Capacity allocation and congestion management

Vivi Mathiesen (Ed.)

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REPORT

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A new model for the power market?

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Abstract: This report contains initial considerations with regards to alternative market design, taking elements both from nodal pricing and from the current Norwegian market design. A key aspect is the incorporation of a detailed network model in the price setting algorithm so as to enable simultaneous price and load flow calculations. Such a model seems to yield higher utilisation of the network, and more correct price signals to market actors compared to current market design.

Key words: Congestion management, capacity allocation, market design.

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Preface

Within the Nordic market there have been on-going discussions about congestion management for years, as the four countries seem to have preferred basically two separate approaches to congestion management. Norway and Denmark have applied market splitting, whereas Sweden and Finland have applied countertrade to deal with structural congestions. However, by 2012 Sweden will introduce market splitting with four price areas within their borders, so it seems the discussions have reached a conclusion in the Nordic market, at least for the time being. Discussions continue within Europe in the context of development towards a single energy market.

Congestion management and capacity calculation are corner stones in any electricity market design. The regulators through ERGEG are currently working on Framework Guidelines for Capacity Allocation and Congestion Management, and thus a unified model for Europe may be the result.

In the interest of a best possible design and functioning of the electricity market, the Director at the Energy and Regulation Department at NVE mandated an internal project group to investigate whether and how the Norwegian electricity market can become more efficient through an alternative organisation of capacity allocation and congestion management. The starting point has been the Norwegian part of the Nordic electricity market, and a report made for NVE by SNF (2007) about Congestion management in the Nordic market.

This report brings some initial considerations with regards to an alternative market design for the Norwegian market. NVE will continue its quest for an ideal market model, and mapping experiences from markets with nodal pricing is the next step for this project.

Oslo, December 2010

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Introduction

The model for capacity allocations and congestion management (CA&CM) is essential to the functioning of any electricity market. With the transition towards one internal European electricity market, there are calls for a unified approach for CA&CM and for use of market based principles. The Nordic market has more than a decade of experience with market based congestion management in a multilateral market. The Nordic market design is well functioning and efficient with merits over many other electricity market designs in place in Europe today. However, the current CA&CM model in the Nordic market does leave scope for efficiency gains.

An internal project group at NVE has qualitatively evaluated the merits of an alternative market design to see whether and how the efficiency of the market can be improved. In this paper we only make statements for the Norwegian market even though many of the descriptions may also be true for the whole of the Nordic market. For the sake of simplicity, we refer to the Norwegian market.

The model investigated takes elements both from nodal pricing and from the current Nordic/Norwegian market design. A key aspect of this new model is the incorporation of a detailed network model in the price setting algorithm so as to enable simultaneous price and load flow calculations. According to NVE's investigation this model seems to yield higher utilisation of the network, and more correct price signals to market actors compared to the current Nordic market.

The model prescribes a detailed configuration of bidding areas based on physical modalities of the network. However the project group has not concluded on whether to recommend nodal or zonal pricing for Norway. There are signals of mixed international experience with nodal pricing and the project group wishes to investigate this more closely. Likewise the project group wishes to analyse, quantitatively, the merits of nodal and zonal pricing in Norway.

1 The Norwegian electricity market

1.1 Market based since 1990

The Norwegian electricity market has applied market based principles for congestion management since early 1990 when the market was de-regulated on the wholesale side and divided into zones (later called elspot areas). The core of this model is the day-ahead spot market where wholesale electricity prices are calculated on an hourly basis for the following day, at a common Nordic power exchange, Nord Pool Spot (NPS)[1]. The market is divided into elspot areas that reflect structural congestions in the network. Norway is currently divided into five elspot areas and congestions within an elspot area are managed through counter trade (re-dispatch).

Demand and supply for electricity vary greatly throughout the day. Thus, hourly prices are important to reflect the "true value" of the electricity. Likewise prices are also to some extent allowed to vary geographically in the elspot areas. This enhances economic efficiency of the system by securing "correct" price signals to the actors both per hour and geographical area. In comparison to a nodal pricing system where supply and demand bids are a multitude of geographically areas (nodes), price signals in the Nordic market are not fully efficient.

Statnett, the TSO, calculates and publishes available capacities on transmission lines between the bidding areas (maximal possible transmission between locations in the grid). This information is used by NPS in clearing the market, i.e. the market is cleared subject to transmission constraints between the elspot areas.

1.2 Determining transfer capacity

Statnett determines capacity between the elspot areas denoted as net transfer capacity (NTC), by deducting total reliability margin from total transfer capacity:[2]

$$NTC = TTC - TRM$$

TTC: Total Transfer Capacity

TRM: Total Reliability Margin

TRM is typically set to a fixed number. In principle, this margin shall take account of unintended deviations of physical flows due to physical functioning of load-frequency

[1] NPS is the main Nordic market place of electricity. Since year 2000, producers, distributors, large consumers and industrial companies of the whole Nordic area have traded on NPS. The traded volume on NPS constitutes over 70 percent of the total Nordic electricity consumption.

[2] The principles determining capacities and margins are agreed upon by the Nordic TSOs, and are established in the Nordic Grid Code.

regulations. In addition inaccuracies in data collection and measurements are included in this margin.

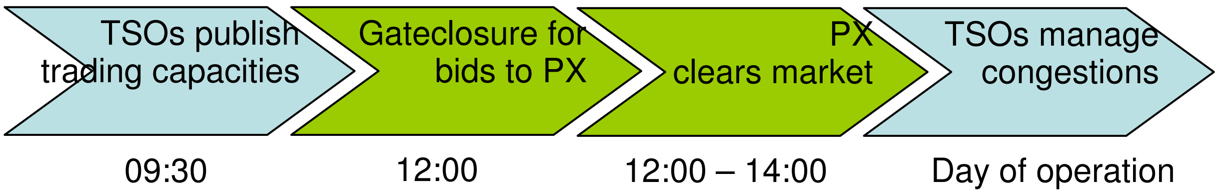
The process starts with the assessment of TTC. This is the maximum possible transfer capacity between two areas given operational security standards and the TSO's estimation of generation and load patterns. The determined capacity is critically dependent on the TSO's estimation of load flow in the network, and this is a factor of temperature, weather forecast, possible outages and faults in the network as well as import / export and the localisation of generation and demand. The objective is to maximise trading capacity to the day ahead market taking into account all of these factors whilst maintaining system and operational security.

Where the border of an elspot area coincides with a national border, the TSOs on either side of the interconnection calculate the capacity separately, and if their respective values differ the lowest value is used.

1.3 Congestion management day ahead

The available net transfer capacity is calculated in due time before the day of operation, prior to actors submitting their bids for trade and consequently also prior to the clearing of the market. Statnett publishes trading capacities at 09:30 day ahead (i.e. up to 38 hours before the operational hour). Gate closure for submitting bids to the day ahead market is 12:00. Nord Pool Spot uses the submitted trading capacities as constraints in their market clearing and price determining algorithm.

Figure 1 Setting capacity and clearing the market



- 9:30 – The TSO calculates and delivers trading capacities to the power exchange (PX), which use the capacities as constraints in market clearing and price setting algorithm.
- 9:30 – The trading capacities are published on Nord Pool Spot's website.
- 12:00 - Market actors (generators / large consumers / supply companies etc.) submit supply and demand bids knowing the available trading capacities on interconnectors between elspot areas. The individual bids are tagged with the relevant elspot area where the actor is connected to the grid.
- Before 14:00 – The PX clears the market and sets a price on the basis of supply and demand bids, given the available trading capacities (i.e. the price is set subject to constraints in the network through an iterative calculation).

If there are binding capacity restrictions between elspot areas, these become separate price zones. This is known as market splitting.

This sequence of events describes the Norwegian market, but is common for several European markets as well. I.e. the TSO determines trading capacity before trade is known. This entails that the TSO must “guess” what trade flows will be during the day of operation.

The TSO has incentive to be conservative in its estimation of available capacity since overestimation is associated with the high costs of counter trade / re-dispatch, whereas underestimating capacity is not associated with direct costs for the TSO.

Given that TSOs tend to be conservative in their estimations, this poses an inefficiency that has direct impact on congestion management in the form of less than optimal utilisation of network resources.

The last point on the flow chart above denotes congestion management in the operational hour – this is dealt with in the next section.

1.4 Congestion management in the operational hour

In the Nordic market there are mainly two methods for congestion management:[3]

1. Market splitting (day ahead)
2. Counter trade (operational hour)

In the day ahead time frame, congestions (binding restrictions in the trading capacity between bidding areas) are handled by market splitting. I.e. the bidding areas become separate price areas.[4]

The actors in the electricity market in Norway have to be in balance when they go into the operational hour, e.g. a submitted bid to the day ahead market has to be delivered. If an actor sees that he cannot fulfil his obligation, he can buy or sell his imbalance in the intraday market or as an active actor or in the balancing market during the operational hour. If the actor does none of these, he is settled by the TSO on his imbalance at the balancing price in that hour.

During the operational hour, i.e. after the day ahead market has been cleared, the TSO manages congestions by way of counter trade, by utilising bids in the balancing market[5]. The merit order list for the balancing market comprises all production and major consumption units that have submitted price volume bids for additional or reduced production at minimum 15 minutes notice, i.e. actors that are willing to deviate from the submitted schedules in the day ahead market are given compensation in the balancing market. All bids in the balancing market must be linked to the elspot areas where the

[3] FOR 2002-05-07 nr 448: Forskrift om systemansvaret i kraftsystemet. http://www.lovdata.no/for/sf/oe/xe-20020507-0448.html (Norwegian only). Reduction of cross border capacity is mentioned in the regulation as a last resort when market splitting and counter trade have been exhausted.

4 Statnett may introduce new elspot areas, and this must be announced at least one week ahead. Thus, market splitting is a feasible method for congestions that are foreseen at least one week ahead of the day of operation.

[5] In Norway the TSO must chose bids from the balancing market merit order, whereas in e.g. Sweden the TSO can use special reserves for counter trade.

production or consumption is connected. The TSO picks objects on either side of the congested corridor accordingly so that production is increased on the deficit side and decreased on the surplus side of the congested corridor without exceeding the nominated trading capacities, mentioned above. The objects are remunerated according to marginal bid price among the objects that are called upon for upwards and downwards regulation of the specific congestion, respectively.

To the extent that an elspot area reflects congestions in the network, the need for the TSO to perform re-dispatch / counter trade during the operational hour is reduced.

1.5 Inefficiencies in the current design

Geographic patterns of production and consumption vary and affect both the demand for transmission and capacities. Congestions in the grid arise when the desired transfer of electricity from producers to consumers exceeds capacities of the transmission grid. However, the current market model in Norway does not yield true price signals, for that, the current number of elspot areas is too few, i.e. the division is too coarse. Secondly, because the utilisation of transfer capacity is based on estimation before binding bids are known, the current model does not yield optimal utilisation of transfer capacity.

The announced trading capacity can enable actors to adjust their production portfolio and submit bids that deviate from marginal price, and this behaviour can indeed influence on price differences between elspot areas. E.g. generators with power stations in more than one elspot area can speculate in congesting a corridor and getting a high price in one area rather than bidding in generation evenly at several power stations. Also it could be possible that producers speculate in being called on for re-dispatch and gaining a high remuneration for that. I.e. the current system where available trading capacity is published to the market opens up for abuse of dominant market position.

Although the current model takes some account of locational pricing (i.e. there are currently five elspot areas in Norway), the price signals are not accurate. There are still regular internal congestions within the elspot areas that have to be dealt with by Statnett through countertrade / re-dispatch. Thus the current model does not yield true prices to the market.

The true value of electricity depends on the willingness to pay of consumers, productions costs and limitations of the grid, and it is a goal to get as close as possible to this. Since current prices are not based on the physical properties of the grid, the prices give wrong signals about the value of electricity to generation and consumption units. This implies inaccurate signals both in terms of planning production and consumption short term, but also long term in terms of where to locate new resources, including investment in infrastructure. The pricing does not reveal where shortages are in the market. This leads to an inefficient market solution.

2 An alternative design

2.1 Between nodal and zonal

With a view to dealing with the inefficiencies in the current market model, NVE has looked at various models for nodal pricing. Nodal pricing is well known from academic literature and from markets in e.g. North America and New Zealand. Nodal pricing is a disaggregated system whereby consumers and producers submit their bids at the node (grid point) where they are physically connected. Each node will have its own price determined by supply and demand at that node. Nodal pricing is economically efficient since it, in theory, yields optimal pricing and thus optimal load flow.

The resulting price signals are important to market actors both for short and long term planning of production and consumption (including long term signals for localisation of investments in infrastructure and production resources).

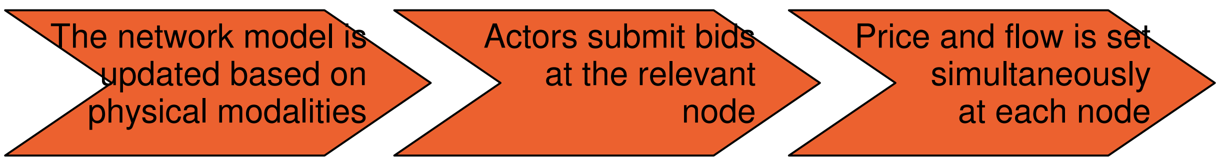
An argument against nodal pricing has been it is too complicated for market actors (e.g. electricity consumers with consumption in several nodes) to hedge price risks. One way of dealing with this would be to aggregate nodes into zones after the bidding.[6] I.e. actors submit their bids at nodes where supply and demand are matched to form nodal prices, but the nodes are aggregated to form one or more price zones so that wholesalers and consumers are faced with fewer prices than in a full nodal system.

The key component of this model is that price and loadflow is set simultaneously, thus eliminating the step where the TSO estimates available capacity. The focus is on getting correct and efficient prices and optimal dispatch / flow in the system. I.e. this model would not yield ex ante information on available trading capacity on interconnectors as the current model does. The uncertainty of availability of the network (the TSO guessing on capacity prior to trade) is reduced in this model because flow (trade) and prices are set simultaneously, thus the load flow prediction is based on commercially binding bids.

This model does however, not eliminate uncertainty of actual flows since the market is cleared day-ahead – up to 36 hours before the operational hour. Nevertheless, the transactions agreed upon day-ahead are binding for the actors and therefore give grounds for a more reliable estimation of flows than the TSOs' prognostications.

A detailed network model is a prerequisite in this market model, and it should which reflect physical modalities of the network down to each node (unique network point / area). To utilise the full potential of the network model, a more geographically diversified (nodal) submission of bids would be necessary. Below is a flow chart that in a simplified way shows the steps from submission of bids to price setting.

Figure 2 Simultaneous price and flow calculation



[6] Bjørndal and Jörnsten (2007)

- The TSO updates the network model with current and actual physical modalities day ahead prior to the price and flow calculation.
- Actors submit bids at the network node where their consumption or production is connected.
- Prices and load flows are set simultaneously in an iterative process on the basis of supply and demand bids, and constraints in the network model

The price and flow calculation could be done by either TSO or the power exchange, or the two in close cooperation. The essential point in this model is that flow and prices are solved simultaneously within the same algorithm.

The key aspect of this model is that the price calculation takes into account the physical properties of the grid together with detailed information about the location of production and consumption. This enables a better utilisation of the transmission network.

2.2 Roles of TSO and PX

With the new model, two functions which today are taken care of by the TSO and the PX respectively, namely the calculation of capacity (i.e. flow) and price, will be performed by one of them. In theory, it is possible for either of the two to set prices and flows. How will the role division between TSO and the PX be? One feasible solution would be that the TSO is responsible for the network model and for delivering daily updated information to the PX, and for the PX to receive bids and offers from the market and to set prices and flows. In this possible organisation, the TSO would have a slightly smaller role than today, since it would not set the capacities and publish these to the market, but rather update a network model for information to the power exchange. The PX would, consequently have a larger role to play by setting the flow in addition to the prices.

This model would entail including a network model in the price setting algorithm to enable calculation of load flows. It is feasible that Nord Pool Spot's current model SESAM can include a network model. At what effort, however, needs to be investigated further.

2.3 Specification bidding areas and price zones

For the model to be sufficiently specified one needs to consider the level of detail of the grid model, the number of bidding areas and the configuration of zones. What is optimal depends on several considerations with respect to the functioning of the Nordic market.

In the existing Nord Pool system the number of zones equals the number of bidding areas (elspot areas). This is not necessary. In principle we may keep the same number of elspot areas as price areas (and configuration of these) as today, but increase the number of bidding areas according to the nodes of a more detailed network model. However, the number of and configuration of zones are crucial to the performance of the model and should reflect bottlenecks in the grid.

Today the price setting does not take into account relevant information about location of bids and characteristics of the transmission network. Therefore determination of capacities between the bidding areas in advance of the optimisation day-ahead or use of counter trade in the operating phase is necessary to keep the system within safe limits. However, this may deviate significantly from an optimal utilisation of the system.

The Nordic grid consists of a large number of injection and withdrawal points. For practical reasons it may be necessary to make simplifications with respect to the network model and aggregate injection and withdrawal points into nodes of the network model implemented in the price calculation. This also means that the number of bidding areas decrease compared to what would be necessary with a completely detailed network model (such as in a nodal pricing system). This may be viewed as an advantage for wholesalers and producers, since relating to fewer bidding zones means they do not need to submit bids for as many bidding areas.

3 Considerations in market design

3.1 Disaggregation – how far shall we go?

What is the optimal disaggregation of the Norwegian market? It is important to stress that a more efficient system can be achieved by implementing a network model with a larger number of bidding areas without necessarily changing the number and configuration of price zones. This is the same as imposing a restriction that certain groups of bidding areas shall have equal prices. This can be specified mathematically in the optimisation problem. These zone restrictions, however, are not necessary for the solution to be feasible with respect to the physical properties of the system, on the contrary, the aggregation of bidding areas may lead to flows in the “wrong direction”, i.e. from high price bidding areas to low price bidding areas. Since imposing restrictions that effectively constrain the maximisation problem will reduce social welfare, the theoretically most efficient model would be to have no zones and allow each location to have different prices, i.e. nodal pricing also known as locational marginal pricing.

However, there are good arguments for having price zones and the reduction in social welfare may not be substantial compared to the nodal pricing solution. This depends obviously on a good zone configuration reflecting important bottlenecks in the grid. Which bottlenecks are effective may vary with the season and resource situation in the Nordic region. Different configurations may be optimal at different times. To have a predetermined and fixed zone configuration the number of zones should be sufficiently large to reflect all these situations.

Another argument for having zones is simplicity for market actors. A nodal pricing system may be perceived as too complicated to implement in practice. It would also affect the costs and risks of wholesalers (including supply companies and end-users). In this respect a system with price zones may be preferable.

Further the consequences of “full nodal pricing” for end-users have not been evaluated. In a nodal pricing system the price to end-users would vary according to the node at which their consumption is connected. In case there are large price variations between nodes, as there may well be, this system may be politically challenging to defend.

3.2 Abuse of market power

It is often argued that the possibility for abuse of dominant market position increases with more and smaller price zones because there would be fewer actors within each zone. The maximisation of social welfare relies indeed on the assumption that market participants bid their actual marginal cost and marginal willingness to pay. We know that markets are rarely perfect and their true behaviour may be characterised by exercise of market power and strategic bidding. Still, it is not clear that more price zones and fewer generation units within each zone will make exercising of market power more easy.

The answer to the fear of market abuse in a system with small bidding areas is that the prices of all zones will be determined simultaneously without market actors' knowledge of available trading capacities between areas. Not knowing the available trading capacity reduces opportunity to speculate and abuse a dominant position. Furthermore, the price in one area will be affected by other the bidding in other areas, so there are no "islands".

3.3 Security of supply

Nodal pricing, which this model in large part is based on, is also known as bid based, security constrained economic dispatch. System security is an intrinsic part (constraint) of the model and of the price computation. The result is optimal dispatch of electricity and use of infrastructure as well as generation resources, given security constraints defined by the system operator.

The fact that flows are determined based on binding bids will help the system operator in its efforts to maintain operation al security during the operational hour. This represents an improvement compared to today's market model.

When it comes to long term system security, this alternative model will improve investment signals because it yields more precise price signals to the wholesale market. For investors, it is important with stable and predictable market conditions and framework for investment. This holds true for investment in generation resources as well as for investment in large consumption units (e.g. industry) and transmission. The locational price signals will be useful for investors in determining where to locate their investments.

3.4 Possibility for hedging

Market actors that are faced with several prices will need to hedge their price risk. Financial Transmission Rights (FTR) are commonly applied in several US markets for the purpose of hedging risk of varying prices between areas with different price.

In the Nordic market there are a range of financial products available, and Contract for Differences (CfD) are used as a hedging instrument for price risk between elspot areas. There have been concerns by some market parties that the CfDs market is not sufficiently liquid.

A system with many bidding areas or bidding at nodes (which is the ultimate disaggregation of the market) may have more volatile prices than a system with uniform pricing over a large area where price signals are "evened out" though re-dispatch. The need for hedging is important consideration in market design.

As a side note, the Norwegian market is already faced with a multitude of prices, in excess of the number of price areas, since the tariffication is done on a "nodal basis". The marginal loss factor, which today is the main component of the transport tariff, varies depending on location for the market actor. Within a nodal pricing system, this marginal loss factor would be factored into the price from the beginning, i.e. it would not need to be calculated separately. However the locational price variations could potentially be bigger than today, where the marginal loss factor is limited to + - 15 % of the actors price / volume exposure.

3.5 Experience from other markets

There are several real life examples of markets with nodal pricing, e.g. several markets in North America, in addition to Ireland and New Zealand, to mention but a few. To NVE's knowledge there are mixed experiences with the system. E.g. Ireland implemented nodal pricing, but soon resorted back to the previous market model with uniform pricing. Further, there are signs of discontent with nodal pricing in New Zealand, and a review of the system is planned. NVE has not had a chance to investigate these claims, but clearly, experiences from other markets are important in order to compose a complete picture of the pros and cons with nodal pricing. This is a central part of phase two of this project.

4 Summary and next steps

There are potential efficiency gains for the Norwegian electricity market by implementing a new model for capacity calculation and congestion management (CA&CM). The efficiency gains would materialise as higher utilisation of the network capacity and as more accurate price signals to market actors both for short and long term planning og production and consumption. This would also mean fewer and smaller price spikes, and in the context of winter 2009/2010 peak prices, all other things equal, a more optimal utilisation of the system could have avoided the most extreme price occurrences.

These improvements could be achieved by incorporating a more detailed model of the transmission network into the price calculation, and by a simultaneous setting of prices and flows. Such a model could furthermore reduce costs of the system operator because of lower need for re-dispatching. In addition there would be an immediate improvement with respect to utilisation of the existing power system, i.e. both network and generation resources. Flexible bidding from consumers as well as producers, is a prerequisite.

A more optimal configuration of price zones (elspot areas) reflecting important bottlenecks in the grid should be considered. Different configurations may be optimal at different times due to varying seasonal load patterns. A zonal configuration should be fine enough, and robust enough to cope with shifting load patterns. For the time being the current division into five elspot areas should be maintained, but the project group recommends investigating benefits of dividing the market into further zones

The quantitative benefits of a simultaneous setting of prices and flows need to be analysed at zonal and nodal level.

In its further work, the project group aims at clarifying whether and how a network model can be part of SESAM, the price setting algorithm at Nord Pool Spot. This will be done to consider if it is possible to implement a simultaneous setting of flow and price in the current software.

Further, international experiences with nodal pricing will be investigated in order to get a view on the general functioning of the market, price signals, volatility and predictability of prices, etc. Likewise it is important to get a sound view of security of supply both in the short and the long run, from a theoretical point of view but not least from experiences from other markets.

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