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Transmission planning in an imperfectly competitive power sector with environmental externalities[☆]

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ABSTRACT

Policymakers face the challenge of integrating intermittent output from variable renewable energy (VRE). Even in a well-functioning power sector with flexible generation, producers' incentives may not align with society's welfare-maximisation objective. At the same time, political pressure can obstruct policymakers from pricing damage from CO_2 emissions according to its social costs. In facilitating decarbonisation, transmission planning will have to adapt to such economic and environmental distortions. Using a Stackelberg model of the Nordic power sector, we find that a first-best transmission-expansion plan involves better resource sharing between zones, which actually reduces the need for some VRE adoption. Next, we allow for departures from perfect competition and identify an extended transmission-expansion plan under market power by nuclear plants. By contrast, temporal arbitrage by hydro reservoirs does not necessitate transmission expansion beyond that of perfect competition because it incentivises sufficient VRE adoption using existing lines. Meanwhile, incomplete CO_2 pricing under perfect competition requires a transmission plan that matches hydro-rich zones with sites for VRE adoption. However, since incomplete CO_2 pricing leaves fossil-fuelled generation economically viable, it reduces the leverage of strategic producers, thereby catalysing less (more) extensive transmission expansion under market power by nuclear (hydro) plants.

1. Introduction

Spurred by calls to action against climate change, many OECD governments are adopting energy and infrastructure packages commonly known as "Green Deals." Such legislative efforts typically encompass support for decarbonisation of the power sector and electrification of related sectors, e.g., heating, industrial processes, and transport. Over the past decade, support schemes, e.g., feed-in tariffs and renewable portfolio standards (RPS), have lowered the levelised costs of variable renewable energy (VRE), viz., solar and wind power, to near parity with that of gas-fired turbines.[1] Likewise, the emergence of more comprehensive pricing of CO_2 emissions in the form of cap-and-trade protocols such as the EU's Emissions Trading System (ETS)[2] has further displaced fossil-fuelled generation. Hence, the future power system is to be underpinned by VRE output that is complemented by flexibility in both demand, e.g., by coupling with other energy sectors, and supply, e.g., from hydropower and other forms of energy storage.

As part of both the EU's Green Deal[3] and the U.S. Inflation Reduction Act of 2022,[4] infrastructure packages dictate expansions of the transmission system to integrate new VRE capacity. Indeed, solar and wind plants are not only intermittent in output but also remotely located from loads [and associated with higher peak-to-average output ratios]. As Newbery (2023) points out, VRE's peak-to-average

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[1] https://www.eia.gov/outlooks/aeo/electricity_generation/pdf/AEO2023_LCOE_report.pdf
[2] https://climate.ec.europa.eu/eu-action/eu-emissions-trading-system-eu-ets_en
[3] https://ec.europa.eu/info/strategy/priorities-2019-2024/european-green-deal_en
[4] https://www.congress.gov/bill/117th-congress/house-bill/5376

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output ratios (3:1 or higher) exceed those of nuclear plants (typically 0.9:1), thereby potentially exacerbating VRE curtailment with generation-capacity expansion. Thus, the existing transmission network may be inadequate for accommodating higher shares of VRE generation. Furthermore, while flexibility in demand and supply may provide temporal balancing of VRE's intermittency, transmission capacity could play a similar role in mitigating spatial imbalances and facilitating the "absorption" of excess VRE output. From this perspective, a socially optimal transmission plan based on cost minimisation (Garver, 1970) matches the marginal benefits and marginal costs of transmission expansion.

Recent engineering and operational research work extends the generation-and-transmission-expansion planning (GTEP) problem to incorporate the spatio-temporal features of power systems. For example, Rodríguez-Sarasty et al. (2021) devise a multi-year GTEP for northeastern North America that takes hydro operations into account, while Rintamäki et al. (2024) conduct a robust-optimisation GTEP for the Nordic region that focuses on short-term uncertainties in demand and VRE output. In an effort to enhance the methodology for large-scale GTEPs, Moreira et al. (2021) develop computational algorithms, while García-Cerezo et al. (2022) propose clustering procedures for an accurate representation of demand and VRE output. Such analyses assume that all decisions are undertaken by a single cost-minimising (or, welfare-maximising) entity, which could lead to a first-best guideline for transmission expansion (ENTSO-E, 2022). The centralised approach, however, neglects the deregulated nature of the power sector in most OECD countries (Wilson, 2002). In reality, this sector consists of disparate decision makers with possibly conflicting objectives that may not be aligned with welfare maximisation.

Departures from the central-planning perspective assume a welfare-maximising TSO anticipating generation-capacity adoption and operations by profit-maximising power companies. In accommodating the game-theoretic nature of interactions between transmission and generation investment, such papers use bi-level models akin to a Stackelberg leader–follower framework (Gabriel et al., 2013). The lower level comprises a Nash-Cournot game among power companies, which decide upon profit-maximising generation investment, and an independent system operator (ISO), which determines welfare-enhancing power dispatch, while taking the transmission capacity as given. At the upper level, the TSO is responsible for welfare-maximising transmission expansion. The power companies may either be price takers (Garcés et al., 2009) or exert market power (Sauma and Oren, 2006). With competition among power companies unfolding in both investment and operations, the latter model includes three levels. Rather than explicitly solving the tri-level model, the authors evaluate the generation-expansion-and-operations game for selected transmission proposals and assess the impact on social welfare of ignoring the firms' responses. Evidently, such a reactive transmission plan is inferior to a proactive transmission plan that anticipates these responses, and the welfare reduction is found to be about 17%.

Although the engineering/operational research literature tackles game-theoretic issues in the power sector, it either ignores externalities from CO_2 emissions or represents them only indirectly, e.g., as RPS targets or cap-and-trade constraints. For example, bi-level papers on transmission expansion include VRE adoption (Baringo and Conejo, 2012), RPS targets (Maurovich-Horvat et al., 2015), and energy storage (González-Romero et al., 2021), but they do not directly incorporate the cost of damage from CO_2 emissions. This is in spite of the fact that explicit representation of externalities is relevant for policymakers and regulated entities, e.g., the TSO, to capture the tradeoffs between economic and environmental attributes. In fact, Hobbs (2012) cautions against the use of proxy measures such as RPS targets.

In a marked contrast, the literature on environmental economics (Baumol and Oates, 1988) directly processes the policy dilemma associated with decarbonisation by including the cost of damage from CO_2 emissions (Söderholm and Sundqvist, 2003). By internalising such externalities, environmental economics devises optimal policy by trading off the marginal benefits and marginal costs of pollution abatement. For example, the first-best strategy for handling more costly damage from CO_2 emissions may be to curb consumption before contemplating a switch to VRE (Siddiqui et al., 2016). This strand of the literature permits closed-form solutions amenable to comparative statics, e.g., about policy under uncertainty (Weitzman, 1974) or market power (Barnett, 1980). In the context of transmission planning, Downward (2010) uses a Nash game over a given transmission line to illustrate the paradox that can arise from the imposition of a carbon policy. Absent a CO_2 tax, coal-fired generation exports power to the node with the gas-fired plant, thereby congesting the line and enabling the coal generator to act as a monopolist. Once a CO_2 tax is introduced, the new equilibrium relieves congestion on the transmission line to render a duopoly and induces greater output from the gas-fired plant, which leads to higher overall CO_2 emissions. Likewise using a single-line example, Siddiqui et al. (2019) allow for endogenous transmission expansion in a Stackelberg game, with the TSO at the upper level and power companies at the lower level. They demonstrate that welfare losses from incomplete CO_2 pricing under perfect competition cannot be mitigated by countervailing transmission expansion. Meanwhile, partial CO_2 pricing under Cournot competition may be optimal, which generalises the finding of Barnett (1980). However, such analytical tractability comes at the expense of crucial simplifications of the power system's spatio-temporal aspects, and the conclusions may not be applicable in practice.

As indicated, the engineering/operational research literature provides a cursory perspective on environmental externalities, while environmental economics does not incorporate the spatio-temporal features of the power system. Between the two strands of literature, we identify a research gap in how transmission planning should be adapted in a power system with substantial VRE adoption and scope for economic/environmental distortions. Consequently, our overarching research objective is to investigate the impact of imperfect competition and incomplete carbon pricing on transmission planning in the Nordic region.

We use the Nordic region as our case study because of its ample existing fossil-free generation capacity, viz., hydro, nuclear, and VRE, and zonal integration that make it well positioned for meeting the challenge of decarbonising its power sector and investigating transmission expansion as a potential facilitator. The Nordic system comprises Denmark, Finland, Norway, and Sweden, which are further divided into price zones. All countries have wind capacity as well as some solar capacity. Following Amundsen and Bergman (2006), the Nordic market can be characterised as well functioning. Evidence of market power, however, was provided in empirical studies (Tangerås and Mauritzen, 2018; Fogelberg and Lazarczyk, 2019; Lundin and Tangerås, 2020; Lundin, 2021). Moreover, the fact that Sweden had a general CO_2 tax of €106/t in 2018,[5] while the EU ETS price was €15/t in the same year, indicates incomplete CO_2 pricing in sectors covered by the EU ETS, i.e., the higher Swedish CO_2 price on sectors not covered by the EU ETS is very likely to be a better indicator of the social cost of damage. Hence, in spite of its generally desirable characteristics, the Nordic region exhibits evidence of both imperfect competition and incomplete CO_2 pricing.

Given this background, our goal can be decomposed into three research questions (RQs):

RQ 1. *What is the socially optimal transmission plan under perfect competition and full internalisation of the social cost of damage from CO_2 emissions?*

[5] https://www.government.se/government-policy/swedens-carbon-tax/swedens-carbon-tax/

RQ 2. *How is transmission planning affected by imperfect competition when the social cost of damage from CO_2 emissions is fully internalised?*

RQ 3. *What are the socially optimal adaptations to transmission planning under both perfect and imperfect competition when the social cost of damage from CO_2 emissions is only partially internalised?*

Here, RQ 1 addresses a first-best situation in which the Nordic region is immune from strategic behaviour by large power companies and has the political will to fully internalise the cost of damage from CO_2 emissions, i.e., as a Pigouvian tax (Baumol and Oates, 1988). In reality, however, large power companies have sufficient generation capacity to be able to affect market-clearing prices via their output. For example, nuclear plants may withhold generation, while hydro reservoirs may conduct temporal arbitrage to shift production away from peak periods. Thus, RQ 2 addresses modifications to the transmission plan in face of market power, i.e., a second-best outcome in which the regulated TSO adapts to the reality of the market. Focusing on incomplete CO_2 pricing, RQ 3 reflects a situation in which political currents militate against the perceived costs of sustainability measures (Ewald et al., 2022) and lead to a low CO_2 price relative to the social cost of damage. This puts the TSO in a quandary as to how to adapt to politics via a more proactive transmission plan.

The rest of this paper is structured as follows. Section 2 provides an overview of the framework for analysis including a stylised representation of the problem formulation. The experimental design, data sources, and main results appear in Section 3. Section 4 summarises the work's contributions, distils its policy implications, and charts directions for future research in this area. Appendix A, B, and C contain the nomenclature, mathematical model, and supplementary data, respectively.

2. Research methodology

The framework for analysis is a Stackelberg leader–follower game as outlined in Fig. 1. We reflect the power sector's spatio-temporal attributes by implementing this game as a bi-level problem (Gabriel et al., 2013) over a network with the TSO's transmission-investment decisions at the upper level and the decisions of both firms and the independent system operator (ISO) at the lower level. Our framework allows for situations in which firms exercise market power at the lower level. Here, exogenously defined scenarios characterise the type of market power exerted by firms at the lower level, i.e., firms do not endogenously choose which kinds of competitors to be. By contrast, endogenous choices by firms to be Cournot or not would involve binary decisions taken by the firms at the lower level about the exertion of market power. Obtaining and interpreting equilibria in such a context would be challenging, although recent advances on binary equilibrium problems may provide some recourse (Huppmann and Siddiqui, 2018). Another strategic vista that we do not explore is the so-called inc-dec game, in which generators create grid congestion in order to profit from being redispatched (Beckstedde et al., 2023). Thus, firms would act as leaders in that context. Given the diversity of research questions in electricity markets, hierarchical models can be structured in many ways, but an endogenous representation of market power would dramatically increase the complexity of the model. Hence, our choice of the hierarchical structure is justified by the nature of our research questions that stem from the TSO's long-term planning perspective.

Our modelling of investment is static and considers only a snapshot of the future, viz., a time horizon of one year. By contrast, we model operational dynamics with an hourly time resolution. The power-system network is composed of nodes representing separate price areas and arcs defining existing interconnecting transmission lines, some of which are candidates for capacity upgrades. The TSO and ISO control investment and flows, respectively, over the entire network. On the contrary, a node can host several firms, and firms can own plants at several nodes. The firms' portfolios can comprise several technologies such as VRE, hydro reservoirs, and thermal generators.[6]

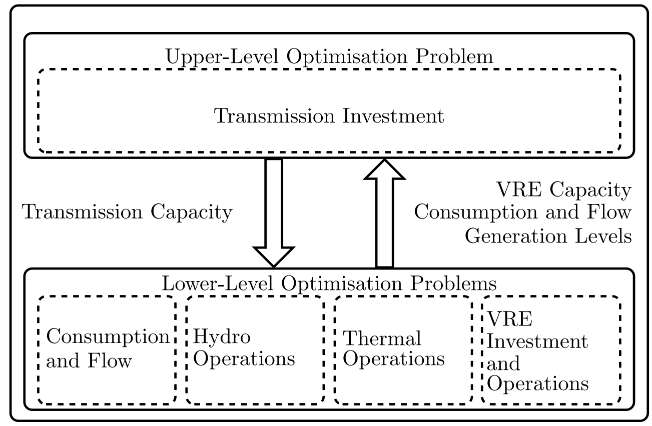


Fig. 1. Framework for analysis.

At the upper level (Fig. 2), a welfare-maximising TSO determines the transmission-capacity investment (B.1). We draw upon some real-world examples to justify this choice of the TSO's objective function. For example, the Nordic TSOs typically have cost effectiveness along with VRE integration within their remit[7] and have a joint strategy to respond to the climate challenge by fostering regional integration of VRE and electrification of the wider economy.[8] Indeed, a coordinated approach to multiregional grid expansion relies heavily on joint initiatives and cross-border interconnection projects. Likewise, at the European level, ENTSO-E serves as a platform for coordinating long-term planning through its ten-year development plans.[9] Nevertheless, deviations from a welfare-maximising objective can still arise as encountered by the Norwegian TSO's having to contend with cost overruns in a grid-expansion project to integrate a wind farm[10] or in cross-border gaming issues (Huppmann and Egerer, 2015). Given this perspective and its caveats, the TSO maximises social welfare, which comprises consumer surplus, producer surplus, merchandising surplus,[11] government revenue from CO_2 taxes paid by producers, the social cost of damage from CO_2 emissions, and the cost of transmission expansion. This is equivalent to gross consumer surplus less the cost of generation, the fixed cost of generation-capacity operations and maintenance (O&M), the social cost of CO_2 emissions, and the costs of generation- and transmission-capacity investment. To facilitate analysis, we assume linear damage costs from CO_2 emissions with a cost rate of S (in €/t). This is supported by Labriet and Loulou (2003)'s empirical evidence for a linear relationship linking regional damages and cumulative global emissions. The TSO adopts transmission capacity at mutually exclusive discrete levels, i.e., one level per candidate line (B.2)–(B.3). The discreteness of transmission capacity allows for line susceptances to increase with capacity. Also, this assumption is adopted in the literature (Baringo and Conejo, 2012; Maurovich-Horvat et al., 2015). As a Stackelberg leader, the TSO anticipates lower-level followers' decisions, viz., about generation-capacity expansion, generation output, consumption, and power flows, when making its transmission-capacity investment decisions. Thus, the TSO is constrained by the lower-level problems of the firms and the ISO.

[6] The latter category includes both zero-emission technologies, viz., biomass and nuclear, and fossil-fuelled generation using gas and coal.

[7] https://webfileservice.nve.no/API/PublishedFiles/Download/201602121/1784331

[8] https://en.energinet.dk/media/iwahnjlz/solutions_report_2022.pdf

[9] https://tyndp2022-project-platform.azurewebsites.net/projectsheets

[10] https://www.tu.no/artikler/kostnadssmell-for-fosen-linjen/346906

[11] The merchandising surplus is the net revenue from exporting power from zones with low electricity prices to zones with high electricity prices.

Maximise Gross Consumer Surplus
- Cost of Thermal Generation
- Amortised Cost of Generation Investment
- Amortised Fixed O&M Cost
- Amortised Cost of Transmission Investment
- Social Cost of CO_2 Emissions (B-1)

s.t.

Discrete Transmission Capacity (B-2)–(B-3)

Maximise Gross Consumer Surplus
- Cost of Thermal Generation
- Amortised Cost of Generation Investment
- Amortised Fixed O&M Cost
- Extended Cost
- Private Cost of CO_2 Emissions (B-56)

s.t.

Energy-Balance Constraint (B-5)
Capacity Limit on Transmission (B-6)–(B-7)
DC Load-Flow Constraints (B-8)–(B-9)
Constraints on Thermal Generation (B-11)–(B-13)
Constraints on VRE Generation (B-14)–(B-15)
Constraints on Hydro Generation (B-16)–(B-20)
Annual Hydro Regulation (B-21)

Fig. 2. Bi-Level Problem.

In fact, three types of agents operate at the lower level, viz., consumers, firms, and the ISO. Consumers are represented implicitly by linear inverse-demand functions that reflect the marginal utility of demand. The ISO maximises gross consumer surplus by determining consumption and power flows (B.4). In doing so, the ISO takes the transmission-capacity adoption of the TSO as given along with all of the firms' decisions, cf. the Nash assumption (Hobbs, 2001). The ISO maintains energy balance between consumption and production (B.5), while ensuring that power flows are within their rated capacities (B.6)–(B.7). As is customary in power-system economics, the DC load-flow approximation is used to model the AC portion of the network (B.8)–(B.9).

Under the Nash supposition, each firm maximises profit by taking the decisions of the ISO and every other firm as given. Naturally, it also takes the TSO's transmission-capacity expansion as given. In maximising its own profit (B.10), the firm decides how to operate its fleet of thermal generators, VRE capacity, and hydro reservoirs, assuming that plants' capacities are made available by paying the O&M cost while also having the possibility to expand VRE capacity. The main components of the objective function (B.10) are revenue from net sales of energy, generation costs, costs of capacity O&M, private costs of CO_2 taxes, and costs of capacity investment. Note that the private costs of CO_2 taxes imposed on industry may be distinct from the social cost of damage from CO_2 emissions. More specifically, the private costs depend on the fraction H of the damage-cost rate, S, that is internalised. A firm's thermal and VRE output is limited by available capacity, (B.11) and (B.14). For thermal units, this is restricted by installed capacity (B.12), whereas that for VRE units is limited by both installed and newly adopted capacity (B.15). Thermal generators are further restricted by their ramp limits (B.13). Hydro units with reservoirs are subject to a water-balance constraint (B.16), i.e., the water level in a given time period is equal to the water level in the previous time period (adjusted for any losses) plus exogenous inflows and water charged to the reservoir (for pumped-hydro units) and minus water discharged from the reservoir. Discharging consists of turbined water for energy production and water spillage. The reservoir level has to remain between lower and upper limits (B.17). Moreover, the charging rate for pumped-hydro units is limited (B.18), and (B.19) specifies the available capacity of hydro units, which constrains their generation. Meanwhile, available hydro capacity is restricted by the installed capacity (B.20). Finally, to facilitate comparison, (B.21) is used in Cournot cases to ensure that hydro units behaving strategically produce at least as much energy annually as under perfect competition. Such a constraint is enforced by legislation in some regions (Debia et al., 2021) and is otherwise motivated by the observation that outright spilling of water would be easy to detect by market inspectors (Bushnell, 2003).

With reference to the setup in Hobbs (2001), it should be noted that he considers a Nash-Cournot game over a network with explicit arbitrage. The point of having arbitrageurs is to eliminate any differences in nodal prices that are in excess of the congestion fees. In each firm's problem, he includes shared constraints (involving the other firms' decision variables) that are meant to arbitrage away nodal price differences beyond the congestion fees. This no-arbitrage model of Cournot competition in a bilateral market based on nodal sales can be converted into a pooled Cournot model based solely on nodal generation. Indeed, Hobbs (2001) proves that the so-called POOLCO will yield the same equilibrium, thereby obviating the need for the firms' nodal-sales variables. Now, Tanaka (2009) shows that the formulation of Hobbs (2001), involving an explicit representation of arbitrage, is equivalent to ensuring that total net injection of energy in the network is zero for any period, which is true by the definition of the network topology in our setting. With suitable modifications, different classes of consumers or even prosumers (Chen et al., 2022; Hassanzadeh Moghimi et al., 2023a) can be incorporated into this framework. Consequently, the requisite no-arbitrage condition from Hobbs (2001), i.e., the congestion fee is the difference between the nodal prices, holds implicitly in our model following Tanaka (2009) and the lower level of Chen et al. (2018).

As is common in detailed power-system models of (hydro) storage operations (Bushnell, 2003; Ekholm and Virasjoki, 2020; Debia et al., 2021; Williams and Green, 2022; Hassanzadeh Moghimi et al., 2023b) and bi-level transmission planning with generation-capacity expansion (Maurovich-Horvat et al., 2015; González-Romero et al., 2021; Belyak et al., 2024), we take an open-loop perspective at the lower level. This means that, given the transmission-expansion plan determined by the TSO in the upper level of Fig. 1, all operational and generation-capacity availability and expansion decisions in the lower level of Fig. 1 are treated as if they were made at the same time. Indeed, Maurovich-Horvat et al. (2015), González-Romero et al. (2021), and Belyak et al. (2024) collapse generation-capacity expansion and operations into a single level, primarily for the sake of computational tractability. The resulting mixed-complementarity problem (MCP) of this open-loop formulation is more straightforward to solve and interpret than the closed-loop formulation as an equilibrium problem with equilibrium constraints (EPEC) (Sauma and Oren, 2006). As Wogrin et al. (2013) note in their comparison of open- and closed-loop generation-expansion problems, the choice of the setup also has implications for the results. For example, under perfectly competitive market operations, strategic generators may withhold capacity adoption in an EPEC vis-à-vis an MCP. While our open-loop approach to generation expansion neglects this possibility, generation expansion by ostensibly price-making firms tends to be limited. Nevertheless, this modelling choice of MCP versus EPEC could have broader consequences for generation expansion beyond our specific situation. In a similar vein for the operational decisions, the open-loop supposition ignores their dynamic nature, e.g., hydro plants may adapt their output to stochastic inflows (Genc et al., 2020). However, additional decision-making levels to account for operations with a multi-stage nature make it computationally challenging to obtain Nash equilibria. Since the theory does not guarantee existence and uniqueness (Murphy and Smeers, 2005; Singh and Wiszniewska-Matyszkiel, 2019), the interpretation of the results would also not be straightforward. Still, we distinguish between the operational and the generation-capacity decisions by letting the former be adapted to each time period, whereas the latter are not, i.e., there is a single generation-capacity availability and expansion decision for each plant of a firm. As indicated in Fig. 2, given the transmission-expansion decisions of the TSO, the lower-level open-loop Nash-Cournot game among the firms and the ISO may be reformulated as a single optimisation problem, viz., a quadratic program (QP), by including the extended-cost function in (B.56) (Hashimoto, 1985; Hobbs, 2001; Suski and Chattopadhyay, 2023).[12]

3. Numerical examples

3.1. Design of experiment

Table 1 illustrates our experimental design to answer questions RQs 1–3. We investigate four *scenarios*, the first being the current baseline and the following three being future scenarios that gradually allow for a higher social cost rate of damage from CO_2 emissions, VRE adoption, and transmission investment:

- Base2018: generation and transmission capacities are at 2018 levels, assuming a social cost rate of damage from CO_2 emissions of €15/t, i.e., $S = 15$,
- FutureC: same as Base2018 except that the social cost rate of damage from CO_2 emissions is €100/t, i.e., $S = 100$,
- FutureCV: same as FutureC except that VRE expansion[13] is allowed by firms at nodes where they own VRE capacity,
- FutureCVT: same as FutureCV except that transmission expansion is allowed on selected lines.

In each scenario, we consider the following three *cases* with varying degrees of competition defined exogenously among firms:[14]

- Perfect competition (PC): all firms are price takers,
- Cournot oligopoly in thermal generation (COG): selected firms with large capacities, e.g., firm $i1$ at $SE3$ and firm $i4$ at both $SE3$ and FI, withhold generation from nuclear plants to manipulate prices,
- Cournot oligopoly in reservoirs (COR): selected firms with strategic reservoirs, e.g., firm $i1$ at $SE1$ and firm $i10$ at $NO4$, exercise market power in hydro-reservoir generation to manipulate prices.[15]

We finally analyse each of the nine aforementioned future scenario/case combinations under the following two *regimes*:

- Complete carbon pricing: the future social cost rate of damage from CO_2 emissions of €100/t is fully internalised, i.e., $H = 1$,
- Incomplete carbon pricing: the CO_2 price (or, tax) perceived by industry remains at the Base2018 rate of €15/t, i.e., $H = 0.15$.

In total, we implement 21 problem instances.[16]

A move down the PC column of Table 1 represents the transition from the Base2018 to the FutureCVT scenario under perfect competition and full internalisation of future damage costs. In terms of the lower-level objective function (B.56), this means that (i) the extended-cost term is excluded and (ii) the private cost of CO_2 emissions is just the social cost, i.e., $H = 1$, which fully internalises the future rate of the social cost of damage from CO_2 emissions, i.e., $S = 100$.[17] By tracing how generation and transmission capacity adapt to the increased social cost rate of damage from CO_2 emissions, we address RQ 1. Our first-best solution stipulates that transmission expansion should enable better sharing of nuclear resources between zones, which also obviates the need for as much VRE adoption.

By moving to the right of the FutureCVT row in Table 1, we compare the results for either the COG or the COR case with those for the PC case in the FutureCVT scenario. Under COG and COR, the relevant extended-cost term appears in the lower-level objective function (B.56) to allow for market power by either nuclear plants or hydro reservoirs. We tackle RQ 2 by providing insights about how the TSO should adapt its

[12] The bi-level problem is solved via implicit enumeration over all possible transmission-expansion combinations. Details are provided in Appendix B.3.

[13] We do not allow expansion of fossil-fuelled, hydro, and nuclear technologies because of environmental, siting, and lead-time restrictions, respectively.

[14] The firms indexed $i1 - i17$ indicate, in order, Vattenfall, E.ON, OKG, Fortum, TVO, PVO, HELEN, Kemijoki, Ørsted, Statkraft, Norsk Hydro, Sira-Kvina, Agder Energi, BKK, E-CO Energi, Sydkraft, and Skellefteå Kraft. We aggregate Swedish, Finnish, Danish, and Norwegian price takers into one fringe firm per country as $i18 - i21$. Thus, firms $i1$, $i4$, and $i10$ are based on the portfolios of Vattenfall, Fortum, and Statkraft, respectively.

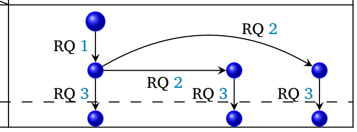
[15] Note that their total nodal amount of net-hydro generation from reservoirs must be at least as much as under PC.

[16] We have one problem instance for each of the three cases (PC, COG, and COR) in the Base2018 scenario plus 18 (= $2 \times 3 \times 3$) problem instances that are associated with two regimes ($H = 1$ and $H = 0.15$), three future scenarios (FutureC, FutureCV, and FutureCVT) per regime, and three cases (PC, COG, and COR) per scenario.

[17] The FutureC and FutureCV scenarios serve as stepping stones to understanding the complete transition but are not explicitly indicated here.

Table 1
Design of Experiment.

Regime	Scenario \ Case	PC	COG	COR
$H = 1$	Base2018			
	FutureCVT			
$H = 0.15$	FutureCVT			



transmission-investment strategy to imperfectly competitive markets.[18] The second-best transmission plan depends on the nature of market power that is exercised. We show that outright withholding by nuclear plants necessitates aggressive transmission expansion to facilitate better sharing of hydro resources between zones and bolstering of VRE adoption. By contrast, temporal arbitrage by hydro reservoirs (Crampes and Moreaux, 2001) actually reduces the flow on some lines as high prices and wind availability boost VRE adoption, which compensates for some seasonal reductions in hydro production. In this case, the first-best transmission plan does not need to be altered.

Moving further down in Table 1, we compare the results of the cases in the FutureCVT scenarios given $H = 1$ with the relevant cases given $H = 0.15$. The two regimes have $H = 1$ and $H = 0.15$ in the lower-level objective function (B.56), respectively. Although the future social cost rate of damage from CO_2 emissions becomes €100/t, i.e., $S = 100$, lack of political will prevents the private CO_2 cost from fully reflecting this externality. In effect, the CO_2 price perceived by industry remains at €15/t, i.e., the Base2018 rate. The issue of the internalisation is the target of RQ 3. Our results reveal that in a perfectly competitive industry with incomplete CO_2 pricing, there is less incentive for consumers to curb quantity demanded and for industry to adopt VRE capacity. As a result, the TSO has to modify its transmission-expansion plan from the first-best one, viz., by enabling the VRE-rich zones to avail more of hydro reservoirs and to boost VRE investment. Since the low CO_2 price leaves fossil-fuelled generation economically viable, firms' exercise of market power is checked. Hence, outright withholding by nuclear plants requires less transmission expansion than under complete CO_2 pricing, while temporal arbitrage by hydro reservoirs yields insufficient incentives for VRE adoption, thereby prompting more transmission expansion vis-à-vis complete CO_2 pricing.

3.2. Data

All parameters are based on the data of Hassanzadeh Moghimi et al. (2023b) from 2018. A summary of the data for thermal plants, firms' ownership, reservoir volumes,[19] estimated hydro inflows, and VRE availability is given in Tables C.1–C.3 and Figs C.1–C.2 in Appendix C. Demand is assumed to have a point elasticity of −0.065 (Neamtu, 2016) with linear inverse-demand functions fitted to observed 2018 price-consumption points for each zone and hour. Due to the computational challenge of modelling hourly operations over a year, we use a clustering procedure to select a representative week of 168 h from each of the four seasons, i.e., we employ a total of 672 representative hours that reflect spatio-temporal variability in consumption, prices, and wind availability.[20]

The annual capital costs for solar and wind technologies are based on the overnight capital costs of a 150 MW PV plant and a 200 MW on-shore wind plant, viz., \$1,313/kW and \$1,265/kW, respectively.[21] These annualise to €85,176/MW and €82,290/MW, respectively, using a 5% per annum interest rate and a thirty-year lifetime. Meanwhile, the annual fixed O&M costs of a 150 MW PV plant and a 200 MW on-shore wind plant are €15,184/MW and €26,260/MW, respectively. Likewise, the annual fixed O&M costs of non-VRE technologies range from €6,968/MW for gas to €121,316/MW for nuclear. Run-of-river hydro plants are assumed to have zero O&M costs, but the reservoir-enabled ones have annual O&M costs of €29,796/MW.

Fig. 3 describes the network. We use the Nord Pool pricing zones for Denmark, Finland, Norway, and Sweden, comprising 12 nodes and 18 transmission lines. Four of these transmission lines are DC (indicated as dashed lines), and the rest are AC. The net transfer capacities of the lines (in MW) are used in each direction,[22] and the susceptances (in S) are estimated based on line lengths and power ratings (Egerer, 2016) (see Tables 2–3). We determine candidate lines for investment by conducting a congestion analysis, using the PC case of the FutureCV scenario in the $H = 1$ regime. Table 4 lists the proportion of representative hours in which the lines are congested in either direction for lines that are congested for at least 40% of the hours.[23] This is our metric to screen the lines. Although lines $\ell 4$ and $\ell 2$ are often congested, they do not include zones with either significant potential for market power or VRE adoption. Thus, only $\ell 6$, $\ell 7$, $\ell 15$, and $\ell 16$ are congested for at least 50% of the time and are considered credible candidate lines (denoted by bold in Fig. 3).[24] Upgrades to capacities of either 400 MW or 800 MW are allowed for each of these four lines at an amortised annual capital cost of €200/MW-km, which is somewhat lower than

[18] We consider COG to be less credible than COR. This is because outright withholding by nuclear plants would trigger price spikes to alert regulators. Lundin (2021) examines possible collusion by nuclear plants in $SE3$ in the early 2000s. Following the launch of an investigation by the Swedish Competition Authority, the companies desisted in their efforts. Later in the decade, the government commissioned a study to determine whether the owners could be forced to divest, but it was not possible to demonstrate that the plants were operating in conflict with the legislation. As a compromise, the owners had to adopt a "code of conduct" with the understanding that tougher measures would be forthcoming in case of noncompliance. By contrast, hydro producers that conduct temporal arbitrage such that their annual production is unchanged exert a more subtle form of market power that comes with more plausible deniability and is less likely to provoke drastic changes in the price, thereby evading regulatory intervention (Bushnell, 2003; Hassanzadeh Moghimi et al., 2023b). For this reason, our ensuing discussion centres more on COR cases but retains COG cases as textbook (but perhaps unrealistic) examples of market power.

[19] In Table C.3, "SRS," "NRS," "NPH," and "SPH" are labels for "strategic reservoir," "non-strategic reservoir," "non-strategic pumped-hydro reservoir," and "strategic pumped-hydro reservoir," respectively.

[20] We track reservoir levels between seasons via linking constraints that enforce that the terminal reservoir level of a given season equals the initial reservoir level of the subsequent season. As such, the terminal reservoir level of a given season is calculated as the season's initial reservoir level plus the cumulative net change in the reservoir level over the representative week multiplied by the approximate number of weeks in the season, i.e., 13.04. This is the so-called "linked representative periods" method (Tejada-Arango et al., 2019).

[21] https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2020.pdf

[22] https://www.nordpoolgroup.com/48fea6/globalassets/download-center/tso/max-ntc.pdf

[23] All lines are used, but some are never congested (lines $\ell 1$, $\ell 3$, $\ell 5$, $\ell 8$, $\ell 11$, and $\ell 13$). Others are seldom congested, i.e., less than 30% of the time (lines $\ell 9$, $\ell 10$, $\ell 12$, and $\ell 14$).

[24] Numerical results with lines $\ell 6$, $\ell 7$, $\ell 15$, and $\ell 18$ as the candidates yield similar qualitative insights. Details are available from the authors upon request.

Table 2
AC Transmission Lines' Thermal Capacities in Positive Direction (MW) and Susceptances (S).

Line	$\ell 1$	$\ell 2$	$\ell 3$	$\ell 4$	$\ell 5$	$\ell 6$	$\ell 7$	$\ell 8$	$\ell 9$	$\ell 10$	$\ell 11$	$\ell 12$	$\ell 13$	$\ell 14$
$\overline{K}_{j0,\ell}$	3500	500	3900	600	1200	1500	700	3300	600	250	7300	2145	5400	1300
$B_{j0,\ell}$	1628	898	1275	1346	317	460	688	798	981	302	1081	822	1226	1578

Table 3
DC Transmission Lines' Thermal Capacities in Positive Direction (MW).

Line	$\ell 15$	$\ell 16$	$\ell 17$	$\ell 18$
$\overline{K}_{j0,\ell}$	680	1200	1632	590

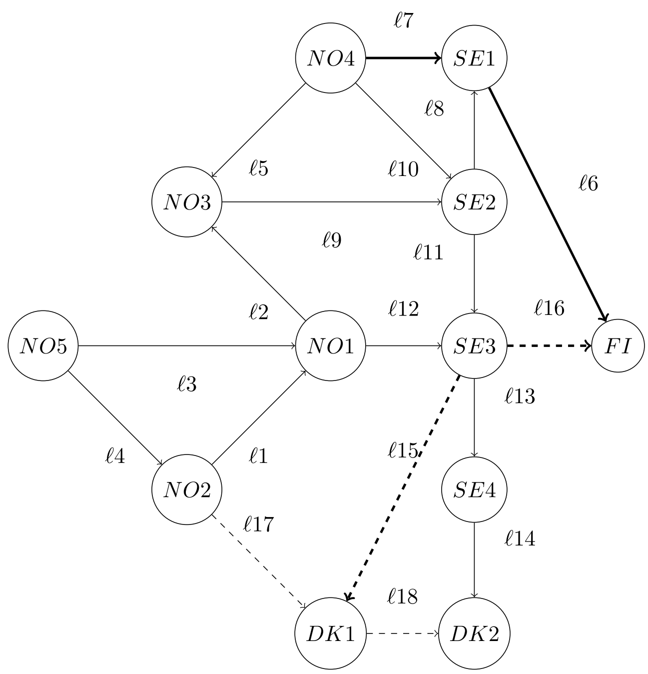


Fig. 3. Stylised Nordic Test Network.

the figure mentioned by Rodríguez-Sarasty et al. (2021) and reflects the fact that we consider upgrades instead of new investments. Table 5 indicates the incremental susceptance (for AC lines only) and annual amortised cost from undertaking a 400 MW upgrade to the lines. For example, a 400 MW increase in the capacity of line $\ell 6$ increases its total susceptance by 141 S and costs €49.44 million. Likewise, an 800 MW in the same line's capacity increases its total susceptance by 282 S and costs €98.88 million.

3.3. Computational implementation

We solve all problem instances in GAMS 40.3.0 using CPLEX 22.1.0.0 deployed on an Intel(R) Core(TM) i7-1280P processor with 32.0 GB of RAM. The cases in the Base2018, FutureC, and FutureCV scenarios solve to optimality in between 70 and 116 s, using only the lower-level QP problem. However, each case in the FutureCVT scenario takes approximately 2 h since enumeration requires solving the lower-level QP problem $3^4 = 81$ times.

3.4. Results for $H = 1$ regime

Here, we set $H = 1$ and assess the impacts of a higher social cost rate of damage from CO_2 emissions and market power on transmission planning. Full internalisation of the social cost of damage from CO_2 emissions on industry enables us to tackle RQs 1–2.

3.4.1. Base2018 scenario

Given the 2018 installed capacities, we summarise the results in Table 6.[25] The results under PC are generally in line with the observed data in the year's representative weeks, i.e., prices, CO_2 emissions, and generation levels are comparable.[26] In terms of strategic behaviour, market power by nuclear plants under COG leads to a transfer of wealth from consumers to producers. In particular, relative to PC, firm $i1$ enjoys a 71.57% increase in its producer surplus from withholding nuclear output. Indeed, by making the price-taking fossil-fuelled plants' capacity limits bind, nuclear plants boosts the electricity price. CO_2 emissions likewise increase under COG vis-à-vis PC. Under COR, welfare metrics are only mildly affected relative to PC. This is because the annual output of strategic reservoirs is constrained to be at least as much as that under PC. Nevertheless, firm $i1$ still exerts temporal arbitrage through its vast reservoirs in $SE1$, shifting water from peak to off-peak seasons to increase prices in peak seasons. By doing so, it boosts its producer surplus by 11.59% from PC.

The spatio-temporal nature of energy exchange among zones $SE1$, $SE3$, and FI is a key driver of the results. For ease of reference, we zoom in on these three nodes in Fig. 4, which indicates 2018 generation-capacity mixes and strategic firms along with the technology through which they may exert market power under either COG or COR. As shown by the figure, $SE1$ primarily relies on hydro and hosts firm $i1$, which may actively use its reservoirs for temporal arbitrage to manipulate prices. Both firms $i1$ and $i4$ may hold back nuclear generation with the same purpose in $SE3$, whereas only firm $i4$ operates strategically in FI.

Table 7 provides details on cumulative seasonal flows, average prices (AP), and net imports (NI). In the first row, under PC, the flows on line $\ell 6$ indicate that power is typically sent from $SE1$ to FI except during spring.[27] This is because spring experiences relatively mild demand at FI. It also coincides with most of the exogenous hydro inflow to $SE1$'s reservoirs (Fig. C.1). Thus, $SE1$ can use this opportunity to accumulate storage in the reservoirs and meet higher consumption across the Nordic region in the remaining seasons with a corresponding pattern in the seasonal average electricity prices at $SE1$ and FI in the third and fifth rows, respectively. Meanwhile, the second row indicates that line $\ell 16$ typically exports power from $SE3$ to FI under PC because FI has a more fossil-fuel-intensive generation portfolio.

[25] We report social welfare, consumer surplus, producer surplus, merchandising surplus, government revenue, the social cost of damage from CO_2 emissions, and the cost of transmission investment as mathematically defined in Appendix B.2.5. Other metrics include CO_2 emissions, firm $i1$'s surplus, the Nordic average price, investment in generation capacity, and investment in transmission lines. In order to investigate how spatio-temporal differences among key zones $SE1$, $SE3$, and FI drive the results, we report their seasonal prices and flows on transmission lines $\ell 6$ and $\ell 16$ that connect them along with their net imports.

[26] For example, the average modelled electricity price is €41.55/MWh compared with the observed average price of €42.04/MWh in the representative weeks. Modelled CO_2 emissions are 28.28 Mt compared to the observed level of 35.1 Mt for both power and heat generation in 2017. In terms of total generation and hydro generation, we have 398 TWh and 212 TWh, respectively, cf. the observed values of 398 TWh and 213 TWh, respectively, in 2018.

[27] The entry [3.285 −1.395 0.428 2.757] in the first row of Table 7 under PC means that 3.285 TWh, 0.428 TWh, and 2.757 TWh of energy are sent from $SE1$ to FI during winter, summer, and fall, respectively. Meanwhile, 1.395 TWh of energy is sent from FI to $SE1$ during spring.

Table 4
Congestion Analysis for the PC Case of the FutureCV Scenario in the $H = 1$ Regime.

Line	$\ell 4$	$\ell 16$	$\ell 2$	$\ell 7$	$\ell 6$	$\ell 15$	$\ell 17$	$\ell 18$
Proportion of Hours Congested	0.923	0.732	0.686	0.646	0.570	0.525	0.488	0.441

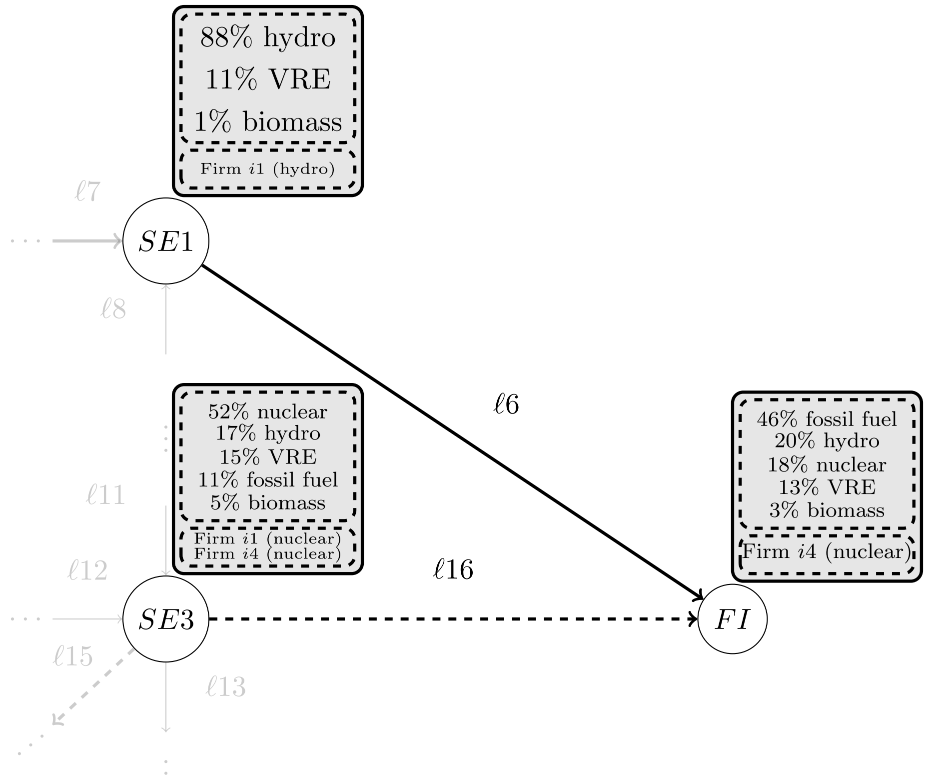


Fig. 4. Network Map of Zones $SE1$, $SE3$, and FI with 2018 Generation-Capacity Mixes and Strategic Firms.

Table 5
Increase in Transmission-Line Susceptance (S) and Amortised Cost (Million €) from 400 MW Capacity Upgrade.

Line	$\ell 6$	$\ell 7$	$\ell 15$	$\ell 16$	$\ell 18$
$B_{j,\ell^{AC}}$	141	213	–	–	–
$C^{trn}_{j,\ell}$	49.44	37.76	45.60	31.92	12.48

The exercise of market power under COG generally boosts average prices by 80% in all three zones, which reduces flows on lines $\ell 6$ and $\ell 16$ vis-à-vis PC. More important, such market power even reverses flows on line $\ell 16$ during some seasons as the greater leverage of nuclear plants in $SE3$ causes prices in that zone to increase relative to those in FI, thereby rendering $SE3$ into a net importer. Temporal arbitrage under COR has a more subtle effect on both seasonal average prices and flows on line $\ell 6$ with a greater tendency for average prices to increase in winter and fall rather than in spring. In effect, firm $i1$ uses its large hydro reservoir in $SE1$ to shift production to spring in order to create scarcity in other seasons, which is why the total flow on line $\ell 6$ during spring under COR is smaller in magnitude vis-à-vis PC. Finally, under PC, $SE1$ and $SE3$ (FI) are net exporters (is a net importer),[28] and this tendency holds in the presence of strategic behaviour, albeit with a noticeable increase (decrease) in $SE3$'s (FI's) annual NI under COG.

[28] The entry [-10.061 −7.921 14.524] in the last row of Table 7 under PC means that $SE1$ and $SE3$ export 10.061 TWh and 7.921 TWh, respectively, annually to other Nordic zones, whereas FI imports 14.524 TWh annually from other Nordic zones.

3.4.2. FutureC scenario

The only change in moving from the Base2018 scenario to FutureC is the increase in the social cost rate of damage from CO_2 emissions from €15/t to €100/t. All other data remain the same, and no investment is allowed in order to establish a future benchmark. While the high CO_2 price has a minor impact on social welfare (Table 8), it has more profound consequences for emissions and the welfare distribution. To facilitate comparison with respective cases in the Base2018 scenario (Table 6), we include percentage changes to the welfare components in parentheses. First, CO_2 emissions drop by over 80% from the Base2018 scenario. Second, the resulting higher electricity prices reduce consumer surplus and increase producer surplus. In particular, firm $i1$'s producer surplus under PC more than doubles vis-à-vis PC in the Base2018 scenario. However, the resulting curb in consumption limits firm $i1$'s market power under COG because it would have to withhold substantially more output to force fossil-fuelled plants to hit their capacity limits. Therefore, its producer surplus increases by 33.36% in moving from PC to COG, cf. 71.57% in the Base2018 scenario.

The flow on line $\ell 6$ from $SE1$ to FI under COG increases vis-à-vis the Base2018 scenario as market power has less impact, while the decrease in line $\ell 16$'s flow from PC to COG is also less drastic than in the Base2018 scenario (Table 9). Likewise, strategic hydro reservoirs' room for manoeuvre is checked under COR as firm $i1$ bolsters its producer surplus by only 0.23% through temporal arbitrage vis-à-vis PC, which is considerably less than the 11.59% increase in the Base2018 scenario. This result arises because the high prices and more even temporal distribution of hydro generation increase the opportunity cost of withholding output during peak seasons. Moreover, "dumping" water in off-peak seasons depresses prices on higher off-peak production volumes. Irrespective of the case, the lack of economically viable

Table 6
Summary Results in the Base2018 Scenario (in Billion € Unless Indicated).

Metric \ Case	PC	COG	COR
Social Welfare	138.942	137.474	138.843
Consumer Surplus	128.144	115.257	126.898
Producer Surplus	10.379	21.241	11.377
Merchandising Surplus	0.420	0.976	0.568
Government Revenue	0.424	0.857	0.427
CO_2 Damage Cost	0.424	0.857	0.427
CO_2 Emissions (Mt)	28.275	57.121	28.470
Firm $i1$'s Surplus	1.467	2.517	1.637
Average Price (€/MWh)	41.548	75.101	44.248

Table 7
Seasonal Flow on $\ell6$ and $\ell16$ (in TWh), Seasonal AP for $SE1$, $SE3$, and FI (in €/MWh), and Annual NI for $SE1$, $SE3$, and FI (in TWh) in the Base2018 Scenario.

Metric \ Case	PC	COG	COR
$\ell6$ Flow	[3.285 −1.395 0.428 2.757]	[3.055 −2.022 0.331 2.170]	[3.283 −0.440 0.109 3.190]
$\ell16$ Flow	[1.925 2.393 2.628 2.503]	[−0.887 −0.706 0.655 0.274]	[1.469 2.193 2.627 1.564]
$SE1$ AP	[47.462 37.945 38.299 42.784]	[79.825 70.042 71.848 77.394]	[51.633 38.598 42.314 49.211]
$SE3$ AP	[50.468 36.500 36.675 42.937]	[91.272 69.074 71.384 82.873]	[53.914 35.263 34.974 49.807]
FI AP	[51.075 37.734 38.298 51.080]	[86.078 66.874 71.482 81.470]	[58.781 37.795 42.260 54.050]
$SE1$ $SE3$ FI NI	[−10.061 −7.921 14.524]	[−10.597 31.773 2.870]	[−10.111 −7.501 13.995]

Table 8
Summary Results in the FutureC Scenario (in Billion € Unless Indicated).

Metric \ Case	PC	COG	COR
Social Welfare	138.057	135.706	137.929
	(−0.637%)	(−1.286%)	(−0.658%)
Consumer Surplus	117.355	102.567	116.808
	(−8.419%)	(−11.010%)	(−7.951%)
Producer Surplus	19.255	32.062	19.512
	(+85.519%)	(+50.944%)	(+71.504%)
Merchandising Surplus	1.448	1.077	1.609
	(+244.762%)	(+10.348%)	(+183.245%)
Government Revenue	0.522	1.469	0.514
	(+23.113%)	(+71.412%)	(+20.375%)
CO_2 Damage Cost	0.522	1.469	0.514
	(+23.113%)	(+71.412%)	(+20.375%)
CO_2 Emissions (Mt)	5.224	14.690	5.139
Firm $i1$'s Surplus	3.064	4.086	3.071
Average Price (€/MWh)	64.753	108.991	65.516

Table 9
Seasonal Flow on $\ell6$ and $\ell16$ (in TWh), Seasonal AP for $SE1$, $SE3$, and FI (in €/MWh), and Annual NI for $SE1$, $SE3$, and FI (in TWh) in the FutureC Scenario.

Metric \ Case	PC	COG	COR
$\ell6$ Flow	[3.285 1.408 3.201 3.285]	[2.998 −0.265 2.907 2.930]	[3.285 1.887 3.195 3.282]
$\ell16$ Flow	[2.620 2.413 2.628 2.628]	[1.724 1.814 2.568 2.228]	[2.617 2.155 2.628 2.611]
$SE1$ AP	[70.033 60.140 61.510 66.619]	[113.737 103.261 106.800 113.468]	[71.119 59.977 64.800 72.225]
$SE3$ AP	[73.164 55.124 56.398 64.396]	[121.365 101.946 106.052 116.682]	[74.338 50.356 51.290 71.154]
FI AP	[119.528 66.713 98.507 117.965]	[126.685 102.927 114.269 125.019]	[119.527 66.405 98.785 118.062]
$SE1$ $SE3$ FI NI	[−10.431 −8.110 21.467]	[−11.153 18.376 16.914]	[−10.453 −8.030 21.659]

flexible fossil-fuelled plants renders FI more of a net importer than in the Base2018 scenario, cf. Tables 9 and 7. Similarly, the flow on line $\ell6$ tends to be from $SE1$ to FI across all seasons and to a greater extent vis-à-vis Base2018.

3.4.3. *FutureCV scenario*

When investment in VRE is enabled, welfare increases slightly in all cases from the FutureC scenario (Table 10) with indicated percentage changes in welfare components from respective cases in the Base2018 scenario (Table 6). Under PC, nearly 10 GW of capacity is adopted, which is all wind and almost all located in FI. For reference, the 2018 VRE installed capacity in the entire Nordic region is 14.698 GW of wind and 1.282 GW of solar. This substantial increase in capacity lowers electricity prices as well as CO_2 emissions, which decline by over 95% from 2018 levels. Consequently, relative to FutureC results, consumer surplus increases and producer surplus decreases.

As there is less need for FI to import from $SE3$, the flow on line $\ell16$ decreases under PC vis-à-vis FutureC (Table 11). However, under COG, withholding by nuclear plants precipitates more VRE adoption, viz., 39.190 GW, which is mostly in FI and $SE3$, where firms $i1$ and $i4$ have strategic assets. While high VRE investment lowers prices and could bolster the incentive to exert market power, a reaction of this magnitude by price-taking fringe firms actually limits the strategic producers' leverage as line $\ell16$ facilitates flow from FI to $SE3$. For example, firm $i1$'s ability to exercise market power is slightly less than that in FutureC, as indicated by the increase in its PS of 30.79% during the transition from PC to COG. Yet, under COR, subtler exertion of market power proves relatively more potent here vis-à-vis both the Base2018 and FutureC scenarios. In spite of the 11.035 GW of VRE capacity adopted (again, all wind and mostly in FI), firm $i1$'s producer surplus increases by 13.44% in moving from PC to COR, which is higher

Table 10
Summary Results in the FutureCV Scenario (in Billion € Unless Indicated).

Metric \ Case	PC	COG	COR
Social Welfare	138.913	137.829	138.797
	(−0.021%)	(+0.258%)	(−0.033%)
Consumer Surplus	129.291	124.742	128.176
	(+0.895%)	(+8.229%)	(+1.007%)
Producer Surplus	8.550	11.238	9.533
	(−17.622%)	(−47.093%)	(−16.208%)
Merchandising Surplus	1.073	1.849	1.088
	(+155.476%)	(+89.445%)	(+91.549%)
Government Revenue	0.105	0.342	0.096
	(−75.236%)	(−60.093%)	(−77.518%)
CO_2 Damage Cost	0.105	0.342	0.096
	(−75.236%)	(−60.093%)	(−77.518%)
CO_2 Emissions (Mt)	1.053	3.420	0.958
Firm $i1$'s Surplus	1.049	1.372	1.190
Average Price (€/MWh)	37.151	48.746	39.933
Generation Expansion (GW)	9.916	39.190	11.035

Table 11
Seasonal Flow on $\ell 6$ and $\ell 16$ (in TWh), Seasonal AP for $SE1$, $SE3$, and FI (in €/MWh), and Annual NI for $SE1$, $SE3$, and FI (in TWh) in the FutureCV Scenario.

Metric \ Case	PC	COG	COR
$\ell 6$ Flow	[2.561 −0.851 1.107 0.941]	[1.510 −0.202 1.789 0.072]	[2.337 −0.236 0.963 1.180]
$\ell 16$ Flow	[0.172 0.333 1.899 0.635]	[−0.134 −0.031 1.295 −0.163]	[0.079 0.251 1.828 −0.541]
$SE1$ AP	[39.109 29.638 29.860 34.166]	[50.939 40.818 41.859 44.795]	[42.661 26.019 33.564 41.198]
$SE3$ AP	[50.499 29.804 29.554 38.513]	[81.379 39.835 44.997 48.929]	[53.282 29.082 28.523 44.400]
FI AP	[78.682 25.918 49.218 41.494]	[83.485 34.915 73.530 42.619]	[78.637 24.966 49.427 43.761]
$SE1$ $SE3$ FI NI	[−9.923 −4.361 6.799]	[−10.108 14.447 4.137]	[−9.850 −4.185 5.861]

Table 12
Summary Results in the FutureCVT Scenario (in Billion € Unless Indicated).

Metric \ Case	PC	COG	COR
Social Welfare	138.938	137.902	138.825
	(−0.003%)	(+0.311%)	(−0.013%)
Consumer Surplus	129.658	125.177	128.780
	(+1.181%)	(+8.607%)	(+1.483%)
Producer Surplus	8.397	11.052	9.128
	(−19.096%)	(−47.969%)	(−19.768%)
Merchandising Surplus	0.947	1.837	0.980
	(+125.476%)	(+88.217%)	(+72.535%)
Government Revenue	0.074	0.204	0.066
	(−82.547%)	(−76.196%)	(−84.543%)
CO_2 Damage Cost	0.074	0.204	0.066
	(−82.547%)	(−76.196%)	(−84.543%)
Transmission-Expansion Cost	0.064	0.163	0.064
CO_2 Emissions (Mt)	0.736	2.035	0.659
Firm $i1$'s Surplus	1.068	1.391	1.175
Average Price (€/MWh)	36.953	48.413	39.074
Generation Expansion (GW)	10.000	39.860	11.282
Transmission Expansion (–)	[0 0 0 2]	[2 0 0 2]	[0 0 0 2]

than the corresponding increase observed in both the Base2018 and FutureC scenarios. This adoption of VRE at FI reduces year-round imports from $SE1$ vis-à-vis FutureC, which frees firm $i1$ to conduct more temporal arbitrage from its large hydro reservoirs at $SE1$. Hence, the leverage of strategic hydro reservoirs is enhanced in a future power system with endogenous VRE capacity expansion.

3.4.4. FutureCVT scenario

Table 12 summarises the impact of allowing for transmission expansion along with generation investment in the future. As before, the percentage change in each welfare component from the respective case in the Base2018 scenario (Table 6) is indicated in parentheses. The final row of the table indicates additions to the transmission-line capacity of the candidate lines. For example, the transmission expansion in the PC case is [0 0 0 2], which corresponds to a 800 MW increment to line $\ell 16$ and no increments to other candidate lines. While this capacity expansion increases welfare by only €25 million from the corresponding case in the FutureCV scenario (Table 10), there are broader implications for its distribution.

The upgrade of line $\ell 16$ enables FI to avail of more of $SE3$'s nuclear resources during the high-price winter and summer seasons, cf. the FutureCVT and FutureCV scenarios (Tables 11 and 13). Therefore, less VRE generation capacity is adopted at FI under PC, i.e., 9.779 GW instead of 9.797 GW as in the corresponding case in the FutureCV scenario. As a result, while prices increase (decrease) slightly at $SE3$ (FI), there is a substantial impact on CO_2 emissions, which decrease by approximately 30% from the corresponding PC case in the FutureCV scenario. Hence, in addressing RQ 1, we note that the socially optimal transmission plan to expand line $\ell 16$ by 800 MW reduces the need for as much VRE capacity adoption at FI by better allocating resources in response to spatio-temporal nodal price differences.

Under COG, the exertion of market power by nuclear plants in $SE3$ and FI adds 800 MW of capacity to line $\ell 6$ on top of 800 MW of capacity to line $\ell 16$. This transmission plan adapts to the withholding of nuclear generation by facilitating an expansion of VRE investment to 39.860 GW as opposed to 39.190 GW from the corresponding case in the FutureCV scenario. As evidenced by the flows on line $\ell 6$ in Table 13

Table 13
Seasonal Flow on $\ell 6$ and $\ell 16$ (in TWh), Seasonal AP for $SE1$, $SE3$, and FI (in €/MWh), and Annual NI for $SE1$, $SE3$, and FI (in TWh) in the FutureCVT Scenario.

Metric \ Case	PC	COG	COR
$\ell 6$ Flow	[2.897 −0.842 0.668 1.044]	[2.452 −1.098 2.326 −0.680]	[2.639 −0.309 0.208 1.482]
$\ell 16$ Flow	[0.490 −0.336 2.779 0.542]	[−0.414 0.072 1.998 −0.143]	[0.223 −0.169 2.930 −1.231]
$SE1$ AP	[40.407 29.931 30.141 33.603]	[52.440 39.401 40.919 43.855]	[44.076 26.152 32.476 40.883]
$SE3$ AP	[51.172 29.969 29.855 38.374]	[85.020 40.145 46.825 46.474]	[53.332 28.804 29.120 43.049]
FI AP	[72.835 26.835 35.128 39.034]	[80.574 30.810 55.492 41.248]	[71.999 25.296 35.671 42.237]
$SE1$ $SE3$ FI NI	[−9.929 −4.355 7.241]	[−10.083 13.696 4.514]	[−9.877 −4.029 5.774]

relative to those under COG in the FutureCV scenario (Table 11), the added transmission capacity serves to export more (hydro) power from $SE1$ to FI during the high-price winter and summer seasons and vice versa during the low-price spring season. Moreover, high VRE availability in fall (Fig. C.2(b)) and adopted generation capacity at FI actually enable $SE1$ to import power on line $\ell 6$. As under PC, the added transmission capacity triggers substantial changes to the power system through the possibility of better resource sharing. In particular, the combined expansion of generation and transmission capacity adapts to nuclear plants' exercise of market power by enabling more hydro resources to be shared, which partially addresses RQ 2.

As for the COR case, it is actually optimal not to expand transmission capacity vis-à-vis PC. This is because firm $i1$'s temporal arbitrage through its hydro reservoir at $SE1$ primarily involves the withholding of water during the winter and fall seasons with "excess" production during spring. Such a manoeuvre to boost winter and fall prices coincides with the seasonal availability of wind at FI (Fig. C.2(b)), which entices VRE expansion at FI. Relative to PC, FI's expanded VRE adoption[29] and firm $i1$'s withholding of hydro generation at $SE1$ mean that FI becomes less of a net importer under COR (Table 13). As depicted in Fig. 5, hourly flows on line $\ell 6$ are modulated under COR by enhanced VRE adoption at FI.[30] Hence, by liberating some existing capacity on line $\ell 6$, temporal arbitrage by hydro reservoirs stimulates adoption of VRE capacity at FI, which is balanced by $SE1$'s hydro without the need for transmission expansion vis-à-vis PC, thereby partially addressing RQ 2.

3.5. Results for $H = 0.15$ regime

To tackle RQ 3, we set $H = 0.15$ and compare the results with those in Section 3.4. In effect, the social cost of damage from CO_2 emissions is not fully imposed on industry, i.e., the future CO_2 price perceived by industry (or, tax) remains at its 2018 rate.

3.5.1. FutureC scenario

With a CO_2 tax of €15/t, the decisions made in all cases of the FutureC scenario in the $H = 0.15$ regime are identical to those in the corresponding cases of the Base2018 scenario in the $H = 1$ regime (see the spatio-temporal results of Table 7). Consequently, prices, CO_2 emissions, and welfare components are all unchanged (Table 6), apart from the social cost of damage from CO_2 emissions. Due to the lack of full internalisation, the damage cost under PC is €2.828 billion, which reduces social welfare to €136.539 billion, cf. €0.424 billion and €138.942 billion, respectively, under PC of the Base2018 scenario in the $H = 1$ regime. Under COR, the results are similar, with damage cost and social welfare of €2.847 billion and €136.423 billion, respectively, whereas the effects are exacerbated under COG, with damage cost and social welfare of €5.712 billion and €132.619 billion, respectively. As expected, the ability of the CO_2 tax to reduce emissions is rolled back, compared to the FutureC scenario in the $H = 1$ regime. Likewise, the mitigating impact of the CO_2 tax on market power is reversed. Intuitively, the lack of a first-best CO_2 tax boosts consumption and reduces prices in the FutureC scenario for $H = 0.15$, thereby facilitating withholding under COG to force fossil-fuelled power plants to generate at capacity and allowing for temporal arbitrage by hydro reservoirs under COR.

3.5.2. FutureCV scenario

Compared to the FutureCV scenario in the $H = 1$ regime, the incentives to curb consumption and to invest in VRE are reduced. In particular, the lower CO_2 tax results in lower electricity prices at $SE3$ and FI as well, cf. Tables 11 and 15, which spurs consumption and holds back VRE adoption. As a result, the higher emissions and welfare loss exhibited in the FutureC scenario due to incomplete CO_2 pricing are magnified when investment in VRE is enabled, cf. Tables 10 and 14, where we facilitate comparison with respective cases in the $H = 1$ regime (Table 10) by including percentage changes to the welfare components in parentheses. On the other hand, the combination of economically viable fossil-fuelled plants and stunted VRE capacity adoption serves to check the exercise of market power vis-à-vis the FutureCV scenario in the $H = 1$ regime. For example, firm $i1$'s producer surplus increases by 16.42% and 0.53% due to the exercise of market power under COG and COR, respectively, compared to 30.79% and 13.44%, respectively, in the FutureCV scenario for $H = 1$.

In terms of the spatio-temporal drivers at $SE1$ and FI, there is more flow on line $\ell 6$ under PC relative to the same scenario and case in the $H = 1$ regime, cf. Tables 11 and 15. This change is due to the lower VRE capacity adopted in the $H = 0.15$ regime, viz., 7.4 GW (all at FI) as opposed to nearly 10 GW, which necessitates increased imports of hydro by FI. Likewise, the lack of VRE capacity adopted at FI leads to more flow on line $\ell 16$ than in the $H = 1$ regime, i.e., using $SE3$'s nuclear capacity to meet consumption at FI. As in the $H = 1$ regime, the exercise of market power by nuclear plants under COG reduces the flows on lines $\ell 6$ and $\ell 16$ relative to those under PC. In fact, FI even exports power to $SE1$ during spring and fall, and flows between $SE3$ and FI generally tend to be reversed. However, in the $H = 0.15$ regime, since fossil-fuelled plants are still economically viable, their greater output at FI amplifies the flow reversal, thereby causing the exertion of market power at FI to be less effective than at $SE3$. By contrast, under COR, there is less VRE adoption and a greater need for flow on line $\ell 6$ from $SE1$ to FI because temporal arbitrage by hydro reservoirs is less effective at manipulating prices than in the $H = 1$ regime. In effect, while partial pricing of the social cost of damage from CO_2 emissions mitigates the exercise of market power under COR, it also increases CO_2 emissions vis-à-vis PC due to less incentive for VRE adoption.

3.5.3. FutureCVT scenario

Under PC in the $H = 0.15$ regime, there is less adoption of VRE capacity relative to that in the same scenario and case of the $H = 1$ regime, cf. Tables 12 and 16, where we again enable comparison with respective cases in the $H = 1$ regime (Table 12) by including percentage changes to the welfare components in parentheses. VRE investment takes place only at FI, and the lack of a first-best CO_2 tax prompts the TSO to modify its transmission plan to comprise 400 MW of capacity in both lines $\ell 6$ and $\ell 16$ in order to *increase* VRE capacity from its

[29] FI's VRE capacity investment is 10.660 GW under COR as opposed to 9.779 GW under PC.

[30] The standard error of the flows is reduced to 882 MWh under COR from 1,086 MWh under PC, while the average of the absolute value of the flows is 865 MWh and 1,081 MWh under COR and PC, respectively.

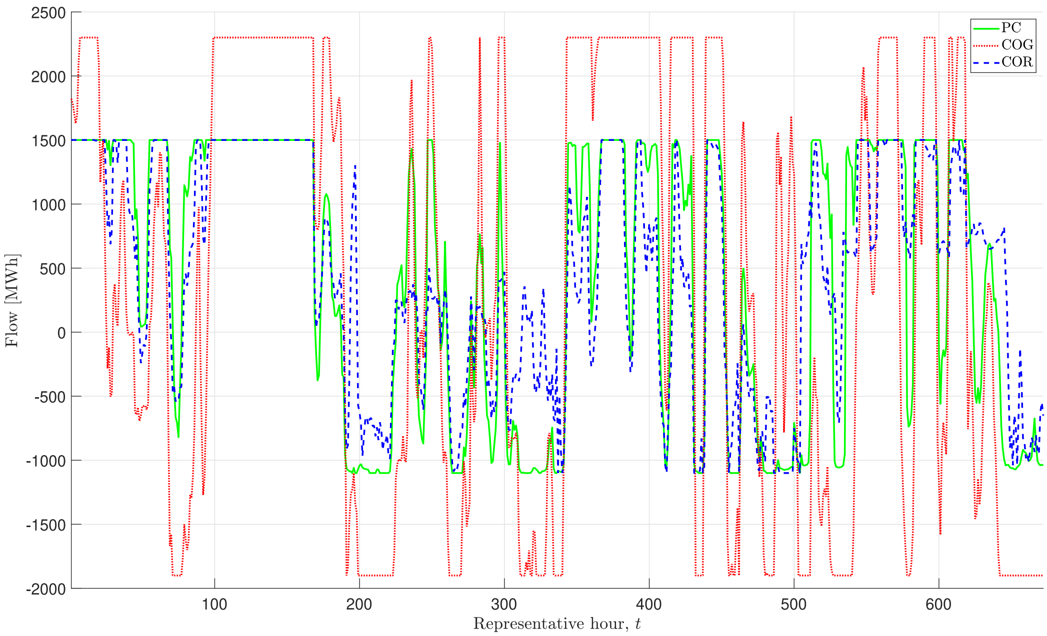


Fig. 5. Hourly Flows on Line $\ell 6$ in the FutureCVT Scenario (in MWh).

Table 14
Summary Results in the FutureCV Scenario with $H = 0.15$ (in Billion € Unless Indicated).

Metric \ Case	PC	COG	COR
Social Welfare	138.315 (−0.431%)	136.137 (−1.228%)	138.106 (−0.498%)
Consumer Surplus	130.120 (+0.641%)	126.511 (+1.418%)	129.677 (+1.171%)
Producer Surplus	8.488 (−0.725%)	10.774 (−4.129%)	8.718 (−8.549%)
Merchandising Surplus	0.474 (−55.825%)	0.952 (−48.513%)	0.567 (−47.886%)
Government Revenue	0.135 (+28.571%)	0.370 (+8.187%)	0.151 (+57.292%)
CO_2 Damage Cost	0.903 (+760.00%)	2.471 (+622.515%)	1.007 (+948.958%)
CO_2 Emissions (Mt)	9.027	24.710	10.075
Firm $i1$'s Surplus	1.133	1.319	1.139
Average Price (€/MWh)	37.033	46.408	37.743
Generation Expansion (GW)	7.400	34.051	8.196

Table 15
Seasonal Flow on $\ell 6$ and $\ell 16$ (in TWh), Seasonal AP for $SE1$, $SE3$, and FI (in €/MWh), and Annual NI for $SE1$, $SE3$, and FI (in TWh) in the FutureCV Scenario with $H = 0.15$.

Metric \ Case	PC	COG	COR
$\ell 6$ Flow	[2.876 −0.567 1.475 1.419]	[1.163 −0.279 1.438 −0.628]	[2.775 0.034 1.245 2.227]
$\ell 16$ Flow	[−0.019 0.640 2.201 1.089]	[−0.799 −1.064 0.714 −0.873]	[−0.224 0.546 2.063 −1.284]
$SE1$ AP	[43.225 33.012 33.463 37.094]	[52.320 40.482 41.724 43.072]	[44.505 30.124 34.879 40.442]
$SE3$ AP	[47.699 32.111 31.932 37.721]	[68.997 41.053 43.351 46.845]	[48.706 29.879 29.351 41.712]
FI AP	[51.319 30.014 35.307 38.166]	[60.903 29.909 43.179 41.379]	[51.028 28.890 35.155 40.717]
$SE1$ $SE3$ FI NI	[−9.981 −5.462 9.113]	[−10.108 22.968 −0.327]	[−9.936 −5.702 7.382]

level under PC in the FutureCV scenario of the $H = 0.15$ regime, cf. Tables 14 and 16. This is in marked contrast to how the TSO adds transmission capacity only to line $\ell 16$ in the $H = 1$ regime to *reduce* VRE capacity at FI. Simply put, the limited price signal to curb CO_2 emissions necessitates transmission capacity that can avail of additional hydro resources from $SE1$ to compensate for an insufficient curb on consumption at FI. Indeed, hydro resources are better able to balance the (intermittent) VRE output adopted at FI. Consequently, incomplete carbon pricing triggers the TSO to support higher seasonal flows from $SE1$ to FI vis-à-vis $H = 1$, cf. Tables 13 and 17 (cf. Figs. 5 and 6). An exception is during spring, which experiences an increase in the flow in the opposite direction. We address RQ 3 by noting that incomplete carbon pricing leads to transmission expansion of line $\ell 6$ but less expansion of line $\ell 16$ such as to facilitate VRE adoption under PC as a countervailing measure.

The reduced tendency for strategic withholding under COG in the $H = 0.15$ regime vis-à-vis the $H = 1$ regime results in relatively less VRE adoption, which can still be balanced by economically viable fossil-fuelled plants. Thus, there is only 400 MW of capacity addition for lines $\ell 6$ and $\ell 16$ (Table 16) as opposed to 800 MW for both in the $H = 1$ regime (Table 12). By contrast, the less effective exercise of temporal arbitrage under COR actually makes the case for more

Table 16
Summary Results in the FutureCVT Scenario with $H = 0.15$ (in Billion € Unless Indicated).

Metric \ Case	PC	COG	COR
Social Welfare	138.365 (−0.412%)	136.197 (−1.236%)	138.150 (−0.486%)
Consumer Surplus	130.083 (+0.328%)	126.540 (+1.089%)	129.935 (+0.897%)
Producer Surplus	8.594 (+2.346%)	10.790 (−2.371%)	8.505 (−6.825%)
Merchandising Surplus	0.424 (−55.227%)	0.957 (−47.904%)	0.551 (−43.776%)
Government Revenue	0.116 (+56.757%)	0.355 (+74.020%)	0.131 (+98.485%)
CO_2 Damage Cost	0.771 (+941.892%)	2.364 (+1,058.824%)	0.870 (+1,218.182%)
Transmission-Expansion Cost	0.081 (+26.563%)	0.081 (−50.307%)	0.102 (+59.375%)
CO_2 Emissions (Mt)	7.713	23.639	8.704
Firm $i1$'s Surplus	1.162	1.320	1.123
Average Price (€/MWh)	37.368	46.457	37.288
Generation Expansion (GW)	7.824	34.309	8.638
Transmission Expansion (–)	[1 0 0 1]	[1 0 0 1]	[0 1 0 2]

Table 17
Seasonal Flow on $\ell 6$ and $\ell 16$ (in TWh), Seasonal AP for $SE1$, $SE3$, and FI (in €/MWh), and Annual NI for $SE1$, $SE3$, and FI (in TWh) in the FutureCVT Scenario with $H = 0.15$.

Metric \ Case	PC	COG	COR
$\ell 6$ Flow	[3.675 −1.262 1.191 1.312]	[1.435 −0.628 1.588 −1.146]	[2.993 −0.951 0.499 2.557]
$\ell 16$ Flow	[−0.342 0.702 2.974 1.001]	[−1.155 −1.589 0.411 −1.326]	[−0.328 0.717 3.369 −2.069]
$SE1$ AP	[44.151 32.928 33.560 37.014]	[52.715 39.912 41.495 42.750]	[44.620 32.150 34.948 39.656]
$SE3$ AP	[48.278 32.565 32.682 37.649]	[69.508 41.064 43.412 46.355]	[48.233 29.587 29.813 40.704]
FI AP	[49.251 30.800 34.185 37.431]	[60.432 30.335 41.223 41.062]	[49.134 29.004 33.884 40.127]
$SE1$ $SE3$ FI NI	[−9.980 −5.508 9.252]	[−10.103 24.390 −2.409]	[−9.974 −5.314 6.847]

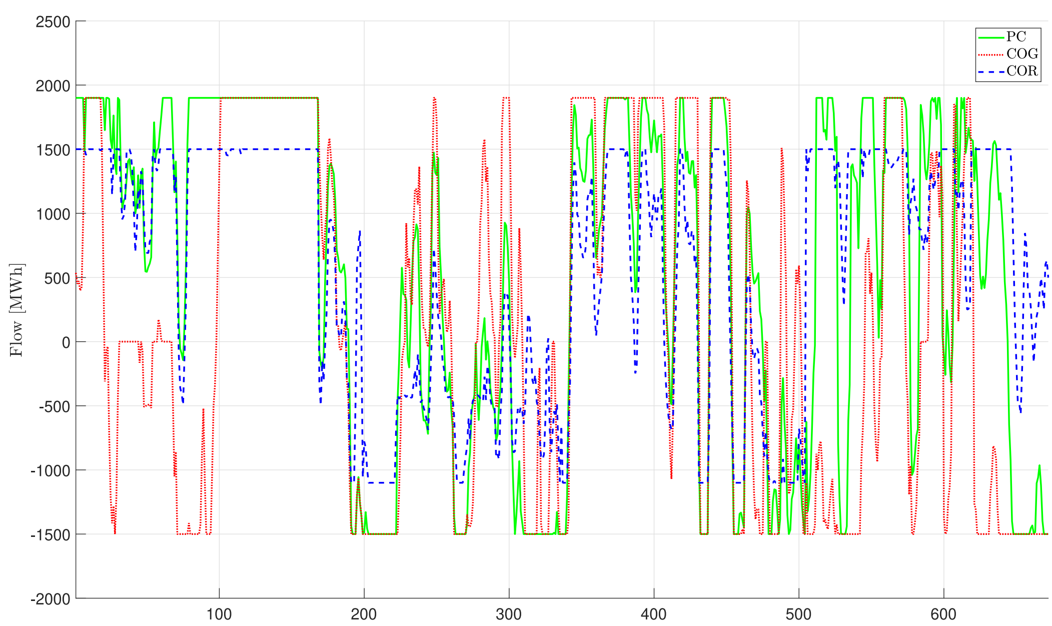


Fig. 6. Hourly Flows on Line $\ell 6$ in the FutureCVT Scenario with $H = 0.15$ (in MWh).

transmission expansion than in the $H = 1$ regime. This is because there is less possibility for expanded VRE capacity adoption at FI to occur as a consequence of price manipulation. Combined with the fact that consumption is not curbed due to incomplete carbon pricing, better interconnections with large hydro reservoirs at $SE1$ and $NO4$ are required, thereby leading to expansion of line $\ell 7$ by 400 MW and line $\ell 16$ by 800 MW. Hence, in addressing RQ 3 under imperfect competition, we note that incomplete carbon pricing could lead to either higher or lower transmission capacity relative to complete carbon pricing, depending on the spatio-temporal impacts of market power exercised.

4. Conclusions and policy implications

Climate packages envisage a decarbonised power sector as the lynchpin of an increasingly electrified economy. Rapid decreases in investment costs have rendered VRE technologies economically viable, but their integration into the power sector is hampered by their intermittent output and the remoteness of attractive solar and wind sites. Along with flexible demand and supply, transmission expansion is posited as a means to support VRE adoption. However, both engineering/operational research and environmental-economics models exhibit limitations in their assessments of transmission expansion in a market environment. In particular, the former overlook externalities under imperfect competition, whereas the latter abstract from the power sector's physical attributes. We address this gap in the literature concerning policy-enabling models for transmission expansion that incorporate both the market structure and the spatio-temporal texture of power sectors.

Our contribution in this context is to tackle RQs 1–3 via a calibrated model of the Nordic power sector and to distil the following policy implications. First, a socially optimal transmission plan, i.e., in a perfectly competitive market and with full internalisation of the social cost of damage from CO_2 emissions, leverages the higher ensuing electricity prices to curb consumption and to permit more efficient sharing of generation resources (RQ 1). Sufficient existing generation capacity, e.g., from nuclear plants at $SE3$, is liberated such that additional transmission capacity can enable its utilisation by the more fossil-fuel-dependent FI zone. Subsequently, less VRE capacity needs to be adopted at FI than in a scenario without transmission expansion, which lays bare the tradeoff between curbing consumption and adopting VRE capacity that can arise even without economic and environmental distortions. Second, imperfect competition in the presence of full CO_2 pricing has contrasting impacts on transmission expansion depending on the type of market power exerted (RQ 2). Under a textbook example of generation withholding by nuclear plants, the severity of the distortion necessitates additional transmission expansion vis-à-vis perfect competition. This intervention compensates for restricted nuclear output by facilitating adequate VRE adoption at FI that can be balanced by hydro from $SE1$. By contrast, temporal arbitrage by large reservoirs at $SE1$ leads to higher electricity prices during those seasons with high wind availability at FI, which entices VRE adoption there. As a result, the transmission plan from perfect competition suffices to integrate VRE because power flows on the existing line between $SE1$ and FI are reduced in magnitude. Third, incomplete CO_2 pricing explores the consequences of political pressures on transmission planning (RQ 3). Under perfect competition, the lack of a price signal to curb consumption prevents efficient sharing of existing generation resources, which requires the TSO to reinforce the line between $SE1$ and FI. Thus, in contrast to the result with full CO_2 pricing, the TSO needs to be more proactive in mitigating the environmental distortion by actually inducing VRE adoption. Since incomplete CO_2 pricing limits the scope for the exercise of market power, transmission plans under strategic behaviour by nuclear and hydro plants need to be tailored accordingly. In case of the former (latter), less propensity to withhold (to conduct temporal arbitrage) means that less (more) transmission capacity is optimal than in the corresponding case with full CO_2 pricing.

Future work could expand the research vistas to assess alternative energy policies. Apart from carbon pricing, we could explore subsidies and other support mechanisms, e.g., in the context of regional trade in the Middle East and North Africa (Timilsina and Deluque Curiel, 2023). By contrast, we may use our approach to study market power exerted by fossil-fuelled plants in interconnected regions with contrasting emission policies and gauge the implications for carbon leakage (Višković et al., 2021). Turning to the comparative advantage of a price instrument over a quantity instrument, we could take the perspective of a policymaker at the upper level, endogenously setting environmental regulation in an imperfectly competitive industry (Shittu et al., 2015). While we devised socially optimal transmission plans for the Nordic region, further integration of power sectors between neighbouring regions would warrant a cooperative game-theoretic approach to determine how to allocate benefits and costs from shared resources such as transmission interconnections (Kristiansen et al., 2018).

CRediT authorship contribution statement

Farzad Hassanzadeh Moghimi: Conceptualization, Data curation, Investigation, Methodology, Software, Writing – original draft, Writing – review & editing. **Trine K. Boomsma:** Conceptualization, Funding acquisition, Investigation, Methodology, Project administration, Supervision, Validation, Writing – original draft, Writing – review & editing. **Afzal S. Siddiqui:** Conceptualization, Formal analysis, Funding acquisition, Investigation, Methodology, Project administration, Software, Supervision, Validation, Writing – original draft, Writing – review & editing.

Declaration of competing interest

The authors declare the following financial interests/personal relationships which may be considered as potential competing interests: Afzal Siddiqui reports a relationship with Research Institute of Industrial Economics that includes: consulting or advisory.

Appendix A. Nomenclature

Indices and sets

$e \in \mathcal{E}_{i,n}$ Variable renewable energy (VRE) unit of firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$.

$i \in \mathcal{I}$ Firms.

$j \in \mathcal{J}_\ell$ Discrete capacity level of transmission investment on line ℓ.

$\ell \in \mathcal{L}$ Transmission lines.

$\ell^{\mathbf{AC}} \in \mathcal{L}^{\mathbf{AC}} \subset \mathcal{L}$ AC transmission lines.

$\ell^{\mathbf{DC}} \in \mathcal{L}^{\mathbf{DC}} \subset \mathcal{L}$ DC transmission lines.

$\mathcal{L}_n^+, \mathcal{L}_n^-$ Transmission line starting/ending at node n.

$n \in \mathcal{N}$ Nodes.

$\mathcal{N}_{i,w} \subset \mathcal{N}$ Nodes containing hydro unit w belonging to firm i.

$n^{\mathbf{AC}} \in \mathcal{N}^{\mathbf{AC}} \subset \mathcal{N}$ AC nodes.

$n^{\mathbf{DC}} \in \mathcal{N}^{\mathbf{DC}} \subset \mathcal{N}$ DC nodes.

n_ℓ^+, n_ℓ^- Node index for starting/ending node of transmission line ℓ.

$t \in \mathcal{T}$ Time periods.

$u \in \mathcal{U}_{i,n}$ Thermal generation units of firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$.

$w \in \mathcal{W}_{i,n}$ Hydro unit of firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$.

$\Omega^{\mathbf{LL}}$ Lower-level primal variables.

$\Omega^{\mathbf{DV}}$ Lower-level dual variables.

Parameters

$A_{n,t}^e$ Availability factor for VRE unit $e \in \mathcal{E}_{i,n}$ at node $n \in \mathcal{N}$ at time $t \in \mathcal{T}$ (–).[31]

[31] "(–)" refers to a unitless item.

$B_{j,\ell^{AC}}$ Susceptance of AC transmission line $\ell^{AC} \in \mathcal{L}^{AC}$ at level $j \in \mathcal{J}_\ell$ (S).

$C^{\mathbf{ava}}_{i,n,u}/C^{\mathbf{ava}}_{e,i,n}/C^{\mathbf{ava}}_{i,n,w}$ Amortised annual O&M cost of capacity for thermal unit $u \in \mathcal{U}_{i,n}$/VRE unit $e \in \mathcal{E}_{i,n}$/hydro unit $w \in \mathcal{W}_{i,n}$ of firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$ (€/MW).

$C^{\mathbf{gen}}_{e,i,n}$ Amortised annual investment cost of capacity for VRE unit $e \in \mathcal{E}_{i,n}$ of firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$ (€/MW).

$C^{\mathbf{trn}}_{j,\ell}$ Amortised annual investment cost of capacity for transmission line $\ell \in \mathcal{L}$ at level $j \in \mathcal{J}_\ell$ (€).

$C_{i,n,t,u}$ Cost of generation for generation unit $u \in \mathcal{U}_{i,n}$ at node $n \in \mathcal{N}$ for firm $i \in \mathcal{I}$ at time $t \in \mathcal{T}$ (€/MWh).

$D^{\mathbf{int}}_{n,t}$ Intercept of linear inverse-demand curve at node $n \in \mathcal{N}$ at time $t \in \mathcal{T}$ (€/MWh).

$D^{\mathbf{slp}}_{n,t}$ Slope of inverse-demand curve at node $n \in \mathcal{N}$ at time $t \in \mathcal{T}$ (€/MWh^2).

$E^{\mathbf{sto}}_{i,n,w}$ Self-discharge rate of hydro unit $w \in \mathcal{W}_{i,n}$ of firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$ (m^3/m^{3}h).

$F_{i,n,w}$ Pumped-hydro efficiency of hydro unit $w \in \mathcal{W}_{i,n}$ of firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$ (MWh/m^3).

$\overline{G}_{i,n,u}$ Maximum generation capacity of generation unit $u \in \mathcal{U}_{i,n}$ of firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$ (MW).

$\overline{G}^{e}_{i,n}$ Maximum generation capacity of VRE unit $e \in \mathcal{E}_{i,n}$ of firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$ (MW).

H Fraction of social cost of damage from CO_2 emissions imposed on industry $[0, 1]$.

$I_{i,n,t,w}$ Natural inflow to hydro unit $w \in \mathcal{W}_{i,n}$ belonging to firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$ at time $t \in \mathcal{T}$ (m^3).

$\overline{K}_{j,\ell}/\underline{K}_{j,\ell}$ Capacity of transmission line $\ell \in \mathcal{L}$ at level $j \in \mathcal{J}_\ell$ in positive/negative direction (MW).

$P_{i,n,u}$ CO_2 emission rate of generation unit $u \in \mathcal{U}_{i,n}$ of firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$ (t/MWh).

$Q_{i,n,w}$ Generation efficiency of hydro unit $w \in \mathcal{W}_{i,n}$ of firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$ (MWh/m^3).

$\overline{R}_{i,n,w}/\underline{R}_{i,n,w}$ Maximum/minimum reservoir volume of hydro unit $w \in \mathcal{W}_{i,n}$ of firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$ (m^3).

$R^{\mathbf{in}}_{i,n,w}$ Maximum charging rate for hydro unit $w \in \mathcal{W}_{i,n}$ of firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$ (m^3/m^{3}h).

$R^{\mathbf{up}}_{u}/R^{\mathbf{down}}_{u}$ Ramp-up/ramp-down rate for generation unit $u \in \mathcal{U}_{i,n}$ (–).

S Social cost rate of damage from CO_2 emissions (€/t).

T_t Duration of period $t \in \mathcal{T}$ (h).

V Scaling factor for power flow (–).

$\overline{Y}_{i,n,w}$ Maximum generation capacity of hydro unit $w \in \mathcal{W}_{i,n}$ of firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$ (MW).

$Z_{i,n}$ Regulation of net-hydro reservoir generation by firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$ (MWh).

Variables

Binary variables

$x_{j,\ell}$ Binary variable that is equal to 1 if discrete capacity level $j \in \mathcal{J}_\ell$ is selected for line ℓ and 0 otherwise.

Primal variables

$a_{i,n,u}/a^{e}_{i,n}/a_{i,n,w}$ Available capacity of thermal unit $u \in \mathcal{U}_{i,n}$/VRE unit $e \in \mathcal{E}_{i,n}$/hydro unit $w \in \mathcal{W}_{i,n}$ of firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$ (MW).

$b^{e}_{i,n}$ Adopted capacity of VRE unit $e \in \mathcal{E}_{i,n}$ of firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$ (MW).

$f_{j,\ell,t}$ Power flow on transmission line $\ell \in \mathcal{L}$ at discrete capacity level $j \in \mathcal{J}_\ell$ at time $t \in \mathcal{T}$ (MW).

$\hat{f}_{\ell,t}$ Realised power flow on transmission line $\ell \in \mathcal{L}$ at time $t \in \mathcal{T}$ (MW).

$g_{i,n,t,u}$ Generation of thermal unit $u \in \mathcal{U}_{i,n}$ of firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$ at time $t \in \mathcal{T}$ (MWh).

$g^{e}_{i,n,t}$ Generation of VRE unit $e \in \mathcal{E}_{i,n}$ of firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$ at time $t \in \mathcal{T}$ (MWh).

$q_{n,t}$ Consumption at node $n \in \mathcal{N}$ at time $t \in \mathcal{T}$ (MWh).

$r^{\mathbf{in}}_{i,n,t,w}$ Volume of water pumped into hydro unit $w \in \mathcal{W}_{i,n}$ of firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$ at time $t \in \mathcal{T}$ (m^3).

$r^{\mathbf{out}}_{i,n,t,w}$ Volume of water turbined from hydro unit $w \in \mathcal{W}_{i,n}$ of firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$ at time $t \in \mathcal{T}$ (m^3).

$r^{\mathbf{sto}}_{i,n,t,w}$ Volume of water stored in hydro unit $w \in \mathcal{W}_{i,n}$ of firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$ at time $t \in \mathcal{T}$ (m^3).

$v_{n,t}$ Voltage angle of node $n^{AC} \in \mathcal{N}^{\mathcal{AC}}$ at time $t \in \mathcal{T}$ (rad).

$z_{i,n,t,w}$ Volume of water spilt from hydro unit $w \in \mathcal{W}_{i,n}$ of firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$ at time $t \in \mathcal{T}$ (m^3).

Dual variables

$\beta^{\mathbf{ava}}_{i,n,u}/\beta^{\mathbf{ava}}_{e,i,n}/\beta^{\mathbf{ava}}_{i,n,w}$ Shadow price of generation-capacity availability of thermal unit $u \in \mathcal{U}_{i,n}$/VRE unit $e \in \mathcal{E}_{i,n}$/hydro unit $w \in \mathcal{W}_{i,n}$ of firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$ (€/MW).

$\beta_{i,n,t,u}$ Shadow price of generation capacity of thermal unit $u \in \mathcal{U}_{i,n}$ of firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$ at time $t \in \mathcal{T}$ (€/MWh).

$\beta^{e}_{i,n,t}$ Shadow price of generation capacity of VRE unit $e \in \mathcal{E}_{i,n}$ of firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$ at time $t \in \mathcal{T}$ (€/MWh).

$\beta^{\mathbf{up}}_{i,n,t,u}/\beta^{\mathbf{down}}_{i,n,t,u}$ Shadow price of ramp-up/ramp-down rate of thermal unit $u \in \mathcal{U}_{i,n}$ of firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$ at time $t \in \mathcal{T}$ (€/MWh).

$\gamma_{i,n}$ Shadow price of hydro regulation for firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$ (€/MWh).

$\eta_{j,\ell^{AC},t}$ Shadow price of energy flow on AC line $\ell^{AC} \in \mathcal{L}^{AC}$ at discrete capacity level $j \in \mathcal{J}_\ell$ at time $t \in \mathcal{T}$ (€/MWh).

$\theta_{n,t}$ Shadow price of market-clearing condition at node $n \in \mathcal{N}$ at time $t \in \mathcal{T}$ (€/MWh).

$\overline{\kappa}_{n^{AC},t}/\underline{\kappa}_{n^{AC},t}$ Shadow price of maximum/minimum voltage angle at node $n^{AC} \in \mathcal{N}^{AC}$ at time $t \in \mathcal{T}$ (€/rad).

$\lambda^{\mathbf{bal}}_{i,n,t,w}$ Shadow price of water stored in reservoir of hydro unit $w \in \mathcal{W}_{i,n}$ of firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$ at time $t \in \mathcal{T}$ (€/m^3).

$\lambda^{\mathbf{in}}_{i,n,t,w}$ Shadow price of charging rate of hydro unit $w \in \mathcal{W}_{i,n}$ of firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$ at time $t \in \mathcal{T}$ (€/m^3).

$\lambda^{\mathbf{h}}_{i,n,t,w}$ Shadow price of turbine capacity of hydro unit $w \in \mathcal{W}_{i,n}$ of firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$ at time $t \in \mathcal{T}$ (€/MWh).

$\lambda^{\mathbf{ub}}_{i,n,t,w}/\lambda^{\mathbf{lb}}_{i,n,t,w}$ Shadow price of maximum/minimum reservoir capacity of hydro unit $w \in \mathcal{W}_{i,n}$ of firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$ at time $t \in \mathcal{T}$ (€/m^3).

$\overline{\mu}_{j,\ell,t}/\underline{\mu}_{j,\ell,t}$ Shadow price of positive/negative transmission capacity of line $\ell \in \mathcal{L}$ at discrete capacity level $j \in \mathcal{J}_\ell$ at time $t \in \mathcal{T}$ (€/MWh).

$\psi_{\ell,t}$ Shadow price of realised power flow on line $\ell \in \mathcal{L}$ at time $t \in \mathcal{T}$ (€/MW).

Appendix B. Mathematical model

B.1. Upper level: Mathematical formulation for the TSO's problem

$$\begin{aligned}
\underset{x_{j,\ell}}{\text{Maximise}} \sum_{n\in\mathcal{N}}\sum_{t\in\mathcal{T}}\Bigg[&\left(D^{\text{int}}_{n,t}q_{n,t} - \frac{1}{2}D^{\text{slp}}_{n,t}q^2_{n,t}\right) - \sum_{i\in\mathcal{I}}\sum_{u\in\mathcal{U}_{i,n}} C_{i,n,t,u}g_{i,n,t,u}\Bigg] \\
&- \sum_{i\in\mathcal{I}}\sum_{n\in\mathcal{N}}\sum_{u\in\mathcal{U}_{i,n}} C^{\text{ava}}_{i,n,u}a_{i,n,u} - \sum_{i\in\mathcal{I}}\sum_{n\in\mathcal{N}}\sum_{e\in\mathcal{E}_{i,n}} C^{\text{ava}}_{e,i,n}a^e_{i,n} \\
&- \sum_{i\in\mathcal{I}}\sum_{n\in\mathcal{N}}\sum_{w\in\mathcal{W}_{i,n}} C^{\text{ava}}_{i,n,w}a_{i,n,w} \\
&- \sum_{i\in\mathcal{I}}\sum_{n\in\mathcal{N}}\sum_{e\in\mathcal{E}_{i,n}} C^{\text{gen}}_{e,i,n}b^e_{i,n} \\
&- \sum_{i\in\mathcal{I}}\sum_{n\in\mathcal{N}}\sum_{t\in\mathcal{T}}\sum_{u\in\mathcal{U}_{i,n}} SP_{i,n,u}g_{i,n,t,u} - \sum_{\ell\in\mathcal{L}}\sum_{j\in\mathcal{J}_\ell} C^{\text{trn}}_{j,\ell}x_{j,\ell} \qquad \text{(B.1)}
\end{aligned}$$

$$\text{s.t. } x_{j,\ell} \in \{0,1\},\ \forall j \in \mathcal{J}_\ell, \ell \qquad \text{(B.2)}$$

$$\sum_{j\in\mathcal{J}_\ell} x_{j,\ell} = 1,\ \forall \ell \qquad \text{(B.3)}$$

B.2. Lower level: Mathematical formulations for the followers' problems

B.2.1. Mathematical formulation for the ISO

$$\underset{\Gamma^{\text{ISO}}}{\text{Maximise}} \sum_{n\in\mathcal{N}}\sum_{t\in\mathcal{T}}\left(D^{\text{int}}_{n,t}q_{n,t} - \frac{1}{2}D^{\text{slp}}_{n,t}q^2_{n,t}\right) \qquad \text{(B.4)}$$

$$\begin{aligned}
\text{s.t. } q_{n,t} = &\sum_{i\in\mathcal{I}}\sum_{u\in\mathcal{U}_{i,n}} g_{i,n,t,u} + \sum_{i\in\mathcal{I}}\sum_{e\in\mathcal{E}_{i,n}} g^e_{i,n,t} \\
&+ \sum_{i\in\mathcal{I}}\sum_{w\in\mathcal{W}_{i,n}}\left(Q_{i,n,w}r^{\text{out}}_{i,n,t,w} - F_{i,n,w}r^{\text{in}}_{i,n,t,w}\right) \\
&- \sum_{\ell\in\mathcal{L}^+_n} V\,T_t\hat{f}_{\ell,t} + \sum_{\ell\in\mathcal{L}^-_n} V\,T_t\hat{f}_{\ell,t} \ :\ \theta_{n,t}, \forall n,t \qquad \text{(B.5)}
\end{aligned}$$

$$\underline{\mu}_{j,\ell,t}\ :\ -T_t\underline{K}_{j,\ell} \le VT_tf_{j,\ell,t} \le T_t\overline{K}_{j,\ell}\ :\ \overline{\mu}_{j,\ell,t}, \forall j \in \mathcal{J}_\ell, \ell, t \qquad \text{(B.6)}$$

$$\hat{f}_{\ell,t} = \sum_{j\in\mathcal{J}_\ell} f_{j,\ell,t}\ :\ \psi_{\ell,t}, \forall \ell, t \qquad \text{(B.7)}$$

$$\begin{aligned}
T_tf_{j,\ell^{\text{AC}},t} = x_{j,\ell^{\text{AC}}}T_tB_{j,\ell^{\text{AC}}}\left(v_{n^+_\ell,t} - v_{n^-_\ell,t}\right) \\
:\ \eta_{j,\ell^{\text{AC}},t}, \forall j \in \mathcal{J}_\ell, \ell^{\text{AC}} \in \mathcal{L}^{\text{AC}}, t \qquad \text{(B.8)}
\end{aligned}$$

$$\underline{\kappa}_{n^{\text{AC}},t}\ :\ -\pi \le v_{n^{\text{AC}},t} \le \pi\ :\ \overline{\kappa}_{n^{\text{AC}},t}, \forall n^{\text{AC}} \in \mathcal{N}^{\text{AC}}, t \qquad \text{(B.9)}$$

Here, $\Gamma^{\text{ISO}} \equiv \{q_{n,t} \ge 0, \hat{f}_{\ell,t}$ u.r.s., $f_{j,\ell,t}$ u.r.s., $v_{n^{AC},t}$ u.r.s.$\}$ and "u.r.s." refers to "unrestricted in sign." Lower-case Greek letters next to the constraints indicate the associated dual variables. In conducting a welfare-maximising dispatch, the ISO faces a problem that is akin to that of the ISO in Tanaka (2009) or the lower level of Chen et al. (2018). Yet, (B.5) implies that the feasible set of the ISO's problem depends on the firms' decisions, which leads to a generalised Nash equilibrium (GNE) instead of a simple Nash equilibrium at the lower level. Since the ISO in our model is a non-strategic entity that handles the system's "residual" operations, the equilibrium problem in our lower level may be resolved as a Nash equilibrium. Here, we make use of Oggioni et al. (2012)'s argument about shared constraints for resources in which agents are not strategic. They show that such constraints may be excised from the agents' optimisation problems and replaced by equivalent market-clearing conditions with corresponding dual variables. Any decision variables for such agents that appear in the market-clearing conditions are subsequently "priced" in the relevant objective functions. In our case, the energy-balance constraint (B.5) would be removed from the ISO's optimisation problem and posed as a market-clearing condition with dual variable $\theta_{n,t}$. Next, the nodal consumption, $q_{n,t}$, and the net nodal export, $\sum_{\ell\in\mathcal{L}^+_n} V\,T_t\hat{f}_{\ell,t} - \sum_{\ell\in\mathcal{L}^-_n} V\,T_t\hat{f}_{\ell,t}$, would be priced at $\theta_{n,t}$ in the ISO's objective function (B.4).

B.2.2. Mathematical formulation for firm i

$$\begin{aligned}
\underset{\Gamma^{\text{i}}}{\text{Maximise}} \sum_{n\in\mathcal{N}}\sum_{t\in\mathcal{T}}\Bigg[&\left(D^{\text{int}}_{n,t} - D^{\text{slp}}_{n,t}q_{n,t}\right)\Bigg(\sum_{u\in\mathcal{U}_{i,n}} g_{i,n,t,u} + \sum_{e\in\mathcal{E}_{i,n}} g^e_{i,n,t} + \sum_{w\in\mathcal{W}_{i,n}} Q_{i,n,w}r^{\text{out}}_{i,n,t,w} \\
&- \sum_{w\in\mathcal{W}_{i,n}} F_{i,n,w}r^{\text{in}}_{i,n,t,w}\Bigg) - \sum_{u\in\mathcal{U}_{i,n}}\left(C_{i,n,t,u} + HSP_{i,n,u}\right)g_{i,n,t,u}\Bigg] \\
&- \sum_{n\in\mathcal{N}}\sum_{u\in\mathcal{U}_{i,n}} C^{\text{ava}}_{i,n,u}a_{i,n,u} - \sum_{n\in\mathcal{N}}\sum_{e\in\mathcal{E}_{i,n}} C^{\text{ava}}_{e,i,n}a^e_{i,n} - \sum_{n\in\mathcal{N}}\sum_{w\in\mathcal{W}_{i,n}} C^{\text{ava}}_{i,n,w}a_{i,n,w} \\
&- \sum_{n\in\mathcal{N}}\sum_{e\in\mathcal{E}_{i,n}} C^{\text{gen}}_{e,i,n}b^e_{i,n} \qquad \text{(B.10)}
\end{aligned}$$

$$\text{s.t. } g_{i,n,t,u} \le T_ta_{i,n,u}\ :\ \beta_{i,n,t,u}, \forall n,t,u \in \mathcal{U}_{i,n} \qquad \text{(B.11)}$$

$$a_{i,n,u} \le \overline{G}_{i,n,u}\ :\ \beta^{\text{ava}}_{i,n,u}, \forall n, u \in \mathcal{U}_{i,n} \qquad \text{(B.12)}$$

$$\begin{aligned}
\beta^{\text{down}}_{i,n,t,u}\ :\ -T_tR^{\text{down}}_u a_{i,n,u} \le g_{i,n,t,u} - g_{i,n,t-1,u} \le T_tR^{\text{up}}_u a_{i,n,u} \\
:\ \beta^{\text{up}}_{i,n,t,u}, \forall n,t,u \in \mathcal{U}_{i,n} \qquad \text{(B.13)}
\end{aligned}$$

$$g^e_{i,n,t} \le T_tA^e_{n,t}a^e_{i,n}\ :\ \beta^e_{i,n,t}, \forall e \in \mathcal{E}_{i,n}, n, t \qquad \text{(B.14)}$$

$$a^e_{i,n} \le \overline{G}^e_{i,n} + b^e_{i,n}\ :\ \beta^{\text{ava}}_{e,i,n}, \forall e \in \mathcal{E}_{i,n}, n \qquad \text{(B.15)}$$

$$\begin{aligned}
r^{\text{sto}}_{i,n,t,w} = (1 - E^{\text{sto}}_{i,n,w})^{T_t}r^{\text{sto}}_{i,n,t-1,w} + r^{\text{in}}_{i,n,t,w} - r^{\text{out}}_{i,n,t,w} - z_{i,n,t,w} + I_{i,n,t,w}\ :\ \lambda^{\text{bal}}_{i,n,t,w}, \\
\forall n,t,w \in \mathcal{W}_{i,n} \qquad \text{(B.16)}
\end{aligned}$$

$$\lambda^{\text{lb}}_{i,n,t,w}\ :\ \underline{R}_{i,n,w} \le r^{\text{sto}}_{i,n,t,w} \le \overline{R}_{i,n,w}\ :\ \lambda^{\text{ub}}_{i,n,t,w}, \forall n,t,w \in \mathcal{W}_{i,n} \qquad \text{(B.17)}$$

$$r^{\text{in}}_{i,n,t,w} \le T_tR^{\text{in}}_{i,n,w}\overline{R}_{i,n,w}\ :\ \lambda^{\text{in}}_{i,n,t,w}, \forall n,t,w \in \mathcal{W}_{i,n} \qquad \text{(B.18)}$$

$$Q_{i,n,w}r^{\text{out}}_{i,n,t,w} \le T_ta_{i,n,w}\ :\ \lambda^{\text{h}}_{i,n,t,w}, \forall n,t,w \in \mathcal{W}_{i,n} \qquad \text{(B.19)}$$

$$a_{i,n,w} \le \overline{Y}_{i,n,w}\ :\ \beta^{\text{ava}}_{i,n,w}, \forall n, w \in \mathcal{W}_{i,n} \qquad \text{(B.20)}$$

$$\sum_{t\in\mathcal{T}}\sum_{w\in\mathcal{W}_{i,n}}\left(Q_{i,n,w}r^{\text{out}}_{i,n,t,w} - F_{i,n,w}r^{\text{in}}_{i,n,t,w}\right) \ge Z_{i,n}\ :\ \gamma_{i,n}, \forall n \qquad \text{(B.21)}$$

Here, $\Gamma^{\text{i}} \equiv \{a_{i,n,u} \ge 0, a^e_{i,n} \ge 0, a_{i,n,w} \ge 0, b^e_{i,n} \ge 0, g_{i,n,t,u} \ge 0, g^e_{i,n,t} \ge 0, r^{\text{in}}_{i,n,t,w} \ge 0, r^{\text{out}}_{i,n,t,w} \ge 0, r^{\text{sto}}_{i,n,t,w} \ge 0, z_{i,n,t,w} \ge 0\}$. The first term in (B.10) depends on the equilibrium price and net sales of energy, while the next two terms reflect the generation costs of thermal units and the price of CO_2 emission permits, which is distinct from the social cost of damage from CO_2 emissions. The final four terms comprise amortised O&M costs for thermal, VRE, and hydro units along with the capacity-expansion costs for VRE units. Price-taking behaviour in both thermal generation and reservoirs is captured by treating the price in (B.10) as exogenous, which means that Karush–Kuhn–Tucker (KKT) conditions (B.37), (B.41), and (B.42) in Appendix B.2.4 omit all terms related to the marginal revenue such as $D^{\text{slp}}_{n,t}\left(\sum_{u'\in\mathcal{U}_{i,n}} g_{i,n,t,u'} + \sum_{w'\in\mathcal{W}_{i,n}} Q_{i,n,w'}r^{\text{out}}_{i,n,t,w'} - \sum_{w'\in\mathcal{W}_{i,n}} F_{i,n,w'}r^{\text{in}}_{i,n,t,w'}\right)$. In case of Cournot behaviour in both thermal generation and reservoirs, the electricity price in (B.10) is not taken as exogenous by firm $i \in \mathcal{I}$. Instead, the electricity price is explicitly treated as a function of total nodal consumption in the firm's objective function

(B.10) using the energy-balance constraint (B.5) with the understanding that the decision variables of all other agents besides firm $i \in \mathcal{I}$ are taken as given. Thus, KKT conditions (B.37), (B.41), and (B.42) in Appendix B.2.4 are written as indicated, i.e., they include the terms related to the marginal revenue such as $D^{\text{slp}}_{n,t}\Big(\sum_{u' \in \mathcal{U}_{i,n}} g_{i,n,t,u'} + \sum_{w' \in \mathcal{W}_{i,n}} Q_{i,n,w'} r^{\text{out}}_{i,n,t,w'} - \sum_{w' \in \mathcal{W}_{i,n}} F_{i,n,w'} r^{\text{in}}_{i,n,t,w'}\Big)$. Market power exerted only in thermal generation and not by reservoirs is handled by reflecting merely the impact of thermal generation on the price in (B.10) by treating $q_{n,t}$ as a constant when multiplying it by $\sum_{e \in \mathcal{E}_{i,n}} g^e_{i,n,t} + \sum_{w \in \mathcal{W}_{i,n}} Q_{i,n,w} r^{\text{out}}_{i,n,t,w} - \sum_{w \in \mathcal{W}_{i,n}} F_{i,n,w} r^{\text{in}}_{i,n,t,w}$, which means that KKT condition (B.37) omits $D^{\text{slp}}_{n,t}\Big(\sum_{w \in \mathcal{W}_{i,n}} Q_{i,n,w} r^{\text{out}}_{i,n,t,w} - \sum_{w \in \mathcal{W}_{i,n}} F_{i,n,w} r^{\text{in}}_{i,n,t,w}\Big)$ and KKT conditions (B.41)–(B.42) omit $D^{\text{slp}}_{n,t}\Big(\sum_{u \in \mathcal{U}_{i,n}} g_{i,n,t,u} + \sum_{w' \in \mathcal{W}_{i,n}} Q_{i,n,w'} r^{\text{out}}_{i,n,t,w'} - \sum_{w' \in \mathcal{W}_{i,n}} F_{i,n,w'} r^{\text{in}}_{i,n,t,w'}\Big)$. Market power by reservoirs only is handled analogously, i.e., by treating $q_{n,t}$ as a constant when multiplying it by $\sum_{u \in \mathcal{U}_{i,n}} g_{i,n,t,u} + \sum_{e \in \mathcal{E}_{i,n}} g^e_{i,n,t}$, which means that KKT condition (B.37) omits $D^{\text{slp}}_{n,t}\Big(\sum_{u' \in \mathcal{U}_{i,n}} g_{i,n,t,u'} + \sum_{w \in \mathcal{W}_{i,n}} Q_{i,n,w} r^{\text{out}}_{i,n,t,w} - \sum_{w \in \mathcal{W}_{i,n}} F_{i,n,w} r^{\text{in}}_{i,n,t,w}\Big)$ and KKT conditions (B.41)–(B.42) merely omit $D^{\text{slp}}_{n,t} \sum_{u \in \mathcal{U}_{i,n}} g_{i,n,t,u}$. In a similar vein, the equivalent quadratic programming (QP) reformulation in (B.56) of Appendix B.2.5 can capture either perfect competition by discarding the "extended cost" term altogether, perfect competition only in reservoirs by deleting the $\sum_{w \in \mathcal{W}_{i,n}} Q_{i,n,w} r^{\text{out}}_{i,n,t,w} - \sum_{w \in \mathcal{W}_{i,n}} F_{i,n,w} r^{\text{in}}_{i,n,t,w}$ terms from the extended cost, or perfect competition only in thermal generation by dropping the $\sum_{u \in \mathcal{U}_{i,n}} g_{i,n,t,u}$ terms from the extended cost (Ekholm and Virasjoki, 2020).

B.2.3. KKT conditions for the ISO

$$0 \le q_{n,t} \perp -\left(D^{\text{int}}_{n,t} - D^{\text{slp}}_{n,t} q_{n,t}\right) + \theta_{n,t} \ge 0, \forall n,t \tag{B.22}$$

$$\hat{f}_{\ell,t} \text{ u.r.s., } \psi_{\ell,t} + VT_t \theta_{n^+_\ell,t} - VT_t \theta_{n^-_\ell,t} = 0, \forall \ell, t \tag{B.23}$$

$$f_{j,\ell,t} \text{ u.r.s., } T_t \eta_{j,\ell^{\text{AC}},t} + V\, T_t \overline{\mu}_{j,\ell,t} - V\, T_t \underline{\mu}_{j,\ell,t} - \psi_{\ell,t} = 0, \forall j \in \mathcal{J}_\ell, \ell, t \tag{B.24}$$

$$\begin{aligned} v_{n^{\text{AC}},t} \text{ u.r.s., } & -\sum_{\ell \in \mathcal{L}^+_n} \sum_{j \in \mathcal{J}_\ell} x_{j,\ell^{\text{AC}}} T_t B_{j,\ell^{\text{AC}}} \eta_{\ell^{\text{AC}},t} + \sum_{\ell \in \mathcal{L}^-_n} \sum_{j \in \mathcal{J}_\ell} x_{j,\ell^{\text{AC}}} T_t B_{j,\ell^{\text{AC}}} \eta_{\ell^{\text{AC}},t} \\ & + \overline{\kappa}_{n^{\text{AC}},t} - \underline{\kappa}_{n^{\text{AC}},t} = 0, \ \forall n^{\text{AC}} \in \mathcal{N}^{\text{AC}}, t \end{aligned} \tag{B.25}$$

$$\begin{aligned} \theta_{n,t} \text{ u.r.s., } & q_{n,t} - \sum_{i \in \mathcal{I}} \sum_{u \in \mathcal{U}_{i,n}} g_{i,n,t,u} - \sum_{i \in \mathcal{I}} \sum_{e \in \mathcal{E}_{i,n}} g^e_{i,n,t} \\ & - \sum_{i \in \mathcal{I}} \sum_{w \in \mathcal{W}_{i,n}} \left(Q_{i,n,w} r^{\text{out}}_{i,n,t,w} - F_{i,n,w} r^{\text{in}}_{i,n,t,w}\right) \\ & + \sum_{\ell \in \mathcal{L}^+_n} V\, T_t \hat{f}_{\ell,t} - \sum_{\ell \in \mathcal{L}^-_n} V\, T_t \hat{f}_{\ell,t} = 0, \forall n, t \end{aligned} \tag{B.26}$$

$$0 \le \underline{\mu}_{j,\ell,t} \perp T_t \underline{K}_{j,\ell} + VT_t f_{j,\ell,t} \ge 0, \forall j \in \mathcal{J}_\ell, \ell, t \tag{B.27}$$

$$0 \le \overline{\mu}_{j,\ell,t} \perp T_t \overline{K}_{j,\ell} - VT_t f_{j,\ell,t} \ge 0, \forall j \in \mathcal{J}_\ell, \ell, t \tag{B.28}$$

$$\eta_{j,\ell^{\text{AC}},t} \text{ u.r.s., } x_{j,\ell^{\text{AC}}} T_t B_{j,\ell^{\text{AC}}} \left(v_{n^+_\ell,t} - v_{n^+_\ell,t}\right) - T_t f_{j,\ell^{\text{AC}},t} = 0, \forall j \in \mathcal{J}_\ell, \ell^{\text{AC}} \in \mathcal{L}^{\text{AC}}, t \tag{B.29}$$

$$\psi_{\ell,t} \text{ u.r.s., } \hat{f}_{\ell,t} - \sum_{j \in \mathcal{J}_\ell} f_{j,\ell,t} = 0, \forall \ell, t \tag{B.30}$$

$$0 \le \underline{\kappa}_{n^{\text{AC}},t} \perp \pi + v_{n^{\text{AC}},t} \ge 0, \forall n^{\text{AC}} \in \mathcal{N}^{\text{AC}}, t \tag{B.31}$$

$$0 \le \overline{\kappa}_{n^{\text{AC}},t} \perp \pi - v_{n^{\text{AC}},t} \ge 0, \forall n^{\text{AC}} \in \mathcal{N}^{\text{AC}}, t \tag{B.32}$$

The KKT conditions have standard economic interpretations. For example, (B.22) indicates that the marginal utility of electricity consumption is equal to its marginal value of generation if consumption is strictly positive.

B.2.4. KKT conditions for firm i

$$\begin{aligned} 0 \le a_{i,n,u} \perp\ & C^{\text{ava}}_{i,n,u} + \beta^{\text{ava}}_{i,n,u} - \sum_{t \in \mathcal{T}} T_t \beta_{i,n,t,u} - \sum_{t \in \mathcal{T}} T_t R^{\text{up}}_u \beta^{\text{up}}_{i,n,t,u} \\ & - \sum_{t \in \mathcal{T}} T_t R^{\text{down}}_u \beta^{\text{down}}_{i,n,t,u} \ge 0, \ \forall n, u \in \mathcal{U}_{i,n} \end{aligned} \tag{B.33}$$

$$0 \le a^e_{i,n} \perp C^{\text{ava}}_{e,i,n} + \beta^{\text{ava}}_{e,i,n} - \sum_{t \in \mathcal{T}} T_t A^e_{n,t} \beta^e_{i,n,t} \ge 0, \ \forall e \in \mathcal{E}_{i,n}, n \tag{B.34}$$

$$0 \le a_{i,n,w} \perp C^{\text{ava}}_{i,n,w} + \beta^{\text{ava}}_{i,n,w} - \sum_{t \in \mathcal{T}} T_t \lambda^{\text{h}}_{i,n,t,w} \ge 0, \ \forall n, w \in \mathcal{W}_{i,n} \tag{B.35}$$

$$0 \le b^e_{i,n} \perp C^{\text{gen}}_{e,i,n} - \beta^{\text{ava}}_{e,i,n} \ge 0, \ \forall e \in \mathcal{E}_{i,n}, n \tag{B.36}$$

$$\begin{aligned} 0 \le g_{i,n,t,u} \perp\ & \Big[C_{i,n,t,u} + HSP_{i,n,u} - \left(D^{\text{int}}_{n,t} - D^{\text{slp}}_{n,t} q_{n,t}\right) \\ & + D^{\text{slp}}_{n,t}\Big(\sum_{u' \in \mathcal{U}_{i,n}} g_{i,n,t,u'} + \sum_{w \in \mathcal{W}_{i,n}} Q_{i,n,w} r^{\text{out}}_{i,n,t,w} - \sum_{w \in \mathcal{W}_{i,n}} F_{i,n,w} r^{\text{in}}_{i,n,t,w}\Big)\Big] \\ & + \beta_{i,n,t,u} + \beta^{\text{up}}_{i,n,t,u} - \beta^{\text{up}}_{i,n,t+1,u} + \beta^{\text{down}}_{i,n,t+1,u} - \beta^{\text{down}}_{i,n,t,u} \ge 0, \\ & \forall n, t, u \in \mathcal{U}_{i,n} \end{aligned} \tag{B.37}$$

$$0 \le g^e_{i,n,t} \perp -\left(D^{\text{int}}_{n,t} - D^{\text{slp}}_{n,t} q_{n,t}\right) + \beta^e_{i,n,t} \ge 0, \ \forall e \in \mathcal{E}_{i,n}, n, t \tag{B.38}$$

$$0 \le r^{\text{sto}}_{i,n,t,w} \perp \lambda^{\text{bal}}_{i,n,t,w} - (1 - E^{\text{sto}}_{i,n,w})^{T_t} \lambda^{\text{bal}}_{i,n,t+1,w} + \lambda^{\text{ub}}_{i,n,t,w} - \lambda^{\text{lb}}_{i,n,t,w} \ge 0, \forall n, t, w \in \mathcal{W}_{i,n} \tag{B.39}$$

$$0 \le z_{i,n,t,w} \perp \lambda^{\text{bal}}_{i,n,t,w} \ge 0, \forall n, t, w \in \mathcal{W}_{i,n} \tag{B.40}$$

$$\begin{aligned} 0 \le r^{\text{in}}_{i,n,t,w} \perp\ & \Big[F_{i,n,w}\left(D^{\text{int}}_{n,t} - D^{\text{slp}}_{n,t} q_{n,t}\right) \\ & - F_{i,n,w} D^{\text{slp}}_{n,t}\Big(\sum_{u \in \mathcal{U}_{i,n}} g_{i,n,t,u} + \sum_{w' \in \mathcal{W}_{i,n}} Q_{i,n,w'} r^{\text{out}}_{i,n,t,w'} - \sum_{w' \in \mathcal{W}_{i,n}} F_{i,n,w'} r^{\text{in}}_{i,n,t,w'}\Big)\Big] \\ & - \lambda^{\text{bal}}_{i,n,t,w} + \lambda^{\text{in}}_{i,n,t,w} + F_{i,n,w} \gamma_{i,n} \ge 0, \forall n, t, w \in \mathcal{W}_{i,n} \end{aligned} \tag{B.41}$$

$$\begin{aligned} 0 \le r^{\text{out}}_{i,n,t,w} \perp\ & \Big[-Q_{i,n,w}\left(D^{\text{int}}_{n,t} - D^{\text{slp}}_{n,t} q_{n,t}\right) \\ & + Q_{i,n,w} D^{\text{slp}}_{n,t}\Big(\sum_{u \in \mathcal{U}_{i,n}} g_{i,n,t,u} + \sum_{w' \in \mathcal{W}_{i,n}} Q_{i,n,w'} r^{\text{out}}_{i,n,t,w'} - \sum_{w' \in \mathcal{W}_{i,n}} F_{i,n,w'} r^{\text{in}}_{i,n,t,w'}\Big)\Big] \\ & + \lambda^{\text{bal}}_{i,n,t,w} + Q_{i,n,w} \lambda^{\text{h}}_{i,n,t,w} - Q_{i,n,w} \gamma_{i,n} \ge 0, \forall n, t, w \in \mathcal{W}_{i,n} \end{aligned} \tag{B.42}$$

$$\begin{aligned} \lambda^{\text{bal}}_{i,n,t,w} \text{ u.r.s., } & r^{\text{sto}}_{i,n,t,w} - (1 - E^{\text{sto}}_{i,n,w})^{T_t} r^{\text{sto}}_{i,n,t-1,w} \\ & - r^{\text{in}}_{i,n,t,w} + r^{\text{out}}_{i,n,t,w} + z_{i,n,t,w} - I_{i,n,t,w} = 0, \\ & \forall n, t, w \in \mathcal{W}_{i,n} \end{aligned} \tag{B.43}$$

$$0 \le \beta^e_{i,n,t} \perp T_t A^e_{n,t} a^e_{i,n} - g^e_{i,n,t} \ge 0, \forall e \in \mathcal{E}_{i,n}, n, t \tag{B.44}$$

$$0 \le \beta^{\text{ava}}_{e,i,n} \perp \overline{G}^e_{i,n} + b^e_{i,n} - a^e_{i,n} \ge 0, \forall e \in \mathcal{E}_{i,n}, n \tag{B.45}$$

$$0 \le \beta_{i,n,t,u} \perp T_t a_{i,n,u} - g_{i,n,t,u} \ge 0, \forall n, t, u \in \mathcal{U}_{i,n} \tag{B.46}$$

$$0 \le \beta^{\text{ava}}_{i,n,u} \perp \overline{G}_{i,n,u} - a_{i,n,u} \ge 0, \forall n, u \in \mathcal{U}_{i,n} \tag{B.47}$$

$$0 \le \beta^{\text{up}}_{i,n,t,u} \perp T_t R^{\text{up}}_u a_{i,n,u} + g_{i,n,t-1,u} - g_{i,n,t,u} \ge 0, \forall n, t, u \in \mathcal{U}_{i,n} \tag{B.48}$$

$$0 \le \beta^{\text{down}}_{i,n,t,u} \perp T_t R^{\text{down}}_u a_{i,n,u} + g_{i,n,t,u} - g_{i,n,t-1,u} \ge 0, \forall n, t, u \in \mathcal{U}_{i,n} \tag{B.49}$$

$$0 \le \lambda^{\text{in}}_{i,n,t,w} \perp T_t R^{\text{in}}_{i,n,w} \overline{R}_{i,n,w} - r^{\text{in}}_{i,n,t,w} \ge 0, \forall n, t, w \in \mathcal{W}_{i,n} \tag{B.50}$$

$$0 \le \lambda^{\text{h}}_{i,n,t,w} \perp T_t a_{i,n,w} - Q_{i,n,w} r^{\text{out}}_{i,n,t,w} \ge 0, \forall n, t, w \in \mathcal{W}_{i,n} \tag{B.51}$$

$$0 \le \beta^{\text{ava}}_{i,n,w} \perp \overline{Y}_{i,n,w} - a_{i,n,w} \ge 0, \forall n, w \in \mathcal{W}_{i,n} \tag{B.52}$$

$$0 \le \lambda^{\text{ub}}_{i,n,t,w} \perp \overline{R}_{i,n,w} - r^{\text{sto}}_{i,n,t,w} \ge 0, \forall n, t, w \in \mathcal{W}_{i,n} \tag{B.53}$$

$$0 \le \lambda^{\text{lb}}_{i,n,t,w} \perp r^{\text{sto}}_{i,n,t,w} - \underline{R}_{i,n,w} \ge 0, \forall n, t, w \in \mathcal{W}_{i,n} \tag{B.54}$$

$$0 \le \gamma_{i,n} \perp \sum_{t \in \mathcal{T}} \sum_{w \in \mathcal{W}_{i,n}} \left(Q_{i,n,w} r^{\text{out}}_{i,n,t,w} - F_{i,n,w} r^{\text{in}}_{i,n,t,w}\right) - Z_{i,n} \ge 0, \forall n \tag{B.55}$$

Firm $i \in \mathcal{I}$'s KKT conditions also lend themselves to economic interpretations depending on the specification of market power. For example, (B.37) for a price taker, i.e., ignoring the derivative of the extended-cost term, $D^{\mathrm{slp}}_{n,t}$ $(\sum_{u' \in \mathcal{U}_{i,n}} g_{i,n,t,u'} + \sum_{w \in \mathcal{W}_{i,n}} Q_{i,n,w} r^{\mathrm{out}}_{i,n,t,w} - \sum_{w \in \mathcal{W}_{i,n}} F_{i,n,w} r^{\mathrm{in}}_{i,n,t,w})$, states that if thermal generation is strictly positive, then the price of electricity equals the marginal cost of generation plus the cost of CO_2 permits plus any capacity rents. By contrast, the marginal cost of generation plus the cost of CO_2 permits plus any capacity rents exceeds the electricity price (again ignoring the derivative of the extended-cost term) if thermal generation is zero. In case of a Cournot firm, (B.37) states that the marginal cost of generation plus the cost of CO_2 permits plus any capacity rents exceeds the marginal revenue if thermal generation is zero. Here, the marginal revenue refers to the electricity price minus the derivative of the extended-cost term that internalises the price impact of an infinitesimal increase in thermal output.

B.2.5. Equilibrium problem and single equivalent optimisation problem

Since each optimisation problem, (B.4)–(B.9) and (B.10)–(B.21), $\forall i \in \mathcal{I}$, is convex, it may be replaced by its KKT conditions to render a mixed-complementarity problem (MCP), (B.22)–(B.32) and (B.33)–(B.55), $\forall i \in \mathcal{I}$, which can be recast as a single optimisation problem. This transformation is possible because the inverse-demand curves are linear and transport costs are proportional to distance (Hashimoto, 1985). The resulting QP problem maximises a quadratic objective function (B.56) and incorporates Cournot behaviour via extended costs, $-\sum_{n \in \mathcal{N}} \sum_{t \in \mathcal{T}} \sum_{i \in \mathcal{I}} \frac{D^{\mathrm{slp}}_{n,t}}{2} \left(\sum_{u \in \mathcal{U}_{i,n}} g_{i,n,t,u} + \sum_{w \in \mathcal{W}_{i,n}} \left(Q_{i,n,w} r^{\mathrm{out}}_{i,n,t,w} - F_{i,n,w} r^{\mathrm{in}}_{i,n,t,w}\right)\right)^2$. Perfect competition is rendered by excluding the extended-cost term. Market power in thermal generation only is modelled by dropping the hydro-related terms, $\sum_{w \in \mathcal{W}_{i,n}} \left(Q_{i,n,w} r^{\mathrm{out}}_{i,n,t,w} - F_{i,n,w} r^{\mathrm{in}}_{i,n,t,w}\right)$. Similarly, market power in hydro reservoirs only is captured by deleting the thermal-related term, $\sum_{u \in \mathcal{U}_{i,n}} g_{i,n,t,u}$. The QP's constraints are those from the underlying optimisation problems, (B.5)–(B.9) and (B.11)–(B.21), $\forall i \in \mathcal{I}$.

$$
\begin{aligned}
\underset{\Omega^{\mathrm{LL}}}{\text{Maximise}} \ & \sum_{n \in \mathcal{N}} \sum_{t \in \mathcal{T}} \Bigg[\left(D^{\mathrm{int}}_{n,t} q_{n,t} - \frac{1}{2} D^{\mathrm{slp}}_{n,t} q^2_{n,t} \right) \\
& - \sum_{i \in \mathcal{I}} \Bigg\{ \frac{D^{\mathrm{slp}}_{n,t}}{2} \left(\sum_{u \in \mathcal{U}_{i,n}} g_{i,n,t,u} + \sum_{w \in \mathcal{W}_{i,n}} \left(Q_{i,n,w} r^{\mathrm{out}}_{i,n,t,w} - F_{i,n,w} r^{\mathrm{in}}_{i,n,t,w} \right) \right)^2 \\
& + \sum_{u \in \mathcal{U}_{i,n}} \left(C_{i,n,t,u} + HSP_{i,n,u} \right) g_{i,n,t,u} \Bigg\} \Bigg] \\
& - \sum_{i \in \mathcal{I}} \sum_{n \in \mathcal{N}} \sum_{u \in \mathcal{U}_{i,n}} C^{\mathrm{ava}}_{i,n,u} a_{i,n,u} - \sum_{i \in \mathcal{I}} \sum_{n \in \mathcal{N}} \sum_{e \in \mathcal{E}_{i,n}} C^{\mathrm{ava}}_{e,i,n} a^e_{i,n} \\
& - \sum_{i \in \mathcal{I}} \sum_{n \in \mathcal{N}} \sum_{w \in \mathcal{W}_{i,n}} C^{\mathrm{ava}}_{i,n,w} a_{i,n,w} \\
& - \sum_{i \in \mathcal{I}} \sum_{n \in \mathcal{N}} \sum_{e \in \mathcal{E}_{i,n}} C^{\mathrm{gen}}_{e,i,n} b^e_{i,n} \qquad \text{(B.56)} \\
\text{s.t.} \ & \text{(B.5)–(B.9)} \\
& \text{(B.11)–(B.21)}, \ \forall i \in \mathcal{I}
\end{aligned}
$$

where Ω^{LL} comprises the ISO's decisions, Γ^{ISO}, and all of the firms' decisions, Γ^{i}, $\forall i \in \mathcal{I}$.[32]

B.3. Solution approach for Bi-level problem

The bi-level problem is:

$$
\begin{aligned}
\underset{\{x_{j,\ell}\} \cup \Omega^{\mathrm{LL}}}{\text{Maximise}} \quad & \text{(B.1)} \\
\text{s.t.} \quad & \text{(B.2)–(B.3)} \\
& \underset{\Omega^{\mathrm{LL}}}{\text{Maximise}} \quad \text{(B.56)} \\
& \text{s.t.} \quad \text{(B.5)–(B.9)} \\
& \qquad \text{(B.11)–(B.21)}, \ \forall i \in \mathcal{I}
\end{aligned}
$$

A standard solution approach for the bi-level problem is to replace the lower-level problem by its KKT conditions to obtain a mathematical program with equilibrium constraints (MPEC). Using disjunctive constraints, the complementarity conditions among the KKT conditions may be linearised to convert the MPEC into a mixed-integer quadratic program (MIQP). Alternatively, the lower level may be replaced instead by its primal constraints, dual constraints, and strong-duality expression to lead to a mathematical program with primal and dual constraints (MPPDC), which could be reformulated as a mixed-integer quadratically constrained quadratic program (MIQCQP). In either case, the problem instances do not scale well, e.g., due to the large number of binary variables or tuning of big-M parameters (Pineda and Morales, 2019). Thus, standard solvers like CPLEX and Gurobi are limited in tackling realistic problem instances. For these reasons, we resort to enumeration (Virasjoki et al., 2020; Belyak et al., 2024) by solving the lower-level problem in Appendix B.2.5 for all possible combinations of transmission investments. In effect, the variables $x_{j,\ell}$ are fixed in the lower-level QP, which means solving a maximum of $|\mathcal{J}|^{|\mathcal{L}|}$ problem instances in order to obtain the optimal solution.

[32] Social welfare (SW) differs from (B.56) because it equals the sum of consumer surplus (CS), producer surplus (PS), merchandising surplus (MS), and government revenue (GR) minus the social cost of damage from CO_2 emissions (DC) and the cost of transmission expansion (TC), where:

• $CS = \sum_{n \in \mathcal{N}} \sum_{t \in \mathcal{T}} \left(D^{\mathrm{int}}_{n,t} q_{n,t} - \frac{1}{2} D^{\mathrm{slp}}_{n,t} q^2_{n,t} \right) - \sum_{n \in \mathcal{N}} \sum_{t \in \mathcal{T}} \theta_{n,t} q_{n,t}$, i.e., gross consumer surplus minus the cost of electricity purchases.

• $PS = \sum_{i \in \mathcal{I}} \sum_{n \in \mathcal{N}} \sum_{t \in \mathcal{T}} \theta_{n,t} \Big(\sum_{u \in \mathcal{U}_{i,n}} g_{i,n,t,u} + \sum_{e \in \mathcal{E}_{i,n}} g^e_{i,n,t} + \sum_{w \in \mathcal{W}_{i,n}} \left(Q_{i,n,w} r^{\mathrm{out}}_{i,n,t,w} - F_{i,n,w} r^{\mathrm{in}}_{i,n,t,w} \right) \Big) - \sum_{i \in \mathcal{I}} \sum_{n \in \mathcal{N}} \sum_{t \in \mathcal{T}} \sum_{u \in \mathcal{U}_{i,n}} \left(C_{i,n,t,u} + HSP_{i,n,u} \right) g_{i,n,t,u} - \sum_{i \in \mathcal{I}} \sum_{n \in \mathcal{N}} \sum_{u \in \mathcal{U}_{i,n}} C^{\mathrm{ava}}_{i,n,u} a_{i,n,u} - \sum_{i \in \mathcal{I}} \sum_{n \in \mathcal{N}} \sum_{e \in \mathcal{E}_{i,n}} C^{\mathrm{ava}}_{e,i,n} a^e_{i,n} - \sum_{i \in \mathcal{I}} \sum_{n \in \mathcal{N}} \sum_{w \in \mathcal{W}_{i,n}} C^{\mathrm{ava}}_{i,n,w} a_{i,n,w} - \sum_{i \in \mathcal{I}} \sum_{n \in \mathcal{N}} \sum_{e \in \mathcal{E}_{i,n}} C^{\mathrm{gen}}_{e,i,n} b^e_{i,n}$, i.e., revenues from electricity sales minus the costs of generation, CO_2 permits, capacity O&M, and capacity expansion.

• $MS = \sum_{n \in \mathcal{N}} \sum_{t \in \mathcal{T}} \theta_{n,t} \left(\sum_{\ell \in \mathcal{L}^-_n} VT_t \hat{f}_{\ell,t} - \sum_{\ell \in \mathcal{L}^+_n} VT_t \hat{f}_{\ell,t} \right)$, i.e., the revenues from net imports at each node.

• $GR = \sum_{i \in \mathcal{I}} \sum_{n \in \mathcal{N}} \sum_{t \in \mathcal{T}} \sum_{u \in \mathcal{U}_{i,n}} HSP_{i,n,u} g_{i,n,t,u}$, i.e., the CO_2 permit price multiplied by nodal CO_2 emissions.

• $DC = \sum_{i \in \mathcal{I}} \sum_{n \in \mathcal{N}} \sum_{t \in \mathcal{T}} \sum_{u \in \mathcal{U}_{i,n}} SP_{i,n,u} g_{i,n,t,u}$, i.e., the social cost of damage from CO_2 emissions multiplied by nodal CO_2 emissions.

• $TC = \sum_{j \in \mathcal{J}_\ell} \sum_{\ell \in \mathcal{L}} C^{\mathrm{trn}}_{j,\ell} x_{j,\ell}$. The payment term in CS plus the revenue term in PS plus MS equal zero via energy balance (B.5), and the cost of CO_2 permits in PS cancels with GR. Thus, $SW = \sum_{n \in \mathcal{N}} \sum_{t \in \mathcal{T}} \left(D^{\mathrm{int}}_{n,t} q_{n,t} - \frac{1}{2} D^{\mathrm{slp}}_{n,t} q^2_{n,t} \right) - \sum_{i \in \mathcal{I}} \sum_{n \in \mathcal{N}} \sum_{t \in \mathcal{T}} \sum_{u \in \mathcal{U}_{i,n}} C_{i,n,t,u} g_{i,n,t,u} - \sum_{i \in \mathcal{I}} \sum_{n \in \mathcal{N}} \sum_{u \in \mathcal{U}_{i,n}} C^{\mathrm{ava}}_{i,n,u} a_{i,n,u} - \sum_{i \in \mathcal{I}} \sum_{n \in \mathcal{N}} \sum_{e \in \mathcal{E}_{i,n}} C^{\mathrm{ava}}_{e,i,n} a^e_{i,n} - \sum_{i \in \mathcal{I}} \sum_{n \in \mathcal{N}} \sum_{w \in \mathcal{W}_{i,n}} C^{\mathrm{ava}}_{i,n,w} a_{i,n,w} - \sum_{i \in \mathcal{I}} \sum_{n \in \mathcal{N}} \sum_{e \in \mathcal{E}_{i,n}} C^{\mathrm{gen}}_{e,i,n} b^e_{i,n} - \sum_{i \in \mathcal{I}} \sum_{n \in \mathcal{N}} \sum_{t \in \mathcal{T}} \sum_{u \in \mathcal{U}_{i,n}} SP_{i,n,u} g_{i,n,t,u} - \sum_{j \in \mathcal{J}_\ell} \sum_{\ell \in \mathcal{L}} C^{\mathrm{trn}}_{j,\ell} x_{j,\ell}$. In case of exogenous net imports to the Nordic region, $X_{n,t}$ (in MWh), we modify the numerical implementation as follows:

• In nodal energy balance (B.5), subtract $X_{n,t}$ from $q_{n,t}$.

• Calculate the cost of exogenous net imports to the Nordic region, $IC = \sum_{n \in \mathcal{N}} \sum_{t \in \mathcal{T}} \theta_{n,t} X_{n,t}$.

• Subtract IC, TC, and DC from the sum of CS, PS, MS, and GR to yield $SW = \sum_{n \in \mathcal{N}} \sum_{t \in \mathcal{T}} \left(D^{\mathrm{int}}_{n,t} q_{n,t} - \frac{1}{2} D^{\mathrm{slp}}_{n,t} q^2_{n,t} \right) - \sum_{i \in \mathcal{I}} \sum_{n \in \mathcal{N}} \sum_{t \in \mathcal{T}} \sum_{u \in \mathcal{U}_{i,n}} C_{i,n,t,u} g_{i,n,t,u} - \sum_{i \in \mathcal{I}} \sum_{n \in \mathcal{N}} \sum_{u \in \mathcal{U}_{i,n}} C^{\mathrm{ava}}_{i,n,u} a_{i,n,u} - \sum_{i \in \mathcal{I}} \sum_{n \in \mathcal{N}} \sum_{e \in \mathcal{E}_{i,n}} C^{\mathrm{ava}}_{e,i,n} a^e_{i,n} - \sum_{i \in \mathcal{I}} \sum_{n \in \mathcal{N}} \sum_{w \in \mathcal{W}_{i,n}} C^{\mathrm{ava}}_{i,n,w} a_{i,n,w} - \sum_{i \in \mathcal{I}} \sum_{n \in \mathcal{N}} \sum_{e \in \mathcal{E}_{i,n}} C^{\mathrm{gen}}_{e,i,n} b^e_{i,n} - \sum_{i \in \mathcal{I}} \sum_{n \in \mathcal{N}} \sum_{t \in \mathcal{T}} \sum_{u \in \mathcal{U}_{i,n}} SP_{i,n,u} g_{i,n,t,u} - \sum_{j \in \mathcal{J}_\ell} \sum_{\ell \in \mathcal{L}} C^{\mathrm{trn}}_{j,\ell} x_{j,\ell} - \sum_{n \in \mathcal{N}} \sum_{t \in \mathcal{T}} \theta_{n,t} X_{n,t}$.

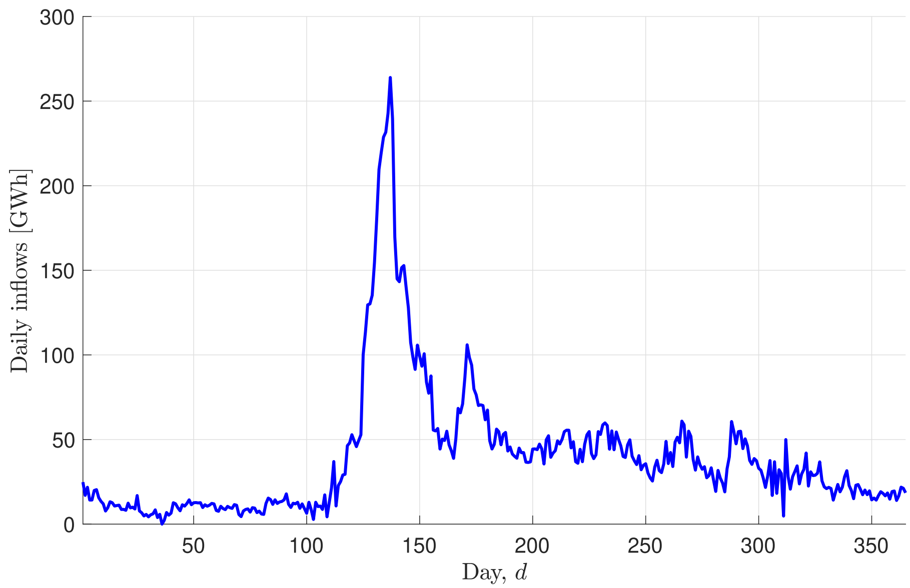


Fig. C.1. Daily Estimated Hydro Inflows to Firm $i1$'s Strategic Reservoir at $SE1$ (in GWh).

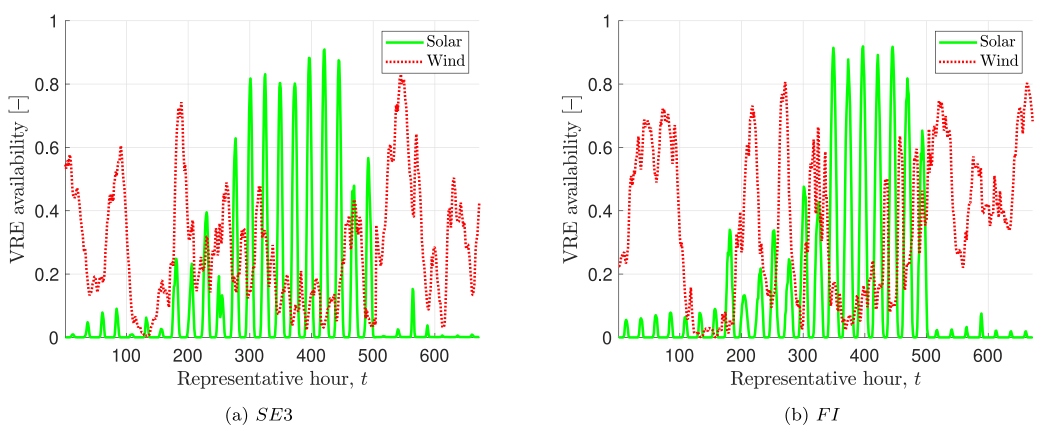


Fig. C.2. VRE Availability in Representative Weeks (–).

Table C.1
Thermal Generation Costs (in €/MWh), Emission Rates (in t/MWh), and Ramp Rates (–).

Unit	$C_{i,n,t,u}$	$P_{i,n,u}$	R_u^{up}
Coal $u1$	32	0.83	0.2
Gas $u2$	65	0.50	0.5
CCGT $u3$	48	0.37	0.5
Oil $u4$	67	0.72	0.7
Biomass $u5$	59	0.00	0.2
Nuclear $u6$	21	0.00	0.1
Peat $u7$	22	1.09	0.1
Waste $u8$	22	0.94	0.1
CHP Coal $u9$	37	0.83	0.1
CHP Waste $u10$	22	0.94	0.1
CHP Gas $u11$	57	0.50	0.1
CHP Oil $u12$	33	0.72	0.1
CHP Peat $u13$	22	1.09	0.1
CHP Biomass $u14$	27	0.00	0.1

Table C.2
Firms' Installed Capacities by Node and Unit (in GW).

Nodes	Firm	$u1$	$u2$	$u3$	$u4$	$u5$	$u6$	$u7$	$u8$	$u9$	$u10$	$u11$	$u12$	$u13$	$u14$	Wind	Solar	Hydro
$SE1-SE4$	$i1$	–	–	–	–	–	4.9	–	–	–	0.1	–	–	–	0.1	0.3	–	7.5
	$i2$	–	–	–	–	–	0.7	–	–	–	–	–	–	–	0.1	0.2	–	–
	$i3$	–	–	–	–	–	0.8	–	–	–	–	–	–	–	–	–	–	–
	$i4$	–	–	–	–	–	1.4	–	–	–	0.1	–	–	0.2	0.1	0.1	–	3.5
	$i10$	–	–	–	–	–	–	–	–	–	–	–	–	–	–	0.1	–	1.1
	$i16$	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	2.2
	$i17$	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	0.5
	$i18$	–	0.4	–	1.8	–	–	–	–	–	–	–	–	–	0.1	5.6	0.2	1.6
FI	$i4$	0.3	–	–	–	–	1.5	–	–	0.1	–	0.3	–	–	0.1	–	–	1.5
	$i6$	0.3	–	–	–	–	1.0	–	–	–	–	–	–	–	0.4	–	–	0.4
	$i7$	–	–	–	0.1	–	–	–	–	0.2	–	0.7	–	0.2	–	–	–	–
	$i8$	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	0.4
	$i19$	–	–	–	1.2	–	0.3	–	–	0.7	0.2	0.9	0.1	2.1	–	1.9	0.2	0.7
$DK1-DK2$	$i1$	0.4	–	–	–	–	–	–	–	–	–	–	–	–	–	0.8	–	–
	$i9$	1.4	0.7	1.2	–	0.1	–	–	–	–	–	0.3	–	–	1.6	0.4	–	–
	$i20$	0.4	–	0.3	–	–	–	–	–	–	–	–	–	–	–	4.4	0.9	–
$NO1-NO5$	$i2$	–	0.2	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	$i4$	–	–	–	–	–	–	–	–	–	–	–	–	–	–	0.1	–	–
	$i10$	–	–	–	–	–	–	–	–	–	–	–	–	–	–	0.2	–	9.5
	$i11$	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	2.3
	$i12$	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	3.9
	$i13$	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	2.0
	$i14$	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1.8
	$i15$	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	4.4
	$i21$	–	0.8	0.1	–	–	–	–	0.1	–	–	–	–	–	–	1.7	0.1	12.4

Table C.3
Firms' Estimated Hydro Reservoir Volumes by Node and Type (in GWh).

Nodes	Firm	SRS	NRS	NPH	SPH
$SE1-SE4$	$i1$	12 210	4668		
	$i4$		5952		
	$i10$		2533		
	$i16$		4105		
	$i17$		1626		
	$i18$		2457		
FI	$i6$		1268		
	$i8$		4262		
$NO1-NO5$	$i10$	17 707	15 508	2823	
	$i11$	99	5406		
	$i12$		4328	681	
	$i13$	276	4506	95	
	$i14$	2016	1331		130
	$i15$	4646	4746		421
	$i21$		26 234	701	

Appendix C. Supplementary data

See Figs. C.1 and C.2, Tables C.1–C.3.

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