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ORIGINAL PAPER

Flexible supply meets flexible demand: prosumer impact on strategic hydro operations

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Abstract

Ambitious climate packages promote the integration of variable renewable energy (VRE) and electrification of the economy. For the power sector, such a transformation means the emergence of so-called prosumers, i.e., agents that both consume and produce electricity. Due to their inflexible VRE output and flexible demand, prosumers will potentially add endogenous net sales with seasonal patterns to the power system. With its vast hydro reservoirs and ample transmission capacity, the Nordic region is seemingly well positioned to cope with such intermittent VRE output. However, the increased requirement for flexibility may be leveraged by incumbent producers to manipulate prices. Via a Nash-Cournot model with a representation of the Nordic region's spatio-temporal features and reservoir volumes, we examine how hydro producers' ability to manipulate electricity prices through temporal arbitrage is affected by (i) VRE-enabled prosumers and (ii) the latter plus a high CO_2 price. We find that hydro reservoirs could exploit prosumers' patterns of net sales to conduct temporal arbitrage more effectively, viz., by targeting periods in which prosumers are net buyers (net sellers) to withhold (to "dump") water. Meanwhile, a higher CO_2 price would further enhance hydro reservoirs' market power because flexible price-taking thermal plants would be unable to ramp up production in order to counter such producers' strategy to target VRE's intermittency. Hence, in spite of a flexible demand side to complement additional intermittent VRE output, strategic hydro producers may still exacerbate price manipulation in a future power sector via more tailored exercise of market power.

Keywords Game theory · Market power · Hydropower · Prosumer · Variable renewable energy

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JEL Classification C7 · D4 · D6 · L1 · L94 · Q4

1 Introduction

1.1 Background

Climate packages call for both steep reductions in power-sector CO_2 emissions and electrification of the wider economy. For example, the Nordic countries have committed to carbon neutrality[1] with stringent measures in line with the European Union (EU) target to cut CO_2 emissions by at least 55% by 2030 compared to 1990 levels.[2] Underpinning this transformation will be substantial investment in variable renewable energy (VRE), such as wind and solar power.

Given its intermittent output, VRE requires flexible resources, e.g., storage and demand response, to integrate it into the power system. From this perspective, the Nordic region appears well positioned to absorb substantial VRE capacity due to its hydro reservoirs and transmission links (Amundsen and Bergman 2006). Yet, the additional need for flexibility and the advent of VRE-enabled prosumers, i.e., entities that both produce and consume electricity (Ramyar et al. 2020; Wu and Conejo 2022), could impact hydro producers' potential leverage to exert market power. Here, we examine how Nordic hydro producers' ability to manipulate electricity prices via temporal arbitrage (Bushnell 2003; Tangerås and Mauritzen 2018) would be affected by (i) VRE-enabled prosumers and (ii) the latter plus a high CO_2 price. This analysis has policy implications for not only other hydro-dependent jurisdictions, e.g., Québec (Debia et al. 2021), but also generic storage operations, e.g., in Germany (Schill and Kemfert 2011), the U.K. (Williams and Green 2022), and Western Europe (Ekholm and Virasjoki 2020), which are likely to figure prominently in VRE-dependent power systems.

1.2 Literature review

In deregulated electricity industries, the potential for market power by strategic producers is well known (Wilson 2002). Power companies with substantial market shares can manipulate electricity prices to their advantage through their investment and operational decisions. While market monitoring and regulators endeavour to mitigate the potential for price manipulation, e.g., via generation withholding (Tanaka 2009), there are still subtle channels that firms exploit to exert market power, especially via storage (Sioshansi 2010, 2014).

One such conduit is hydro reservoirs. As shown analytically (Crampes and Moreaux 2001), a hydro producer with market power could manipulate prices by moving water from peak periods to off-peak ones. In doing so, its additional benefit from higher prices during peak periods would outweigh any forgone revenue due to lower off-peak prices. More important, total hydro production over the entire time

[1] https://www.norden.org/en/declaration/declaration-nordic-carbon-neutrality.

[2] https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:52020PC0563.

horizon would be unchanged, which could make it challenging for market inspectors to detect such manipulation. This phenomenon was demonstrated in a case study of the California hydro-thermal power system (Bushnell 2003). Expanding the framework to consider transmission constraints and carbon policy, an analysis of the New York-Québec interconnection revealed potential for such temporal arbitrage by a large hydro producer (Debia et al. 2021). Furthermore, an attempt to regulate not only the net-hydro production but also the net imports to prevent a hydro producer from "dumping" its output in another zone would actually facilitate spatial arbitrage by firms with pumped-hydro storage facilities.

In fact, even the Nordic region is not immune from such market power since hydro producers may take advantage of the increased requirement for flexibility stemming from additional VRE output. Empirical studies using data from 2011–2013 have revealed the potential for strategic behaviour by hydro producers (Tangerås and Mauritzen 2018), thermal producers via unit failures (Fogelberg and Lazarczyk 2019), and generic Cournot behaviour (Lundin and Tangerås 2020). Taking a computational Nash-Cournot approach, Hassanzadeh Moghimi et al. (2023) use 2018 Nord Pool data to demonstrate the potential for Bushnell (2003)-like behaviour by large hydro producers, viz., to increase (decrease) prices by allocating less (more) water in peak (off-peak) periods. They further investigate how structural changes to the supply side and a high CO_2 price as part of a plausible 2030 climate package could affect such incentives for temporal arbitrage. In effect, they exogenously (i) double the installed 2018 VRE capacities in the existing firms' portfolios and (ii) increase the CO_2 price to €100/t from its 2018 level of €15/t. Consequently, a large strategic hydro producer could increase its operating profit by 11.9% from behaving à la Cournot as opposed to merely 1.99% via a similar strategy in 2018. This result is due to the fact that the climate package increases intermittent output, lowers prices, and renders fossil-fuelled plants unviable. Hence, strategic hydro reservoirs face lower opportunity costs and fewer countervailing manoeuvres from other flexible plants when conducting temporal arbitrage.

At the same time, climate packages envisage that flexibility from the demand side may be bolstered due to aggregators that can marshal the consumption patterns of plug-in electric vehicles (PEVs) (Momber et al. 2015) and building occupants (Ottesen et al. 2016). While such studies assume stochastic but exogenous prices, recent work in this strand of the literature has explored the impact of strategic behaviour by aggregators. For example, Momber et al. (2016) use a bi-level model in which a PEV aggregator at the upper level anticipates lower-level market clearing when setting retail prices. Likewise, Ruhi et al. (2018) examine a strategic aggregator's incentive as a leader to manipulate electricity prices by "spilling" output from a portfolio of distributed energy resources (DER). In a similar vein, Siddiqui and Siddiqui (2022) analyse strategic DER investment by a prosumer that acts as a Stackelberg leader to boost electricity prices via its installed capacity.

In order to investigate a prosumer's behaviour in a standard transmission-constrained oligopoly (Hobbs 2001), Ramyar et al. (2020) introduce a prosumer with both intermittent DER and a backup generator. Besides these generation sources, the prosumer has a gross-benefit function that values its own consumption. Since the other entities in the model, viz., conventional consumers and producers, are all price takers, there is no advantage to the prosumer from exerting market power. Intuitively, the response by price-taking consumers and producers subverts any strategic behaviour by the prosumer as illustrated in a 24-node test network. An extension to this framework treats the prosumer as a Stackelberg leader instead of a Cournot player (Ramyar and Chen 2020). Once the prosumer is able to anticipate the decisions of the followers, it benefits from behaving as a Stackelberg leader rather than as a price taker or a Cournot agent. Thus, the extant literature on prosumers either (i) ignores market power altogether by focusing on decision making under uncertain exogenous prices or (ii) treats them as price makers. Between these polar opposites, a a more nuanced possibility is overlooked in the literature, viz., the ability of incumbent producers to exploit intermittent net sales by prosumers.

1.3 Research objectives and contribution

While strategic behaviour by incumbent producers in the power market has been extensively studied, only recently has the effect of prosumers on the wholesale market drawn some attention. However, their role in and impact on a (hydro) storage-dependent power system that is subject to a CO_2 price is relatively less explored. Given this research gap, we contribute to advancing the understanding of how prosumer behaviour in a hydro-rich power system with vast reservoirs drives market outcomes. In effect, as a complement to Hassanzadeh Moghimi et al. (2023)'s investigation of structural changes to the supply side, we probe how changes to the demand side through the electrification of the wider economy and the introduction of prosumers affect the incumbent producers' incentives to exert market power by tackling the following research questions (RQs):

Research Question RQ 1 What will be the impact of the advent of prosumers with high VRE capacity and flexible consumption on the potential for the exercise of market power by both hydro and thermal producers?

Research Question RQ 2 How will future carbon policy comprising a high CO_2 price affect the potential for the exercise of market power by both hydro and thermal producers in the presence of prosumers?

In addressing RQ 1, we find that generating firms' leverage from withholding nuclear capacity in order to push up power prices is mitigated in the presence of VRE-enabled aggregators who pool prosumers' offers and predominantly switch to being net sellers. By contrast, the ability of hydro reservoirs to exercise market power by reallocating water from peak to off-peak periods is enhanced in the presence of prosumers by exploiting intermittencies in their net sales. As for RQ 2, a high CO_2 price augments hydro reservoirs' leverage as flexible price-taking plants, i.e., gas-fired ones, are less able to respond to such temporal arbitrage. Similarly, strategic nuclear plants benefit by withholding output so that fossil-fuelled plants set the market-clearing price. Hence, even in a well-functioning power sector such as the Nordic one, flexible demand and carbon policy may be exploited by incumbent flexible producers, which has consequences for (hydro) storage operations in other power systems.

On the methodological side, our approach of representing chronological loads and VRE output based on a clustering analysis also effectively downscales the problem instances to facilitate computationally efficient solutions while maintaining the chronology of load, hydro inflows, and VRE output. Moreover, separating prosumers' gross benefit from conventional consumers' demand in the wholesale market enables the interaction between prosumers and the main grid to be modelled through the shift of residual supply curves.

The rest of this paper is organised as follows. Section 2 formulates the mathematical models, provides Karush-Kuhn-Tucker (KKT) conditions for each agent's problem, and reformulates the mixed-complementarity problem (MCP) as a single-agent optimisation problem. A numerical case study is presented in Sect. 3 with concluding remarks provided in Sect. 4. Appendix A contains supplementary data.

2 Methodology

2.1 Nomenclature

Primal Variables

$e \in \mathcal{E}$: Variable renewable energy (VRE) sources.

$i \in \mathcal{I}$: Firms (conventional producers).

$j \in \mathcal{J}$: Aggregators.

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

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

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

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

$n^{\mathrm{AC}} \in \mathcal{N}^{\mathrm{AC}} \subset \mathcal{N}$: AC 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 units of firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$.

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

Parameters

$B_{\ell^{AC}}$: Susceptance of transmission line $\ell^{AC} \in \mathcal{L}^{AC}$ (S).

$C_{i,n,t,u}$: Generation cost of 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).

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

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

$D^{\text{int,agg}}_{j,n,t}$: Intercept of marginal utility of aggregator $j \in \mathcal{J}$ at node $n \in \mathcal{N}$ at time $t \in \mathcal{T}$ (€/MWh).

$D^{\text{slp,agg}}_{j,n,t}$: Slope of marginal utility of aggregator $j \in \mathcal{J}$ at node $n \in \mathcal{N}$ at time $t \in \mathcal{T}$ (€/MWh^2).

$E^{\text{sto}}_{i,n,w}$: 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 unit $u \in \mathcal{U}_{i,n}$ of firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$ (MW).

$G^{e}_{i,n,t}$: Exogenous output of VRE $e \in \mathcal{E}$ belonging to firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$ at time $t \in \mathcal{T}$ (MWh).

$G^{e,\text{agg}}_{j,n,t}$: Exogenous output of VRE $e \in \mathcal{E}$ of aggregator $j \in \mathcal{J}$ at node $n \in \mathcal{N}$ at time $t \in \mathcal{T}$ (MWh).

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

$\overline{K}_{\ell}/\underline{K}_{\ell}$: Capacity of the transmission line $\ell \in \mathcal{L}$ in positive/negative direction (MW).

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

$Q_{i,n,w}$: Production 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 storage capacity of hydro unit $w \in \mathcal{W}_{i,n}$ of firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$ (m^3).

$R^{\text{in}}_{i,n,w}$: Maximum charging 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).

$R^{\text{up}}_{u}/R^{\text{down}}_{u}$: Ramp-up/-down limit for unit $u \in \mathcal{U}_{i,n}$ (–).

S: Price of CO_2 emission permits (€/t).

T_t: Duration of period t (h).

V: Scaling factor for power flow (–).

$Y_{i,n,w}$: 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 for firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$ (MWh).

Primal variables

$f_{\ell,t}$: Power flow on line $\ell \in \mathcal{L}$ at time $t \in \mathcal{T}$ (MW).

$g_{i,n,t,u}$: Generation by 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).

$q_{n,t}$: Consumers' quantity demanded at node $n \in \mathcal{N}$ at time $t \in \mathcal{T}$ (MWh).

$q^{\text{agg}}_{j,n,t}$: Aggregator $j \in \mathcal{J}$'s quantity demanded at node $n \in \mathcal{N}$ at time $t \in \mathcal{T}$ (MWh).
$r^{\text{in}}_{i,n,t,w}$: 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).
$r^{\text{sto}}_{i,n,t,w}$: 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).
$v_{n^{AC},t}$: Voltage angle of node $n^{AC} \in \mathcal{N}^{AC}$ at time $t \in \mathcal{T}$ (rad).
$y_{i,n,t,w}$: 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).
$z_{i,n,t,w}$: Water spilled 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

$\beta_{i,n,t,u}$: Shadow price of generation capacity of thermal unit $u \in \mathcal{U}_{i,n}$ belonging to firm $i \in \mathcal{I}$ at node $n \in \mathcal{N}$ at time $t \in \mathcal{T}$ (€/MWh).
$\beta^{\text{up}}_{i,n,t,u}/\beta^{\text{down}}_{i,n,t,u}$: Shadow price of ramp-up/-down limit 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).
$\eta_{\ell^{AC},t}$: Shadow price of energy flow on AC line $\ell^{AC} \in \mathcal{L}^{AC}$ 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).
$\lambda^{\text{bal}}_{i,n,t,w}$: Shadow price 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).
$\lambda^{\text{in}}_{i,n,t,w}$: 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).
$\lambda^{\text{h}}_{i,n,t,w}$: 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).
$\lambda^{\text{ub}}_{i,n,t,w}/\lambda^{\text{lb}}_{i,n,t,w}$: Shadow price of maximum/minimum 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).
$\overline{\mu}_{\ell,t}/\underline{\mu}_{\ell,t}$: Shadow price of positive/negative capacity of line $\ell \in \mathcal{L}$ at time $t \in \mathcal{T}$ (€/MWh).

2.2 Framework for analysis

We use a bottom-up equilibrium model comprising a Nash-Cournot game over a network (Hobbs 2001) among power-generating firms, an independent system operator (ISO), and aggregators (Fig. 1). Consumers are represented by linear inverse-demand functions at each node and in each period. The linearity assumption is based on Nord Pool's bidding rules, viz., continuous and piecewise-linear supply and demand curves.[3] It is also a fairly common assumption in the existing literature (Hobbs 2001; Metzler et al. 2003). Furthermore, allowing for non-linear demand functions complicates the solution procedure because KKT conditions will also have non-linear terms, thereby giving rise to a non-linear MCP overall. As Egging-Bratseth et al. (2020) point out, even oligopolistic problems that result in linear MCPs are more computationally efficient to solve as non-linear optimisation problems. Indeed, an MCP that results from an equilibrium problem with affine inverse-demand functions can be reformulated (under mild conditions, such as convex cost functions) as a single convex optimisation problem, which can be tackled directly via solvers such as CPLEX. While iso-elastic demand functions are also used in energy economics, they cannot be reformulated as non-linear optimisation problems and necessitate solving non-linear MCPs unless firms are symmetric, which is not the case in reality. Finally, Metzler et al. (2003) mention non-linear MCPs arising from non-linear demand functions and observe that such an "analysis is made more complicated without yielding significantly more insights."

Profit-maximising firms' hydro, thermal, and VRE units are subject to operational, storage, and water-regulatory constraints. An exogenous CO_2 price is imposed on generation emissions. Meanwhile, aggregators own VRE capacity with intermittent output and have gross-benefit functions that quantify the value of their own consumption. They decide endogenously to buy or sell electricity in order to maximise net revenue from market interactions plus gross benefit from consumption of electricity. In essence, aggregators marshal prosumers' VRE output and consumption preferences in order to determine their endogenous net sales to the grid at node n during period t, $\sum_{e \in \mathcal{E}} G^{e,\text{agg}}_{j,n,t} - q^{\text{agg}}_{j,n,t}$, which may be negative. Thus, the aggregators' endogenous net sales reflect structural changes to the demand side of the power sector due to the electrification of other sectors, such as heating and transport. In other words, we treat prosumers as additional net loads from the perspective of the power sector and not as defections by existing conventional consumers. A surplus-maximising ISO decides upon consumption and power flows to maintain nodal energy balance during each period. The Nash assumption means that each agent takes the decisions of all other agents as given when making its own decision.

Our Nash-Cournot approach is rich in spatio-temporal details, which enables it to capture the texture of the Nordic power sector. For example, not only capacities of plants and transmission lines but also volumes of and periodic inflows to hydro reservoirs are modelled. However, as is customary in Nash-Cournot policy analyses, we make an open-loop assumption, i.e., we treat all decisions over the representative weeks of a year as if they were made simultaneously. By contrast, a closed-loop model that allowed for periodic decisions adapted to (stochastic) hydro inflows would have been more realistic. Indeed, hydro scheduling in reality is more complex than we could possibly capture in a computational Nash-Cournot model. For example, stochastic dual dynamic programming (SDDP) can

[3] https://www.nordpoolgroup.com/en/trading/Day-ahead-trading/Order-types/Hourly-bid/.

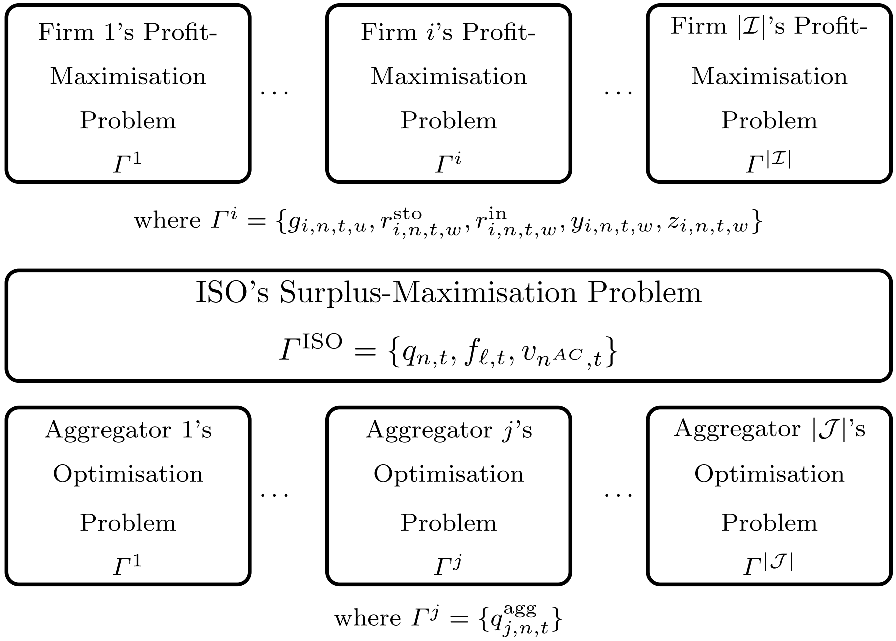

Fig. 1 Nash-Cournot framework for analysis

tackle realistic problem instances, e.g., of the Brazilian power system (de Matos et al. 2015). Yet, in such analyses, there is typically a single welfare maximiser without strategic behaviour. Departures from perfect competition are instead addressed by Scott and Read (1996)'s Cournot version of so-called "constructive dual dynamic programming" and Genc et al. (2020)'s infinite-horizon game, which reflects the market in Ontario with strategic hydro and thermal producers. In this context, Markov perfect equilibria are obtained via approximations of the expected value functions that appear in the hydro producer's Bellman equation. Based on analytical models (Crampes and Moreaux 2001; Debia et al. 2019), a closed-loop Cournot approach that considers uncertainty would smooth out temporal arbitrage. Still, (weakened) incentives for strategic behaviour as in an open-loop model would remain. Given this background, our open-loop Cournot model is suitable for our objective to analyse strategic reservoir operations in the Nordic power sector by incorporating the system's spatio-temporal texture, viz., heterogeneous firms, seasonal variations, and transmission constraints, in a computationally tractable manner. We recognise that this choice involves a tradeoff because we neglect uncertainty, dynamic decisions, and risk aversion, where the extent of risk aversion is somewhat subjective. In effect, the added features of stochastic or closed-loop models would likely come at the cost of computational tractability of the problem instances, viz., optimisation problems constrained by other optimisation problems would have to be solved without the theoretical underpinning to guarantee existence and uniqueness of equilibria (Murphy and Smeers 2005; Singh and Wiszniewska-Matyszkiel 2019). Thus, we take the open-loop Nash-Cournot route and lay out each agent's optimisation problem in Sect. 2.3 followed by the KKT conditions that constitute the corresponding MCP in Sect. 2.4 and an equivalent quadratic programming (QP) reformulation of the MCP in Sect. 2.5.

2.3 Agents' optimisation problems

2.3.1 Firm *i*'s problem

Each firm $i \in \mathcal{I}$ aims to maximise its own profit by operating its portfolio of generation units, viz., hydro, thermal, and VRE (wind or solar), which are denoted by $w \in \mathcal{W}_{i,n}$, $u \in \mathcal{U}_{i,n}$, and $e \in \mathcal{E}$, respectively. The two main parts of its objective function (1) are revenue from selling energy and costs of operation. In the first part of the function is the revenue from net energy sales, $\sum_{u \in \mathcal{U}_{i,n}} g_{i,n,t,u} + \sum_{e \in \mathcal{E}} G^e_{i,n,t} + \sum_{w \in \mathcal{W}_{i,n}} Q_{i,n,w} y_{i,n,t,w} - \sum_{w \in \mathcal{W}_{i,n}} F_{i,n,w} r^{\mathrm{in}}_{i,n,t,w}$, at the nodal electricity price, $D^{\mathrm{int}}_{n,t} - D^{\mathrm{slp}}_{n,t} q_{n,t}$, where $q_{n,t}$ is the nodal consumption. The second part is the operating cost of thermal units, $C_{i,n,t,u}$, and the price of CO_2 emission permits, S, which is based on the EU ETS permit price and is taken as exogenous because firms in the Nordic region are assumed to be too small to influence it. VRE output is considered to be cost free and is represented by its exogenous output, $G^e_{i,n,t}$. By having no operating cost, VRE is in the priority to be dispatched in the energy market.

Based on the Nash assumption, each firm takes as given the decisions of all other firms, all aggregators, and the ISO. In addition to the generation units, firms can take advantage of hydro units for energy storage in reservoirs, which might be used to exert market power. In case of a Cournot oligopoly, total quantity demanded, $q_{n,t}$, in the firm's objective function (1) cannot be assumed exogenous since it is affected by the firm's decisions. Therefore, the net production of the firms, which is related to the total demanded quantity of the system via the energy-balance constraint (11), should be considered in the KKT conditions. Consequently, KKT conditions (15), (18), and (19) for thermal and hydro operations are written based on the exercise of market power in both thermal generation and hydro storage and ignore the impact of the higher price on revenues from VRE output, which is treated as exogenous.[4] It is also possible to account for market power only in thermal generation and not in hydro storage.[5] Likewise, the

[4] Price-taking behaviour in both thermal generation and hydro storage is handled by treating the price in (1) as exogenous, which means that KKT conditions (15), (18), and (19) would omit $D^{\mathrm{slp}}_{n,t}\left(\sum_{u' \in \mathcal{U}_{i,n}} g_{i,n,t,u'} + \sum_{w' \in \mathcal{W}_{i,n}} Q_{i,n,w'} y_{i,n,t,w'} - \sum_{w' \in \mathcal{W}_{i,n}} F_{i,n,w'} r^{\mathrm{in}}_{i,n,t,w'} \right)$.

[5] For example, to indicate market power in thermal generation but not in hydro storage, only the impact of thermal generation on the price is included in (1) by treating $q_{n,t}$ as a constant when multiplying it by $\sum_{e' \in \mathcal{E}_{i,n}} G^{e'}_{i,n,t} + \sum_{w' \in \mathcal{W}_{i,n}} Q_{i,n,w'} y_{i,n,t,w'} - \sum_{w' \in \mathcal{W}_{i,n}} F_{i,n,w'} r^{\mathrm{in}}_{i,n,t,w'}$. Thus, the KKT condition for $g_{i,n,t,u}$, (15), would omit $\sum_{w' \in \mathcal{W}_{i,n}} Q_{i,n,w'} y_{i,n,t,w'} - \sum_{w' \in \mathcal{W}_{i,n}} F_{i,n,w'} r^{\mathrm{in}}_{i,n,t,w'}$ and the KKT conditions for $r^{\mathrm{in}}_{i,n,t,w}$ and $y_{i,n,t,w}$, (18) and (19), respectively, would omit $D^{\mathrm{slp}}_{n,t}\left(\sum_{u' \in \mathcal{U}_{i,n}} g_{i,n,t,u'} + \sum_{w' \in \mathcal{W}_{i,n}} Q_{i,n,w'} y_{i,n,t,w'} - \sum_{w' \in \mathcal{W}_{i,n}} F_{i,n,w'} r^{\mathrm{in}}_{i,n,t,w'} \right)$ when allowing for Cournot behaviour in thermal generation but price-taking behaviour in hydro storage.

equivalent QP reformulation in (39) can allow for either perfect competition by dropping the "extended cost" term altogether or perfect competition in hydro storage alone by dropping the relevant $\sum_{w\in\mathcal{W}_{i,n}} Q_{i,n,w}y_{i,n,t,w} - \sum_{w\in\mathcal{W}_{i,n}} F_{i,n,w}r^{\text{in}}_{i,n,t,w}$ terms from the extended cost.[6]

Given this background, the problem faced by firm i is:

$$\text{Maximise}_{\Gamma^{\text{i}}} \sum_{n\in\mathcal{N}}\sum_{t\in\mathcal{T}}\Bigg[\left(D^{\text{int}}_{n,t} - D^{\text{slp}}_{n,t}q_{n,t}\right)\Bigg(\sum_{u\in\mathcal{U}_{i,n}} g_{i,n,t,u} + \sum_{e\in\mathcal{E}} G^{e}_{i,n,t} + \sum_{w\in\mathcal{W}_{i,n}} Q_{i,n,w}y_{i,n,t,w} - \sum_{w\in\mathcal{W}_{i,n}} F_{i,n,w}r^{\text{in}}_{i,n,t,w}\Bigg) - \sum_{u\in\mathcal{U}_{i,n}}\left(C_{i,n,t,u} + SP_{i,n,u}\right)g_{i,n,t,u}\Bigg] \tag{1}$$

$$\text{s.t. } g_{i,n,t,u} \le T_t\overline{G}_{i,n,u} \;:\; \beta_{i,n,t,u}, \forall n, t, u \in \mathcal{U}_{i,n} \tag{2}$$

$$\beta^{\text{down}}_{i,n,t,u} \;:\; -T_tR^{\text{down}}_{u}\overline{G}_{i,n,u} \le g_{i,n,t,u} - g_{i,n,t-1,u} \le T_tR^{\text{up}}_{u}\overline{G}_{i,n,u} \;:\; \beta^{\text{up}}_{i,n,t,u}, \forall n, t, u \in \mathcal{U}_{i,n} \tag{3}$$

$$r^{\text{sto}}_{i,n,t,w} = (1 - E^{\text{sto}}_{i,n,w})^{T_t} r^{\text{sto}}_{i,n,t-1,w} + r^{\text{in}}_{i,n,t,w} - y_{i,n,t,w} - z_{i,n,t,w} + I_{i,n,t,w} \;:\; \lambda^{\text{bal}}_{i,n,t,w}, \forall n, t, w \in \mathcal{W}_{i,n} \tag{4}$$

$$\lambda^{\text{lb}}_{i,n,t,w} \;:\; \underline{R}_{i,n,w} \le r^{\text{sto}}_{i,n,t,w} \le \overline{R}_{i,n,w} \;:\; \lambda^{\text{ub}}_{i,n,t,w}, \forall n, t, w \in \mathcal{W}_{i,n} \tag{5}$$

$$r^{\text{in}}_{i,n,t,w} \le T_tR^{\text{in}}_{i,n,w}\overline{R}_{i,n,w} \;:\; \lambda^{\text{in}}_{i,n,t,w}, \forall n, t, w \in \mathcal{W}_{i,n} \tag{6}$$

$$Q_{i,n,w}y_{i,n,t,w} \le T_tY_{i,n,w} \;:\; \lambda^{\text{h}}_{i,n,t,w}, \forall n, t, w \in \mathcal{W}_{i,n} \tag{7}$$

$$\sum_{t\in\mathcal{T}}\sum_{w\in\mathcal{W}_{i,n}}\left(Q_{i,n,w}y_{i,n,t,w} - F_{i,n,w}r^{\text{in}}_{i,n,t,w}\right) \ge Z_{i,n} \;:\; \gamma_{i,n}, \forall n \in \mathcal{N} \tag{8}$$

where $\Gamma^{\text{i}} = \{g_{i,n,t,u} \ge 0, r^{\text{sto}}_{i,n,t,w} \ge 0, r^{\text{in}}_{i,n,t,w} \ge 0, y_{i,n,t,w} \ge 0, z_{i,n,t,w} \ge 0\}$. Dual variables associated with each constraint are given next to the colons. As mentioned earlier, the profit in (1) includes the revenue from net sales minus the cost of generation and CO_2 emissions. Eq. (2) captures the production limits of thermal units, $\overline{G}_{i,n,u}$, while (3) indicates the ramp limits of thermal units, $R^{\text{up}}_{u}\overline{G}_{i,n,u}$ and $R^{\text{down}}_{u}\overline{G}_{i,n,u}$. Constraints (4)–(6) represent the operation of hydro units through storage balance, reservoir-capacity limits, and charging bounds for pumped-hydro units. Specifically, (4) handles reservoir levels for hydro plants, viz., the terminal reservoir level is the initial reservoir level plus natural inflows to the reservoir and any water charged into the reservoir minus any water removed from the reservoir for electricity generation and

[6] Perfect competition in thermal generation alone is handled by dropping the $\sum_{u\in\mathcal{U}_{i,n}} g_{i,n,t,u}$ term from the extended cost.

spillage. Since run-of-river units do not have any storage capability, they operate only through time-varying natural inflows, $I_{i,n,t,w}$. In addition to the maximum and minimum storage capacity, $\overline{R}_{i,n,w}$ and $\underline{R}_{i,n,w}$, respectively,[7] in (5), the storage self-discharge rate, $E^{\text{sto}}_{i,n,w}$,[8] and charging rate, $R^{\text{in}}_{i,n,w}$, in (4) and (6), respectively, are also considered to ensure that the operational limits of storage systems are met. Only pumped-hydro units are capable of endogenously charging the storage system, i.e., the variable $r^{\text{in}}_{i,n,t,w}$ is equal to zero for the rest of the hydro units. Moreover, generation limits of hydro units are enforced in (7), i.e., their electricity generated cannot exceed the installed hydro capacity. Finally, (8) is used in Cournot settings to prohibit "spilling" from hydro reservoirs at nodes where the firm behaves strategically, i.e., the total annual net generation from strategic reservoirs must be at least as much as the annual perfectly competitive production, $Z_{i,n}$.

2.3.2 Aggregator *j*'s problem

Prosumers are agents with possibly both generation and consumption as opposed to conventional consumers or producers. Interaction of the prosumers with the market can be facilitated through an aggregator that accumulates DER and offers it to the wholesale market. As a result, aggregators can operate in the market through bidirectional interactions while also offering demand-side flexibility. For example, an aggregator's loads might stem from either a fleet of PEVs or building stock.

Aggregator $j \in \mathcal{J}$'s problem is to maximise its profit from market interactions and the gross benefit from its own consumption. It is capable of exogenous production, $G^{e,\text{agg}}_{j,n,t}$, through small-scale VRE $e \in \mathcal{E}$. The two main parts of its objective function (9) are the revenue/expenses from net sales, $\sum_{e\in\mathcal{E}} G^{e,\text{agg}}_{j,n,t} - q^{\text{agg}}_{j,n,t}$, at the nodal electricity price, $D^{\text{int}}_{n,t} - D^{\text{slp}}_{n,t} q_{n,t}$, and gross benefit from electricity consumption, $D^{\text{int,agg}}_{j,n,t} q^{\text{agg}}_{j,n,t} - \frac{1}{2} D^{\text{slp,agg}}_{j,n,t} \left(q^{\text{agg}}_{j,n,t}\right)^2$, e.g., due to its own price-responsive demand. Each aggregator takes as given the decisions of all other aggregators, all firms, and the ISO when solving its problem as follows:

$$\begin{aligned}\text{Maximise}_{\Gamma^{\text{j}}} \sum_{n\in\mathcal{N}} \sum_{t\in\mathcal{T}} \Bigg[& \left(D^{\text{int}}_{n,t} - D^{\text{slp}}_{n,t} q_{n,t}\right)\left(\sum_{e\in\mathcal{E}} G^{e,\text{agg}}_{j,n,t} - q^{\text{agg}}_{j,n,t}\right) \\ & + D^{\text{int,agg}}_{j,n,t} q^{\text{agg}}_{j,n,t} - \frac{1}{2} D^{\text{slp,agg}}_{j,n,t}\left(q^{\text{agg}}_{j,n,t}\right)^2 \Bigg]\end{aligned} \tag{9}$$

where $\Gamma^{\text{j}} = \{q^{\text{agg}}_{j,n,t} \geq 0\}$.

[7] Boundary conditions on reservoir levels are based on the initial and terminal reservoir levels for 2018 that correspond to historical Nord Pool data.

[8] Without loss of generality, it is set to zero.

2.3.3 ISO's problem

The ISO maximises gross consumer surplus to ensure socially optimal system operations (10) while clearing the energy market.[9] As per the Nash assumption, it takes the decisions of firms and aggregators as given when selecting power flows, $f_{\ell,t}$, voltage angles, $v_{n^{AC},t}$, and nodal consumption, $q_{n,t}$ in the following problem formulation:

$$\text{Maximise}_{\Gamma^{\text{ISO}}} \sum_{n\in\mathcal{N}} \sum_{t\in\mathcal{T}} \left(D^{\text{int}}_{n,t} q_{n,t} - \frac{1}{2} D^{\text{slp}}_{n,t} q^2_{n,t} \right) \tag{10}$$

$$\begin{aligned} \text{s.t. } q_{n,t} = & \sum_{i\in\mathcal{I}} \sum_{u\in\mathcal{U}_{i,n}} g_{i,n,t,u} + \sum_{i\in\mathcal{I}} \sum_{e\in\mathcal{E}} G^{e}_{i,n,t} + \sum_{i\in\mathcal{I}} \sum_{w\in\mathcal{W}_{i,n}} \left(Q_{i,n,w} y_{i,n,t,w} - F_{i,n,w} r^{\text{in}}_{i,n,t,w} \right) \\ & + \sum_{j\in\mathcal{J}} \sum_{e\in\mathcal{E}} G^{e,\text{agg}}_{j,n,t} - \sum_{j\in\mathcal{J}} q^{\text{agg}}_{j,n,t} - \sum_{\ell\in\mathcal{L}^{+}_{n}} V\,T_t f_{\ell,t} + \sum_{\ell\in\mathcal{L}^{-}_{n}} V\,T_t f_{\ell,t} \;:\; \theta_{n,t}, \forall n, t \end{aligned} \tag{11}$$

$$T_t f_{\ell^{\text{AC}},t} = T_t B_{\ell^{\text{AC}}} \left(v_{n^{+}_{\ell},t} - v_{n^{-}_{\ell},t} \right) \;:\; \eta_{\ell^{\text{AC}},t}, \forall \ell^{\text{AC}} \in \mathcal{L}^{\text{AC}}, t \tag{12}$$

$$\underline{\mu}_{\ell,t} \;:\; -T_t \underline{K}_{\ell} \leq V T_t f_{\ell,t} \leq T_t \overline{K}_{\ell} \;:\; \overline{\mu}_{\ell,t}, \forall \ell, t \tag{13}$$

$$\underline{\kappa}_{n^{\text{AC}},t} \;:\; -\pi \leq v_{n^{\text{AC}},t} \leq \pi \;:\; \overline{\kappa}_{n^{\text{AC}},t}, \forall n^{\text{AC}} \in \mathcal{N}^{\text{AC}}, t \tag{14}$$

where $\Gamma^{\text{ISO}} = \{q_{n,t} \geq 0, f_{\ell,t} \text{ u.r.s.}, v_{n^{AC},t} \text{ u.r.s.}\}$ and "u.r.s." refers to "unrestricted in sign." The energy-balance condition (11) ensures that net generation plus net imports equals consumption in the power system at each node and during each period. AC lines in the network are treated with the DC load-flow approximation (12) and limits on voltage angles at corresponding nodes (14). Thermal limits of both AC and DC lines are considered in (13) to ensure that power flows are within rated capacities.

2.4 KKT conditions for optimisation problems

Since each optimisation problem is convex, the equilibrium problem comprising (1)–(8), $\forall i \in \mathcal{I}$, (9), $\forall j \in \mathcal{J}$, and (10)–(14) may be replaced by its KKT conditions. The resulting set of KKT conditions will comprise an MCP, which we reformulate as a single-agent QP (Hashimoto 1985) in Sect. 2.5.

[9] As alluded to by Tanaka (2009), the ISO actually conducts a welfare-maximising redispatch. However, since it treats the decisions of all other agents as given in accordance with the Nash assumption, it is sufficient to state that the ISO maximises gross consumer surplus instead of social welfare. In reality, since the ISO's decisions occur after those of the generators, a fully accurate modelling of the sequence of market clearing would render an equilibrium problem with equilibrium constraints (EPEC) instead of an MCP. The challenge of solving an EPEC by iteratively solving mathematical programs with equilibrium constraints (MPECs) as Yao et al. (2008) do is likely to be exacerbated by features such as hydro reservoirs and the need to represent sufficient time periods to capture the availability of VRE output over the year.

2.4.1 KKT conditions for firm $i \in \mathcal{I}$

Firm i's KKT conditions follow from its optimisation problem (1)–(8):

$$\begin{aligned} 0 \leq g_{i,n,t,u} \perp\; & C_{i,n,t,u} + SP_{i,n,u} - \left(D^{\text{int}}_{n,t} - D^{\text{slp}}_{n,t} q_{n,t}\right) \\ & + D^{\text{slp}}_{n,t}\left(\sum_{u' \in \mathcal{U}_{i,n}} g_{i,n,t,u'} + \sum_{w \in \mathcal{W}_{i,n}} \left(Q_{i,n,w} y_{i,n,t,w} - F_{i,n,w} r^{\text{in}}_{i,n,t,w}\right)\right) \\ & + \beta_{i,n,t,u} + \beta^{\text{up}}_{i,n,t,u} - \beta^{\text{up}}_{i,n,t+1,u} + \beta^{\text{down}}_{i,n,t+1,u} - \beta^{\text{down}}_{i,n,t,u} \geq 0,\ \forall n, t, u \in \mathcal{U}_{i,n} \end{aligned} \tag{15}$$

$$0 \leq r^{\text{sto}}_{i,n,t,w} \perp \lambda^{\text{bal}}_{i,n,t,w} - (1 - E^{\text{sto}}_{i,n,w})^{T_t} \lambda^{\text{bal}}_{i,n,t+1,w} + \lambda^{\text{ub}}_{i,n,t,w} - \lambda^{\text{lb}}_{i,n,t,w} \geq 0, \forall n, t, w \in \mathcal{W}_{i,n} \tag{16}$$

$$0 \leq z_{i,n,t,w} \perp \lambda^{\text{bal}}_{i,n,t,w} \geq 0, \forall n, t, w \in \mathcal{W}_{i,n} \tag{17}$$

$$\begin{aligned} 0 \leq r^{\text{in}}_{i,n,t,w} \perp\; & F_{i,n,w}\left(D^{\text{int}}_{n,t} - D^{\text{slp}}_{n,t} q_{n,t}\right) \\ & - F_{i,n,w} D^{\text{slp}}_{n,t}\left(\sum_{u \in \mathcal{U}_{i,n}} g_{i,n,t,u} + \sum_{w' \in \mathcal{W}_{i,n}} \left(Q_{i,n,w'} y_{i,n,t,w'} - F_{i,n,w'} r^{\text{in}}_{i,n,t,w'}\right)\right) \\ & - \lambda^{\text{bal}}_{i,n,t,w} + \lambda^{\text{in}}_{i,n,t,w} + F_{i,n,w}\gamma_{i,n} \geq 0, \forall n, t, w \in \mathcal{W}_{i,n} \end{aligned} \tag{18}$$

$$\begin{aligned} 0 \leq y_{i,n,t,w} \perp\; & -Q_{i,n,w}\left(D^{\text{int}}_{n,t} - D^{\text{slp}}_{n,t} q_{n,t}\right) \\ & + Q_{i,n,w} D^{\text{slp}}_{n,t}\left(\sum_{u \in \mathcal{U}_{i,n}} g_{i,n,t,u} + \sum_{w' \in \mathcal{W}_{i,n}} \left(Q_{i,n,w'} y_{i,n,t,w'} - F_{i,n,w'} r^{\text{in}}_{i,n,t,w'}\right)\right) \\ & + \lambda^{\text{bal}}_{i,n,t,w} + Q_{i,n,w}\lambda^{\text{h}}_{i,n,t,w} - Q_{i,n,w}\gamma_{i,n} \geq 0, \forall n, t, w \in \mathcal{W}_{i,n} \end{aligned} \tag{19}$$

$$\lambda^{\text{bal}}_{i,n,t,w} \text{ u.r.s., } r^{\text{sto}}_{i,n,t,w} - (1 - E^{\text{sto}}_{i,n,w})^{T_t} r^{\text{sto}}_{i,n,t-1,w} - r^{\text{in}}_{i,n,t,w} + y_{i,n,t,w} + z_{i,n,t,w} - I_{i,n,t,w} = 0, \forall n, t, w \in \mathcal{W}_{i,n} \tag{20}$$

$$0 \leq \beta_{i,n,t,u} \perp T_t \overline{G}_{i,n,u} - g_{i,n,t,u} \geq 0, \forall n, t, u \in \mathcal{U}_{i,n} \tag{21}$$

$$0 \leq \beta^{\text{up}}_{i,n,t,u} \perp T_t R^{\text{up}}_{u} \overline{G}_{i,n,u} + g_{i,n,t-1,u} - g_{i,n,t,u} \geq 0, \forall n, t, u \in \mathcal{U} \tag{22}$$

$$0 \leq \beta^{\text{down}}_{i,n,t,u} \perp T_t R^{\text{down}}_{u} \overline{G}_{i,n,u} + g_{i,n,t,u} - g_{i,n,t-1,u} \geq 0, \forall n, t, u \in \mathcal{U} \tag{23}$$

$$0 \leq \lambda^{\text{in}}_{i,n,t,w} \perp T_t R^{\text{in}}_{i,n,w} \overline{R}_{i,n,w} - r^{\text{in}}_{i,n,t,w} \geq 0, \forall n, t, w \in \mathcal{W}_{i,n} \tag{24}$$

$$0 \leq \lambda^{\text{h}}_{i,n,t,w} \perp T_t Q_{i,n,w} - y_{i,n,t,w} \geq 0, \forall n, t, w \in \mathcal{W}_{i,n} \tag{25}$$

$$0 \leq \lambda^{\text{ub}}_{i,n,t,w} \perp \overline{R}_{i,n,w} - r^{\text{sto}}_{i,n,t,w} \geq 0, \forall n, t, w \in \mathcal{W}_{i,n} \tag{26}$$

$$0 \leq \lambda^{\text{lb}}_{i,n,t,w} \perp r^{\text{sto}}_{i,n,t,w} - \underline{R}_{i,n,w}\overline{R}_{i,n,w} \geq 0, \forall n, t, w \in \mathcal{W}_{i,n} \tag{27}$$

$$0 \leq \gamma_{i,n} \perp \sum_{t \in \mathcal{T}} \sum_{w \in \mathcal{W}_{i,n}} \left(Q_{i,n,w} y_{i,n,t,w} - F_{i,n,w} r^{\text{in}}_{i,n,t,w} \right) - Z_{i,n} \geq 0, \forall n \in \mathcal{N} \tag{28}$$

2.4.2 KKT conditions for aggregator $j \in \mathcal{J}$

Aggregator j's KKT conditions follow from its optimisation problem (9):

$$0 \leq q^{\text{agg}}_{j,n,t} \perp \left(D^{\text{int}}_{n,t} - D^{\text{slp}}_{n,t} q_{n,t} \right) - D^{\text{int,agg}}_{j,n,t} + D^{\text{slp,agg}}_{j,n,t} q^{\text{agg}}_{j,n,t} \geq 0, \forall n, t \tag{29}$$

2.4.3 KKT conditions for ISO

The ISO's KKT conditions follow from its optimisation problem (10)–(14):

$$0 \leq q_{n,t} \perp -\left(D^{\text{int}}_{n,t} - D^{\text{slp}}_{n,t} q_{n,t} \right) + \theta_{n,t} \geq 0, \forall n \in \mathcal{N}, t \in \mathcal{T} \tag{30}$$

$$f_{\ell,t} \text{ u.r.s.}, T_t \eta_{\ell^{\text{AC}},t} + V\, T_t \overline{\mu}_{\ell,t} - V\, T_t \underline{\mu}_{\ell,t} + V\, T_t \theta_{n^+_\ell,t} - V\, T_t \theta_{n^-_\ell,t} = 0, \forall \ell \in \mathcal{L}, t \in \mathcal{T} \tag{31}$$

$$v_{n^{\text{AC}},t} \text{ u.r.s.}, \; -\sum_{\ell \in \mathcal{L}^+_n} T_t B_{\ell^{\text{AC}}} \eta_{\ell^{\text{AC}},t} + \sum_{\ell \in \mathcal{L}^-_n} T_t B_{\ell^{\text{AC}}} \eta_{\ell^{\text{AC}},t} + \overline{\kappa}_{n^{\text{AC}},t} - \underline{\kappa}_{n^{\text{AC}},t} = 0, \forall n^{\text{AC}} \in \mathcal{N}^{\text{AC}}, t \in \mathcal{T} \tag{32}$$

$$\begin{aligned} \theta_{n,t} \text{ u.r.s.}, q_{n,t} &- \sum_{i \in \mathcal{I}} \sum_{u \in \mathcal{U}_{i,n}} g_{i,n,t,u} - \sum_{i \in \mathcal{I}} \sum_{e \in \mathcal{E}} G^e_{i,n,t} - \sum_{i \in \mathcal{I}} \sum_{w \in \mathcal{W}_{i,n}} \left(Q_{i,n,w} y_{i,n,t,w} - F_{i,n,w} r^{\text{in}}_{i,n,t,w} \right) \\ &- \sum_{j \in \mathcal{J}} \sum_{e \in \mathcal{E}} G^{e,\text{agg}}_{j,n,t} + \sum_{j \in \mathcal{J}} q^{\text{agg}}_{j,n,t} + \sum_{\ell \in \mathcal{L}^+_n} V\, T_t f_{\ell,t} - \sum_{\ell \in \mathcal{L}^-_n} V\, T_t f_{\ell,t} = 0, \forall n \in \mathcal{N}, t \in \mathcal{T} \end{aligned} \tag{33}$$

$$\eta_{\ell^{\text{AC}},t} \text{ u.r.s.}, T_t B_{\ell^{\text{AC}}} \left(v_{n^+_\ell,t} - v_{n^+_\ell,t} \right) - T_t f_{\ell^{\text{AC}},t} = 0, \; \forall \ell^{\text{AC}} \in \mathcal{L}^{\text{AC}}, t \in \mathcal{T} \tag{34}$$

$$0 \leq \underline{\mu}_{\ell,t} \perp T_t \underline{K}_\ell + V T_t f_{\ell,t} \geq 0, \forall \ell \in \mathcal{L}, t \in \mathcal{T} \tag{35}$$

$$0 \leq \overline{\mu}_{\ell,t} \perp T_t \overline{K}_\ell - V T_t f_{\ell,t} \geq 0, \forall \ell \in \mathcal{L}, t \in \mathcal{T} \tag{36}$$

$$0 \leq \underline{\kappa}_{n^{\text{AC}},t} \perp \pi + v_{n^{\text{AC}},t} \geq 0, \forall n^{\text{AC}} \in \mathcal{N}^{\text{AC}}, t \in \mathcal{T} \tag{37}$$

$$0 \leq \overline{\kappa}_{n^{\mathrm{AC}},t} \perp \pi - \nu_{n^{\mathrm{AC}},t} \geq 0, \forall n^{\mathrm{AC}} \in \mathcal{N}^{\mathrm{AC}}, t \in \mathcal{T} \tag{38}$$

2.5 Equivalent single optimisation problem

The MCP from Sect. 2.4, viz., (15)–(28), $\forall i \in \mathcal{I}$, (29), $\forall j \in \mathcal{J}$, and (30)–(38), can now be recast as a single QP problem that maximises social welfare (in case of perfect competition) exclusive of government revenue from CO_2 permit sales.[10] The firms' market power is modelled by inclusion of the term $-\sum_{n\in\mathcal{N}}\sum_{t\in\mathcal{T}}\sum_{i\in\mathcal{I}}\frac{D^{\mathrm{slp}}_{n,t}}{2}\left(\sum_{u\in\mathcal{U}_{i,n}} g_{i,n,t,u} + \sum_{w\in\mathcal{W}_{i,n}} Q_{i,n,w}y_{i,n,t,w} - \sum_{w\in\mathcal{W}_{i,n}} F_{i,n,w}r^{\mathrm{in}}_{i,n,t,w}\right)^2$, i.e., the quadratic "extended cost" (Hashimoto 1985), in the objective function.

$$\begin{aligned}
\text{Maximise}_{\Gamma} \sum_{n\in\mathcal{N}}\sum_{t\in\mathcal{T}} \Bigg[& \left(D^{\mathrm{int}}_{n,t}q_{n,t} - \frac{1}{2}D^{\mathrm{slp}}_{n,t}q^2_{n,t}\right) + \sum_{j\in\mathcal{J}}\left(D^{\mathrm{int,agg}}_{j,n,t}q^{\mathrm{agg}}_{j,n,t} - \frac{1}{2}D^{\mathrm{slp,agg}}_{j,n,t}\left(q^{\mathrm{agg}}_{j,n,t}\right)^2\right) \\
& - \sum_{i\in\mathcal{I}}\frac{D^{\mathrm{slp}}_{n,t}}{2}\left(\sum_{u\in\mathcal{U}_{i,n}} g_{i,n,t,u} + \sum_{w\in\mathcal{W}_{i,n}} Q_{i,n,w}y_{i,n,t,w} - \sum_{w\in\mathcal{W}_{i,n}} F_{i,n,w}r^{\mathrm{in}}_{i,n,t,w}\right)^2 \\
& - \sum_{i\in\mathcal{I}}\sum_{u\in\mathcal{U}_{i,n}}\left(C_{i,n,t,u} + SP_{i,n,u}\right)g_{i,n,t,u}\Bigg] \\
\text{s.t. } & (2) - (8),\ \forall i \in \mathcal{I} \\
& (11) - (14)
\end{aligned} \tag{39}$$

where Γ comprises $\Gamma^{\mathrm{i}}, \forall i \in \mathcal{I}$, $\Gamma^{\mathrm{j}}, \forall j \in \mathcal{J}$, and Γ^{ISO}. The QP's constraints, (2)–(8), $\forall i \in \mathcal{I}$, and (11)–(14), are those from the agents' optimisation problems.

3 Numerical examples

3.1 Data description

We implement the Nash-Cournot model for a 12-node, 18-line Nordic network (Fig. 2) using publicly available data. The full dataset from 2018 includes VRE availabilities (see Fig. 3 for $SE1$), installed generation capacities, firms' capacity ownership,[11] demand parameters, estimated hydro inflows (see Fig. 4 for Vattenfall's strategic reservoir at $SE1$), net exchanges with neighbouring non-Nordic regions, and firms' estimated reservoir volumes. Conventional consumers' linear

[10] Since we exclude the cost of damage from CO_2 emissions, our subsequent calculations of social welfare are technically social surplus.

[11] The firms are indexed $i1 - i17$. In order, they indicate 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 also bundle Swedish, Finnish, Danish, and Norwegian price takers into one fringe firm per country in turn as $i18 - i21$.

inverse-demand functions, $D^{\text{int}}_{n,t} - D^{\text{slp}}_{n,t} q_{n,t}, \forall n, t$, are fitted to the observed reference quantity demanded and reference price for 2018, i.e., $(q^{\text{ref}}_{n,t}, p^{\text{ref}}_{n,t})$, using a point elasticity of −0.065.[12] The price elasticity in Nord Pool is greater (in absolute terms) than −0.10 only during off-peak hours (Neamtu 2016). Therefore, our elasticity parameter is well within the empirical estimates for the Nordic region. Moreover, it should be emphasised that the introduction of prosumers already bolsters the price elasticity of either the residual or the total demand facing producers. For example, if prosumers are net buyers (net sellers), then the total (residual) inverse-demand function presented to producers will be flatter, i.e., more price responsive. In effect, we investigate whether hydro producers would be able to exert more leverage even in the presence of elasticity-enhancing prosumers.

Four representative weeks, i.e., one for each season, are selected based on minimising the Euclidean distance of the seasonal-weekly values of averages and standard errors from each season's centroid for the observed consumption, prices, and wind availability using a clustering procedure. Therefore, each problem instance is based on four representative weeks of 168 h each that capture operations over an entire year using 672 h instead of 8,760 h.[13] The full dataset and relevant sources are provided in Hassanzadeh Moghimi et al. (2023). We summarise those data in Tables 4, 5, 6, 7 and 8 of Appendix A[14] and here elaborate upon our treatment of prosumers and computational issues in Sects. 3.1.1 and 3.1.2, respectively.

3.1.1 Prosumer data

Each aggregator's VRE capacity equals the VRE capacity that belongs to the power-generating firms at that node, which corresponds to a notional doubling of VRE capacity by the year 2030. Accordingly, each aggregator's gross-benefit function's parameters are tuned so that annual VRE output by each aggregrator equals its own annual reference consumption. This is to ensure that the additional VRE output by aggregators is self consumed on average to reflect electrification of heating and transport. For example, if quantity demanded by conventional consumers at a node is 100 TWh over the year and VRE output added by the aggregator is 10 TWh, then the aggregator's reference quantity demanded in each hour is $\frac{10}{100} = 0.10$ of the conventional consumers'. Thus, each aggregator j's linear inverse-demand function, $D^{\text{int,agg}}_{j,n,t} - D^{\text{slp,agg}}_{j,n,t} q^{\text{agg}}_{j,n,t}, \forall n, t$, has the same slope as that of conventional consumers at

[12] Assuming a price elasticity of −0.065, we first estimate $D^{\text{slp}}_{n,t}$ as $-\frac{p^{\text{ref}}_{n,t}}{-0.065 \times q^{\text{ref}}_{n,t}}$ using the definition of price elasticity. Second, via the point-slope equation of a line, we determine $D^{\text{int}}_{n,t}$ as $p^{\text{ref}}_{n,t} + D^{\text{slp}}_{n,t} \times q^{\text{ref}}_{n,t}$.

[13] It is worth mentioning that in order to track reservoir levels correctly between seasons, we employ linking constraints in our analyses to ensure that the terminal reservoir level of a given season equals the initial reservoir level of the subsequent season. The terminal reservoir level of a given season is, in turn, calculated as the season's initial reservoir level plus the cumulative net change in the reservoir level over the representative week multiplied by the number of weeks in the season, i.e., approximately 13.04. This is the so-called "linked representative periods" method of Tejada-Arango et al. (2019).

[14] In Table 8, "SRS," "NRS," "NPH," and "SPH" refer to "strategic reservoir," "non-strategic reservoir," "non-strategic pumped-hydro reservoir," and "strategic pumped-hydro reservoir," resepectively.

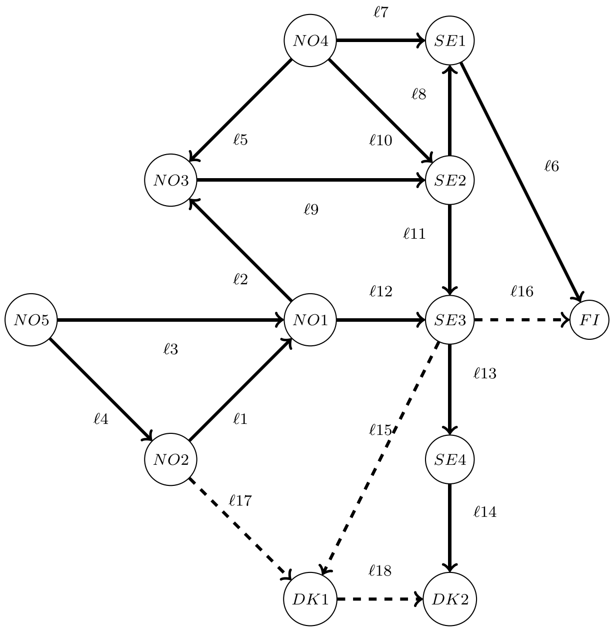

Fig. 2 Stylised nordic network

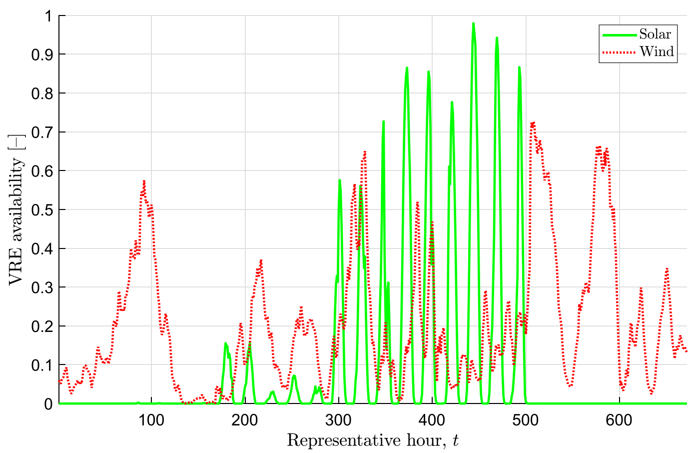

Fig. 3 VRE availability in representative weeks at $SE1$ (–)

node n during period t but passes through the point $\left(\frac{q^{\mathrm{ref}}_{n,t}}{10}, p^{\mathrm{ref}}_{n,t}\right)$ instead of $(q^{\mathrm{ref}}_{n,t}, p^{\mathrm{ref}}_{n,t})$. In effect, each aggregator conceptually adds both electricity consumption and production to the market, e.g., via electrification of heating or transport, and the absolute value of its price elasticity of demand at its reference point, $\left(\frac{q^{\mathrm{ref}}_{n,t}}{10}, p^{\mathrm{ref}}_{n,t}\right)$, is higher than

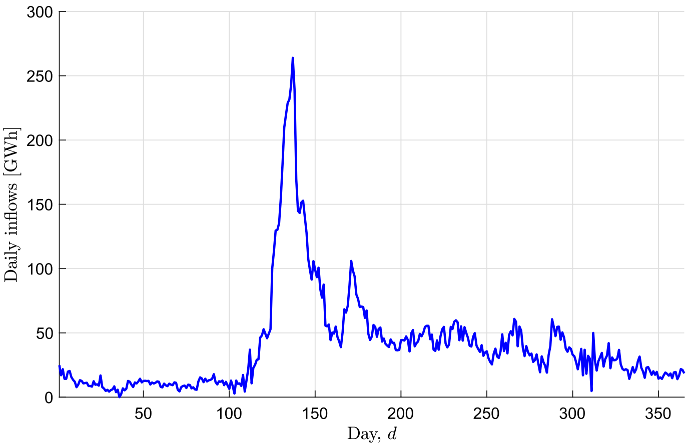

Fig. 4 Daily estimated hydro inflows to Vattenfall's strategic reservoir at *SE*1 (GWh)

that of conventional consumers at their reference point, $(q_{n,t}^{\mathrm{ref}}, p_{n,t}^{\mathrm{ref}})$. Indeed, if prosumers are associated with electrification of the heating and transport sectors, then their increased price responsiveness vis-à-vis conventional consumers in the power sector is justified by the thermal property of building envelopes to retain heat (Groissböck et al. 2014) and the temporal substitutability of transport (Litman 2022).

3.1.2 Computational implementation

In addition to a base 2018 scenario without prosumers and under a CO_2 price of €15/t that reflects the 2018 EU ETS average,[15] we also implement two future scenarios for 2030: 2030AV and 2030AVC. In particular, 2030AV allows for a single price-taking aggregator at each node (except for *NO*1 and *NO*5 due to negligible VRE capacity) with its own (i) demand function and (ii) VRE capacity.[16] This scenario enables us to address RQ 1. Meanwhile, the 2030AVC scenario is the same as the 2030AV scenario except for a €100/t CO_2 price,[17] which facilitates a further investigation of a stringent carbon policy on market outcomes, viz., RQ 2.

In order to assess market power, each scenario is implemented under three test cases as follows:

- Perfect competition (PC): all firms are price takers
- Cournot oligopoly in thermal generation (COG): only firms with large nuclear capacities, e.g., Vattenfall at node *SE*3 and Fortum at *FI*, behave à la Cournot in thermal generation

[15] https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:52019DC0557R(01)&from=EN.

[16] The installed hydro, thermal, and VRE capacities of the power-generating firms remain the same as in the base 2018 scenario.

[17] While this is supposed to reflect future carbon policy, it is already in line with Sweden's tax of €110/t on CO_2 emissions excluded from the EU ETS, cf. https://www.government.se/government-policy/swedens-carbon-tax/swedens-carbon-tax/.

– Cournot oligopoly in reservoirs (COR): only firms with strategic reservoirs that are not part of cascaded riversheds shared with other firms' reservoirs, e.g., Vattenfall at *SE*1 and Statkraft at *NO*4, behave à la Cournot in hydro generation without "spilling" water vis-à-vis PC

Each QP problem instance takes a few seconds to solve to optimality with GAMS 35.1.0 using CPLEX 20.1.0.1 deployed on an Intel Core i7-8650U CPU@1.90GHz quad-core processor and 16.0 GB of RAM.[18] Since the aforementioned test cases (PC, COG, and COR) are utilised to investigate strategic behaviour through thermal and hydro units via three scenarios (base 2018, 2030AV, and 2030AVC), we have a total of nine problem instances.

3.2 Results

3.2.1 Base 2018 scenario

We begin with the base 2018 scenario, which is identical to the corresponding one in Hassanzadeh Moghimi et al. (2023). While this scenario does not directly address either RQ 1 or RQ 2, it, nevertheless, establishes a benchmark for how market power may be exerted in the "existing" Nordic power system without either prosumers or a high CO_2 price. In terms of calibration, we provide the following metrics:

– The base results under the PC case for 2018 lead to total generation of 400 TWh, which compares favourably to actual generation of 398 TWh in 2018.[19]
– The modelled PC total net-hydro generation is 212 TWh, which is also in line with the actual generation of 213 TWh in 2018.
– The modelled PC average electricity price is €39.32/MWh, cf. the average price of €42.04/MWh in the representative weeks of 2018.[20]
– The modelled PC total CO_2 emissions are 31.5 Mt, which track well with the actual emissions of 35.1 Mt for both power and heat generation in 2017.[21]
– The modelled reservoir levels track the data well for *SE*1 (see Figure 9 in Hassanzadeh Moghimi et al. (2023)), viz., the actual relative reservoir levels usually lie in between our modelled PC and COR reservoir levels.

Hence, based on these metrics, we believe that our model provides a credible basis for examining at least the potential of the plausible open-loop exercise of market power in a future Nordic system.

[18] All COR instances require relaxing the $Z_{i,n}$ parameter in the water-regulation constraint (8) by 0.001% to obtain optimal solutions to the QP. According to GAMS, this is due to scaling issues related to the wide range of parameters. It does not affect our qualitative findings.

[19] https://www.nordicenergy.org/publications/tracking-nordic-clean-energy-progress-2020/.

[20] https://www.nordpoolgroup.com/en/Market-data1/Dayahead/Area-Prices/ALL1/Yearly/?view=table.

[21] https://www.nordicenergy.org/publications/tracking-nordic-clean-energy-progress-2020/.

Towards this end, the numerical results in Table 1 summarise the welfare loss from market power under either COG or COR.[22] In effect, there is a welfare transfer from consumers to firms under the COG and COR cases compared to the PC case. Under COG, the average Nordic price increases to €70.45/MWh from €39.32/MWh under PC. CO_2 emissions also increase noticeably as the withholding of nuclear capacity by Vattenfall at *SE*3 forces price-taking fossil-fuelled generators' capacity limits to become binding. Consequently, Vattenfall's firm surplus increases by 30.85%, i.e., from €2.01 billion to €2.63 billion (Table 1), due to its withholding of nuclear output under COG vis-à-vis PC.

The strategic use of reservoirs is illustrated by comparing PC and COR results. Figure 5 shows that Vattenfall at *SE*1 is able to move water from the peak winter and fall seasons to primarily the off-peak spring season in order to increase peak prices even though off-peak prices decrease (Crampes and Moreaux 2001; Bushnell 2003; Debia et al. 2021; Hassanzadeh Moghimi et al. 2023). Overall, average prices increase slightly to €39.97/MWh for the Nordic region as a whole, which is closer to the Nordic average of €42.04/MWh in the representative weeks of 2018. Yet, at *SE*1, the impact is more pronounced as the average price becomes €41.03/MWh as opposed to €38.92/MWh under PC. This is in spite of the regulation on strategic annual net-hydro generation to prevent "spilling" water relative to PC. Still, overall net-hydro operations plus net imports are impacted to the extent that *SE*1 becomes a net exporter in the spring under COR instead of a net importer under PC. This temporal shift enables Vattenfall to export the "excess" hydro production (Figs. 6, 7 and 8). Via this temporal arbitrage, Vattenfall increases prices in the winter and fall while decreasing them in the spring (Fig. 9). Hence, Vattenfall's overall firm surplus increases from €2.01 billion to €2.05 billion (Table 1), i.e., by 1.99%.

3.2.2 2030AV scenario

We consider this scenario to investigate RQ 1, i.e., the impact of future changes to the demand side stemming from aggregators (with VRE capacity and flexible consumption) on the exertion of market power and operation of hydro reservoirs in the Nordic grid. The summary of the numerical results is in Table 2. Since the annual consumption of aggregators is scaled such that it can "absorb" their annual VRE output, welfare components and emissions under PC are similar to those in the base 2018 scenario under PC (Table 1). Likewise, the average Nordic price under PC is still €39.32/MWh. Indeed, the only distinct change is the addition of the prosumer-surplus metric. However, as we will discuss in more detail, what is important in the 2030AV scenario is that the uneven production and consumption patterns of the aggregator can be exploited by market power under COR at *SE*1 to a greater extent. This is because VRE availability is highest during spring and fall (Fig. 3) and net sales (net purchases) by the

[22] We indicate social welfare as well as its components, viz., consumer surplus, firm surplus, prosumer surplus, merchandising surplus, and government revenue. In addition, the annual CO_2 emissions and Vattenfall's firm surplus are presented.

aggregator at *SE*1 under PC are highest during spring and fall (winter and summer) (Fig. 10) in spite of the fact that quantity demanded by conventional consumers peaks during winter and fall (Fig. 11).

In terms of strategic behaviour with thermal generation (COG), capacity withholding, viz., from nuclear plants, increases firm surplus (prosumer surplus) by 62.43% (1.92%), while social welfare and consumer surplus decrease by 1.16% and 7.67%, respectively (Table 2). By withholding from its large nuclear capacity at *SE*3, Vattenfall increases its firm surplus by 15.76% from PC as prices increase to an overall Nordic average of €65.02/MWh, which is less than the corresponding increase in the base 2018 scenario. Consequently, the benefit to Vattenfall under COG is relatively low in this 2030AV scenario vis-à-vis the base 2018 scenario, when its firm surplus was boosted by 30.85% in moving from PC to COG. Intuitively, the impact of market power under COG is limited because the aggregators typically switch to becoming net suppliers in all seasons (Fig. 10). Thus, an attempt by Vattenfall to withhold its nuclear capacity to induce more price-taking fossil-fuelled generation at full capacity is mitigated, as evidenced by the smaller increase in both average prices and CO_2 emissions from PC to COG in this 2030AV scenario vis-à-vis the base 2018 scenario.

By contrast, strategic behaviour with hydro reservoirs (COR) is facilitated in 2030AV relative to the base 2018 scenario (Fig. 12). While social welfare, consumer surplus, and prosumer surplus are marginally reduced from PC, firm surplus increases by 1.74% as a result of the hydro units' strategic behaviour (Table 2). As in the base 2018 scenario, prices are not drastically affected, i.e., the Nordic average price is €40.08/MWh (and the *SE*1 average price is €40.95/MWh as opposed to €39.05/MWh under PC), but Vattenfall enjoys a 2.46% increase in its firm surplus merely by shifting production from its reservoirs at *SE*1 (Fig. 13). This is done by exploiting the fact that the aggregator at *SE*1 is a net buyer in the summer but a net seller in the spring and the fall under PC (Fig. 10). Thus, in going from PC to COR, vis-à-vis the base 2018 scenario, Vattenfall withholds more (less) water in the summer (fall), thereby adapting its strategy to the VRE availability pattern, which shows relatively low (high) availability in the summer (fall). Likewise, when Vattenfall "dumps" the water in the spring, the opportunity cost related to the price-depressing effect of its increased production is cushioned because the aggregators reduce their net sales. Hence, in tackling RQ 1, we find that the advent of aggregators would bolster (mitigate) the ability of strategic hydro (thermal) producers to exert market power in a future 2030 Nordic power system.

3.2.3 2030AVC scenario

Here, we investigate the additional impact of a future carbon policy (involving a high CO_2 price of €100/t) on the exertion of market power in the presence of aggregators, i.e., RQ 2. As anticipated, the high CO_2 price reduces emissions by nearly 90% from the PC case in the 2030AV scenario. There is a slight decrease in social welfare and a wealth transfer from consumers to firms and prosumers (Table 3), primarily due to the increase in the average Nordic electricity price from €39.32/MWh to €55.51/MWh (Fig. 14). In a similar vein, the *SE*1 average price increases

Table 1 Numerical results for the base 2018 scenario (in billion € unless indicated) that indicate the welfare and emission impacts of the exercise of market power

Metric	Case		
	PC	COG	COR
Social welfare	142.29	140.69	142.21
Consumer surplus	129.46	117.47	128.94
Firm surplus	12.01	21.70	12.20
Prosumer surplus	–	–	–
Merchandising surplus	0.35	0.70	0.59
Government revenue	0.47	0.82	0.48
CO_2 emissions (Mt)	31.46	54.70	32.26
Vattenfall's firm surplus	2.01	2.63	2.05

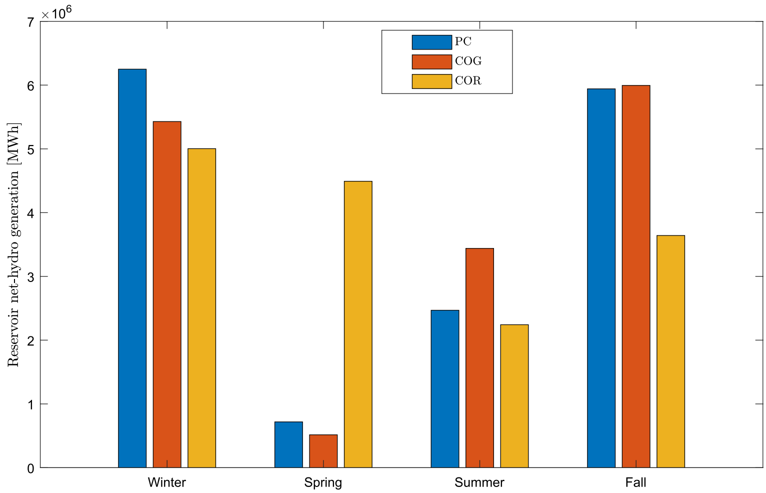

Fig. 5 Net hydro-reservoir generation by Vattenfall at *SE*1 (MWh) that indicates temporal arbitrage due to the exercise of market power under COR

to €53.99/MWh under PC in 2030AVC from €39.05/MWh under PC in 2030AV. As a result, the aggregator at *SE*1 becomes more of a net seller (Fig. 15), which is also generally true for all aggregators in the Nordic region.

Regarding strategic behaviour under COG, while the overall increase in firm surplus of 57.70% vis-à-vis PC is somewhat less than the corresponding value of 62.43% in the 2030AV scenario, the increase in Vattenfall's firm surplus from withholding nuclear output is bolstered to 19.42% (Table 3) as opposed to 15.76% in the 2030AV scenario. Intuitively, extremely high electricity prices under COG (averaging €93.46/MWh for the entire Nordic region) caused by carbon policy entice net sales by aggregators even more (Fig. 15). Furthermore, the inability of price-taking flexible assets, viz., gas-fired plants, to respond to higher prices vis-à-vis the 2030AV scenario gives Vattenfall more leverage in exerting market power via its nuclear plants, e.g., to withhold output in order to force otherwise idle fossil-fuelled plants to set the

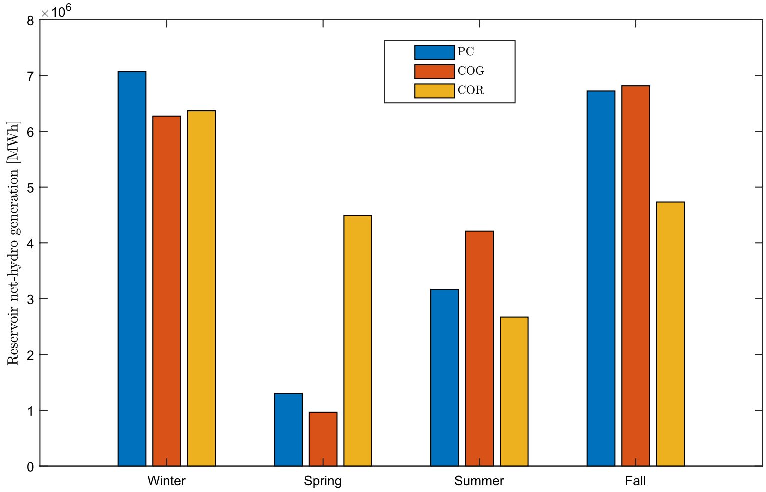

Fig. 6 Total net-hydro generation at *SE*1 (MWh) that indicates the impact of temporal arbitrage due to the exercise of market power under COR

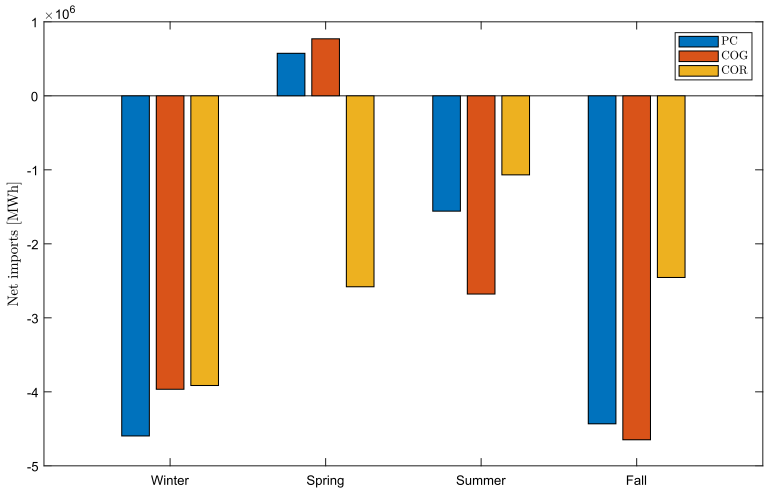

Fig. 7 Net imports at *SE*1 (MWh) that indicate reversal in net imports during spring due to the exercise of market power under COR

market-clearing price. This lack of response refers to the economic unviability of fossil-fuelled power plants due to the high CO_2 price. Indeed, when the CO_2 price is high, fossil-fuelled plants are less able to respond because their operating costs are exorbitant. Thus, it becomes easier for strategic plants to exert market power.

Under COR, the exertion of market power through hydro reservoirs is also more effective with a high CO_2 price. In particular, overall firm surplus increases by 2.53% from PC compared to 1.74% in the 2030AV scenario, while

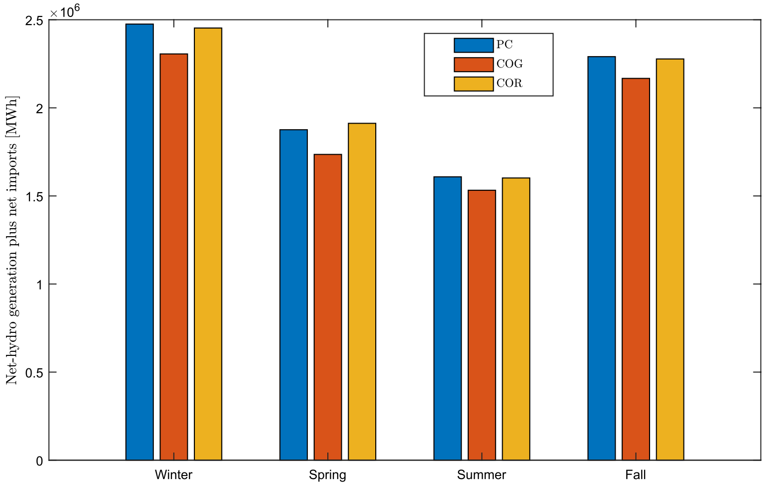

Fig. 8 Net-hydro generation plus net imports at $SE1$ (MWh) that indicates impact on consumption due to the exercise of market power under COG and COR

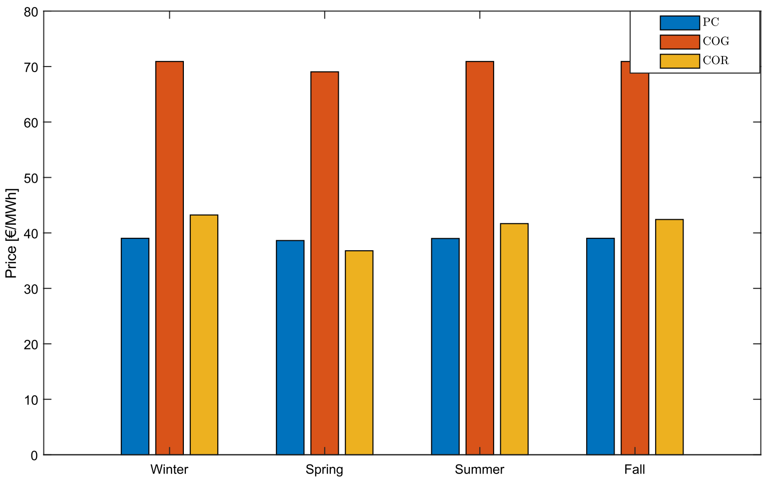

Fig. 9 Seasonal average prices at $SE1$ (€/MWh) that indicate manipulation due to the exercise of market power under COG and COR

Vattenfall's firm surplus increases by 2.91% (Table 3), cf. 2.46% in the 2030AV scenario. The average Nordic electricity price is €56.86/MWh, whereas that for $SE1$ is €58.31/MWh. In effect, although the aggregator is a consistent net seller under COR in the 2030AVC scenario, Vattenfall's net-hydro generation at $SE1$ is also more evenly distributed among the seasons under PC in the 2030AVC scenario (Fig. 16) than in the 2030AV scenario. This is due to limited generation from price-taking flexible units, such as gas-fired plants, elsewhere in the Nordic region, and it is precisely their unprofitability that gives Vattenfall more

Table 2 Numerical results for the 2030AV scenario (in billion € unless indicated) that indicate the welfare and emission impacts of the exercise of market power in the presence of VRE-enabled aggregators

Metric	Case		
	PC	CO G	COR
Social welfare	147.08	145.37	146.99
Consumer surplus	129.33	119.41	128.81
Firm surplus	12.03	19.54	12.23
Prosumer surplus	4.69	4.78	4.69
Merchandising surplus	0.56	0.85	0.77
Government revenue	0.47	0.78	0.48
CO_2 emissions (Mt)	31.59	51.84	31.96
Vattenfall's firm surplus	2.03	2.35	2.08

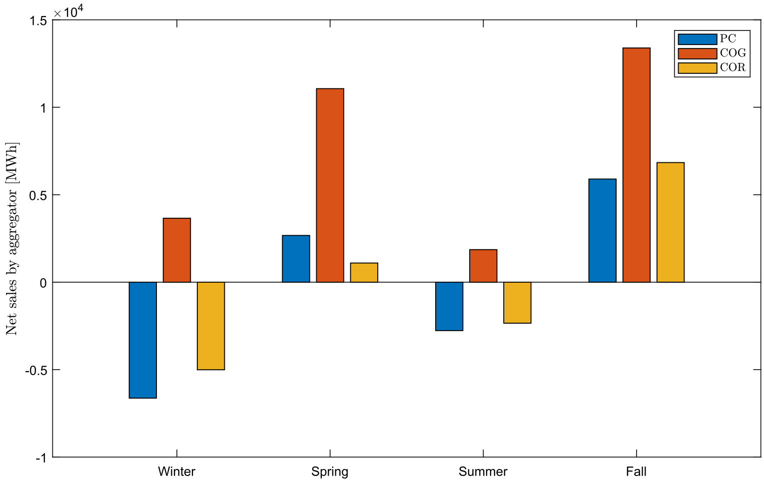

Fig. 10 Net sales by the aggregator at *SE*1 in 2030AV (MWh) that indicate how prosumers become net sellers under COG and change their patterns of net sales under COR

scope to exploit the intermittency of VRE generation in spite of the aggregator's countervailing flexibility in net sales. Hence, Vattenfall's leverage under COR as a provider of relatively scarce flexible and carbon-free generation is enhanced in the 2030AVC scenario relative to that in the 2030AV scenario, which enables us to address RQ 2 by concluding that carbon policy in the presence of aggregators would intensify the market power of both thermal and hydro producers.

4 Discussion and conclusions

Climate packages in OECD countries, such as those in the Nordic region, typically envisage both drastic reductions in power-sector CO_2 emissions and electrification of the wider economy where VRE owned by prosumers is expected to play a prominent role. Reservoirs in a hydro-dominant power system such as

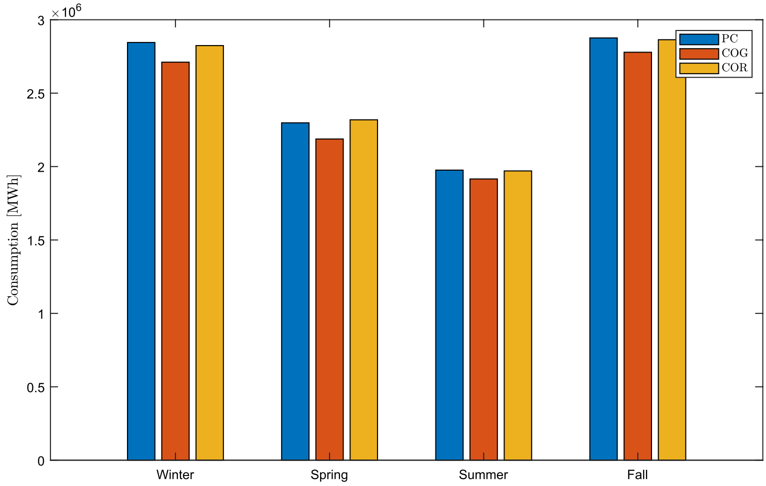

Fig. 11 Consumption at *SE*1 in 2030AV (MWh) that indicates the effect of market power under COG and COR in the presence of VRE-enabled aggregators

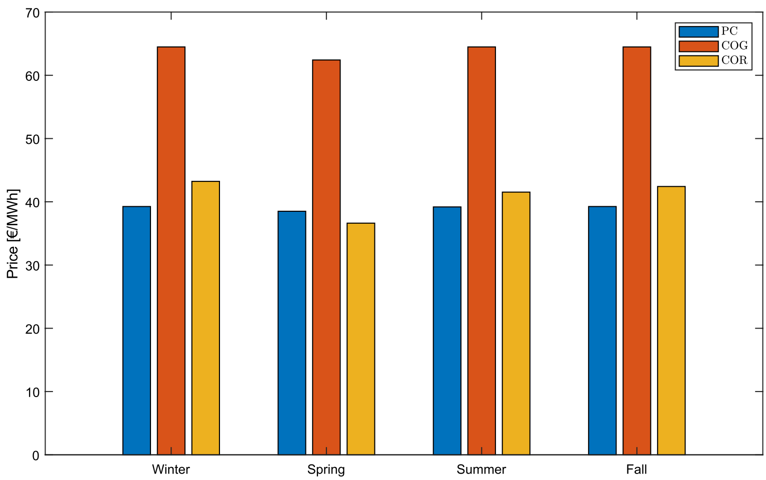

Fig. 12 Seasonal average prices at *SE*1 in 2030AV (€/MWh) that indicate manipulation due to the exercise of market power under COG and COR in the presence of VRE-enabled aggregators

the Nordic region's may also allow firms to reallocate their water strategically to boost their profits. Thus, an emerging concern is the strategic behaviour of incumbent producers with (hydro) storage in the presence of prosumers. Since generic storage is also a lynchpin for integrating VRE output even in regions that do not have hydro resources, our assessment of prosumers' impact on hydro producers' market power (RQ 1) and additionally carbon policy's interaction with strategic operations (RQ 2) addresses a timely issue that has yet not been tackled in the literature.

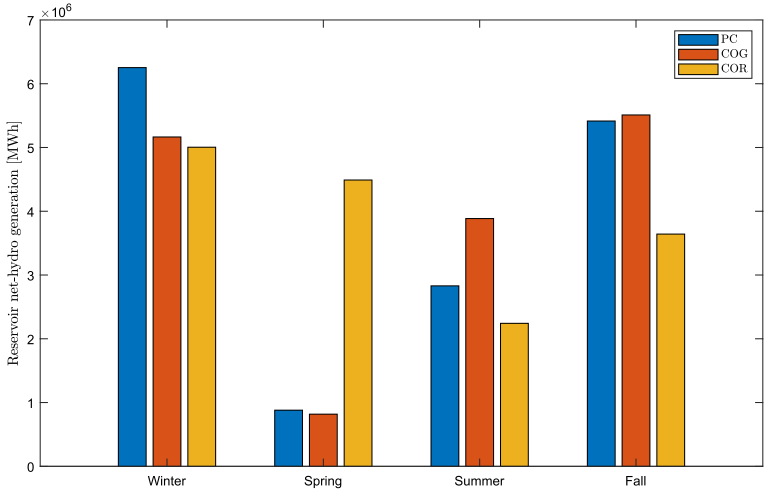

Fig. 13 Net hydro-reservoir generation by Vattenfall at *SE*1 in 2030AV (MWh) that indicates temporal arbitrage due to the exercise of market power under COR in the presence of VRE-enabled aggregators

Table 3 Numerical results for the 2030AVC scenario (in billion € unless indicated) that indicate the welfare and emission impacts of the exercise of market power in the presence of VRE-enabled aggregators and a high CO_2 price

Metric	Case		
	PC	COG	COR
Social welfare	146.21	144.38	146.11
Consumer surplus	121.16	108.10	120.38
Firm surplus	18.18	28.67	18.64
Prosumer surplus	4.77	5.24	4.78
Merchandising surplus	1.68	1.38	1.90
Government revenue	0.42	0.99	0.41
CO_2 emissions (Mt)	4.16	9.91	4.10
Vattenfall's firm surplus	3.09	3.69	3.18

We apply a spatially constrained Nash-Cournot framework to investigate how price-taking prosumers, represented through aggregators, could facilitate either capacity withholding by thermal plants or temporal arbitrage by strategic hydro reservoirs. Our analysis is based on Nordic data and captures salient spatio-temporal features of the power system. In addressing RQ 1 for thermal plants, we find that aggregators with VRE output may switch from being net buyers to net sellers in the face of capacity withholding by thermal plants and effectively attenuate price increases along with market power. Yet, firms with strategic thermal plants may have the incentive to manipulate prices more effectively and benefit more from withholding nuclear capacity under a high CO_2 price when prosumers exist, which is the focus of RQ 2. This is mainly because price-taking gas-fired plants find it economically less viable to ramp up output given the high incurred emission costs. By contrast, firms with strategic hydro reservoirs may benefit from temporal arbitrage

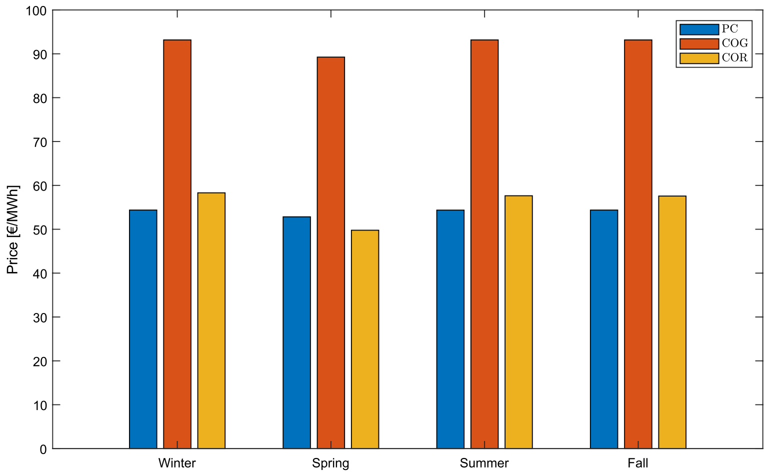

Fig. 14 Seasonal average prices at *SE*1 in 2030AVC (€/MWh) that indicate manipulation due to the exercise of market power under COG and COR in the presence of VRE-enabled aggregators and a high CO_2 price

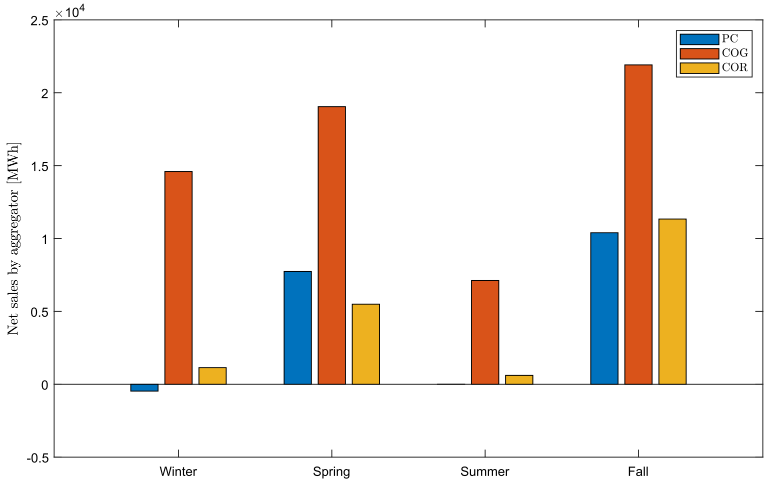

Fig. 15 Net sales by the aggregator at *SE*1 in 2030AVC (MWh) that indicate how prosumers generally become net sellers and change their patterns of net sales under COR in the presence of a high CO_2 price

in the presence of prosumers (RQ 1) by fine tuning their seasonal water allocation to target the additional intermittency from VRE output. Moreover, a high CO_2 price in addition to prosumers (RQ 2) could further bolster such hydro reservoirs' leverage by limiting the response from price-taking flexible (gas-fired) plants. Thus, the answer to RQ 1 varies depending on the type of power plant, whereas it points towards enhancing the market power of both types of plants in the context of RQ 2.

By anticipating future climate packages' impact on demand-side participation due to greater sector coupling and carbon pricing, our analysis contributes

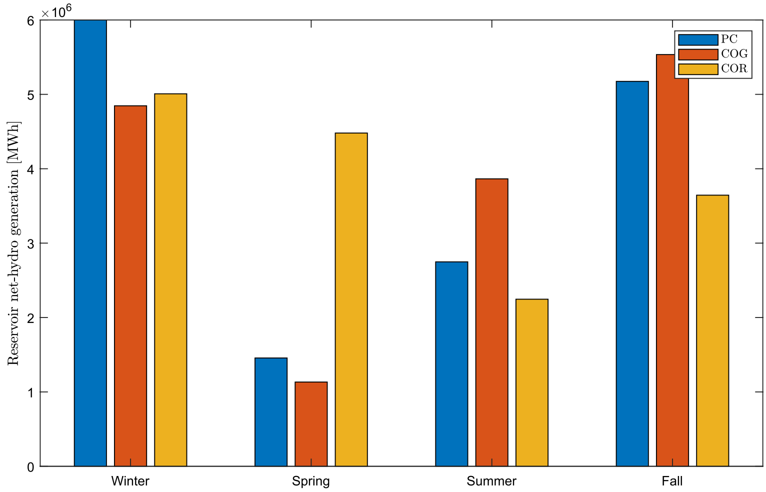

Fig. 16 Net hydro-reservoir generation by Vattenfall at $SE1$ in 2030AVC (MWh) that indicates temporal arbitrage due to the exercise of market power under COR in the presence of VRE-enabled aggregators and a high CO_2 price

to informing our understanding of prosumers' plausible interaction with a hydro-dominant power system. While our results are based on a credibly calibrated bottom-up equilibrium model and could have implications for power systems where storage is likely to figure prominently, it still necessitated simplifying assumptions (as discussed in Sect. 2.2) to obtain computationally tractable problem instances. Therefore, our analysis does not suggest that all strategic hydro producers will *definitively* have scope to exert more leverage in a future power system. For example, we did not consider that VRE-enabled aggregators could prompt standalone merchant providers to furnish storage services via grid-scale batteries, thereby curbing strategic producers' market power. Likewise, our open-loop approach neglects the dynamic nature of a closed-loop game. By contrast, analytical models of strategic storage operations (Crampes and Moreaux 2001; Debia et al. 2019) derive closed-loop equilibria to test the sensitivity of open-loop results. Although they find that incentives for temporal arbitrage in a closed-loop model still exist, by internalising the responses of competitors, a strategic storage operator in a closed-loop setting would be more prudent about shifting its production to the off-peak period. Nevertheless, our approach is consistent in that it compares the potential for open-loop strategic behaviour under 2018 and 2030 scenarios.

Future work in this area could build upon our analysis in several directions. First, investment in flexible assets by strategic entities in a future power system with VRE-enabled aggregators could be analysed via bi-level models (Virasjoki et al. 2020). Likewise, the incentives for strategic behaviour by prosumers themselves could be investigated (Ramyar and Chen 2020; Siddiqui and Siddiqui 2022). Second, from the policy perspective, bi-level models could be devised to propose countervailing transmission plans (Pozo et al. 2013), while cooperative game theory (Kristiansen et al. 2018) could design resource regulation to mitigate welfare distortions under future climate packages with sector coupling (Mitridati et al. 2021). Third, extending the analysis to a closed-loop model (Genc et al. 2020) could incorporate stochastic hydro inflows and VRE output to assess the extent to which temporal arbitrage would be attractive to strategic producers under uncertainty and dynamic decision making. Finally, the scope of the equilibrium framework could be expanded to model the electrified sectors, viz., heating (Virasjoki et al. 2018) and transport (Sioshansi 2012), explicitly in order to enrich the ensuing policy conclusions in the presence of prosumers.

A Supplementary data

See Tables 4, 5, 6, 7 and 8

Table 4 AC transmission lines' thermal capacities in positive direction (MW) and susceptances (S)

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

Table 5 DC transmission lines' thermal capacities in positive direction (MW)

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

Table 6 Thermal generation costs (€/MWh), emission rates (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 7 Firms' installed capacities by node and unit (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 8 Firms' hydro reservoir volumes by node and type (GWh)

Nodes	Firm	SRS	NRS	NPH	SPH
SE1 – SE4	$i1$	12210	4668		
	$i4$		5952		
	$i10$		2533		
	$i16$		4105		
	$i17$		1626		
	$i18$		2457		
FI	$i6$		1268		
	$i8$		4262		
NO1 – NO5	$i10$	17707	15508	2823	
	$i11$	99	5406		
	$i12$		4328	681	
	$i13$	276	4506	95	
	$i14$	2016	1331		130
	$i15$	4646	4746		421
	$i21$		26234	701	

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Declarations

Conflict of interest The authors declare that they have no conflict of interest.

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