost ratios of different types of lines, with a 400 kV overhead line assigned a factor of one and therefore representing the reference km. Thus, if the model concluded that a 1 km line needed to be reinforced to carry an additional 1 MW of power, but the relevant line type was twice as costly as the reference 400kV overhead line, the line type would have an expansion factor of 2, and the model would report a change in transmission needs of 2 MWkm.

To calculate the nodal impact of marginal injections and withdrawals, the model is first run using both the 'peak security' and 'year round' backgrounds to establish, for each circuit, which scenario results in the highest flow. This scenario is considered to be relevant for dimensioning the relevant asset. The MWkm for each circuit is calculated, applying the relevant expansion factors, and the total MWkm of all Peak Security and Year Round circuits is calculated.

The model is then run with an additional 1 MW injection at one node, and a cumulative 1 MW of additional offtake distributed proportionally among all other nodes, and the change in Peak Security and Year Round MWkm noted. The same process is applied to all nodes to establish a full set of nodal figures. The impact of an increase in offtake at each node is taken to be equal but opposite to the impact of an increased injection.

Calculating the zonal impact

Nodes are grouped into geographically and electrical proximate zones that have similar marginal costs associated with additional generation. Their nodal prices must be within +/-£1.00/kW of the zonal price. The zonal impact is calculated separately for generation and demand – each have their own zones because it's difficult in practice to split demand customers on distribution networks served by multiple transmission network nodes.

In each case, the zonal impact is a weighted average of the nodal impacts, with the weights determined by the share of zonal generation or demand, as appropriate, located at the relevant node. Nodes with negative demand are assigned zero weight in the calculation of demand impacts.

Monetising the impact

These zonal marginal km are converted into tariffs by multiplying them by the so-called 'expansion constant' and the 'locational security factor'.

The expansion constant monetises the impact and is expressed in £/MWkm. It is intended to represent the annuitised value of the transmission network infrastructure investment required to transport 1 MW over 1 km. It equals the sum of an estimate of the transmission annuitised cost of the assets involved and an estimate of the overheads involved.

The asset cost component is derived from the projected cost of a 400 kV overhead line, including an estimate of the cost of capital. An audited process looks at historic project costs and tender valuations and makes adjustments based on price indices (e.g. those for steel and labour) to develop current cost estimates for a range of circuit types. These inform both the expansion constant, and the setting of the expansion factors (or circuit cost ratios) discussed earlier. The estimated cost of the 400 kV overhead line is annuitized using an estimate of the Weighted Average Cost of Capital and the asset life to form the asset cost element of the 'expansion constant'.

The overhead elements are calculated on the basis of an 'overhead factor' equal to total business overheads divided by the total Gross Asset Value of the transmission system. Multiplying this factor by the estimated cost of a km of 400 kV overhead line gives the estimate of relevant network overheads.

By combining these overhead costs with the annuitized asset value, we get the 'expansion constant' used to monetise the zonal impacts.

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Finally, the end result is multiplied by a ‘locational security factor’. The locational security factor reflects that fact that the transmission network needs to provide a degree of redundancy not yet accounted for. The factor is calculated by re-running the transport model to calculate nodal marginal costs while now imposing national security requirements with regard to resilience in the face of single and double circuit faults. The results from this ‘secure’ run are then compared with those from the standard transport model results described above and fit using the Least Squares Fit method to estimate an uplift factor that accounts for the additional costs of securing the transmission network. This factor is currently 1.8.

4 DESCRIPTION OF THE SWEDISH TRANSMISSION GRID TARIFF

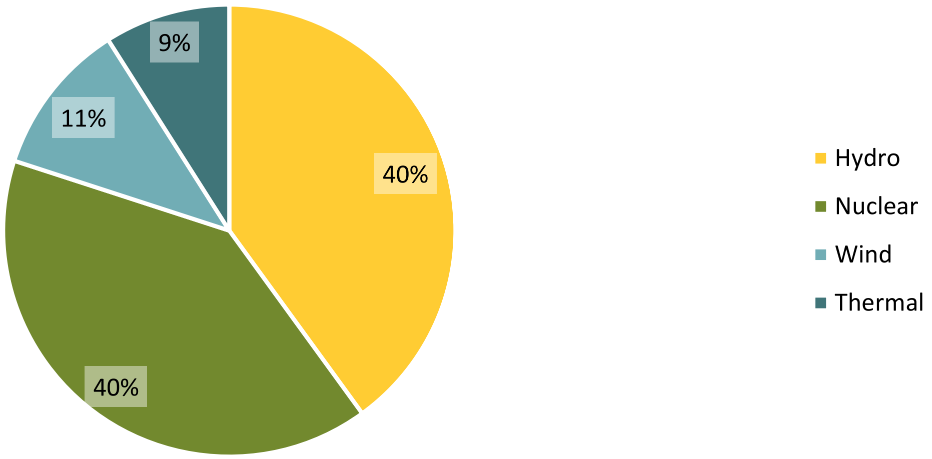
In this chapter, we describe the elements of the current Swedish tariff. In order to assess the efficiency of the tariff, it is useful to understand the context. Therefore, we start with a short overview of the Swedish electricity system and some fearures of the market and regulatory framework, before we describe the elements in the transmission grid tariff.

4.1 Overview of the Swedish electricity system

4.1.1 Electricity production and consumption

In 2017, the total electricity production in Sweden was 160 500 GWh, with hydro and nuclear power the dominating energy sources, each accounting for 40 percent. The rest is wind, thermal and solar generation. The share of wind power is increasing, and represented 11 percent of generation in 2017, see Figure 11.

Figure 11: Electricity production in Sweden, 2017



Source: SCB. Solar represents 0.14 percent.[8]

In 2016, the share of energy produced from renewable resources in Sweden was 53.8 percent. This is above the 2020 target of 49 percent.[9] By 2040, the target is to increase the renewable share to 100 percent. Wind generation is expected to increase from 17,6 TWh to around 30 TWh in 2021 (THEMA, 2019)[10].

Figure 12 shows the development in installed capacity relative to demand. While installed capacity has increased and maximum load has decreased, the estimated available capacity margin in winter peak load, as assessed in a statistical 10-year winter, has not increased. The reason is that all generation capacity is not expected to be available in winter peak. Specifically, Svenska kraftnät assesses that in the worst case, only 11 percent of wind power capacity is available at winter peak, and in addition, all hydropower capacity cannot be used at the same time due to cascading. The depicted capacity margin does however not include interconnector capacity and expected imports (see next section).

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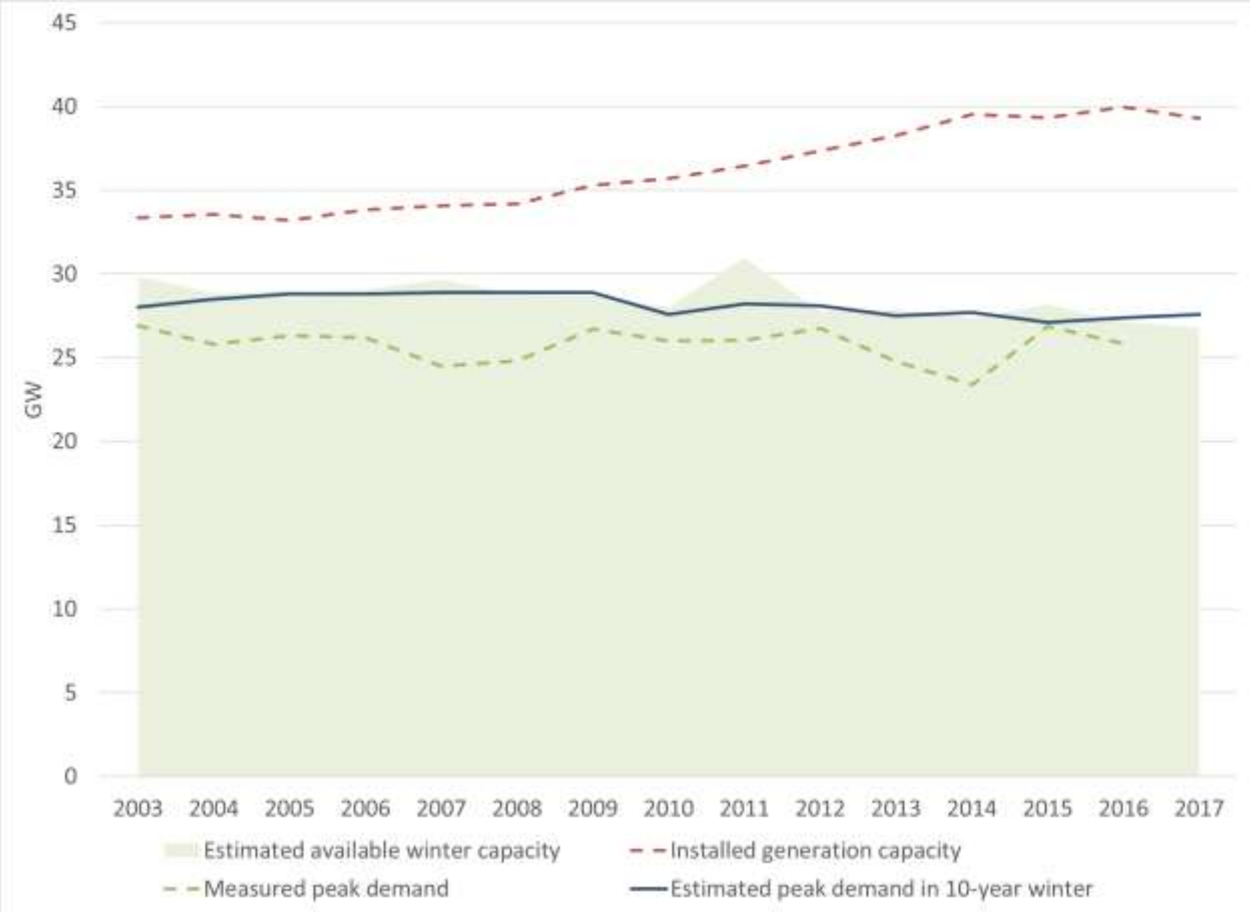
[8] https://www.scb.se/hitta-statistik/sverige-i-siffror/miljo/elektricitet-i-sverige/

[9] https://ec.europa.eu/eurostat/documents/2995521/8612324/8-25012018-AP-EN.pdf/9d28caef-1961-4dd1-a901-af18f121fb2d

[10] Market analysis of the Elcertificate market, March 2019

Figure 12: Historical development in generation capacity and peak load

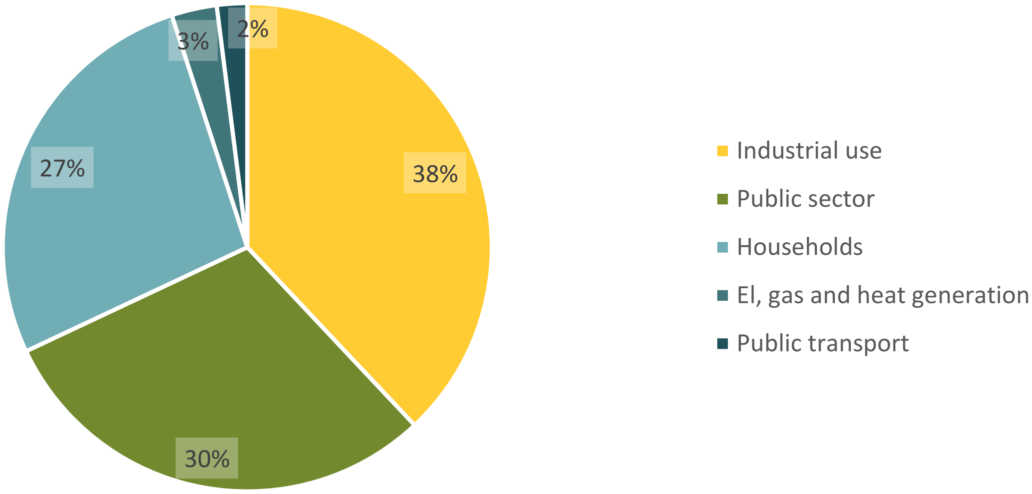


Source: Energimyndigheten (2018)[11]

On the demand side, industry is the largest consumption sector with 38 percent, closely followed by the public sector with 30 percent and households with 27 percent (see Figure 13).

[11] https://energimyndigheten.a-w2m.se/Home.mvc?ResourceId=5738

Figure 13: Electricity use in Sweden, 2017



Source: SCB.[12]

4.1.2 Market

The Swedish electricity market was deregulated in 1996. In the Nordics, wholesale electricity is traded at a common power exchange, Nord Pool Spot, which is jointly owned by the TSOs. At Nord Pool Spot, a common system price (without congestion) and area prices (subject to transmission constraints) is set for each hour of the day according to bids in the Day Ahead market.

In 2011, Sweden was divided into four bidding zones. The area price differences reflect hourly congestions between bidding zones and provide locational signals for supply and demand, as well as a shadow price on grid capacity. Congestions within bidding zones are managed by redispatch.

4.1.3 Connections to adjacent markets

The transmission grid consists of 15,000 km 400 kV and 220 kV power lines, and 16 international connections. The transmission capacity is largest towards Norway (4,000 MW), Finland (2,700 MW) and Denmark (2,000 MW). A third interconnector between Sweden and Finland is planned.

Today, the capacity towards Germany is 600 MW (Baltic Cable), but a new cable with capacity of 700 MW is planned (Hansa PowerBridge) and expected to be operational from around 2025. Sweden was recently connected to Lithuania through the NordBalt cable (700 MW). Sweden is also connected to Poland, where the capacity is 600 MW (SwePol Link).

4.2 Structural features of the grid

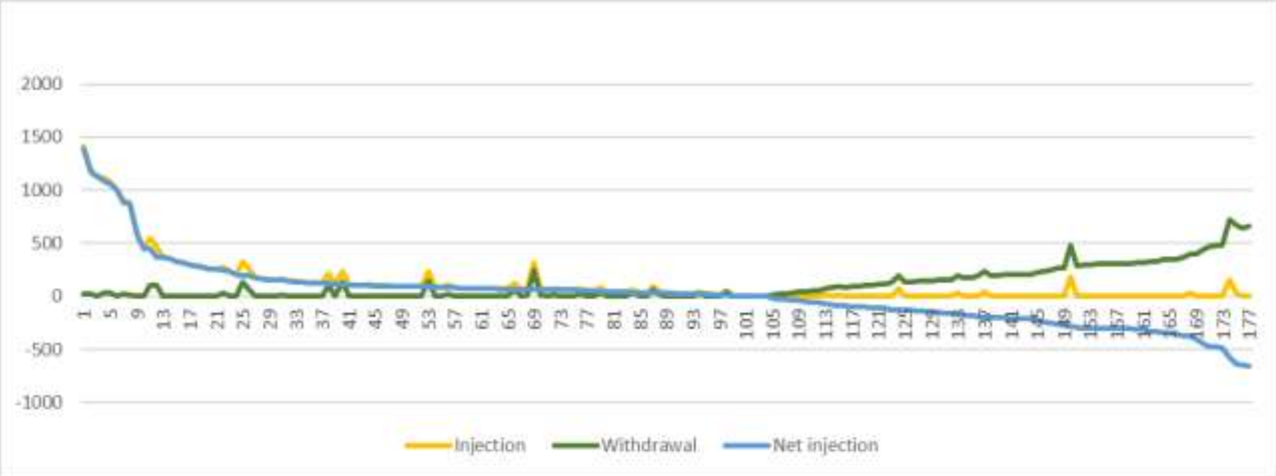
There are 179 connection nodes in the Swedish transmission grid. A total of 28 companies are connected to the grid, these are regional grid owners and mainly large generators. For historical reasons some smaller generators are connected to the transmission grid as well. A few large companies operate regional grids in more than one bidding zone (Vattenfall (all bidding zones), EoN (SE2, SE3, and SE4), Ellevio (SE2 and SE3)). Smaller generators and all industrial users are connected to the regional grid. Hence, even regional grid customers may have periods with net injection to the transmission grid, depending on the structure of generation and demand in the region.

[12] https://www.scb.se/hitta-statistik/sverige-i-siffror/miljo/elektricitet-i-sverige/

Subscribed capacities

The figure below shows the total annual subscribed capacity (see section 4.4.3) for injection and withdrawal per node in the Swedish transmission grid, sorted by net injection. Hence, the generator nodes are on the left side and the consumer nodes on the right side of the chart. We see that most nodes are clearly mainly one category or the other, but a few generator or export nodes also have withdrawal subscriptions and a few consumer or import nodes also have injection subscription.

Figure 14: Annual capacity subscription per node, sorted by net injection, MW

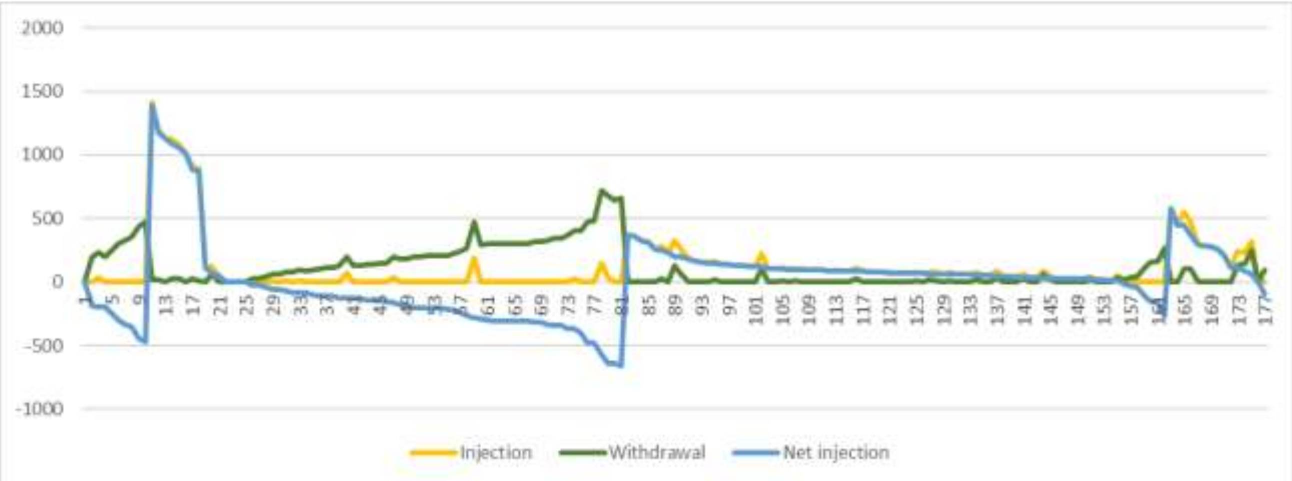


Source: Svenska kraftnät

Svenska kraftnät encourage all new customers, both load and generation, to connect to the regional grids. Still, the injection and withdrawal patterns in each node is likely to change due to connections in the regional grids.

Figure 15 illustrates the differences in capacity subscriptions between the bidding zones, going from SE1 in the north to SE4 in the south. Each jump in the net injection function implies a shift from one bidding zone to the next. Thus, we can see that all but one node in SE1 are net injection nodes, the situation is more balanced in most nodes in SE2, most nodes in SE3 are net withdrawal nodes, with a few notable exceptions, and all nodes in SE4 are net withdrawal nodes. This also illustrates that the main transmission flows go from north to south.

Figure 15: Annual capacity subscriptions per node, sorted by bidding zone and net injection, MW



Source: Svenska kraftnät

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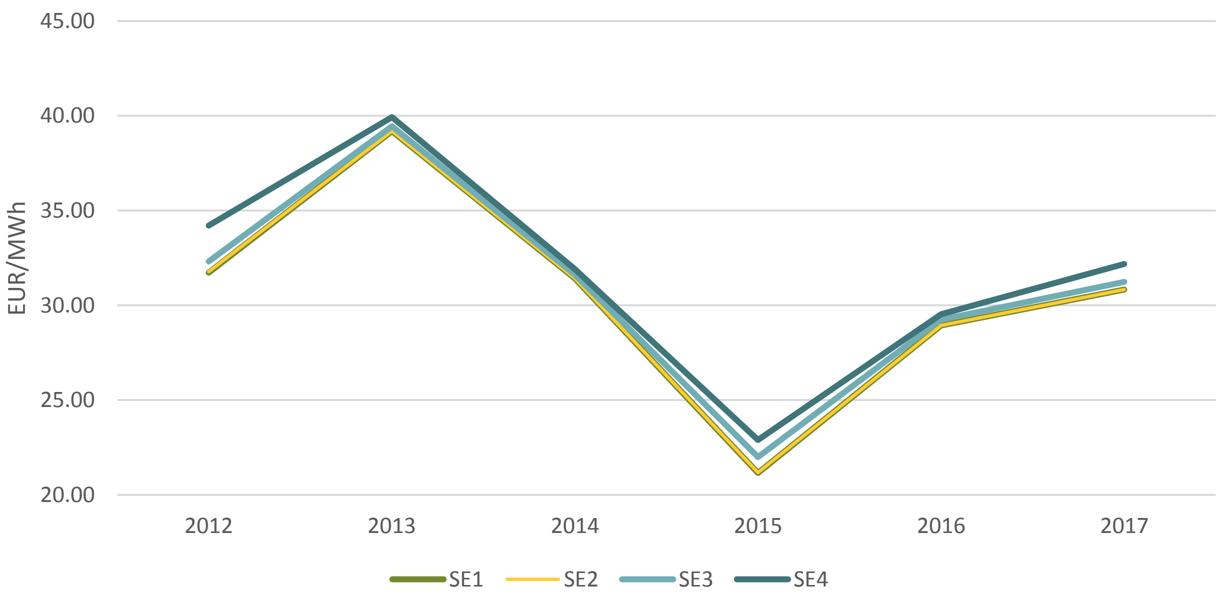
Zonal prices

The chart below illustrates the consistent, although not significant price differences between the Swedish bidding zones. While prices in SE1 and SE2 are almost always identical, the price level in SE4 is consistently higher than in the other bidding zones.

According to the Swedish NRA (national regulatory authority in energy), Energimarknadsinspektionen (EI), day-ahead prices were identical in all Swedish bidding zones in around 60 percent of all hours in 2017 (Energimarknadsinspektionen, 2018a). According to the report, the main sources of price differences are grid constraints and loss of production capacity, mainly in bidding zone SE4. EI expects a reduction in these price differences when Sydvästlänken becomes operational (expected in July 2019, according to Svenska kraftnät).

Figure 16: Average annual prices in the Swedish bidding zones, 2012-2017

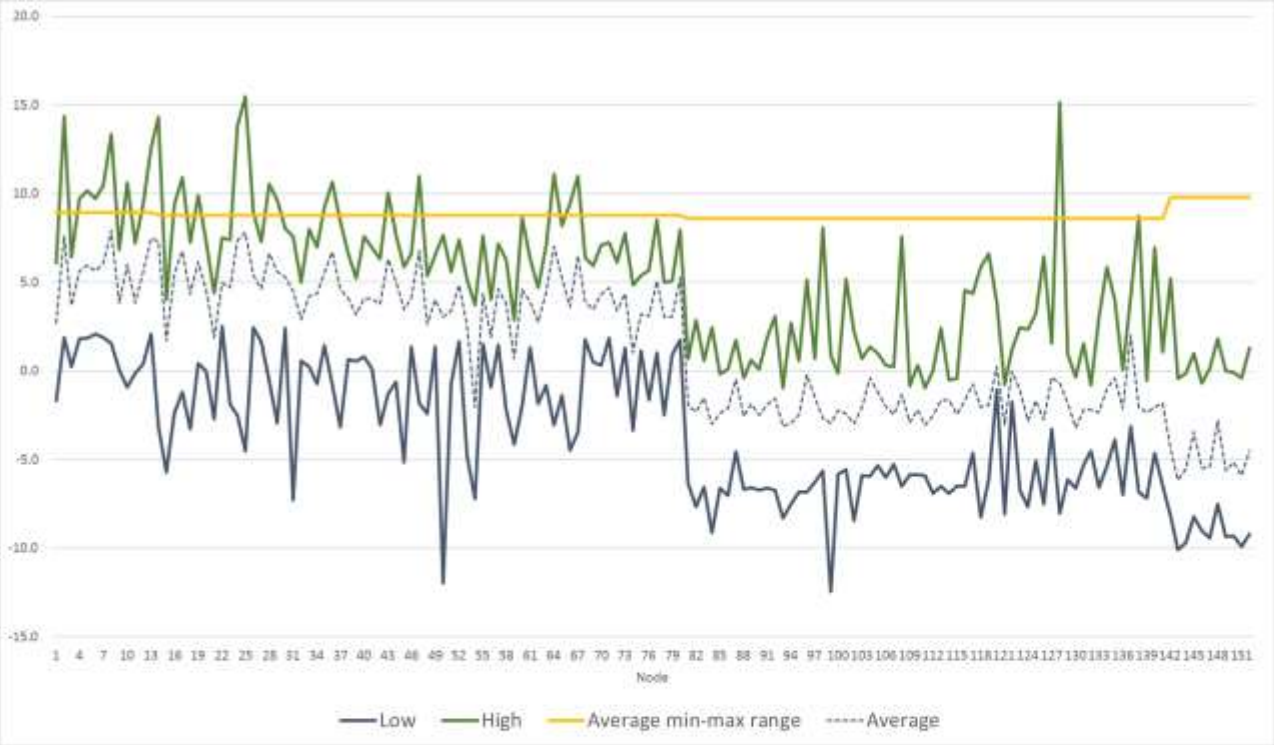


Source: Nord Pool

Marginal losses

Figure 17 illustrates the variation in metered average weekly loss coefficients per node during the year, represented by the min-max range. The calculations are based on snapshots for 6 points in time during the week: 3.30 am, 11.30 pm, and 7.30 pm on Wednesdays and Sundays. The graph gives an impression of the variation, but does not reflect the full variation, for example between night and day, between working days and weekends, nor the variation during weeks.

Figure 17: Marginal loss coefficient max-min ranges per node, 2018



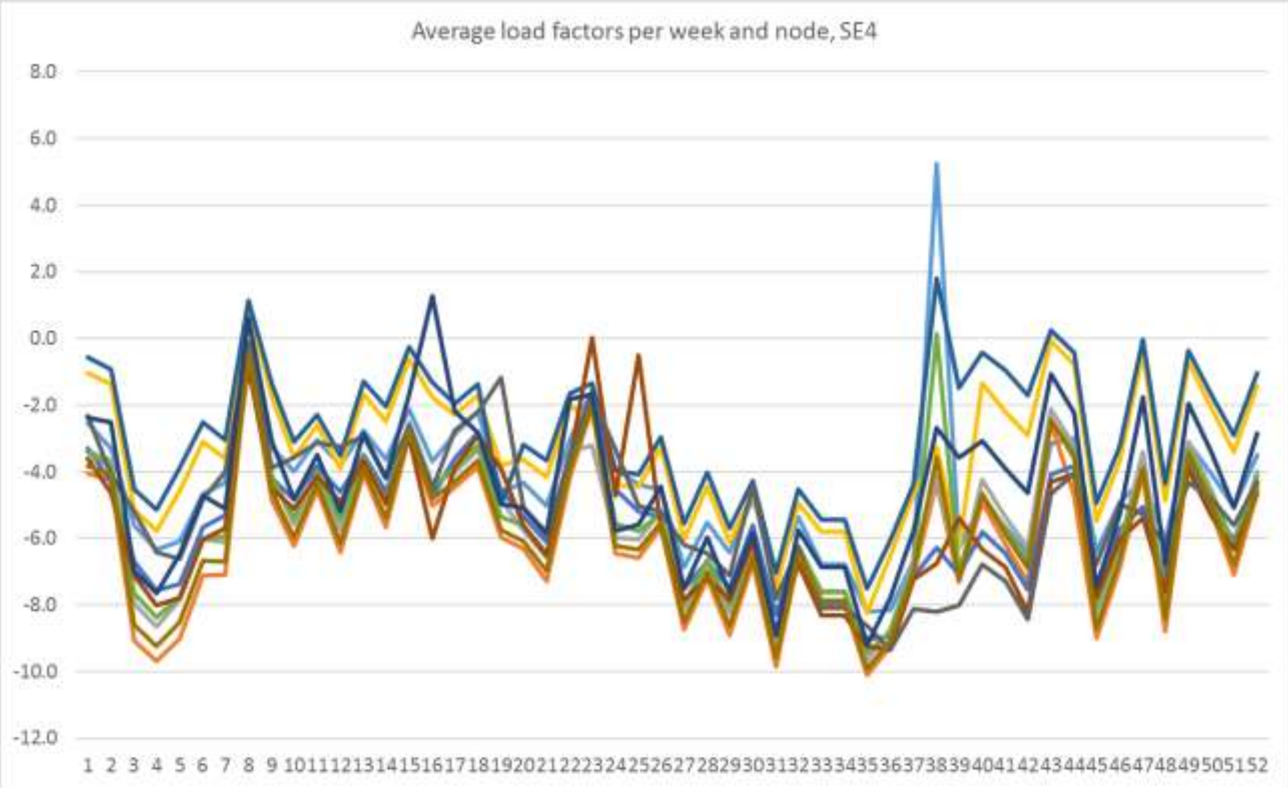
Source: Svenska kraftnät

The average min-max range of losses is about 9 percent with only six nodes showing a range larger than 15 percent. About 30 percent of the nodes have min-max ranges above 10 percent. The yellow line shows the average min-max range for each bidding zone, indicating that the min-max ranges are on average roughly of the same magnitude. The dotted line shows the annual average per node.

The geographical pattern reflects the positive energy balance in the north (SE1 and SE2) and the negative energy balance in the south (SE3 and SE4), but there are clear differences between nodes within the bidding zones.

The seasonal variation is exemplified by the weekly loss factors for all nodes in SE4 in Figure 18. The loss factors clearly vary substantially from week to week, without a clear seasonal pattern.

Figure 18: Weekly average loss factors



Source: Svenska kraftnät

4.3 Grid access

The Electricity Act entitles customers' connection and access to the grid, unless special circumstances apply. If the capacity is insufficient for connection of a new customer, Svenska kraftnät can deny connection for a limited (unspecified) time.

Existing customers wishing to increase their allocated capacity do not have a corresponding right. If a new customer applies for connection and an existing customer applies for an increase in his allocated capacity at the same time, Svenska kraftnät grants access according to a *first come first serve* principle.

4.4 Overview of tariffs

The Swedish transmission grid tariff consists of energy charges and capacity charges. In addition, for completeness, we include a description of connection charges. Although formally not a part of the transmission tariff, the application of connection charges may have implications for the design of the tariff elements.

4.4.1 Connection charges

Connection charges apply if connection of a new customer (or an increase in the capacity subscription of an existing customer) requires investments in the grid. Svenska kraftnät first calculates whether capacity is available in the current grid, and, if measures are required, the cost of these measures. Measures in the meshed grid that benefit all grid customers and which cannot be related to specific customers are socialized. The model is referred to as a form of «deep connection charge» (cf. e.g. ENTSO-E, 2018)[13].

Deep connection charges are evaluated from case to case according to principles formulated in Svenska kraftnät (2013). The main principle is that grid costs related to capacity and security of supply due to the connection should be covered by the connection charge. The connection charge should be equal to the increased investment costs of Svenska kraftnät. If a connection implies that a planned investment must be implemented earlier than planned, the connection charge is based on a calculation of the cost of accelerating the investment.

In the calculated connection charge, internal costs of Svenska kraftnät should also be included, e.g. costs related to project management. Changes in maintenance costs and the cost of the feasibility study are not included.

Svenska kraftnät offers an investment loan for (regional) grid companies to cover their investment costs related to connection of renewable generation. If such a loan is granted, the full deep connection charge is not levied on the “first” customer. The charge is adjusted for such *threshold effects* by only levying the share of the investment that the new customer triggers. Subsequent customers using the same investment then repays that loan through the deep element of the connection charge.

The tariff charges for a customer are not affected by the connection charge.

4.4.2 Energy charges

Energy charges cover the cost of energy losses in the grid. Injection and withdrawal from the transmission grid affect the losses, depending on the location and timing of withdrawals and injections. Losses are charged per customer according to their energy generation or consumption and differentiated according to their connection node to reflect that losses in the grid associated with changes in injection or withdrawal varies according to the energy balance and location of each node.

Svenska kraftnät must buy the energy transmission losses in the market. The total energy charges covers Svenska kraftnät’s loss costs and consist of a loss coefficient (energy lost), the price per kWh and a correction factor:

- The loss coefficient is based on calculations of the marginal impact on losses if one more MWh is fed into the grid in each node. Loss coefficients are calculated each year and fixed per node.
- The correction coefficient transforms marginal losses to average losses, ensuring that total energy charges does not exceed Svenska kraftnät’s actual costs for energy losses. The correction coefficient is set at 0.8.
- The energy price is currently based on the actual per MWh cost Svenska kraftnät incurs for lost energy and is set one year in advance according to long-term futures prices. (Svenska kraftnät buys long-term forward contracts to lock in the cost of losses in advance.) From 2020, new principles will apply for the pricing of energy losses, where actual hourly prices in the relevant price area will be used.

The energy charge for each customer is levied per MWh injection or withdrawal.

4.4.3 Capacity charges

The main tariff revenues are collected through capacity charges, and the basic capacity charge is based on annual capacity subscriptions. But even allocated capacity specified in connection

[13] According to ENTSO-E (2018), «deep» connection charges imply that a grid customer must pay for the infrastructure connecting the customer to the transmission grid, plus all measures strengthening or increasing the capacity in the exising grid necessary to connect the customer. The alternative is «shallow» connection charges where the customer only pays for the infrastructure connecting the customer to the transmission grid (lines/cables and other necessary elements).

agreements, temporary subscriptions and exceedance penalty fees affect the incentives of grid customers and grid costs.

Allocated capacity

The capacity charges in the Swedish transmission tariff are related to capacity subscriptions. The capacity subscription may however be different from the allocated capacity that is specified in connection agreements ("anslutningsavtal"). The allocated capacity is important because grid customers are guaranteed access to the allocated capacity, thus, Svenska kraftnät is obliged to invest in the grid in order to fulfil this guarantee. Svenska kraftnät guarantees that the allocated capacity is available as long as the customer is not in breach of the agreement. Connection charges (see above) are however calculated based on the allocated capacity.

For historical reasons, all grid customers do not have connection agreements, but new transmission grid customers must sign such an agreement. The connection agreement gives the right to a specified allocated capacity (for injection and/or withdrawal). The customer must use the allocated capacity within a specified date. If the customer does not use the allocated capacity within the specified deadline, the unused capacity reverts to Svenska kraftnät and can be allocated to other customers.[14] After this date, the customer is not obliged to use the allocated capacity every year, it is rather supposed to represent the long-term capacity need of the customer. The customer can apply for a change (increase) in the allocated capacity, in which case the connection agreement must be revised.

The customer is not charged for the allocated capacity. Still, the allocated capacity defines the maximum physical capacity that the customer has the right to subscribe to. The customer's annual capacity subscription can however be lower than its allocated capacity (see next section).

For customers without a connection agreement, the subscribed annual capacity (see next section) constitutes the allocated capacity. The annual subscription is subject to approval by Svenska kraftnät every year.

Today, 51 nodes have connection agreements. In order to improve the basis for grid planning, Svenska kraftnät is working to increase the number. Currently, about seven new connection agreements are signed each year. For existing customers, such agreements are typically established in cases where the customer wants to increase its subscribed capacity. Svenska kraftnät cannot require that existing customers enter into connection agreements. However, Svenska kraftnät has internally addressed the issue and looked at different solutions to strengthen the incentives to sign connection ageements.

The difference between the allocated capacity and the subscribed capacity of a customer is denoted *unutilized capacity*. This capacity cannot be allocated to other customers in the grid as long as the connection agreement is valid. Svenska kraftnät has internally looked at different ways to minimize unutilized capacity and it is a part of the current assessment of the transmission grid tariff.

Annual capacity subscriptions

Transmission grid customers subscribe to a given capacity each year, this is part of the utilization agreement (nyttjandeavtal). The subscribed capacity cannot be higher than the allocated capacity unless the connection agreement is renegotiated.

An annual capacity charge applies to the subscribed capacity. The capacity charge is differentiated between nodes in the grid in order to provide locational signals. The north has a relatively higher ratio of generation to demand than does the south. The surplus generation in the north is thus transported to the more densely populated areas in the south where generation capacity is not

[14] If the customer is in breach due to delays, e.g., in the construction of a power plant, Svenska kraftnät is likely to grant an extension of the agreement. If a project is substantially delayed, and in particular at risk of not being realized at all, Svenska kraftnät is more likely to withdraw the agreement and the associated capacity.

sufficient to cover annual energy demand. Due to the prevailing flow direction in the grid, the capacity charge for injection is higher in the north and lower in the south, see Figure 19. Min-max charges for each bidding zone are shown in Table 3.

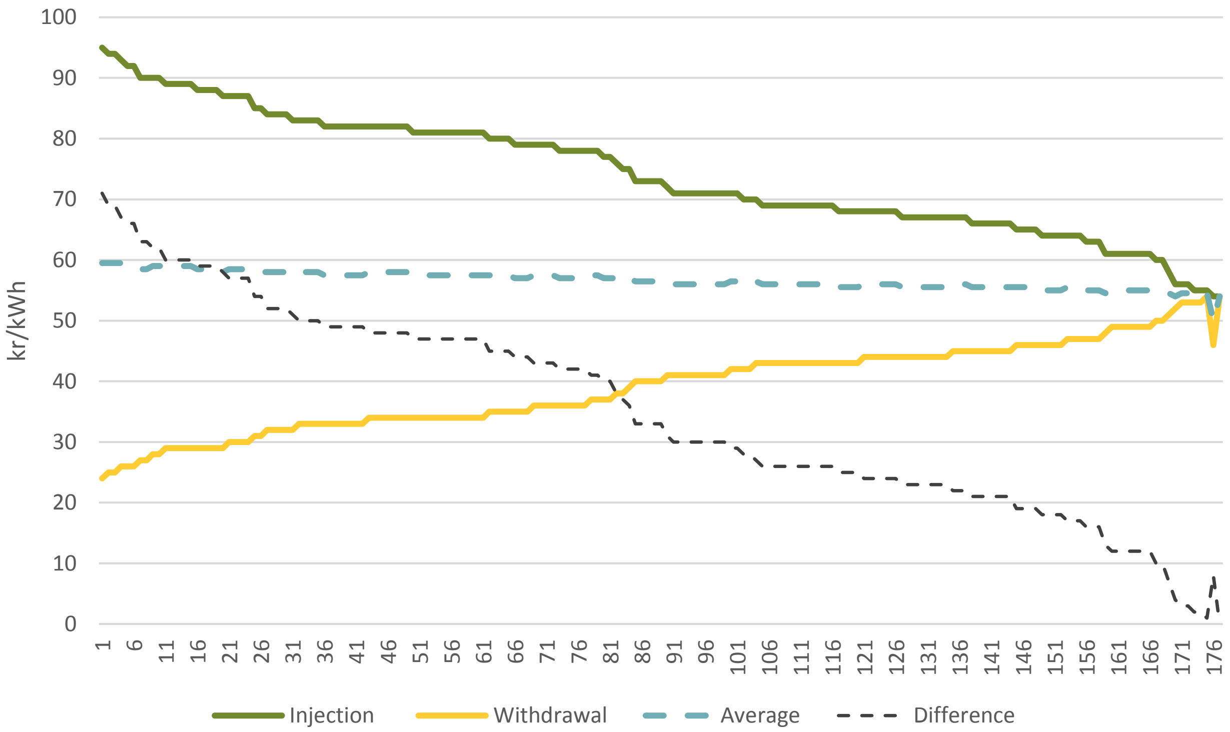
Table 3: Max and min capacity charges for injection and withdrawal per bidding zone, kr/kW, 2018.

	Injection		*Withdrawal*	
	Min	*Max*	*Min*	*Max*
SE1	46	54	54	63
SE2	38	49	61	76
SE3	29	37	77	89
SE4	24	28	90	95

Source: Svenska kraftnät

Customers who sometimes withdraw power from the grid and sometimes inject power into the grid have separate subscriptions for withdrawal and injection.

Figure 19: Annual capacity charges for injection and withdrawal per node, kr/kW



Source: Svenska kraftnät

Exceedance of the annual capacity subscription

A customer can exceed the annual subscribed capacity by entering a temporary subscription, which is subject to approval by Svenska kraftnät. If the subscription (annual and/or temporary) is exceeded, an exceedance penalty applies. The exceedance penalty is substantially higher than the charge for a temporary subscription. In principle, exceedance without a temporary subscription is not allowed.

If a customer expects to exceed its subscribed capacity, it should apply for a temporary increase in its subscription no later than an hour before the exceedance occurs. Svenska kraftnät will accept the application provided that the temporary subscription does not compromise the operation of the grid.

The temporary subscription is charged as a fixed fee related to the volume of the subscription, in addition to a variable fee that covers actual injection or withdrawal. In 2018, the charges for temporary subscriptions were equal to 1/200 of the annual capacity charge, levied for each week and kW. The charge for the per kWh actual injection or withdrawal constituted 1/500 of the annual capacity charge (i.e. the usage fee was energy based).

The exceedance penalty is set to 1/500 of the annual capacity charge for the maximum capacity by which the subscription is exceeded. From the third hour of exceedance within the same day, a penalty of 1/50 of the annual capacity charge applies.

For 2019, the exceedance penalties are increased and fixed: The exceedance penalty is 2800 SEK/MW per hour starting in the third hour of exceedance within one day. In the first hour of exceedance, the penalty is 20 percent of the full charge, and for the second hour it is 50 percent.

Table 4: Capacity subscription charges, 2018 and 2019

	Annual subscription 2018	*Temporary subscription 2018*		*Exceedance 2018*			*Exceedance 2019*		
		Capacity	*Use*	*1st h*	*2nd h*	*3rd h*	*1st h*	*2nd h*	*3rd h*
	kr/kW/year	kr/MW/week	kr/MWh/week	kr/MW	kr/MW	kr/MW	kr/MW	kr/MW	kr/MW
Injection									
Min	24	120	48	48	48	480	560	1400	2800
Average	39	195	78	78	78	782	560	1400	2800
Max	54	270	108	108	108	1080	560	1400	2800
Withdrawal									
Min	54	270	108	108	108	1080	560	1400	2800
Average	74	371	148	148	148	1484	560	1400	2800
Max	95	475	190	190	190	1900	560	1400	2800

Source: Svenska kraftnät

The figure below shows that the new exceedance penalty fees are substantially higher than the current ones. The increase is higher for customers with low annual subscription charges and higher for injection than for withdrawal.

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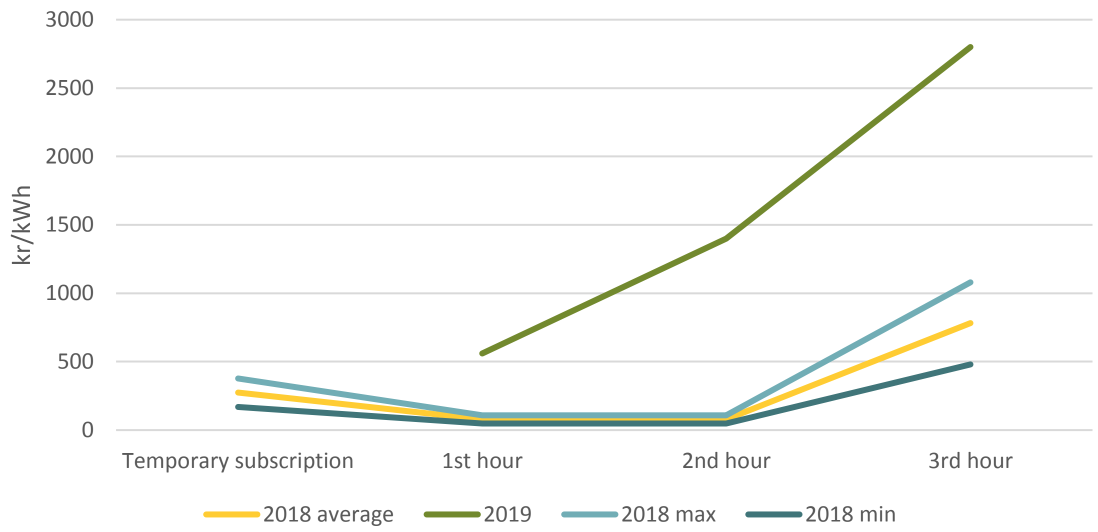
Figure 20: Exceedance penalty fees 2018 and 2019, kr/MW.



Source: Svenska kraftnät

Allocation of capacity charges between generators and consumers

Today, the allocation of capacity charges (total revenues) between generators and consumers is 35 and 65 percent respectively. The share of the producers has gone from 30 percent to 35 percent. The intention of Svenska kraftnät has been to reduce the difference between the two customer groups, i.e. increase charges for producers and reduce the charge for consumers. European law limits the grid tariff for generators (G-tariff). In the Nordic market, the allowed charge span is between 0 and 1.2 €/MWh. Svenska kraftnät's average G-tariff is currently about 0,9 €/MWh.

Joint subscriptions due to transit[15]

Several regional grids are connected to the transmission grid in more than one node. Since electricity takes the path of least resistance through the grid, transit flows can occur. Transit refers to situations where flows of electricity from one node to another in the transmission grid causes flows in the regional grid. Such flows increase the metered withdrawal in one connection point while at the same time increasing the metered injection in another. Due to the structure of the grid tariff, transit imposes a cost to the regional grid owners. Because of transit, regional grid owners may have to subscribe to a larger annual capacity than what would be equal to their actual use. Some customers may only have a withdrawal subscription and no injection subscription, or vice versa. Transit flows could force them to have both subscriptions. The impact of transit may also change the flow over different nodes, thereby forcing the regional grid owner to increase its capacity subscription in several nodes. Transit flows could however also have the opposite effect, i.e., they could reduce the metered values.

Today, Svenska kraftnät offers *joint subscriptions (summaabonnemang)* to customers if the effect of transit exceeds a specified threshold. This threshold is set according to both the size of transit and the frequency of transit. The purpose of joint subscriptions is to correct the capacity subscriptions of the regional grid owners for the increase in annual capacity charges due to transit.

The first step of the calculation is to identify single hours with very high capacity need.

The second step is to calculate the transit volume. The transit volume is calculated as the difference between the maximum used and the needed capacity. The capacity need refers to maximum total withdrawal and maximum total injection, for one hour. The maximum used capacity is identified by

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[15] Svenska kraftnät (2014).

analyzing hourly data for withdrawal and injection. The customer is eligible to a joint subscription if the difference between the used and needed capacity is larger than a specified threshold value.

The calculation is done differently depending on whether the flow on nodes that connect a regional grid customer always have net withdrawal or if there are periods with net injection. The result of the calculation is a ratio/share between the capacity use and the capacity need.

In the case of an area with permanent net withdrawal:

$$\frac{\Sigma_{for\ all\ points}\ max\ P_{ut} + \Sigma_{for\ all\ points}\ max\ P_{in}}{max\ \Sigma_{for\ all\ points}\ P}$$

For areas with temporary net injection:

$$\frac{\Sigma_{\text{for all points}}\ \max P_{ut} + \Sigma_{for\ all\ points}\ \max P_{in}}{\max \Sigma_{for\ all\ points}\ P + \Sigma_{for\ all\ points}|min\Sigma P|}$$

The final step is to identify the share of hours per year where the threshold value is exceeded. A percentile is used instead of the maximal withdrawal per node.

Transit volumes are calculated annually. A customer is eligible to a joint subscription if the threshold value is exceeded in one of the last two years. The customers themselves need to apply for joint subscriptions and specify the nodes for which the subscription should apply.

For customers with joint subscriptions, temporary subscriptions and exceedance penalties apply to the joint subscribed capacity. In some cases, connection nodes with different capacity charges are part of the same joint subscription. Costs will then be set proportionally to the ratio of the per node subscription charges.

4.4.4 Locational signals

In order to provide long-term locational signals to grid customers, the annual and temporary capacity charges are differentiated between different connection nodes in the grid. Specifically, the annual capacity charge for injection is increasing with the latitude of the connection node, while the annual capacity charge for withdrawal is decreasing with latitude. The rationale for this is the flow pattern in the Swedish grid that goes predominantly from north to south.

Differentiated capacity charges were introduced at the end of the 1990’s. After bidding zones were introduced November 1st, 2011, the differentiation was reduced by 25 percent, commencing from 2012. Svenska kraftnät argued that the differentiation of capacity charges is meant to give long-term, stable locational signals (THEMA, 2017b). Since area prices would also provide locational signals based on grid bottlenecks and be correlated with capacity charges, Svenska kraftnät reasoned that the differentiation of capacity charges could be reduced.

In 2014, Svenska kraftnät assessed the differentiation again, but did not make any substantial changes. However the methodolody was changed. The new methodology was implemented from 2016. The current approach to the differentiation of capacity charges can be divided in three steps:

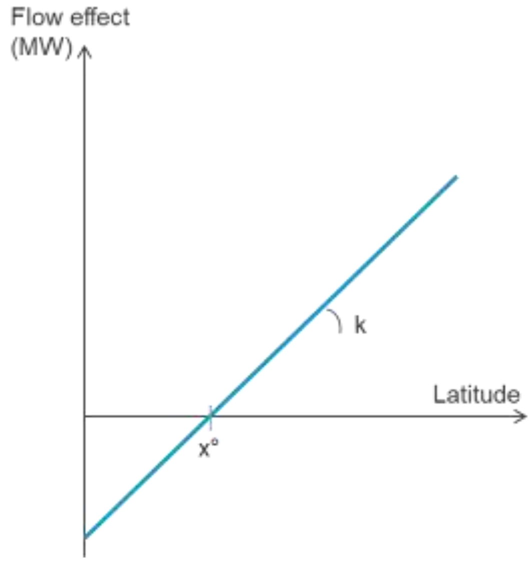
1. Calculate the part of the total cost base in the meshed grid that does not depend on geography.
2. Estimate by flow analyses how much an additional MW inserted into the system affects the flow in the common grid and identify the neutral latitude (long-term analysis).
3. Annually calculate how the flow effect translates into costs for the common grid.

In the first step, Svenska kraftnät choses to approximate the costs that do not depend on geography as the cost associated with stations and connections lines. It is estimated that stations represent 30 percent of the costs and connection lines 15 percent. The differentiation is thus applied to the remaining 55 percent of the total cost base. However, the locational signal should not exceed the actual impact on the flows calculated in step three, even if this implies that the aggregated locational signal does not add up to 55 percent of the total cost base.

Flow analyses are used to estimate how an additional MW inserted into the system at different latitudes affects the flow in the common grid (i.e. the flows across the three main intersections in the grid). The results are linearized and the latitude at which (marginal) injection and withdrawals are neutral in terms of the flow effect is identified (i.e. does not affect the maximum flow in the grid, given by x^0 in the illustration) and the slope of the differentiation function is determined (*k*). This is illustrated in Figure 21.

The marginal impact on the flow depends on where the additional MW inserted is located, that is point p. The effect in point p is calculated as $k * \Delta°$, where $\Delta°$ refers to degrees away from the neutral point, x^0. As the flow analysis captures the long-run marginal impact, it is not, and should not be, updated on a yearly basis.

Figure 21: Illustration of marginal effect on flow



Source: Svenska kraftnät

The next step is to translate the flow effect into a cost effect. Based on step one and two, the cost is calculated annually to find the locational signal of the capacity charge. The average cost per MW:

$$average\ cost = \frac{0.55CB}{total\ common\ flow * 2}$$

This means that the cost of a marginal increase (inserting an additional MW into the system) in a point is:

$$marginal\ cost = k * \frac{0{,}55CB}{total\ common\ flow * 2} * \Delta°$$

Where CB = Cost Base per MW maximum system load, k is the slope of the linear differentiation function, Δ° = the distance from the neutral latitude and the common flow is the average flow across the intersections in one direction. Both k and the neutral latitude have different values for withdrawal and injection. In the current tariff, the neutral latitude is 57˚ for injection and 67˚ for withdrawal. The slope of the differentiation function is 0.022 per MW for injection and 0.030 per MW of withdrawal.

The approach is illustrated in Figure 22. The result of the calculation is linearized based on the latitude of each node, and the linear function determines the capacity charge for each node.

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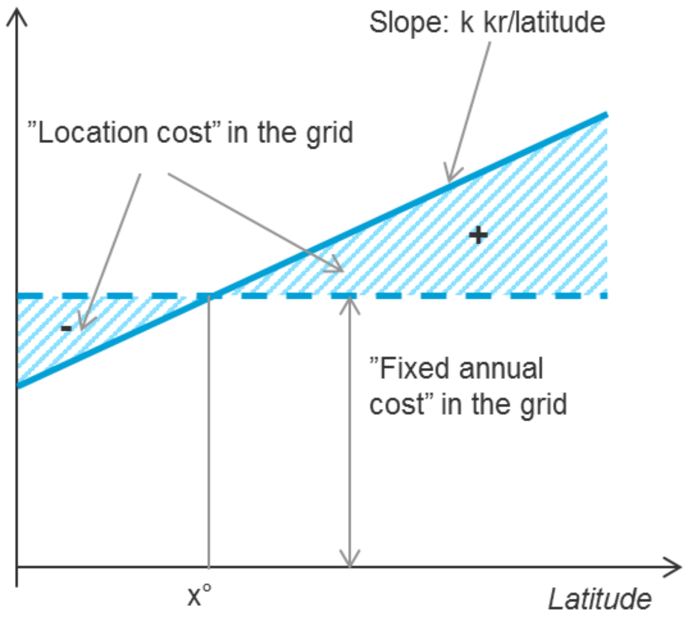
Figure 22: Differentiation of the capacity charge



Source: Svenska kraftnät

The aggregated locational cost of the total subscribed capacity is calculated to make sure the total locational signal does not exceed actual locational costs in the grid. If this amount does not add up to 55 percent of the cost base, the residual is distributed evenly per MW.

$$locational\ (L) = \frac{k * 0{,}55CB * \Delta^{\circ}}{total\ common\ flow * 2}$$

$$non - locational = \frac{0.55CB - \sum \mathrm{L}}{\text{total MW inserted}} + \frac{0.45CB}{total\ MW\ inserted}$$

The total capacity charge is equal to the locational part (L) plus the non-locational part. The total costs to be covered are calculated annually, which will result in an equally large percentage change per point.

4.4.5 Other tariff elements

There are no other tariff elements in the Swedish tariff. Reactive power is not charged, as for example in the Norwegian tariff. Ancillary services are included in the capacity charge and not treated as a separate element as in the UK tariff.

4.5 The impact of Svenska kraftnät's tariffs on regional grid tariffs

According to the Swedish Energy Act, Ellagen, the regional grid companies are obliged to carry over the geographical differentiation from the transmission grid tariff to the regional grid tariff. However, this provision seems to be interpreted and applied differently by different regional grid owners.[16]

Whereas some regional grid owners apply the same capacity charge to all grid customers within each bidding zone, others differentiate according to the capacity charge in the nearest connection point in the transmission grid. One grid company reports that the capacity subscription charge also reflects the distance to the closest connection point.

Both annual and temporary subscriptions are allowed, and, according to interviews with regional grid ownvers, some customers are reported to optimize the use of annual subscriptions, temporary

[16] Based on tariff information from the grid companies' web sites and interviews with three regional grid owners.

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subscription and exceedance penalty charges. According to one interviewee, optimization may become more interesting for regional grid owners due to the change in charges from 2019 (see section 4.4.3).

At least one regional grid company differentiates the subscription capacity charge, by applying a winter charge in addition to the annual charge. The winter charge applies to capacity subscription from 6 a.m. to 10 p.m. (weekdays) from November to March, and provides an additional incentive to lower the subscribed capacity during winter peaks. In this case, 30 percent of the charge is levied according to the annual subscription and 70 percent according to the winter subscription. As an example, the annual subscription can be 90 kr/kWh while the winter subscription is 210 kr/kWh. The annual subscriptions form the basis for the regional grid owners' annual subscription towards Svenska kraftnät. Experience shows that fewer customers lower their winter subscription compared to the annual subscription than expected. Some consumers are compensated for reduction in their annual subscription due to bottlenecks in the grid.

The energy charges in the regional grids are typically low and reflect the charges paid to Svenska kraftnät plus losses in the regional grid.

The grid owner has an obligation to connect new customers. One grid company reports that deep connection charges are subject to discretionary assessments from case to case, e.g. how deep they are. Another reports that connection charges are customer specific, but with an additional standard charge for costs inflicted on higher grid levels (differentiated per grid area).

The dimensioning of regional grids is typically based on predictions for future flows, taking into account the expected future aggregated profiles of supply and demand. One interviewee notes that the regional grid is increasingly dimensioned to accommodate local generation (wind power).

The generator agreements include guaranteed capacity. If Svenska kraftnät curtails generators in order to handle grid congestions, the generator is compensated by Svenska kraftnät.

5 ASSESSMENT OF THE SWEDISH TARIFF MODEL

In this chapter we assess each of the tariff elements in the Swedish transmission tariff, described in chapter 4, according to the criteria established in chapter 2. We assess the efficiency of each tariff element in turn. The identified inefficiencies and the criteria they are based on are summarized in the final section of this chapter. The next chapter presents our proposal for a more efficient tariff structure.

5.1 Energy charges

Discussion

According to theory, charges for energy losses should be differentiated per node, per hour, and (symmetrically) between injection and withdrawal. The charge should be positive whenever changes in injection or withdrawal increases losses, and negative if losses are reduced.

The Swedish energy charge is differentiated by node, can be positive or negative, and is symmetrical between injection and withdrawal. The energy charge is calculated according to an (estimated) annual loss factor and the pricing is based on market prices.

The energy charge deviates from the principles for optimal energy charging in the following ways

- The loss factor for each node is fixed for a year. This means that the loss factor does not vary between high and low load hours in the grid.
- The correction factor in effect implies that losses are charged according to average losses, and not marginal losses.
- Pricing is currently based on an annual average expected energy price.

The first two features imply that the energy charge does not constitute an efficient price signal about the costs that injection and withdrawal impose on the system at different times.

The change from the expected average annual energy price to charging based on actual hourly market prices per bidding zone, that is to be implemented from 2020, improves the efficiency of the energy charge.

Actual *loss factors* can only be calculated ex post, and generators and consumers are likely to adapt to expected energy charges. Thus, it makes sense to base loss factors on expected values that are clearly communicated to the market. Depending on the configuration of the grid and the structure of the market, loss factors may not vary substantially from hour to hour or day to day. This implies that it may be practical to set the same loss factor for several chunks of hours. The granularity should be decided based on grid modelling and experience. Nevertheless, applying the same loss factor for a whole year is in all likelihood too crude (cf. section 4.2) and will mute the price signal from the energy charge. Most importantly, it implies that the energy charge is too low in hours with high capacity utilization in the grid.

The *correction factor* creates inefficiencies for two reasons: it mutes the price signal additionally and it reduces the revenues from energy charges. The latter implies that a larger share of grid costs must be covered by residual charges. As we have seen above, residual charges are likely to adversely affect both short and long-term decisions by grid customers. Thus, the smaller the portion of grid costs that need to be covered by residual charges, the better, provided of course that the other grid elements yield correct price signals.

The capping of the maximum loss factor implied by applying average loss factors and the correction factor, may be justified for distributional reasons: Peaks in loss factors may be due to events that are beyond the control of grid customers, and prolonged periods with high loss factors can be due to missing investments in the grid, and as such, the responsibility of the TSO (provided that such investments would be net beneficial to the system). On the other hand, it may be argued that the short-term price signal provided by the energy charge is particularly important in such times of stress in the system.

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All countries do not apply energy loss charges in their tariffs. Norway and the UK does, and they estimate loss factors at a finer granularity than Svenska kraftnät. In Norway loss factors are calculated weekly and differentiated between day and night, although capped at +/- 15 percent, and zonal prices are used in the calculation of energy charges. In the UK, transmission loss multipliers in the BSUoS tariff are calculated on a zonal and seasonal basis since 2018.

Conclusions

In general, energy charges should be brought more in line with the actual marginal cost of energy losses in the grid. This means that the loss factors should be differentiated in line with the variation in actual marginal losses, and not based on average annual loss factors as today. The actual differentiation – hourly, weekly, day/night – should be based on grid modelling and experience data.

The correction factor reduces the efficiency of the energy charge further and increases the residual income need. Thus, the correction factor should be scrapped in order to bring the price signal from the energy charge in line with marginal costs.

5.2 Connection charges and accounting for threshold effects

Discussion

Grid customers should pay *shallow* connection charges that cover customer-specific grid costs only, i.e., grid elements exclusively related to the connection of the individual customer and cannot be used by others. Applying such (shallow) connection charges is efficient as it reflects welfare economic costs related to the specific grid customer.

Deep connection charges are applied by Svenska kraftnät today and imply that even grid elements that may or will be used by others are included in the connection charge. The deep elements in the connection charge are calculated for changes in capacity need in the meshed grid, be it for a new consumer or for expansion in the capacity need of an existing customer (changes in allocated capacity). Connection charges are based on case-to-case assessments. Deep elements are however limited to local or regional effects.[17] As such, the deep elements of the connection charge reflect a geographically differentiated charge reflecting (at least partly) the long-term impact on grid costs. In principle, the full impact on grid costs of a new customer may be included in the connection charge.

As argued in chapter 2, deep connection charges imply discrimination of new load and a degree of randomness related to the timing of applications for changes in capacity allocation. Thus, new load or generation that is net beneficial for society, risks not being connected to the grid.

Although the adjustment for threshold effects for connection of renewable generation in regional grids improves the efficiency of deep connection charges, it does not remove them all together. A more efficient solution would be to expose all customers to a locational signal based on the same principles.

Conclusions

Covering shallow connection costs through customer-specific connection charges is in accordance with the criteria. Impacts on investment costs in the meshed grid or costs related to grid elements that may or will be used by others should however not be included. Charges reflecting long-term marginal grid costs should rather be reflected in general tariff elements that apply to all users of the relevant grid elements (see next section).

However, if deep connection charges are used, accounting for threshold effects mitigate the distortive effects of the charges.

[17] Necessary investments in the main intersections between bidding zones are explicitly excluded.

5.3 Capacity charges

In the Swedish tariff, capacity charges cover all grid costs except those covered by connection charges and energy charges. As both connection charges and energy charges are calculated so that they cover actual connection and loss costs, total capacity charges are equal to operation, maintenance and investment costs in the meshed grid (except deep connection charges). Moreover, capacity charges are differentiated to provide long-term locational signals to grid customers. The charges are calculated so that they include a common element and a locational element. The total cost base is allocated between injection and load based on an assessment of the drivers for grid investments. The ratio is not calculated every year, but is intended to reflect to what extent long-term grid investments are driven by changes in generation or consumption.

According to the efficiency criteria established in chapter 2, the capacity charges in the Swedish tariff may be seen as serving two purposes which have “opposite” objectives:

1. to *provide long-term investment incentives* for grid customers and as such serve to coordinate investments in supply, demand and grid,
2. to *cover residual costs* in the grid, and as such should have a neutral effect on grid customers’ short-term operation and long-term investment decisions.

In order to assess the first feature, it is necessary to understand the basis for investment decisions in the Swedish grid. In order to assess the second feature, it is necessary to analyse the neutrality of the basic charge, or in other words the degree to which the design of the capacity charge provide undue incentives for grid customers.

The efficiency of the capacity charges cannot be assessed independently of the rest of the grid structure. For example, the locational incentives provided by the capacity charge have to be regarded in connection with bidding zones, guaranteed capacity access (allocated capacity) and the subscription of capacity.

5.3.1 Long-term investment incentives

Discussion

The coordination of investments in generation, consumption and the grid is affected by several elements in the Swedish tariff design, and by the bidding zone delimitation. Ideally, price signals affecting the investments of grid customers should be based on the impact of such investments on grid investments. Investments in generation and consumption will typically affect the long-term cost level in the grid in general, but in addition, the location of such investments in the grid plays a role and investments in generation and consumption affect investment costs in the grid differently.

The need for and extent of tariff elements signalling investment costs should take into account the efficiency of investment signals provided by other elements, such as energy charges, deep connection charges and bidding zones. The combined signal should correspond to the impact on investment cost in the grid.

In the following, we discuss the implication of each design feature of capacity charges in turn, then assess the combined impact on the efficiency of grid investments.

Unutilized allocated capacity

Access to capacity according to the connection agreement is guaranteed. This guarantee has important implications for Svenska kraftnät’s investments in the grid. As we understand it, Svenska kraftnät is currently obliged to provide the allocated capacity, regardless of whether it is used or not, or whether capacity on the same line/in the same node is used simultaneously by multiple customers or not.

Apart from its impact on connection charges, customers do not have economic incentives to reduce the capacity allocation when entering into the connection agreement. Consider the following example: A nuclear plant decommissions one or two reactors, thus reducing its maximum capacity.

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A wind power investor wishes to connect a wind farm in the node and applies for a connection agreement with Svenska kraftnät. The grid capacity is more than sufficient after the reduction in nuclear capacity, but as long as the nuclear plant holds on to its allocated capacity, Svenska kraftnät has to increase the grid capacity before the wind farm can be connected. This increases total grid costs and the connection charge for the wind farm, and reduces efficiency.

The obligation to use the allocated capacity within a specified deadline mitigates over-booking. When an investor plans to develop new generation or load, it needs to make sure that the transmission grid can provide sufficient capacity. Svenska kraftnät must make this assessment which is also the basis for calculation of connection charges and threshold effects. The grid customer is however not obliged to use the allocated capacity – the investment may be postponed, shelved, or adjusted. By imposing a deadline for the use of the allocated capacity, Svenska kraftnät avoids developing the grid according to capacity that may not be realized after all.

Once the customer has used the allocated capacity once, it does not – within the current framework – need to fully use the allocated capacity ever again. Svenska kraftnät is however not at liberty to allocate the capacity to anyone else as long as the connection agreement of the incumbent is not changed. Thus, there is a risk that Svenska kraftnät has to increase grid capacity and levy additional connection charges unnecessarily. If the connection of new capacity is subject to unnecessary connection charges, there is a risk that generation or consumption that is otherwise profitable is deterred from entering the system. Both effects represent a loss in social welfare. There is a risk that the possibility to hold on to unused allocated capacity may constitute a competitive advantage for incumbents. In theory, they may time their own development of new capacity with changes in the initial capacity subscription. As such, the allocated capacity constitutes a free option for the incumbent.

Although specifying a capacity in connection agreements may be helpful for planning purposes, it is highly probable that *guaranteeing* the capacity implies that Svenska kraftnät invests in too much capacity. There are two reasons for this: i) customers will not typically have maximum load at the same time, and ii) if the capacity is scarce during annual peaks, some of the customers may be willing to reduce their load in the relevant hours at a lower total cost than the associated investment cost. The current tariff model is not designed for Svenska kraftnät to take such considerations into account when deciding to invest in the grid.

Since Svenska kraftnät does not have any available measures to make the capacity available to others, unutilized capacity in the system could increase over time.

Charges for subscribed capacity

All customers must subscribe to a level of annual capacity as part of the utilization agreement. The annual capacity subscription can be lower than the allocated capacity, but not higher. If a customer wants an annual subscription that is higher than the allocated capacity, it must apply for an increase in its capacity allocation as well.

The question is to what extent investment decisions in generation and consumption are affected by the capacity charges, and to what extent capacity charges reflect long-term marginal grid costs. The question is two-fold: i) Does the capacity charge affect investment incentives for generation and consumption, and ii) Does the differentiation of capacity charges affect the location of investments? First, we look at the general long-term implications of a capacity charge. We return to the locational signals in the next section.

Impacts of a capacity charge

Levying a charge on the maximum capacity of grid customers is likely to impact the dimensioning of generation and load. The impact depends on the value of the additional (marginal) capacity to the customer and the level of the charge. The value of additional capacity is likely to vary among grid customers.

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In general, we want to expose grid users to a capacity charge that signals the marginal cost that their capacity for injection and withdrawal has on investment costs in the grid. The investment costs in the grid should be determined by the assessed need for capacity in system peak. Therefore, a capacity charge should be related to the grid customers' likely impact on system peak load.

The load patterns of different grid customers are likely to vary substantially, and in addition, their ability to adjust their injection or withdrawal to the capacity charges varies as well. Thus, different grid customers will take into account the capacity charges in their investment decisions in different ways:

1. *Flexible hydro producer:* The flexibility of a hydro-producer is determined by the ratio of generation capacity and reservoir capacity. A hydro-producer with a reservoir can increase its flexibility by increasing its installed capacity, thereby being able to produce more in hours with high prices. An increase in capacity will increase the value of the hydro resources. Increasing the installed capacity will however also affect the capacity charge (via an increased annual subscription or via increases in temporary subscriptions). If it is necessary to expand grid capacity in order to utilize the extra capacity beyond what is reflected by other grid elements, a capacity charge that reflects marginal long-term grid costs should apply.
2. *Run-of-river hydro producer:* A run-of-river producer must produce the hydro-power according to variable precipitation. It cannot, by definition, store the water. Run-of-river generation is however typically high in wet periods that do not necessarily coincide with periods of high system load. Thus, the capacity charge may unduly deter investments in run-of-river generation capacity, if increased capacity does not trigger additional investments in grid capacity.
3. *Nuclear plant:* Nuclear plant are baseload producers which generally produce the same all year round and are in any case likely to produce at full capacity in system peak hours. Therefore, capacity charges are not likely to affect the dimensioning of nuclear plants.
4. *Wind producer:* Wind producers probably dimension their wind farms according to the local resource and technical constraints. However, a capacity-based charge that does not reflect marginal grid costs works as a tax on capacity and may deter investments. This has many similarities with the run-of-river hydro case.
5. *Consumer regional grid customer.* Again, we must distinguish between charges that reflect marginal grid costs and charges that merely collect revenue. A consumer in the regional grid will in general be affected by a capacity charge and choose a lower installed capacity, which may be economically inefficient if the charge is greater than the long-term marginal grid costs of the capacity in question. For an industrial consumer with a high load factor, the choice between a capacity charge and an energy charge is likely to be low or negligible in practice.
6. *Producer regional grid customer.* For a producer in the regional grid subject to a similar tariff model as in the transmission grid, the incentives for investment will be similar to the incentives for producers in the transmission grid (with the provision that nuclear is not likely to be connected to the regional grid).
7. *Combined consumer / producer regional grid customer.* For a combined consumer / producer in the regional grid the impact of a capacity charge depends on the design of the charge and the characteristics of the generation and consumption. A flexible producer may be able to generate in a manner that minimizes the need for subscribed capacity. This may however not impact the dimensioning of the grid, as the consumer may need full backup from the grid in case the power plant is down for maintenance or suffers an outage.

It emerges that a general weakness of the current capacity charging is that the capacity subscription is not related to the dimensioning of the grid, i.e. a customer with peak load in the summer pays the same capacity charge as a customer with peak load in the winter although their impact on grid investment costs should be very different.

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Moreover, the minimum capacity charge seems to be based on total or average grid costs which may not be a good proxy for marginal grid costs going forward.

Locational differentiation

In general, differentiation should reflect differences in the impact on grid investment costs according to the location of supply and demand. Investments in grid capacity should be based on the expected value of the increased capacity. By providing locational price signals, the system operator can communicate the difference in grid costs of location in different nodes in the transmission grid. The difference in the capacity charges between two nodes, should in other words reflect the difference in marginal long-term grid costs associated with the two nodes. Since the impacts differ between injection and withdrawal, the charges should be different for generation and load.

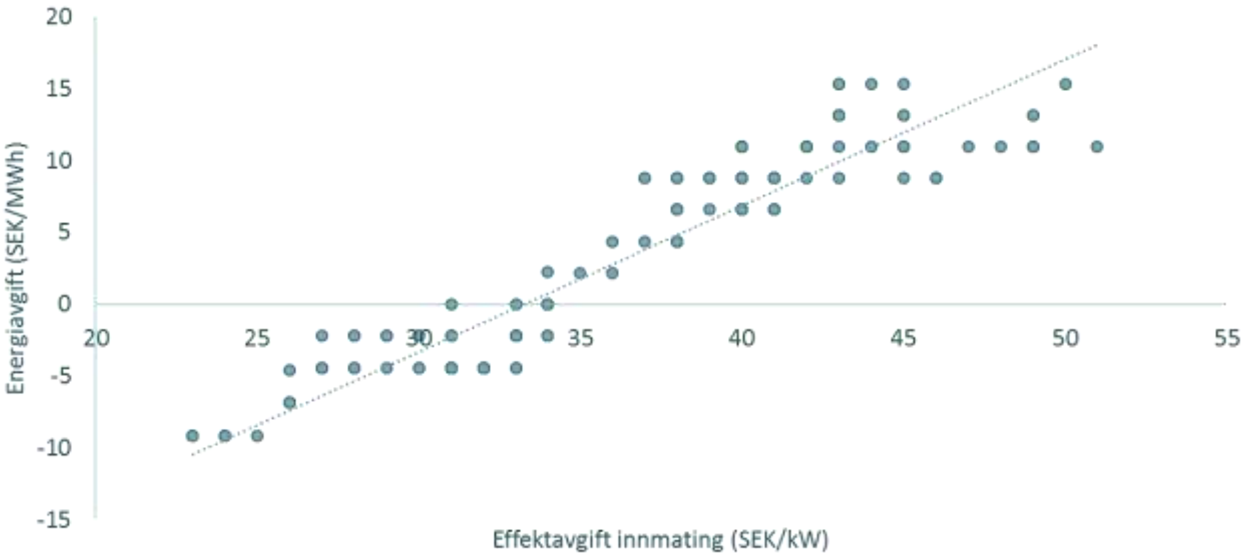
It is difficult to accurately estimate the impact of a marginal change in injection or withdrawal on long-term marginal grid costs. One aspect is the lumpy nature of grid investments, another that grid investments are in many cases carried out before the scarcity occurs or becomes acute (the dimensioning of grid capacity also takes into account security margins that are necessary to handle trips and need for in reserves the system).

Introduction of bidding zones and price differences between zones provide a locational signal and congestion rents reflect the value of reducing the congestion between zones. Energy charges also reflect capacity utilization in the grid as losses increase (exponentially) with capacity utilization. Both zonal prices and energy charges provide some incentives for location of supply and demand, but the lumpiness of grid investments and the need to maintain security margins imply that short-term signals are likely to be too weak to yield sufficient incentives for the grid customers' location decisions. In addition, the impact on grid investments is likely to vary between nodes within bidding zones (also demonstrated by calculations made by Svenska kraftnät). Therefore, additional locational signals should probably be provided through differentiated capacity charges.

Today's differentiation of the Swedish capacity charge seems to be based on principles compatible with theory.

The figure below shows that the capacity charge is highly correlated with the energy charge (94 percent correlation), implying that areas with a high energy charge also have high capacity charges, as they should, as high losses also indicates high capacity utilization. In principle, the differentiation based on energy losses may form an adequate basis even for the geographical differentiation of locational capacity charges/fixed costs. Even though the capacity charge correlates nicely with the energy charge, the slope of the differentiation function may still be too high or too low. The differentiation should be based on assessments of the impact on grid investments.

Figure 23: Relation between capacity charges and energy charges in different transmission nodes in the Swedish central grid



Source: Svenska kraftnät «Stamnätstariffen 2017», THEMA (2017)

Conclusions

All in all, the current capacity charges seem to be weakly linked to the actual marginal grid investment costs. Annual subscription can be changed from year to year, and it may actually be that temporary capacity subscriptions better reflect the capacity that is relevant for the dimensioning of the grid. Investments in the grid are, as we understand it, to a large extent based on the capacity allocation in the connection agreements, in addition to the need for reinvestments and assessments of generation and consumption developments. If Svenska kraftnät is obliged to dimension the grid in order to guarantee that all grid customers can use the allocated capacity to its full extent simultaneously, the grid is likely to be over-invested.

As long as Svenska kraftnät's investments are linked to allocated capacities, the capacity charges for grid customers should also be based on allocated capacities. This would also provide incentives for grid customers to adjust the capacity in their connection agreement if permanent changes are made. Even if capacity charges are not based on allocated capacities, grid customers with connection agreements should be obligated to notify Svenska kraftnät of permanent reductions in affecting maximum load, just as they have to notify Svenska kraftnät if they plan to make permanent increases in maximum load.

Different grid customers have different injection and withdrawal patterns and individual peak injection and withdrawals do not coincide with the system peak load. In order to provide efficient investment incentives, capacity charges in general be related to the features that affect capacity expansion in the meshed grid, i.e., some measure of system peak, and it should reflect the marginal investment cost of such capacity expansion.

The general capacity charge in the Swedish tariff is not related to non-locational marginal investment costs, but is calculated as the average cost per MW that is not covered by other tariff elements.

The current geographical differentiation is a practical approximation of the basic principles. It is based on modelling of the impact on transmission flows if injection or withdrawal increases in different nodes in the system. The differentiation is long-term stable, which is important when the incentives are directed towards investments. However, the basis for the charge is the current costs of Svenska kraftnät, which depends on the cost of historical investments and depreciation times. These costs may not be an accurate measure of the marginal costs going forward. Furthermore, it is a complex empiricial question whether the geographical differentiation is an accurate reflection of the underlying geographical marginal costs.

The deep elements of the connection charge reflect locational costs in the local and regional meshed grid, and is assessed case by case. The main weakness of deep connection charges is that they only apply to new grid customers who “trigger” grid investments.

5.3.2 Neutral recovery of residual costs

Discussion

As established above, neutral tariff elements should be applied in order to cover residual costs, i.e. the revenues needed to recover total grid costs in addition to the revenues collected through efficient price signals. The Swedish grid tariff does not distinguish between long-term price signals and residual costs. In this section, we therefore assess the capacity charge against the criteria for neutral grid tariffs. Above, we have pointed out that the capacity charges do affect the long-term investment decisions in the grid, and that the price signals are not likely to be efficient. In this section we discuss whether the capacity charges impact the short-term behaviour of grid customers, and as such the optimal utilization of grid capacity.

Impact on short-term generation and consumption

If the customers have an incentive to subscribe to their maximum capacity, the capacity charges do not affect the short-term behaviour of the grid customer. Generation and / or consumption will be optimized according to energy charges, market prices and costs.

A grid customer will however not necessarily subscribe to the expected maximum capacity for the coming year. The more variable the customer expects withdrawal and / or injection to be, the less likely it is to subscribe to its maximal capacity (and possibly to subscribe to the entire allocated capacity).

The trade-off is as follows. Let us assume that the customer (for simplicity, looking at a generator) has a maximum capacity of 200 MW, and that this amount is equal to its allocated capacity. It also expects to inject 200 MW as a maximum, but only in a few hours each year. The current marginal charge for an increase in the subscribed capacity is 50 kr/kW (cf. section 4.4.3). If it subscribes to let’s say 150 MW it still has the opportunity to increase its generation if that is desirable. The savings in terms of total costs depend on the load factor in the relevant weeks, as the price of a temporary subscription depends on the utilization of the capacity as well, in terms of a per kWh fee. The decisions facing the grid customer are:

1. Annual subscription: In the beginning of each year, the customers must decide the annual subscription. The average annual subscription fee for generators is 39.000 kr/MW/year. This should be weighed against the cost of temporary subscriptions for one or more weeks a year. Here it makes a difference if the generator expects to enter into a temporary subscription for just a week or two, or for several weeks, what capacity utilization he expects in these weeks, and how uncertain the need for and value of a temporary subscription are. There is also an additional cost related to the risk that Svenska kraftnät will not allow a temporary capacity subscription if grid capacity is scarce. The generator should figure this extra risk into its calculation of the optimal annual capacity subscription.
2. Temporary subscription: If the generator did not subscribe to his full capacity, he will be faced by the decision to enter into temporary subscriptions during the year. The temporary subscription comes with a cost that must be weighed against the increased revenues that can be made by increasing the capacity utilization during the temporary subscription period. If the generator expects to utilize the temporary subscription only for a few hours and market prices are low, it is more likely to forego the temporary subscription. The per kWh weekly subscription cost for a generator with a 50 percent load factor is 8 öre/kWh. A generator expecting a 30 percent load factor and paying the maximum subscription fee faces a per kWh weekly subscription cost of over 11 öre/kWh. (The numbers are shown in

Table 5 below.) The decisions can also be affected by the exceedance fees. If the customer only expects to exceed the subscribed capacity for an hour or two and quite infrequently, it may risk paying the exceedance fee instead of entering into a temporary subscription.

3. Utilization of the temporary subscription: Since there is a per kWh charge for utilization of the temporary subscription, the grid customer may in theory not use the subscribed capacity if the per kWh charge is higher than the increased revenues from the market. The per kWh charge may be up to almost 11 öre/kWh, see the table below.

When making the decisions, the generator should reason “backwards”: The decision to enter into a temporary subscription depends on how much the generator expects to use the capacity, and the decision on the annual capacity subscription depends on the expected value of a temporary subscription.

Table 5: Injection costs for temporary capacity subscription

	Average capacity fees			*Maximum capacity fees*
	Full load	*50 percent load*	*30 percent load*	
Subscription fee per MW/week	195	195	195	270
Injection kWh/week	168 000	84 000	50 400	50 400
Usage fee, öre/kWh	7.8	7.8	7.8	10.8
Total fee, öre/kWh	7.9	8	8.2	11.3

Source: Svenska kraftnät, own calculations

In 2018, for temporary subscriptions, a charge equal to 1/200 of the annual capacity charge is levied for each week and kW. In addition, a charge constituting 1/500 of the annual capacity charge is levied per used kWh (i.e. energy based).

Exceedance charges also affect the grid customers decisions on capacity subscriptions. The higher the exceedance charges, the higher will a customer with variable use of transmission set its capacity subscription. Here, it is important to note that the (new) exceedance charge is not related to the capacity situation in the grid at the time of exceedance, and it is not differentiated between nodes in the grid. Hence, the exceedance charge is not related to long-term grid costs. It is also not intended to be so, but still provides a short-term signal that affects grid customers use of the grid.

The main purpose of the exceedance charge seems to be to strongly incentivize grid customers to make annual and temporary subscriptions that are as accurate as possible. This may be beneficial for operational planning purposes, but we do not see how variations in the grid customers’ annual and temporary subscriptions affect grid investment costs.

The exceedance charges introduce an uncertainty for grid customers. The uncertainty can be significant for grid customers who cannot easily predict or control their injections and withdrawals. Exceedance charges are however lower in the first and second hour of exceedance, giving the grid customer the opportunity to apply for a temporary capacity subscription before the full exceedance charge kicks in. Although the purpose of the exceedance charge is to deter grid customers from exceedance, in particular the reduced charges in the first two hours of exceedance, seem to invite grid customers to risk exceedance rather than subscribe to capacity temporarily.

The discussion above shows that the system of capacity subscriptions and exceedance charges potentially affects the short-term withdrawals and injections of power in the grid. As the charges are not related to the capacity situation in the grid, the consequence can be that the grid is not utilized to its full benefit in periods when there is no scarcity in the grid.

In principle, if there is capacity available in the grid, it is efficient to use it in the short term if market prices and costs deem it profitable. The short-term impact on grid costs should be reflected in the energy charge. A temporary increase in withdrawal or injection does not impose an increase in the long-term grid cost. Imposing such fees thus runs the risk of distorting short-term generation and consumption decisions. (The extra cost of temporary subscription and exceedance charges.)

Conclusions

In terms of the impact on short-term utilization of the grid, capacity subscriptions should not be applied, as it risks under-utilization of the grid and distortion of grid customers injection and withdrawal.

By applying a temporary capacity charge that is weekly and also varies with energy injection or withdrawal, the incentives to use available grid capacity is weakened. This represents an economic loss to society. A subscriber who can control its injections and withdrawals is likely to adjust its grid use according to the charges.

An efficient price signal should only affect the long-term behavior of grid customers, and not the short-term behavior as long as grid capacity is not scarce.

Residual revenues should be charged by a neutral grid element. Although complete neutrality is difficult to achieve, the Norwegian residual tariff on generators may serve as a good example. (We will return to the distribution of residual charges below.) Generators are charged according to their average annual energy injection over the last 10 years. This implies that they are not incentivized to deflect generation in high-load periods.

5.4 Allocation of residual charges between injection and withdrawal

Discussion

The “taxation” of grid users in order to cover residual costs is deemed to yield efficiency losses (cf. chapter 2).

According to THEMA (2017), the efficiency loss will be minimized by applying residual cost charges on both generators and consumers, even if the grid is connected to adjacent areas via interconnectors. Optimal allocation implies equating the marginal efficiency loss of a change in the generator and consumer charges. The efficient allocation depends on the elasticities of supply and demand, including the export elasticity and the power balance. In practice, the levels must be estimated by empirical (model-based) analyses, taking into account long-term market dynamics, including the impact of different framework conditions in the integrated market area.

In general, the principles for calculation for G-tariffs should be harmonized among TSOs/control areas, but not the levels because residual costs and the elasticities of demand and generation are deemed to vary.

Via the connection charges and capacity charges, some of the residual costs of Svenska kraftnät are probably covered by generators. The international comparison shows that while Sweden and Norway have positive G-tariffs, most other countries levy all residual costs on consumers.

Conclusions

The distribution of residual costs between injection and withdrawal should be based on assessments of the relative price elasticities of generation and consumption.

5.5 Other tariff elements

Discussion

Svenska kraftnät does not have a tariff for reactive power in the current model. We are aware that Statnett and several Swedish regional grid companies use tariffs for consumption of reactive power. The aim is to provide a price signal related to reactive power that punishes reactive power that inflicts costs on the system and to reward reactive power that is beneficial for the system.

The Norwegian TSO, Statnett, applies a tariff charge for injection or withdrawal of reactive power that is disadvantageous for the system, in order to incentivize instalment of compensation devices where they are needed. Generators are generally expected to keep their contribution of reactive power around zero and are compensated for documented beneficial contributions outside a specified bandwidth around zero.

It is our understanding that the issue of reactive power is becoming more important due to more renewable power generation in the system and more capacity-demanding consumption devices (including electric vehicles), plus increased undergrounding of transmission lines. Hence, price signals may be desirable as part of the TSO toolbox to handle to problems that arise. However, it is also our understanding that there are important practical issues that need to be resolved, inter alia related to metering of reactive power. It is also not straightforward to design the proper tariff mechanism and parameters, and it would require a more detailed technical study in order to make specific recommendations on this issue.

Conclusions

Svenska kraftnät should investigate further whether a tariff for reactive power should be introduced and how it can be designed. For that purpose we recommend that the company seeks to learn from the experiences of Statnett and possibly other TSOs and also from Swedish regional grid companies.

5.6 Summary of identified inefficiencies

Figure 24 provides a high-level comparison of the elements of the current tariff structure with the criteria for optimal tariff design established in chapter 2 (cf. Figure 10), while Table 6 provides some more detail on the identified inefficiencies and the sources of these inefficiencies in terms of which criteria they are in breach of.

In the next section we present our recommendations for an amended tariff structure in more detail, i.e. how the identified inefficiencies may be removed or reduced.

Figure 24: The current Swedish tariff compared to optimal tariff design

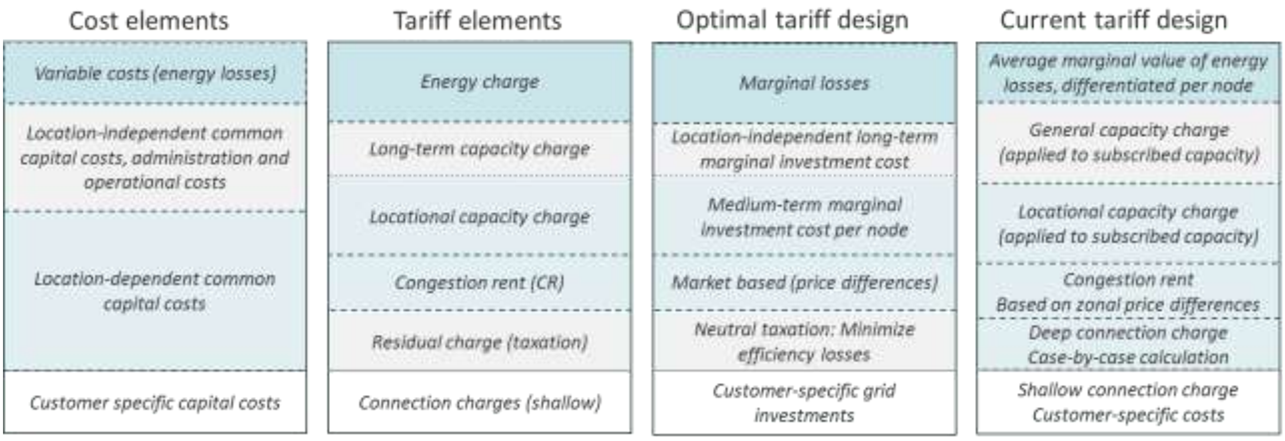


Table 6: Summary of identified inefficiencies in the current Swedish transmission grid tariff

Tariff element	Identified inefficiencies in the grid tariff	Relevant efficiency criteria
Energy charge	Energy charges are differentiated according to average annual marginal loss factors. The correction charge further reduces the efficiency of the energy charge.	Loss factors should be differentiated in line with the variation in actual marginal losses. Energy charges should reflect the marginal value of energy losses.
Connection charges	Deep connection charges that depend on the timing of connection to the meshed grid.	Connection charges should only cover customer-specific grid costs, i.e. be shallow. Shallow connection charges should be applied in combination with a uniform locational capacity charge reflecting the marginal impact on medium-term costs in the meshed grid.
Capacity charges	Current capacity charges are weakly linked to long-term marginal grid costs. The geographical differentiation based on latitude is a crude approximation to the actual differences in the impact of location in different nodes on grid investment costs. Basing charges on annual capacity subscriptions, temporary subscriptions and exceedance penalties, runs the risk of adversely affecting grid customers' short-term use of the grid. Capacity charges cover residual costs.	Capacity charges should be linked to decisions by grid customers that affect the dimensioning and thus, long-term grid costs. Capacity charges should be levied as a general charge applying to all grid customers. The charge should reflect the long-term cost of grid expansion that is largely independent of the current grid configuration and congestion pattern. A locational capacity charge should be applied that signals the differences in the impact on grid investments depending on the location in the grid. This locational signal should ideally be differentiated between nodes. Residual costs should be covered by a separate residual charge that should be as neutral as possible.

6 RECOMMENDED CHANGES IN THE TARIFF STRUCTURE

Based on the assessment summarized in the table above, we recommend an amended tariff structure for the Swedish transmission grid, summarized in Table 7.

Table 7: Recommended transmission grid tariff structure

Tariff element	Design and rationale	Cost base
Connection charges	Shallow, reflecting customer-specific connection costs only.	Cost of connection components that can only be used by one customer. The cost should be calculated case by case.
Energy charges	Reflecting energy losses according to variations in marginal loss factors and actual market prices. Together with zonal price differences, energy charges signal how the customers' short-term operation affects grid costs.	Loss factors differentiated according to historical data, e.g. weekly, monthly or seasonally, between night and day, and between working days and weekends. Applied loss factors should be updated per period based on estimations for the next period. Charges should be based on actual hourly zonal prices.
General capacity charge	Uniform charge reflecting the long-term impact on grid investment costs of changes in injection or withdrawal from the grid that is independent of the timing and location of the grid customer. The general capacity charge reflects the basic cost associated with a MW being connected/having access to the common grid.	The marginal cost of grid investments that is not location-specific, reflecting the lowest common denominator for the cost of access to the grid. This element could, e.g., be based on the annual cost of station capacity. The charge should be based on the customers' expected withdrawal or injection in dimensioning hours (system peak). Charges should be long-term stable but should reflect the general cost development of relevant grid components.
Locational capacity charge	Differentitated charge reflecting the medium-term impact on grid investment costs of a change in injection or withdrawal that depends on the location of the customer. The locational capacity charge incentivizes customers to make locational decisions that take into account the current configuration and congestion patterns in the grid that are not reflected in energy charges and zonal prices.	Marginal cost of grid expansion based on flow-analyses of increases in withdrawal and injection per node in the transmission grid, based on the current grid configuration. Charges should be based on the customers' expected injection or withdrawal in dimensioning hours (nodal peak). Charges could be both positive and negative. Charges should be updated in accordance with changes in the grid configuration, for example every 3 years in order to provide predictability.
Residual charge	Residual charges should cover costs not covered by the other tariff elements. Residual charges should be designed so as to not affect the short-term utilization of the grid and should affect the long-term behaviour of grid customers as little as possible. Residual charges should be allocated between generators and consumers according to relative long-term elasticities.	Residual costs = total annual costs – (revenues from other tariff elements + congestion revenues) The allocation of residual costs should be based on empirical studies of price elasticities. Generators (injection) could be charged according to annual average electricity generation over the last 5-10 years. Consumers (withdrawal) could also be charged according to annual energy consumption. Charges could be differentiated according to elasticities between consumer groups.

The recommendations do not represent a radical change in the tariff structure but implies a clearer separation of elements with different purposes and a clearer link to economic theory.

The main recommended changes are:

1. In general, to establish a clearer link between marginal costs and tariff elements that are introduced to provide price signals in different time-frames.
2. To differentiate energy charges to better reflect actual losses in the grid. Such differentiation becomes more important as the share of intermittent renewable generation increases in the system.
3. To apply shallow connection charges and let the deep elements be captured by a general geographically differentiated capacity charge.
4. To base capacity charges on long-term marginal grid costs and link geographical differentiation to medium term impacts, reflecting the current grid configuration, and the general charge to long-term impacts on grid investment costs, i.e. a basis charge for access to the grid.
5. To levy capacity charges according to the load that is relevant for the dimensioning of the grid in order to relate the price incentives for grid customers more directly to the investment costs in the grid.
6. To introduce a residual charge that is distributed among grid customers according to the Ramsey principle for efficient taxation.
7. To consider introduction of a tariff for reactive power.

We can make some additional comments on the cost basis for the charges:

- Capacity charges should not be based on the individual high load of the customers, but on a measure that is linked to the capacity used in assessments of the need for investments in the grid, such as the customer's load in system peak. For withdrawal, we propose to use the average load in 3-5 high-load reference hours over the last 5-10 years as the basis for capacity charges. Using annual data and absolute maximum values can yield perverse short-term incentives and counteract flexibility and capacity availability which are beneficial for the system. The reference hours should not be fixed, but defined ex post. The reference hours should also be separated by e.g., a minimum number of days, in order to be as representative as possible and not provide incentives for adverse behaviour. Alternatively, the average load over a number of peak periods could be applied. The precise design should be analysed more closely in relation to drivers for grid investments and the responses from grid customers.
- The marginal cost estimates should ideally be based on long-term grid modelling. Moreover, the cost per MW must be based on expected per MW costs: In principle, an increase in the load in one node of 1 MW could trigger investment in 100 MW grid capacity. The marginal cost should then be the cost of the 100 MW capacity per MW.
- The cost basis for the geographical differentiation could be based on the current definition of location-specific investment costs. Changes in flow on the main interfaces in the grid could also be maintained as the basis for the geographical differentiation. Further empirical analyses could be carried out to check that the charges correspond with marginal cost, e.g. based on in-depth studies of actual grid investment cases.
- Consumers with interruptible contracts should in general not pay capacity charges for the share of their capacity that can be interrupted. However, this requires that the interruptible contracts are sufficiently long-term to have an actual impact on grid investments. This also implies that interruptible contracts should not be offered generally, but be reserved for the cases where such contracts clearly reduce grid investment costs. In relevant cases, interruptible contracts should be offered to all grid customers which could potentially provide valuable flexibility.
- Different types of generators also affect grid investments differently, and such differences should ideally be reflected in the capacity charges. The same capacities of flexible hydro-power and wind power are for example likely to affect grid investment costs differently. This

issue is however a complex one, also from a legal perspective, and should be analysed further. Importantly, the capacity charges should be designed so that they do not counteract the development of valuable flexibility and capacity in the system. At the same time, energy charges and locational signals should even apply to flexible generation, as the value of flexibility also depends on the location of the flexibility resources in the grid. Capacity charges for generation could for example be based on the expected winter capacity (for new generation), and for existing generation on the average injection during winter high load hours. Basing the capacity charges on only a few peak hours, could yield adverse incentives leading to artificial price spikes and capacity scarcity.

- The sum of capacity charges will not cover residual costs. Due to the economic characteristics of the grid, marginal costs are typically lower than the average costs. Instead, a residual charge that is not related to capacity should be introduced. We propose that the charge is based on the average annual energy injected or withdrawn over the last 5-10 years for both injection and load. The cost will have some impact on long-term investments in electricity consuming equipment and on generators' costs, but should not affect the short-term generation and consumption patterns.
- The distribution of residual charges should be based on grid customers' price elasticities. This principle should apply both to the allocation between generators and consumer, but even within the generator and consumer groups. Elasticities are an empirical question and they are difficult to estimate reliably. A practical approach must be adopted based on assessment of available data and statistical analysis.

We also recommend the following regarding joint capacity charges and unutilized allocated capacity:

- Svenska kraftnät should offer joint capacity charges for regional grid owners with transit in the hours that determine the capacity used as basis for the capacity charges (reference periods, cf. point 5 above). A simple solution could be to base the netting on historical data or model analysis of the typical transit patterns in the periods the capacity charges are based on.
- The guarantee related to allocated capacity according to the connection agreements should be conditional. Specifically, grid customers should be obliged to give up capacity if they make permanent changes in their load that free up capacity that can be used by others. For example, grid customers could be required to report on their capacity situation every or every other year, and to report on permanent changes in capacity. Alternatively, Svenska kraftnät could monitor capacity utilization and have the right to ask for a statement of the same. Such provisions would require changes in connection agreements and probably in the legal framework. We note however, that replacing deep connection charges with general locational signals should make it easier to introduce such an obligation. We do not recommend the introduction of a penalty fee related to unutilized capacity. Such a fee could give perverse incentives to utilize the capacity to its maximum once a year, and would in any case require that the grid customer gets a chance to provide a statement of the reason for the unutilized capacity. In any case, a definition of "permanent reduction in capacity" must be developed.

The principles applied in the transmission tariff will be more efficient if they are also applied to grid customers in the regional grid. Since "demand" in the Swedish transmission grid is to a large extent represented by regional grid owners, the gains of a more efficient transmission tariff, depends on the impact on regional grid tariffs.

7 IMPACT ASSESSMENT

In this chapter we present an impact assessment of our proposed changes to the tariff model. We consider the individual elements from the perspective of the different groups of grid users and from an economic efficiency perspective. We have not assessed other impacts such as e.g., on operational security, administrative costs or requirements for IT solutions.

First we assess the impact in terms of grid costs for different grid customers, and provide an illustrative calculation of changes in the distribution of total grid costs among different types of generators including the locational element.

Next we consider the impact on the short- and long-term incentives for using and connecting to the grid and the distributional effects.

Finally, we analyse the consequences for Svenska kraftnät. For Svenska kraftnät the incentives for operating and developing the grid do not depend directly on the tariff model. Rather, these incentives depend on the economic regulation (the revenue cap) and the obligations on Svenska kraftnät that follow from Swedish and EU legislation. Instead, we consider the indirect impact on Svenska kraftnät from changes to the incentives faced by grid users and the volatility of annual tariff revenues.

7.1 Tariff elements for injection and withdrawal

According to our proposal, the total tariff structure for injection and withdrawal respectively would be as described in the tables below. We also comment qualitatively on the change in the total charge relative to the existing tariff structure.

7.1.1 Injection charges

Element	Cost basis	Differentiation	Comment
Shallow connection charge	Connection costs	Customer-specific	Lower than today's charge as deep elements are excluded
Energy charge	Marginal nodal energy losses priced at market values (SEK/MWh)	Per node, over time, surplus (+)/deficit (-) area, area prices	Larger variations than today, more accurate price signal. Somewhat higher total charge, probably small redistribution effects.
General capacity charge	Marginal long-term grid investment cost, SEK/MW according to expected injection in system peak load periods	Same for all	Substantially lower than today's basic capacity charge which includes all costs in the meshed grid.
Locational capacity charge	Marginal medium-term grid investment cost, SEK/MW according to expected injection in local dimensioning hours	Per node	Positive in surplus areas, negative in deficit areas. Differentiation probably similar to todays difference between min and max capacity charge.
Residual charge	Average residual cost, SEK/MWh, e.g. according to 10-year annual average injection	Same for all injection	New positive element that replaces a substantial part of current capacity charges

7.1.2 Withdrawal charges

Element	Cost basis	Differentiation	Comment
Shallow connection charge	Connection costs	Customer-specific	Lower than today's charge as deep elements are excluded
Energy charge	Nodal energy losses priced at market values (SEK/MWh)	Per node, over time, surplus (-)/deficit (+) area, area prices	Larger variations than today, more accurate price signal. Somewhat higher total charge, probably small redistribution effects.
General capacity charge	Marginal long-term grid investment cost, SEK/MW according to withdrawal in system peak load	Same for all	Substantially lower than today's basic capacity charge which includes all costs in the meshed grid.
Locational capacity charge	Marginal medium-term grid investment cost, SEK/MW according to expected withdrawal in local dimensioning hours	Per node	Positive in deficit areas, negative in surplus areas. Differentiation probably similar to todays difference between min and max capacity charge.
Residual charge	Average residual cost, SEK/MWh, e.g. according to 10-year annual average generation	Same for all withdrawal	New positive element that replaces a substantial part of current capacity charges

It emerges that a smaller share of the grid costs will be charged according to capacity, i.e. per MW, and more according to energy, i.e. MWh. In particular, the revenues accruing from capacity charges will be reduced substantially and the revenue loss will be replaced by a residual charge based on average energy. This also implies a reallocation of some of the grid costs among customers. Base load (injection and withdrawal) will pay a larger share of the residual charge than peak load, and the capacity charges paid by peak load and flexible generation will be lower. The differentiation of capacity charges will probably not change substantially, but the levels of capacity charges will be lower.

We elaborate on the impacts on different kinds of grid customers in the next section, illustrating both distributional and incentive effects.

7.2 Comparison of generator charges with exising and new tariff structure

To illustrate the long-run consequences of the proposed changes to the capacity charge for generation, we have constructed the following simplified example:

- We consider a market with two price areas, 1 and 2.
- In area 1 there is a total of 3000 MW of capacity divided equally between wind power, run-of-river hydro and flexible hydro. Total energy generation is 3 TWh, 6 TWh and 3 TWh respectively.
- In area 2 there is a total of 1500 MW of capacity, of which 1000 is nuclear power and 500 is wind. Total energy generation is 8.5 and 1.5 TWh respectively.

We assume the following capacity charges for injection in the existing tariff regime:

- 60 SEK/kW in area 1 and 30 SEK/kW in area 2. The implicit locational signal is 30 SEK/kW.

The corresponding capacity charges per kWh and per generation technology in each area are summarised in the table below. As can be seen from the table, generators in area 1 pay a higher capacity charge than generators in area 2. Furthermore, the charge is greater the lower the load factor. The long-run marginal cost impact of the capacity charge is therefore higher for wind power and flexible hydro compared to run-of-river hydro and nuclear.

	Technology	Capacity (MW)	Load factor (h/y)	Capacity charge (SEK/kW)	Capacity charge (öre/kWh)
Area 1	*Wind power*	1000	3000	60	2.0
	Run-of-river hydro	1000	6000	60	1.0
	Flexible hydro	1000	3000	60	2.0
Area 2	*Wind power*	500	3000	30	1.0
	Nuclear	1000	8500	30	0.4

We now consider the impact of a tariff model along the lines we proposed in the previous chapter. Specifically, we consider the following tariff components and rates:

- A base capacity charge equal to the assumed long-run marginal cost that is independent of the geographical location of consumption and generation. For illustration purposes we set this at 30 SEK/kW.
- A locational signal of +/- 15 SEK/kW. Hence generators in area 1 are subject to an extra charge of 15 SEK/kW and generators in area 2 get a deduction of 15 SEK/kW. The implicit locational signal is 30 SEK/kW as in the original model.
- A residual tariff charged per kWh average generation equal to 0.5 øre/kWh.

The tariff rates have been calibrated to yield the same total income for the grid operator with both tariff models given our assumptions on capacities and load factors.

	Technology	Capacity (MW)	Load factor (h/y)	Base plus locational charge (SEK/kW)	Base plus locational charge (öre/kWh)	Residual tariff (öre/kWh)	Sum generator tariff (öre/kWh)	Change from original model (öre/kWh)
Area 1	*Wind power*	1000	3000	30+15=45	1.2	0.5	1.7	-0.3
	Run-of-river hydro	1000	6000	30+15=45	0.6	0.5	1.1	+0.1
	Flexible hydro	1000	3000	30+15=45	1.2	0.5	1.7	-0.3
Area 2	*Wind power*	500	3000	30-15=15	0.2	0.5	0.7	-0.3
	Nuclear	1000	8500	30-15=15	0.1	0.5	0.6	+0.2

From these examples we see that the difference in tariff cost per kWh between technologies is lower with the proposed model, thus leading to less distortion assuming that the tariffs reflect differences in long-run network costs more accurately than the current model. The capacity charge is lower for all generators. At the same time, the locational signal is still present and yields a lower tariff cost for generators in area 2.

7.3 Changes in the capacity charge

7.3.1 Incentives for generators

We discuss the incentives for investment first.

For generators the general incentives to invest will be unchanged given that the average tariff level for generators will be the same with our proposed model as in the current model. However, there will be changes to the incentives of individual generators depending on localisation and type of generation technology.

Any changes in the locational signals depend on the methodology for setting the relevant cost base and also the degree of detail in the load flow analysis. This cannot be estimated without a detailed analysis.

We can be more specific about the impact of the change of charging base for the residual component. For generators, part of the tariff (the residual component) will be based on average energy rather than capacity. This will strengthen the competitive position of e.g. wind power and hydro against base load technologies. We emphasise that the price signals including the locational signals are maintained through the other parts of the tariff. The aim here is to make sure that the tax element of the tariff functions as neutrally as possible.

In the table below, we illustrate the consequences of an energy-based residual tariff with a simple example. The total cost to be covered by the residual tariff is 80 SEK. There are three generators, each with a capcacity of 1 kW, with 3000, 5000 and 8000 full load hours respectively, i.e. a total generation of 16 000 kWh. A residual tariff of 0.5 øre/kWh will meet the income requirement of 80 SEK. If the same amount is to be recovered through a capacity-based tariff, the capacity charge per kW must be 26.67 SEK/kW. This translates into an effective tariff per kWh of 0.33 øre for the baseload generation and 0.89 øre for the generation with the lowest number of full load hours. A residual tariff based on capacity therefore leads to a distortion in generation investment as the full cost increases without any foundation (remember that the marginal cost element is reflected in the general and locational capacity charge and the shallow connection charge).

Table 8: Consequences of energy-based residual tariff

Full load hours	*Residual tariff (öre/kWh)*	*Tariff cost (SEK/kW)*	*Equivalent capacity tariff (SEK/kW)*	*Capacity tariff (öre/kWh)*
8000	0.5	40	26.67	0.33
5000	0.5	25	26.67	0.53
3000	0.5	15	26.67	0.89

Regarding the short-term incentives, the charging base is an important factor. We may distinguish between the following mechanisms:

- *Installed capacity.* With installed capacity as the charging base, the actual capacity use does not influence the short-run marginal cost and the supply of flexible generation.
- *Subscribed capacity.* With subscribed capacity the short-run marginal cost is not affected as long as the capacity use is lower than the subscribed level. With temporary subscriptions and/or exceedance fees, the generators will need to weigh the benefits from increased use of capacity against the increased tariff costs, hence affecting short-run marginal costs and market bids.
- *Capacity use in reference hours.* With capacity use in reference hours as the charging base the maximum use in these hours will come at a very high cost as this use will affect the total cost of production over the year. This will affect the marginal cost and hence generator bids and market prices, resulting in possible distortion due to demand being crowded out from

excessive prices (excessive compared to the correct economic level). This applies even if the reference hours are intended to be random and not possible to perfectly foresee for the generators (it will be possible to assess the probability of when the reference hours will occur, in particular if nodal or system peaks are used). However, the effect is significantly reduced if the reference period is sufficiently long, for instance average capacity use in the winter months.

- *Maximum capacity use.* Maximum capacity use at generator level (i.e. regardless of system or nodal peaks) will have similar incentive effects as capacity use in reference hours. A marginal MW of generation will impact the total tariff cost and hence the short-run marginal cost.

Ideally we would want the tariff charging base to have as little impact as possible on the short-run marginal cost and price formation in the electricity market. On this background, capacity use over a large number of reference hours or a measure approaching available winter capacity as in the Norwegian model would seem like a good way forward. However, the charging base should be considered in more detail before settling on a new model. The impact on the short-term operation of flexible, peak-load generation capacity is particularly important as this capacity is crucial in scarcity periods and more sensitive to incentives in the grid tariff than base-load and in-flexible capacity.

7.3.2 Incentives for consumers

For a hypothetical consumer connecting to the transmission grid, the proposed changes will not impact the average tariff, provided that the maximum G-tariff applies to generators. The impact on the locational signals is uncertain as discussed for generation above.

As long as costs of the overlying grid are treated as pass-through in the revenue cap regulation of the regional grids, changes to the capacity charge do not directly alter the incentives of the regional grid companies to optimise consumption. There is an incentive mechanism in the current regulatory revenue cap model related to the load factor in exchange points between grid levels and costs of the overlying grid, but this mechanism is complex and does not give a direct link between Svenska kraftnät's tariffs, grid costs and behaviour in the underlying grids (see Energimarknadsinspektionen, 2018b).

7.3.3 Distributional effects

Ex ante it is difficult to assess the distributional effects of the changes to the capacity charge and the introduction of three separate tariff components, both qualitatively and quantitatively. However, the move to a separate residual tariff for generation charged on the basis of average generation will shift part of the tariff costs from generators with low load factors (wind power, flexible hydro) to baseload generation.

7.3.4 Consequences for Svenska kraftnät

For Svenska kraftnät the impact of the changes to the capacity charge is difficult to assess. In principle it should lead to more efficient investments in power generation. How changes in generation investment influence investments in the grid is not possible to assess in advance.

Revenue stability should be approximately the same as in the current model, all else equal.

7.4 Removing subscribed capacity as basis for the capacity charge

7.4.1 Incentives for generators

For generators there will no longer be an extra cost if the subscribed capacity is exceeded. Rather, the marginal cost of feeding into the grid will only depend on the general tariff rate and not the ratio of the market value of extra power compared to the tariff for temporary subscription or the charge for exceeding the subscription. Outside the nodal and system peak hours the marginal network cost will in fact be limited to the energy charge. In addition there will be a small impact on the residual tariff

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provided the average generation is updated on a rolling basis. However, as there is a time lag in the updating of the charging base and the effect is spread out over a number of years, the marginal cost impact will be significantly lower than the nominal tariff. In total, the proposed model should improve incentives for providing long-term and short-term flexibility. Below, we describe an example of how the current model affects investment decisions.

Harmonization of generator tariffs in the Nordics and EU[18]

In 2014, THEMA studied harmonization of generator tariffs in the Nordics and the EU. To illustrate how the tariff system influences economic decisions of power generators in Sweden, three different cases are studied.

First, the report analyses the profitability of a new wind power plant according to two different capacity charges, due to geographical location. The capacity charge is 47.7 SEK/kWh in SE1 and 23.6 SEK/kWh in SE4. This results in a difference in investment costs of 23.6 SEK, solely due to the difference in capacity charge. This, they argue, will lead to overinvestment in SE4 if the capacity charge does not reflect real network costs.

The two other cases analyse how the choice of capacity subscription affects economic decisions. The Swedish G-tariff is capacity-based. This affects economic decisions on whether to increase the capacity in existing hydropower plants by making small additional investments or investing in pumped storage.

For existing wind or run-of-river power plants, it is most likely optimal to subscribe to a capacity equal to the installed capacity. For hydropower plants with reservoirs, the situation is different. Generators who have the possibility of storing energy can adjust the subscribed capacity without it affecting the total amount of energy produced. If they choose to reduce the subscribed capacity, this will increase the risk of lost generation in periods with high inflows. To subscribe to temporary subscriptions, and by that exceed the annual subscribed capacity, the benefit needs to be higher than the additional cost this imposes. In practice, this will only happen when the market price of electricity is high enough.

7.4.2 Incentives for consumers

In the currently hypothetical case of consumers directly connected to the transmission grid, the costs for extra withdrawal of power will be zero outside the reference hours used for the general and local components of the capacity charge. This will typically be relevant in the hours with spare capacity in the system and/or at the local node. This should provide more efficient utilisation of the grid and increased consumer surplus from electricity consumption.

Similar incentives will arise if customers in regional grids are subject to the same tariff principles as those used by Svenska kraftnät. Currently, regional grids use different models for capacity charges. Some base their charges on subscribed capacity while others use maximum capacity. In our view it should be clarified in the regulation that end-users in the regional grid should be subject to the same tariff principles as those used by Svenska kraftnät (while the tariff level may still vary).

7.4.3 Distributional effects

The distributional effects depend on whether there will be a systematic impact on the charging base. This depends inter alia on the correlation between subscribed capacity and the capacity use during the reference hours. It also depends on whether the changes to the model lead to changes in the behaviour of the grid users (e.g. that they choose to reduce or increase their grid use due to the changes in the implicit price signals).

[18] THEMA (2015): Harmonisation of generator tariffs in the Nordics and the EU. Commissioned by Fortum, Skellefteå Kraft, Statkraft and Vattenfall.

Assuming that there is a high degree of correlation between subscribed capacity levels and the charging base under the proposed model, we expect the distributional effects from removing subscribed capacity to be small, all else being equal.

7.4.4 Consequences for Svenska kraftnät

Removing subscribed capacity as a charging basis should enable more flexibility on the part of generators and underlying regional grids as they are no longer constrained by their subscribed capacity levels. This should contribute to more efficient use of the grid in the short run and more efficient investments in the long run.

While removing subscribed capacity may seem to give Svenska kraftnät less information about the grid use of the customers, we would argue that this information is neither necessary nor sufficient for operational purposes. Firstly, the key source of information about actual grid use is the volumes submitted in bids in the day-ahead market. Secondly, grid users may deviate from subscribed capacity in either direction. In this regard, under-use of subscribed capacity may be equally detrimental to the system as excess use.

The tariff revenues may become less predictable when moving from subscribed capacity to a charging basis given by consumption in reference hours or maximum consumption. However, this also depends on the extent to which the grid customers use temporary subscriptions and/or pay excess charges. The subscribed capacity levels may also vary on basis with variations in inflows, temperatures and economic activity, both on an annual basis and within the year (using temporary subscriptions). We are therefore not able to quantify the impact, but we consider the consequences to be small.

7.5 Changes to the energy charge

We have proposed changes to the energy charge that lead to higher variability within the year and a larger interval for the resulting energy charges. We consider the incentive effects of the different elements together in the following.

7.5.1 Incentives for generators

Removing the correction factor on marginal loss factors and the adjustment factor of 0.8 will improve the quality of the price signals in the transmission grid. Along with the move to hourly area prices already decided by Svenska kraftnät from 2020, this ensures that the price signal related to marginal losses in the grid approaches the optimal nodal signal according to economic theory. This should lead to more efficient allocation of generation connected to the transmission grid in the short run and will also give more appropriate long-term signals for investments in generation.

7.5.2 Incentives for consumers

The incentives for consumers will in principle also improve with the proposed changes to the energy charge. However, as the underlying regional grids can pass through transmission costs to their consumers, the grid companies do not have a direct incentive to optimise their use of the transmission grid (see section 7.3.2 above).

If individual consumers were to be connected to the transmission grid, the proposed changes would also ensure more correct incentives than the current model.

7.5.3 Distributional effects

The level of revenue from the energy charge should increase with the removal of the adjustment factor and lifting or removing the cap on individual loss factors. This will reduce the residual tariff and redistribute costs between generators and consumers, all else being equal.

The distributional effects from changes to the energy charge between nodes will again depend on whether there are any systematic changes. In general, and assuming that the current loss factors are reflective of the more variable loss factors under the new model, removing the adjustment will

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increase the costs paid by generators in the north of Sweden and consumers in the south. For generators in the south and consumers in the north costs will be reduced (higher negative loss factors).

More frequent updates and hourly pricing may also have an impact, along with any changes in behaviour due to the changed price signals. These effects cannot be quantified without a detailed model that includes both market and grid aspects.

7.5.4 Consequences for Svenska kraftnät

For Svenska kraftnät, the changes to the price signals should improve the utilisation of the grid in the short term and lead to lower overall costs of losses, again all else being equal.

To the extent that the stronger and more correct signals also affect the long-term behaviour of grid customers, network investments may also be reduced. A more correct locational signal should give a better utilisation of the grid.

Furthermore, the expected revenue from the energy charge should increase, leading to a lower residual need for income and lower tariffs to ensure cost recovery. The energy charge itself will be more variable.

The revenue from energy charges to Svenska kraftnät will be more variable, but this can be matched by changing the purchase profile of losses as well (i.e. move from annual purchases of losses to spot price-based purchases on a daily basis). Hence there should still be a high correlation between the variability in tariff revenues and Svenska kraftnät's costs.

The annual revenues from the energy charge will increase compared to the current model. This will however offset through lower residual tariffs within a given revenue cap (or target revenue level if Svenska kraftnät does not charge the full revenue cap). As the capacity and residual tariffs are set for a year at a time, the changes in the energy charge will lead to larger annual revenue imbalances and possibly also imbalances at the end of the regulatory period (currently four years). However, we consider that this effect is likely to be small and to be outweighted by the efficiency gains from a more efficient energy charging regime. Such imbalances should also be possible to mitigate through good forward-looking analysis and forecasts of the cost of losses.

7.6 Changes in cost distribution

We do not recommend specific changes to the distribution of costs between generators and consumers in the transmission grid. However, we do recommend that Svenska kraftnät considers the cost distribution and the level of the residual tariffs for different customer groups in light of the respective price elasticities for transmission demand. On this background, we consider the impacts of a higher residual tariff for generators in the following.

7.6.1 Incentives for generators

Current Swedish tariff levels for generators are lower than in Norway on average, and lower than the EU cap. If the residual tariff cost faced by generators is increased, this will in isolation lead to weaker investment incentives for generation. However, it can be argued that an increase to the level in EU Regulation 838/2010 will lead to a level playing field with Norwegian generators, which are the closest competitors to Swedish generation in the long run. For other countries the competition is limited by transmission capacity constraints, which means that increases in the long-run marginal cost of generation in Sweden will be partly offset by higher prices.

7.6.2 Incentives for consumers

A higher residual tariff for generators will lead to a lower tariff cost for underlying regional grids and the consumers connected at that grid level. The higher price for consumers must however be compared to the lower tariff cost. Also, consumers will be faced by a price increase from the portion of the tariff increase for generators that is passed through in Swedish electricity prices.

Ideally, the residual tariffs should be differentiated between groups of consumers depending on the price elasticity of demand. This has been a key element in the recent debate on the further development of the Norwegian transmission tariff (cf. also the German transmission tariff model and the French system which are described in THEMA, 2018). It is however beyond the scope of this report to analyse and recommend options for cost distribution at lower grid levels.

7.6.3 Distributional effects

A higher residual tariff for generators will lead to a higher share of transmission costs paid directly by generators. The long-term effects will depend on how prices and investments are affected.

Distribution between consumers and generators – case study of Norway

In theory, how to optimally distribute residual costs is clear. Residual costs should be divided between input and output so that the efficiency loss is minimized. However, what this means in practice needs to be investigated empirically. In THEMA (2017a) we studied this question for Statnett. By using THEMA's power market model, the consequences of increasing the tariff for producers and consumers were illustrated.

Some central assumptions are endogenous investments in new power production and inelastic demand. Exceptions are investments in wind and solar due to subsidizing renewable energy sources, and investments related to the continuation of elcert in Sweden. The effect was calculated in 2030. Together with the removal of the capital tax on nuclear power, Sweden is left with a considerable energy surplus in 2030. This reduces the probability of pure market-based investments in new production.

Model simulations were done with and without an extra cost for Norwegian production capacity of 2 EUR/MWh (level chosen randomly for illustrative purposes). Even though the situation in Norway is not identical to Sweden, the results can be useful.

As expected, the investments in Norwegian power production is reduced. The reduction amounts to about 1 TWh a year. This is mainly replaced with increased production of natural gas in Europe, as the Nordics already have a power surplus. Existing power plants provide most of the increase in gas production.

The price effect shows that demand for Norwegian export is relatively elastic. An increase in the G-tariff of 2 EUR/MWh increases the power price in Norway by 0.35 EUR/MWh. It is the producers who bears the burden of the increase in the G-tariff. This result is however under the assumption of inelastic demand.

Model simulations where one assumes elastic demand shows even smaller price effects.[19] Using the same elasticity and letting the consumers pay the residual costs through a larger fixed fee (lump sum), the Norwegian power price is reduced by 0.2 EUR/MWh in 2030. Demand in Norway is reduced by 1.4 TWh, but because of increased export, the reduction in Norwegian production is limited to 0.5 TWh.

Model simulations of the effects of the Swedish G-tariff

In order to investigate the impact on investments in Swedish generation capacity for different levels of the G-tariff, we have carried out some simplified model simulations of the market effects. The simulations are made using a version of our electricity market model The-MA, in which investments are endogenous, i.e., investments are made when and where they are profitable based on total costs (long-term cost of energy, LCOE) and market values. We have assumed that investments in Swedish onshore wind power is based on power market prices only, implying that investors expect the elcertificate price to be zero.

[19] Long-term elasticity of demand of -0.2.

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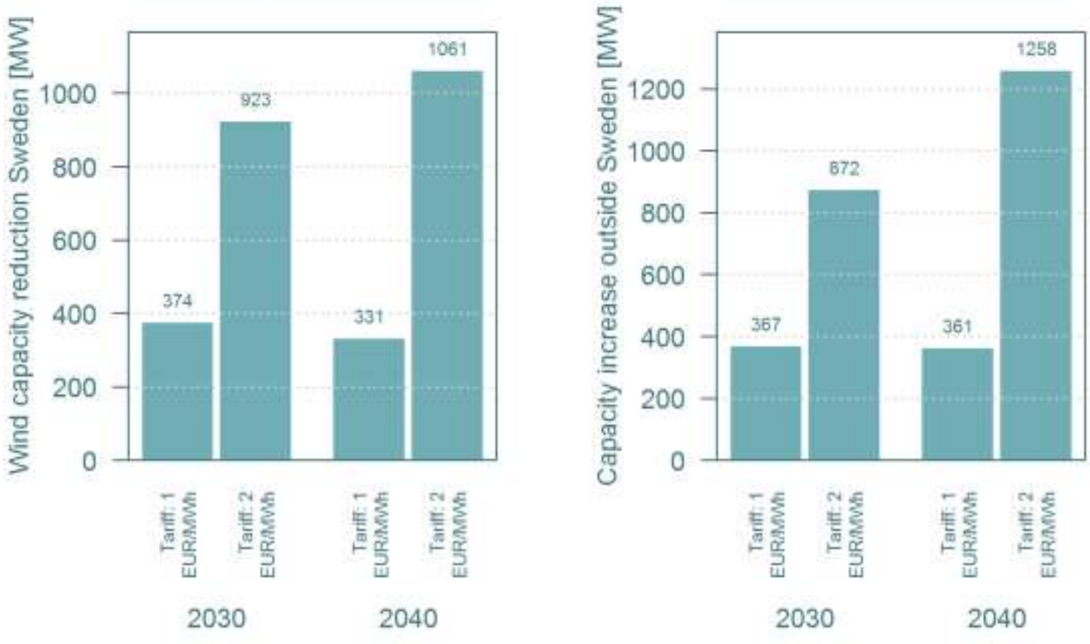
Using this approach, we have analysed the impact on investments for different levels of G-tariffs in Sweden, namely 0, 1, and 2 €/MWh. The current cap on G-tariffs according to EU regulations is 1,2 €/MWh.

The impact on investments is shown in Figure 25 (left panel). Compared to a reference situation with no residual G-tariff, a 1 €/MWh tariff reduces investments by some 350 MW in both 2030 and 2040. Doubling the tariff to 2 €/MWh has a much stronger impact, reducing investments by some 1000 MW in both years. For reference, the total endogenous investments in the case with no G-tariff is 5 000 MW in 2030 and 13 000 MW capacity in 2040.

The reduced wind power capacity in Sweden impacts investment incentives in other market areas, shown in Figure 25 (right panel). Reduced wind power generation in Sweden is counteracted by increased power generation capacity in other markets, although not perfectly as the impact depends on the impact on trade and price patterns. Some of the reduced generation in Sweden is counteracted by increased generation in existing conventional power plants, but the main effect is increased investments, mainly in wind power, but some solar capacity as well. That investments in other markets in 2040 surpasses the reduction in capacity in Sweden, indicates that Swedish wind power is replaced by less efficient wind power capacity in other markets.

Figure 25: G-tariff impact on investments in Sweden (left panel) and in the rest of the interconnected market area (right panel), MW



The total welfare economic impact for Sweden implied by residual tariffs must take into account the impact on power prices. Changes in average power prices in Sweden are shown in Figure 26. While a G-tariff of 1 €/MWh increases prices by 0.2 – 0.3 €/MWh, a G-tariff of 2 €/MWh, increases prices by 0.75 – 0.9 €/MWh. The share of the increased cost that is passed on to end-consumers is thus 20 – 30 percent and 35 – 45 percent respectively, i.e. the bulk of the cost is borne by Swedish generators. The results should be interpreted with some caution, however, since we have assumed that demand is not price sensitive in the simulations.

The total welfare economic impact should take into account the demand response to increased power prices. As illustrated in Figure 26, demand response reduces the price impact of the shift in the supply curve, and increases the share borne by generators. The impact depends on the price elasticities.

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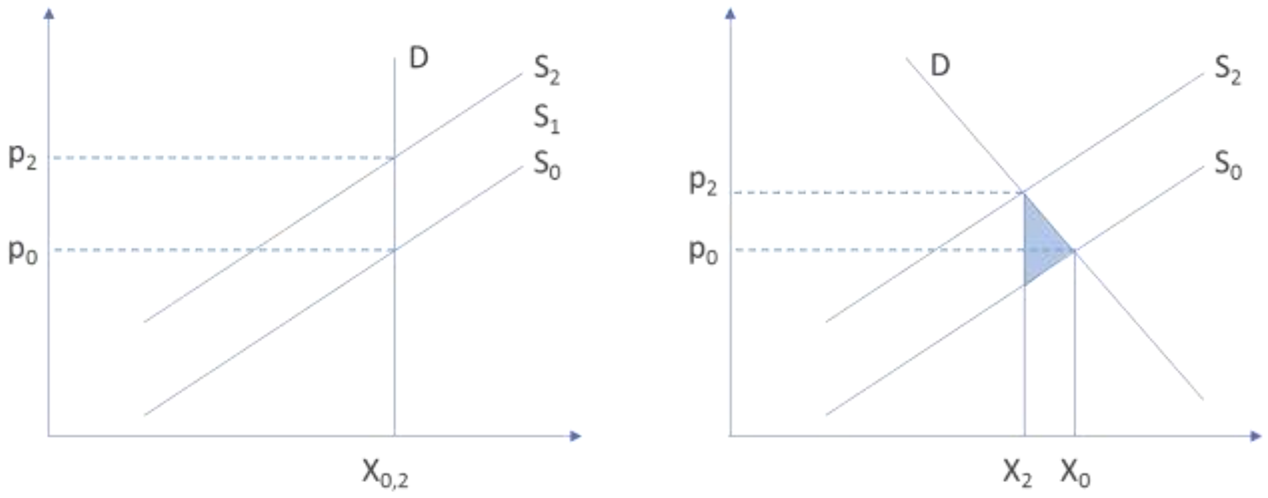
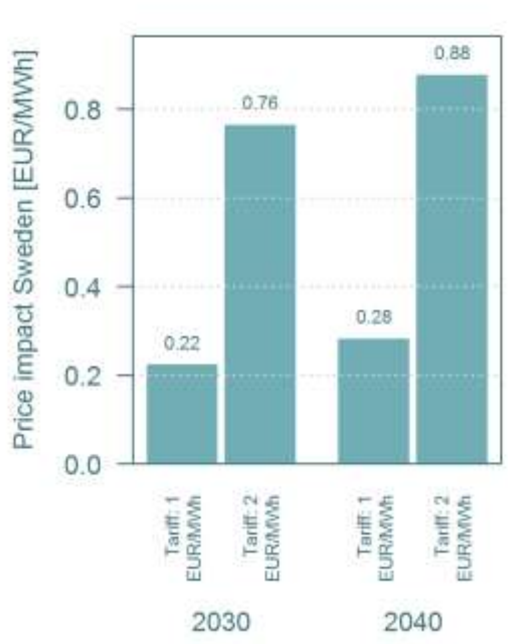
Figure 26: Efficiency impacts of price elasticities of demand



Although the increase in power prices due to residual G-tariffs affects consumption in Sweden, the impact is less than if the entire residual tariff is levied on end-users. The efficiency loss of residual consumers tariffs can be reduced by applying Ramsey-differentiation among consumer groups.

Figure 27: Impact on Swedish average annual power prices of unilateral residual G-tariffs in Sweden, €/MWh



7.6.4 Consequences for Svenska kraftnät

For Svenska kraftnät there may be an indirect effect on total costs from any changes in investment behaviour. This is not possible to assess ex ante.

7.7 Shallow connection charges

7.7.1 Incentives for generators

A shallow connection charge should lead to lower costs and also lower uncertainty about the costs of connecting generators to the grid. This will strengthen the incentives for connecting new generation to the grid, although this may be partly offset by higher expected tariff costs through the locational signals and the general capacity charge that will both reflect deep connection costs. The deep costs will not be paid upfront, but over time.

7.7.2 Incentives for consumers

In the current grid without consumers directly connected to the transmission grid the move to shallow connection charges does not impact the incentives. In the hypothetical event that large consumers are allowed to connect to the transmission grid, the incentives for connection will be strengthened.

For the underlying regional grids, the incentives to connect to the transmission grid will be unchanged as any connection costs will be treated as pass-through in the economic regulation. Again, the existing incentive mechanism in the revenue cap regulation related to overlying grids is not necessarily suited for giving the right incentives from Svenska kraftnät's tariffs to consumers in the regional grids.

7.7.3 Distributional effects

A shallow connection charge will redistribute some costs from new generators to existing customers. However, the monetary impact is uncertain as there is little information available on the extent to which deep connection charges have actually been used. It should also be noted that the initial redistribution will be offset over time via the locational signals.

7.7.4 Consequences for Svenska kraftnät

For Svenska kraftnät a higher share of costs will need to be recovered through the ordinary tariffs. However, this again depends on whether deep connection charges are actually used.

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APPENDIX: TARIFFS IN SELECTED COUNTRIES

Finland

Overview of the electricity system

The transmission system operator in Finland, Fingrid, operates 14,600 km of transmission lines and 120 substations. Finland consists of one bidding zone and is part of the synchronous inter-Nordic power system. Finland also have DC transmission links towards Russia and Estonia.

According to the National Energy and Climate strategy for 2030, electricity consumption in 2020 will be about 88 TWh and 92 TWh in 2030.

In a normal year, Finland depends on import of electricity and have an import capacity of around 5,200 MW. Actual import in a normal year is between 2,000 – 4,000 MW. The total installed generation capacity was 17,400 MW in 2017. Expected available capacity during winter period 2018-2019 is about 12,000 MW. Peak load demand is estimated to be 15,300 MW in a very cold winter day in 2018-2019 and is expected to increase by 100 MW annually until 2021 (Energy Authority Finland, 2018).

Finland's dependency in electricity import is expected to decline when the nuclear power plant Olkiluoto 3 (1,600 MW) is operational from January 2020.[20] This will strongly affect their dependency on import. It is also expected that more power plants will be commissioned in near future.

Nuclear power represents the largest source of electricity production in Finland, closely followed by hydro and bio fuels. The rest is coal, oil, wind, peat, waste and natural gas.

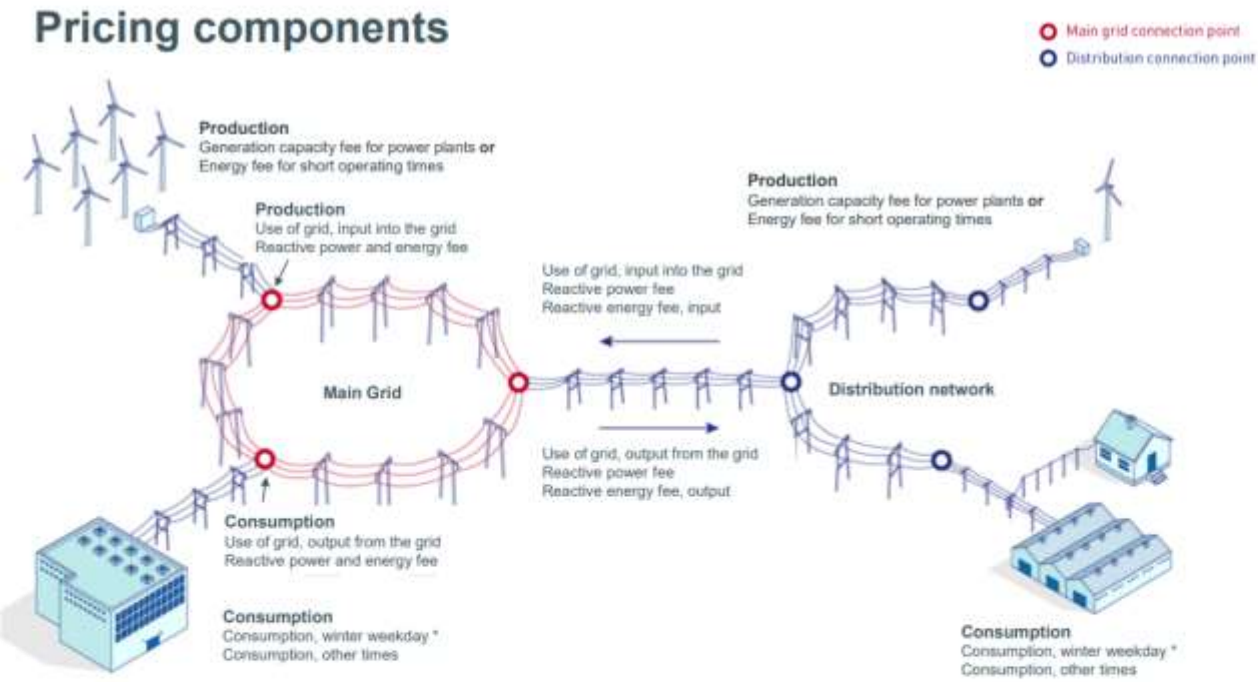
Finland have a peak load reserve, which is a strategic reserve not available in the market. In total, the reserve was 729 MW during the winter season of 2017-2018, whereas 707 MW from power plants and 22 MW from demand side response facilities.

Overview of the tariff structure

Customers pay a grid connection fee (when they are connected to the grid) and a grid service fee. The pricing components in the grid service fee are illustrated in Figure 28.

[20] *According to latest news: http://www.world-nuclear-news.org/Articles/New-delay-in-start-up-of-Finnish-EPR*

Figure 28: Pricing components in the Finnish transmission tariff



Source: Fingrid (2019).

Finland constitutes one single bidding zone. The tariff does not include any locational elements and there is no price signal related to losses. The tariff does not account for price sensitivity and other consumption characteristics in load tariffs.

Variable tariff elements

Prices for each tariff element are summarized in Figure 29.

Consumers pay a consumption fee for the transmission of electrical energy. The consumption fee is differentiated between winter weekdays and other times of the year. Consumers also pay a user fee for withdrawal from the grid.

Producers with power plants producing at least 1 MW pay a generation capacity fee. In case of short operating times, producers are offered an agreement where they pay for net production instead.

Producers also pay a user fee for input into the grid. The user fees are charged based on the amount of energy transferred through a connection point (Fingrid, 2019).

Reactive power is charged based on the monthly highest hourly reactive power transmitted through the customer’s metering point.

Figure 29: Unit prices 2018, Finland

Unit prices	Year 2018
Consumption, winter weekday *)	9 €/MWh
Consumption, other times	2,70 €/MWh
Use of grid, output from the grid	1,09 €/MWh
Use of grid, input into the grid	0,72 €/MWh
Generation capacity fee for power plants	1 950 €/MW, a 162,50 €/MW, month
Energy fee for short operating times	3,20 €/MWh
Reactive power fee	666,00 €/MVar, month
Reactive energy fee, output	5,00 €/MVarh
Reactive energy fee, input	5,00 €/MVarh

Prices exluding VAT
*) Winter weekday 900 hrs, December – February at 7.00 am – 9.00 pm

FINGRID

Source: www.fingrid.fi

Connection charges

In Finland, connection charges in the transmission grid are shallow. New customers pay a fixed connection fee to be connected to the main grid. The fee is equal to the average costs of connection, which is updated annually and varies with voltage level.

New customers are charged additionally if a new substation is needed. The cost charged is the actual cost of the substation. In some cases, the new customer is also charged with 0.5 million EUR for an additional transformer.

Fixed / residual elements

Generators connected to the transmission grid pay an annual capacity charge. The charge is 1,950 EUR/MW/year, in addition to 162.5 EUR per MW of available capacity per month.

Other relevant features

According to ACER, energy-based generator charges should be set equal to 0 EUR/MWh, but Finland is exempt from this, and can be set to less than or equal to 1.2 EUR/MWh.[21]

ENTSO-E have used a “base case” to estimate how the network operator charges are shared between generation and load. In Finland, they find that generation cover 19 % and load cover 81 % (ENTSO-E, 2018).

21 http://www.ewea.org/fileadmin/files/library/publications/position-papers/EWEA-position-paper-on-harmonised-transmission-tariffs-and-grid-connection-regimes.pdf

Denmark

Overview of the electricity system

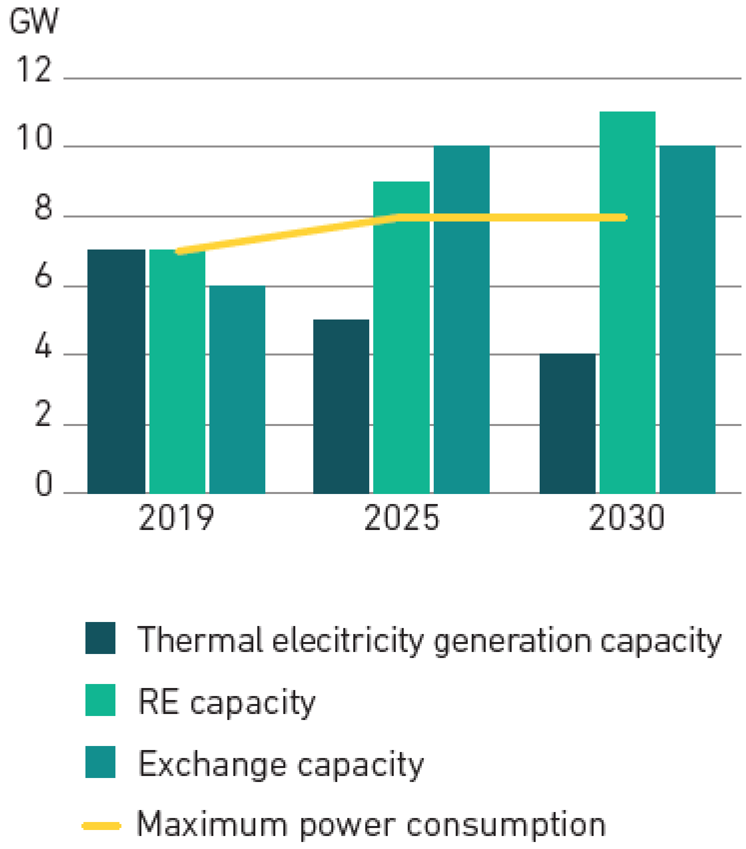
The Danish transmission system operator, Energinet, operates 7,000 km of transmission power lines and cables. The Danish electricity system is divided into two bidding zones. DK2 is part of the Nordic interconnected system, while DK1 belong to Continental Europe.

There is less exchange capacity in Eastern Denmark (DK2), than in Western Denmark (DK1). There is risk of power shortages in Eastern Denmark, and this is expected to increase over time, some due to data centres connecting to the transmission grid. Consider a time-limited strategic reserve to maintain adequacy in Eastern Denmark (2025-2029 + option of 5 years). Closely linked to Southern Sweden.

Eastern Denmark (DK2) has connection capacity towards Sweden, Germany and Norway. Western Denmark (DK1) has connection capacity towards Norway and Germany. The capacity will increase in the future due to projects as Kriegers Flak (towards Germany via off-shore windfarms), Cobra Cable (700 MW towards the Netherlands) and Viking link (1,400 MW towards UK).

In 2017, total installed capacity in Denmark was 14,942 MW. Denmark has experienced increase in wind and solar, while thermal has declined. This trend is expected to continue. Together with increasing capacity, the electricity grid needs to expanse. 750 km new cables and overhear lines the next 10 years is planned.

Figure 30: Maximum power consumption, and electricity generation and exchange capacity



Source: Energinet, 2017.

Connection charges

Connection charges are super shallow in Denmark.

Variable tariff elements

Both consumers and generators pay tariff elements varying with their use of the grid.

Consumption

Consumers pay 8 øre/kWh in total. This covers a transmission grid tariff of 3.8 øre/kWh and a system tariff of 4.2 øre/kWh. The transmission grid tariff covers Energinets expenses related to operating and maintaining the transmission grid and interconnectors. The system tariff cover costs related to security and quality of supply.

Consumers also pay a balance tariff of 1.44 DKK/MWh. The balance tariff cover costs related to buying power reserves.

Production

The generation fee is 0.3 DKKøre/kWh. PVs, wind power and decentral plants subject to a purchase obligation are exempt.

Generation also pay a balance tariff of 0.69 DKK/MWh.

Customers with their own 132/150kV transformers pay a transmission grid tariff of 3.6 DKKøre/kWh.

Fixed / residual elements

Finally, Energinet charges a monthly balance fee of 1,500 DKK/month to cover their administrative expenses related to settlement of balancing responsible actors.

Other relevant features

There are no locational signals in the Danish tariff, and there is no price signal related to losses.

Load tariffs are not differentiated to account for price sensitivity or other consumption characteristics.

Germany

Overview of the electricity system

Germany has four transmission grid operators who handle the high voltage grid; TenneT, 50Hertz, Amprion and Transnet BW. Germany and Luxembourg constitute one bidding zone, after Austria “broke out” in 2018.

The total power production in Germany was 642 TWh, while total consumption was 595 TWh (Agora & Sandbag, 2019). Generation capacity in 2018 was 215.6 GW, including plants in Austria, Luxembourg and Switzerland that feed into the German grid (Bundesnetzagentur, 2018b).

Along with Germany’s Energiewende, they continue their phase out nuclear energy and decommission of old coal-fired power plants together with an increase in renewable energy. To achieve this, the infrastructure needs to be upgraded (Bundesnetzagentur, 2018a). Germany is experiencing challenges with grid congestions due to a mismatch between the location of generation and consumption. There is a surplus area in the north with high generation and low demand, and shortage area in the south with low generation and high demand. It is politically difficult to decide to split Germany into two or more bidding zones.

General characteristics of the tariff model

Final customers are not treated differently than distributors.

Germany have four transmission grid operators who handle the high voltage grid. Distribution system operators handle everything else (PwC, 2017).

The transmission grid tariffs consist of three components:

- Annual capacity charge

- Energy charge
- Charge for metering, billing and metering point operation per meter point.

Large consumers who fulfil requirements related to energy use and consumption receive a reduction in the tariff. The reduction is based on an assessment of the costs of a so-called “physical path” from the large consumer to the nearest generator or network node that can serve the entire consumption of the large consumer. The reduction is given as shown in the table below.

Table 9: Criteria for tariff reductions in Germany

	Annual consumption	*Reduction in tariff*
<10 GWh	≥ 7,000 hours	Up to 80%
<10 GWh	≥ 7,500 hours	Up to 85%
<10 GWh	≥ 8,000 hours	Up to 90%

Source: PwC (2017)

The tariff reduction is covered through a separate fee. This fee is differentiated depending on consumption and electricity intensity. Customers with more than 1 GWh annual consumption and at least 4 percent electricity intensity receive more than 90 percent reduction in this fee (PwC, 2017).

Connection charges

Connection charges in Germany are classified as shallow to super shallow by ENTSO-E. Grid users only pay for actual costs related to their own connection line or substation. Other general reinforcements are socialized via tariffs.

Variable tariff elements

Only consumption pay a tariff element varying with their use of the grid.

EVH grid: annual capacity charge of 10.36 EUR/kW if less than 2,500 hours and 73.13 EUR/kW if more than 2,500 hours. They also pay an energy charge of 2.86/0.35 cent/kWh.

EVH/HV substations: annual capacity charge 22.94 EUR/kW if less than 2,500 hours and 105.61 EUR/kW if more than 2,500 hours. They also pay an energy charge of 3.41/0.11 cent/kWh.

Germany does not have a price signal related to transmission losses and they do not have locational signals.

Fixed / residual elements

Annual price for metering point operation.

For customers with a temporary higher consumption than the rest of the year, a monthly price is offered.

Customers with peak load at different times than the grid peak load is offered an individual tariff. The individual tariff cannot be less than 20 percent of the regular tariff and need to be approved by the regulator.

Other relevant features

Consumption of reactive energy outside contracted limits is charged by 0.29 cent/kWh.

Feed-in of reactive energy outside contracted limits is charged with 0.23 cent/kWh.

Separate prices for provision and use of grid reserve capacity.

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Other energy related fees

Where large consumers have special arrangements, consumers are charged. This includes the combined heat and power generation surcharge (CHP), that covers subsidies given to plants fulfilling certain criteria. There is also a fee to finance offshore wind, and a fee to contribute to finance renewable energy other than offshore wind (EEG-Umlage). Large consumption is typically exempt from these fees.

Poland

Overview of the electricity system

PSE is the transmission system operator in Poland. Poland has interconnections towards Germany, Slovakia, the Czech Republic, Ukraine, Lithuania and Sweden. Poland consists of one bidding zone.

161.7 TWh of electricity was produced in Poland in 2015. Total consumption was 161.4 TWH and is expected to increase. Poland has been a net exporter of electricity, but exports have dropped lately.

Total installed capacity in 2015 was 40.4 GW, while peak demand was 25.1 GW. Peak demand happens during the winter season, but due to power plants being shut down in the summer time this is when the margins are most tight.

Total electricity consumption in 2015 was 161.7 TWh. Hard coal and lignite consisted 84 percent of production in 2015. In the period between 2020 and 2035, Poland plans to decommission 50 percent of their installed capacity. In 2017, the Polish parliament decided to introduce a market-wide capacity mechanism, approved by the EU Commission (10 years use) as long as they also introduce market reforms.

General characteristics of the tariff model

According to ENTSO-E (2018):

> *"There is no differentiation between final consumers and distributors but between kinds of points of delivery (PoD). There are two different rates for access to the transmission network: one called "final" PoD (where end consumption is connected) and other called "network" PoD (which are PoD of DSOs having more than two PoDs, and these PoDs are nodes of meshed distribution network 110 kV). In final PoD contractual capacity is reserved by and extra charges applied in case of exceeding, in network PoD contractual capacity is determined based on actual energy flows, no extra charges in case of exceeding. The total charge (without non-TSO charges) for users connected in "final PoDs" amounts to 70% of the charge paid by DSO in "network PoDs"."*

Both energy- and capacity-based charges are used.

General characteristics of the tariff model

There are no bidding areas within Poland.

There are no locational signals in the Polish tariff, and there is not price signal related to losses.

Only load is charged with transmission tariffs.

Connection charges

Connection charges are shallow in Poland. Discounts on the connection charges are available for renewable generation units with an installed capacity of 5 MW or less and cogeneration units with an installed capacity of 1 MW or less (50 per cent). RES units with an installed capacity less than or equal to 40 kW are exempt from connection charges.

Other relevant features

There are discounts available on certain tariff elements for large consumers with a high load factor (400 GWh/50 per cent utilisation of contractual capacity) and whose costs of electrical energy are at least 15 per cent of total production costs. There are also discounts available depending on the electricity intensity of the final consumer (share of electricity costs of gross value added).

Lithuania

Overview of the electricity system

Litgrid, the transmission system operator in Lithuania, operates 6,687 km of power transmission lines and 234 substations. The Lithuanian grid is connected to Latvia (1,200 MW), Belarus (1,350 MW), the Kaliningrad region in Russia (600 MW), Poland (500 MW) and Sweden (700 MW).

Installed generation capacity in Lithuania is about 3,700 MW (Litgrid, 2019a). In 2018, the total consumption of electricity was 11.2 TWh while electricity generation was 3.2 TWh (Litgrid, 2019b).

The first wind farm was connected to the transmission grid in 2016 and is expected to increase. However, due to decommissioning of thermal power plants, total installed capacity is expected to decrease in their 2026 estimate (Litgrid, 2017).

Lithuania has a centralized power generation system where production is connected to the transmission grid and consumption is connected to the distribution grid. Litgrid prefers all consumption to be connected to the distribution grid. In case of technical or operational reasons in the distribution grid, consumption can in some cases be connected to the transmission grid.

General characteristics of the tariff model

There are no bidding areas within Lithuania.

There are no locational signals in the Lithuanian tariff, and there is no price signal related to losses.

Only load is charged, i.e., the G-tariff is zero.

Connection charges

Connection charges are deep in Lithuania.

Variable tariff elements

Load pay a transmission service price of 0.69 cent/kWh (110-330 kV) and a system service price of 0.353 cent/kWh. The energy component is 0.441 cent/kWh (110-330 kV), and the capacity component is 1.326 cent/kWh (110-330 kV). The price of system services is 1.934 cent/kWh.

Fixed / residual elements

The tariff is not differentiated to account for price sensitivity or other consumption characteristics.

Other relevant features

Generation and use of reactive power by DNOs and consumers (>30kW) is charged by 0.142/0.071 cent/kVArh.