Svk Project on Scarcity Pricing

Phase 2: Simulations for Sweden

Wednesday February 1, 2023

Table of Contents

Executive Summary

This report documents Phase 2 of the study of a scarcity pricing mechanism for the Swedish power system.

Scarcity pricing based on operating reserve demand curves (ORDC) is a market design proposal which aims at introducing the trading of reserves in real-time markets using a price-elastic demand curve for real-time balancing capacity. The aim of the mechanism is to produce real-time price signals in the real-time market which are awarded to both standby unused capacity as well as to balancing energy that is activated during tight system conditions, with the goal of paying flexible assets for performing under stressful system conditions, when the system needs them most. The mechanism thus targets both system flexibility as well as system adequacy, by generating revenues on top of the marginal cost of the marginal unit, referred to as “adders”, which are payable to capacities that are online under tight system conditions. These adders are intended to result in price spikes that are lower but more frequent than those of alternative real-time market designs, and which are thus intended to generate a more reliable long-run investment signal. The mechanism has seen broad application in US markets, either through direct real-time co-optimization of energy and reserves, or though the ex-post application of scarcity adders that depend on the instantaneous loss of load probability and the value of lost load of the system. The mechanism is also discussed or approximately implemented in a number of European member states.

The Swedish system is particularly interesting in the context of scarcity pricing. The system experiences system-wide scarcity during the winter, however it also experiences scarcity in the southern part of the country during the summer, when corridors are congested and flexibility cannot be made available in the south, even if the total net demand of the system during those months is not as high as during the winter. This scarcity is confirmed by a proof of concept that our team has developed for the Swedish system during the first phase of this project [1].

During Phase 1 of this project, a proposal for implementing scarcity pricing in Sweden without requiring MARI to transition to co-optimization was elaborated. The objective of the second phase of this project is to compare the accuracy of this proposal, which relies on ex-post scarcity adders, to the outcome of a real-time co-optimization of energy and reserve via numeric simulations with models of escalated complexity. (i) The tests results are first provided for a single-area model of Sweden without transmission constraints. (ii) The complexity of the two alternative approaches is then increased by considering a multi-area setup with an ORDC only in SE4. (iii) Finally, the coherence between the results obtained with co-optimization and the proposed design is investigated in a multi-area model of Sweden with an ORDC in every zone of the Swedish system. The accuracy of the proposed design that relies on approximating co-optimization through ex-post adders is shown to be acceptable for each case study, provided that there exist sufficient flexible resources that are kept in reserve. Note that, even though the proposed design provides noticeable results in terms of accuracy, the choice can be made by Svk to run a co-optimization model in-house in parallel with MARI in order to implement scarcity pricing in Sweden.

1. Context of the Project

The present report is the deliverable of Phase 2 of a project titled “Scarcity pricing mechanism for the Swedish / Nordic balancing market”. The project has been commissioned by Svenska Kraftnät in the context of the framework agreement for the provision of expert advisory and analytical support on electricity market design and quantitative analysis.

The project aims at studying the possible design of a scarcity pricing mechanism for the Swedish / Nordic balancing market. As part of the redesign of the Nordic balancing markets, the introduction of scarcity pricing is under consideration. The goal of Svenska Kraftnät in this project is to gain greater insights into possible models for introducing scarcity pricing in the Swedish / Nordic balancing market.

The specific goals of Svenska Kraftnät in this project are:

- To develop a proposal for the introduction of scarcity pricing in the Swedish / Nordic balancing market, and
- To develop a model simulating the effect of scarcity pricing in the Swedish system.

In response to this call, N-SIDE has proposed a comprehensive study for the possible application of scarcity pricing in the context of Sweden and more broadly the Nordic system. Important market design elements have been explored and developed throughout the first phase of the project. This second phase focuses on comparing the proposed design for the implementation of scarcity pricing in Sweden (developed during Phase 1) based on ex-post adders to a co-optimization of balancing energy and reserve in real-time, through simulations. The obtained results are detailed and analyzed in the following chapters of this report.

Note that this phase of the project builds up on a stylized model of the Swedish system which was developed during Phase 1, and which serves as a basis for simulating the effect of scarcity pricing using real data.

2. Methodology

This section is dedicated to the presentation of the simulation methodology that is adopted in this second phase of the project. Some principles of scarcity pricing along with reminding the proposed design of Phase 1 for the implementation of scarcity pricing in Sweden are also covered in this section. For a more detailed presentation of the proposed design and the scarcity pricing concepts that are mentioned in this section, we refer the reader to the report of the first phase of the project [1] and recently published work by members of the team [2].

Scarcity pricing refers to the practice or set of mechanisms that are in place in electricity markets for setting prices above the short-run marginal cost of generation resources during periods of system stress. Scarcity pricing relies in the acknowledgement of the increasingly important role of reserves and reliability in future power systems. The idea proposed by Hogan [3] relies on an explicit valuation of reserves and takes the point of view that the real-time market trades not only energy but also balancing capacity, in a multi-product auction. This proposition can be formulated by a co-optimization formulation of the balancing market. However, given that co-optimization is not currently implemented or foreseen in the immediate future in European balancing platforms such as MARI, the question becomes how one can approximate the co-optimization outcome. This question is addressed in the first phase of this project, and is based on a three-step procedure proposed by Papavasiliou [1] [4] [5]:

1. Run the energy-only balancing platform, i.e. MARI
2. Compute the scarcity adder based on how much reserve is available in the system in real time
3. Adjust settlement by using the balancing price and the computed adder.

The co-optimization model and the proposed design are presented in Figure 1 and will be presented in further detail in the following sections.

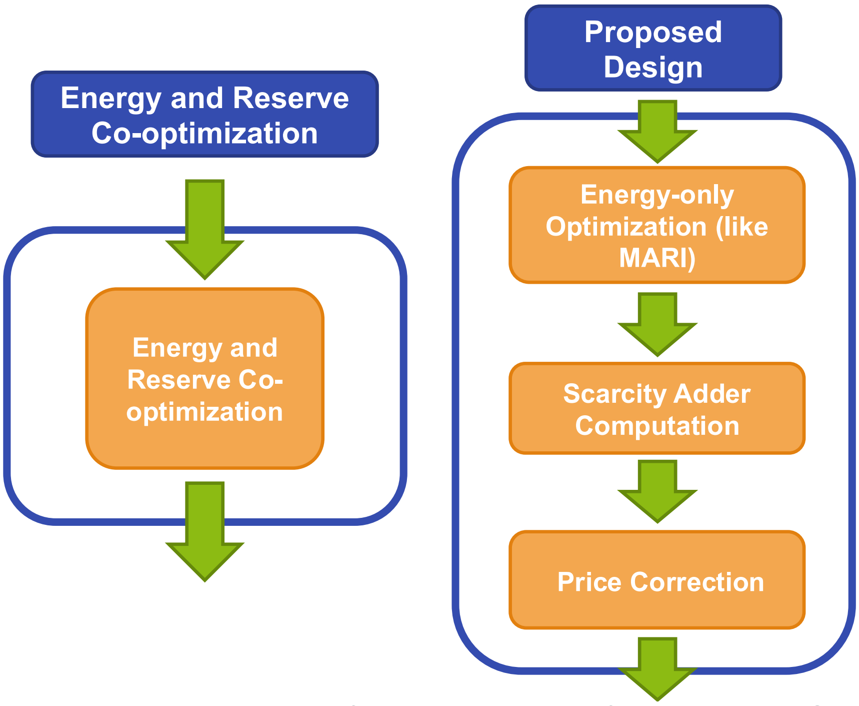


Figure 1 – Two possible approaches for the implementation of scarcity pricing in Sweden.

The objective of this second phase is therefore to verify via simulations that the proposed design approximates as closely as possible the outcome and the business rules of the co-optimization of energy and reserve in real time in the Swedish system. The aforementioned goal will be achieved by comparing the results obtained with the two approaches for different models of Sweden.

2.1 Real-time Co-optimization of Energy and Reserve

In this part, we present the co-optimization model used to implement scarcity pricing in Sweden, which is represented as a multi-zone system. A co-optimization model of energy and reserves on a network can be expressed as follows:

$$max_{d,p,r,dr,f,fR} VOLL \cdot \sum_{z \in Z} d_z - \sum_{g \in G} MC_g \cdot p_g + \int_{x=0}^{dr_z} ORDC_z(x)dx \quad (1.1)$$

$$(\lambda_z): d_z - \sum_{g \in G_z} p_g + \sum_{k=(z,\cdot) \in K} f_k - \sum_{k=(\cdot,z) \in K} f_k = 0 \quad (1.2)$$

$$(\lambda R_z): dR_z - \sum_{g \in G_z} r_g + \sum_{k=(z,\cdot) \in K} (fR_k^+ - fR_k^-) - \sum_{k=(\cdot,z) \in K} (fR_k^+ - fR_k^-) = 0, z \in Z \quad (1.3)$$

$$(\mu_g): p_g + r_g \leq P_g, g \in G \quad (1.4)$$

$$(\gamma_g): r_g \leq R_g, g \in G \quad (1.5)$$

$$(\nu_z): d_z \leq D_z, z \in Z \quad (1.6)$$

$$(\lambda_k^+): f_k + fR_k^+ \leq T_k, k \in K \quad (1.7)$$

$$(\lambda_k^-): -T_k \leq f_k - fR_k^-, k \in K \quad (1.8)$$

$$d, p, dr, r, fR^{+/-} \geq 0 \quad (1.9)$$

The objective function presented in term (1.1) corresponds to economic welfare that consists of economic welfare generated by the trading of energy (the two first terms of equation (1.1)) and economic welfare generated by the trading of balancing capacity (the third term of equation (1.1)). Constraint (1.2) corresponds to the market clearing condition for energy, and is applied per zone. Similarly, constraint (1.3) is a market clearing condition for balancing capacity, and it too applies per zone, which implies a separate price for balancing capacity per zone. Constraint (1.4) is a "linking of bids" constraint, which requires that the amount of energy and balancing capacity traded by a flexible resource not exceed its physical capacity, meaning that the flexible resource cannot double-book its capacity in both the energy and balancing capacity market. Constraint (1.5) expresses the fact that inflexible resources cannot provide balancing capacity. Constraint (1.6) is the quantity limit on how much energy is consumed. Constraints (1.7) and (1.8) correspond to the upward and downward limits of available transmission capacity respectively, while constraint (1.9) determines the non-negative variables in the problem.

Here, we use the so-called inscribed boxes formulation for the exchange of balancing capacity [6] [7]. The idea is to define a "flow" of balancing capacity in the market clearing model, but in such a way that balancing capacity flows do not net out. We prevent the netting out of balancing capacity flows because there is inherent uncertainty about whether these flows are activated or not in real time. The underlying formulation is based on results from computational geometry [8]. The concept has a precedent in tackling "non-intuitive" flows in the day-ahead energy market, and in the computation of ATC capacities in the intraday market.

Note that the model in this section ignores time indexing. The actual model is in fact dynamic, since hydro storage is involved, but the temporal dimension does not add to the comprehension of the interactions between pricing and ORDC, and is therefore left out in this report, in order to simplify the exposition of concepts.

2.2 Proposed Design for Implementing Scarcity Pricing in Sweden

This section elaborates on the three-step procedure for implementing the proposed design. As depicted in Figure 1 and explained previously, the proposed design consists of the following three-step procedure:

1. Run the energy-only balancing platform, i.e. MARI.
2. Compute the scarcity adder based on how much reserve is available in the system in real time.

3. Adjust settlement by using the balancing price and the computed adder.

Since the first step is straightforward, as it relies on an external platform, only the second and third steps of this procedure are discussed in this section.

First of all, one can wonder how to compute the scarcity adder in the second step. This computation relies on an ORDC (Operating Reserve Demand Curve) function encoding the valuation of a certain amount of available reserve in the system. There exist multiple types of ORDC functions, as highlighted in [1]. In this project, we will only focus on an ORDC curve computed based on the LOLP (Loss of load probability) and the VOLL (value of lost load), which is expressed as follows:

$$ORDC\left(\sum_{g\in G} r_g\right) = LOLP\left(\sum_{g\in G} r_g\right) \cdot \left(VOLL - \widehat{MC}\left(\sum_{g\in G} p_g\right)\right) \qquad (1)$$

Here, $\widehat{MC}$ represents the marginal cost of the marginal unit in the system, and the Loss of load probability (LOLP) is defined based on the statistics of the imbalance distribution via the following formula [1]:

$$LOLP\left(\sum_{g\in G} r_g\right) = \mathbb{P}\left[Imb \geq \sum_{g\in G} r_g\right] = 1 - \Phi_{\mu,\sigma}\left(\sum_{g\in G} r_g\right) \qquad (2)$$

In order to obtain the desired scarcity adder, this ORDC curve should be evaluated at the amount of capacity left in the system. The available reserve can be measured by observing the leftover capacity remaining after the use of the balancing capacity platform (i.e. MARI). Note that, in a multi-area model, the transmission lines and the interaction between zones should be taken into account when evaluating the ORDC curve of a particular zone. We elaborate on the changes that are required in the sections that are devoted to the two case studies that represent Sweden through multiple zones, instead of one.

After the computation of the scarcity adder using the ORDC function, we can now correct the balancing price using this information. In a single-area model, this requires adding the scarcity adder on top of the balancing price computed by MARI. This addition provides the new balancing price. In a multi-area model, as in the case of the second step of this procedure, the interaction between the zones should be taken into account while making the correction. The modifications of the procedure in this particular case will be detailed in the sequel, in the sections devoted to the simulations using a multi-area setup.

3. Simulations for the Swedish system

As mentioned previously, the objective of the second phase of the project is to compare the real-time co-optimization of energy and reserve with the proposed design of the first phase of this project. These two approaches are both applied to Sweden, in order to observe how well the proposed design approximates the behavior of the co-optimization model. The analysis is provided in this section for three different case studies:

- Sweden as a single area
- Sweden represented by multiple areas with an ORDC only in SE4
- Sweden represented by multiple areas with an ORDC in each zone

The comparison results are shown for each case study in the sequel of this document.

3.1 Data Input

Before diving into the comparison of both models, this section details the different sources of data, as well as the assumptions and modifications that are adopted for performing the simulations for Sweden. Note that no changes have been made to the data compared to the first part of this project [1].

Svk has provided imbalance data per zone for 2021. The data has been transformed by our team to 15-minute resolution. Note that 32719 entries are available after the transformation of our data, whereas 35040 entries should be available. We fill out the missing values with data that has been provided by Svk during previous collaborations[1] which is based on 2018. We use this data to calibrate an ORDC which is used in our subsequent proof of concept. The mean of the imbalances is 28.9 MW, and the standard deviation is 505.4 MW. Applying the standard ORDC formula which is provided in Equation (1) gives us the following:

$$VR(r) = \left(VOLL - \widehat{MC}\right) \cdot LOLP(r)$$

We assume a VOLL of 7869 €/MWh, which is based on input from Svk. Figure 2 provides the ORDC curve obtained for $\widehat{MC}$ equal to 0 €/MWh.

[1] The 2021 data that has been provided to us runs up to December 7, 2021. We fill out the missing values with data from January 2018.

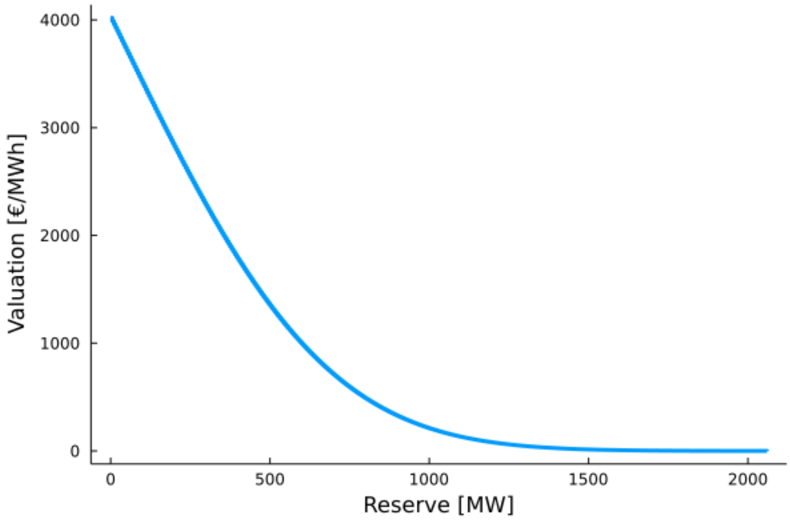


Figure 2 – ORDC based on Swedish system imbalances for an assumed system lambda of 0 €/MWh.

Other data input can be summarized as follows:

- Demand data is available per zone for 2021, and provided from Svk.
- Generation capacities, variable operating and maintenance costs, emissions rates, and fuel costs are sourced from a third party.
- Efficiencies, ramp rates, and energy storage capacities of reservoirs are sourced from the ten-year network development plant.
- Following information provided by Svk, the energy capacity of each reservoir is as follows: SE1 at 14426.3 GWh, SE2 at 14798.6 GWh, SE3 at 2635.1 GWh, and SE4 at 71.4 GWh. The total capacity of Sweden is[2] thus equal to 31.9 TWh.
- Water inflow time series and wind production time series are sourced from a third party.
- The 2019 price of CO_2 is 24 €/tonCO_2. We use it as a proxy for 2021.

The capacities and costs of the different Swedish technologies are presented in Table 1. We compute marginal costs as follows from the raw input data:

$$MC_i = \frac{CO_2Price[€/tonCO_2] \cdot EmmissionsRate_i[tonCO_2/MWh]}{Efficiency_i} + \frac{FuelCost_{Fuel(i)}[€/MWh]}{Efficiency_i} + VOM[€/MWh]$$

Technology	Marginal Cost	Nominal Capacity SE1 [MW]	Nominal Capacity SE2 [MW]	Nominal Capacity SE3 [MW]	Nominal Capacity SE4 [MW]	Total nominal capacity [MW]

[2] Based on communication with Svk, it has been explained that the theoretical energy capacity of Sweden is equal to 33.7 TWh, from zero to full storage. However, this differs from the amount of energy that is actually usable, and which is rather closer to 29 TWh. Following discussions with Svk, we use an intermediate value of 31.9 TWh in the energy capacity rating of the reservoirs in our model.

Condenser	180	0	0	243	662	905
Hydro Dam	2.7	5320	8076	2593	345	16334
Nuclear	14.2	0	0	6871	0	6871
OCGT	49.6	1	2	962	618	1583
Wind Onshore	0	1652	3876	2891	1598	10017

Table 1 - Spatial allocation and marginal cost of different technologies of the Swedish system in our multi-area model

We have access to third-party data for the average availability of different technologies. For hydro, we override this data with the data given by Svk, whereby out of the 16334 MW of hydro capacity only 12200 MW is effectively usable[3], due to various environmental and other constraints, which implies an availability of 80.8% for hydro generators. VOM in the above equation stands for variable operating and maintenance costs. $EfficiencyRate$ stands for the efficiency by which the primary fuel of each technology is converted into electricity.

Based on information received by Svk, which is sourced from Nordpool spot, we assume that reservoirs commence from a storage level of 24.8 TWh in the beginning of the year, and end with a storage level of 19.6 TWh.

In order to better align the results of our model to the average prices that were observed in Sweden in 2021, we have included linear supply functions at every zone of the model, which correspond to export price elasticity. This introduces a certain degree of price variability in the model beyond the marginal costs of the technologies that are listed in Table 1.

In order to calibrate these “border supply functions”, we first conduct a sensitivity analysis which leads to the following interesting observation: ranging the exports from 100% to 70% of their value leads to a drop in average prices from approximately 120 €/MWh to approximately 35 €/MWh, with the drop occurring abruptly at approximately 75% of exports. Since historical average energy prices in 2021 have ranged at around 60-70 €/MWh, we introduce a linear supply function that starts at 0 €/MWh and

[3] Based on information received by Svk, the nominal rating of hydro resources is actually in the range of 13.2 GW. However, this value is rather an upper bound, as it requires short- and long-term dispatch strategies to be aligned. In a typical year, the rating is instead in the range of 12 GW – 12.4 GW, hence our choice of 12.2 GW. This discounting allows us to indirectly account for aggregation approximation errors, as well as limited water rights in the summer. Limited water rights imply that, even if abundant capacity is available nominally, there are not enough rights to generate hydropower. Hydropower production needs to be planned ahead, and reservoirs should have optimal head levels at all plants, and optimal levels in storage stations. Water rights correspond to permits, which indicate a typical flow that needs to be discharged (e.g. water rights can stipulate that “from January until September x cubic meters per second should be discharged, and water cannot go above or below certain head levels”. These water rights are related to the need of preserving the physical environment for recreation activities, preserving biodiversity, controlling flooding, and other purposes. Actual hydropower capacity in the summer may even be as low as approximately 10-11 GW. This is anyway difficult to know on the basis of historical data, because in the past hydropower units in Sweden have never produced at their full capacity during the summer, since market prices are lower during these periods. Winter months are more likely to reflect the true capacity of the hydropower plants, if one attempts to infer this capacity from historical data.

increases up to 120 €/MWh at 30% of the average exported energy throughout the year. This export price elasticity allows the prices to depressurize, but not excessively.

Concretely, for the single-area model we have a "border supply function" that rises up to 120 €/MWh at 898 MW. For the multi-area model, it is observed that SE2 actually imports on average, so its "border supply function" is set to 0 MW, whereas the border supply functions of the other zones rise to 180 €/MWh at the following capacities: SE1 at 290 MW, SE3 at 192 MW, and SE4 at 432 MW.

In order to model Sweden using a multi-area model, additional information are provided in addition to the data sources reported previously.

- ATC data is available between bidding zones for 2021 by Svk. Missing values are filled out with the data of the previous time step. From this ATC data, we can compute interconnector capacities.
- It is clearly pointed out by Svk that all nuclear capacity is in SE3.
- The hydro capacities are based on Table 3 of [9]. We further use the inflow profile provided to us by a third party multiplied by the ratio of installed hydro capacity in each Swedish zone in order to infer a storage inflow time series per zone. It has been communicated to us by Svk that the storage inflows for 2021 amount to 67.8 TWh, thus the original storage inflow time series has been scaled up to reflect this total inflow over the year.
- We attribute the "OCGT_A" technology of our data to the "Gasturbiner + övrigt" technology of Table 3 of [9].
- We ignore the "Kraftvärme, fjärrvärme" and "Kraftvärme, industry" technologies of Table 3 of [9], since these technologies are anyway following a heating profile and are therefore not flexible.
- We introduce a new "Condenser" technology to the model, and set its marginal cost to 180 €/MWh, following guidance from Svk. Note that, in Sweden, this technology acts as strategic reserve.
- Imports/exports are provided by Svk, and sourced from NordPool. The topology of the interconnections of the Swedish system are indicated in Figure 3. Intraday values are added to the day-ahead values.
- For wind production we have the following link giving us annual TWh production in Sweden: https://www.statista.com/statistics/737840/electricity-from-wind-production-sweden/. We then use profiles of wind production (over the entire Swedish system) from a third party. We use the data provided by Svk regarding weekly production of wind in each Swedish zone to partition the profile given by a third party per zone.

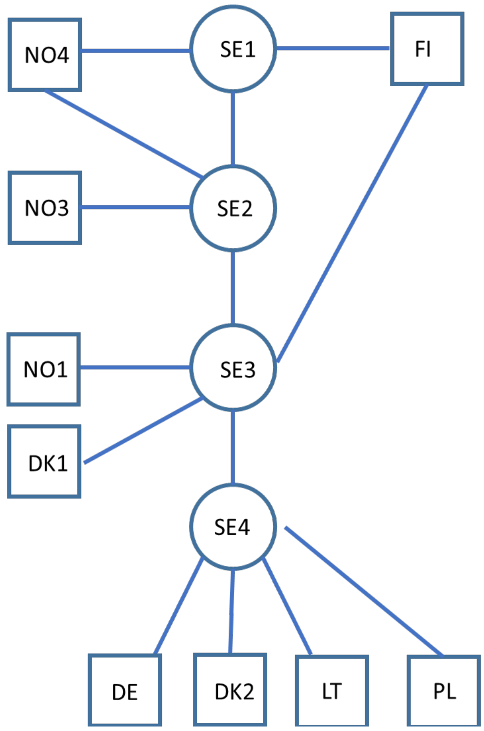


Figure 3 – Interconnections of Swedish system to zones out of Sweden. Circles indicate Swedish zones, boxes indicate zones out of Sweden.

The spatial distribution of capacities in the multi-area model, along with their marginal cost, is presented in Table 1. We note that, in practice, icing on rivers causes reduced availability of hydro capacity. For instance, 2 GW of hydro capacity was unavailable in SE1 and SE2 due to icing for an entire weekend in November 2021. This feature can be added straightforwardly to our model, and would result in higher scarcity adders than what is observed currently.

3.2 Sweden Represented as a Single Area

We commence the comparison between the two approaches presented in Figure 1 by considering Sweden as a unique zone. In this case, the ORDC function is presented in Figure 2.

3.2.1 Base Case Simulations

The results obtained for this first case study are presented in Table 2. We can observe that the average energy and reserve prices are not consistent between the two approaches. Indeed, over the year, the relative difference of energy prices is equal to 3.38% on average, while it can reach up to 21.78% at its maximum. The same conclusions can be derived from Figure 4. Indeed, the blue line in both graphs represents the reference line on which the different data points should land if the two approaches are providing identical values in terms of energy (left) and reserve (right) prices. As it can be observed from the figure, the dots significantly differ from the reference line as the co-optimization prices (energy and reserve) become higher.

	Average Energy Prices [€/MWh]	Average Available Reserve [MW]	Average Reserve Prices [€/MWh]
Co-Optimization of Energy and Reserve	73.27	8610.35	0.39
Ex-post adders	78.60	8608.04	5.58

Table 2 – Average energy and reserve prices along with the average available reserve over the year computed when considering Sweden as a unique zone for the two approaches.

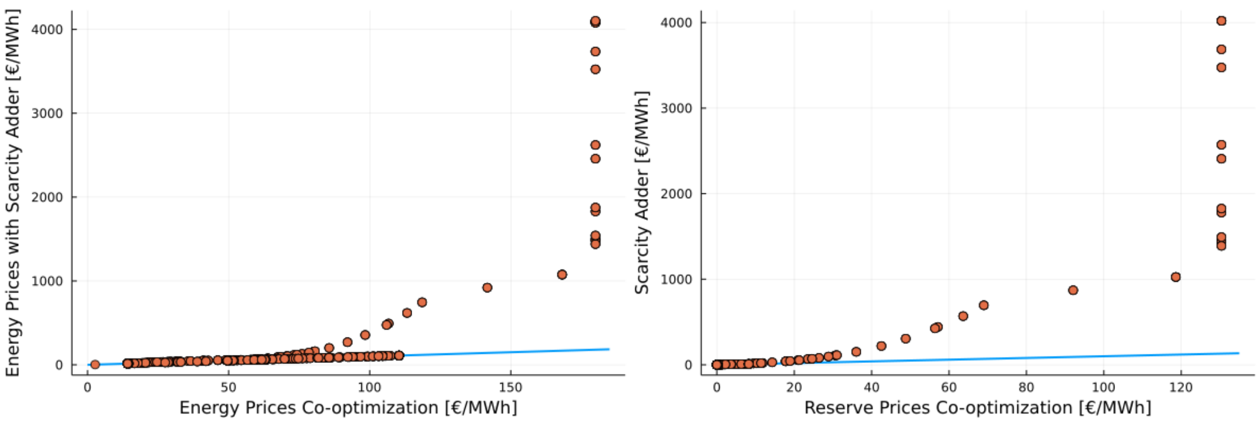


Figure 4 – Comparison of the energy (left) and reserve (right) prices obtained for the two approaches are represented by the dots. The blue line corresponds to the reference on which the dots should land if the two approaches are providing identical results.

In order to understand the origin of these large differences between the two approaches, Figure 5 presents the evolution of the absolute difference in energy and reserve prices respectively between the two approaches during the studied year. This graph actually demonstrates that the large discrepancies only appear at the beginning of the year, during winter. Table 3 details the energy and reserve dispatch of both approaches when considering the circled blue period (04/02/2021 at 8:15am). By analyzing this table, we can observe that the co-optimization model is able to anticipate the need for dispatching the most expensive technology (condenser) in order to be able to keep capacity available on a cheaper technology which is flexible and is therefore able to provide reserve. On the contrary, the energy-only platform uses all the technology going from the cheapest to the most expensive unit. Since the most expensive technology cannot provide reserve but is the only technology with spare capacity in this case, the energy-only dispatch does not benefit from any available reserve. This situation explains the high price difference observed in Figure 5.

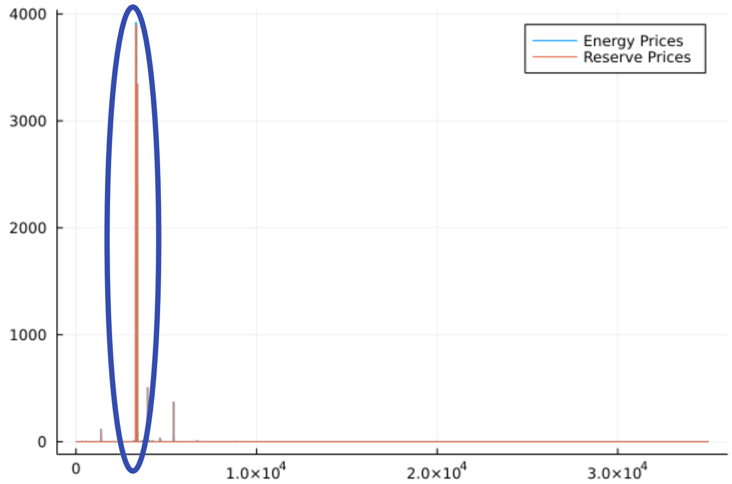


Figure 5 – Evolution of the absolute difference of energy and reserve prices between the two approaches during the studied year.

Technology	Marginal Cost [€/MWh]	Able to provide reserve?	Total nominal capacity [MW]	Energy Dispatch Co-Optimization [MW]	Available Reserve Co-Optimization [MW]	Energy Dispatch MARI [MW]	Energy Dispatch MARI [MW]
Condenser	180	No	905	**650.48**	0	**0**	0
Hydro Dam	**2.7**	**Yes**	16334	16334	0	16334	0
Nuclear	14.2	No	6871	6871	0	6871	0
OCGT	**49.6**	**Yes**	1583	**478**	**1105**	**1583**	**0**
Wind Onshore	0	No	10017	1660	0	1660	1660

Table 3 – Energy and reserve dispatch from the two approaches for each technology used in Sweden on 04/02/2021 at 8:15am.

Finally, from the previous observations, we can conclude that the most expensive technology in Sweden is non-flexible in our model of MARI. This creates large discrepancies between the MARI dispatch and the co-optimization of energy and reserve. However, we believe that, since our model of MARI is a deterministic model with perfect foresight, it fails to capture certain real-world precautions that asset owners would resort to in order to protect the system from real-world uncertainties. Indeed, we can argue that the dispatch would keep some hydro power in reserve because hydro units have opportunity cost related to uncertainty which is not captured in our proxy of MARI (a deterministic one-year optimization with perfect foresight). Therefore, it was proposed by our team to divide the power output of hydro technologies into two portions for subsequent simulations:

- A small portion of the power capacity of hydro resources will only be available at a higher price than the most expensive non-flexible technology of the mix.
- The rest of the hydro capacity will remain at its original computed price.

This partitioning is adopted and simulated in the subsequent sections of this report.

3.2.2 Simulations with a portion of expensive hydro power

As discussed previously, this section presents the updated version of the results obtained with Sweden considered as a unique zone. Specifically, we consider 10% of the hydro power capacity as the most expensive technology (181 €/MWh) and 90% at its original marginal cost. The results are presented in Table 4. From this table, we can observe that the two approaches are providing coherent results. Indeed, only minor differences can be observed between the two approaches with slightly larger prices for the proposed design with ex-post adders. This is further confirmed by the average energy price relative difference which is now equal to 0.037%, compared to 3.38% in the previous case study. Finally, the observation that the proposed design with ex-post adders approximates well the behavior of the co-optimization of energy and reserve is further validated in Figure 6. Indeed, the dots are landing on (or very close to) the reference line which shows that energy and reserve prices are almost identical with both approaches.

	Average Energy Prices [€/MWh]	Average Available Reserve [MW]	Average Reserve Prices [€/MWh]
Co-Optimization of Energy and Reserve	74.58	8582.047	0.0735
Ex-post adders	74.62	8581.976	0.0775

Table 4 - Average energy and reserve prices along with the average available reserve over the year obtained when considering Sweden as a unique zone for the two approaches. These simulations account for 10% of the hydro power production being considered as expensive.

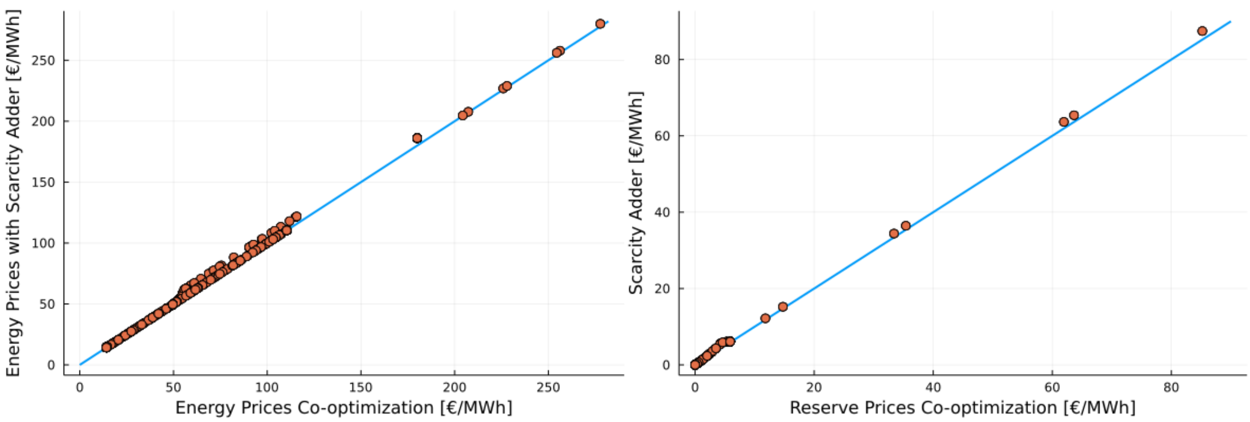


Figure 6 - Comparison of the energy (left) and reserve (right) prices obtained for the two approaches represented by the dots when considering 10% of expensive hydro power. The blue line corresponds to the reference on which the dots should land if the two approaches are providing identical results.

3.2.3 Discussion on Strategic and Disturbance Reserves

An interesting point to underline with respect to reserve in Sweden is that there is currently a distinction between strategic reserve and disturbance reserve. Details on these two types of reserve for the entire Nordic region can be found in the report of the first phase of the project [1].

In Sweden, disturbance reserve mainly corresponds to gas turbines that are owned by a company that is affiliated to Svk, or are secured by long-term contracts. In addition, yearly supplementary procurement is performed in order to secure dimensioning. This reserve is used in order to cover for large incidents and can only be activated when all market bids have been used. This reserve does not affect any price for the moment (mFRR or imbalance price). Disturbance reserve corresponds to 764 MW in SE3 and 540 MW in SE4 of the OCGT technology.

On the other hand, strategic reserves are only used as a last resort, out of the balancing market, used for congestion, but also if balancing resources are exhausted. In Sweden, as of the coming winter, strategic reserves will not be activated on the day-ahead market (as they used to be) but as the last resource to exhaust when balancing resources have been depleted. Strategic reserve corresponds to 560 MW of the condenser technology in SE4, and is assumed to be available from 15/11 until 15/03. Outside this period, strategic reserve is used as a regular technology (which is eligible for bidding into MARI and affecting the computation of the scarcity adder).

In order to observe if it would be interesting to consider strategic and disturbance reserve in MARI or for the computation of the scarcity adder, several simulations are performed. The specific assumptions of these simulations are provided in Table 5. Note that simulations 1 and 2 correspond respectively to the first two simulations presented in this section, when considering Sweden as a single zone.

Simulation Number	Strategic Reserve in MARI	Strategic Reserve in Scarcity Adder	Disturbance Reserve in MARI	Disturbance Reserve in Scarcity Adder	Percentage of Expensive Hydro
1	Yes	Yes	Yes	Yes	0%
2	Yes	Yes	Yes	Yes	10%
3	No	Yes	Yes	Yes	0%
4	No	Yes	Yes	Yes	10%
5	No	No	Yes	Yes	0%
6	No	No	Yes	Yes	10%
7	No	No	No	Yes	0%

Table 5 – Features of the different simulations run when considering strategic and disturbance reserve as specific reserve participating or not in MARI and in the computation of the scarcity adder. These simulations were performed for the case study considering Sweden as a single area.

The results obtained for the different simulations presented in the previous table are summarized in Table 6. From these results, we observe that, when both strategic and disturbance reserves are not allowed to participate in MARI, the resulting average energy prices are excessively high. This observation suggests that at least one of the two types of specific reserve should be included in MARI. Moreover, we observe that, for all settings, considering 10% of expensive hydropower allows the proposed design with ex-post adders to better approximate the results obtained by the co-optimization of reserve and energy, as already observed in the previous section. However, the improvement is reduced when strategic reserve is only used for the computation of the scarcity adder. Finally, scarcity adders are observed to be lower when strategic reserve is kept only for the computation of the scarcity adder.

Simulation Number	Percentage of Expensive Hydro	Average Relative Difference between Energy Prices	Average Energy Price (Co-optimization) [€/MWh]	Average Scarcity Adder (ex-post adder) [€/MWh]
1	0%	3.32%	73.27	5.58
2	10%	0.037%	74.58	0.078
3	0%	0.7%	73.07	1.16
4	10%	0.1%	74.59	0.037
5	0%	2.17%	73.62	5.58
6	10%	0.035%	75.08	0.55
7	0%	75.1%	4759.49	58.53

Table 6 – Results obtained for each simulation setup provided in Table 5.

Based on the results that are presented in Table 6 and on discussions with Svk, it was decided to only retain options 5 and 6 when considering Sweden as a multi-zone area. Therefore, the simulation results that are reported in the remaining sections consider that disturbance reserves are available in MARI and for the computation of the scarcity adder, whereas strategic reserve is not available for any of the two aforementioned steps.

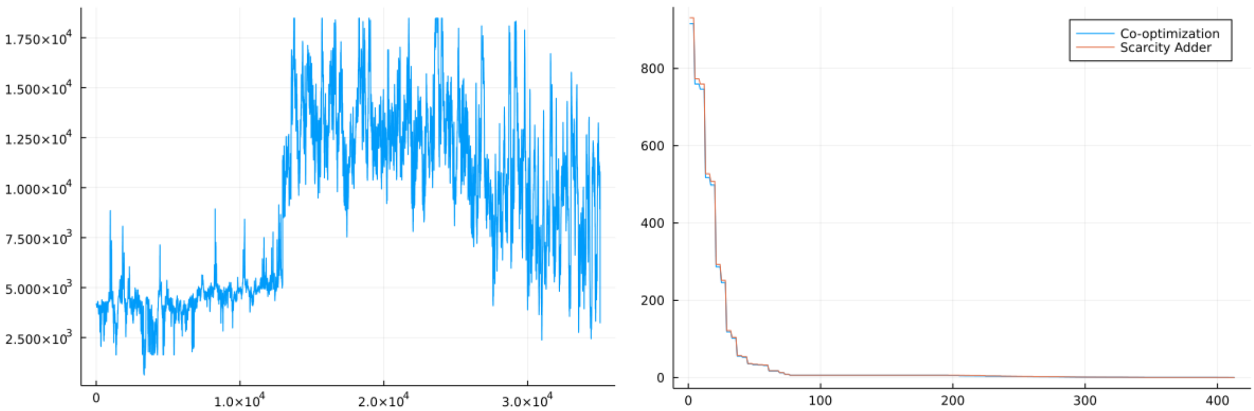


Figure 7 – On the left, the evolution of the total available reserve in the system in MW. On the right, the reserve price duration curve of the system using both approaches. These results are provided for the simulation case 6 (10% of expensive hydro without strategic reserve being accounted for).

Figure 7 provides certain insights about simulation case 6. In this figure, on the left, we can observe the evolution of the available system reserve over the year. The right illustration specifies the reserve price duration curve, showing that, in practice, the system experiences high reserve prices only during a reduced number of 15-minute periods during the year.

3.3 Sweden Represented with Multiple Areas with ORDC only in SE4

Now that the results have been presented for the two approaches when considering Sweden as a single zone, the model is escalated in terms of complexity in this section by representing Sweden as multiple areas. In order to commence with a simpler multi-area setup, we propose in this section to only apply an ORDC function in SE4. This ORDC function is presented in Figure 8 for convenient reference.

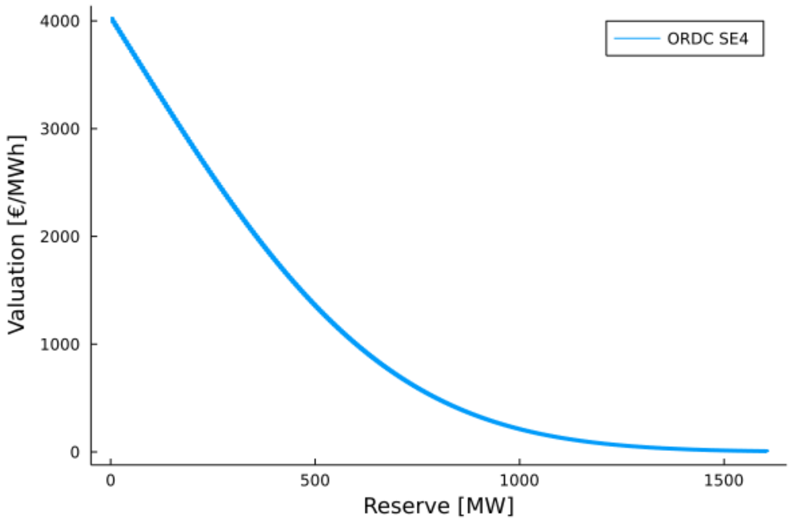


Figure 8 – ORDC function in SE4 based on Swedish system imbalances for an assumed system lambda of 0 €/MWh in a multi-area setup.

Now that Sweden is represented by multiple zones, we need to account for the interactions between the different zones when computing the scarcity adder of each zone and correcting the balancing price (see the second and third steps of the proposed design in Figure 1). In order to understand the interactions taking place between the zones in the current simulated context, we observe the results obtained from the co-optimization model. These results indicate that, in this context, all zones tend to send their available reserve capacity to SE4 if there is enough space on the transmission lines. This observation is coherent with the fact that only reserve in SE4 is valued in the objective function of the co-optimization in this context. This means that reserve provision is mostly interesting in SE4, which explains the shipment of reserve towards this specific zone. This observation leads us to propose the following adaptions to the second and third step of the procedure of the proposed design:

- ***Step 2 – Scarcity Adder Computation***: All available reserves from other zones are transferred to SE4 up until the capacity left on each transmission line after the energy dispatch provided by the balancing platform (i.e. MARI).

- ***Step 3 – Balancing Price Correction***: As in the case of the single-zone setup, the scarcity adder computed for SE4 (during Step 2) is added on top of the balancing price of SE4 obtained via MARI. Regarding the other zones, the scarcity adder of SE4 is applied to their balancing price only if the path between the zones is not congested (when both energy flows from MARI and reserve flows from Step 2 are accounted for).

Concerning the adaptations made to the third step regarding prices in other zones than SE4, these are described in the first phase of this project by analyzing the optimal pricing behavior of the co-optimization model [1]. From this analysis, it was concluded that, if there is a congested link in the network, then the energy price is equal in the downstream subnetwork, it is also equal in the upstream subnetwork, and the two energy prices are separated by the scarcity adder. These conclusions are explained graphically in Figure 9.

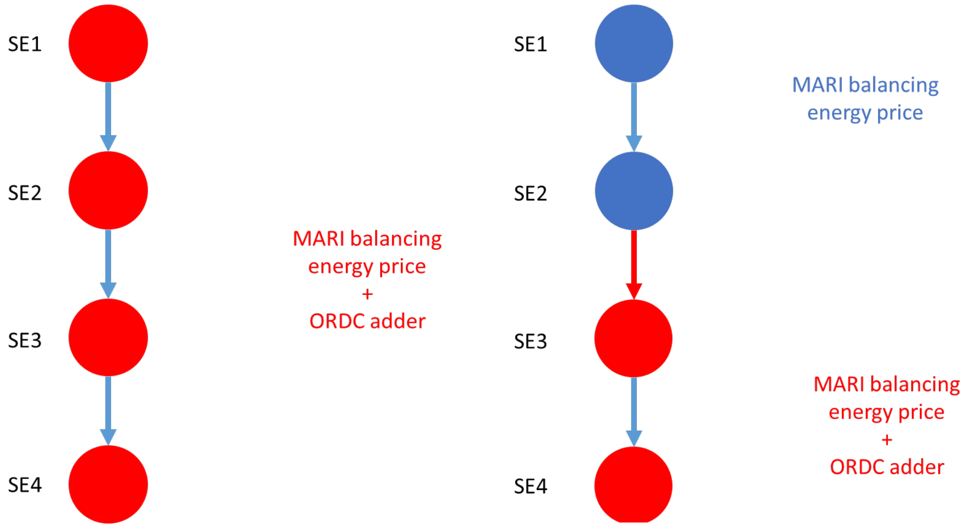


Figure 9 – Scarcity pricing in the multi-zone system of Sweden. Red circles represent nodes where a scarcity adder applies, whereas blue circles represent nodes where a scarcity adder does not apply. Blue arrows indicate links which do not experience congestion, whereas red arrows indicate links which do experience congestion.

After modifying the procedure of the proposed design to improve the quality of its approximation of the co-optimization set in a multi-area with ORDC in SE4 only, we can now proceed with the results of the simulations. The results for this case study are provided in Table 7 in which no strategic reserve is considered but disturbance reserve is included in MARI and the computation of the scarcity adder. From this table, we observe that the coherence between the results obtained with the two approaches is improved when using 10% of expensive hydro power as with the single-zone simulations. This is further confirmed by observing the comparison of energy prices (Figure 10) and reserve prices (Figure 11) between the simulation with 0% of expensive hydropower (left) and the one with 10% of expensive hydropower (right).

Simulation Number	Percentage of Expensive Hydro	Average Relative Difference between Energy Prices	Average Energy Price (Co-optimization) [€/MWh]	Average Scarcity Adder (ex-post adder) [€/MWh]
5	0%	SE1 → 0.78% SE2 → 0.78% SE3 → 0.78% SE4 → 0.79%	SE1 → 72.18 SE2 → 72.18 SE3 → 72.18 SE4 → 72.21	SE1 → 2.28 SE2 → 2.28 SE3 → 2.28 SE4 → 2.31
6	10%	SE1 → 0.02% SE2 → 0.02% SE3 → 0.02% SE4 → 0.03%	SE1 → 73.72 SE2 → 73.76 SE3 → 73.76 SE4 → 73.78	SE1 → 0.45 SE2 → 0.45 SE3 → 0.45 SE4 → 0.49

Table 7 – Results obtained for simulation setups 5 and 6 for the multi-are case study with an ORDC function only in SE4.

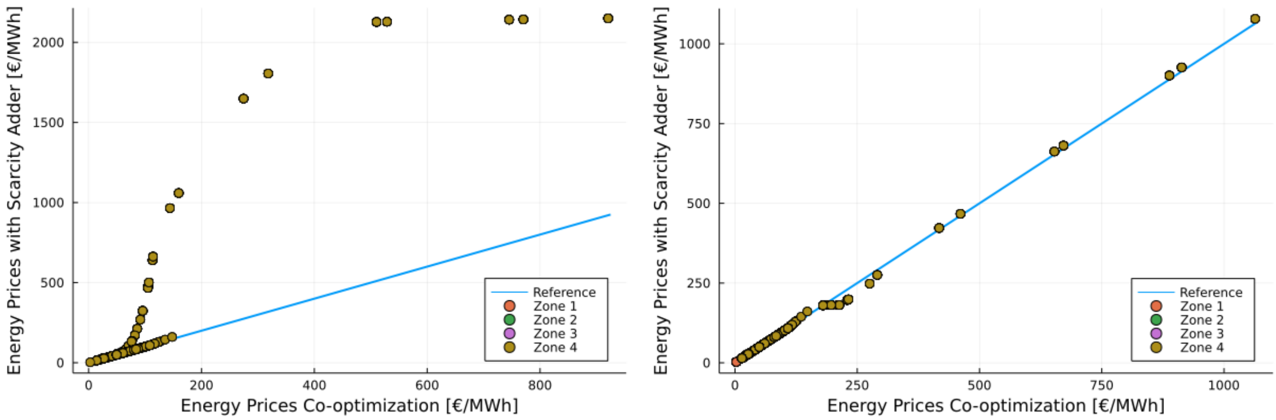


Figure 10 - Comparison of energy prices obtained for the two approaches represented by the dots without (left) and with (right) 10% of expensive hydro power. The blue line represents the reference on which the dots should land if the two approaches are providing identical results.

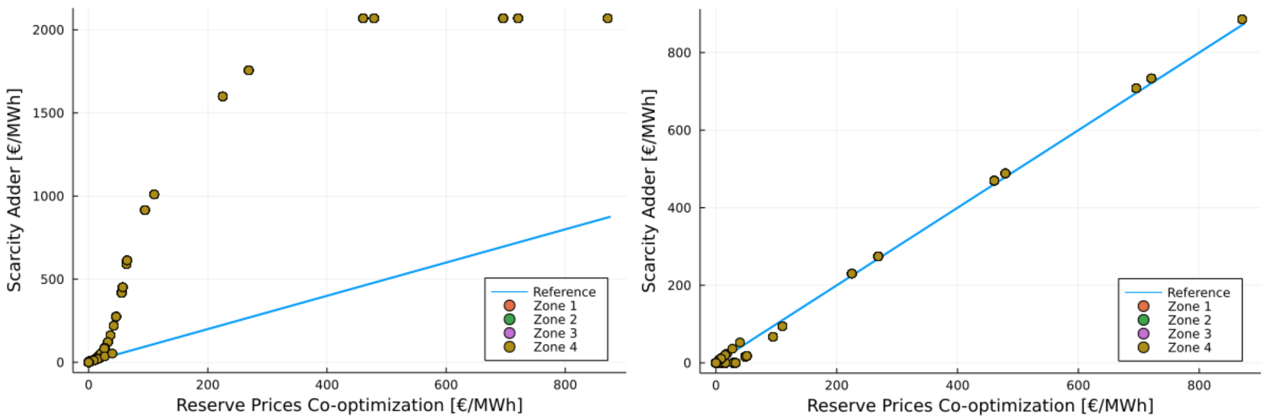


Figure 11 - Comparison of reserve prices obtained for the two approaches represented by the dots without (left) and with (right) 10% of expensive hydro power. The blue line represents the reference on which the dots should land if the two approaches were providing coherent results.

Figure 12 represents the reserve price duration curve of the case study which considers 10% of expensive hydro power. From this figure, we can observe that the curve is notably similar to the one obtained in the right of Figure 7 for the single-zone setup. Indeed, the system in this case is also experiencing a scarce situation for only a few periods during the year, thus leading to non-zero reserve prices.

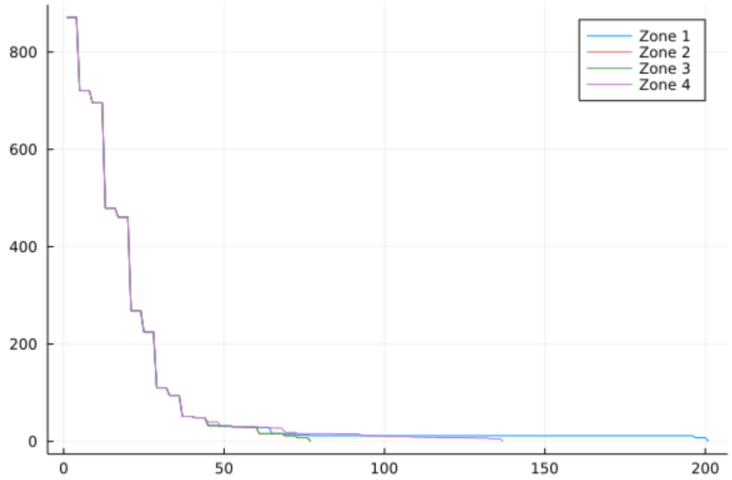


Figure 12 - Reserve price duration curve of the system using both approaches for the multi-area model with ORDC in SE4 only. These results are provided only for simulation case 6 (10% of expensive hydro without strategic reserve being accounted for).

3.4 Sweden Represented with Multiple Areas with an ORDC in Each Zone

In this last results section, we are now considering the Swedish system with multiple zones and with a separate ORDC function in each zone. The ORDC function of each zone is presented in Figure 13 for convenient reference.

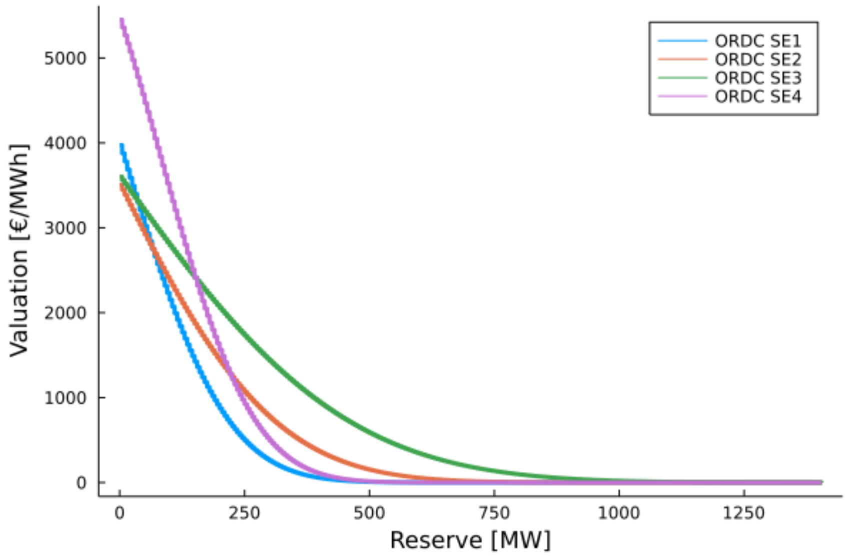


Figure 13 – ORDC function for each zone of Sweden for an assumed system lambda of 0 €/MWh.

As in the previous case study which was considering Sweden as a multi-zone system but with an ORDC function present only in SE4, the second and third step of the proposed design have to be adapted in order to account for the interactions between the different zones and the different ORDC functions. In order to understand the interactions taking place between the zones in the current simulated context, we observe the results obtained from the co-optimization model, as we did in the previous sections. These results indicate that, in this context, no congestion is observed for each of the transmission lines during the entire year. This observation suggests that the system in this case only experiences global scarcity[4]. Based on the discussion on congestion that is developed in the previous section, this means that the total reserve that is available in the system is shared between the different zones such that the reserve price is the same in every zone. The following observation leads us to propose the following adaptions to the second and third step of the proposed design procedure for this particular case study:

- ***Step 2 – Scarcity Adder Computation***: All available reserves from all zones are summed up in order to compute the total available reserve capacity. This total available reserve capacity is shared between zones in order to obtain the same scarcity adder in every zone. A bisection algorithm is used in order to find the distribution of the total available reserve between zones and the system scarcity adder.

- ***Step 3 – Balancing Price Correction***: Since no congestion is observed on any of the transmission lines during the entire year, the scarcity adder computed in Step 2 is applied to every zone in order to correct the balancing price of each zone that is obtained via MARI. This rule is coherent with the discussion on congestion that was presented in the previous section.

Concerning the adaptions made to the second step of the procedure, we now describe the bisection algorithm that is used in order to compute the scarcity adder in this case. Figure 14 illustrates the different steps that are undertaken during the bisection algorithm described in the sequel of this document. The bisection algorithm is executed as follows:

- **Inputs:**
  - Total available reserve present in the system: w
  - ORDC functions of each zone

- **Algorithm Initialization:**
  - Compute the maximum possible valuation (a) from all ORDC curves and the total available reserve corresponding to this valuation
  - Compute the minimum possible valuation (b) from all ORDC curves and its respective total available reserve

- **At each iteration:**
  - Compute a new valuation: $x = \frac{a+b}{2}$
  - Compute its corresponding total available reserve by using the ORDC curves: $y = y_1 + y_2 + y_3 + y_4$
  - Stopping Criterion:
    - If the input total available reserve (w) and the one computed for the new valuation (y) are *close enough* then the algorithm returns the new valuation (x) and stops.
    - If the input total available reserve (w) *is strictly lower* than the one computed for the new valuation (y), then the minimum possible

[4] Note that this observation is already reported in the first phase of this project [1].

valuation is replaced by the new valuation of the iteration ($b = x$) and a new iteration starts.

- Otherwise, the maximum possible valuation is replaced by the new valuation computed during the iteration ($a = x$) and a new iteration starts.

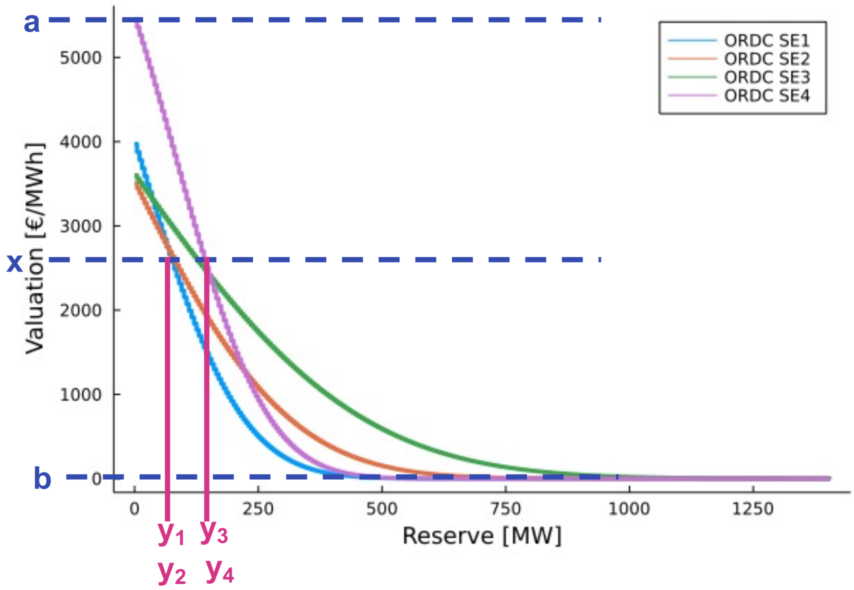


Figure 14 – Illustration of the different steps of the bisection algorithm used for computing the scarcity adder value for the multi-area case study with separate ORDCs in each zone.

Now that all the ingredients are available, Table 8 presents the results obtained for the simulations performed for the multi-zone model of Sweden with a separate ORDC in each zone. This table contains the results of the two approaches that are compared for both the setting without and with 10% of expensive hydropower. As for the two other case studies analyzed previously, we can observe from the results that using 10% of expensive hydropower is resulting in prices that are closer to each other in the co-optimization and ex-post adder approaches. This observation is further confirmed by analyzing Figure 16 and Figure 15. These two figures compare energy and reserve prices between the two approaches for both the case with and without 10% of expensive hydropower. However, with respect to the other multi-area case study, the average relative difference between energy prices is higher in this case. This can be explained by the complexity of the current case study. Indeed, in this case study, since the bisection algorithm relies on a certain tolerance, it is expected to provide results in the ex-post adder approach that are less precise than with the other case study.

Simulation Number	Percentage of Expensive Hydro	Average Relative Difference between Energy Prices	Average Energy Price (Co-optimization) [€/MWh]	Average Scarcity Adder (ex-post adders) [€/MWh]
5	0%	SE1 → 5.01% SE2 → 5.01% SE3 → 5.01% SE4 → 5.01%	SE1 → 74.66 SE2 → 74.66 SE3 → 74.66 SE4 → 74.66	SE1 → 7.71 SE2 → 7.71 SE3 → 7.71 SE4 → 7.71

6	10%	SE1 → 0.75% SE2 → 0.75% SE3 → 0.75% SE4 → 0.75%	SE1 → 76.04 SE2 → 76.04 SE3 → 76.04 SE4 → 76.04	SE1 → 3.52 SE2 → 3.52 SE3 → 3.52 SE4 → 3.52

Table 8 - Results obtained for simulation setups 5 and 6 for the multi-are case study with ORDC functions in every zone.

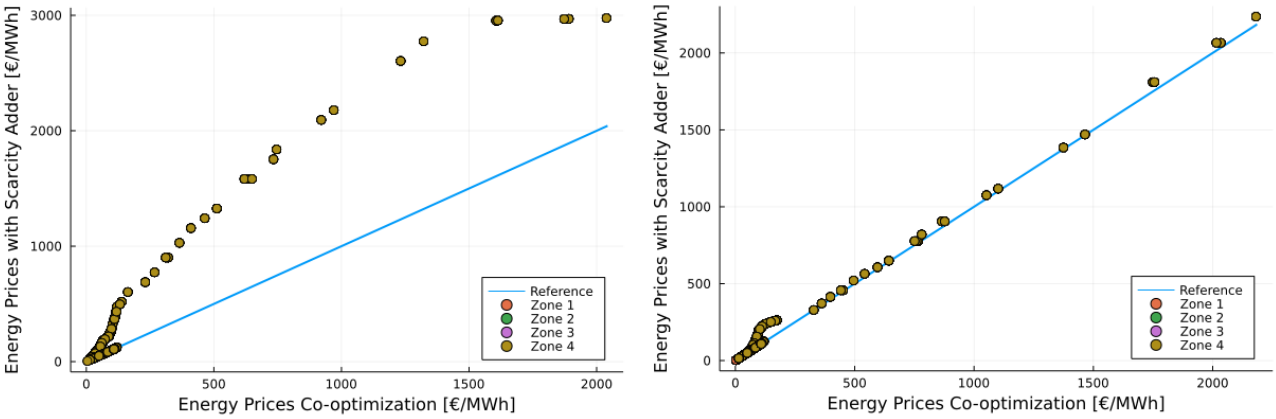


Figure 16 - Comparison of energy prices obtained for the two approaches represented by the dots without (left) and with (right) 10% of expensive hydro power. The blue line corresponds to the reference on which the dots should land if the two approaches are providing identical results.

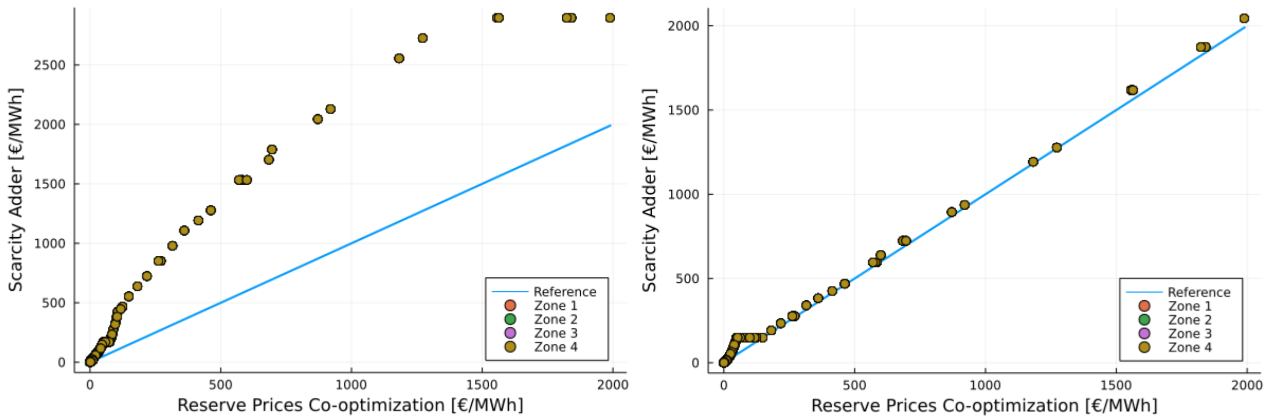


Figure 15 - Comparison of reserve prices obtained for the two approaches represented by the dots without (left) and with (right) 10% of expensive hydro power. The blue line corresponds to the reference on which the dots should land if the two approaches are providing identical results.

As in the other case study, Figure 17 presents the reserve price duration curve for the simulation considering 10% of expensive hydropower. From this figure, we can observe that the system still experiences scarcity only during a few periods of the year. However, the number of scarcity periods and the peak value of this curve seem to be larger relative to the two other case studies.

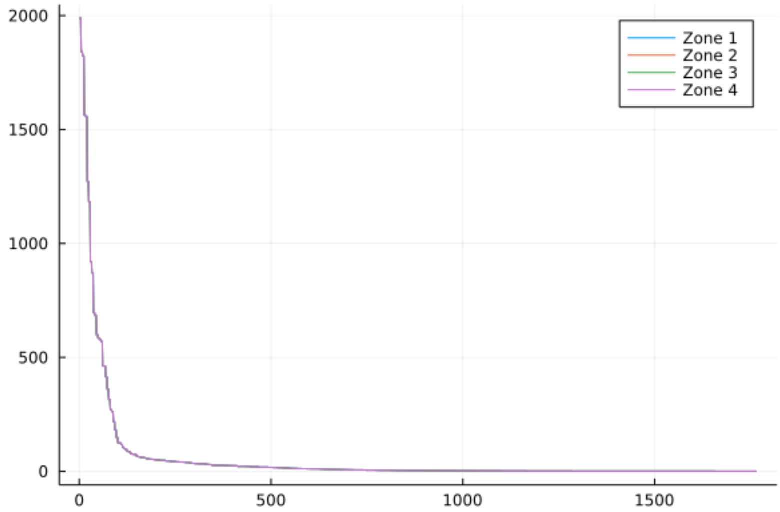


Figure 17 - Reserve price duration curve of the system using both approaches for the multi-area model with a separate ORDC in every zone. These results are provided only for simulation case 6 (10% of expensive hydro without strategic reserve being accounted for).

3.5 Discussion

Based on the different results shown in the previous sections, different subjects are discussed in detail in this section that pertain to the impact of ORDC curves on the results of the different simulations, with a specific focus on the average value of the scarcity adders.

3.5.1 Differences between the "Multi-Area Multi-ORDC" and "Single-Area" case studies

Even though no congestion between the different zones is observed in the "Multi-Area Multi-ORDC" case study, the scarcity adders obtained in this case study are not equivalent to the one of the "Single-Area" case study. This difference could be attributed to several different factors.

The first thing to note is that the average scarcity adder which is equal to 7.71 €/MWh, and which is reported in Table 8, corresponds to the case where the simulations assume that 0% of the hydro capacity is expensive. The average reserve price produced by the co-optimization model, which corresponds to the same simulation settings, is quite different. This can, in part, be attributed to the fact that the co-optimization model and our proposed closed-form formula for approximating the co-optimization outcome do not align perfectly well. The average reserve price of the co-optimization model in this case is equal to 3.15€/MWh. Moreover, by analyzing the results that are presented in Table 6, we can observe that the use of strategic and disturbance reserve along with the amount of assumed expensive hydro power have an impact on the average scarcity adder. It is therefore important to compare the two cases studies (Single-Area and Multi-Area) only for the same simulation setup. We can compare the two values for simulation number 6: 0.55 €/MWh (Single-Area) and 3.52 €/MWh (Multi-Area). There, the difference cannot be due to strategic and disturbance reserves, since they are considered in the same way in both cases. This difference is only due to the differences between the two case studies. We comment on these differences in the following paragraphs.

An important difference between the two models is that the system without a network really is quite different from the one with a network, even when ORDCs are ignored in the model. For instance, the system without a network has one reservoir, whereas the one with a network has four reservoirs, one for each zone, and is thus essentially a more constrained version of the one without a network. This means that one can expect differences in dispatch, and different energy prices, even if we completely ignore ORDCs.

When ORDCs are accounted for, there is no guarantee that adders would be equal, even in the absence of congestion (see the results of pages 13 and 42 of the Phase 1 report [1]). This depends on how the operating reserve demand curves are calibrated. If we use the calibration of formulas 1 and 2 of the present report, then no such behavior guaranteed.

It is important to point out that, since the shape of the demand curves can ultimately be decided by TSOs, the demand curves can be engineered to exhibit a behavior whereby a single ORDC gives the same adder as multiple ORDCs in a system without congestion. Specifically, a condition that can ensure this is the following:

$$ORDC(R) = ORDC_{SE1}(R_{SE1}) + ORDC_{SE2}(R_{SE2}) + ORDC_{SE3}(R_{SE3}) + ORDC_{SE4}(R_{SE4})$$

for all $(R, R_{SE1}, R_{SE2}, R_{SE3}, R_{SE4})$ such that $R = R_{SE1} + R_{SE2} + R_{SE3} + R_{SE4}$, where we note that the co-optimization will select R_{SEi} such that $ORDC_{SEi}(R_{SEi})$ are equal for all i. This equation states that a sufficient condition for the adders to be equal in simple settings (single period, no binding network constraints) is for the single-area ORDC to be the *horizontal sum* of the multi-area ORDC. For instance, if we had identical ORDCs in each zone, we could obtain their horizontal sum as $ORDC(R) = ORDC_z(\frac{R}{4})$, where $ORDC_z$ is the ORDC of each zone. Applying formulas 1 and 2 on historical data does not guarantee such behavior (i.e. that the horizontal sum of the per-area ORDCs is the ORDC of the single-area model, see figure 18). Note, however, that formulas 1 and 2 of the present report are advisory and variations can be (and are, in practice [2]) adopted when implementing scarcity pricing. One of the important advantages of ORDCs is that they allow TSOs to value reserves as they see fit, based on their operating principles.

3.5.2 Interplay of adders and ORDCs in the "Multi-Area Multi-ORDC" case study

In view of the discussion of section 3.5.1, one might naturally pose the question of whether
1. the adder used in the multi-ORDC model is the highest adder among separately calculated adders, or whether
2. it is based on combining all the ORDCs to one before computing the adder.

Interestingly, it turns out that both interpretations are correct, but the second one is more natural.

The bisection algorithm that we propose for computing adders in the multi-ORDC case allocates reserves so that the adder is equal in all zones. In this sense, the resulting adder is the highest adder among separately calculated adders, but all the separately calculated adders are equal, so this statement is not entirely representative of what our bisection method is doing. Since we compute the adder by taking the horizontal sum of all the ORDCs, the second interpretation is also correct: we are essentially merging the ORDCs into one and then computing the adder based on the total leftover reserve in the system. It is fair to say that, among the two interpretations, the second one is more aligned with the underlying mathematics.

The horizontal sum of the multi-area model is juxtaposed against the single-area model in Figure 18. What we observe is that the horizontal sum of the ORDCs of the multi-area model is uniformly above the ORDC of the single-area model. This can, in part, explain the tendency for higher adders in the multi-ORDC model. The fact that the two ORDCs do not coincide relates to formulas 1 and 2 of the present report. If a certain area has imbalances with higher variance than another area, then these will tend to produce valuations that are higher (e.g. in the 5000 €/MWh range) than those of a single-area model where imbalances of different zones tend to cancel each other out and thus produce an overall imbalance signal with lower variance, and thus an ORDC with lower valuation.

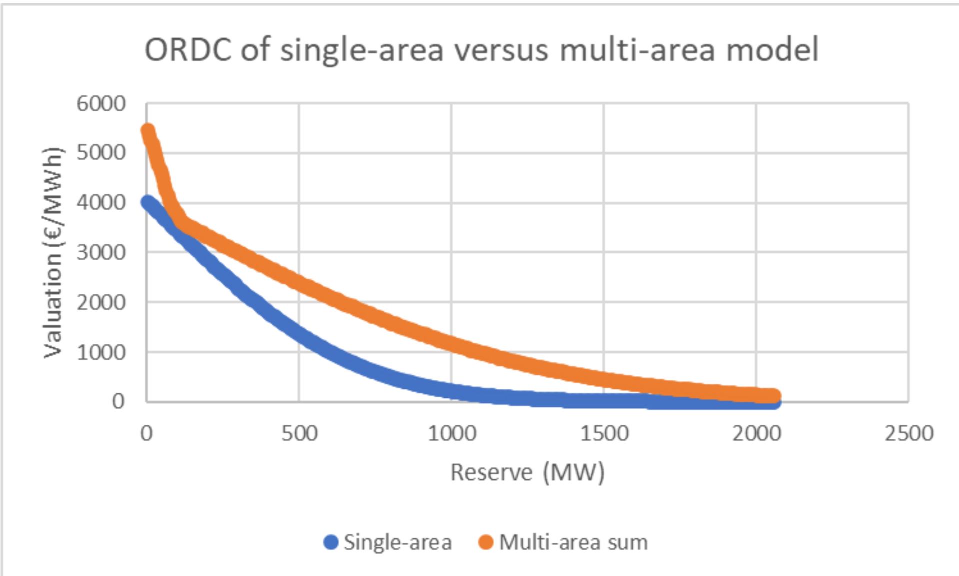


Figure 18 - Comparison of the ORDC curve used for the single-area model against the horizontal sum of the different ORDCs of the different zones in the multi-ORDC model.

3.5.3 Congestion patterns

A question that has been raised by Svk and other Nordic TSOs during the project relates to the limited degree of congestion in the system. The Swedish system has recently exhibited systematic congestion from the North to the South, as indicated in Figure 19. Concretely, one can observe a fairly consistent separation between Northern zones SE1 and SE2 (with lower prices) and Southern zones SE3 and SE4 (with higher prices), especially as of June 2021, and until December 2021. Given that this time interval is included in our model horizon, one would expect our model to reflect such congestion patterns as well.

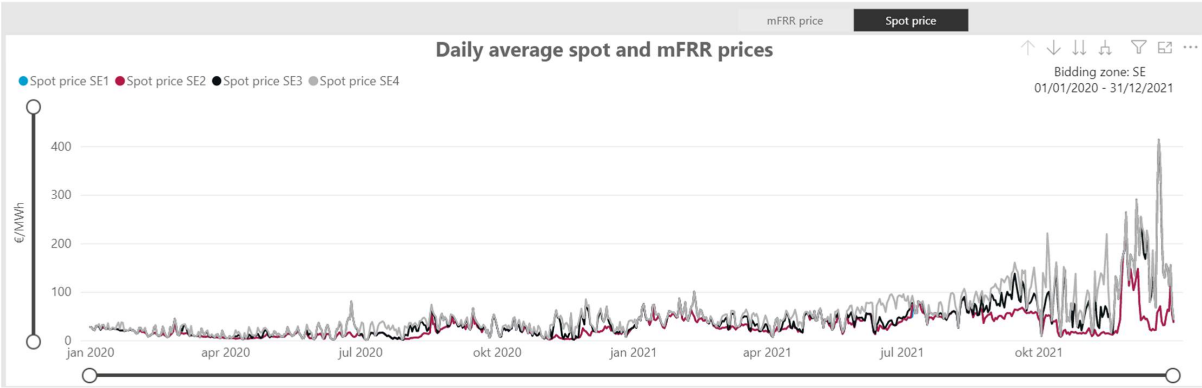
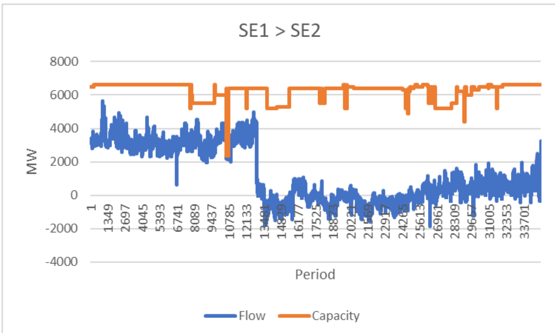
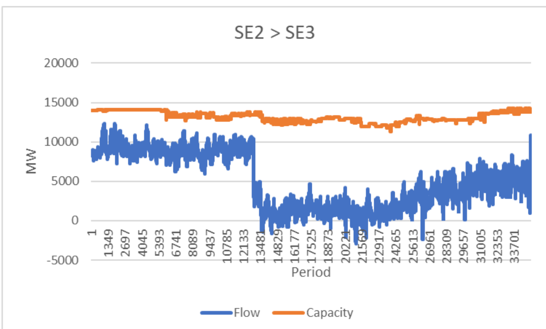


Figure 19: Prices in the Nordic system from January 1, 2020, until December 31, 2021.

Figure 20 presents the energy flows and the line capacity of each link in the model throughout the simulation horizon of the model. Although there is a tendency for power to flow from the North to the South, there is no congestion, and there is an abrupt drop in North-to-South flows in period 12960. This drop in flows occurs exactly in period 12960, which is the moment in time where our model requires hydro levels to attain their minimum storage level. Thus, the drop in flow relates to the fact that, when the model is left free to optimize beyond period 12960, it finds it more efficient to produce less power from hydro resources in the north, thereby correspondingly reducing its north-to-south flows. But the important observation here is that there are no periods where any of the line constraints are binding, which is clearly at odds with the observation of Figure 19, where we observe a congestion from the north to the south.





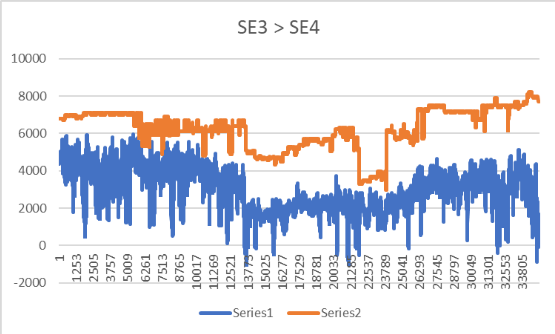


Figure 20: Energy flows versus physical capacities in the multi-area multi-ORDC model in the simulations that use the settings of phase 1.

Why is there a discrepancy?

In the baseline model, there are two technologies that have identical marginal costs throughout all zones:

- HDAM at 2.7 €/MWh
- Wind at 0 €/MWh

This implies that capacities in the North and the South of Sweden are indistinguishable. This is clearly an oversimplification of reality, yet one which was not challenged by Svk throughout the project. The reality of the system is that there are various heterogeneous generators belonging to each of these categories of technologies (i.e. some CCGTs are cheaper than others), thus a more accurate stylized model would be one in which each zone has a marginal cost curve that commences at a certain minimal marginal cost and increases up to a certain maximal marginal cost. Given that there is more capacity of these technologies installed in the North, this tends to introduce a bias to the model in terms of North-to-South flows, since the availability of cheap resources in the North of the country is underestimated.

In order to test whether this simplification of homogeneous resources throughout the system can result in an underestimation of congestion, we present updated simulation results whereby the marginal cost of the HDAM resources in the north is decreased to 2.6 €/MWh, and the marginal cost of the wind resources in the south is increased to 0.1 €/MWh. Thus, the marginal cost of the resources in the North is made slightly lower than those in the South. The resulting flows turn out to be identical to those of Figure 20. This rules this explanation out as a possible driver of the results.

Another possible explanation for the underestimation of congestion in our model is that the difference with observed historical congestion patterns may be due to baseline flows implied from non-Swedish resources. There is a clear bias in the baseline flows from North to South based on the day-ahead data that Svk has shared, which means that North-to-South ATCs are lower than the other way around. But it is not clear, from the available data, that this is due to non-Swedish trades. It would thus be necessary to know what part of the North-to-South Swedish interconnector capacity is occupied due to trades not taking place in Sweden (so-called transient flows). In our model, this is assumed to be equal to zero, for lack of any available data. In case this value is not zero (and given the historical pattern of North-to-South flows in the region, this is likely to be the case), then this could be a possible explanation for the observed discrepancy. But since Svk has not been able to furnish specific data regarding transient flows, it is impossible to test this assumption in our model. This could constitute a possible follow-up investigation in an eventual extension of our analysis on a more detailed model of the Swedish system.

In order to get more insights from our model about the reason why no congestion was observed in the “Multi-Area Multi-ORDC” case study with respect to the “Multi-Area One-ORDC” case, we investigate a particular time period (22697) which exhibits congestion in the link SE3-SE4 in the “Multi-Area One-ORDC” case study but not in the other one. From there, we observed that more reserve is produced in total by the co-optimization program when multiple ORDC are considered. Indeed, about 4600MW of reserve is created in the multi ORDC case while only about 1300MW is present in the single ORDC case study.

Another interesting observation came up from this analysis. By observing Figure 13, we see that it is more interesting to provide reserve first to SE4 in a multi ORDC setting. However, it is only the case until reserve in this particular zone reaches about 250MW. At that point, it becomes more interesting for the co-optimization model to provide reserve to SE3 and SE2. Therefore, by focusing on these two zones instead of SE4, it frees up the usually congested link SE3-SE4 since no power from the other zones (SE3, SE2 and SE1) is available anymore to send to SE4. This phenomenon allows the link SE3-SE4 not to be congested in the multi ORDC case while this link is fully used in the single ORDC case since power from other zones tend to be sent to SE4. Note that, in the multi ORDC case, the other links (SE1-SE2 and SE2-SE3) have such high capacity that they were not observed to be congested in both case studies. In the multi ORDC case, SE4 is therefore “on its own” or at least “less helped by other zones” than in the single ORDC setup. Indeed, this causes an increase in the total production costs of the system (about 113 euros in total) but 4 times more reserve is also provided in this case study with respect to the one with a single ORDC.

What does this discrepancy imply in terms of our analysis?

The heuristic method that we have developed for approximating scarcity prices in the multi-area model relies on the observation that, in the absence of congestion, the optimal dispatch of a co-optimization is one which equalizes the price of reserve across zones. This can be argued easily by contradiction: if the marginal value of reserve is not equal across zones of an uncongested system, then one can increase economic welfare by transferring reserve from one region to another. This action results in a still feasible dispatch, but one with higher welfare.

But this argument can be applied equally well to any sub-region of a radial network. This suggests the following generalization of our proposed heuristic for approximating adders, when a single link is congested:

- Given the MARI dispatch, identify the congested link along the North-to-South path.
- Compute the available headroom (Pmax minus MARI dispatch) in the Northern and Southern part of the system. Denote these as R_{North} and R_{South} respectively.

- Use our proposed bisection method in order to compute a common reserve price for the congested Southern pocket (which would typically be SE4 alone, or the SE3-SE4 pocket), using R_{South} as input in the bisection method. Uplift the energy price of the congested pocket by the computed adder.
- Apply the same procedure for computing a common adder for the North, where R_{North} is used as input in the procedure.

In case there are multiple links congested simultaneously, the procedure can be applied identically in each of the uncongested sub-areas. The key observation is that the energy-only MARI dispatch, whenever it produces congestion, will be such that the congestion is caused exclusively by energy flows. This means that the available headroom (Pmax minus dispatch) of each uncongested subregion can be easily computed, and the bisection method can be used for computing adders in each of the uncongested subregions.

Given the lack of available data for verifying congestion in our model, we have not tested this approach in numerical simulations. But the procedure is clearly defined, and could be investigated in further detail in an eventual follow-up study.

3.5.4 Incentives of market participants and congestion revenues in a cross-border setting

Incentives of market participants depend on how exactly the scarcity pricing design is implemented. The proposal in [2] argues that adders should be applied while respecting the alignment of imbalance settlement with balancing prices, and so as to additionally introduce a settlement of real-time reserve. If this would be the case, then market participants would have an incentive to bid their entire flexibility truthfully to the balancing market (which is a good thing), because their incentive to hold capacity on reserve for the adder on real-time balancing capacity is equally strong to their incentive to be activated upwards in order to receive the adder on balancing energy. On the other hand, if an adder is applied only on imbalances, BSPs are given an incentive to self-dispatch upwards, which undermines efficiency (and possibly implies that a zone implementing adders in a misaligned way would tend to absorb negative imbalances of neighbors to an inefficient degree). Therefore, a proper implementation of scarcity pricing which is aligned with first principles does not imply transferring of imbalances between bidding zones. On the other hand, an inaccurate proxy of scarcity pricing where adders are only applied on imbalance settlement can lead to an inefficient upward activation of BSPs in bidding zones where the adder is applied, which contravenes article 3(m) of the Clean Energy Package.

Furthermore, when the design is implemented properly, there is no direct foreseen increase in congestion incomes. The idea of applying adders in order to approximate the outcome of a co-optimization is that these adders only affect the settlement of BSPs and BRPs within a given zone, and these adders are not implicated in inter-TSO settlement. In the design that is proposed in [2] and in the Phase 1 deliverable [1], the MARI platform prices are kept as they are, and the implied congestion revenues remain intact. If, on the other hand, there are indirect effects of inefficient dispatch due to an approximation of the design that deviates from first principles, such as those that are described in section 6.2.2 of [1], then one might observe the tendency of BSPs within a zone to self-dispatch upwards, and thus produce congestion, which may have implications on congestion rent.

3.5.5 Costs and benefits

Observing the different duration curves representing the scarcity adder (Figure 7, Figure 12 and Figure 17), it can be observed that the adder values are relatively small during most of the year while reaching high values for a few periods of the year. Based on this observation, one can raise the question of whether the implementation of scarcity pricing will provide sufficient surplus to BRPs, BSPs and TSOs so as to compensate for the additional complexity that it will bring to the market.

This question of course cannot be answered in a quantitative way, since quantifying the complexity of implementation is non-trivial. Given that most developed US markets (ERCOT, PJM, ISO-NE, MISO, CAISO, SPP [2]) are implementing the design, one could argue that there is a precedent which establishes that the complexity is manageable. And the whole idea of introducing adders is to mitigate complexity, since the adders serve as an approximation of real-time co-optimization (i.e. they aim at avoiding a complete overhaul of MARI and possibly other pan-European balancing platforms, which would be a substantially more complex task).

The question of generated surplus / value-added is also non-trivial. The point of the design is to provide long-term incentives for motivating investors to build out flexible assets. In a future where renewable resources push energy prices near zero and where value migrates from energy to reserves, it is hard to imagine how a design that does not place reserve valuation in the forefront would accomplish such a task, and although alternatives may exist, the appeal of ORDCs is that they can integrate with the existing design, maintain coherent <u>locational</u> investment incentives (which other mechanisms may not be able to do), but also co-exist with alternatives. Thus, the question of added value to BRPs, BSPs and TSOs becomes a question of how much we value reliability, adequacy, and a proper siting of investment in future market operations.

Despite the current market situation where prices are already quite high, it is not clear that the ongoing energy crisis is a reliable solution for our future needs for flexibility, or that the ongoing crisis renders a scarcity pricing design irrelevant. On the one hand, the adders are designed to recede when the energy-only design generates scarcity revenues. Thus, if the energy market can signal investment, then the adders do not add unnecessary revenue streams on top of this signal. On the other hand, a good part of the surplus resulting from the current crisis is categorized as windfall profit and recuperated by European governments. An investor might be quite nervous to bet their investment on a crisis that may or may not be clawed back by the respective national government, depending on prevailing sentiment. By contrast, a sound and thoughtful evolution of European market coupling likely entails much less regulatory uncertainty and scope for interference from political panic.

4. Conclusion

During this second phase of the study of implementing a scarcity pricing mechanism for the Swedish power system, we compare the results obtained with a co-optimization model of energy and reserve in real time with the design proposed during the first phase of this project, which relies on an ex-post addition of adders. This proposal allows us to implement scarcity pricing without requiring MARI to transition to co-optimization. These two approaches are compared in terms of accuracy for different case studies of increasing complexity: (i) a single-area model of Sweden; (ii) a multi-area model of Sweden with ORDC only in SE4; and (iii) a multi-area model of Sweden with ORDC in every zone. In general, in all cases, we observe that assuming that 10% of the hydropower technology corresponds to high opportunity cost is required in order to improve the accuracy of the proposed design. This assumption is deemed acceptable, since in our deterministic model of MARI, the value of water linked to uncertainty is not taken into account. The proposed design procedure is adapted for every case study in order to better align with the business rules that apply in the co-optimization of energy and reserve. Among these adaptions, it is worth highlighting rules that apply the scarcity adder to a zone based on observed congestion or not between this zone and its neighbors. For all cases, it is observed that the proposed design approximates closely the results of the co-optimization (in the case where 10% of hydropower is considered to have a high opportunity cost). Therefore, we can conclude that the proposed design seems to be a promising candidate for implementing scarcity pricing in Sweden. However, if Svk is willing to run a co-optimization program in parallel with MARI, this can also be an option for implementing scarcity pricing in Sweden. In the future, it will be interesting to check how these results and pricing methodologies should be adapted when considering the entire Nordic region for the implementation of scarcity pricing.

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Appendix A: Notation of Model (1)

In this section, we present the notation that is used in the co-optimization model of energy and reserve with transmission constraints that is detailed in this report.

Sets
G: set of flexible production units in the system
Z: set of zones in the system
G_z: set of generators in zone z
K: set of links

Variables
d_z: demand served in zone z
p_g: production of flexible unit g
r_g: reserve capacity of flexible unit g
dr: amount of reserve demand that is satisfied
f_k: flow on link k
$fR_k^{+/-}$: reserve flow in the reference direction / opposite to the reference direction of link k

Parameters and functions
$VOLL$: value of lost load
MC_g: marginal cost function of unit g
$ORDC(\cdot)$: operating reserve demand curve
P_g: nominal rating of unit g
R_g: reserve capacity of unit g
D_z: inelastic demand in zone z